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Frank D'Andrea
Vice President, Chief Regulatory Officer,
Chief Risk Officer

BY COURIER

March 29, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli,

EB-2017-0049 – Technical Conference Undertakings for Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application (the "Application")

Please find enclosed responses to undertakings from the Technical Conference held on March 1-5, 2018 in regards to the above noted proceeding. A response to JT1.18 is not yet available as the 2018 Team Scorecard has not yet been approved by Hydro One's Board of Directors. It will be provided when it becomes available.

This filing has been submitted electronically using the Board's Regulatory Electronic Submission System and two (2) hard copies will be sent via courier.

Hydro One's points of contact for service of documents associated with the Application remain as listed in Exhibit A, Tab 2 Schedule 1.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Encls.
cc. EB-2017-0049 parties (electronic)

UNDERTAKING – JT 1.8

Undertaking

To provide the MD&A and consolidated financial statements for Hydro One Limited and Hydro One Inc.

Response

Please see attached:

Attachment 1 – 2017 Hydro One Limited Financial Statements
Attachment 2 – 2017 Hydro One Limited MD&A
Attachment 3 – 2017 Hydro One Inc. Financial Statements
Attachment 4 – 2017 Hydro One Inc. MD&A

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Limited (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgment, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 12, 2018.

Management is responsible for establishing and maintaining adequate disclosure controls and procedures and internal control over financial reporting as described in the annual MD&A. Management evaluated the effectiveness of the design and operation of internal control over financial reporting based on the framework and criteria established in the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective at a reasonable level of assurance as of December 31, 2017. As required, the results of that evaluation were reported to the Audit Committee of the Hydro One Board of Directors and the external auditors.

The Consolidated Financial Statements have been audited by KPMG LLP, independent external auditors appointed by the shareholders of the Company. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with United States Generally Accepted Accounting Principles. The Independent Auditors' Report outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over reporting and disclosure. The Audit Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit Committee, with and without the presence of management, to discuss their audit findings.

On behalf of Hydro One's management:

Mayo Schmidt	Christopher Lopez
President and Chief Executive Officer	Senior Vice President, Finance acting in the capacity of chief financial officer

To the Shareholders of Hydro One Limited

We have audited the accompanying consolidated financial statements of Hydro One Limited, which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of operations and comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Hydro One Limited as at December 31, 2017 and December 31, 2016, and its consolidated results of operations and its consolidated cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
February 12, 2018

HYDRO ONE LIMITED
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2017 and 2016

Year ended December 31 *(millions of Canadian dollars, except per share amounts)*	2017	2016
Revenues		
Distribution (includes $279 related party revenues; 2016 – $160) *(Note 27)*	4,366	4,915
Transmission (includes $1,523 related party revenues; 2016 – $1,553) *(Note 27)*	1,578	1,584
Other	46	53
	5,990	6,552
Costs		
Purchased power (includes $1,594 related party costs; 2016 – $2,103) *(Note 27)*	2,875	3,427
Operation, maintenance and administration *(Note 27)*	1,066	1,069
Depreciation and amortization *(Note 5)*	817	778
	4,758	5,274
Income before financing charges and income taxes	**1,232**	**1,278**
Financing charges *(Note 6)*	439	393
Income before income taxes	**793**	**885**
Income taxes *(Note 7)*	111	139
Net income	**682**	**746**
Other comprehensive income	1	—
Comprehensive income	**683**	**746**
Net income attributable to:		
Noncontrolling interest *(Note 26)*	6	6
Preferred shareholders	18	19
Common shareholders	658	721
	682	**746**
Comprehensive income attributable to:		
Noncontrolling interest *(Note 26)*	6	6
Preferred shareholders	18	19
Common shareholders	659	721
	683	**746**
Earnings per common share *(Note 24)*		
Basic	$1.11	$1.21
Diluted	$1.10	$1.21
Dividends per common share declared *(Note 23)*	$0.87	$0.97

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE LIMITED
CONSOLIDATED BALANCE SHEETS
At December 31, 2017 and 2016

December 31 *(millions of Canadian dollars)*	2017	2016
Assets		
Current assets:		
Cash and cash equivalents	25	50
Accounts receivable *(Note 8)*	636	838
Due from related parties *(Note 27)*	253	158
Other current assets *(Note 9)*	105	102
	1,019	1,148
Property, plant and equipment *(Note 10)*	19,947	19,140
Other long-term assets:		
Regulatory assets *(Note 12)*	3,049	3,145
Deferred income tax assets *(Note 7)*	987	1,235
Intangible assets *(Note 11)*	369	349
Goodwill *(Note 4)*	325	327
Other assets	5	7
	4,735	5,063
Total assets	**25,701**	**25,351**
Liabilities		
Current liabilities:		
Short-term notes payable *(Note 15)*	926	469
Long-term debt payable within one year *(Notes 15, 17)*	752	602
Accounts payable and other current liabilities *(Note 13)*	905	945
Due to related parties *(Note 27)*	157	147
	2,740	2,163
Long-term liabilities:		
Long-term debt (includes $541 measured at fair value; 2016 – $548) *(Notes 15, 17)*	9,315	10,078
Convertible debentures *(Notes 16, 17)*	487	—
Regulatory liabilities *(Note 12)*	128	209
Deferred income tax liabilities *(Note 7)*	71	60
Other long-term liabilities *(Note 14)*	2,707	2,752
	12,708	13,099
Total liabilities	**15,448**	**15,262**
Contingencies and Commitments (Notes 29, 30)		
Subsequent Events (Note 32)		
Noncontrolling interest subject to redemption *(Note 26)*	22	22
Equity		
Common shares *(Note 22)*	5,631	5,623
Preferred shares *(Note 22)*	418	418
Additional paid-in capital *(Note 25)*	49	34
Retained earnings	4,090	3,950
Accumulated other comprehensive loss	(7)	(8)
Hydro One shareholders' equity	10,181	10,017
Noncontrolling interest *(Note 26)*	50	50
Total equity	**10,231**	**10,067**
	25,701	**25,351**

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

David Denison
Chair

Philip Orsino
Chair, Audit Committee

HYDRO ONE LIMITED
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the years ended December 31, 2017 and 2016

Year ended December 31, 2017 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Hydro One Shareholders' Equity	Non-controlling Interest *(Note 26)*	Total Equity
January 1, 2017	5,623	418	34	3,950	(8)	10,017	50	10,067
Net income	—	—	—	676	—	676	4	680
Other comprehensive income	—	—	—	—	1	1	—	1
Distributions to noncontrolling interest	—	—	—	—	—	—	(4)	(4)
Dividends on preferred shares	—	—	—	(18)	—	(18)	—	(18)
Dividends on common shares	—	—	—	(518)	—	(518)	—	(518)
Common shares issued	8	—	(8)	—	—	—	—	—
Stock-based compensation *(Note 25)*	—	—	23	—	—	23	—	23
December 31, 2017	**5,631**	**418**	**49**	**4,090**	**(7)**	**10,181**	**50**	**10,231**

Year ended December 31, 2016 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholders' Equity	Non-controlling Interest *(Note 26)*	Total Equity
January 1, 2016	5,623	418	10	3,806	(8)	9,849	52	9,901
Net income	—	—	—	740	—	740	4	744
Other comprehensive income	—	—	—	—	—	—	—	—
Distributions to noncontrolling interest	—	—	—	—	—	—	(6)	(6)
Dividends on preferred shares	—	—	—	(19)	—	(19)	—	(19)
Dividends on common shares	—	—	—	(577)	—	(577)	—	(577)
Stock-based compensation *(Note 25)*	—	—	24	—	—	24	—	24
December 31, 2016	**5,623**	**418**	**34**	**3,950**	**(8)**	**10,017**	**50**	**10,067**

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE LIMITED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2017 and 2016

Year ended December 31 *(millions of Canadian dollars)*	2017	2016
Operating activities		
Net income	682	746
Environmental expenditures	(24)	(20)
Adjustments for non-cash items:		
Depreciation and amortization (excluding asset removal costs)	727	688
Regulatory assets and liabilities	112	(16)
Deferred income taxes	85	114
Other	21	10
Changes in non-cash balances related to operations *(Note 28)*	113	134
Net cash from operating activities	**1,716**	**1,656**
Financing activities		
Long-term debt issued	—	2,300
Long-term debt repaid	(602)	(502)
Short-term notes issued	3,795	3,031
Short-term notes repaid	(3,338)	(4,053)
Convertible debentures issued *(Note 16)*	513	—
Dividends paid	(536)	(596)
Distributions paid to noncontrolling interest	(6)	(9)
Other *(Note 16)*	(27)	(10)
Net cash from (used in) financing activities	**(201)**	**161**
Investing activities		
Capital expenditures *(Note 28)*		
Property, plant and equipment	(1,467)	(1,600)
Intangible assets	(80)	(61)
Acquisitions *(Note 4)*	—	(224)
Capital contributions received *(Note 28)*	9	21
Other	(2)	3
Net cash used in investing activities	**(1,540)**	**(1,861)**
Net change in cash and cash equivalents	(25)	(44)
Cash and cash equivalents, beginning of year	50	94
Cash and cash equivalents, end of year	**25**	**50**

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Limited (Hydro One or the Company) was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario). On October 31, 2015, the Company acquired Hydro One Inc., a company previously wholly-owned by the Province of Ontario (Province). The acquisition of Hydro One Inc. by Hydro One was accounted for as a common control transaction and Hydro One is a continuation of business operations of Hydro One Inc. At December 31, 2017, the Province held approximately 47.4% (2016 - 70.1%) of the common shares of Hydro One.

The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These Consolidated Financial Statements include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations, goodwill and asset impairments, contingencies, unbilled revenues, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Rate Setting

The Company's Transmission Business consists of the transmission business of Hydro One Inc., which includes the transmission business of Hydro One Networks Inc. (Hydro One Networks), Hydro One Sault Ste. Marie LP (HOSSM) (formerly Great Lakes Power Transmission LP), and its 66% interest in B2M Limited Partnership (B2M LP). The Company's Distribution Business consists of the distribution business of Hydro One Inc., which includes the distribution businesses of Hydro One Networks, as well as Hydro One Remote Communities Inc. (Hydro One Remote Communities).

Transmission

In November 2017, the Ontario Energy Board (OEB) approved Hydro One Networks' 2017 transmission rates revenue requirement of $1,438 million. See Note 12 - Regulatory Assets and Liabilities for additional information.

In December 2015, the OEB approved B2M LP's 2015-2019 rates revenue requirements of $39 million, $36 million, $37 million, $38 million and $37 million for the respective years. On January 14, 2016, the OEB approved the B2M LP revenue requirement recovery through the 2016 Uniform Transmission Rates, and the establishment of a deferral account to capture costs of Tax Rate and Rule changes. On June 8, 2017, the OEB approved the 2017 rates revenue requirement of $34 million, updated for the cost of capital parameters.

On September 28, 2017, the OEB issued its Decision and Order on HOSSM's 2017 transmission rates application, denying the requested revenue requirement for 2017. HOSSM's 2016 approved revenue requirement of $41 million will remain in effect for 2017.

Distribution

In March 2015, the OEB approved Hydro One Networks' distribution revenue requirements of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The OEB has subsequently approved updated revenue requirements of $1,410 million for 2016 and $1,415 million for 2017.

On March 30, 2017, the OEB approved an increase of 1.9% to Hydro One Remote Communities' basic rates for the distribution and generation of electricity, with an effective date of May 1, 2017.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The

Company's regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations in the period that the assessment is made.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments with an original maturity of three months or less.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Distribution revenue also includes an amount relating to rate protection for rural, residential, and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The Company estimates the allowance for doubtful accounts on billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Noncontrolling interest

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to shareholders of Hydro One. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income and other comprehensive income (OCI) attributable to the noncontrolling interest and any dividends or distributions paid to the noncontrolling interest.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net income or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

Income Taxes

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax liabilities are recognized on all taxable temporary differences between the tax bases and carrying amounts of assets and liabilities. Deferred income tax assets are recognized for deductible temporary differences between tax bases and carrying amounts of assets and liabilities, the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Company records regulatory assets and liabilities associated with deferred income tax assets and liabilities that will be included in the rate-setting process.

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Consolidated Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent reviews resulted in changes to rates effective January 1, 2015 and January 1, 2017 for Hydro One Networks' distribution and transmission businesses, respectively. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average	Rate	
	Service Life	Range	Average
Property, plant and equipment:			
Transmission	55 years	1% - 3%	2%
Distribution	46 years	1% - 7%	2%
Communication	16 years	1% - 15%	6%
Administration and service	20 years	1% - 20%	6%
Intangible assets	10 years	10%	10%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

Based on assessment performed as at September 30, 2017, the Company has concluded that goodwill was not impaired at December 31, 2017.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. Management assesses the fair value of such long-lived assets using commonly accepted techniques. Techniques used to determine fair value include, but are not limited to, the use of recent third-party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2017 and 2016, no asset impairment had been recorded for assets within either the Company's regulated or unregulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading and for convertible debentures, the Company defers the external transaction costs related to obtaining financing and presents such amounts net of related debt or convertible debentures on the Consolidated Balance Sheets. Deferred issuance costs are amortized over the contractual life of the related debt or convertible debentures on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and OCI. Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 17 - Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized on its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives that required bifurcation at December 31, 2017 or 2016.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

<u>Defined Benefit Pension</u>

Defined benefit pension costs are recorded on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are fair valued at the end of each year. Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for its pension plan.

<u>Post-retirement and Post-employment Benefits</u>

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. The actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Stock-Based Compensation

Share Grant Plans

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transfered from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans

The Company records the liabilities associated with its Directors' and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on the Company's common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the restricted share units (RSUs) and performance share units (PSUs), issued under its LTIP, at fair value based on the grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with contaminated land assessment and remediation and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company’s transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company’s easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

The Company’s asset retirement obligations recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being “clearly and closely related” to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13 2017-14	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.
2016-02 2018-01	February 2016 – January 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-04	January 2017	The amendment removes the second step of the current two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company’s employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

4. BUSINESS COMBINATIONS

Avista Corporation Purchase Agreement

On July 19, 2017, Hydro One reached an agreement to acquire Avista Corporation (Merger) for approximately $6.7 billion in an all-cash transaction. Avista Corporation is an investor-owned utility providing electric generation, transmission, and distribution services. It is headquartered in Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger is subject to receipt of certain regulatory and government approvals, and the satisfaction of customary closing conditions. See Note 16 - Convertible Debentures and Note 17 - Fair Value of Financial Instruments and Risk Management for details of convertible debentures and foreign exchange contract, respectively, related to financing of the Merger.

Acquisition of HOSSM

On October 31, 2016, Hydro One acquired HOSSM, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario from Brookfield Infrastructure Holdings Inc. The total purchase price for HOSSM was approximately $376 million, including the assumption of approximately $150 million in outstanding indebtedness. During 2017, the Company completed the final determination of the fair value of assets acquired and liabilities assumed with no significant changes, which resulted in a total goodwill of approximately $157 million arising from the HOSSM acquisition. The difference between the preliminary and final purchase price allocation to fair value of assets acquired and liabilities related to a $2 million decrease in deferred income tax liabilities which resulted in a corresponding decrease to goodwill. The following table summarizes the final fair value of the assets acquired and liabilities assumed:

(millions of dollars)	
Cash and cash equivalents	5
Property, plant and equipment	221
Intangible assets	1
Regulatory assets	50
Goodwill	157
Working capital	(2)
Long-term debt	(186)
Pension and post-employment benefit liabilities, net	(5)
Deferred income taxes	(15)
	226

Goodwill arising from the HOSSM acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and HOSSM. HOSSM contributed revenues of $6 million and less than $1 million of net income to the Company's consolidated financial results for the year ended December 31, 2016. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. HOSSM's financial information was not material to the Company's consolidated financial results for the year ended December 31, 2016 and therefore, has not been disclosed on a pro forma basis.

Agreement to Purchase Orillia Power

On August 15, 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power), an electricity distribution company located in Simcoe County, Ontario, from the City of Orillia for approximately $41 million, including the assumption of approximately $15 million in outstanding indebtedness and regulatory liabilities, subject to closing adjustments. The acquisition is subject to regulatory approval by the OEB.

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 *(millions of dollars)*	2017	2016
Depreciation of property, plant and equipment	641	612
Asset removal costs	90	90
Amortization of intangible assets	62	56
Amortization of regulatory assets	24	20
	817	778

6. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2017	2016
Interest on long-term debt	450	424
Interest on convertible debentures	24	—
Interest on short-term notes	6	9
Unrealized loss on foreign exchange contract	3	—
Other	14	16
Less: Interest capitalized on construction and development in progress	(56)	(54)
Interest earned on cash and cash equivalents	(2)	(2)
	439	393

7. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Income before income taxes	793	885
Income taxes at statutory rate of 26.5% (2016 - 26.5%)	210	235
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(55)	(53)
Pension contributions in excess of pension expense	(13)	(16)
Overheads capitalized for accounting but deducted for tax purposes	(17)	(16)
Interest capitalized for accounting but deducted for tax purposes	(15)	(14)
Environmental expenditures	(6)	(5)
Other	3	5
Net temporary differences	(103)	(99)
Net permanent differences	4	3
Total income taxes	111	139

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Current income taxes	26	25
Deferred income taxes	85	114
Total income taxes	111	139
Effective income tax rate	14.0%	15.7%

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates. Deferred income tax assets and liabilities arise from differences between the tax basis and the carrying amounts of the assets and liabilities. At December 31, 2017 and 2016, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of dollars)*	2017	2016
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	125	495
Non-depreciable capital property	271	271
Post-retirement and post-employment benefits expense in excess of cash payments	561	607
Environmental expenditures	71	74
Non-capital losses	255	213
Tax credit carryforwards	49	27
Investment in subsidiaries	84	75
Other	13	3
	1,429	1,765
Less: valuation allowance	(364)	(352)
Total deferred income tax assets	1,065	1,413
Less: current portion	—	—
	1,065	1,413
Deferred income tax liabilities		
Regulatory amounts that are not recognized for tax purposes	(47)	(153)
Goodwill	(10)	(10)
Capital cost allowance in excess of depreciation and amortization	(75)	(64)
Other	(17)	(11)
Total deferred income tax liabilities	(149)	(238)
Less: current portion	—	—
	(149)	(238)
Net deferred income tax assets	916	1,175

The net deferred income tax assets are presented on the Consolidated Balance Sheets as follows:

December 31 *(millions of dollars)*	2017	2016
Long-term:		
Deferred income tax assets	987	1,235
Deferred income tax liabilities	(71)	(60)
Net deferred income tax assets	916	1,175

The valuation allowance for deferred tax assets as at December 31, 2017 was $364 million (2016 - $352 million). The valuation allowance primarily relates to temporary differences for non-depreciable assets and investments in subsidiaries. As of December 31, 2017 and 2016, the Company had non-capital losses carried forward available to reduce future years' taxable income, which expire as follows:

Year of expiry *(millions of dollars)*	2017	2016
2034	2	2
2035	222	222
2036	560	580
2037	175	—
Total losses	959	804

8. ACCOUNTS RECEIVABLE

December 31 *(millions of dollars)*	2017	2016
Accounts receivable – billed	298	431
Accounts receivable – unbilled	367	442
Accounts receivable, gross	665	873
Allowance for doubtful accounts	(29)	(35)
Accounts receivable, net	636	838

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016
Allowance for doubtful accounts – beginning	(35)	(61)
Write-offs	25	37
Additions to allowance for doubtful accounts	(19)	(11)
Allowance for doubtful accounts – ending	(29)	(35)

9. OTHER CURRENT ASSETS

December 31 *(millions of dollars)*	2017	2016
Regulatory assets *(Note 12)*	46	37
Materials and supplies	18	19
Prepaid expenses and other assets	41	46
	105	102

10. PROPERTY, PLANT AND EQUIPMENT

December 31, 2017 *(millions of dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	15,509	5,162	989	11,336
Distribution	10,213	3,513	149	6,849
Communication	1,266	853	31	444
Administration and service	1,561	857	46	750
Easements	638	70	—	568
	29,187	10,455	1,215	19,947

December 31, 2016 *(millions of dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	14,692	4,862	910	10,740
Distribution	9,656	3,305	243	6,594
Communication	1,233	777	20	476
Administration and service	1,632	924	61	769
Easements	628	67	—	561
	27,841	9,935	1,234	19,140

Financing charges capitalized on property, plant and equipment under construction were $54 million in 2017 (2016 - $52 million).

11. INTANGIBLE ASSETS

December 31, 2017 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	698	370	41	369
Other	5	5	—	—
	703	375	41	369

December 31, 2016 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	621	326	53	348
Other	5	4	—	1
	626	330	53	349

Financing charges capitalized to intangible assets under development were $2 million in 2017 (2016 - $2 million). The estimated annual amortization expense for intangible assets is as follows: 2018 - $67 million; 2019 - $57 million; 2020 - $40 million; 2021 - $39 million; and 2022 - $36 million.

12. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 *(millions of dollars)*	2017	2016
Regulatory assets:		
Deferred income tax regulatory asset	1,762	1,587
Pension benefit regulatory asset	981	900
Post-retirement and post-employment benefits	36	243
Environmental	196	204
Share-based compensation	40	31
Debt premium	27	32
Foregone revenue deferral	23	—
Distribution system code exemption	10	10
B2M LP start-up costs	4	5
Retail settlement variance account	—	145
2015-2017 rate rider	—	7
Pension cost variance	—	4
Other	16	14
Total regulatory assets	3,095	3,182
Less: current portion	(46)	(37)
	3,049	3,145
Regulatory liabilities:		
Green Energy expenditure variance	60	69
External revenue variance	46	64
CDM deferral variance	28	54
Pension cost variance	23	—
2015-2017 rate rider	6	—
Deferred income tax regulatory liability	5	4
Other	17	18
Total regulatory liabilities	185	209
Less: current portion	(57)	—
	128	209

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2017 income tax expense would have been higher by approximately $113 million (2016 - $104 million).

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Decision). In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a Decision and Order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an additional impairment of up to approximately $370 million related to Hydro One Networks' distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which is scheduled for mid-February 2018. In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company's Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

Pension Benefit Regulatory Asset

In accordance with OEB rate orders, pension costs are recovered on a cash basis as employer contributions are paid to the pension fund in accordance with the Pension Benefits Act (Ontario). The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, OCI would have been lower by $80 million and operation, maintenance and administration expenses would have been higher by $1 million (2016 - OCI higher by $52 million).

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2017 OCI would have been higher by $207 million (2016 - lower by $3 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2017, the environmental regulatory asset increased by $1 million (2016 - decreased by $1 million) to reflect related changes in the Company's PCB liability, and increased by $7 million (2016 - $10 million) due to changes in the land assessment and remediation liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2017 operation, maintenance and administration expenses would have been higher by $8 million (2016 - $9 million). In addition, 2017 amortization expense would have been lower by $24 million (2016 - $20 million), and 2017 financing charges would have been higher by $8 million (2016 - $8 million).

Share-based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2017 operation, maintenance and administration expenses would have been higher by $8 million (2016 - $9 million). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.

Debt Premium

The value of debt assumed in the acquisition of HOSSM has been recorded at fair value in accordance with US GAAP - Business Combinations. The OEB allows for recovery of interest at the coupon rate of the Senior Secured Bonds and a regulatory asset has been recorded for the difference between the fair value and face value of this debt. The debt premium is recovered over the remaining term of the debt.

Foregone Revenue Deferral

As part of its September 2017 decision on Hydro One Networks' transmission rate application for 2017 and 2018 rates, the OEB approved the foregone revenue account to record the difference between revenue earned under the rates approved as part of the decision, effective January 1, 2017, and revenue earned under the interim rates until the approved 2017 rates were implemented. The OEB approved a similar account for B2M LP in June 2017 to record the difference between revenue earned under the newly approved rates, effective January 1, 2017, and the revenue recorded under the interim 2017 rates. The balances of these accounts will be returned to or recovered from ratepayers, respectively, over a one-year period ending December 31, 2018. The draft rate order submitted by Hydro One Networks was approved by the OEB in November, 2017. This draft rate order reflects the September 2017 decision, including a reduction of the amount of cash taxes approved for recovery in transmission rates due to the OEB's basis to share the savings resulting from a deferred tax asset with ratepayers. The Company's position in the aforementioned Motion is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. Therefore, the Company has also reflected the impact of the Company's position with respect to the Motion in the Foregone Revenue Deferral account. The timing for recovery of this impact will be determined as part of the outcome of the Motion.

Distribution System Code (DSC) Exemption

In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the DSC, with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by Hydro One Networks that resulted from the connection of certain renewable generation facilities. The OEB ruled that identified specific expenditures can be recorded in a deferral account subject to the OEB's review in subsequent Hydro One Networks distribution applications. In March 2015, the OEB approved the disposition of the DSC exemption deferral account balance at December 31, 2013, including accrued interest, which was recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account. There were no additions to this regulatory account in 2017 or 2016. The remaining balance in this account at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application.

B2M LP Start-up Costs

In December 2015, OEB issued its decision on B2M LP's application for 2015-2019 and as part of the decision approved the recovery of $8 million of start-up costs relating to B2M LP. The costs are being recovered over a four-year period which began in 2016, in accordance with the OEB decision.

Retail Settlement Variance Account (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In March 2015, the OEB approved the disposition of the total RSVA balance accumulated from January 2012 to December 2013, including accrued interest, to be recovered through the 2015-2017 Rate Rider.

2015-2017 Rate Rider

In March 2015, as part of its decision on Hydro One Networks' distribution rate application for 2015-2019, the OEB approved the disposition of certain deferral and variance accounts, including RSVAs and accrued interest. The 2015-2017 Rate Rider account included the balances approved for disposition by the OEB and was disposed of in accordance with the OEB decision over a 32-month period ended on December 31, 2017. The balance remaining in the account represents an over-collection to be returned to ratepayers in a future rate application. We have not requested recovery of the remaining balance of this account in the current distribution rate application.

Pension Cost Variance

A pension cost variance account was established for Hydro One Networks' transmission and distribution businesses to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the deficit of pension costs paid as compared to OEB-approved amounts. In March 2015, the OEB approved the disposition of the distribution business portion of the total pension cost variance account at December 31, 2013, including accrued interest, which was recovered through the 2015-2017 Rate Rider. In September 2017, the OEB approved the disposition of the transmission business portion of the total pension cost variance account as at December 31, 2015, including accrued interest, which is being recovered over a two-year period ending December 31, 2018. In the absence of rate-regulated accounting, 2017 revenue would have been higher by $24 million (2016 - $25 million).

Green Energy Expenditure Variance

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts. In September 2017, the OEB approved the disposition of the external revenue variance account as at December 31, 2015, including accrued interest, which is being returned to customers over a two-year period ending December 31, 2018.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. The balance in the CDM deferral variance account relates to the actual 2013 and 2014 CDM compared to the amounts included in 2013 and 2014 revenue requirements, respectively. There were no additions to this regulatory account in 2017 or 2016. The balance of the account at December 31, 2015, including interest, was approved for disposition in the 2017-2018 transmission rate decision and is currently being drawn down over a 2-year period ending December 31, 2018.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

December 31 *(millions of dollars)*	2017	2016
Accounts payable	177	181
Accrued liabilities	572	659
Accrued interest	99	105
Regulatory liabilities *(Note 12)*	57	—
	905	945

14. OTHER LONG-TERM LIABILITIES

December 31 *(millions of dollars)*	2017	2016
Post-retirement and post-employment benefit liability *(Note 19)*	1,519	1,641
Pension benefit liability *(Note 19)*	981	900
Environmental liabilities *(Note 20)*	168	177
Asset retirement obligations *(Note 21)*	9	9
Long-term accounts payable and other liabilities	30	25
	2,707	2,752

15. DEBT AND CREDIT AGREEMENTS

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under Hydro One Inc.'s Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by Hydro One Inc.'s committed revolving credit facilities totalling $2.3 billion.

At December 31, 2017, Hydro One's consolidated committed, unsecured and undrawn credit facilities totalling $2,550 million consisted of the following:

(millions of dollars)	Maturity	Amount
Hydro One Inc.		
Revolving standby credit facility	June 2022[1]	2,300
Hydro One		
Five-year senior, revolving term credit facility	November 2021	250
Total		2,550

[1] In June 2017, the maturity date of Hydro One Inc.'s $2.3 billion credit facilities was extended from June 2021 to June 2022.

The Company may use the credit facilities for working capital and general corporate purposes. If used, interest on the credit facilities would apply based on Canadian benchmark rates. The obligation of each lender to make any credit extension under its credit facility is subject to various conditions including that no event of default has occurred or would result from such credit extension.

Long-Term Debt

The following table presents long-term debt outstanding at December 31, 2017 and 2016:

December 31 *(millions of dollars)*	2017	2016
5.18% Series 13 notes due 2017	—	600
2.78% Series 28 notes due 2018	750	750
Floating-rate Series 31 notes due 2019[1]	228	228
1.48% Series 37 notes due 2019[2]	500	500
4.40% Series 20 notes due 2020	300	300
1.62% Series 33 notes due 2020[2]	350	350
1.84% Series 34 notes due 2021	500	500
3.20% Series 25 notes due 2022	600	600
2.77% Series 35 notes due 2026	500	500
7.35% Debentures due 2030	400	400
6.93% Series 2 notes due 2032	500	500
6.35% Series 4 notes due 2034	385	385
5.36% Series 9 notes due 2036	600	600
4.89% Series 12 notes due 2037	400	400
6.03% Series 17 notes due 2039	300	300
5.49% Series 18 notes due 2040	500	500
4.39% Series 23 notes due 2041	300	300
6.59% Series 5 notes due 2043	315	315
4.59% Series 29 notes due 2043	435	435
4.17% Series 32 notes due 2044	350	350
5.00% Series 11 notes due 2046	325	325
3.91% Series 36 notes due 2046	350	350
3.72% Series 38 notes due 2047	450	450
4.00% Series 24 notes due 2051	225	225
3.79% Series 26 notes due 2062	310	310
4.29% Series 30 notes due 2064	50	50
Hydro One Inc. long-term debt (a)	9,923	10,523
6.6% Senior Secured Bonds due 2023 (Face value - $110 million)	136	144
4.6% Note Payable due 2023 (Face value - $36 million)	40	40
HOSSM long-term debt (b)	176	184
	10,099	10,707
Add: Net unamortized debt premiums	14	15
Add: Unrealized mark-to-market gain[2]	(9)	(2)
Less: Deferred debt issuance costs	(37)	(40)
Total long-term debt	10,067	10,680

[1] The interest rates of the floating-rate notes are referenced to the three-month Canadian dollar bankers' acceptance rate, plus a margin.

[2] The unrealized mark-to-market net gain relates to $50 million of the Series 33 notes due 2020 and $500 million Series 37 notes due 2019. The unrealized mark-to-market net gain is offset by a $9 million (2016 - $2 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

(a) Hydro One Inc. long-term debt

At December 31, 2017, long-term debt of $9,923 million (2016 - $10,523 million) was outstanding, the majority of which was issued under Hydro One Inc.'s Medium Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At December 31 2017, $1.2 billion remained available for issuance until January 2018. In 2017, no long-term debt was issued and $600 million of long-term debt was repaid under the MTN Program (2016 - $2,300 million issued and $500 million repaid).

(b) HOSSM long-term debt

At December 31, 2017, long-term debt of $176 million (2016 - $184 million), with a face value of $146 million (2016 - $148 million) was held by HOSSM. In 2017, $2 million of HOSSM long-term debt was repaid (2016 - $2 million).

The total long-term debt is presented on the consolidated balance sheets as follows:

December 31 *(millions of dollars)*	2017	2016
Current liabilities:		
Long-term debt payable within one year	752	602
Long-term liabilities:		
Long-term debt	9,315	10,078
Total long-term debt	10,067	10,680

Principal and Interest Payments

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
1 year	752	2.8
2 years	731	1.6
3 years	653	2.9
4 years	503	1.9
5 years	604	3.2
	3,243	2.5
6 – 10 years	631	3.5
Over 10 years	6,195	5.2
	10,069	4.2

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of dollars)*
2018	426
2019	402
2020	384
2021	370
2022	355
	1,937
2023-2027	1,672
2028+	4,081
	7,690

16. CONVERTIBLE DEBENTURES

(millions of dollars, except as otherwise noted)	
Maturity date	September 30, 2027
Coupon rate	4.00%
Conversion price per common share	$ 21.40
Carrying value at December 31, 2016	—
Receipt of Initial Instalment, net of deferred financing costs	486
Amortization of deferred financing costs	1
Carrying value at December 31, 2017	487
Face value at December 31, 2017	513

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Convertible Debentures) represented by instalment receipts, which included the exercise in full of the over-allotment option granted to the underwriters to purchase an additional $140 million aggregate principal amount of the Convertible Debentures (Debenture Offering).

The Convertible Debentures were sold on an instalment basis at a price of $1,000 per Convertible Debenture, of which $333 (Initial Instalment) was paid on closing of the Debenture Offering and the remaining $667 (Final Instalment) is payable on a date (Final Instalment Date) to be fixed by the Company following satisfaction of conditions precedent to the closing of the acquisition of Avista Corporation. The gross proceeds received from the Initial Instalment were $513 million. The Company incurred financing costs of

$27 million, which are being amortized to financing charges over approximately 10 years, the contractual term of the Convertible Debentures, using the effective interest rate method.

The Convertible Debentures will mature on September 30, 2027. A coupon rate of 4% is paid on the $1,540 million aggregate principal amount of the Convertible Debentures, and based on the carrying value of the Initial Instalment, this translates into an effective annual yield of 12%. After the Final Instalment Date, the interest rate will be 0%. The interest expense recorded in 2017 is $24 million.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the closing of the Debenture Offering, holders of the Convertible Debentures who have paid the Final Instalment on or before the Final Instalment Date will be entitled to receive, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the closing of the Debenture Offering had the Convertible Debentures remained outstanding and continued to accrue interest until and including such date (Make-Whole Payment). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the closing of the Debenture Offering.

At the option of the holders and provided that payment of the Final Instalment has been made, each Convertible Debenture will be convertible into common shares of the Company at any time on or after the Final Instalment Date, but prior to the earlier of maturity or redemption by the Company, at a conversion price of $21.40 per common share, being a conversion rate of 46.7290 common shares per $1,000 principal amount of Convertible Debentures. The conversion feature meets the definition of a Beneficial Conversion Feature (BCF), with an intrinsic value of approximately $92 million. Due to the contingency associated with the debentureholders' ability to exercise the conversion, the BCF has not been recognized. Between the time the contingency is resolved and the Final Instalment Date, the Company will recognize approximately $92 million of interest expense associated with amortization of the BCF.

Prior to the Final Instalment Date, the Convertible Debentures may not be redeemed by the Company, except that the Convertible Debentures will be redeemed by the Company at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions necessary to approve the acquisition of Avista Corporation will not be satisfied; (ii) termination of the acquisition agreement; and (iii) May 1, 2019 if notice of the Final Instalment Date has not been given to holders on or before April 30, 2019. Upon any such redemption, the Company will pay for each Convertible Debenture (i) $333 plus accrued and unpaid interest to the holder of the instalment receipt; and (ii) $667 to the selling debentureholder on behalf of the holder of the instalment receipt in satisfaction of the final instalment. In addition, after the Final Instalment Date, any Convertible Debentures not converted may be redeemed by the Company at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date.

At maturity, the Company will have the right to pay the principal amount due in common shares, which will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

17. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2017 and 2016, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2017 and 2016 are as follows:

December 31 *(millions of dollars)*	2017 Carrying Value	2017 Fair Value	2016 Carrying Value	2016 Fair Value
$50 million of MTN Series 33 notes	49	49	50	50
$500 million MTN Series 37 notes	492	492	498	498
Other notes and debentures	9,526	11,027	10,132	11,462
Long-term debt, including current portion	10,067	11,568	10,680	12,010

Fair Value Measurements of Derivative Instruments

At December 31, 2017, Hydro One Inc. had interest-rate swaps in the amount of $550 million (2016 – $550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One Inc.'s fair value hedge exposure was approximately 6% (2016 – 5%) of its total long-term debt. At December 31, 2017, Hydro One Inc. had the following interest-rate swaps designated as fair value hedges:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt; and
- two $125 million and one $250 million fixed-to-floating interest-rate swap agreements to convert the $500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt.

At December 31, 2017 and 2016, the Company had no interest-rate swaps classified as undesignated contracts.

In October 2017, the Company entered into a deal-contingent foreign exchange forward contract to convert $1.4 billion Canadian to US dollars at an initial forward rate of 1.27486 Canadian per 1.00 US dollars, and a range up to 1.28735 Canadian per 1.00 US dollars based on the settlement date. The contract is contingent on the Company closing the proposed Avista Corporation acquisition (see Note 4 - Business Combinations) and is intended to mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed with the issuance of Convertible Debentures (see Note 16 - Convertible Debentures). If the acquisition does not close, the contract would not be completed and no amounts would be exchanged. The contract can be executed upon approval of the acquisition up to March 31, 2019. This contract is an economic hedge and does not qualify for hedge accounting. It has been accounted for as an undesignated contract.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2017 and 2016 is as follows:

December 31, 2017 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	25	25	25	—	—
	25	25	25	—	—
Liabilities:					
Short-term notes payable	926	926	926	—	—
Long-term debt, including current portion	10,067	11,568	—	11,568	—
Convertible debentures	487	574	574	—	—
Derivative instruments					
Fair value hedges – interest-rate swaps	9	9	9	—	—
Foreign exchange contract	3	3	—	—	3
	11,492	13,080	1,509	11,568	3

December 31, 2016 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	50	50	50	—	—
	50	50	50	—	—
Liabilities:					
Short-term notes payable	469	469	469	—	—
Long-term debt, including current portion	10,680	12,010	—	12,010	—
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	2	—	—
	11,151	12,481	471	12,010	—

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

The fair value of the convertible debentures is based on their closing price on December 29, 2017 (last business day in December 2017), as posted on the Toronto Stock Exchange.

The Company uses derivative instruments as an economic hedge for foreign exchange risk. The value of the foreign exchange contract is derived using valuation models commonly used for derivatives. These valuation models require a variety of inputs, including contractual terms, forward price yield curves,probability of closing the Avista Corporation acquisition, and the contract settlement of date. The Company's valuation models also reflect measurements for credit risk. The fair value of the foreign exchange contract includes significant unobservable inputs, and therefore has been classified accordingly as Level 3. The significant unobservable inputs used in the fair value measurement of the foreign exchange contract relates to the assessment of probabililty of closing the Avista Corporation acquisition and the contract settlement date.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2017 and 2016.

Year ended December 31 *(millions of dollars)*	2017	2016
Fair value, beginning of year	—	—
Unrealized loss on foreign exchange contract included in financing charges *(Note 6)*	3	—
Fair value, end of year	3	—

There were no transfers between any of the fair value levels during the years ended December 31, 2017 or 2016.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the years ended December 31, 2017 and 2016.

The Company is exposed to foreign exchange fluctuations as a result of entering into a deal-contingent foreign exchange forward agreement (see section Fair Value Measurements of Derivative Instruments above).This agreement is intended to mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed with the issuance of Convertible Debentures (see Note 16 - Convertible Debentures).

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2017 and 2016 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2017 and 2016, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a material amount of revenue from any single customer. At December 31, 2017 and 2016, there was no material accounts receivable balance due from any single customer.

At December 31, 2017, the Company's provision for bad debts was $29 million (2016 – $35 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2017, approximately 5% (2016 – 6%) of the Company's net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2017 and 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2017, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

18. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing access to capital, the Company targets to maintain strong credit quality. At December 31, 2017 and 2016, the Company's capital structure was as follows:

December 31 *(millions of dollars)*	2017	2016
Long-term debt payable within one year	752	602
Short-term notes payable	926	469
Less: cash and cash equivalents	(25)	(50)
	1,653	1,021
Long-term debt	9,315	10,078
Convertible debentures	487	—
Preferred shares	418	418
Common shares	5,631	5,623
Retained earnings	4,090	3,950
Total capital	21,594	21,090

Hydro One Inc. and HOSSM have customary covenants typically associated with long-term debt. Hydro One Inc.'s long-term debt and credit facility covenants limit permissible debt to 75% of its total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

19. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a defined contribution pension plan (DC Plan), a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One.

Hydro One contributions to the DC Plan for the year ended December 31, 2017 were $1 million (2016 - less than $1 million). At December 31, 2017, Company contributions payable included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2016 - less than $1 million).

Pension Plan, Supplemental Plan, and Post-Retirement and Post-Employment Plans

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for The Society of Energy Professionals (The Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2017 of $87 million (2016 - $108 million) were based on an actuarial valuation effective December 31, 2016 (2016 - based on an actuarial valuation effective December 31, 2015) and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2018 and 2019 are approximately $71 million for each year based on the actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings. Future minimum contributions beyond 2019 will be based on an actuarial valuation effective no later than December 31, 2019. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for limitations imposed by the *Income Tax Act* (Canada). The Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment benefit plans (Plans) as an asset or liability on its Consolidated Balance Sheets, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. The measurement date for the Plans is December 31.

Year ended December 31 (millions of dollars)	Pension Benefits 2017	Pension Benefits 2016	Post-Retirement and Post-Employment Benefits 2017	Post-Retirement and Post-Employment Benefits 2016
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	7,774	7,683	1,690	1,610
Current service cost	147	144	49	42
Employee contributions	49	45	—	—
Interest cost	304	308	67	67
Benefits paid	(368)	(354)	(44)	(43)
Net actuarial loss (gain)	352	(52)	(197)	14
Projected benefit obligation, end of year	8,258	7,774	1,565	1,690
Change in plan assets				
Fair value of plan assets, beginning of year	6,874	6,731	—	—
Actual return on plan assets	662	370	—	—
Benefits paid	(368)	(354)	(34)	(43)
Employer contributions	87	108	34	43
Employee contributions	49	45	—	—
Administrative expenses	(27)	(26)	—	—
Fair value of plan assets, end of year	7,277	6,874	—	—
Unfunded status	981	900	1,565	1,690

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets as follows:

December 31 *(millions of dollars)*	Pension Benefits 2017	Pension Benefits 2016	Post-Retirement and Post-Employment Benefits 2017	Post-Retirement and Post-Employment Benefits 2016
Other assets[1]	1	1	—	—
Accrued liabilities	—	—	53	56
Pension benefit liability	981	900	—	—
Post-retirement and post-employment benefit liability[2]	—	—	1,519	1,641
Net unfunded status	980	899	1,572	1,697

[1] Represents the funded status of HOSSM defined benefit pension plan.

[2] Includes $7 million (2016 - $7 million) relating to HOSSM post-employment benefit plans.

The funded or unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations for the Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the projected benefit obligation (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan:

December 31 *(millions of dollars)*	2017	2016
PBO	8,258	7,774
ABO	7,614	7,094
Fair value of plan assets	7,277	6,874

On an ABO basis, the Pension Plan was funded at 96% at December 31, 2017 (2016 - 97%). On a PBO basis, the Pension Plan was funded at 88% at December 31, 2017 (2016 - 88%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2017 and 2016 for the Pension Plan:

Year ended December 31 *(millions of dollars)*	2017	2016
Current service cost	147	144
Interest cost	304	308
Expected return on plan assets, net of expenses	(442)	(432)
Amortization of actuarial losses	79	96
Net periodic benefit costs	88	116
Charged to results of operations[1]	39	48

[1] The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2017, pension costs of $87 million (2016 - $108 million) were attributed to labour, of which $39 million (2016 - $48 million) was charged to operations, and $48 million (2016 - $60 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2017 and 2016 for the post-retirement and post-employment benefit plans:

Year ended December 31 *(millions of dollars)*	2017	2016
Current service cost	49	42
Interest cost	67	67
Amortization of actuarial losses	16	15
Net periodic benefit costs	132	124
Charged to results of operations	59	55

Assumptions

The measurement of the obligations of the Plans and the costs of providing benefits under the Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed-income securities.

The following weighted average assumptions were used to determine the benefit obligations at December 31, 2017 and 2016:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	2017	2016	2017	2016
Significant assumptions:				
Weighted average discount rate	3.40%	3.90%	3.40%	3.90%
Rate of compensation scale escalation (long-term)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Rate of increase in health care cost trends[1]	—	—	4.04%	4.36%

[1] 5.26% per annum in 2018, grading down to 4.04% per annum in and after 2031 (2016 - 6.25% in 2017, grading down to 4.36% per annum in and after 2031).

The following weighted average assumptions were used to determine the net periodic benefit costs for the years ended December 31, 2017 and 2016. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

Year ended December 31	2017	2016
Pension Benefits:		
Weighted average expected rate of return on plan assets	6.50%	6.50%
Weighted average discount rate	3.90%	4.00%
Rate of compensation scale escalation (long-term)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	15	15
Post-Retirement and Post-Employment Benefits:		
Weighted average discount rate	3.90%	4.10%
Rate of compensation scale escalation (long-term)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	15.2	15.3
Rate of increase in health care cost trends[1]	4.36%	4.36%

[1] 6.25% per annum in 2017, grading down to 4.36% per annum in and after 2031 (2016 - 6.38% in 2016, grading down to 4.36% per annum in and after 2031).

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third-party bond yield curve corresponding to each duration. The yield curve is based on "AA" long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of a 1% change in health care cost trends on the projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2017 and 2016 is as follows:

December 31 *(millions of dollars)*	2017	2016
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	250	289
Effect of a 1% decrease in health care cost trends	(189)	(221)

The effect of a 1% change in health care cost trends on the service cost and interest cost for the post-retirement and post-employment benefits for the years ended December 31, 2017 and 2016 is as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	29	23
Effect of a 1% decrease in health care cost trends	(20)	(17)

The following approximate life expectancies were used in the mortality assumptions to determine the projected benefit obligations for the pension and post-retirement and post-employment plans at December 31, 2017 and 2016:

December 31, 2017				December 31, 2016			
Life expectancy at 65 for a member currently at				Life expectancy at 65 for a member currently at			
Age 65		Age 45		Age 65		Age 45	
Male	Female	Male	Female	Male	Female	Male	Female
22	24	23	24	22	24	23	24

Estimated Future Benefit Payments

At December 31, 2017, estimated future benefit payments to the participants of the Plans were:

(millions of dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2018	326	53
2019	335	54
2020	342	56
2021	350	57
2022	358	58
2023 through to 2027	1,886	312
Total estimated future benefit payments through to 2027	3,597	590

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

Year ended December 31 *(millions of dollars)*	2017	2016
Pension Benefits:		
Actuarial loss (gain) for the year	159	35
Amortization of actuarial losses	(79)	(96)
	80	(61)
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	(197)	14
Amortization of actuarial losses	(16)	(15)
Amounts not subject to regulatory treatment	6	4
	(207)	3

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016
Pension Benefits:		
Actuarial loss	981	900
Post-Retirement and Post-Employment Benefits:		
Actuarial loss	36	243

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 *(millions of dollars)*	2017	2016	2017	2016
Actuarial loss	84	79	2	6

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that Pension Plan assets will be sufficient to pay Pension Plan benefits when due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies and Procedures (SIPP), which is reviewed and approved by the Human Resource Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

Pension Plan Asset Mix

At December 31, 2017, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	55	60
Debt securities	35	31
Other[1]	10	9
	100	100

[1] Other investments include real estate and infrastructure investments.

At December 31, 2017, the Pension Plan held $11 million (2016 - $11 million) Hydro One corporate bonds and $415 million (2016 - $450 million) of debt securities of the Province.

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2017 and 2016. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. At December 31, 2017 and 2016, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan's Statement of Investment Beliefs and Guidelines provides guidelines and restrictions for eligible investments taking into account credit ratings, maximum investment exposure and other controls in order to limit the impact of this risk. The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivative instruments by transacting only with highly rated financial institutions, and also by ensuring that exposure is diversified across counterparties. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

Fair Value Measurements

The following tables present the Pension Plan assets measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2017 and 2016:

December 31, 2017 *(millions of dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	—	16	549	565
Cash and cash equivalents	153	—	—	153
Short-term securities	—	109	—	109
Derivative instruments	—	5	—	5
Corporate shares - Canadian	921	—	—	921
Corporate shares - Foreign	3,307	125	—	3,432
Bonds and debentures - Canadian	—	1,879	—	1,879
Bonds and debentures - Foreign	—	194	—	194
Total fair value of plan assets[1]	4,381	2,328	549	7,258

[1] At December 31, 2017, the total fair value of Pension Plan assets and liabilities excludes $28 million of interest and dividends receivable, $10 million of pension administration expenses payable, $1 million of sold investments receivable, and $1 million of purchased investments payable.

December 31, 2016 *(millions of dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	—	20	425	445
Cash and cash equivalents	146	—	—	146
Short-term securities	—	127	—	127
Corporate shares - Canadian	911	—	—	911
Corporate shares - Foreign	2,985	113	—	3,098
Bonds and debentures - Canadian	—	1,943	—	1,943
Bonds and debentures - Foreign	—	193	—	193
Total fair value of plan assets[1]	4,042	2,396	425	6,863

[1] At December 31, 2016, the total fair value of Pension Plan assets excludes $27 million of interest and dividends receivable, $15 million of purchased investments payable, $9 million of pension administration expenses payable, and $7 million of sold investments receivable.

See note 17 - Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2017 and 2016. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 *(millions of dollars)*	2017	2016
Fair value, beginning of year	425	301
Realized and unrealized gains	(31)	23
Purchases	171	151
Sales and disbursements	(16)	(50)
Fair value, end of year	549	425

There were no significant transfers between any of the fair value levels during the years ended December 31, 2017 and 2016.

The Company performs sensitivity analysis for fair value measurements classified in Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions. This sensitivity analysis resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value

Pooled funds mainly consist of private equity, real estate and infrastructure investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Real estate and infrastructure investments represent funds that invest in real assets which are not publicly traded on a stock exchange. Investment strategies in real estate include limited partnerships that seek to generate a total return through income and capital growth by investing primarily in global and Canadian limited partnerships. Investment strategies in infrastructure include limited partnerships in core infrastructure assets focusing on assets that generate stable, long-term cash flows and deliver incremental returns relative to conventional fixed-income investments. Private equity, real estate and infrastructure valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Since these valuation inputs are not highly observable, private equity and infrastructure investments have been categorized as Level 3 within pooled funds.

Cash equivalents consist of demand cash deposits held with banks and cash held by the investment managers. Cash equivalents are categorized as Level 1.

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities are categorized as Level 2.

Derivative instruments are used to hedge the Pension Plan's foreign currency exposure back to Canadian dollars. The most significant currencies being hedged against the Canadian dollar are the United States dollar, Euro, and Japanese Yen. The terms to maturity of the forward exchange contracts at December 31, 2017 are within three months. The fair value of the derivative instruments is determined using inputs other than quoted prices that are observable for these assets. The fair value is determined using standard interpolation methodology primarily based on the World Markets exchange rates. Derivative instruments are categorized as Level 2.

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

20. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2017 and 2016:

Year ended December 31, 2017 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities - beginning	143	61	204
Interest accretion	6	2	8
Expenditures	(16)	(8)	(24)
Revaluation adjustment	1	7	8
Environmental liabilities - ending	134	62	196
Less: current portion	(20)	(8)	(28)
	114	54	168

Year ended December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities - beginning	148	59	207
Interest accretion	7	1	8
Expenditures	(11)	(9)	(20)
Revaluation adjustment	(1)	10	9
Environmental liabilities - ending	143	61	204
Less: current portion	(18)	(9)	(27)
	125	52	177

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

December 31, 2017 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	142	64	206
Less: discounting environmental liabilities to present value	(8)	(2)	(10)
Discounted environmental liabilities	134	62	196

December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	158	66	224
Less: discounting environmental liabilities to present value	(15)	(5)	(20)
Discounted environmental liabilities	143	61	204

At December 31, 2017, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2018	28
2019	27
2020	32
2021	34
2022	31
Thereafter	54
	206

Hydro One records a liability for the estimated future expenditures for land assessment and remediation and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act, 1999*, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, Hydro One's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is $142 million (2016 - $158 million). These expenditures are expected to be incurred over the period from 2018 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2017 to increase the PCB environmental liability by $1 million (2016 - reduce by $1 million).

Land Assessment and Remediation

The Company's best estimate of the total estimated future expenditures to complete its land assessment and remediation program is $64 million (2016 - $66 million). These expenditures are expected to be incurred over the period from 2018 to 2044. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2017 to increase the land assessment and remediation environmental liability by $7 million (2016 - $10 million).

21. ASSET RETIREMENT OBLIGATIONS

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2017, Hydro One had recorded asset retirement obligations of $9 million (2016 - $9 million), primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

22. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2017, the Company had 595,386,711 (2016 – 595,000,000) common shares issued and outstanding.

The amount and timing of any dividends payable by Hydro One is at the discretion of the Hydro One Board of Directors and is established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board of Directors may consider relevant.

The following tables present the changes to common shares during the years ended December 31, 2017 and 2016:

	Ownership by		
Year ended December 31, 2017 *(number of shares)*	Public	Province	Total
Common shares – beginning	178,196,340	416,803,660	595,000,000
Secondary offering[1]	120,000,000	(120,000,000)	—
Common shares issued - share grants[2]	371,611	—	371,611
Common shares issued - LTIP[3]	15,100	—	15,100
Sale of common shares[4]	14,391,012	(14,391,012)	—
Common shares – ending	312,974,063	282,412,648	595,386,711
	52.6%	47.4%	100%

[1] On May 17, 2017, Hydro One announced the closing of a secondary offering by the Province, on a bought deal basis, of 120 million common shares of Hydro One on the Toronto Stock Exchange. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

[2] On April 1, 2017, Hydro One issued from treasury 371,611 common shares in accordance with provisions of the Power Workers' Union (PWU) Share Grant Plan.

[3] In 2017, Hydro One issued from treasury 15,100 common shares in accordance with provisions of the LTIP.

[4] On December 29, 2017, the Province sold 14,391,012 common shares of Hydro One to OFN Power Holdings LP, a limited partnership wholly-owned by Ontario First Nations Sovereign Wealth LP, which is in turn owned by 129 First Nations in Ontario. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

	Ownership by		
Year ended December 31, 2016 *(number of shares)*	Public	Province	Total
Common shares – beginning	94,896,340	500,103,660	595,000,000
Secondary offering[1]	83,300,000	(83,300,000)	—
Common shares – ending	178,196,340	416,803,660	595,000,000
	29.9%	70.1%	100%

[1] On April 14, 2016, Hydro One announced the closing of a secondary offering by the Province, on a bought deal basis, of 72,434,800 common shares of Hydro One on the Toronto Stock Exchange. In addition, the Province granted the underwriters an over-allotment option to purchase up to an additional 10,865,200 common shares of Hydro One which was fully exercised and closed on April 29, 2016. Hydro One did not receive any of the proceeds from the sale of common shares by the Province.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2017 and 2016, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At

December 31, 2017 and 2016, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

Hydro One may from time to time issue preferred shares in one or more series. Prior to issuing shares in a series, the Hydro One Board of Directors is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of preferred shares. Holders of Hydro One's preferred shares are not entitled to receive notice of, to attend or to vote at any meeting of the shareholders of Hydro One except that votes may be granted to a series of preferred shares when dividends have not been paid on any one or more series as determined by the applicable series provisions. Each series of preferred shares ranks on parity with every other series of preferred shares, and are entitled to a preference over the common shares and any other shares ranking junior to the preferred shares, with respect to dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One.

For the period commencing from the date of issue of the Series 1 preferred shares and ending on and including November 19, 2020, the holders of Series 1 preferred shares are entitled to receive fixed cumulative preferential dividends of $1.0625 per share per year, if and when declared by the Board of Directors, payable quarterly. The dividend rate will reset on November 20, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.53%. The Series 1 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One on November 20, 2020 and on November 20 of every fifth year thereafter at a redemption price equal to $25.00 for each Series 1 preferred share redeemed, plus any accrued or unpaid dividends. The holders of Series 1 preferred shares will have the right, at their option, on November 20, 2020 and on November 20 of every fifth year thereafter, to convert all or any of their Series 1 preferred shares into Series 2 preferred shares on a one-for-one basis, subject to certain restrictions on conversion. At December 31, 2017, no preferred share dividends were in arrears.

The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends, if and when declared by the Board of Directors, at a rate equal to the sum of the then three-month Government of Canada treasury bill rate and 3.53% as reset quarterly. The Series 2 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One at a redemption price equal to $25.00 for each Series 2 preferred share redeemed, if redeemed on November 20, 2025 or on November 20 of every fifth year thereafter, or $25.50 for each Series 2 preferred share redeemed, if redeemed on any other date after November 20, 2020, in each case plus any accrued or unpaid dividends. The holders of Series 2 preferred shares will have the right, at their option, on November 20, 2025 and on November 20 of every fifth year thereafter, to convert all or any of their Series 2 preferred shares into Series 1 preferred shares on a one-for-one basis, subject to certain restrictions on conversion.

Share Ownership Restrictions

The *Electricity Act* imposes share ownership restrictions on securities of Hydro One carrying a voting right (Voting Securities). These restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert) may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities, including common shares of the Company (Share Ownership Restrictions). The Share Ownership Restrictions do not apply to Voting Securities held by the Province, nor to an underwriter who holds Voting Securities solely for the purpose of distributing those securities to purchasers who comply with the Share Ownership Restrictions.

23. DIVIDENDS

In 2017, preferred share dividends in the amount of $18 million (2016 - $19 million) and common share dividends in the amount of $518 million (2016 - $577 million) were declared. The 2016 common share dividends include $77 million for the post-Initial Public Offering (IPO) period from November 5 to December 31, 2015, and $500 million for the year ended December 31, 2016.

24. EARNINGS PER COMMON SHARE

Basic earnings per common share (EPS) is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding.

Diluted EPS is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding adjusted for the effects of potentially dilutive stock-based compensation plans, including the share grant plans and the LTIP, which are calculated using the treasury stock method.

Year ended December 31	2017	2016
Net income attributable to common shareholders *(millions of dollars)*	658	721
Weighted average number of shares		
Basic	595,287,586	595,000,000
Effect of dilutive stock-based compensation plans	2,234,665	1,700,823
Diluted	597,522,251	596,700,823
EPS		
Basic	$1.11	$1.21
Diluted	$1.10	$1.21

The common shares contingently issuable as a result of the Convertible Debentures are not included in diluted EPS until conditions for closing the Avista Corporation acquisition are met.

25. STOCK-BASED COMPENSATION

Share Grant Plans

Hydro One has two share grant plans (Share Grant Plans), one for the benefit of certain members of the PWU (PWU Share Grant Plan) and one for the benefit of certain members of The Society (Society Share Grant Plan).

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 3,979,062 common shares were granted under the PWU Share Grant Plan.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of The Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 1,433,292 common shares were granted under the Society Share Grant Plan.

The fair value of the Hydro One 2015 share grants of $111 million was estimated based on the grant date share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2017, 371,611 common shares were granted under the Share Grant Plans (2016 - nil). Total share based compensation recognized during 2017 was $17 million (2016 - $21 million) and was recorded as a regulatory asset.

A summary of share grant activity under the Share Grant Plans during years ended December 31, 2017 and 2016 is presented below:

Year ended December 31, 2017	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	5,334,415	$20.50
Vested and issued[1]	(371,611)	—
Forfeited	(137,072)	$20.50
Share grants outstanding - ending	4,825,732	$20.50

[1] On April 1, 2017, Hydro One issued from treasury 371,611 common shares to eligible employees in accordance with provisions of the PWU Share Grant Plan.

Year ended December 31, 2016	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	5,412,354	$20.50
Forfeited	(77,939)	$20.50
Share grants outstanding - ending	5,334,415	$20.50

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

During the years ended December 31, 2017 and 2016, the Company granted awards under the Directors' DSU Plan, as follows:

Year ended December 31 *(number of DSUs)*	2017	2016
DSUs outstanding - beginning	99,083	20,525
DSUs granted	88,007	78,558
DSUs outstanding - ending	187,090	99,083

For the year ended December 31, 2017, an expense of $2 million (2016 - $2 million) was recognized in earnings with respect to the Directors' DSU Plan. At December 31, 2017, a liability of $4 million (2016 - $2 million), related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

During the years ended December 31, 2017 and 2016, the Company granted awards under the Management DSU Plan, as follows:

Year ended December 31 *(number of DSUs)*	2017	2016
DSUs outstanding - beginning	—	—
Granted	68,897	—
Paid	(1,068)	—
DSUs outstanding - ending	67,829	—

For the year ended December 31, 2017, an expense of $2 million (2016 - $nil) was recognized in earnings with respect to the Management DSU Plan. At December 31, 2017, a liability of $2 million (2016 - $nil) related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Employee Share Ownership Plan

In 2015, Hydro One established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2017, Company contributions made under the ESOP were $2 million (2016 - $2 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One and its subsidiaries, and all equity-based awards will be settled in newly issued shares of Hydro One from treasury, consistent with the provisions of the plan. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One.

The LTIP provides flexibility to award a range of vehicles, RSUs, PSUs, stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

During 2017 and 2016, the Company granted awards under its LTIP as follows:

Year ended December 31 *(number of units)*	PSUs 2017	PSUs 2016	RSUs 2017	RSUs 2016
Units outstanding - beginning	230,600	—	254,150	—
Units granted	303,240	235,420	242,860	258,970
Units vested	(609)	—	(14,079)	—
Units forfeited	(103,251)	(4,820)	(89,501)	(4,820)
Units outstanding - ending	429,980	230,600	393,430	254,150

The grant date total fair value of the awards granted in 2017 was $13 million (2016 - $12 million). The compensation expense related to these awards recognized by the Company during 2017 was $6 million (2016 - $3 million).

26. NONCONTROLLING INTEREST

On December 16, 2014, transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the Saugeen Ojibway Nation (SON) acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired. The SON's initial investment in B2M LP consists of $50 million of Class A units and $22 million of Class B units.

The Class B units have a mandatory put option which requires that upon the occurrence of an enforcement event (i.e. an event of default such as a debt default by the SON or insolvency event), Hydro One purchase the Class B units of B2M LP for net book value on the redemption date. The noncontrolling interest relating to the Class B units is classified on the Consolidated Balance Sheet as temporary equity because the redemption feature is outside the control of the Company. The balance of the noncontrolling interest is classified within equity.

The following tables show the movements in noncontrolling interest during the years ended December 31, 2017 and 2016:

Year ended December 31, 2017 *(millions of dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest - beginning	22	50	72
Distributions to noncontrolling interest	(2)	(4)	(6)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest - ending	22	50	72

Year ended December 31, 2016 *(millions of dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest - beginning	23	52	75
Distributions to noncontrolling interest	(3)	(6)	(9)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest - ending	22	50	72

27. RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One.

Year ended December 31 *(millions of dollars)*			
Related Party	Transaction	2017	2016
Province	Dividends paid	301	451
IESO	Power purchased	1,583	2,096
	Revenues for transmission services	1,521	1,549
	Amounts related to electricity rebates	357	—
	Distribution revenues related to rural rate protection	247	125
	Distribution revenues related to the supply of electricity to remote northern communities	32	32
	Funding received related to CDM programs	59	63
OPG	Power purchased	9	6
	Revenues related to provision of construction and equipment maintenance services	3	5
	Costs related to the purchase of services	1	1
OEFC	Power purchased from power contracts administered by the OEFC	2	1
OEB	OEB fees	8	11
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	3

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest-free and settled in cash.

28. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2017	2016
Accounts receivable	195	(60)
Due from related parties	(95)	33
Materials and supplies	1	2
Prepaid expenses and other assets	7	(15)
Accounts payable	7	19
Accrued liabilities	(89)	53
Due to related parties	10	9
Accrued interest	(6)	9
Long-term accounts payable and other liabilities	(2)	6
Post-retirement and post-employment benefit liability	85	78
	113	134

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts presented in the Consolidated Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2017	2016
Capital investments in property, plant and equipment	(1,493)	(1,630)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	26	30
Cash outflow for capital expenditures – property, plant and equipment	(1,467)	(1,600)

The following table reconciles investments in intangible assets and the amounts presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2017	2016
Capital investments in intangible assets	(74)	(67)
Net change in accruals included in capital investments in intangible assets	(6)	6
Cash outflow for capital expenditures – intangible assets	(80)	(61)

Capital Contributions

Hydro One enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One will periodically reassess the estimated of load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to fixed assets in service. In 2017, capital contributions from these reassessments totalled $9 million (2016 - $21 million), which represents the difference between the revised load forecast of electricity transmitted compared to the load forecast in the original contract, subject to certain adjustments.

Supplementary Information

Year ended December 31 *(millions of dollars)*	2017	2016
Net interest paid	475	418
Income taxes paid	12	32

29. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities, and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, an estimate of a possible loss related to this claim cannot be made.

To date, four putative class action lawsuits have been filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. The Washington state court issued an order staying the litigation until after the plaintiffs file an amended complaint, which must be no later than 30 days after Avista Corporation or Hydro One publicly announces that the Merger has closed. Second, *Jenß v. Avista Corp., et al., Samuel v. Avista Corp., et al., and Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and named as defendants Avista Corporation and its directors; *Sharpenter* also named Hydro One, Olympus Holding Corp., and Olympus Corp. The lawsuits alleged that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. *Jenß, Samuel, and Sharpenter* were all voluntarily dismissed by the respective plaintiffs with no consideration paid by any of the defendants. The one remaining class action is consistent with expectations for US merger transactions and, while there is no certainty as to outcome, Hydro One believes that the lawsuit is not material to Hydro One.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2017, the Company paid approximately $2 million (2016 - $1 million) in respect of consents obtained. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

30. COMMITMENTS

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter:

December 31, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing agreements	139	95	2	2	2	7
Long-term software/meter agreement	17	17	16	2	1	3
Operating lease commitments	12	7	11	6	4	4

Outsourcing Agreements

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society and the PWU to facilitate the insourcing of these services effective March 1, 2018.

Brookfield Global Integrated Solutions (formerly Brookfield Johnson Controls Canada LP) (Brookfield) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The agreement with Brookfield for these services expires in December 2024.

Long-term Software/Meter Agreement

Trilliant Holdings Inc. and Trilliant Networks (Canada) Inc. (collectively Trilliant) provide services to Hydro One for the supply, maintenance and support services for smart meters and related hardware and software, including additional software licences, as well as certain professional services. The agreement with Trilliant for these services expires in December 2025, but Hydro One has the option to renew for an additional term of five years at its sole discretion.

Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service-related functions and storing telecommunications equipment. These leases have typical terms of between three and five years, but several leases have lesser or greater terms to address special circumstances and/or opportunities. Renewal options, which are generally prevalent in most leases, have similar terms of three to five years. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases. During the year ended December 31, 2017, the Company made lease payments totalling $12 million (2016 - $11 million).

Other Commitments

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next 5 years and thereafter:

December 31, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Credit facilities	—	—	—	250	2,300	—
Letters of credit[1]	177	—	—	—	—	—
Guarantees[2]	325	—	—	—	—	—

[1] Letters of credit consist of a $154 million letter of credit related to retirement compensation arrangements, a $16 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[2] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees and/or letters of credit if these purchasers fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amount of the parental guarantees.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for Hydro One Inc.'s liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One Inc. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One Inc. is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure Hydro One Inc.'s liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit.

31. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, which includes certain corporate activities and the operations of the Company's telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

Year ended December 31, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,578	4,366	46	5,990
Purchased power	—	2,875	—	2,875
Operation, maintenance and administration	375	593	98	1,066
Depreciation and amortization	420	390	7	817
Income (loss) before financing charges and income taxes	783	508	(59)	1,232
Capital investments	968	588	11	1,567

Year ended December 31, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,584	4,915	53	6,552
Purchased power	—	3,427	—	3,427
Operation, maintenance and administration	382	608	79	1,069
Depreciation and amortization	390	379	9	778
Income (loss) before financing charges and income taxes	812	501	(35)	1,278
Capital investments	988	703	6	1,697

Total Assets by Segment:

December 31 *(millions of dollars)*	2017	2016
Transmission	13,608	13,071
Distribution	9,259	9,379
Other	2,834	2,901
Total assets	25,701	25,351

Total Goodwill by Segment:

December 31 *(millions of dollars)*	2017	2016
Transmission *(Note 4)*	157	159
Distribution	168	168
Total goodwill	325	327

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

32. SUBSEQUENT EVENTS

Dividends

On February 12, 2018, preferred share dividends in the amount of $4 million and common share dividends in the amount of $131 million ($0.22 per common share) were declared.

The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the consolidated financial statements and accompanying notes thereto (Consolidated Financial Statements) of Hydro One Limited (Hydro One or the Company) for the year ended December 31, 2017. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. This MD&A provides information for the year ended December 31, 2017, based on information available to management as of February 12, 2018.

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

Year ended December 31 *(millions of dollars, except as otherwise noted)*	2017	2016	Change
Revenues	5,990	6,552	(8.6%)
Purchased power	2,875	3,427	(16.1%)
Revenues, net of purchased power[1]	3,115	3,125	(0.3%)
Operation, maintenance and administration costs	1,066	1,069	(0.3%)
Depreciation and amortization	817	778	5.0%
Financing charges	439	393	11.7%
Income tax expense	111	139	(20.1%)
Net income attributable to common shareholders of Hydro One	**658**	**721**	**(8.7%)**
Basic earnings per common share (EPS)	$1.11	$1.21	(8.3%)
Diluted EPS	$1.10	$1.21	(9.1%)
Basic adjusted non-GAAP EPS (Adjusted EPS)[1]	$1.17	$1.21	(3.3%)
Diluted Adjusted EPS[1]	$1.16	$1.21	(4.1%)
Net cash from operating activities	1,716	1,656	3.6%
Funds from operations (FFO)[1]	1,579	1,494	5.7%
Capital investments	1,567	1,697	(7.7%)
Assets placed in-service	1,592	1,605	(0.8%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	19,587	20,690	(5.3%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	25,876	26,289	(1.6%)

	2017	2016
Debt to capitalization ratio[2]	52.9%	52.6%

[1] See section "Non-GAAP Measures" for description and reconciliation of basic and diluted Adjusted EPS, FFO and Revenues, net of purchased power.

[2] Debt to capitalization ratio has been presented at December 31, 2017 and 2016, and has been calculated as total debt (includes total long-term debt, convertible debentures and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to noncontrolling interest.

OVERVIEW

Hydro One is the largest electricity transmission and distribution company in Ontario. Through its wholly-owned subsidiary, Hydro One Inc., Hydro One owns and operates substantially all of Ontario's electricity transmission network, and approximately 123,000 circuit kilometres of primary low-voltage distribution network. Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

For the year ended December 31, 2017, Hydro One's business segments accounted for the Company's total revenues, net of purchased power, as follows:

	Transmission	Distribution	Other
Percentage of Company's total revenues, net of purchased power	51%	48%	1%

At December 31, 2017, Hydro One's business segments accounted for the Company's total assets as follows:

	Transmission	Distribution	Other
Percentage of Company's total assets	53%	36%	11%

Transmission Segment

Hydro One's transmission business owns, operates and maintains Hydro One's transmission system, which accounts for approximately 98% of Ontario's transmission capacity based on revenue approved by the Ontario Energy Board (OEB). The transmission business consists of the transmission system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks Inc. (Hydro One Networks) and Hydro One Sault Ste. Marie LP (HOSSM) (formerly Great Lakes Power Transmission LP), as well as a 66% interest in B2M Limited Partnership (B2M LP), a limited partnership between Hydro One and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. The Company's transmission business is a rate-regulated business that earns revenues mainly from charging transmission rates that are approved by the OEB.

	2017	2016
Electricity transmitted[1] *(MWh)*	132,090,992	136,989,747
Transmission lines spanning the province *(circuit-kilometres)*	30,290	30,259
Rate base *(millions of dollars)*	11,251	10,775
Capital investments *(millions of dollars)*	968	988
Assets placed in-service *(millions of dollars)*	889	937

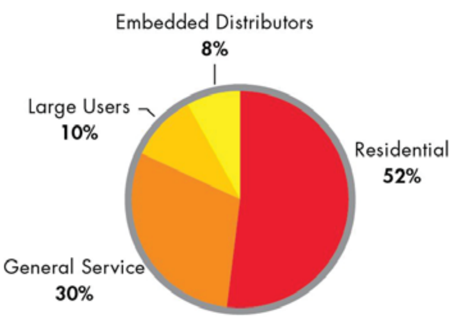
[1] Electricity transmitted represents total electricity transmission in Ontario by all transmitters.

Distribution Segment

Hydro One's distribution business is the largest in Ontario and consists of the distribution system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks and Hydro One Remote Communities Inc. The Company's distribution business is a rate-regulated business that earns revenues mainly by charging distribution rates that are approved by the OEB.

	2017	2016
Electricity distributed to Hydro One customers *(GWh)*	25,876	26,289
Electricity distributed through Hydro One lines *(GWh)*[1]	36,525	37,394
Distribution lines spanning the province *(circuit-kilometres)*	123,361	122,599
Distribution customers *(number of customers)*	1,372,362	1,355,302
Rate base *(millions of dollars)*	7,389	7,056
Capital investments *(millions of dollars)*	588	703
Assets placed in-service *(millions of dollars)*	689	662

[1] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the Independent Electricity System Operator (IESO).



2017 Distribution Revenues

Other Business Segment

Hydro One's other business segment consists of the Company's telecommunications business and certain corporate activities. The telecommunications business provides telecommunications support for the Company's transmission and distribution businesses, and also offers communications and IT solutions to organizations with broadband network requirements utilizing Hydro One Telecom Inc.'s (Hydro One Telecom) fibre optic network to provide diverse, secure and highly reliable broadband connectivity. Hydro One's other business segment is not rate-regulated.

PRIMARY FACTORS AFFECTING RESULTS OF OPERATIONS

Transmission Revenues

Transmission revenues primarily consist of regulated transmission rates approved by the OEB which are charged based on the monthly peak electricity demand across Hydro One's high-voltage network. Transmission rates are designed to generate revenues necessary to construct, upgrade, extend and support a transmission system with sufficient capacity to accommodate maximum forecasted demand and a regulated return on the Company's investment. Peak electricity demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting electricity to markets outside of Ontario. Ancillary revenues include revenues from providing maintenance services to power generators and from third-party land use.

Distribution Revenues

Distribution revenues include regulated distribution rates approved by the OEB and amounts to recover the cost of purchased power used by the customers of the distribution business. Distribution rates are designed to generate revenues necessary to construct and support the local distribution system with sufficient capacity to accommodate existing and new customer demand and a regulated return on the Company's investment. Accordingly, distribution revenues are influenced by distribution rates, the cost of purchased power, and the amount of electricity the Company distributes. Distribution revenues also include ancillary distribution service revenues, such as fees related to the joint use of Hydro One's distribution poles by the telecommunications and cable television industries, as well as miscellaneous revenues such as charges for late payments.

Purchased Power Costs

Purchased power costs are incurred by the distribution business and represent the cost of the electricity purchased by the Company for delivery to customers within Hydro One's distribution service territory. These costs are comprised of the following: the wholesale commodity cost of energy; the Global Adjustment, which is the difference between amounts the IESO pays energy producers for the electricity they produce and the actual fair market value of this electricity; and the wholesale market service and transmission charges levied by the IESO. Hydro One passes the cost of electricity that it delivers to its customers, and is therefore not exposed to wholesale electricity commodity price risk

Operation, Maintenance and Administration Costs

Operation, maintenance and administration (OM&A) costs are incurred to support the operation and maintenance of the transmission and distribution systems, and other costs such as property taxes related to transmission and distribution lines, stations and buildings. Transmission OM&A costs are incurred to sustain the Company's high-voltage transmission stations, lines, and rights-of-way, and include preventive and corrective maintenance costs related to power equipment, overhead transmission lines, transmission station sites, and forestry control to maintain safe distance between line spans and trees. Distribution OM&A costs are required to maintain the Company's low-voltage distribution system to provide safe and reliable electricity to the Company's residential, small business, commercial, and industrial customers across the province. These include costs related to distribution line clearing and forestry control to reduce power outages caused by trees, line maintenance and repair, land assessment and remediation, as well as issuing timely and accurate bills and responding to customer inquiries. Hydro One manages its costs through ongoing efficiency and productivity initiatives, while continuing to complete planned work programs associated with the development and maintenance of its transmission and distribution networks.

Depreciation and Amortization

Depreciation and amortization costs relate primarily to depreciation of the Company's property, plant and equipment, and amortization of certain intangible assets and regulatory assets. Depreciation and amortization also includes the costs incurred to remove property, plant and equipment where no asset retirement obligations have been recorded on the balance sheet.

Financing Charges

Financing charges relate to the Company's financing activities, and include interest expense on the Company's long-term debt and short-term borrowings, and gains and losses on interest rate swap agreements, contingent foreign exchange or other similar contracts, net of interest earned on short-term investments. A portion of financing charges incurred by the Company is capitalized to the cost of property, plant and equipment associated with the periods during which such assets are under construction before being placed in-service.

RESULTS OF OPERATIONS

Net Income

Net income attributable to common shareholders for the year ended December 31, 2017 of $658 million is a decrease of $63 million or 8.7% from the prior year. Significant influences on net income included:

- decrease in transmission and distribution revenues due to lower energy consumption during 2017 resulting from milder weather;
- higher transmission revenues driven by OEB's decision on the 2017-2018 transmission rates filing;
- transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- lower OM&A costs primarily resulting from a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, insurance proceeds received due to failed equipment at two transformer stations, and a tax recovery of previous year's expenses; as well as reduced vegetation management costs and lower support services costs. These factors were offset by higher consulting costs primarily related to the acquisition of Avista Corporation; and lower bad debt expense in 2016 due to revised estimates of uncollectible accounts resulting from the stabilization of the customer information system;
- increased financing charges primarily due to the issuance of convertible debentures in August 2017; as well as a higher weighted average long-term debt portfolio during 2017 compared to 2016, including long-term debt assumed as part of the HOSSM acquisition in the fourth quarter of 2016; and
- higher depreciation expense due to an increase in property, plant and equipment.

EPS and Adjusted EPS

EPS of $1.11 in 2017, compared to $1.21 in 2016. The decrease in EPS was driven by lower net income in 2017, as discussed above. Adjusted EPS, which adjusts for costs related to the Avista Corporation acquisition, was $1.17 in 2017, compared to $1.21 in 2016. The decrease in Adjusted EPS was also driven by lower net income in 2017, as discussed above, excluding the aforementioned impact related to Avista Corporation acquisition. See section "Non-GAAP Measures" for description of Adjusted EPS.

Revenues

Year ended December 31 *(millions of dollars, except as otherwise noted)*	2017	2016	Change
Transmission	1,578	1,584	(0.4%)
Distribution	4,366	4,915	(11.2%)
Other	46	53	(13.2%)
Total revenues	5,990	6,552	(8.6%)
Transmission	1,578	1,584	(0.4%)
Distribution, net of purchased power	1,491	1,488	0.2%
Other	46	53	(13.2%)
Total revenues, net of purchased power	3,115	3,125	(0.3%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	19,587	20,690	(5.3%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	25,876	26,289	(1.6%)

Transmission Revenues

Transmission revenues decreased by 0.4% in 2017 primarily due to the following:

- lower average monthly Ontario 60-minute peak demand mainly due to milder weather in the first three quarters of 2017;
- decreased OEB-approved transmission rates primarily reflecting a reduction in 2017 allowed ROE for the transmission business from 9.19% to 8.78%; offset by
- higher revenues driven by the OEB's decision on the 2017-2018 transmission rates filing; and
- additional revenues resulting from the acquisition of HOSSM in the fourth quarter of 2016.

Distribution Revenues, Net of Purchased Power

Distribution revenues, net of purchased power, increased by 0.2% in 2017 primarily due to the following:

- lower energy consumption mainly resulting from milder weather in the first three quarters of 2017; offset by
- higher external revenues related to Conservation and Demand Management (CDM) incentive bonus; and
- higher OEB-approved distribution rates for 2017, net of a reduction in 2017 allowed ROE for the distribution business from 9.19% to 8.78%.

OM&A Costs

Year ended December 31 *(millions of dollars)*	2017	2016	Change
Transmission	375	382	(1.8%)
Distribution	593	608	(2.5%)
Other	98	79	24.1%
	1,066	1,069	(0.3%)

Transmission OM&A Costs

The decrease of 1.8% in transmission OM&A costs for the year ended December 31, 2017 was primarily due to:

- a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulation;
- lower support services costs; and
- insurance proceeds received due to equipment failures at the Fairchild and Campbell transmission stations; partially offset by
- higher volume of environmental management program work.

Distribution OM&A Costs

The decrease of 2.5% in distribution OM&A costs for the year ended December 31, 2017 was primarily due to:

- continued lower expenditures for vegetation management due to strategic changes to the forestry program scope that resulted in cost efficiency and improved management of the Company's rights of ways;
- lower volume of line maintenance work;
- lower spend on development and research programs; and
- a tax recovery of previous year's expenses; partially offset by
- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system, partially offset by lower bad debt expense in 2017 attributable to lower write-offs and improved accounts receivable aging; and
- increased storm restoration costs as a result of Hurricane Irma restoration efforts in Florida. These restoration efforts had no impact on the Company's net income, as related revenues were recorded in distribution revenues during the year.

Other OM&A Costs

The increase in other OM&A costs for the year ended December 31, 2017 was driven by higher consulting costs primarily related to the acquisition of Avista Corporation.

Depreciation and Amortization

The increase of $39 million or 5.0% in depreciation and amortization costs for 2017 was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

Financing Charges

The increase of $46 million or 11.7% in financing charges for the year ended December 31, 2017 was primarily due to the following:

- an increase in interest expense on long-term debt driven by a higher weighted average long-term debt portfolio during 2017 including the long-term debt assumed as part of the HOSSM acquisition in the fourth quarter of 2016; partially offset by a decrease in the weighted average interest rate for long-term debt; and
- an increase in interest expense related to the Convertible Debentures issued in August 2017.

Income Tax Expense

Income tax expense for the year ended December 31, 2017 decreased by $28 million compared to 2016, and the Company realized an effective tax rate of approximately 14.0% in 2017, compared to approximately 15.7% realized in 2016. The decreases in the tax expense and the effective tax rate are primarily due to lower income before taxes in 2017.

Common Share Dividends

In 2017, the Company declared and paid cash dividends to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount (millions of dollars)
February 9, 2017	March 14, 2017	March 31, 2017	$0.21	125
May 3, 2017	June 13, 2017	June 30, 2017	$0.22	131
August 8, 2017	September 12, 2017	September 29, 2017	$0.22	131
November 9, 2017	December 12, 2017	December 29, 2017	$0.22	131
				518

Following the conclusion of the fourth quarter of 2017, the Company declared a cash dividend to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount (millions of dollars)
February 12, 2018	March 13, 2018	March 29, 2018	$0.22	131

SELECTED ANNUAL FINANCIAL STATISTICS

Year ended December 31 (millions of dollars, except per share amounts)	2017	2016	2015
Revenues	5,990	6,552	6,538
Net income attributable to common shareholders	658	721	690
Basic EPS	$1.11	$1.21	$1.39
Diluted EPS	$1.10	$1.21	$1.39
Basic Adjusted EPS	$1.17	$1.21	$1.16
Diluted Adjusted EPS	$1.16	$1.21	$1.16
Dividends per common share declared	$0.87	$0.97[1]	$1.83
Dividends per preferred share declared	$1.06	$1.12	$1.03

[1] The $0.97 per share dividends declared in 2016 included $0.13 for the post-IPO period from November 5 to December 31, 2015, and $0.84 for the year ended December 31, 2016.

December 31 (millions of dollars)	2017	2016	2015
Total assets	25,701	25,351	24,294
Total non-current financial liabilities	9,802	10,078	8,207

QUARTERLY RESULTS OF OPERATIONS

Quarter ended (millions of dollars, except EPS)	Dec 31, 2017	Sep 30, 2017	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016
Revenues	1,439	1,522	1,371	1,658	1,614	1,706	1,546	1,686
Purchased power	662	675	649	889	858	870	803	896
Revenues, net of purchased power	777	847	722	769	756	836	743	790
Net income to common shareholders	155	219	117	167	128	233	152	208
Basic EPS	$0.26	$0.37	$0.20	$0.28	$0.22	$0.39	$0.26	$0.35
Diluted EPS	$0.26	$0.37	$0.20	$0.28	$0.21	$0.39	$0.25	$0.35
Basic Adjusted EPS[1]	$0.29	$0.40	$0.20	$0.28	$0.22	$0.39	$0.26	$0.35
Diluted Adjusted EPS[1]	$0.28	$0.40	$0.20	$0.28	$0.21	$0.39	$0.25	$0.35

[1] See section "Non-GAAP Measures" for description of Adjusted EPS.

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

CAPITAL INVESTMENTS

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution system assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations.

Assets Placed In-Service

The following table presents Hydro One's assets placed in-service during the year ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016	Change
Transmission	889	937	(5.1%)
Distribution	689	662	4.1%
Other	14	6	133.3%
Total assets placed in-service	1,592	1,605	(0.8%)

Transmission Assets Placed In-Service

Transmission assets placed in-service decreased by $48 million or 5.1% during the year ended December 31, 2017 primarily due to the following:

- substantial investments of two major local area supply projects, Guelph Area Transmission Refurbishment and Toronto Midtown Transmission Reinforcement, were placed in-service in 2016;
- completion of the Advanced Distribution System project at Owen Sound transmission station in 2016;
- timing of assets placed in-service for the sustainment investments at Burlington and Bruce A transmission stations; partially offset by investments at Aylmer and Overbrook transmission stations; and
- lower volume of end-of-life transformer replacements work; partially offset by
- substantial investments of major development projects at Leamington and Holland transmission stations were placed in-service in the fourth quarter of 2017;
- higher volume of overhead lines and component refurbishments and replacements; and
- the completion of the Field Workforce Optimization (Move-to-Mobile) project in June 2017.

Distribution Assets Placed In-Service

Distribution assets placed in-service increased by $27 million or 4.1% during the year ended December 31, 2017 primarily due to the following:

- higher volume of subdivision connections due to increased demand;
- the completion of the Move-to-Mobile project in June 2017;
- the completion of an operation center in Bolton in February 2017;
- the completion of the Outage Response Management System (ORMS) project in the third quarter of 2017; and
- substantial investments that were placed in-service for the Leamington transmission station feeder development project; partially offset by
- the Advanced Metering Infrastructure Wireless Telecom project was placed in-service during 2016;
- lower volume of generation connection projects; and
- lower volume of distribution station refurbishments and spare transformer purchases.

Capital Investments

The following table presents Hydro One's capital investments during the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016	Change
Transmission			
Sustaining	764	750	1.9%
Development	137	156	(12.2%)
Other	67	82	(18.3%)
	968	988	(2.0%)
Distribution			
Sustaining	280	384	(27.1%)
Development	227	217	4.6%
Other	81	102	(20.6%)
	588	703	(16.4%)
Other	11	6	83.3%
Total capital investments	1,567	1,697	(7.7%)

Transmission Capital Investments

Transmission capital investments decreased by $20 million or 2.0% during the year ended December 31, 2017. Principal impacts on the levels of capital investments included:

- construction work on Clarington Transmission Station project is substantially complete and therefore, lower investments in 2017;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- lower volume of transmission station refurbishments and component replacements work; and
- substantial completion of the Guelph Area Transmission Refurbishment project in 2016; partially offset by
- higher volume of overhead lines and component refurbishments and replacements; and
- substantial completion of the Leamington transmission station project to address the electricity needs in Windsor and Essex County.

Distribution Capital Investments

Distribution capital investments decreased by $115 million or 16.4% during the year ended December 31, 2017. Principal impacts on the levels of capital investments included:

- lower volume of work within station refurbishment programs;
- lower volume of line refurbishments and replacements work;
- lower volume of wood pole replacements;
- lower volume of fleet and work equipment purchases;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- completion of the Bolton Operation Centre; partially offset by
- higher volume of work on new connections and upgrades due to increased demand.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at December 31, 2017:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To Date
Development Projects:					
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$57 million[1]	$52 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$267 million	$223 million
East-West Tie Station Expansion	Northern Ontario	New transmission connection and station expansion	2021	$157 million	$7 million
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	2024	$350 million	$1 million
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2020	$109 million[2]	$105 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$103 million	$85 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2022	$93 million	$51 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2023	$95 million	$44 million

[1] In February 2018, the estimated cost to complete the Supply to Essex County Transmission Reinforcement project was reduced from $73 million to $57 million.
[2] The estimated cost to complete the Bruce A Transmission Station project is currently under review.

Future Capital Investments

Following is a summary of estimated capital investments by Hydro One over the years 2018 to 2022. The Company's estimates are based on management's expectations of the amount of capital expenditures that will be required to provide transmission and distribution services that are efficient, reliable, and provide value for customers, consistent with the OEB's Renewed Regulatory Framework. The 2018 transmission capital investments estimates differ from the prior year disclosures, representing an annual decrease of $122 million to reflect the OEB's focus on planning practices and the pacing of sustainment capital investments, specifically, tower coating, stations, and insulator investments, as indicated in the OEB's 2017-2018 transmission rates decision issued in September 2017. The projections and the timing of 2019-2022 expenditures are subject to approval by the OEB.

The following table summarizes Hydro One's annual projected capital investments for 2018 to 2022, by business segment:

(millions of dollars)	2018	2019	2020	2021	2022
Transmission	1,010	1,217	1,278	1,486	1,404
Distribution	641	751	715	719	805
Other	9	8	6	9	8
Total capital investments	**1,660**	**1,976**	**1,999**	**2,214**	**2,217**

The following table summarizes Hydro One's annual projected capital investments for 2018 to 2022, by category:

(millions of dollars)	2018	2019	2020	2021	2022
Sustainment	1,103	1,220	1,328	1,547	1,608
Development	340	484	487	490	430
Other[1]	217	272	184	177	179
Total capital investments	**1,660**	**1,976**	**1,999**	**2,214**	**2,217**

[1] "Other" capital expenditures consist of special projects, such as those relating to information technology.

SUMMARY OF SOURCES AND USES OF CASH

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

Year ended December 31 *(millions of dollars)*	2017	2016
Cash provided by operating activities	1,716	1,656
Cash provided by (used in) financing activities	(201)	161
Cash used in investing activities	(1,540)	(1,861)
Decrease in cash and cash equivalents	(25)	(44)

Cash provided by operating activities

Cash from Operating Activities increased by $60 million during 2017 primarily due to changes in regulatory variance and deferral accounts, as well as lower energy-related receivables which decreased as a result of improved collections in 2017. These factors were partially offset by changes in accrual balances.

Cash provided by financing activities

Sources of cash

- The Company did not issue long-term debt in 2017, compared to proceeds from the issuance of $2.3 billion in 2016.
- The Company received proceeds of $3,795 million from the issuance of short-term notes in 2017, compared to $3,031 million received in 2016.
- In 2017, the Company received proceeds of $513 million, representing the first instalment of the convertible debentures issued, gross of $27 million financing costs, compared to no convertible debentures issuances in 2016.

Uses of cash

- Dividends paid in 2017 were $536 million, consisting of $518 million common share dividends and $18 million of preferred share dividends, compared to dividends of $596 million paid in 2016, consisting of $577 million common share dividends and $19 million of preferred share dividends. The 2016 common share dividends included $77 million of dividends for the post-IPO period from November 5 to December 31, 2015, and $500 million of dividends for the year ended December 31, 2016.
- The Company repaid $3,338 million of short-term notes in 2017, compared to $4,053 million repaid in 2016.
- The Company repaid $602 million of long-term debt in 2017, compared to long-term debt of $502 million repaid in 2016.

Cash used in investing activities

Uses of cash

- Capital expenditures were $114 million lower in 2017, primarily due to lower volume and timing of capital investment work.
- In 2016, the Company paid $224 million to acquire HOSSM, compared to no acquisition payments made in 2017.

LIQUIDITY AND FINANCING STRATEGY

Short-term liquidity is provided through funds from operations, Hydro One Inc.'s commercial paper program, and the Company's consolidated bank credit facilities. Under the commercial paper program, Hydro One Inc. is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At December 31, 2017, Hydro One Inc. had $926 million in commercial paper borrowings outstanding, compared to $469 million outstanding at December 31, 2016. In addition, the Company has revolving bank credit facilities totalling $2,550 million maturing in 2021 and 2022. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the commercial paper program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At December 31, 2017, the Company's long-term debt in the principal amount of $10,069 million included $9,923 million of long-term debt, the majority of which was issued under Hydro One Inc.'s Medium Term Note (MTN) Program, and long-term debt in the principal amount of $146 million held by HOSSM. At December 31, 2017, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2018 and 2064, and at December 31, 2017, had an average term to maturity of approximately 15.8 years and a weighted average coupon rate of 4.2%.

In March 2016, Hydro One filed a universal short form base shelf prospectus (Universal Base Shelf Prospectus) which allows the Company to offer, from time to time in one or more public offerings, up to $8.0 billion of debt, equity or other securities, or any combination thereof, during the 25-month period ending on April 30, 2018. During the second quarter of 2017, Hydro One announced the closing of a secondary offering of a portion of its common shares previously owned by the Province. See "Other Developments - Secondary Common Share Offering" for details of this transaction. Upon closing of the transaction, $3,240 million remained available under the Universal Base Shelf Prospectus.

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Convertible Debentures) represented by instalment receipts, which included the exercise in full of the over-allotment option granted to the underwriters to purchase an additional $140 million aggregate principal amount of the Convertible Debentures. The Convertible Debentures instalment receipts trade on the Toronto Stock Exchange under the ticker symbol "H.IR". The Convertible Debentures were sold as part of Hydro One's acquisition financing strategy to acquire Avista Corporation (see section Other Developments - Avista Corporation Purchase agreement), which includes the issuance of $1,540 million of Hydro One common shares and US$2.6 billion of Hydro One debt. The Convertible Debentures were sold to satisfy the equity component of the acquisition financing strategy.

To mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed by the issuance of Convertible Debentures, in October 2017, the Company entered into a deal-contingent foreign exchange forward contract to convert $1.4 billion Canadian to US dollars at an initial forward rate of 1.27486 Canadian per 1.00 US dollars and a range up to 1.28735 Canadian per 1.00 US dollars based on the settlement date. The contract is contingent on the Company closing the proposed Avista Corporation acquisition. If the acquisition does not close, the contract would not be completed and no amounts would be exchanged. The contract can be executed upon approval of the acquisition up to March 31, 2019. The balance of the Avista Corporation acquisition will be financed by issuing long-term debt denominated in US dollars which will act as an economic hedge. At December 31, 2017, a fair value loss of $3 million was recorded with a corresponding derivative liability.

At December 31, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Credit Ratings

At December 31, 2017, Hydro One's corporate credit ratings were as follows:

Rating Agency	Corporate Credit Rating
Standard & Poor's Rating Services (S&P)[1]	A

[1] On July 19, 2017, S&P revised its outlook on the Company to negative from stable, while affirming the existing corporate credit rating.

Hydro One has not obtained a credit rating in respect of any of its securities. An issuer rating from S&P is a forward-looking opinion about an obligor's overall creditworthiness. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due but it does not apply to any specific financial obligation. An obligor with a long-term credit rating of 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories.

The rating above is not a recommendation to purchase, sell or hold any of Hydro One's securities and does not comment on the market price or suitability of any of the securities for a particular investor. There can be no assurance that the rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn entirely by S&P at any time in the future. Hydro One has made, and anticipates making, payments to S&P pursuant to agreements entered into with S&P in respect of the rating assigned to Hydro One and expects to make payments to S&P in the future to the extent it obtains a rating specific to any of its securities.

At December 31, 2017, Hydro One Inc.'s long-term and short-term debt ratings were as follows:

Rating Agency	Short-term Debt Rating	Long-term Debt Rating
DBRS Limited	R-1 (low)	A (high)
Moody's Investors Service (Moody's)[1]	Prime-2	A3
S&P[1]	A-1	A

[1] On July 19, 2017, S&P and Moody's revised their outlooks on Hydro One Inc. to negative from stable, while affirming the existing debt ratings.

Effect of Interest Rates

The Company is exposed to fluctuations of interest rates as its regulated return on equity (ROE) is derived using a formulaic approach that takes into account changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. See section "Risk Management and Risk Factors - Risks Relating to Hydro One's Business - Market, Financial Instrument and Credit Risk" for more details.

Pension Plan

In 2017, Hydro One contributed approximately $87 million to its pension plan, compared to contributions of approximately $108 million in 2016, and incurred $88 million in net periodic pension benefit costs, compared to $116 million incurred in 2016.

In May 2017, Hydro One filed an actuarial valuation of its Pension Plan as at December 31, 2016. Based on this valuation and 2017 levels of pensionable earnings, the 2017 annual Company pension contributions have decreased by approximately $17 million from $105 million as estimated at December 31, 2016, primarily due to improvements in the funded status of the plan and future actuarial assumptions, and also reflect the impact of changes implemented by management to improve the balance between employee and Company contributions to the Pension Plan. Hydro One estimates that total Company pension contributions for 2018 and 2019 will be approximately $71 million for each year.

The Company's pension benefits obligation is impacted by various assumptions and estimates, such as discount rate, rate of return on plan assets, rate of cost of living increase and mortality assumptions. A full discussion of the significant assumptions and estimates can be found in the section "Critical Accounting Estimates - Employee Future Benefits".

OTHER OBLIGATIONS

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations and commercial commitments:

December 31, 2017 *(millions of dollars)*	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations *(due by year)*					
Long-term debt – principal repayments	10,069	752	1,384	1,107	6,826
Long-term debt – interest payments	7,690	426	786	725	5,753
Convertible debentures - principal repayments[1]	513	—	—	—	513
Convertible debentures - interest payments	601	62	123	123	293
Short-term notes payable	926	926	—	—	—
Pension contributions[2]	151	71	80	—	—
Environmental and asset retirement obligations	215	28	59	65	63
Outsourcing agreements	247	139	97	4	7
Operating lease commitments	44	12	18	10	4
Long-term software/meter agreement	56	17	33	3	3
Total contractual obligations	20,512	2,433	2,580	2,037	13,462
Other commercial commitments *(by year of expiry)*					
Credit facilities[3]	2,550	—	—	2,550	—
Letters of credit[4]	177	177	—	—	—
Guarantees[5]	325	325	—	—	—
Total other commercial commitments	3,052	502	—	2,550	—

[1] The Company expects that the Convertible Debentures will be converted to common shares upon closing of the Avista Corporation acquisition.
[2] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2018 and 2019 minimum pension contributions are based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings.
[3] In June 2017, the maturity date of Hydro One Inc.'s $2.3 billion credit facilities was extended from June 2021 to June 2022.
[4] Letters of credit consist of a $154 million letter of credit related to retirement compensation arrangements, a $16 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.
[5] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

REGULATION

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual rate of return on its deemed 40% equity level invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral and variance accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings:

Application	Years	Type	Status
Electricity Rates			
Hydro One Networks	2017-2018	Transmission – Cost-of-service	OEB decision received[1]
Hydro One Networks	2015-2017	Distribution – Custom	OEB decision received
Hydro One Networks	2018-2022	Distribution – Custom	OEB decision pending
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
HOSSM	2017-2018	Transmission – Revenue Cap	OEB decision received
Mergers Acquisitions Amalgamations and Divestitures (MAAD)			
Orillia Power Distribution Corporation	n/a	Acquisition	OEB decision pending
Leave to Construct			
East-West Tie Station Expansion	n/a	Section 92	OEB decision pending

[1] In October 2017, the Company filed a Motion to Review and Vary the OEB's decision and filed an appeal with the Divisional Court of Ontario.

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Rate Application Status	Rate Order Status
Transmission					
Hydro One Networks	2017	8.78% (A)	$10,523 million	Approved in September 2017	Approved in November 2017
	2018	9.00% (A)	$11,148 million	Approved in September 2017	Approved in December 2017
B2M LP	2017	8.78% (A)	$509 million	Approved in December 2015	Approved in June 2017
	2018	9.00% (A)	$502 million	Approved in December 2015	Filed in December 2017
	2019	9.00% (F)	$496 million	Approved in December 2015	To be filed in 2018 Q4
HOSSM	2017	9.19% (A)	$218 million	Approved in September 2017	n/a
	2018	9.19% (A)	$218 million	Approved in September 2017	n/a
Distribution					
Hydro One Networks	2017	8.78% (A)	$7,190 million	Approved in March 2015	Approved in December 2016
	2018	9.00% (A)	$7,666 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2019	9.00% (F)	$8,027 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2020	9.00% (F)	$8,430 million	Filed in March 2017[1]	To be filed in 2019 Q4
	2021	9.00% (F)	$8,960 million	Filed in March 2017[1]	To be filed in 2020 Q4
	2022	9.00% (F)	$9,327 million	Filed in March 2017[1]	To be filed in 2021 Q4

[1] On June 7 and December 21, 2017, Hydro One Networks filed updates to the application reflecting recent financial results and other adjustments.

Electricity Rates Applications

Hydro One Networks - Transmission

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Decision), with 2017 rates effective January 1, 2017. Key changes to the application as filed included reductions in planned capital expenditures of $126 million and $122 million for 2017 and 2018, respectively, in OM&A expenses related to compensation by $15 million for each year, and in estimated tax savings from the IPO by $24 million and $26 million for 2017 and 2018, respectively. On October 10, 2017, Hydro One Networks filed a Draft Rate Order reflecting the changes outlined in the Decision.

In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a Decision and Order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an additional impairment of up to approximately $370 million related to Hydro One Networks' distribution deferred income tax regulatory asset.

In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which is scheduled for mid-February 2018. In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million, resulting in an annual decrease to FFO in the range of $50 million to $60 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company's Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

In October 2017, the intervenor Anwaatin Inc. also filed a Motion to Review and Vary the OEB Decision (Anwaatin Motion) alleging that the OEB breached its duty of procedural fairness, failed to respond to certain evidence, and failed to provide reasons on the capital budget as it related to reliability issues impacting Anwaatin Inc.'s constituents. The Anwaatin Motion will be heard by the OEB on February 13, 2018.

On November 23, 2017, the OEB approved the 2017 rates revenue requirement of $1,438 million. On December 20, 2017, the OEB approved the 2018 rates revenue requirement of $1,511 million, which included a $25 million increase from the approved amount, as a result of the OEB-updated cost of capital parameters. Uniform Transmission Rates (UTRs), reflecting these approved amounts, were approved by the OEB on February 1, 2018 to be effective as of January 1, 2018.

Hydro One Networks - Distribution

On March 31, 2017, Hydro One Networks filed a custom application with the OEB for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework (2018-2022 Distribution Application), which was subsequently updated on June 7 and December 21, 2017. The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels. Management expects that a decision will be received in 2018.

On November 17, 2017, Hydro One filed with the OEB a request for interim rates based on current OEB-approved rates, adjusted for an updated load forecast. On December 1, 2017, the OEB denied this request and set interim rates based on current OEB-approved rates with no adjustments.

In Hydro One's December 21, 2017 update to the 2018-2022 Distribution Application, Hydro One described the impact to the proposed revenue requirement of various developments since initially filing the application. These included, without limitation, the updated cost of capital parameters and inflation factor for 2018 issued by the OEB, and reductions in the 2018 OM&A forecast and 2018-2022 capital forecasts.

B2M LP

In December 2015, the OEB approved B2M LP's revenue requirement for years 2015 to 2019, subject to annual updates in each of 2016, 2017 and 2018 to adjust its revenue requirement for the following year consistent with the OEB's updated cost of capital parameters. On June 8, 2017, the OEB approved B2M LP's Rate Order reflecting 2017 transmission revenue requirement of $34 million, effective January 1, 2017.

On February 1, 2018, the OEB issued its Decision and Rate Order for 2018 UTRs declaring the 2018 UTRs as interim, as the B2M LP application for an update to its 2018 transmission revenue requirement is still under consideration by the OEB.

HOSSM

On September 28, 2017, the OEB issued its Decision and Order on HOSSM's 2017 transmission rates application, denying the requested revenue requirement for 2017. HOSSM's 2016 approved revenue requirement of $41 million will remain in effect for 2017 and 2018.

Hydro One Remote Communities Inc.

On August 28, 2017, Hydro One Remote Communities Inc. filed an application with the OEB seeking approval of its 2018 revenue requirement of $57 million and electricity rates effective May 1, 2018. On December 14, 2017, the OEB issued a Procedural Order with key dates for filing additional materials and reply submissions. On February 7, 2018, Hydro One Remote Communities Inc. and the intervenors in the rate proceeding reached a full settlement agreement on all issues. The agreement is expected to be reviewed by the OEB for approval in March 2018. Upon the OEB's approval, new rates are expected to be implemented by May 1, 2018.

Hydro One Remote Communities Inc. is fully financed by debt and is operated as a break-even entity with no ROE.

MAAD Applications

Orillia Power MAAD Application

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power). The acquisition is subject to regulatory approval by the OEB. On July 27, 2017, the OEB issued a Procedural Order No.6 (Procedural Order) in the matter of Hydro One's MAAD application to acquire Orillia Power. The Procedural Order stated that the OEB has decided to delay a decision on the Orillia Power MAAD application until Hydro One defends its cost allocation proposal in the 2018-2022 Distribution Application hearing to determine if the Orillia Power acquisition is likely to cause harm to any of its current customers. Because of the timetable of the 2018-2022 Distribution Application hearing, and the time it will take to receive a decision in that hearing, the effect of the Procedural Order will be to delay the Orillia Power MAAD application decision by as much as 18 months or more. On August 14, 2017, Hydro One filed a Motion to Review and Vary the Procedural Order requesting the OEB to allow the Orillia Power MAAD application to proceed immediately in the ordinary course. On October 24, 2017, the OEB issued a Procedural Order in response to Hydro One's Motion to Review and Vary, with key dates for filing additional materials on the Motion, hearing date, and filing of reply submissions. Final argument on the Motion to Review and Vary was filed on December 13, 2017.

On January 4, 2018, the OEB issued its Decision on Hydro One's Motion to Review and Vary, granting the motion and referring the MAAD file back to the original OEB panel for reconsideration. The OEB's findings were based on both procedural unfairness and the impact that a lengthy delay will have on the operations of Orillia Power. On February 5, 2018, the OEB issued Procedural Order No. 7 directing Hydro One to file evidence or submissions on its expectations of the overall cost structures following the deferred rebasing period and the effect on Orillia Power customers by February 15, 2018.

Other Applications

East-West Tie

In 2013, NextBridge Infrastructure (NextBridge), a partnership between NextEra Energy Canada, Enbridge Inc., and Borealis Infrastructure was designated by the OEB to complete the development work for the East-West Tie Line Project, a 230 kV, 400 km transmission line connecting Hydro One's Wawa and Lakehead transmission stations. This project is necessary to ensure the reliability of electricity supply in Northwestern Ontario, and was included as a priority project in the Province's 2010 Long-Term Energy Plan. On July 31, 2017, Hydro One filed a Leave to Construct application with the OEB to perform station upgrades to its Wawa and Lakehead transmission stations (East-West Tie Station Expansion), necessary to support the East-West Tie Line Project. Hydro One is acting as an intervenor in NextBridge's East-West Tie Line Project application.

On September 22, 2017, Hydro One filed with the OEB a Letter of Intent indicating that the Company plans to file a Leave to Construct application to construct the East-West Tie Line Project. On December 21, 2017, Hydro One re-confirmed with the OEB that it still intends to file this application in early 2018.

On November 13, 2017, NextBridge filed a letter with the OEB asserting that the OEB should strictly limit Hydro One's intervenor status to matters related to interconnection of the NextBridge East-West Tie Line Project to Hydro One transmission facilities and to ensure that Hydro One does not use its status as the Province's incumbent transmitter to compete unfairly against NextBridge's Leave to Construct application.

On December 1, 2017, the IESO released its needs assessment for the East-West Tie Line Project, as requested by the Minister of Energy. The IESO has reconfirmed that the project is still the recommended solution to supply electricity in Northwestern Ontario and continues to recommend an in-service date of 2020.

On December 5, 2017, Hydro One filed a letter with the OEB in response to NextBridge's request to impose limitations on Hydro One's participation as an intervenor. In the letter, Hydro One asked that the OEB allow Hydro One's status as an intervenor in the proceeding with full intervenor rights, and that the OEB reject NextBridge's requests relating to (i) documentation provided to Hydro One, (ii) creation of a confidentiality screen, and (iii) creation of novel filing requirements for a Leave to Construct application by Hydro One.

On December 21, 2017, both NextBridge and Hydro One received interrogatories from the OEB and Intervenors related to their respective Leave to Construct applications. Hydro One submitted its responses by the January 25, 2017 due date.

Other Regulatory Developments

Fair Hydro Plan and First Nations Rate Assistance Program

In March 2017, Ontario's Minister of Energy announced the Fair Hydro Plan, which included changes to the Global Adjustment, the Rural or Remote Electricity Rate Protection (RRRP) Program, the introduction of the First Nations rate assistance program, and improving the allocation of delivery charges across the rural and urban geographies of the province. Hydro One worked collaboratively with the OEB on the First Nations rate assistance program, and was a key stakeholder in providing solutions that address both the Global Adjustment and RRRP elements. The Fair Hydro Plan came into effect on July 1, 2017 and resulted in a reduction of approximately 25% on electricity bills for typical Ontario residential customers. The Province also launched a new Affordability Fund aimed at assisting electricity customers who cannot qualify for low-income conservation programs. Additional enhancements were also made to the existing Ontario Electricity Support Program (OESP).

Hydro One customers saw the full benefits of the Fair Hydro Plan for all electricity consumed after July 1, 2017. A typical rural residential customer using 750 kWh per month will see savings on their monthly bills of 31% on average, or approximately $600 annually. These changes did not have an impact on the net income of the Company.

Hydro One continues to work with First Nations customers living on reserves to help ensure the required applications are submitted to receive the benefits associated with the First Nations rate assistance program which provides a credit on the delivery charge.

OEB Pension and Other Post-Employment Benefits Costs

On September 14, 2017, the OEB issued its final report, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (Report), that establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. The Report also provides for the establishment of a variance account, effective January 1, 2018, to track the difference between the forecasted accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to the differential.

Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers, including a higher cost recovered through rates, more volatility relating to the ability to predict the effect on rates, and the pension offset (cumulative difference between the cash and accrual basis which is $981 million as at December 31, 2017) having to be recovered in rates on an accelerated basis. As the Report establishes that a basis other than the accrual accounting method may be acceptable if resulting in just and reasonable rates, Hydro One believes that the cash basis treatment of pension costs would continue to be supportable.

OTHER DEVELOPMENTS

Strategy

In 2017, the Company's Board of Directors approved Hydro One's strategy which details the Company's goal to become North America's leading utility, centered around three key pillars: (i) optimization and innovation, (ii) diversification, and (iii) growth.

Common Shares

On May 17, 2017, Hydro One completed a secondary offering (Offering) by the Province, on a bought deal basis, of 120 million common shares of Hydro One. Following completion of the Offering, the Province directly held approximately 49.9% of Hydro One's total issued and outstanding common shares. This non-dilutive Offering increased the public ownership of Hydro One to approximately 50.1% or 298.6 million common shares. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

On December 29, 2017, the Province sold 14,391,012 common shares of Hydro One, representing approximately 2.4% of the outstanding common shares, to OFN Power Holdings LP, a limited partnership wholly-owned by Ontario First Nations Sovereign Wealth LP, which is in turn owned by 129 First Nations in Ontario. After completing this transaction, the Province owns approximately 47.4% or 282.4 million common shares of Hydro One. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

Collective Agreements

On April 7, 2017, Hydro One reached an agreement with the Canadian Union of Skilled Workers (CUSW) for a renewal of the collective agreement. The agreement is for a five-year term, covering May 1, 2017 to April 30, 2022. The agreement was ratified by the CUSW and the Hydro One Board of Directors in May 2017.

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society of Energy Professionals (the Society) and the Power Workers' Union (PWU) to facilitate the insourcing of these services effective March 1, 2018.

The current collective agreement with the PWU expires on March 31, 2018. In January 2018, Hydro One and the PWU commenced collective bargaining with the official exchange of bargaining agendas. Both sides acknowledged their commitment to working towards the timely completion of collective bargaining.

Exemptive Relief

On June 6, 2017, the Canadian securities regulatory authorities granted (i) the Minister of Energy, (ii) Ontario Power Generation Inc. (on behalf of itself and the segregated funds established as required by the *Nuclear Fuel Waste Act* (Canada)) and (iii) agencies of the Crown, provincial Crown corporations and other provincial entities (collectively, the Non-Aggregated Holders) exemptive relief, subject to certain conditions, to enable each Non-Aggregated Holder to treat securities of Hydro One that it owns or controls separately from securities of Hydro One owned or controlled by the other Non-Aggregated Holders for purposes of certain take-over bid, early warning reporting, insider reporting and control person distribution rules and certain distribution restrictions under Canadian securities laws. Hydro One was also granted relief permitting it to rely solely on insider reports and early warning reports filed by Non-Aggregated Holders when reporting beneficial ownership or control or direction over securities in an information circular or annual information form in respect of securities beneficially owned or controlled by any Non-Aggregated Holder subject to certain conditions.

Avista Corporation Purchase Agreement

On July 19, 2017, Hydro One reached an agreement to acquire Avista Corporation (Merger) for approximately $6.7 billion in an all-cash transaction. Avista Corporation is an investor-owned utility providing electric generation, transmission, and distribution services. It is headquartered in Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger is expected to occur in the second half of 2018, subject to receipt of certain regulatory and government approvals, and the satisfaction of customary closing conditions.

On September 14, 2017, Hydro One and Avista Corporation filed applications with state utility commissions in Washington, Idaho, Oregon, Montana, and Alaska, as well as with the Federal Energy Regulatory Commission, requesting regulatory approval of the Merger on or before August 14, 2018. On November 21, 2017, the Merger was approved by the shareholders of Avista Corporation. On January 16, 2018, the Federal Energy Regulatory Commission approved the Merger application. Required filings with a number of other agencies will be made in the coming months, including with the Committee on Foreign Investment in the United States, the

Federal Communications Commission, and the Department of Justice and the Federal Trade Commission pursuant to the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*.

Convertible Debenture Offering

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company and its wholly-owned subsidiary, 2587264 Ontario Inc., completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures represented by instalment receipts (Debenture Offering). Upon closing of the Avista Corporation transaction and conversion of the Convertible Debentures into Hydro One common shares, the Province's ownership of Hydro One will decrease to approximately 42.3%. See section "Liquidity and Financing Strategy".

The Province waived its pre-emptive right to participate in the Debenture Offering under the governance agreement entered into between Hydro One and the Province dated November 5, 2015 (Governance Agreement). In consideration of granting the waiver, Hydro One agreed that until July 19, 2018: (i) the Company shall not issue common shares pursuant to the Company's equity compensation plans and any dividend reinvestment plan in an aggregate number that exceeds 1% of the common shares outstanding as of July 19, 2017; and (ii) the Company shall not issue voting securities (or securities convertible into voting securities) pursuant to any acquisition transaction without complying with the pre-emptive right provisions of the Governance Agreement.

Litigation

<u>Litigation Relating to the Merger</u>

To date, four putative class action lawsuits have been filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. The Washington state court issued an order staying the litigation until after the plaintiffs file an amended complaint, which must be no later than 30 days after Avista Corporation or Hydro One publicly announces that the Merger has closed. Second, *Jenß v. Avista Corp., et al., Samuel v. Avista Corp., et al., and Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and named as defendants Avista Corporation and its directors; *Sharpenter* also named Hydro One, Olympus Holding Corp., and Olympus Corp. The lawsuits alleged that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. *Jenß, Samuel, and Sharpenter* were all voluntarily dismissed by the respective plaintiffs with no consideration paid by any of the defendants. The one remaining class action is consistent with expectations for US merger transactions and, while there is no certainty as to outcome, Hydro One believes that the lawsuit is not material to Hydro One.

<u>Class Action Lawsuit</u>

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities Inc., and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, an estimate of a possible loss related to this claim cannot be made.

Appointment of Chief Financial Officer

On January 28, 2018, Mr. Paul Dobson was appointed to the position of Chief Financial Officer of Hydro One, effective March 1, 2018. Mr. Dobson was most recently the Chief Financial Officer at Direct Energy Ltd. in Houston, Texas.

HYDRO ONE WORK FORCE

Hydro One has a skilled and flexible work force of approximately 5,400 regular employees and 2,000 non-regular employees province-wide, comprising of a mix of skilled trades, engineering, professional, managerial and executive personnel. Hydro One's regular employees are supplemented primarily by accessing a large external labour force available through arrangements with the Company's trade unions for variable workers, sometimes referred to as "hiring halls", and also by access to contract personnel. The hiring halls offer Hydro One the ability to flexibly utilize highly trained and appropriately skilled workers on a project-by-project and seasonal basis.

The following table sets out the number of Hydro One employees as at December 31, 2017:

	Regular Employees	Non-Regular Employees	Total
PWU[1]	3,362	706	4,068
The Society	1,379	35	1,414
Canadian Union of Skilled Workers (CUSW) and construction building trade unions[2]	—	1,254	1,254
Total employees represented by unions	4,741	1,995	6,736
Management and non-represented employees	681	23	704
Total employees	5,422	2,018	7,440

[1] Includes 575 non-regular "hiring hall" employees covered by the PWU agreement.
[2] The construction building trade unions have collective agreements with the Electrical Power Systems Construction Association (EPSCA).

Share-based Compensation

During 2017 and 2016, the Company granted awards under its Long-term Incentive Plan, consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled. At December 31, 2017 and 2016, 429,980 and 230,600 PSUs, respectively, and 393,430 and 254,150 RSUs, respectively, were outstanding.

NON-GAAP MEASURES

FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders. As such, FFO provides a consistent measure of the cash generating performance of the Company's assets.

Year ended December 31 *(millions of dollars)*	2017	2016
Net cash from operating activities	1,716	1,656
Changes in non-cash balances related to operations	(113)	(134)
Preferred share dividends	(18)	(19)
Distributions to noncontrolling interest	(6)	(9)
FFO	1,579	1,494

Adjusted Net Income and Adjusted EPS

The following basic and diluted Adjusted EPS has been calculated by management on a supplementary basis which excludes costs related to the Avista Corporation acquisition from net income. Adjusted EPS is used internally by management to assess the Company's performance and is considered useful because it excludes the impact of acquisition-related costs and provides users with a comparative basis to evaluate the current ongoing operations of the Company compared to prior year.

Year ended December 31	2017	2016
Net income attributable to common shareholders *(millions of dollars)*	658	721
Costs related to acquisition of Avista Corporation *(millions of dollars)*	36	—
Adjusted net income attributable to common shareholders *(millions of dollars)*	694	721
Weighted average number of shares		
Basic	595,287,586	595,000,000
Effect of dilutive stock-based compensation plans	2,234,665	1,700,823
Diluted	597,522,251	596,700,823
Adjusted EPS		
Basic	$1.17	$1.21
Diluted	$1.16	$1.21

Revenues, net of purchased power

Revenues, net of purchased power is defined as revenues less purchased power. Management believes that revenue, net of purchased power is helpful as a measure of net revenues for the Distribution segment, as purchased power is fully recovered through revenues.

Year ended December 31 *(millions of dollars)*	2017	2016
Revenues	5,990	6,552
Less: Purchased power	2,875	3,427
Revenues, net of purchased power	3,115	3,125

Year ended December 31 *(millions of dollars)*	2017	2016
Distribution revenues	4,366	4,915
Less: Purchased power	2,875	3,427
Distribution revenues, net of purchased power	1,491	1,488

FFO, basic and diluted Adjusted EPS, and Revenues, net of purchased power are not recognized measures under US GAAP and do not have a standardized meaning prescribed by US GAAP. They are therefore unlikely to be directly comparable to similar measures presented by other companies. They should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under US GAAP.

RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One. The following is a summary of the Company's related party transactions during the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2017	2016
Province	Dividends paid	301	451
IESO	Power purchased	1,583	2,096
	Revenues for transmission services	1,521	1,549
	Amounts related to electricity rebates	357	—
	Distribution revenues related to rural rate protection	247	125
	Distribution revenues related to the supply of electricity to remote northern communities	32	32
	Funding received related to CDM programs	59	63
OPG	Power purchased	9	6
	Revenues related to provision of construction and equipment maintenance services	3	5
	Costs related to the purchase of services	1	1
OEFC	Power purchased from power contracts administered by the OEFC	2	1
OEB	OEB fees	8	11
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	3

RISK MANAGEMENT AND RISK FACTORS

Risks Relating to Hydro One's Business

Regulatory Risks and Risks Relating to Hydro One's Revenues

Risks Relating to Obtaining Rate Orders

The Company is subject to the risk that the OEB will not approve the Company's transmission and distribution revenue requirements requested in outstanding or future applications for rates. Rate applications for revenue requirements are subject to the OEB's review process, usually involving participation from intervenors and a public hearing process. There can be no assurance that resulting decisions or rate orders issued by the OEB will permit Hydro One to recover all costs actually incurred, costs of debt and income taxes, or to earn a particular ROE. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, such as occurred in the September 28, 2017 and November 9, 2017 OEB decisions (details above in "Electricity Rates Applications - Hydro One Networks - Transmission"), may materially adversely affect: Hydro One's transmission or distribution businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the cost and issuance of long-term debt, and other matters, any of which may in turn have a material adverse effect on the Company. In addition, there is no assurance that the Company will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement and cash flows could be impacted.

Risks Relating to Actual Performance Against Forecasts

The Company's ability to recover the actual costs of providing service and earn the allowed ROE depends on the Company achieving its forecasts established and approved in the rate-setting process. Actual costs could exceed the approved forecasts if, for example, the Company incurs operations, maintenance, administration, capital and financing costs above those included in the Company's approved revenue requirement. The inability to obtain acceptable rate decisions or to recover any significant difference between forecast and actual expenses could materially adversely affect the Company's financial condition and results of operations.

Further, the OEB approves the Company's transmission and distribution rates based on projected electricity load and consumption levels, among other factors. If actual load or consumption materially falls below projected levels, the Company's revenue and net income for either, or both, of these businesses could be materially adversely affected. Also, the Company's current revenue requirements for these businesses are based on cost and other assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in the Company's costs.

The Company is subject to risk of revenue loss from other factors, such as economic trends and weather conditions that influence the demand for electricity. The Company's overall operating results may fluctuate substantially on a seasonal and year-to-year basis based on these trends and weather conditions. For instance, a cooler than normal summer or warmer than normal winter can be expected to reduce demand for electricity below that forecast by the Company, causing a decrease in the Company's revenues from the same period of the previous year. The Company's load could also be negatively affected by successful Conservation and Demand Management programs whose results exceed forecasted expectations.

Risks Relating to Rate-Setting Models for Transmission and Distribution

The OEB approves and periodically changes the ROE for transmission and distribution businesses. The OEB may in the future decide to reduce the allowed ROE for either of these businesses, modify the formula or methodology it uses to determine the ROE, or reduce the weighting of the equity component of the deemed capital structure. Any such reduction could reduce the net income of the Company.

The OEB's recent Custom Incentive Rate-setting model requires that the term of a custom rate application be a minimum five-year period. There are risks associated with forecasting key inputs such as revenues, operating expenses and capital, over such a long period. For instance, if unanticipated capital expenditures arise that were not contemplated in the Company's most recent rate decision, the Company may be required to incur costs that may not be recoverable until a future period or not recoverable at all in future rates. This could have a material adverse effect on the Company.

After rates are set as part of a Custom Incentive Rate application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital (including ROE), working capital allowance or sales volumes. If there were an increase in interest rates over the period of a rate decision and no corresponding changes were permitted to the Company's allowed cost of capital (including ROE), then the result could be a decrease in the Company's financial performance.

To the extent that the OEB approves an In-Service Variance Account for the transmission and/or distribution businesses, and should the Company fail to meet the threshold levels of in-service capital, the OEB may reclaim a corresponding portion of the Company's revenues.

Risks Relating to Capital Expenditures

In order to be recoverable, capital expenditures require the approval of the OEB, either through the approval of capital expenditure plans, rate base or revenue requirements for the purposes of setting transmission and distribution rates, which include the impact of capital expenditures on rate base or cost of service. There can be no assurance that all capital expenditures incurred by Hydro One will be approved by the OEB. Capital cost overruns may not be recoverable in transmission or distribution rates. The Company could incur unexpected capital expenditures in maintaining or improving its assets, particularly given that new technology may be required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. There is risk that the OEB may not allow full recovery of such expenditures in the future. To the extent possible, Hydro One aims to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

Any regulatory decision by the OEB to disallow or limit the recovery of any capital expenditures would lead to a lower than expected approved revenue requirement or rate base, potential asset impairment or charges to the Company's results of operations, any of which could have a material adverse effect on the Company.

Risks Relating to Regulatory Treatment of Deferred Tax Asset

As a result of leaving the PILs Regime and entering the Federal Tax Regime in connection with the IPO of the Company, Hydro One recorded a deferred tax asset due to the revaluation of the tax basis of Hydro One's fixed assets at their fair market value and recognition of eligible capital expenditures. The OEB's September 28, 2017 and November 9, 2017 decisions (see details above in "Electricity Rates Applications - Hydro One Networks - Transmission") alter Hydro One's allocation of the tax savings resulting from the deferred tax asset. If this approach is followed (pending the outcome of the Motion and Appeal), the exposure from the potential impairment from the regulatory treatment of the deferred tax asset could be a one-time decrease in net income, resulting in annual decreases to FFO.

Risks Relating to Other Applications to the OEB

The Company is also subject to the risk that it will not obtain, or will not obtain in a timely manner, required regulatory approvals for other matters, such as leave to construct applications, applications for mergers, acquisitions, amalgamations and divestitures, and environmental approvals. Decisions to acquire or divest other regulated businesses licensed by the OEB are subject to OEB approval. Accordingly, there is the risk that such matters may not be approved or that unfavourable conditions will be imposed by the OEB.

Indigenous Claims Risk

Some of the Company's current and proposed transmission and distribution assets are or may be located on reserve (as defined in the *Indian Act* (Canada)) (Reserve) lands, and lands over which Indigenous people have Aboriginal, treaty, or other legal claims. Some Indigenous leaders, communities, and their members have made assertions related to sovereignty and jurisdiction over Reserve lands and traditional territories and are increasingly willing to assert their claims through the courts, tribunals, or by direct action. These claims and/or settlement of these claims could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations, including the development of current and future projects.

The Company's operations and activities may give rise to the Crown's duty to consult and potentially accommodate Indigenous communities. Procedural aspects of the duty to consult may be delegated to the Company by the Province or the federal government. A perceived failure by the Crown to sufficiently consult an Indigenous community, or a perceived failure by the Company in relation to delegated consultation obligations, could result in legal challenges against the Crown or the Company, including judicial review or injunction proceedings, or could potentially result in direct action against the Company by a community or its citizens. If this occurs, it could disrupt or delay the Company's operations and activities, including current and future projects, and have a material adverse effect on the Company.

Risk from Transfer of Assets Located on Reserves

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to assets located on Reserves. The transfer of title to these assets did not occur because authorizations originally granted by the federal government for the construction and operation of these assets on Reserves could not be transferred without required consent. In several cases, the authorizations had either expired or had never been issued.

Currently, the OEFC holds legal title to these assets and it is expected that the Company will manage them until it has obtained permits to complete the title transfer. To occupy Reserves, the Company must have valid permits. For each permit, the Company must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the issuance of a permit. For transmission assets, the Company must negotiate terms of payment. It is difficult to predict the aggregate amount that the Company may have to pay to obtain the required agreements from First Nations. If the Company cannot reach satisfactory agreements with the relevant First Nation to obtain federal permits, it may have to relocate these assets to other locations and restore the lands at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. In either case, the costs relating to these assets could have a material adverse effect on the Company if the costs are not recoverable in future rate orders.

Compliance with Laws and Regulations

Hydro One must comply with numerous laws and regulations affecting its business, including requirements relating to transmission and distribution companies, environmental laws, employment laws and health and safety laws. The failure of the Company to comply with these laws could have a material adverse effect on the Company's business. See also "- Health, Safety and Environmental Risk".

For example, Hydro One's licensed transmission and distribution businesses are required to comply with the terms of their licences, with codes and rules issued by the OEB, and with other regulatory requirements, including regulations of the National Energy Board. In Ontario, the Market Rules issued by the IESO require the Company to, among other things, comply with the reliability standards established by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council, Inc. (NPCC). The incremental costs associated with compliance with these reliability standards are expected to be recovered through rates, but there can be no assurance that the OEB will approve the recovery of all of such incremental costs. Failure to obtain such approvals could have a material adverse effect on the Company.

There is the risk that new legislation, regulations, requirements or policies will be introduced in the future. These may require Hydro One to incur additional costs, which may or may not be recovered in future transmission and distribution rates.

Risk of Natural and Other Unexpected Occurrences

The Company's facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including but not limited to cyber and physical terrorist type attacks, events which originate from third-party connected systems, or any other potentially catastrophic events. The Company's facilities may not withstand occurrences of this type in all circumstances. The Company does not have insurance for damage to its transmission and distribution wires, poles and towers located outside its transmission and distribution stations resulting from these or other events. Where insurance is available for other assets, such insurance coverage may have deductibles, limits and/or exclusions. Losses from lost revenues and repair costs could be substantial, especially for many of the Company's facilities that are located in remote areas. The Company could also be subject to claims for damages caused by its failure to transmit or distribute electricity or costs related to ensuring its continued ability to transmit or distribute electricity.

Risk Associated with Information Technology Infrastructure and Data Security

The Company's ability to operate effectively in the Ontario electricity market is, in part, dependent upon it developing, maintaining and managing complex information technology systems which are employed to operate and monitor its transmission and distribution facilities, financial and billing systems and other business systems. The Company's increasing reliance on information systems and expanding data networks increases its exposure to information security threats. The Company's transmission business is required to comply with various rules and standards for transmission reliability, including mandatory standards established by the NERC and the NPCC. These include standards relating to cyber-security and information technology, which only apply to certain of the Company's assets (generally being those whose failure could impact the functioning of the bulk electricity system). The Company may maintain different or lower levels of information technology security for its assets that are not subject to these mandatory standards. The Company must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information and information regarding consumers, wholesalers, generators and retailers.

Cyber-attacks or unauthorized access to corporate and information technology systems could result in service disruptions and system failures, which could have a material adverse effect on the Company, including as a result of a failure to provide electricity to customers. Due to operating critical infrastructure, Hydro One may be at greater risk of cyber-attacks from third parties (including state run or controlled parties) that could impair or incapacitate its assets. In addition, in the course of its operations, the Company collects, uses, processes and stores information which could be exposed in the event of a cyber-security incident or other unauthorized access or disclosure, such as information about customers, suppliers, counterparties, employees and other third parties.

Security and system disaster recovery controls are in place; however, there can be no assurance that there will not be system failures or security breaches or that such threats would be detected or mitigated on a timely basis. Upon occurrence and detection, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on the Company.

Labour Relations Risk

The substantial majority of the Company's employees are represented by either the PWU or the Society. Over the past several years, significant effort has been expended to increase Hydro One's flexibility to conduct operations in a more cost-efficient manner. Although the Company has achieved improved flexibility in its collective agreements, the Company may not be able to achieve further improvements. The Company reached an agreement with the PWU for a renewal collective agreement with a three-year term, covering the period from April 1, 2015 to March 31, 2018 and an early renewal collective agreement with the Society with a three-year term, covering the period from April 1, 2016 to March 31, 2019. The Company also reached a renewal collective agreement with the Canadian Union of Skilled Workers for a five-year term, covering the period from May 1, 2017 to April 30, 2022. Additionally, the EPSCA and a number of construction unions have reached renewal agreements, to which Hydro One is bound, for a five-year term, covering the period from May 1, 2015 to April 30, 2020. Agreements have also been reached with the Society and the PWU to facilitate the insourcing of customer service operations services effective March 1, 2018. Future negotiations with unions present the risk of a labour disruption and the ability to sustain the continued supply of energy to customers. The Company also faces financial risks related to its ability to negotiate collective agreements consistent with its rate orders. In addition, in the event of a labour dispute, the Company could face operational risk related to continued compliance with its requirements of providing service to customers. Any of these could have a material adverse effect on the Company.

Work Force Demographic Risk

By the end of 2017, approximately 22% of the Company's employees who are members of the Company's defined benefit and defined contribution pension plans were eligible for retirement, and by the end of 2018, approximately 20% could be eligible. These percentages are not evenly spread across the Company's work force, but tend to be most significant in the most senior levels of the Company's staff and especially among management staff. During 2017, approximately 5% of the Company's work force (up from 3% in 2016) elected to retire. Accordingly, the Company's continued success will be tied to its ability to continue to attract and retain sufficient qualified staff to replace the capability lost through retirements and meet the demands of the Company's work programs.

In addition, the Company expects the skilled labour market for its industry will remain highly competitive. Many of the Company's current and potential employees being sought after possess skills and experience that are also highly coveted by other organizations inside and outside the electricity sector. The failure to attract and retain qualified personnel for Hydro One's business could have a material adverse effect on the Company.

Risk Associated with Arranging Debt Financing

The Company expects to borrow to repay its existing indebtedness and to fund a portion of capital expenditures. Hydro One Inc. has substantial debt principal repayments, including $752 million in 2018, $731 million in 2019, and $653 million in 2020. In addition, from time to time, the Company may draw on its syndicated bank lines and/or issue short-term debt under Hydro One Inc.'s $1.5 billion commercial paper program which would mature within approximately one year of issuance. The Company also plans to incur continued material capital expenditures for each of 2018 and 2019. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of the Company's existing indebtedness and capital expenditures. The Company's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, the Company's results of operations and financial position, market conditions, the ratings assigned to its debt securities by credit rating agencies, an inability of the Corporation to comply with its debt covenants, and general economic conditions. A downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt. Any failure or inability on the Company's part to borrow the required amounts of debt on satisfactory terms could impair its ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on the Company. This risk may be further exacerbated by the funding requirements for completing the Merger. See also "Risk Factors Relating to the Merger - Sources of funding that would be used to fund the Merger may not be available".

Market, Financial Instrument and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated ROE is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk. The Company is exposed to foreign exchange risk in connection with the Merger. See "Risk Factors Relating to the Merger - Foreign exchange risk". In the future, the Company may be exposed to additional foreign exchange risk in connection with other acquisitions or transactions in which it completes in a currency other than Canadian dollars. Although the Company may attempt to mitigate such risk through hedging transactions, there can be no assurance any such hedge will fully mitigate the risk of currency exchange fluctuations.

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. The Company estimates that a decrease of 100 basis points in the combination of the forecasted long-term Government of Canada bond yield and the A-rated utility corporate bond yield spread used in determining its rate of return would reduce the Company's transmission business' 2019 net income by approximately $24 million. For the distribution business, after distribution rates are set as part of a Custom Incentive Rate application, the OEB does not expect to address annual rate applications for updates to allowed ROE, so fluctuations will have no impact to net income. The Company periodically utilizes interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. Hydro One monitors and minimizes credit risk through various techniques, including dealing with highly rated counterparties, limiting total exposure levels with individual counterparties, entering into agreements which enable net settlement, and by monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. The Company is required to procure electricity on behalf of competitive retailers and certain local distribution companies for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into the Company's service agreements with these retailers in accordance with the OEB's Retail Settlement Code.

The failure to properly manage these risks could have a material adverse effect on the Company.

Risks Relating to Asset Condition and Capital Projects

The Company continually incurs sustainment and development capital expenditures and monitors the condition of its transmission assets to manage the risk of equipment failures and to determine the need for and timing of major refurbishments and replacements of its transmission and distribution infrastructure. However, the lack of real time monitoring of distribution assets increases the risk of distribution equipment failure. The connection of large numbers of generation facilities to the distribution network has resulted in greater than expected usage of some of the Company's equipment. This increases maintenance requirements and may accelerate the aging of the Company's assets.

Execution of the Company's capital expenditure programs, particularly for development capital expenditures, is partially dependent on external factors, such as environmental approvals, municipal permits, equipment outage schedules that accommodate the IESO, generators and transmission-connected customers, and supply chain availability for equipment suppliers and consulting services. There may also be a need for, among other things, *Environmental Assessment Act* (Ontario) approvals, approvals which require public meetings, appropriate engagement with Indigenous communities, OEB approvals of expropriation or early access to property, and other activities. Obtaining approvals and carrying out these processes may also be impacted by opposition to the proposed site of the capital investments. Delays in obtaining required approvals or failure to complete capital projects on a timely basis could materially adversely affect transmission reliability or customers' service quality or increase maintenance costs which could have a material adverse effect on the Company. Failure to receive approvals for projects when spending has already occurred would result in the inability of the Company to recover the investment in the project as well as forfeit the anticipated return on investment. The assets involved may be considered impaired and result in the write off of the value of the asset, negatively impacting net income. External factors are considered in the Company's planning process. If the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce network capacity, result in customer interruptions, compromise the reliability of the Company's networks or increase the costs of operating and maintaining these assets. Any of these consequences could have a material adverse effect on the Company.

Increased competition for the development of large transmission projects and legislative changes relating to the selection of transmitters could impact the Company's ability to expand its existing transmission system, which may have an adverse effect on the Company. To the extent that other parties are selected to construct, own and operate new transmission assets, the Company's share of Ontario's transmission network would be reduced.

Health, Safety and Environmental Risk

The Company is subject to provincial health and safety legislation. Findings of a failure to comply with this legislation could result in penalties and reputational risk, which could negatively impact the Company.

The Company is subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject the Company to fines or other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties or governmental orders requiring the Company to take specific actions such as investigating, controlling and remediating the effects of these substances. Contamination of the Company's properties could limit its ability to sell or lease these assets in the future.

In addition, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on the Company's balance sheet. The Company does not have insurance coverage for these environmental expenditures.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases. Failure to obtain necessary approvals or permits could result in an inability to complete projects.

Hydro One emits certain greenhouse gases, including sulphur hexafluoride or "SF_6". There are increasing regulatory requirements and costs, along with attendant risks, associated with the release of such greenhouse gases, all of which could impose additional material costs on Hydro One.

Any regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on the Company.

Pension Plan Risk

Hydro One has the Hydro One Defined Benefit Pension Plan in place for the majority of its employees. Contributions to the pension plan are established by actuarial valuations which are required to be filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2016, and was filed in May 2017, covering a three-year period from 2017 to 2019. Hydro One's contributions to its pension plan satisfy, and are expected to satisfy, minimum funding requirements. Contributions beyond 2019 will depend on the funded position of the plan, which is determined by investment returns, interest rates and changes in benefits and actuarial assumptions at that time. A determination by the OEB that some of the Company's pension expenditures are not recoverable through rates could have a material adverse effect on the Company, and this risk may be exacerbated if the amount of required pension contributions increases.

In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers or material negative impacts on the company should recovery of costs be disallowed by the OEB. See "- Other Post-Employment and Post-Retirement Benefits Risks".

Risk of Recoverability of Total Compensation Costs

The Company manages all of its total compensation costs, including pension and other post-employment and post-retirement benefits, subject to restrictions and requirements imposed by the collective bargaining process. Any element of total compensation costs which is disallowed in whole or part by the OEB and not recoverable from customers in rates could result in costs which could be material and could decrease net income, which could have a material adverse effect on the Company.

Other Post-Employment and Post-Retirement Benefits Risks

The Company provides other post-employment and post-retirement benefits, including workers compensation benefits and long-term disability benefits to qualifying employees. In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently maintains the accrual accounting method with respect to OPEBs. If the OEB directed Hydro One to transition to a different accounting method for OPEBs, this could result in income volatility, due to an inability of the company to book the difference between the accrual and cash as a regulatory asset. A determination that some of the Company's post-employment and post-retirement benefit costs are not recoverable could have a material adverse effect on the Company.

Risk Associated with Outsourcing Arrangements

Hydro One has entered into an outsourcing arrangement with a third party for the provision of back office and IT services and call centre services. If the outsourcing arrangement or statements of work thereunder are terminated for any reason or expire before a new supplier is selected and fully transitioned, the Company could be required to transfer to another service provider or insource, which could have a material adverse effect on the Company's business, operating results, financial condition or prospects.

Risk from Provincial Ownership of Transmission Corridors

The Province owns some of the corridor lands underlying the Company's transmission system. Although the Company has the statutory right to use these transmission corridors, the Company may be limited in its options to expand or operate its systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of the Company's systems may increase safety or environmental risks, which could have a material adverse effect on the Company.

Litigation Risks

In the normal course of the Company's operations, it becomes involved in, is named as a party to and is the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to actual or alleged violations of law, common law damages claims, personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company, which could have a material adverse effect on the Company. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company's business operations, which could adversely affect the Company. See also "Other Developments - Litigation - Class Action Lawsuit" and "- Risk Factors Relating to the Merger - Legal proceedings in connection with the Merger, the outcomes of which are uncertain, could have an adverse impact on Hydro One, including by delaying or preventing the completion of the Merger".

Transmission Assets on Third-Party Lands Risk

Some of the lands on which the Company's transmission assets are located are owned by third parties, including the Province and federal Crown, and are or may become subject to land claims by First Nations. The Company requires valid occupation rights to occupy such lands (which may take the form of land use permits, easements or otherwise). If the Company does not have valid occupational rights on third-party owned lands or has occupational rights that are subject to expiry, it may incur material costs to obtain or renew such occupational rights, or if such occupational rights cannot be renewed or obtained it may incur material costs to remove and relocate its assets and restore the subject land. If the Company does not have valid occupational rights and must incur costs as a result, this could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations.

Reputational, Public Opinion and Political Risk

Reputation risk is the risk of a negative impact to Hydro One's business, operations or financial condition that could result from a deterioration of Hydro One's reputation. Hydro One's reputation could be negatively impacted by changes in public opinion (including as a result of the Merger), attitudes towards the Company's privatization, failure to deliver on its customer promises and other external forces. Adverse reputational events or political actions could have negative impacts on Hydro One's business and prospects including, but not limited to, delays or denials of requisite approvals, such as denial of requested rates, and accommodations for Hydro One's planned projects, escalated costs, legal or regulatory action, and damage to stakeholder relationships.

Risks Associated with Acquisitions

While the Company has experience in operating in the Ontario electricity market, as it pursues acquisitions outside of Ontario it will need to develop additional expertise in these new markets. Such acquisitions include inherent risks that some or all of the expected benefits may fail to materialize, or may not occur within the time periods anticipated, and Hydro One may incur material unexpected costs. Realization of the anticipated benefits will depend, in part, on the Company's ability to successfully integrate the acquired business, including the requirement to devote management attention and resources to integrating business practices and support functions. The failure to realize the anticipated benefits, the diversion of management's attention, or any delays or difficulties encountered in connection with the integration could have an adverse effect on the Company's business, results of operations, financial condition or cash flows. See "Risk Factors Relating to the Merger" for the specific risks in respect of the Company's proposed acquisition of Avista Corporation.

Risk Factors Relating to the Merger

Hydro One may fail to complete the Merger

The closing of the Merger is subject to the normal commercial risks that the Merger will not close on the terms negotiated or at all. The completion of the Merger is subject to receipt of certain regulatory and governmental approvals, including the expiration or termination of any applicable waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*, clearance of the Merger by the Committee on Foreign Investment in the United States, the approval by each of the Idaho Public Utilities Commission, the Public Service Commission of the State of Montana, the Public Utility Commission of Oregon, the Regulatory Commission of Alaska, the Washington Utilities and Transportation Commission, the United States Federal Energy Regulatory Commission and the United States Federal Communications Commission and the satisfaction or waiver of certain closing conditions contained in the Merger Agreement. The failure to obtain the required approvals or satisfy or waive the conditions contained in the Merger Agreement may result in the termination of the Merger Agreement. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that Hydro One will complete the Merger in the timeframe or on the basis described herein, if at all. The termination of the Merger Agreement may have a negative effect on the price of the Instalment Receipts, the Debentures and the Hydro One common shares and will result in the redemption of the Debentures. If the closing of the Merger does not take place as contemplated, the Company could suffer adverse consequences, including the loss of investor confidence, and may incur significant costs or losses, including an obligation to pay or cause to be paid to Avista Corporation a termination fee of US$103 million.

Length of time required to complete the Merger is unknown

As described above under "Hydro One may fail to complete the Merger", the closing of the Merger is subject to the receipt of certain regulatory approvals and the satisfaction of other closing conditions contained in the Merger Agreement. There is no certainty, nor can Hydro One provide any assurance, as to when these conditions will be satisfied, if at all. A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on Hydro One's ability to complete the Merger and on Hydro One's or Avista Corporation's business, financial condition or results of operations. In addition, in the event that such regulatory agencies imposed unfavourable terms and/or conditions on Hydro One or Avista Corporation (including the requirement to sell or divest of certain assets or limitations on the future conduct of the combined entities), Hydro One could still be required to complete the transaction on the terms set forth in the Merger Agreement.

Hydro One intends to complete the Merger as soon as practicable after obtaining the required regulatory approvals and satisfying the other required closing conditions.

Foreign exchange risk

The cash consideration for the Merger is required to be paid in US dollars, while funds raised in the Debenture Offering, which will constitute a portion of the funds ultimately used to finance the Merger, are denominated in Canadian dollars. As a result, increases in the value of the US dollar versus the Canadian dollar prior to payment of the final instalment will increase the purchase price translated in Canadian dollars and thereby reduce the proportion of the purchase price for the Merger ultimately obtained by Hydro One under the Debenture Offering, which could cause a failure to realize the anticipated benefits of the Merger. This risk has been partially mitigated through entering into a foreign exchange forward agreement to convert $1.4 billion Canadian to US dollars which is contingent upon the closing of the Merger.

In addition, the operations of Avista Corporation are conducted in US dollars. Following the Merger, the consolidated net earnings and cash flows of Hydro One will be impacted to a much greater extent by movements in the US dollar relative to the Canadian dollar. In particular, decreases in the value of the US dollar versus the Canadian dollar following the Merger could negatively impact the Company's net earnings as reported in Canadian dollars, which could cause a failure to realize the anticipated benefits of the Merger.

Additional demands will be placed on Hydro One as a result of the Merger

As a result of the pursuit and completion of the Merger, additional demands will be placed on the Company's managerial, operational and financial personnel and systems. No assurance can be given that the Company's systems, procedures and controls will be adequate to support the expansion of the Company's operations resulting from the Merger. The Company's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to maintain its operational and financial controls and reporting systems.

Sources of funding that would be used to fund the Merger may not be available

Hydro One intends to finance the cash purchase price of the Merger and the Merger-related expenses at the closing of the Merger with a combination of some or all of the following: (i) net proceeds of the first instalment (to the extent available) and final instalment under the Debenture Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under Hydro

One's $250 million credit facility; and (iv) existing cash on hand and other sources available to the Company. There is no guarantee that adequate sources of funding will be available to Hydro One or its affiliates at the desired time or at all, or on cost-efficient terms. The inability to obtain adequate sources of funding to fund the Merger may result in Hydro One being unable to complete the Merger or may negatively impact Hydro One, including its ability to finance the Merger. In addition, any movement in interest rates or changes in tax rates that could affect the underlying after-tax cost of any financing may affect the expected accretion of the Merger.

Hydro One expects to incur significant Merger-related expenses

Hydro One expects to incur a number of costs associated with completing the Merger. The substantial majority of these costs will be non-recurring expenses resulting from the Merger and will consist of transaction costs related to the Merger, including costs relating to the financing of the Merger and obtaining regulatory approvals. Additional unanticipated costs may be incurred.

Legal proceedings in connection with the Merger, the outcomes of which are uncertain, could have an adverse impact on Hydro One, including by delaying or preventing the completion of the Merger

One of the four putative class action lawsuits commenced since the announcement of the Merger is still in existence, namely a putative class action lawsuit that has been filed in Washington state court which names Hydro One, Olympus Holding Corp. and Olympus Corp. as defendants and alleges that they aided and abetted Avista Corporation's directors' breach of their fiduciary duties in connection with the Merger. The court issued an order staying the litigation until after the plaintiffs file an amended complaint, which must be no later than 30 days after Avista Corporation or Hydro One publicly announces that the Merger has closed. The plaintiffs in the lawsuit are seeking to enjoin the Merger and may pursue other remedies, including monetary damages and attorneys' fees. The lawsuit and other potential legal proceedings could have an adverse impact on Hydro One, including by delaying or preventing the Merger from becoming effective. See also "Other Developments - Litigation - Litigation Relating to the Merger".

Risk Factors Relating to the Post-Merger Business and Operations of Hydro One and Avista Corporation

Hydro One will substantially increase its amount of indebtedness following the Merger

After giving effect to the Merger, Hydro One will have a significant amount of debt, including approximately US$1.9 billion of debt of Avista Corporation assumed by Hydro One as a result of the Merger. As of March 31, 2017, on a *pro forma* basis after giving effect to the Merger, but assuming conversion of all Debentures to Hydro One common shares (*pro formas* assumed no exercise of the Over-Allotment Option), Hydro One would have had approximately $17,098 million of total indebtedness outstanding. Hydro One's substantially increased amount of indebtedness following the Merger may adversely affect Hydro One's cash flow and ability to operate its business.

The Offering could result in a downgrade of Hydro One's credit ratings

The change in the capital structure of Hydro One as a result of the Merger and the Debenture Offering or otherwise could cause credit rating agencies which rate the outstanding debt obligations of Hydro One and Hydro One Inc. to re-evaluate and potentially downgrade their current credit ratings, which could increase the Company's borrowing costs.

Risks Relating to the Company's Relationship with the Province

Ownership and Continued Influence by the Province and Voting Power; Share Ownership Restrictions

The Province currently owns approximately 47.4**%** of the outstanding common shares of Hydro One. The *Electricity Act* restricts the Province from selling voting securities of Hydro One (including common shares) of any class or series if it would own less than 40% of the outstanding number of voting securities of that class or series after the sale and in certain circumstances also requires the Province to take steps to maintain that level of ownership. Accordingly, the Province is expected to continue to maintain a significant ownership interest in voting securities of Hydro One for an indefinite period.

As a result of its significant ownership of the common shares of Hydro One, the Province has, and is expected indefinitely to have, the ability to determine or significantly influence the outcome of shareholder votes, subject to the restrictions in the governance agreement entered into between Hydro One and the Province dated November 5, 2015 (Governance Agreement; available on SEDAR at www.sedar.com). Despite the terms of the Governance Agreement in which the Province has agreed to engage in the business and affairs of the Company as an investor and not as a manager, there is a risk that the Province's engagement in the business and affairs of the Company as an investor will be informed by its policy objectives and may influence the conduct of the business and affairs of the Company in ways that may not be aligned with the interests of other shareholders.

The share ownership restrictions in the *Electricity Act* (Share Ownership Restrictions) and the Province's significant ownership of common shares of Hydro One together effectively prohibit one or more persons acting together from acquiring control of Hydro One. They also may limit or discourage transactions involving other fundamental changes to Hydro One and the ability of other shareholders to successfully contest the election of the directors proposed for election pursuant to the Governance Agreement. The Share Ownership Restrictions may also discourage trading in, and may limit the market for, the common shares and other voting securities.

Nomination of Directors and Confirmation of Chief Executive Officer and Chair

Although director nominees (other than the Chief Executive Officer) are required to be independent of both the Company and the Province pursuant to the Governance Agreement, there is a risk that the Province will nominate or confirm individuals who satisfy the independence requirements but who it considers are disposed to support and advance its policy objectives and give disproportionate weight to the Province's interests in exercising their business judgment and balancing the interests of the stakeholders of Hydro One. This, combined with the fact certain matters require a two-thirds vote of the Board of Directors, could allow the Province to unduly influence certain Board actions such as confirmation of the Chair and confirmation of the Chief Executive Officer.

Board Removal Rights

Under the Governance Agreement, the Province has the right to withhold from voting in favour of all director nominees and has the right to seek to remove and replace the entire Board of Directors, including in each case its own director nominees but excluding the Chief Executive Officer and, at the Province's discretion, the Chair. In exercising these rights in any particular circumstance, the Province is entitled to vote in its sole interest, which may not be aligned with the interests of other shareholders.

More Extensive Regulation

Although under the Governance Agreement, the Province has agreed to engage in the business and affairs of Hydro One as an investor and not as a manager and has stated that its intention is to achieve its policy objectives through legislation and regulation as it would with respect to any other utility operating in Ontario, there is a risk that the Province will exercise its legislative and regulatory power to achieve policy objectives in a manner that has a material adverse effect on the Company.

Prohibitions on Selling the Company's Transmission or Distribution Business

The *Electricity Act* prohibits the Company from selling all or substantially all of the business, property or assets related to its transmission system or distribution system that is regulated by the OEB. There is a risk that these prohibitions may limit the ability of the Company to engage in sale transactions involving a substantial portion of either system, even where such a transaction may otherwise be considered to provide substantial benefits to the Company and the holders of the common shares.

Future Sales of Common Shares by the Province

Although the Province has indicated that it does not intend to sell further common shares of Hydro One, the registration rights agreement between Hydro One and the Province dated November 5, 2015 (available on SEDAR at www.sedar.com) grants the Province the right to request that Hydro One file one or more prospectuses and take other procedural steps to facilitate secondary offerings by the Province of the common shares of Hydro One. Future sales of common shares of Hydro One by the Province, or the perception that such sales could occur, may materially adversely affect market prices for these common shares and impede Hydro One's ability to raise capital through the issuance of additional common shares, including the number of common shares that Hydro One may be able to sell at a particular time or the total proceeds that may be realized.

Limitations on Enforcing the Governance Agreement

The Governance Agreement includes commitments by the Province restricting the exercise of its rights as a holder of voting securities, including with respect to the maximum number of directors that the Province may nominate and on how the Province will vote with respect to other director nominees. Hydro One's ability to obtain an effective remedy against the Province, if the Province were not to comply with these commitments, is limited as a result of the *Proceedings Against the Crown Act* (Ontario). This legislation provides that the remedies of injunction and specific performance are not available against the Province, although a court may make an order declaratory of the rights of the parties, which may influence the Province's actions. A remedy of damages would be available to Hydro One, but damages may not be an effective remedy, depending on the nature of the Province's non-compliance with the Governance Agreement.

CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of Hydro One Consolidated Financial Statements requires the Company to make key estimates and critical judgments that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. Hydro One bases its estimates and judgments on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities, as well as identifying and assessing the Company's accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments. Hydro One has identified the following critical accounting estimates used in the preparation of its Consolidated Financial Statements:

Revenues

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Regulatory Assets and Liabilities

Hydro One's regulatory assets represent certain amounts receivable from future electricity customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The regulatory assets mainly include costs related to the pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, share-based compensation costs, and environmental liabilities. The Company's regulatory liabilities represent certain amounts that are refundable to future electricity customers, and pertain primarily to OEB deferral and variance accounts. The regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the amounts have been approved for inclusion in the electricity rates by the OEB, or if such approval is judged to be probable by management. If management judges that it is no longer probable that the OEB will allow the inclusion of a regulatory asset or liability in future electricity rates, the applicable carrying amount of the regulatory asset or liability will be reflected in results of operations in the period that the judgment is made by management.

Environmental Liabilities

Hydro One records a liability for the estimated future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment, and for the assessment and remediation of chemically contaminated lands. There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

Hydro One's employee future benefits consist of pension and post-retirement and post-employment plans, and include pension, group life insurance, health care, and long-term disability benefits provided to the Company's current and retired employees. Employee future benefits costs are included in Hydro One's labour costs that are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets. Changes in assumptions affect the benefit obligation of the employee future benefits and the amounts that will be charged to results of operations or capitalized in future years. The following significant assumptions and estimates are used to determine employee future benefit costs and obligations:

Weighted Average Discount Rate

The weighted average discount rate used to calculate the employee future benefits obligation is determined at each year end by referring to the most recently available market interest rates based on "AA"-rated corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rate at December 31, 2017 decreased to 3.40% (from 3.90% at December 31, 2016) for pension benefits and decreased to 3.40% (from 3.90% at December 31, 2016) for the post-retirement and post-employment plans. The decrease in the discount rate has resulted in a corresponding increase in employee future benefits liabilities for the pension, post-retirement and post-employment plans for accounting purposes. The liabilities are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates.

Expected Rate of Return on Plan Assets

The expected rate of return on pension plan assets is based on expectations of long-term rates of return at the beginning of the year and reflects a pension asset mix consistent with the pension plan's current investment policy.

Rates of return on the respective portfolios are determined with reference to respective published market indices. The expected rate of return on pension plan assets reflects the Company's long-term expectations. The Company believes that this assumption is reasonable because, with the pension plan's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed-income and short-term investment returns. The net result, on a long-term basis, is a lower return than might be expected by investing in equities alone. In the short term, the pension plan can experience fluctuations in actual rates of return.

Rate of Cost of Living Increase

The rate of cost of living increase is determined by considering differences between long-term Government of Canada nominal bonds and real return bonds, which decreased from 1.80% per annum as at December 31, 2016 to approximately 1.60% per annum as at December 31, 2017. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for employee future benefits liability valuation purposes as at December 31, 2017.

Salary Increase Assumptions

Salary increases should reflect general wage increases plus an allowance for merit and promotional increases for current members of the plan, and should be consistent with the assumptions for consumer price inflation and real wage growth in the economy. The merit and promotion scale was developed based on the salary increase assumption review performed in 2017. The review considers actual salary experience from 2002 to 2016 using valuation data for all active members as at December 31, 2016, based on age and service and Hydro One's expectation of future salary increases. Additionally, the salary scale reflect negotiated salary rate increases over the contract period.

Mortality Assumptions

The Company's employee future benefits liability is also impacted by changes in life expectancies used in mortality assumptions. Increases in life expectancies of plan members result in increases in the employee future benefits liability. The mortality assumption used at December 31, 2017 is 95% of 2014 Canadian Pensioners Mortality Private Sector table projected generationally using improvement Scale B.

Rate of Increase in Health Care Cost Trends

The costs of post-retirement and post-employment benefits are determined at the beginning of the year and are based on assumptions for expected claims experience and future health care cost inflation. For the post-retirement benefit plans, a trend study of historical Hydro One experience was conducted in 2017, which resulted in a change in the prescription drug, dental and hospital trends to be used for 2017 year-end reporting purposes. A 1% increase in the health care cost trends would result in a $29 million increase in 2017 interest cost plus service cost, and a $250 million increase in the benefit liability at December 31, 2017.

Valuation of Deferred Tax Assets

Hydro One assesses the likelihood of realizing deferred tax assets by reviewing all readily available current and historical information, including a forecast of future taxable income. To the extent management considers it is more likely than not that some portion or all of the deferred tax assets will not be realized, a valuation allowance is recognized.

Asset Impairment

Within Hydro One's regulated businesses, the carrying costs of most of the long-lived assets are included in the rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through OEB-approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. The Company regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2017, no asset impairment had been recorded for assets within Hydro One's regulated or unregulated businesses.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Hydro One has concluded that goodwill was not impaired at December 31, 2017. Goodwill represents the cost of acquired distribution and transmission companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure controls and procedures are part of a broad internal control framework integral to ensuring that the Company fairly presents in all material respects the financial condition, results of operations and cash flows of the Company for the periods presented in this MD&A and the Company's Annual Report. Disclosure controls and procedures include processes designed to ensure that information is recorded, processed, summarized and reported on a timely basis to the Company's management, including its Chief Executive and Chief Financial Officers, as appropriate, to make timely decisions regarding required disclosure. At the direction of the Company's Chief Executive Officer and the Senior Vice President, Finance, acting in the capacity of Chief Financial Officer, management evaluated disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, management concluded that the Company's disclosure controls and procedures were effective at a reasonable level of assurance as at December 31, 2017.

Internal control over financial reporting is a subset of the internal control framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with US GAAP. The Company's internal control over financial reporting framework includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and disposition of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with US GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorization of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's consolidated financial statements.

The Company's management, at the direction of the Chief Executive Officer and with the participation of the Senior Vice President, Finance, acting in the capacity of Chief Financial Officer, evaluated the effectiveness of the design and operation of internal control over financial reporting based on the framework and criteria established in the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective at a reasonable level of assurance as at December 31, 2017.

Together, disclosure controls and procedures and internal control over financial reporting provide internal control over reporting and disclosure. Internal control, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and due to its inherent limitations, may not prevent or detect all misrepresentations. Furthermore, the effectiveness of internal control is affected by change and subject to the risk that internal control effectiveness may change over time.

The role of Chief Financial Officer was vacated effective May 19, 2017. Responsibilities of the Chief Financial Officer have been temporarily assigned to other senior executives with full oversight provided by the Chief Executive Officer. This model is expected to remain in place until Paul Dobson assumes the role of the new Chief Financial Officer on March 1, 2018. There were no significant changes in the design of the Company's internal control over financial reporting during the three months ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the operation of the Company's internal control over financial reporting.

Management will continue to monitor its systems of internal control over reporting and disclosure and may make modifications from time to time as considered necessary.

NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13 2017-14	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.
2016-02 2018-01	February 2016 – January 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-04	January 2017	The amendment removes the second step of the current two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

SUMMARY OF FOURTH QUARTER RESULTS OF OPERATIONS

Three months ended December 31 *(millions of dollars, except EPS)*	2017	2016	Change
Revenues			
Distribution	1,049	1,228	(14.6%)
Transmission	379	373	1.6%
Other	11	13	(15.4%)
	1,439	1,614	(10.8%)
Costs			
Purchased power	662	858	(22.8%)
OM&A			
Distribution	146	163	(10.4%)
Transmission	79	98	(19.4%)
Other	19	26	(26.9%)
	244	287	(15.0%)
Depreciation and amortization	214	204	4.9%
	1,120	1,349	(17.0%)
Income before financing charges and income taxes	**319**	**265**	**20.4%**
Financing charges	119	101	17.8%
Income before income taxes	**200**	**164**	**22.0%**
Income taxes	38	29	31.0%
Net income	**162**	**135**	**20.0%**
Net income attributable to common shareholders of Hydro One	**155**	**128**	**21.1%**
Basic EPS	$0.26	$0.22	18.2%
Diluted EPS	$0.26	$0.21	23.8%
Basic Adjusted EPS	$0.29	$0.22	31.8%
Diluted Adjusted EPS	$0.28	$0.21	33.3%
Capital Investments			
Distribution	161	201	(19.9%)
Transmission	267	274	(2.6%)
Other	3	2	50.0%
	431	**477**	**(9.6%)**
Assets Placed In-Service			
Distribution	207	211	(1.9%)
Transmission	522	488	7.0%
Other	4	0	100.0%
	733	**699**	**4.9%**

Net Income

Net income attributable to common shareholders for the quarter ended December 31, 2017 of $155 million is an increase of $27 million or 21.1% from the prior year. Significant influences on net income included:

- increase in distribution revenues due to higher energy consumption;
- higher transmission revenues driven by OEB's decision on the 2017-2018 transmission rates filing;
- transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- lower OM&A costs primarily resulting from a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, insurance proceeds received on failed equipment at two transformer stations, a tax recovery of previous year's expenses, lower support services costs, and reduced vegetation management costs;
- higher depreciation expense due to an increase in rate base; and
- increased financing charges primarily due to the issuance of Convertible Debentures in August 2017.

EPS and Adjusted EPS

EPS was $0.26 in the three months ended December 31, 2017, compared to $0.22 in the prior year. The increase in EPS was driven by higher net income for the fourth quarter of 2017, as discussed above. Adjusted EPS, which adjusts for costs related to Avista Corporation acquisition, was $0.29 in the three months ended December 31, 2017, compared to $0.22 in the prior year. The increase in Adjusted EPS was also driven by higher net income for the fourth quarter of 2017, net of aforementioned impact related to Avista Corporation acquisition.

Revenues

The quarterly increase of $6 million or 1.6% in transmission revenues was primarily due to higher revenues driven by the OEB's decision on the 2017-2018 transmission rates filing, partially offset by lower OEB-approved transmission rates.

The quarterly increase of $17 million or 4.6% in distribution revenues, net of purchased power, was primarily due to higher energy consumption mainly resulting from colder weather in the fourth quarter of 2017; and higher external revenues related to CDM incentive bonus; partially offset by reduction in 2017 allowed ROE for the distribution business.

OM&A Costs

The quarterly decrease of $19 million or 19.4% in transmission OM&A costs was primarily due to a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, lower support services costs, and insurance proceeds received due to equipment failures at the Fairchild and Campbell transmission stations.

The quarterly decrease of $17 million or 10.4% in distribution OM&A costs was primarily due to lower expenditures for vegetation management programs due to strategic changes to the forestry program scope that resulted in cost efficiency and improved management of the Company's rights of ways; lower bad debt expense attributable to lower write-offs and improved accounts receivable aging; and a tax recovery of previous year's expenses.

A further decrease of $7 million in other OM&A is primarily due to lower corporate organizational costs in the other segment.

Depreciation and Amortization

The increase of $10 million or 4.9% in depreciation and amortization costs for the fourth quarter of 2017 was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

Financing Charges

The quarterly increase of $18 million or 17.8% in financing charges was primarily due to an increase in interest expense related to the Convertible Debentures issued in August 2017; partially offset by a decrease in interest expense on long-term debt resulting from a decrease in weighted average long-term debt outstanding during the quarter, together with a decrease in the weighted average interest rate.

Income Taxes

Income tax expense for the fourth quarter of 2017 increased by $9 million compared to 2016, and the Company realized an effective tax rate of approximately 19.0% in the fourth quarter of 2017, compared to approximately 17.7% realized in 2016. The increase in the tax expense is primarily due to higher income before taxes in the fourth quarter of 2017.

Capital Investments

The decrease in transmission capital investments during the fourth quarter was primarily due to the following:

- lower volume and timing of spare transformer equipment purchases;
- timing and substantial completion of major development projects, including Guelph Area Transmission Refurbishment, Midtown Transmission Reinforcement, and Holland and Hawthorne transmission stations; and
- timing of work related to the Clarington Transmission Station project; partially offset by
- timing on work on station refurbishments and equipment replacement projects; and
- timing of work at Leamington transmission station.

The decrease in distribution capital investments during the fourth quarter was primarily due to the following:

- timing of capital contributions for jointly used facilities and lower volume of line relocation work;
- substantial completion of work on the Bolton Operation Centre in the fourth quarter of 2016;
- lower volume of work within distribution station refurbishment programs;
- timing of information technology projects including e-Billing and website redesign;
- lower volume of line refurbishments and replacements work; and
- lower volume of fleet and work equipment purchases; partially offset by
- high volume of work on new connections and upgrades due to increased demand.

Assets Placed In-Service

The increase in transmission assets placed in-service during the fourth quarter was primarily due to the following:

- substantial investments of major development projects at Leamington and Holland transmission stations were placed in-service in the fourth quarter of 2017;
- higher volume of investments for overhead lines and component refurbishments and replacement programs;
- timing of assets placed in-service for sustainment investment projects including the transformer asset replacement project at Overbrook transmission station and the breaker replacement project at Richview transmission station; partially offset by
- a large number of cumulative sustainment investments that were placed in-service in the fourth quarter of 2016 at the Bruce A and Burlington transmission stations;
- timing of investments that were placed in-service for the Advanced Distribution System project; and
- timing of assets that were placed in-service in the fourth quarter of 2016 for certain information technology development projects.

The decrease in distribution assets placed in-service during the fourth quarter was primarily due to the following:

- timing of distribution station refurbishments and spare transformer purchases; and
- lower volume of work on distribution generation connection projects; partially offset by
- higher volume of subdivision connections due to increased demand; and
- substantial investments that were placed in-service in the fourth quarter of 2017 for the Leamington transmission station feeder development project.

FORWARD-LOOKING STATEMENTS AND INFORMATION

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting decisions, rates and expected impacts and timing; the Company's liquidity and capital resources and operational requirements; the standby credit facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects and initiatives, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; the OEB; the Motion and the Appeal; the Anwaatin Motion; the East-West Tie Line Project and related regulatory application; collective agreements; Inergi outsourcing and customer service operations arrangements; the pension plan, future pension contributions, valuations and expected impacts; impacts of OEB treatment of pension and OPEBs costs; dividends; credit ratings; Hydro One's strategy and goals; effect of interest rates; non-GAAP measures; critical accounting estimates, including environmental liabilities, regulatory assets and liabilities, and employee future benefits; occupational rights; internal control over financial reporting and disclosure; the Fair Hydro Plan and First Nations Rate Assistance Program, including expected outcomes and impacts; recent accounting-related guidance; the Universal Base Shelf Prospectus; the Convertible Debentures; the Province's waiver of its pre-emptive right under the Governance Agreement to participate in the Debenture Offering; the Company's acquisitions and mergers, including Orillia Power and Avista Corporation; the appointment of Hydro One's new Chief Financial Officer; risk associated with acquisitions; cyber and data security; expectations related to work force demographics; the Company's financing strategy and foreign currency hedging relating to the acquisition of Avista Corporation; class action litigation, including litigation relating to the Merger; the risk that the Company may fail to complete the Merger; risk related to the length of time required to complete the Merger; foreign exchange risk; risks related to additional demands placed on Hydro One as a result of the Merger; risks related to availability of planned sources of funding to be used to fund the Merger; risks and expectations related to Hydro One incurring significant Merger-related expenses; risks and expectations related to Hydro One substantially increasing its amount of indebtedness following the Merger; the Province's ownership of HydroOne; future sales of shares of Hydro One; and reputational, public opinion and political risk. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; continued use of US GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- risks associated with the Province's share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets located on reserves (as defined in the *Indian Act* (Canada));
- the risks associated with information system security and maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section "Risk Management and Risk Factors" in this MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future investments, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com and the Company's website at www.HydroOne.com/Investors.

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Inc. (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgment, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 12, 2018.

Management is responsible for establishing and maintaining adequate disclosure controls and procedures and internal control over financial reporting as described in the annual MD&A. Management evaluated the effectiveness of the design and operation of internal control over financial reporting based on the framework and criteria established in the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective at a reasonable level of assurance as of December 31, 2017. As required, the results of that evaluation were reported to the Audit Committee of the Hydro One Board of Directors and the external auditors.

The Consolidated Financial Statements have been audited by KPMG LLP, independent external auditors appointed by the shareholders of the Company. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with United States Generally Accepted Accounting Principles. The Independent Auditors' Report outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control over reporting and disclosure. The Audit Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit Committee, with and without the presence of management, to discuss their audit findings.

On behalf of Hydro One's management:

Mayo Schmidt
President and Chief Executive Officer

Christopher Lopez
Senior Vice President, Finance
acting in the capacity of chief financial officer

To the Shareholder of Hydro One Inc.

We have audited the accompanying consolidated financial statements of Hydro One Inc., which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of operations and comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Hydro One Inc. as at December 31, 2017 and December 31, 2016, and its consolidated results of operations and its consolidated cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
February 12, 2018

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2017 and 2016

Year ended December 31 *(millions of Canadian dollars, except per share amounts)*	2017	2016
Revenues		
Distribution (includes $279 related party revenues; 2016 – $160) *(Note 26)*	4,366	4,915
Transmission (includes $1,526 related party revenues; 2016 – $1,556) *(Note 26)*	1,581	1,587
	5,947	6,502
Costs		
Purchased power (includes $1,594 related party costs; 2016 – $2,103) *(Note 26)*	2,875	3,427
Operation, maintenance and administration *(Note 26)*	1,014	1,043
Depreciation and amortization *(Note 5)*	810	769
	4,699	5,239
Income before financing charges and income taxes	**1,248**	**1,263**
Financing charges *(Note 6)*	411	392
Income before income taxes	**837**	**871**
Income taxes *(Note 7)*	120	135
Net income	**717**	**736**
Other comprehensive income	—	—
Comprehensive income	**717**	**736**
Net income attributable to:		
Noncontrolling interest *(Note 25)*	6	6
Common shareholder	711	730
	717	**736**
Comprehensive income attributable to:		
Noncontrolling interest *(Note 25)*	6	6
Common shareholder	711	730
	717	**736**
Earnings per common share *(Note 23)*		
Basic	$4,999	$5,132
Diluted	$4,999	$5,132
Dividends per common share declared *(Note 22)*	$105	$14

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS
At December 31, 2017 and 2016

December 31 *(millions of Canadian dollars)*	2017	2016
Assets		
Current assets:		
Cash and cash equivalents	—	48
Accounts receivable *(Note 8)*	635	833
Due from related parties *(Note 26)*	439	224
Other current assets *(Note 9)*	104	97
	1,178	1,202
Property, plant and equipment *(Note 10)*	19,871	19,068
Other long-term assets:		
Regulatory assets *(Note 12)*	3,049	3,145
Deferred income tax assets *(Note 7)*	954	1,213
Intangible assets *(Note 11)*	369	349
Goodwill *(Note 4)*	325	327
Other assets	5	6
	4,702	5,040
Total assets	**25,751**	**25,310**
Liabilities		
Current liabilities:		
Bank indebtedness	3	—
Short-term notes payable *(Note 15)*	926	469
Long-term debt payable within one year *(Notes 15, 16)*	752	602
Accounts payable and other current liabilities *(Note 13)*	892	933
Due to related parties *(Note 26)*	343	253
	2,916	2,257
Long-term liabilities:		
Long-term debt (includes $541 measured at fair value; 2016 – $548) *(Notes 15, 16)*	9,315	10,078
Regulatory liabilities *(Note 12)*	128	209
Deferred income tax liabilities *(Note 7)*	70	60
Other long-term liabilities *(Note 14)*	2,734	2,765
	12,247	13,112
Total liabilities	**15,163**	**15,369**
Contingencies and Commitments (Notes 28, 29)		
Subsequent Events (Note 31)		
Preferred shares *(Note 21)*	486	—
Noncontrolling interest subject to redemption *(Note 25)*	22	22
Equity		
Common shares *(Note 21)*	4,856	5,391
Retained earnings	5,183	4,487
Accumulated other comprehensive loss	(9)	(9)
Hydro One shareholder's equity	10,030	9,869
Noncontrolling interest *(Note 25)*	50	50
Total equity	**10,080**	**9,919**
	25,751	**25,310**

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

David Denison
Chair

Philip Orsino
Chair, Audit Committee

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the years ended December 31, 2017 and 2016

Year ended December 31, 2017 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholder's Equity	Non-controlling Interest *(Note 25)*	Total Equity
January 1, 2017	5,391	4,487	(9)	9,869	50	9,919
Net income	—	711	—	711	4	715
Other comprehensive income	—	—	—	—	—	—
Distributions to noncontrolling interest	—	—	—	—	(4)	(4)
Dividends on common shares	—	(15)	—	(15)	—	(15)
Return of stated capital *(Note 21)*	(535)	—	—	(535)	—	(535)
December 31, 2017	**4,856**	**5,183**	**(9)**	**10,030**	**50**	**10,080**

Year ended December 31, 2016 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholder's Equity	Non-controlling Interest *(Note 25)*	Total Equity
January 1, 2016	6,000	3,759	(9)	9,750	52	9,802
Net income	—	730	—	730	4	734
Other comprehensive income	—	—	—	—	—	—
Distributions to noncontrolling interest	—	—	—	—	(6)	(6)
Dividends on common shares	—	(2)	—	(2)	—	(2)
Return of stated capital *(Note 21)*	(609)	—	—	(609)	—	(609)
December 31, 2016	**5,391**	**4,487**	**(9)**	**9,869**	**50**	**9,919**

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31, 2017 and 2016

Year ended December 31 *(millions of Canadian dollars)*	2017	2016
Operating activities		
Net income	717	736
Environmental expenditures	(24)	(20)
Adjustments for non-cash items:		
Depreciation and amortization (excluding asset removal costs)	720	679
Regulatory assets and liabilities	112	(16)
Deferred income taxes	96	111
Other	10	10
Changes in non-cash balances related to operations *(Note 27)*	63	168
Net cash from operating activities	**1,694**	**1,668**
Financing activities		
Long-term debt issued	—	2,300
Long-term debt repaid	(602)	(502)
Short-term notes issued	3,795	3,031
Short-term notes repaid	(3,338)	(4,053)
Promissory note issued *(Note 26)*	486	—
Promissory note repaid *(Note 26)*	(486)	—
Return of stated capital	(535)	(609)
Preferred shares issued	486	—
Dividends paid	(15)	(2)
Distributions paid to noncontrolling interest	(6)	(9)
Change in bank indebtedness	3	—
Other	—	(10)
Net cash from (used in) financing activities	**(212)**	**146**
Investing activities		
Capital expenditures *(Note 27)*		
Property, plant and equipment	(1,456)	(1,594)
Intangible assets	(80)	(61)
Acquisitions *(Note 4)*	—	(224)
Capital contributions received *(Note 27)*	9	21
Other	(3)	3
Net cash used in investing activities	**(1,530)**	**(1,855)**
Net change in cash and cash equivalents	(48)	(41)
Cash and cash equivalents, beginning of year	48	89
Cash and cash equivalents, end of year	**—**	**48**

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the Business Corporations Act (Ontario) and is wholly-owned by Hydro One Limited. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These Consolidated Financial Statements include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations, goodwill and asset impairments, contingencies, unbilled revenues, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Rate Setting

The Company's Transmission Business consists of the transmission business of Hydro One Networks Inc. (Hydro One Networks), Hydro One Sault Ste. Marie LP (HOSSM) (formerly Great Lakes Power Transmission LP), and its 66% interest in B2M Limited Partnership (B2M LP). The Company's Distribution Business consists of the distribution businesses of Hydro One Networks, as well as Hydro One Remote Communities Inc. (Hydro One Remote Communities).

<u>Transmission</u>

In November 2017, the Ontario Energy Board (OEB) approved Hydro One Networks' 2017 transmission rates revenue requirement of $1,438 million. See Note 12 - Regulatory Assets and Liabilities for additional information.

In December 2015, the OEB approved B2M LP's 2015-2019 rates revenue requirements of $39 million, $36 million, $37 million, $38 million and $37 million for the respective years. On January 14, 2016, the OEB approved the B2M LP revenue requirement recovery through the 2016 Uniform Transmission Rates, and the establishment of a deferral account to capture costs of Tax Rate and Rule changes. On June 8, 2017, the OEB approved the 2017 rates revenue requirement of $34 million, updated for the cost of capital parameters.

On September 28, 2017, the OEB issued its Decision and Order on HOSSM's 2017 transmission rates application, denying the requested revenue requirement for 2017. HOSSM's 2016 approved revenue requirement of $41 million will remain in effect for 2017.

<u>Distribution</u>

In March 2015, the OEB approved Hydro One Networks' distribution revenue requirements of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The OEB has subsequently approved updated revenue requirements of $1,410 million for 2016 and $1,415 million for 2017.

On March 30, 2017, the OEB approved an increase of 1.9% to Hydro One Remote Communities' basic rates for the distribution and generation of electricity, with an effective date of May 1, 2017.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have been applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations in the period that the assessment is made.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments with an original maturity of three months or less.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Distribution revenue also includes an amount relating to rate protection for rural, residential, and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are recorded at their estimated value. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The Company estimates the allowance for doubtful accounts on billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Noncontrolling interest

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to the shareholder of Hydro One. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income and other comprehensive income (OCI) attributable to the noncontrolling interest and any dividends or distributions paid to the noncontrolling interest.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net income or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

Income Taxes

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax liabilities are recognized on all taxable temporary differences between the tax bases and carrying amounts of assets and liabilities. Deferred income tax assets are recognized for deductible temporary differences between tax bases and carrying amounts of assets and liabilities, the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Company records regulatory assets and liabilities associated with deferred income tax assets and liabilities that will be included in the rate-setting process.

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only non-refundable ITCs are recognized as a reduction to income tax expense.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Consolidated Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets.

The capitalized financing costs are a reduction of financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent reviews resulted in changes to rates effective January 1, 2015 and January 1, 2017 for Hydro One Networks' distribution and transmission businesses, respectively. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average	Rate	
	Service Life	Range	Average
Property, plant and equipment:			
Transmission	55 years	1% – 3%	2%
Distribution	46 years	1% – 7%	2%
Communication	16 years	1% – 15%	6%
Administration and service	20 years	1% – 20%	6%
Intangible assets	10 years	10%	10%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

Based on assessment performed as at September 30, 2017, the Company has concluded that goodwill was not impaired at December 31, 2017.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2017 and 2016, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts net of related debt on the Consolidated Balance Sheets. Deferred debt issuance costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and OCI. Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 16 – Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized on its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2017 or 2016.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized on the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Hydro One recognizes its contributions to the defined contribution pension plan as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

<u>Defined Benefit Pension</u>

Defined benefit pension costs are recorded on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are fair valued at the end of each year. Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for its pension plan.

<u>Post-retirement and Post-employment Benefits</u>

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. The actuarial gains and losses on post-employment obligations that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Stock-Based Compensation

<u>Share Grant Plans</u>

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date Hydro One Limited common share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period. Costs are transfered from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans

The Company records the liabilities associated with its Directors' and Management DSU Plans at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on the Hydro One Limited common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the restricted share units (RSUs) and performance share units (PSUs), issued under Hydro One Limited's LTIP, at fair value based on the grant date Hydro One Limited common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgments regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgments about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with contaminated land assessment and remediation and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

Asset retirement obligations are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional asset retirement obligations are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an asset retirement obligation, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

The Company's asset retirement obligations recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13 2017-14	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.
2016-02 2018-01	February 2016 – January 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-04	January 2017	The amendment removes the second step of the current two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

4. BUSINESS COMBINATIONS

Acquisition of HOSSM

On October 31, 2016, Hydro One acquired HOSSM, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario from Brookfield Infrastructure Holdings Inc. The total purchase price for HOSSM was approximately $376 million, including the assumption of approximately $150 million in outstanding indebtedness. During 2017, the Company completed the final determination of the fair value of assets acquired and liabilities assumed with no significant changes, which resulted in a total goodwill of approximately $157 million arising from the HOSSM acquisition. The difference between the preliminary and final purchase price allocation to fair value of assets acquired and liabilities related to a $2 million decrease in deferred income tax liabilities which resulted in a corresponding decrease to goodwill. The following table summarizes the final fair value of the assets acquired and liabilities assumed:

(millions of dollars)	
Cash and cash equivalents	5
Property, plant and equipment	221
Intangible assets	1
Regulatory assets	50
Goodwill	157
Working capital	(2)
Long-term debt	(186)
Pension and post-employment benefit liabilities, net	(5)
Deferred income taxes	(15)
	226

Goodwill arising from the HOSSM acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and HOSSM. HOSSM contributed revenues of $6 million and less than $1 million of net income to the Company's consolidated financial results for the year ended December 31, 2016. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. HOSSM's financial information was not material to the Company's consolidated financial results for the year ended December 31, 2016 and therefore, has not been disclosed on a pro forma basis.

Agreement to Purchase Orillia Power

On August 15, 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power), an electricity distribution company located in Simcoe County, Ontario, from the City of Orillia for approximately $41 million, including the assumption of approximately $15 million in outstanding indebtedness and regulatory liabilities, subject to closing adjustments. The acquisition is subject to regulatory approval by the OEB.

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 *(millions of dollars)*	2017	2016
Depreciation of property, plant and equipment	634	603
Asset removal costs	90	90
Amortization of intangible assets	62	56
Amortization of regulatory assets	24	20
	810	769

6. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2017	2016
Interest on long-term debt	450	424
Interest on short-term notes	6	9
Other	12	15
Less: Interest capitalized on construction and development in progress	(56)	(54)
Interest earned on cash and cash equivalents	(1)	(2)
	411	392

7. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Income before income taxes	837	871
Income taxes at statutory rate of 26.5% (2016 - 26.5%)	222	231
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(55)	(53)
Pension contributions in excess of pension expense	(13)	(16)
Overheads capitalized for accounting but deducted for tax purposes	(17)	(16)
Interest capitalized for accounting but deducted for tax purposes	(15)	(14)
Environmental expenditures	(6)	(5)
Other	1	5
Net temporary differences	(105)	(99)
Net permanent differences	3	3
Total income taxes	120	135

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Current income taxes	24	24
Deferred income taxes	96	111
Total income taxes	120	135
Effective income tax rate	14.3%	15.5%

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates. Deferred income tax assets and liabilities arise from differences between the tax basis and the carrying amounts of the assets and liabilities. At December 31, 2017 and 2016, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of dollars)*	2017	2016
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	109	477
Non-depreciable capital property	271	271
Post-retirement and post-employment benefits expense in excess of cash payments	558	603
Environmental expenditures	71	74
Non-capital losses	240	213
Tax credit carryforwards	49	27
Investment in subsidiaries	84	75
Other	13	3
	1,395	1,743
Less: valuation allowance	(364)	(352)
Total deferred income tax assets	1,031	1,391
Less: current portion	—	—
	1,031	1,391
Deferred income tax liabilities		
Regulatory amounts that are not recognized for tax purposes	(47)	(153)
Goodwill	(10)	(10)
Capital cost allowance in excess of depreciation and amortization	(74)	(64)
Other	(16)	(11)
Total deferred income tax liabilities	(147)	(238)
Less: current portion	—	—
	(147)	(238)
Net deferred income tax assets	884	1,153

The net deferred income tax assets are presented on the Consolidated Balance Sheets as follows:

December 31 *(millions of dollars)*	2017	2016
Long-term:		
Deferred income tax assets	954	1,213
Deferred income tax liabilities	(70)	(60)
Net deferred income tax assets	884	1,153

The valuation allowance for deferred tax assets as at December 31, 2017 was $364 million (2016 – $352 million). The valuation allowance primarily relates to temporary differences for non-depreciable assets and investments in subsidiaries. As of December 31, 2017 and 2016, the Company had non-capital losses carried forward available to reduce future years' taxable income, which expire as follows:

Year of expiry *(millions of dollars)*	2017	2016
2034	2	2
2035	221	221
2036	558	579
2037	123	—
Total losses	904	802

8. ACCOUNTS RECEIVABLE

December 31 *(millions of dollars)*	2017	2016
Accounts receivable – billed	297	427
Accounts receivable – unbilled	367	441
Accounts receivable, gross	664	868
Allowance for doubtful accounts	(29)	(35)
Accounts receivable, net	635	833

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016
Allowance for doubtful accounts – beginning	(35)	(61)
Write-offs	25	37
Additions to allowance for doubtful accounts	(19)	(11)
Allowance for doubtful accounts – ending	(29)	(35)

9. OTHER CURRENT ASSETS

December 31 *(millions of dollars)*	2017	2016
Regulatory assets *(Note 12)*	46	37
Materials and supplies	18	19
Prepaid expenses and other assets	40	41
	104	97

10. PROPERTY, PLANT AND EQUIPMENT

December 31, 2017 *(millions of dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	15,509	5,162	989	11,336
Distribution	10,213	3,513	149	6,849
Communication	1,088	742	22	368
Administration and service	1,561	857	46	750
Easements	638	70	—	568
	29,009	10,344	1,206	19,871

December 31, 2016 *(millions of dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	14,692	4,862	910	10,740
Distribution	9,656	3,305	243	6,594
Communication	1,069	674	9	404
Administration and service	1,632	924	61	769
Easements	628	67	—	561
	27,677	9,832	1,223	19,068

Financing charges capitalized on property, plant and equipment under construction were $54 million in 2017 (2016 – $52 million).

11. INTANGIBLE ASSETS

December 31, 2017 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	698	370	41	369
Other	5	5	—	—
	703	375	41	369

December 31, 2016 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	621	326	53	348
Other	5	4	—	1
	626	330	53	349

Financing charges capitalized to intangible assets under development were $2 million in 2017 (2016 – $2 million). The estimated annual amortization expense for intangible assets is as follows: 2018 – $67 million; 2019 – $57 million; 2020 – $40 million; 2021 – $39 million; and 2022 – $36 million.

12. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 *(millions of dollars)*	2017	2016
Regulatory assets:		
Deferred income tax regulatory asset	1,762	1,587
Pension benefit regulatory asset	981	900
Post-retirement and post-employment benefits	36	243
Environmental	196	204
Share-based compensation	40	31
Debt premium	27	32
Foregone revenue deferral	23	—
Distribution system code exemption	10	10
B2M LP start-up costs	4	5
Retail settlement variance account	—	145
2015-2017 rate rider	—	7
Pension cost variance	—	4
Other	16	14
Total regulatory assets	3,095	3,182
Less: current portion	(46)	(37)
	3,049	3,145
Regulatory liabilities:		
Green Energy expenditure variance	60	69
External revenue variance	46	64
CDM deferral variance	28	54
Pension cost variance	23	—
2015-2017 rate rider	6	—
Deferred income tax regulatory liability	5	4
Other	17	18
Total regulatory liabilities	185	209
Less: current portion	(57)	—
	128	209

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2017 income tax expense would have been higher by approximately $113 million (2016 – $104 million).

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Decision). In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a Decision and Order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an additional impairment of up to approximately $370 million related to Hydro One Networks' distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which is scheduled for mid-February 2018. In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company's Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

Pension Benefit Regulatory Asset

In accordance with OEB rate orders, pension costs are recovered on a cash basis as employer contributions are paid to the pension fund in accordance with the Pension Benefits Act (Ontario). The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, OCI would have been lower by $80 million and operation, maintenance and administration expenses would have been higher by $1 million (2016 – OCI higher by $52 million).

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2017 OCI would have been higher by $207 million (2016 – lower by $3 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2017, the environmental regulatory asset increased by $1 million (2016 – decreased by $1 million) to reflect related changes in the Company's PCB liability, and increased by $7 million (2016 – $10 million) due to changes in the land assessment and remediation liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2017 operation, maintenance and administration expenses would have been higher by $8 million (2016 – $9 million). In addition, 2017 amortization expense would have been lower by $24 million (2016 – $20 million), and 2017 financing charges would have been higher by $8 million (2016 – $8 million).

Share-based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2017 operation, maintenance and administration expenses would have been higher by $7 million (2016 – $9 million). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.

Debt Premium

The value of debt assumed in the acquisition of HOSSM has been recorded at fair value in accordance with US GAAP - Business Combinations. The OEB allows for recovery of interest at the coupon rate of the Senior Secured Bonds and a regulatory asset has been recorded for the difference between the fair value and face value of this debt. The debt premium is recovered over the remaining term of the debt.

Foregone Revenue Deferral

As part of its September 2017 decision on Hydro One Networks' transmission rate application for 2017 and 2018 rates, the OEB approved the foregone revenue account to record the difference between revenue earned under the rates approved as part of the decision, effective January 1, 2017, and revenue earned under the interim rates until the approved 2017 rates were implemented. The OEB approved a similar account for B2M LP in June 2017 to record the difference between revenue earned under the newly approved rates, effective January 1, 2017, and the revenue recorded under the interim 2017 rates. The balances of these accounts will be returned to or recovered from ratepayers, respectively, over a one-year period ending December 31, 2018. The draft rate order submitted by Hydro One Networks was approved by the OEB in November, 2017. This draft rate order reflects the September 2017 decision, including a reduction of the amount of cash taxes approved for recovery in transmission rates due to the OEB's basis to share the savings resulting from a deferred tax asset with ratepayers. The Company's position in the aforementioned Motion is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. Therefore, the Company has also reflected the impact of the Company's position with respect to the Motion in the Foregone Revenue Deferral account. The timing for recovery of this impact will be determined as part of the outcome of the Motion.

Distribution System Code (DSC) Exemption

In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the DSC, with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by Hydro One Networks that resulted from the connection of certain renewable generation facilities. The OEB ruled that identified specific expenditures can be recorded in a deferral account subject to the OEB's review in subsequent Hydro One Networks distribution applications. In March 2015, the OEB approved the disposition of the DSC exemption deferral account balance at December 31, 2013, including accrued interest, which was recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account. There were no additions to this regulatory account in 2017 or 2016. The remaining balance in this account at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application.

B2M LP Start-up Costs

In December 2015, OEB issued its decision on B2M LP's application for 2015-2019 and as part of the decision approved the recovery of $8 million of start-up costs relating to B2M LP. The costs are being recovered over a four-year period which began in 2016, in accordance with the OEB decision.

Retail Settlement Variance Account (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In March 2015, the OEB approved the disposition of the total RSVA balance accumulated from January 2012 to December 2013, including accrued interest, to be recovered through the 2015-2017 Rate Rider.

2015-2017 Rate Rider

In March 2015, as part of its decision on Hydro One Networks' distribution rate application for 2015-2019, the OEB approved the disposition of certain deferral and variance accounts, including RSVAs and accrued interest. The 2015-2017 Rate Rider account included the balances approved for disposition by the OEB and was disposed of in accordance with the OEB decision over a 32-month period ended on December 31, 2017. The balance remaining in the account represents an over-collection to be returned to ratepayers in a future rate application. We have not requested recovery of the remaining balance of this account in the current distribution rate application.

Pension Cost Variance

A pension cost variance account was established for Hydro One Networks' transmission and distribution businesses to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. The balance in this regulatory account reflects the deficit of pension costs paid as compared to OEB-approved amounts. In March 2015, the OEB approved the disposition of the distribution business portion of the total pension cost variance account at December 31, 2013, including accrued interest, which was recovered through the 2015-2017 Rate Rider. In September 2017, the OEB approved the disposition of the transmission business portion of the total pension cost variance account as at December 31, 2015, including accrued interest, which is being recovered over a two-year period ending December 31, 2018. In the absence of rate-regulated accounting, 2017 revenue would have been higher by $24 million (2016 – $25 million).

Green Energy Expenditure Variance

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts. In September 2017, the OEB approved the disposition of the external revenue variance account as at December 31, 2015, including accrued interest, which is being returned to customers over a two-year period ending December 31, 2018.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. The balance in the CDM deferral variance account relates to the actual 2013 and 2014 CDM compared to the amounts included in 2013 and 2014 revenue requirements, respectively. There were no additions to this regulatory account in 2017 or 2016. The balance of the account at December 31, 2015, including interest, was approved for disposition in the 2017-2018 transmission rate decision and is currently being drawn down over a 2-year period ending December 31, 2018.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

December 31 *(millions of dollars)*	2017	2016
Accounts payable	173	177
Accrued liabilities	563	651
Accrued interest	99	105
Regulatory liabilities *(Note 12)*	57	—
	892	933

14. OTHER LONG-TERM LIABILITIES

December 31 *(millions of dollars)*	2017	2016
Post-retirement and post-employment benefit liability *(Note 18)*	1,507	1,628
Pension benefit liability *(Note 18)*	981	900
Environmental liabilities *(Note 19)*	168	177
Due to related parties *(Note 26)*	39	26
Asset retirement obligations *(Note 20)*	9	9
Long-term accounts payable and other liabilities	30	25
	2,734	2,765

15. DEBT AND CREDIT AGREEMENTS

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by the Company's committed revolving credit facilities totalling $2.3 billion. In June 2017, the maturity date of Hydro One's $2.3 billion credit facilities was extended from June 2021 to June 2022.

The Company may use the credit facilities for working capital and general corporate purposes. If used, interest on the credit facilities would apply based on Canadian benchmark rates. The obligation of each lender to make any credit extension under its credit facility is subject to various conditions including that no event of default has occurred or would result from such credit extension.

Long-Term Debt

The following table presents long-term debt outstanding at December 31, 2017 and 2016:

December 31 *(millions of dollars)*	2017	2016
5.18% Series 13 notes due 2017	—	600
2.78% Series 28 notes due 2018	750	750
Floating-rate Series 31 notes due 2019[1]	228	228
1.48% Series 37 notes due 20192	500	500
4.40% Series 20 notes due 2020	300	300
1.62% Series 33 notes due 20202	350	350
1.84% Series 34 notes due 2021	500	500
3.20% Series 25 notes due 2022	600	600
2.77% Series 35 notes due 2026	500	500
7.35% Debentures due 2030	400	400
6.93% Series 2 notes due 2032	500	500
6.35% Series 4 notes due 2034	385	385
5.36% Series 9 notes due 2036	600	600
4.89% Series 12 notes due 2037	400	400
6.03% Series 17 notes due 2039	300	300
5.49% Series 18 notes due 2040	500	500
4.39% Series 23 notes due 2041	300	300
6.59% Series 5 notes due 2043	315	315
4.59% Series 29 notes due 2043	435	435
4.17% Series 32 notes due 2044	350	350
5.00% Series 11 notes due 2046	325	325
3.91% Series 36 notes due 2046	350	350
3.72% Series 38 notes due 2047	450	450
4.00% Series 24 notes due 2051	225	225
3.79% Series 26 notes due 2062	310	310
4.29% Series 30 notes due 2064	50	50
Hydro One long-term debt (a)	9,923	10,523
6.6% Senior Secured Bonds due 2023 (Face value - $110 million)	136	144
4.6% Note Payable due 2023 (Face value - $36 million)	40	40
HOSSM long-term debt (b)	176	184
	10,099	10,707
Add: Net unamortized debt premiums	14	15
Add: Unrealized mark-to-market gain[2]	(9)	(2)
Less: Deferred debt issuance costs	(37)	(40)
Total long-term debt	10,067	10,680

[1] The interest rates of the floating-rate notes are referenced to the three-month Canadian dollar bankers' acceptance rate, plus a margin.

[2] The unrealized mark-to-market net gain relates to $50 million of the Series 33 notes due 2020 and $500 million Series 37 notes due 2019. The unrealized mark-to-market net gain is offset by a $9 million (2016 – $2 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

(a) Hydro One long-term debt

At December 31, 2017, long-term debt of $9,923 million (2016 - $10,523 million) was outstanding, the majority of which was issued under Hydro One's Medium Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At December 31 2017, $1.2 billion remained available for issuance until January 2018. In 2017, no long-term debt was issued and $600 million of long-term debt was repaid under the MTN Program (2016 - $2,300 million issued and $500 million repaid).

(b) HOSSM long-term debt

At December 31, 2017, long-term debt of $176 million (2016 - $184 million), with a face value of $146 million (2016 - $148 million) was held by HOSSM. In 2017, $2 million of HOSSM long-term debt was repaid (2016 - $2 million).

The total long-term debt is presented on the consolidated balance sheets as follows:

December 31 *(millions of dollars)*	2017	2016
Current liabilities:		
Long-term debt payable within one year	752	602
Long-term liabilities:		
Long-term debt	9,315	10,078
Total long-term debt	10,067	10,680

Principal and Interest Payments

Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of dollars)*	Weighted Average Interest Rate *(%)*
1 year	752	2.8
2 years	731	1.6
3 years	653	2.9
4 years	503	1.9
5 years	604	3.2
	3,243	2.5
6 – 10 years	631	3.5
Over 10 years	6,195	5.2
	10,069	4.2

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of dollars)*
2018	426
2019	402
2020	384
2021	370
2022	355
	1,937
2023-2027	1,672
2028+	4,081
	7,690

16. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2017 and 2016, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, bank indebtedness, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2017 and 2016 are as follows:

December 31 *(millions of dollars)*	2017 Carrying Value	2017 Fair Value	2016 Carrying Value	2016 Fair Value
$50 million of MTN Series 33 notes	49	49	50	50
$500 million MTN Series 37 notes	492	492	498	498
Other notes and debentures	9,526	11,027	10,132	11,462
Long-term debt, including current portion	10,067	11,568	10,680	12,010

Fair Value Measurements of Derivative Instruments

At December 31, 2017, Hydro One had interest-rate swaps in the amount of $550 million (2016 – $550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One's fair value hedge exposure was approximately 6% (2016 – 5%) of its total long-term debt. At December 31, 2017, Hydro One had the following interest-rate swaps designated as fair value hedges:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt; and
- two $125 million and one $250 million fixed-to-floating interest-rate swap agreements to convert the $500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt.

At December 31, 2017 and 2016, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2017 and 2016 is as follows:

December 31, 2017 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Bank indebtedness	3	3	3	—	—
Short-term notes payable	926	926	926	—	—
Long-term debt, including current portion	10,067	11,568	—	11,568	—
Derivative instruments					
Fair value hedges – interest-rate swaps	9	9	9	—	—
	11,005	12,506	938	11,568	—

December 31, 2016 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	48	48	48	—	—
	48	48	48	—	—
Liabilities:					
Short-term notes payable	469	469	469	—	—
Long-term debt, including current portion	10,680	12,010	—	12,010	—
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	2	—	—
	11,151	12,481	471	12,010	—

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no transfers between any of the fair value levels during the years ended December 31, 2017 or 2016.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the years ended December 31, 2017 and 2016.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive Income. The net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2017 and 2016 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2017 and 2016, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a material amount of revenue from any single customer. At December 31, 2017 and 2016, there was no material accounts receivable balance due from any single customer.

At December 31, 2017, the Company's provision for bad debts was $29 million (2016 – $35 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2017, approximately 5% (2016 – 6%) of the Company's net accounts receivable were outstanding for more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2017 and 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2017, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, and the revolving standby credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

17. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing access to capital, the Company targets to maintain strong credit quality. At December 31, 2017 and 2016, the Company's capital structure was as follows:

December 31 *(millions of dollars)*	2017	2016
Long-term debt payable within one year	752	602
Short-term notes payable	926	469
Bank indebtedness	3	—
Less: cash and cash equivalents	—	(48)
	1,681	1,023
Long-term debt	9,315	10,078
Preferred shares	486	—
Common shares	4,856	5,391
Retained earnings	5,183	4,487
Total capital	21,521	20,979

Hydro One and HOSSM have customary covenants typically associated with long-term debt. Hydro One's long-term debt and credit facility covenants limit permissible debt to 75% of its total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

18. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a defined contribution pension plan (DC Plan), a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One.

Hydro One contributions to the DC Plan for the year ended December 31, 2017 were $1 million (2016 – less than $1 million). At December 31, 2017, Company contributions payable included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2016 – less than $1 million).

Pension Plan, Supplemental Plan, and Post-Retirement and Post-Employment Plans

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for The Society of Energy Professionals (The Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2017 of $87 million (2016 – $108 million) were based on an actuarial valuation effective December 31, 2016 (2016 - based on an actuarial valuation effective December 31, 2015) and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2018 and 2019 are approximately $71 million for each year based on the actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings. Future minimum contributions beyond 2019 will be based on an actuarial valuation effective no later than December 31, 2019. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for limitations imposed by the *Income Tax Act* (Canada). The Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment benefit plans (Plans) as an asset or liability on its Consolidated Balance Sheets, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. The measurement date for the Plans is December 31.

Year ended December 31 *(millions of dollars)*	Pension Benefits 2017	Pension Benefits 2016	Post-Retirement and Post-Employment Benefits 2017	Post-Retirement and Post-Employment Benefits 2016
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	7,774	7,683	1,676	1,591
Current service cost	147	144	48	41
Employee contributions	49	45	—	—
Interest cost	304	308	67	66
Benefits paid	(368)	(354)	(44)	(43)
Net actuarial loss (gain)	352	(52)	(195)	14
Change due to employees transfer	—	—	—	7
Projected benefit obligation, end of year	8,258	7,774	1,552	1,676
Change in plan assets				
Fair value of plan assets, beginning of year	6,874	6,731	—	—
Actual return on plan assets	662	370	—	—
Benefits paid	(368)	(354)	(34)	(43)
Employer contributions	87	108	34	43
Employee contributions	49	45	—	—
Administrative expenses	(27)	(26)	—	—
Fair value of plan assets, end of year	7,277	6,874	—	—
Unfunded status	981	900	1,552	1,676

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets as follows:

December 31 *(millions of dollars)*	Pension Benefits 2017	Pension Benefits 2016	Post-Retirement and Post-Employment Benefits 2017	Post-Retirement and Post-Employment Benefits 2016
Other assets[1]	1	1	—	—
Accrued liabilities	—	—	52	55
Pension benefit liability	981	900	—	—
Post-retirement and post-employment benefit liability[2]	—	—	1,507	1,628
Net unfunded status	980	899	1,559	1,683

[1] Represents the funded status of HOSSM defined benefit pension plan.
[2] Includes $7 million (2016 – $7 million) relating to HOSSM post-employment benefit plans.

The funded or unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations for the Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the projected benefit obligation (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan:

December 31 *(millions of dollars)*	2017	2016
PBO	8,258	7,774
ABO	7,614	7,094
Fair value of plan assets	7,277	6,874

On an ABO basis, the Pension Plan was funded at 96% at December 31, 2017 (2016 – 97%). On a PBO basis, the Pension Plan was funded at 88% at December 31, 2017 (2016 – 88%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2017 and 2016 for the Pension Plan:

Year ended December 31 *(millions of dollars)*	2017	2016
Current service cost	147	144
Interest cost	304	308
Expected return on plan assets, net of expenses	(442)	(432)
Amortization of actuarial losses	79	96
Net periodic benefit costs	88	116
Charged to results of operations[1]	37	45

[1] The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2017, pension costs of $85 million (2016 – $105 million) were attributed to labour, of which $37 million (2016 – $45 million) was charged to operations, and $48 million (2016 – $60 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2017 and 2016 for the post-retirement and post-employment benefit plans:

Year ended December 31 *(millions of dollars)*	2017	2016
Current service cost	48	41
Interest cost	67	66
Amortization of actuarial losses	16	15
Net periodic benefit costs	131	122
Charged to results of operations	58	53

Assumptions

The measurement of the obligations of the Plans and the costs of providing benefits under the Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed-income securities.

The following weighted average assumptions were used to determine the benefit obligations at December 31, 2017 and 2016:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	2017	2016	2017	2016
Significant assumptions:				
Weighted average discount rate	3.40%	3.90%	3.40%	3.90%
Rate of compensation scale escalation (long-term)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Rate of increase in health care cost trends[1]	—	—	4.04%	4.36%

[1] 5.26% per annum in 2018, grading down to 4.04% per annum in and after 2031 (2016 – 6.25% in 2017, grading down to 4.36% per annum in and after 2031).

The following weighted average assumptions were used to determine the net periodic benefit costs for the years ended December 31, 2017 and 2016. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

Year ended December 31	2017	2016
Pension Benefits:		
Weighted average expected rate of return on plan assets	6.50%	6.50%
Weighted average discount rate	3.90%	4.00%
Rate of compensation scale escalation (long-term)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	15	15
Post-Retirement and Post-Employment Benefits:		
Weighted average discount rate	3.90%	4.10%
Rate of compensation scale escalation (long-term)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	15.2	15.3
Rate of increase in health care cost trends[1]	4.36%	4.36%

[1] 6.25% per annum in 2017, grading down to 4.36% per annum in and after 2031 (2016 – 6.38% in 2016, grading down to 4.36% per annum in and after 2031).

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third-party bond yield curve corresponding to each duration. The yield curve is based on "AA" long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of a 1% change in health care cost trends on the projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2017 and 2016 is as follows:

December 31 *(millions of dollars)*	2017	2016
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	247	286
Effect of a 1% decrease in health care cost trends	(188)	(219)

The effect of a 1% change in health care cost trends on the service cost and interest cost for the post-retirement and post-employment benefits for the years ended December 31, 2017 and 2016 is as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	28	22
Effect of a 1% decrease in health care cost trends	(20)	(16)

The following approximate life expectancies were used in the mortality assumptions to determine the projected benefit obligations for the pension and post-retirement and post-employment plans at December 31, 2017 and 2016:

December 31, 2017 Life expectancy at 65 for a member currently at				December 31, 2016 Life expectancy at 65 for a member currently at			
Age 65		Age 45		Age 65		Age 45	
Male	Female	Male	Female	Male	Female	Male	Female
22	24	23	24	22	24	23	24

Estimated Future Benefit Payments

At December 31, 2017, estimated future benefit payments to the participants of the Plans were:

(millions of dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2018	326	53
2019	335	54
2020	342	56
2021	350	57
2022	358	58
2023 through to 2027	1,886	311
Total estimated future benefit payments through to 2027	3,597	589

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

Year ended December 31 *(millions of dollars)*	2017	2016
Pension Benefits:		
Actuarial loss (gain) for the year	159	35
Amortization of actuarial losses	(79)	(96)
	80	(61)
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	(195)	14
Amortization of actuarial losses	(16)	(15)
Amounts not subject to regulatory treatment	4	4
	(207)	3

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016
Pension Benefits:		
Actuarial loss	981	900
Post-Retirement and Post-Employment Benefits:		
Actuarial loss	36	243

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 *(millions of dollars)*	2017	2016	2017	2016
Actuarial loss	84	79	2	6

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that Pension Plan assets will be sufficient to pay Pension Plan benefits when due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies and Procedures (SIPP), which is reviewed and approved by the Human Resource Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

Pension Plan Asset Mix

At December 31, 2017, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	55	60
Debt securities	35	31
Other[1]	10	9
	100	100

[1] Other investments include real estate and infrastructure investments.

At December 31, 2017, the Pension Plan held $11 million (2016 – $11 million) Hydro One corporate bonds and $415 million (2016 – $450 million) of debt securities of the Province.

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2017 and 2016. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. At December 31, 2017 and 2016, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan's Statement of Investment Beliefs and Guidelines provides guidelines and restrictions for eligible investments taking into account credit ratings, maximum investment exposure and other controls in order to limit the impact of this risk. The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivative instruments by transacting only with highly rated financial institutions, and also by ensuring that exposure is diversified across counterparties. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

Fair Value Measurements

The following tables present the Pension Plan assets measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2017 and 2016:

December 31, 2017 *(millions of dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	—	16	549	565
Cash and cash equivalents	153	—	—	153
Short-term securities	—	109	—	109
Derivative instruments	—	5	—	5
Corporate shares – Canadian	921	—	—	921
Corporate shares – Foreign	3,307	125	—	3,432
Bonds and debentures – Canadian	—	1,879	—	1,879
Bonds and debentures – Foreign	—	194	—	194
Total fair value of plan assets[1]	4,381	2,328	549	7,258

[1] At December 31, 2017, the total fair value of Pension Plan assets and liabilities excludes $28 million of interest and dividends receivable, $10 million of pension administration expenses payable, $1 million of sold investments receivable and $1 million of purchased investments payable.

December 31, 2016 *(millions of dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	—	20	425	445
Cash and cash equivalents	146	—	—	146
Short-term securities	—	127	—	127
Corporate shares – Canadian	911	—	—	911
Corporate shares – Foreign	2,985	113	—	3,098
Bonds and debentures – Canadian	—	1,943	—	1,943
Bonds and debentures – Foreign	—	193	—	193
Total fair value of plan assets[1]	4,042	2,396	425	6,863

[1] At December 31, 2016, the total fair value of Pension Plan assets excludes $27 million of interest and dividends receivable, $15 million of purchased investments payable, $9 million of pension administration expenses payable, and $7 million of sold investments receivable.

See note 16 - Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2017 and 2016. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 *(millions of dollars)*	2017	2016
Fair value, beginning of year	425	301
Realized and unrealized gains	(31)	23
Purchases	171	151
Sales and disbursements	(16)	(50)
Fair value, end of year	549	425

There were no significant transfers between any of the fair value levels during the years ended December 31, 2017 and 2016.

The Company performs sensitivity analysis for fair value measurements classified in Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions. This sensitivity analysis resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value

Pooled funds mainly consist of private equity, real estate and infrastructure investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Real estate and infrastructure investments represent funds that invest in real assets which are not publicly traded on a stock exchange. Investment strategies in real estate include limited partnerships that seek to generate a total return through income and capital growth by investing primarily in global and Canadian limited partnerships. Investment strategies in infrastructure include limited partnerships in core infrastructure assets focusing on assets that generate stable, long-term cash flows and deliver incremental returns relative to conventional fixed-income investments. Private equity, real estate and infrastructure valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Since these valuation inputs are not highly observable, private equity and infrastructure investments have been categorized as Level 3 within pooled funds.

Cash equivalents consist of demand cash deposits held with banks and cash held by the investment managers. Cash equivalents are categorized as Level 1.

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities are categorized as Level 2.

Derivative instruments are used to hedge the Pension Plan's foreign currency exposure back to Canadian dollars. The most significant currencies being hedged against the Canadian dollar are the United States dollar, Euro, and Japanese Yen. The terms to maturity of the forward exchange contracts at December 31, 2017 are within three months. The fair value of the derivative instruments is determined using inputs other than quoted prices that are observable for these assets. The fair value is determined using standard interpolation methodology primarily based on the World Markets exchange rates. Derivative instruments are categorized as Level 2.

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

19. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2017 and 2016:

Year ended December 31, 2017 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities - beginning	143	61	204
Interest accretion	6	2	8
Expenditures	(16)	(8)	(24)
Revaluation adjustment	1	7	8
Environmental liabilities - ending	134	62	196
Less: current portion	(20)	(8)	(28)
	114	54	168

Year ended December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities - beginning	148	59	207
Interest accretion	7	1	8
Expenditures	(11)	(9)	(20)
Revaluation adjustment	(1)	10	9
Environmental liabilities - ending	143	61	204
Less: current portion	(18)	(9)	(27)
	125	52	177

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

December 31, 2017 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	142	64	206
Less: discounting environmental liabilities to present value	(8)	(2)	(10)
Discounted environmental liabilities	134	62	196

December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	158	66	224
Less: discounting environmental liabilities to present value	(15)	(5)	(20)
Discounted environmental liabilities	143	61	204

At December 31, 2017, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2018	28
2019	27
2020	32
2021	34
2022	31
Thereafter	54
	206

Hydro One records a liability for the estimated future expenditures for land assessment and remediation and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations, and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 2.0% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act, 1999*, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, Hydro One's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is $142 million (2016 – $158 million). These expenditures are expected to be incurred over the period from 2018 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2017 to increase the PCB environmental liability by $1 million (2016 – reduce by $1 million).

Land Assessment and Remediation

The Company's best estimate of the total estimated future expenditures to complete its land assessment and remediation program is $64 million (2016 – $66 million). These expenditures are expected to be incurred over the period from 2018 to 2044. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2017 to increase the land assessment and remediation environmental liability by $7 million (2016 – $10 million).

20. ASSET RETIREMENT OBLIGATIONS

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's asset retirement obligations represent management's best estimates of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Asset retirement obligations are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2017, Hydro One had recorded asset retirement obligations of $9 million (2016 – $9 million), primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

21. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2017, the Company had 142,239 common shares issued and outstanding (2016 – 142,239).

In 2017, a return of stated capital in the amount of $535 million (2016 – $609 million) was paid.

The amount and timing of any dividends payable by Hydro One is at the discretion of the Hydro One Board of Directors and is established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board of Directors may consider relevant.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2017, two series of preferred shares are authorized for issuance: the Class A preferred shares and Class B preferred shares. At December 31, 2017, the Company had 485,870 Class B preferred shares and no Class A preferred shares issued and outstanding (2016 - no Class A or Class B preferred shares issued and outstanding).

<u>Class A Preferred Shares</u>

On November 2, 2015, a special resolution of Hydro One Limited (as sole shareholder of Hydro One) was made to amend the articles of Hydro One to delete the share ownership restrictions and to amend the Hydro One preferred share terms to provide for basic redeemable preferred shares. When issued, the Class A preferred shares will be redeemable at the option of the Company. The holders of the Class A preferred shares will be entitled to receive, if and when declared by the Hydro One Board of Directors, non-cumulative preferred share dividends at a rate per year to be determined by the Hydro One Board of Directors. The holders of the Class A preferred shares will not be entitled to receive notice of, or to attend or to vote at, any meeting of the shareholders of Hydro One. The holders of the Class A preferred shares will be entitled to receive, before any distributions to the holders of common shares and any other shares ranking junior to the Class A preferred shares, an amount equal to the amount paid for the Class A preferred shares together with all dividends declared and unpaid up to the date of liquidation, dissolution or winding up of Hydro One, or the date of redemption.

Class B Preferred Shares

On November 10, 2017, a special resolution of Hydro One Limited was made to amend the articles of Hydro One to create an unlimited number of Class B preferred shares. The holders of the Class B preferred shares are entitled to receive quarterly floating-rate cumulative dividends, if and when declared by the Board of Directors, at a rate equal to the sum of the average 3-month Canadian dollar bankers' acceptance rate and 0.25% as reset quarterly. The holders of the Class B preferred shares will not be entitled to receive notice of, or to attend or to vote at, any meeting of the shareholders of Hydro One. The holders of the Class B preferred shares will be entitled to receive, before any distributions to the holders of the Class A preferred shares, the common shares and any other shares ranking junior to the Class B preferred shares, an amount equal to the amount paid for the Class B preferred shares together with all dividends unpaid up to the date of liquidation, dissolution or winding up of Hydro One, or the date of redemption.

The Class B preferred shares have a redemption feature that is outside the control of the Company because the holders can exercise their right to redeem the Class B preferred shares at any time without approval of the Company's Board of Directors. The Class B preferred shares are classified on the Consolidated Balance Sheet as temporary equity because this redemption feature is outside the control of the Company.

On November 20, 2017, Hydro One issued 485,870 Class B preferred shares to 2587264 Ontario Inc., a subsidiary of Hydro One Limited, for proceeds of $486 million.

22. DIVIDENDS

In 2017, common share dividends in the amount of $15 million (2016 – $2 million) were declared and paid.

23. EARNINGS PER COMMON SHARE

Basic and diluted earnings per common share (EPS) is calculated by dividing net income attributable to common shareholder of Hydro One by the weighted average number of common shares outstanding. The weighted average number of shares outstanding at December 31, 2017 was 142,239 (2016 – 142,239). There were no dilutive securities during 2017 or 2016.

24. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the Power Workers' Union (the PWU Share Grant Plan) and one for the benefit of certain members of The Society of Energy Professionals (the Society Share Grant Plan). Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU Share Grant Plan began on July 3, 2015, which is the date the share grant plan was ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 3,952,212 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total share based compensation recognized by Hydro One.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of The Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan began on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 1,367,158 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total share based compensation recognized by Hydro One.

The fair value of the Hydro One Limited 2015 share grants of $111 million was estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. In 2017, 369,266 common shares of Hydro One Limited were granted under the Share Grant Plans (2016 - nil) to eligible employees of Hydro One. Total share based compensation recognized during 2017 was $17 million (2016 – $21 million) and was recorded as a regulatory asset.

A summary of share grant activity under the Share Grant Plans during years ended December 31, 2017 and 2016 is presented below:

Year ended December 31, 2017	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	5,239,678	$20.50
Vested and issued[1]	(369,266)	—
Forfeited	(132,629)	$20.50
Share grants outstanding - ending	4,737,783	$20.50

[1] On April 1, 2017, Hydro One LImited issued from treasury 369,266 common shares to eligible Hydro One employees in accordance with provisions of the PWU Share Grant Plan.

Year ended December 31, 2016	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding – beginning	5,319,370	$20.50
Forfeited[1]	(79,692)	$20.50
Share grants outstanding – ending	5,239,678	$20.50

[1] Includes shares forfeited as well as shares transferred corresponding to transfer of employees from an affiliate company.

Directors' DSU Plan

Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One Limited's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited's Board of Directors.

During the years ended December 31, 2017 and 2016, the Company granted awards under the Directors' DSU Plan, as follows:

Year ended December 31 *(number of DSUs)*	2017	2016
DSUs outstanding – beginning	99,083	20,525
DSUs granted	88,007	78,558
DSUs outstanding – ending	187,090	99,083

For the year ended December 31, 2017, an expense of $2 million (2016 – $2 million) was recognized in earnings with respect to the Directors' DSU Plan. At December 31, 2017, a liability of $4 million (2016 – $2 million), related to outstanding DSUs has been recorded at the closing price of Hydro One Limited's common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

During the years ended December 31, 2017 and 2016, the Company granted awards under the Management DSU Plan, as follows:

Year ended December 31 *(number of DSUs)*	2017	2016
DSUs outstanding - beginning	—	—
Granted	64,828	—
Paid	(1,068)	—
DSUs outstanding - ending	63,760	—

For the year ended December 31, 2017, an expense of $2 million (2016 - $nil) was recognized in earnings with respect to the Management DSU Plan. At December 31, 2017, a liability of $2 million (2016 – $nil) related to outstanding DSUs has been recorded at the closing price of Hydro One Limited common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2017, Company contributions made under the ESOP were $2 million (2016 - $2 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including RSUs, PSUs, stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

During 2017 and 2016, Hydro One Limited granted awards under its LTIP as follows:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	2017	2016	2017	2016
Units outstanding – beginning	228,890	—	252,440	—
Units granted	300,090	233,710	239,280	257,260
Units vested	(609)	—	(14,079)	—
Units forfeited	(103,251)	(4,820)	(89,501)	(4,820)
Units outstanding – ending	425,120	228,890	388,140	252,440

The grant date total fair value of the awards granted in 2017 was $13 million (2016 – $12 million). The compensation expense related to these awards recognized by the Company during 2017 was $6 million (2016 – $3 million).

25. NONCONTROLLING INTEREST

On December 16, 2014, transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the Saugeen Ojibway Nation (SON) acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired. The SON's initial investment in B2M LP consists of $50 million of Class A units and $22 million of Class B units.

The Class B units have a mandatory put option which requires that upon the occurrence of an enforcement event (i.e. an event of default such as a debt default by the SON or insolvency event), Hydro One purchase the Class B units of B2M LP for net book value on the redemption date. The noncontrolling interest relating to the Class B units is classified on the Consolidated Balance Sheet as temporary equity because the redemption feature is outside the control of the Company. The balance of the noncontrolling interest is classified within equity.

The following tables show the movements in noncontrolling interest during the years ended December 31, 2017 and 2016:

Year ended December 31, 2017 *(millions of dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest – beginning	22	50	72
Distributions to noncontrolling interest	(2)	(4)	(6)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest – ending	22	50	72

Year ended December 31, 2016 *(millions of dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest – beginning	23	52	75
Distributions to noncontrolling interest	(3)	(6)	(9)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest – ending	22	50	72

26. RELATED PARTY TRANSACTIONS

Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), the OEB, and Hydro One Telecom, are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One.

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2017	2016
IESO	Power purchased	1,583	2,096
	Revenues for transmission services	1,521	1,549
	Amounts related to electricity rebates	357	—
	Distribution revenues related to rural rate protection	247	125
	Distribution revenues related to the supply of electricity to remote northern communities	32	32
	Funding received related to CDM programs	59	63
OPG	Power purchased	9	6
	Revenues related to provision of construction and equipment maintenance services	2	4
	Costs related to the purchase of services	1	1
OEFC	Power purchased from power contracts administered by the OEFC	2	1
OEB	OEB fees	8	11
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	3
Hydro One Limited	Return of stated capital	535	609
	Dividends paid	15	2
	Stock-based compensation costs	23	24
	Cost recovery for services provided	6	—
Hydro One Telecom	Services received – costs expensed	24	24
	Services received – costs capitalized	—	12
	Revenues for services provided	3	3
2587264 Ontario Inc.	Promissory note issued and repaid[1]	486	—
	Preferred shares issued[2]	486	—

[1] On October 17, 2017, Hydro One issued a promissory note to 2587264 Ontario Inc., a subsidiary of Hydro One Limited, totalling $486 million. On November 20, 2017, Hydro One repaid the $486 million promissory note to 2587264 Ontario Inc., as well as interest totalling $1 million.

[2] On November 20, 2017, Hydro One issued 485,870 Class B preferred shares to 2587264 Ontario Inc. for proceeds of $486 million. See Note 21 for details of the Class B preferred shares.

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest-free and settled in cash.

27. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 *(millions of dollars)*	2017	2016
Accounts receivable	191	(59)
Due from related parties	(215)	(40)
Materials and supplies	1	2
Prepaid expenses and other assets	2	(17)
Accounts payable	7	18
Accrued liabilities	(89)	52
Due to related parties	88	113
Accrued interest	(6)	9
Long-term accounts payable and other liabilities	(2)	6
Post-retirement and post-employment benefit liability	86	84
	63	168

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts presented in the Consolidated Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2017	2016
Capital investments in property, plant and equipment	(1,482)	(1,624)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	26	30
Cash outflow for capital expenditures – property, plant and equipment	(1,456)	(1,594)

The following table reconciles investments in intangible assets and the amounts presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2017	2016
Capital investments in intangible assets	(74)	(67)
Net change in accruals included in capital investments in intangible assets	(6)	6
Cash outflow for capital expenditures – intangible assets	(80)	(61)

Capital Contributions

Hydro One enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One will periodically reassess the estimated of load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to fixed assets in service. In 2017, capital contributions from these reassessments totalled $9 million (2016 – $21 million), which represents the difference between the revised load forecast of electricity transmitted compared to the load forecast in the original contract, subject to certain adjustments.

Supplementary Information

Year ended December 31 *(millions of dollars)*	2017	2016
Net interest paid	452	418
Income taxes paid	11	30

28. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Hydro One, Hydro One Networks, Hydro One Remote Communities, and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, an estimate of a possible loss related to this claim cannot be made.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. In 2017, the Company paid approximately $2 million (2016 – $1 million) in respect of consents obtained. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

29. COMMITMENTS

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter.

December 31, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing agreements	139	95	2	2	2	7
Long-term software/meter agreement	17	17	16	2	1	3
Operating lease commitments	10	5	9	4	1	4

Outsourcing Agreements

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society and the PWU to facilitate the insourcing of these services effective March 1, 2018.

Brookfield Global Integrated Solutions (formerly Brookfield Johnson Controls Canada LP) (Brookfield) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The agreement with Brookfield for these services expires in December 2024.

Long-term Software/Meter Agreement

Trilliant Holdings Inc. and Trilliant Networks (Canada) Inc. (collectively Trilliant) provide services to Hydro One for the supply, maintenance and support services for smart meters and related hardware and software, including additional software licences, as well as certain professional services. The agreement with Trilliant for these services expires in December 2025, but Hydro One has the option to renew for an additional term of five years at its sole discretion.

Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service-related functions and storing telecommunications equipment. These leases have typical terms of between three and five years, but several leases have lesser or greater terms to address special circumstances and/or opportunities. Renewal options, which are generally prevalent in most leases, have similar terms of three to five years. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases. During the year ended December 31, 2017, the Company made lease payments totalling $10 million (2016 – $10 million).

Other Commitments

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next 5 years and thereafter.

December 31, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Credit facilities	—	—	—	—	2,300	—
Letters of credit[1]	177	—	—	—	—	—
Guarantees[2]	325	—	—	—	—	—

[1] Letters of credit consist of a $154 million letter of credit related to retirement compensation arrangements, a $16 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[2] Guarantees consist of prudential support provided to the IESO by Hydro One on behalf of its subsidiaries.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees and/or letters of credit if these purchasers fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the amount of the parental guarantees.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for Hydro One's liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure Hydro One's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit.

30. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, which includes certain corporate activities.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

Year ended December 31, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,581	4,366	—	5,947
Purchased power	—	2,875	—	2,875
Operation, maintenance and administration	391	599	24	1,014
Depreciation and amortization	420	390	—	810
Income (loss) before financing charges and income taxes	770	502	(24)	1,248
Capital investments	968	588	—	1,556

Year ended December 31, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,587	4,915	—	6,502
Purchased power	—	3,427	—	3,427
Operation, maintenance and administration	410	613	20	1,043
Depreciation and amortization	390	379	—	769
Income (loss) before financing charges and income taxes	787	496	(20)	1,263
Capital investments	988	703	—	1,691

Total Assets by Segment:

December 31 *(millions of dollars)*	2017	2016
Transmission	13,612	13,083
Distribution	9,279	9,393
Other	2,860	2,834
Total assets	25,751	25,310

Total Goodwill by Segment:

December 31 *(millions of dollars)*	2017	2016
Transmission *(Note 4)*	157	159
Distribution	168	168
Total goodwill	325	327

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

31. SUBSEQUENT EVENTS

Dividends and Return of Stated Capital

On February 12, 2018, preferred share dividends in the amount of $2 million and common share dividends in the amount of $5 million were declared. On the same date, a return of stated capital in the amount of $128 million was approved.

The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the consolidated financial statements and accompanying notes thereto (Consolidated Financial Statements) of Hydro One Inc. (Hydro One or the Company) for the year ended December 31, 2017. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 - Continuous Disclosure Obligations of the Canadian Securities Administrators. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canada, which can vary from those of the US. This MD&A provides information for the year ended December 31, 2017, based on information available to management as of February 12, 2018.

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

Year ended December 31 *(millions of dollars, except as otherwise noted)*	2017	2016	Change
Revenues	5,947	6,502	(8.5%)
Purchased power	2,875	3,427	(16.1%)
Revenues, net of purchased power[1]	3,072	3,075	(0.1%)
Operation, maintenance and administration costs	1,014	1,043	(2.8%)
Depreciation and amortization	810	769	5.3%
Financing charges	411	392	4.8%
Income tax expense	120	135	(11.1%)
Net income attributable to common shareholder of Hydro One	**711**	**730**	**(2.6%)**
Basic earnings per common share (EPS)	$4,999	$5,132	(2.6%)
Diluted EPS	$4,999	$5,132	(2.6%)
Net cash from operating activities	1,694	1,668	1.6%
Funds from operations (FFO)[1]	1,625	1,491	9.0%
Capital investments	1,556	1,691	(8.0%)
Assets placed in-service	1,578	1,599	(1.3%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	19,587	20,690	(5.3%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	25,876	26,289	(1.6%)

	2017	2016
Debt to capitalization ratio[2]	51.1%	52.9%

[1] See section "Non-GAAP Measures" for description and reconciliation of FFO and Revenues, net of purchased power.
[2] Debt to capitalization ratio has been presented at December 31, 2017 and 2016, and has been calculated as total debt (includes total long-term debt and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholder's equity, including preferred shares but excluding any amounts related to noncontrolling interest.

OVERVIEW

Hydro One is the largest electricity transmission and distribution company in Ontario. Hydro One owns and operates substantially all of Ontario's electricity transmission network, and approximately 123,000 circuit kilometres of primary low-voltage distribution network. Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

For the year ended December 31, 2017, Hydro One's business segments accounted for the Company's total revenues, net of purchased power, as follows:

	Transmission	Distribution	Other
Percentage of Company's total revenues, net of purchased power	51%	49%	0%

At December 31, 2017, Hydro One's business segments accounted for the Company's total assets as follows:

	Transmission	Distribution	Other
Percentage of Company's total assets	53%	36%	11%

Transmission Segment

Hydro One's transmission business owns, operates and maintains Hydro One's transmission system, which accounts for approximately 98% of Ontario's transmission capacity based on revenue approved by the Ontario Energy Board (OEB). The transmission business consists of the transmission system operated by the Company's subsidiaries, Hydro One Networks Inc. (Hydro One Networks) and Hydro One Sault Ste. Marie LP (HOSSM) (formerly Great Lakes Power Transmission LP), as well as a 66% interest in B2M Limited Partnership (B2M LP), a limited partnership between Hydro One and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. The Company's transmission business is a rate-regulated business that earns revenues mainly from charging transmission rates that are approved by the OEB.

	2017	2016
Electricity transmitted[1] *(MWh)*	132,090,992	136,989,747
Transmission lines spanning the province *(circuit-kilometres)*	30,290	30,259
Rate base *(millions of dollars)*	11,251	10,775
Capital investments *(millions of dollars)*	968	988
Assets placed in-service *(millions of dollars)*	889	937

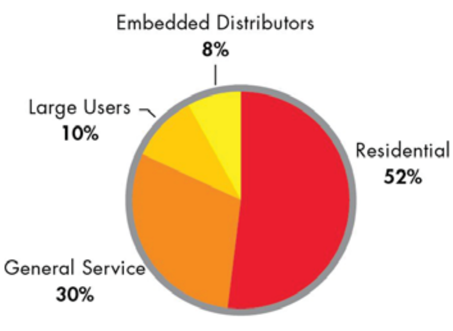
[1] Electricity transmitted represents total electricity transmission in Ontario by all transmitters.

Distribution Segment

Hydro One's distribution business is the largest in Ontario and consists of the distribution system operated by the Company's subsidiaries, Hydro One Networks and Hydro One Remote Communities Inc. The Company's distribution business is a rate-regulated business that earns revenues mainly by charging distribution rates that are approved by the OEB.

	2017	2016
Electricity distributed to Hydro One customers *(GWh)*	25,876	26,289
Electricity distributed through Hydro One lines *(GWh)*[1]	36,525	37,394
Distribution lines spanning the province *(circuit-kilometres)*	123,361	122,599
Distribution customers *(number of customers)*	1,372,362	1,355,302
Rate base *(millions of dollars)*	7,389	7,056
Capital investments *(millions of dollars)*	588	703
Assets placed in-service *(millions of dollars)*	689	662

[1] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the Independent Electricity System Operator (IESO).



2017 Distribution Revenues

Other Business Segment

Hydro One's other business segment consists of certain corporate activities.

PRIMARY FACTORS AFFECTING RESULTS OF OPERATIONS

Transmission Revenues

Transmission revenues primarily consist of regulated transmission rates approved by the OEB which are charged based on the monthly peak electricity demand across Hydro One's high-voltage network. Transmission rates are designed to generate revenues necessary to construct, upgrade, extend and support a transmission system with sufficient capacity to accommodate maximum forecasted demand and a regulated return on the Company's investment. Peak electricity demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting electricity to markets outside of Ontario. Ancillary revenues include revenues from providing maintenance services to power generators and from third-party land use.

Distribution Revenues

Distribution revenues include regulated distribution rates approved by the OEB and amounts to recover the cost of purchased power used by the customers of the distribution business. Distribution rates are designed to generate revenues necessary to construct and support the local distribution system with sufficient capacity to accommodate existing and new customer demand and a regulated return on the Company's investment. Accordingly, distribution revenues are influenced by distribution rates, the cost of purchased power, and the amount of electricity the Company distributes. Distribution revenues also include ancillary distribution service revenues, such as fees related to the joint use of Hydro One's distribution poles by the telecommunications and cable television industries, as well as miscellaneous revenues such as charges for late payments.

Purchased Power Costs

Purchased power costs are incurred by the distribution business and represent the cost of the electricity purchased by the Company for delivery to customers within Hydro One's distribution service territory. These costs are comprised of the following: the wholesale commodity cost of energy; the Global Adjustment, which is the difference between amounts the IESO pays energy producers for the electricity they produce and the actual fair market value of this electricity; and the wholesale market service and transmission charges levied by the IESO. Hydro One passes the cost of electricity that it delivers to its customers, and is therefore not exposed to wholesale electricity commodity price risk

Operation, Maintenance and Administration Costs

Operation, maintenance and administration (OM&A) costs are incurred to support the operation and maintenance of the transmission and distribution systems, and other costs such as property taxes related to transmission and distribution lines, stations and buildings. Transmission OM&A costs are incurred to sustain the Company's high-voltage transmission stations, lines, and rights-of-way, and include preventive and corrective maintenance costs related to power equipment, overhead transmission lines, transmission station sites, and forestry control to maintain safe distance between line spans and trees. Distribution OM&A costs are required to maintain the Company's low-voltage distribution system to provide safe and reliable electricity to the Company's residential, small business, commercial, and industrial customers across the province. These include costs related to distribution line clearing and forestry control to reduce power outages caused by trees, line maintenance and repair, land assessment and remediation, as well as issuing timely and accurate bills and responding to customer inquiries. Hydro One manages its costs through ongoing efficiency and productivity initiatives, while continuing to complete planned work programs associated with the development and maintenance of its transmission and distribution networks.

Depreciation and Amortization

Depreciation and amortization costs relate primarily to depreciation of the Company's property, plant and equipment, and amortization of certain intangible assets and regulatory assets. Depreciation and amortization also includes the costs incurred to remove property, plant and equipment where no asset retirement obligations have been recorded on the balance sheet.

Financing Charges

Financing charges relate to the Company's financing activities, and include interest expense on the Company's long-term debt and short-term borrowings, and gains and losses on interest rate swap agreements, net of interest earned on short-term investments. A portion of financing charges incurred by the Company is capitalized to the cost of property, plant and equipment associated with the periods during which such assets are under construction before being placed in-service.

RESULTS OF OPERATIONS

Net Income

Net income attributable to common shareholder for the year ended December 31, 2017 of $711 million is a decrease of $19 million or 2.6% from the prior year. Significant influences on net income included:

- decrease in transmission and distribution revenues due to lower energy consumption during 2017 resulting from milder weather;
- higher transmission revenues driven by OEB's decision on the 2017-2018 transmission rates filing;
- transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- higher OM&A costs primarily resulting from lower bad debt expense in 2016 due to revised estimates of uncollectible accounts resulting from the stabilization of the customer information system, partially offset by a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, insurance proceeds received due to failed equipment at two transformer stations, a tax recovery of previous year's expenses, reduced vegetation management costs, and lower support services costs;

- higher depreciation expense due to an increase in property, plant and equipment; and
- increased financing charges primarily due to a higher weighted average long-term debt portfolio during 2017 compared to 2016, including long-term debt assumed as part of the HOSSM acquisition in the fourth quarter of 2016.

Revenues

Year ended December 31 *(millions of dollars, except as otherwise noted)*	2017	2016	Change
Transmission	1,581	1,587	(0.4%)
Distribution	4,366	4,915	(11.2%)
Total revenues	5,947	6,502	(8.5%)
Transmission	1,581	1,587	(0.4%)
Distribution, net of purchased power	1,491	1,488	0.2%
Total revenues, net of purchased power	3,072	3,075	(0.1%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	19,587	20,690	(5.3%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	25,876	26,289	(1.6%)

Transmission Revenues

Transmission revenues decreased by 0.4% in 2017 primarily due to the following:

- lower average monthly Ontario 60-minute peak demand mainly due to milder weather in the first three quarters of 2017;
- decreased OEB-approved transmission rates primarily reflecting a reduction in 2017 allowed ROE for the transmission business from 9.19% to 8.78%; offset by
- higher revenues driven by the OEB's decision on the 2017-2018 transmission rates filing; and
- additional revenues resulting from the acquisition of HOSSM in the fourth quarter of 2016.

Distribution Revenues, Net of Purchased Power

Distribution revenues, net of purchased power, increased by 0.2% in 2017 primarily due to the following:

- lower energy consumption mainly resulting from milder weather in the first three quarters of 2017; offset by
- higher external revenues related to Conservation and Demand Management (CDM) incentive bonus; and
- higher OEB-approved distribution rates for 2017, net of a reduction in 2017 allowed ROE for the distribution business from 9.19% to 8.78%.

OM&A Costs

Year ended December 31 *(millions of dollars)*	2017	2016	Change
Transmission	391	410	(4.6%)
Distribution	599	613	(2.3%)
Other	24	20	20.0%
	1,014	1,043	(2.8%)

Transmission OM&A Costs

The decrease of 4.6% in transmission OM&A costs for the year ended December 31, 2017 was primarily due to:

- a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulation;
- lower support services costs; and
- insurance proceeds received due to equipment failures at the Fairchild and Campbell transmission stations; partially offset by
- higher volume of environmental management program work.

Distribution OM&A Costs

The decrease of 2.3% in distribution OM&A costs for the year ended December 31, 2017 was primarily due to:

- continued lower expenditures for vegetation management due to strategic changes to the forestry program scope that resulted in cost efficiency and improved management of the Company's rights of ways;
- lower volume of line maintenance work;
- lower spend on development and research programs; and
- a tax recovery of previous year's expenses; partially offset by

- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system, partially offset by lower bad debt expense in 2017 attributable to lower write-offs and improved accounts receivable aging; and
- increased storm restoration costs as a result of Hurricane Irma restoration efforts in Florida. These restoration efforts had no impact on the Company's net income, as related revenues were recorded in distribution revenues during the year.

Other OM&A Costs

The increase in other OM&A costs for the year ended December 31, 2017 was driven by higher consulting costs primarily related to strategy development and higher corporate management costs in the first quarter of 2017.

Depreciation and Amortization

The increase of $41 million or 5.3% in depreciation and amortization costs for 2017 was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

Financing Charges

The increase of $19 million or 4.8% in financing charges for the year ended December 31, 2017 was primarily due to an increase in interest expense on long-term debt driven by a higher weighted average long-term debt portfolio during 2017 including the long-term debt assumed as part of the HOSSM acquisition in the fourth quarter of 2016; partially offset by a decrease in the weighted average interest rate for long-term debt.

Income Tax Expense

Income tax expense for the year ended December 31, 2017 decreased by $15 million compared to 2016, and the Company realized an effective tax rate of approximately 14.3% in 2017, compared to approximately 15.5% realized in 2016. The decreases in the tax expense and the effective tax rate are primarily due to lower income before taxes in 2017.

SELECTED ANNUAL FINANCIAL STATISTICS

Year ended December 31 *(millions of dollars, except per share amounts)*	2017	2016	2015
Revenues	5,947	6,502	6,529
Net income attributable to common shareholder	711	730	679
Basic EPS	$4,999	$5,132	$6,340
Diluted EPS	$4,999	$5,132	$6,340
Dividends per common share declared	$105	$14	$8,750
Dividends per preferred share declared	—	—	$1.03

December 31 *(millions of dollars)*	2017	2016	2015
Total assets	25,751	25,310	24,169
Total non-current financial liabilities	9,315	10,078	8,207

QUARTERLY RESULTS OF OPERATIONS

Quarter ended *(millions of dollars, except EPS and ratio)*	Dec 31, 2017	Sep 30, 2017	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016
Revenues	1,429	1,511	1,361	1,646	1,604	1,693	1,533	1,672
Purchased power	662	675	649	889	858	870	803	896
Revenues, net of purchased power	767	836	712	757	746	823	730	776
Net income to common shareholder	180	241	120	170	131	233	155	211
Basic and diluted EPS	$1,265	$1,694	$844	$1,195	$921	$1,638	$1,086	$1,485
Earnings coverage ratio[1]	2.7	2.5	2.6	2.7	2.8	2.8	2.7	2.6

[1] Earnings coverage ratio has been presented for the twelve months ended as of each date indicated above and has been calculated as net income before financing charges and income taxes attributable to shareholder of Hydro One, divided by the sum of financing charges, capitalized interest, and preferred dividends.

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

CAPITAL INVESTMENTS

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution system assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations.

Assets Placed In-Service

The following table presents Hydro One's assets placed in-service during the year ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016	Change
Transmission	889	937	(5.1%)
Distribution	689	662	4.1%
Total assets placed in-service	1,578	1,599	(1.3%)

Transmission Assets Placed In-Service

Transmission assets placed in-service decreased by $48 million or 5.1% during the year ended December 31, 2017 primarily due to the following:

- substantial investments of two major local area supply projects, Guelph Area Transmission Refurbishment and Toronto Midtown Transmission Reinforcement, were placed in-service in 2016;
- completion of the Advanced Distribution System project at Owen Sound transmission station in 2016;
- timing of assets placed in-service for the sustainment investments at Burlington and Bruce A transmission stations; partially offset by investments at Aylmer and Overbrook transmission stations; and
- lower volume of end-of-life transformer replacements work; partially offset by
- substantial investments of major development projects at Leamington and Holland transmission stations were placed in-service in the fourth quarter of 2017;
- higher volume of overhead lines and component refurbishments and replacements; and
- the completion of the Field Workforce Optimization (Move-to-Mobile) project in June 2017.

Distribution Assets Placed In-Service

Distribution assets placed in-service increased by $27 million or 4.1% during the year ended December 31, 2017 primarily due to the following:

- higher volume of subdivision connections due to increased demand;
- the completion of the Move-to-Mobile project in June 2017;
- the completion of an operation center in Bolton in February 2017;
- the completion of the Outage Response Management System (ORMS) project in the third quarter of 2017; and
- substantial investments that were placed in-service for the Leamington transmission station feeder development project; partially offset by
- the Advanced Metering Infrastructure Wireless Telecom project was placed in-service during 2016;
- lower volume of generation connection projects; and
- lower volume of distribution station refurbishments and spare transformer purchases.

Capital Investments

The following table presents Hydro One's capital investments during the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016	Change
Transmission			
Sustaining	764	750	1.9%
Development	137	156	(12.2%)
Other	67	82	(18.3%)
	968	988	(2.0%)
Distribution			
Sustaining	280	384	(27.1%)
Development	227	217	4.6%
Other	81	102	(20.6%)
	588	703	(16.4%)
Total capital investments	1,556	1,691	(8.0%)

Transmission Capital Investments

Transmission capital investments decreased by $20 million or 2.0% during the year ended December 31, 2017. Principal impacts on the levels of capital investments included:

- construction work on Clarington Transmission Station project is substantially complete and therefore, lower investments in 2017;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- lower volume of transmission station refurbishments and component replacements work; and
- substantial completion of the Guelph Area Transmission Refurbishment project in 2016; partially offset by
- higher volume of overhead lines and component refurbishments and replacements; and
- substantial completion of the Leamington transmission station project to address the electricity needs in Windsor and Essex County.

Distribution Capital Investments

Distribution capital investments decreased by $115 million or 16.4% during the year ended December 31, 2017. Principal impacts on the levels of capital investments included:

- lower volume of work within station refurbishment programs;
- lower volume of line refurbishments and replacements work;
- lower volume of wood pole replacements;
- lower volume of fleet and work equipment purchases;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- completion of the Bolton Operation Centre; partially offset by
- higher volume of work on new connections and upgrades due to increased demand.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at December 31, 2017:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To Date
Development Projects:					
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$57 million[1]	$52 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$267 million	$223 million
East-West Tie Station Expansion	Northern Ontario	New transmission connection and station expansion	2021	$157 million	$7 million
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	2024	$350 million	$1 million
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2020	$109 million[2]	$105 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$103 million	$85 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2022	$93 million	$51 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2023	$95 million	$44 million

[1] In February 2018, the estimated cost to complete the Supply to Essex County Transmission Reinforcement project was reduced from $73 million to $57 million.
[2] The estimated cost to complete the Bruce A Transmission Station project is currently under review.

Future Capital Investments

Following is a summary of estimated capital investments by Hydro One over the years 2018 to 2022. The Company's estimates are based on management's expectations of the amount of capital expenditures that will be required to provide transmission and distribution services that are efficient, reliable, and provide value for customers, consistent with the OEB's Renewed Regulatory Framework. The 2018 transmission capital investments estimates differ from the prior year disclosures, representing an annual decrease of $122 million to reflect the OEB's focus on planning practices and the pacing of sustainment capital investments, specifically, tower coating, stations, and insulator investments, as indicated in the OEB's 2017-2018 transmission rates decision issued in September 2017. The projections and the timing of 2019-2022 expenditures are subject to approval by the OEB.

The following table summarizes Hydro One's annual projected capital investments for 2018 to 2022, by business segment:

(millions of dollars)	2018	2019	2020	2021	2022
Transmission	1,010	1,217	1,278	1,486	1,404
Distribution	641	751	715	719	805
Total capital investments	**1,651**	**1,968**	**1,993**	**2,205**	**2,209**

The following table summarizes Hydro One's annual projected capital investments for 2018 to 2022, by category:

(millions of dollars)	2018	2019	2020	2021	2022
Sustainment	1,103	1,220	1,328	1,547	1,608
Development	340	484	487	490	430
Other[1]	208	264	178	168	171
Total capital investments	**1,651**	**1,968**	**1,993**	**2,205**	**2,209**

[1] "Other" capital expenditures consist of special projects, such as those relating to information technology.

SUMMARY OF SOURCES AND USES OF CASH

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

Year ended December 31 *(millions of dollars)*	2017	2016
Cash provided by operating activities	1,694	1,668
Cash provided by (used in) financing activities	(212)	146
Cash used in investing activities	(1,530)	(1,855)
Decrease in cash and cash equivalents	(48)	(41)

Cash provided by operating activities

Cash from Operating Activities increased by $26 million during 2017 primarily due to changes in regulatory variance and deferral accounts, as well as lower energy-related receivables which decreased as a result of improved collections in 2017. These factors were partially offset by changes in accrual balances.

Cash provided by financing activities

Sources of cash

- The Company did not issue long-term debt in 2017, compared to proceeds from the issuance of $2.3 billion in 2016.
- The Company received proceeds of $3,795 million from the issuance of short-term notes in 2017, compared to $3,031 million received in 2016.
- The company received $486 million from issuance of preferred shares in 2017, compared to no preferred shares issued in 2016.

Uses of cash

- In 2017, the Company made returns of stated capital totalling $535 million, compared to returns of stated capital totalling $609 million made in 2016.
- The Company repaid $3,338 million of short-term notes in 2017, compared to $4,053 million repaid in 2016.
- The Company repaid $602 million of long-term debt in 2017, compared to long-term debt of $502 million repaid in 2016.

Cash used in investing activities

Uses of cash

- Capital expenditures were $119 million lower in 2017, primarily due to lower volume and timing of capital investment work.
- In 2016, the Company paid $224 million to acquire HOSSM, compared to no acquisition payments made in 2017.

LIQUIDITY AND FINANCING STRATEGY

Short-term liquidity is provided through funds from operations, Hydro One's commercial paper program, and the Company's consolidated bank credit facilities. Under the commercial paper program, Hydro One is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At December 31, 2017, Hydro One had $926 million in commercial paper borrowings outstanding, compared to $469 million outstanding at December 31, 2016. In addition, the Company has revolving bank credit facilities totalling $2.3 billion maturing in 2022. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the commercial paper program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At December 31, 2017, the Company's long-term debt in the principal amount of $10,069 million included $9,923 million of long-term debt, the majority of which was issued under Hydro One's Medium Term Note (MTN) Program, and long-term debt in the principal amount of $146 million held by HOSSM. At December 31, 2017, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2018 and 2064, and at December 31, 2017, had an average term to maturity of approximately 15.8 years and a weighted average coupon rate of 4.2%.

At December 31, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Credit Ratings

At December 31, 2017, Hydro One's long-term and short-term debt ratings were as follows:

Rating Agency	Short-term Debt Rating	Long-term Debt Rating
DBRS Limited	R-1 (low)	A (high)
Moody's Investors Service (Moody's)[1]	Prime-2	A3
Standard & Poor's Rating Services (S&P)[1]	A-1	A

[1] On July 19, 2017, S&P and Moody's revised their outlooks on Hydro One to negative from stable, while affirming the existing debt ratings.

Effect of Interest Rates

The Company is exposed to fluctuations of interest rates as its regulated return on equity (ROE) is derived using a formulaic approach that takes into account changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. See section "Risk Management and Risk Factors - Risks Relating to Hydro One's Business - Market, Financial Instrument and Credit Risk" for more details.

Pension Plan

In 2017, Hydro One contributed approximately $87 million to its pension plan, compared to contributions of approximately $108 million in 2016, and incurred $88 million in net periodic pension benefit costs, compared to $116 million incurred in 2016.

In May 2017, Hydro One filed an actuarial valuation of its Pension Plan as at December 31, 2016. Based on this valuation and 2017 levels of pensionable earnings, the 2017 annual Company pension contributions have decreased by approximately $17 million from $105 million as estimated at December 31, 2016, primarily due to improvements in the funded status of the plan and future actuarial assumptions, and also reflect the impact of changes implemented by management to improve the balance between employee and Company contributions to the Pension Plan. Hydro One estimates that total Company pension contributions for 2018 and 2019 will be approximately $71 million for each year.

The Company's pension benefits obligation is impacted by various assumptions and estimates, such as discount rate, rate of return on plan assets, rate of cost of living increase and mortality assumptions. A full discussion of the significant assumptions and estimates can be found in the section "Critical Accounting Estimates - Employee Future Benefits".

OTHER OBLIGATIONS

Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations and commercial commitments:

December 31, 2017 *(millions of dollars)*	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations *(due by year)*					
Long-term debt – principal repayments	10,069	752	1,384	1,107	6,826
Long-term debt – interest payments	7,690	426	786	725	5,753
Short-term notes payable	926	926	—	—	—
Pension contributions[1]	151	71	80	—	—
Environmental and asset retirement obligations	215	28	59	65	63
Outsourcing agreements	247	139	97	4	7
Operating lease commitments	33	10	14	5	4
Long-term software/meter agreement	56	17	33	3	3
Total contractual obligations	19,387	2,369	2,453	1,909	12,656
Other commercial commitments *(by year of expiry)*					
Credit facilities[2]	2,300	—	—	2,300	—
Letters of credit[3]	177	177	—	—	—
Guarantees[4]	325	325	—	—	—
Total other commercial commitments	2,802	502	—	2,300	—

[1] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2018 and 2019 minimum pension contributions are based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings.

[2] In June 2017, the maturity date of Hydro One's $2.3 billion credit facilities was extended from June 2021 to June 2022.

[3] Letters of credit consist of a $154 million letter of credit related to retirement compensation arrangements, a $16 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[4] Guarantees consist of prudential support provided to the IESO by Hydro One on behalf of its subsidiaries.

REGULATION

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual rate of return on its deemed 40% equity level invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral and variance accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings:

Application	Years	Type	Status
Electricity Rates			
Hydro One Networks	2017-2018	Transmission – Cost-of-service	OEB decision received[1]
Hydro One Networks	2015-2017	Distribution – Custom	OEB decision received
Hydro One Networks	2018-2022	Distribution – Custom	OEB decision pending
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
HOSSM	2017-2018	Transmission – Revenue Cap	OEB decision received
Mergers Acquisitions Amalgamations and Divestitures (MAAD)			
Orillia Power Distribution Corporation	n/a	Acquisition	OEB decision pending
Leave to Construct			
East-West Tie Station Expansion	n/a	Section 92	OEB decision pending

[1] In October 2017, the Company filed a Motion to Review and Vary the OEB's decision and filed an appeal with the Divisional Court of Ontario.

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Rate Application Status	Rate Order Status
Transmission					
Hydro One Networks	2017	8.78% (A)	$10,523 million	Approved in September 2017	Approved in November 2017
	2018	9.00% (A)	$11,148 million	Approved in September 2017	Approved in December 2017
B2M LP	2017	8.78% (A)	$509 million	Approved in December 2015	Approved in June 2017
	2018	9.00% (A)	$502 million	Approved in December 2015	Filed in December 2017
	2019	9.00% (F)	$496 million	Approved in December 2015	To be filed in 2018 Q4
HOSSM	2017	9.19% (A)	$218 million	Approved in September 2017	n/a
	2018	9.19% (A)	$218 million	Approved in September 2017	n/a
Distribution					
Hydro One Networks	2017	8.78% (A)	$7,190 million	Approved in March 2015	Approved in December 2016
	2018	9.00% (A)	$7,666 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2019	9.00% (F)	$8,027 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2020	9.00% (F)	$8,430 million	Filed in March 2017[1]	To be filed in 2019 Q4
	2021	9.00% (F)	$8,960 million	Filed in March 2017[1]	To be filed in 2020 Q4
	2022	9.00% (F)	$9,327 million	Filed in March 2017[1]	To be filed in 2021 Q4

[1] On June 7 and December 21, 2017, Hydro One Networks filed updates to the application reflecting recent financial results and other adjustments.

Electricity Rates Applications

Hydro One Networks - Transmission

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Decision), with 2017 rates effective January 1, 2017. Key changes to the application as filed included reductions in planned capital expenditures of $126 million and $122 million for 2017 and 2018, respectively, in OM&A expenses related to compensation by $15 million for each year, and in estimated tax savings from the IPO by $24 million and $26 million for 2017 and 2018, respectively. On October 10, 2017, Hydro One Networks filed a Draft Rate Order reflecting the changes outlined in the Decision.

In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a Decision and Order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an additional impairment of up to approximately $370 million related to Hydro One Networks' distribution deferred income tax regulatory asset.

In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which is scheduled for mid-February 2018. In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million, resulting in an annual decrease to FFO in the range of $50 million to $60 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company's Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

In October 2017, the intervenor Anwaatin Inc. also filed a Motion to Review and Vary the OEB Decision (Anwaatin Motion) alleging that the OEB breached its duty of procedural fairness, failed to respond to certain evidence, and failed to provide reasons on the capital budget as it related to reliability issues impacting Anwaatin Inc.'s constituents. The Anwaatin Motion will be heard by the OEB on February 13, 2018.

On November 23, 2017, the OEB approved the 2017 rates revenue requirement of $1,438 million. On December 20, 2017, the OEB approved the 2018 rates revenue requirement of $1,511 million, which included a $25 million increase from the approved amount, as a result of the OEB-updated cost of capital parameters. Uniform Transmission Rates (UTRs), reflecting these approved amounts, were approved by the OEB on February 1, 2018 to be effective as of January 1, 2018.

Hydro One Networks - Distribution

On March 31, 2017, Hydro One Networks filed a custom application with the OEB for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework (2018-2022 Distribution Application), which was subsequently updated on June 7 and December 21, 2017. The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels. Management expects that a decision will be received in 2018.

On November 17, 2017, Hydro One filed with the OEB a request for interim rates based on current OEB-approved rates, adjusted for an updated load forecast. On December 1, 2017, the OEB denied this request and set interim rates based on current OEB-approved rates with no adjustments.

In Hydro One's December 21, 2017 update to the 2018-2022 Distribution Application, Hydro One described the impact to the proposed revenue requirement of various developments since initially filing the application. These included, without limitation, the updated cost of capital parameters and inflation factor for 2018 issued by the OEB, and reductions in the 2018 OM&A forecast and 2018-2022 capital forecasts.

B2M LP

In December 2015, the OEB approved B2M LP's revenue requirement for years 2015 to 2019, subject to annual updates in each of 2016, 2017 and 2018 to adjust its revenue requirement for the following year consistent with the OEB's updated cost of capital parameters. On June 8, 2017, the OEB approved B2M LP's Rate Order reflecting 2017 transmission revenue requirement of $34 million, effective January 1, 2017.

On February 1, 2018, the OEB issued its Decision and Rate Order for 2018 UTRs declaring the 2018 UTRs as interim, as the B2M LP application for an update to its 2018 transmission revenue requirement is still under consideration by the OEB.

HOSSM

On September 28, 2017, the OEB issued its Decision and Order on HOSSM's 2017 transmission rates application, denying the requested revenue requirement for 2017. HOSSM's 2016 approved revenue requirement of $41 million will remain in effect for 2017 and 2018.

Hydro One Remote Communities Inc.

On August 28, 2017, Hydro One Remote Communities Inc. filed an application with the OEB seeking approval of its 2018 revenue requirement of $57 million and electricity rates effective May 1, 2018. On December 14, 2017, the OEB issued a Procedural Order with key dates for filing additional materials and reply submissions. On February 7, 2018, Hydro One Remote Communities Inc. and the intervenors in the rate proceeding reached a full settlement agreement on all issues. The agreement is expected to be reviewed by the OEB for approval in March 2018. Upon the OEB's approval, new rates are expected to be implemented by May 1, 2018.

Hydro One Remote Communities Inc. is fully financed by debt and is operated as a break-even entity with no ROE.

MAAD Applications

Orillia Power MAAD Application

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power). The acquisition is subject to regulatory approval by the OEB. On July 27, 2017, the OEB issued a Procedural Order No.6 (Procedural Order) in the matter of Hydro One's MAAD application to acquire Orillia Power. The Procedural Order stated that the OEB has decided to delay a decision on the Orillia Power MAAD application until Hydro One defends its cost allocation proposal in the 2018-2022 Distribution Application hearing to determine if the Orillia Power acquisition is likely to cause harm to any of its current customers. Because of the timetable of the 2018-2022 Distribution Application hearing, and the time it will take to receive a decision in that hearing, the effect of the Procedural Order will be to delay the Orillia Power MAAD application decision by as much as 18 months or more. On August 14, 2017, Hydro One filed a Motion to Review and Vary the Procedural Order requesting the OEB to allow the Orillia Power MAAD application to proceed immediately in the ordinary course. On October 24, 2017, the OEB issued a Procedural Order in response to Hydro One's Motion to Review and Vary, with key dates for filing additional materials on the Motion, hearing date, and filing of reply submissions. Final argument on the Motion to Review and Vary was filed on December 13, 2017.

On January 4, 2018, the OEB issued its Decision on Hydro One's Motion to Review and Vary, granting the motion and referring the MAAD file back to the original OEB panel for reconsideration. The OEB's findings were based on both procedural unfairness and the impact that a lengthy delay will have on the operations of Orillia Power. On February 5, 2018, the OEB issued Procedural Order No. 7 directing Hydro One to file evidence or submissions on its expectations of the overall cost structures following the deferred rebasing period and the effect on Orillia Power customers by February 15, 2018.

Other Applications

East-West Tie

In 2013, NextBridge Infrastructure (NextBridge), a partnership between NextEra Energy Canada, Enbridge Inc., and Borealis Infrastructure was designated by the OEB to complete the development work for the East-West Tie Line Project, a 230 kV, 400 km transmission line connecting Hydro One's Wawa and Lakehead transmission stations. This project is necessary to ensure the reliability of electricity supply in Northwestern Ontario, and was included as a priority project in the Province's 2010 Long-Term Energy Plan. On July 31, 2017, Hydro One filed a Leave to Construct application with the OEB to perform station upgrades to its Wawa and Lakehead transmission stations (East-West Tie Station Expansion), necessary to support the East-West Tie Line Project. Hydro One is acting as an intervenor in NextBridge's East-West Tie Line Project application.

On September 22, 2017, Hydro One filed with the OEB a Letter of Intent indicating that the Company plans to file a Leave to Construct application to construct the East-West Tie Line Project. On December 21, 2017, Hydro One re-confirmed with the OEB that it still intends to file this application in early 2018.

On November 13, 2017, NextBridge filed a letter with the OEB asserting that the OEB should strictly limit Hydro One's intervenor status to matters related to interconnection of the NextBridge East-West Tie Line Project to Hydro One transmission facilities and to ensure that Hydro One does not use its status as the Province's incumbent transmitter to compete unfairly against NextBridge's Leave to Construct application.

On December 1, 2017, the IESO released its needs assessment for the East-West Tie Line Project, as requested by the Minister of Energy. The IESO has reconfirmed that the project is still the recommended solution to supply electricity in Northwestern Ontario and continues to recommend an in-service date of 2020.

On December 5, 2017, Hydro One filed a letter with the OEB in response to NextBridge's request to impose limitations on Hydro One's participation as an intervenor. In the letter, Hydro One asked that the OEB allow Hydro One's status as an intervenor in the proceeding with full intervenor rights, and that the OEB reject NextBridge's requests relating to (i) documentation provided to Hydro One, (ii) creation of a confidentiality screen, and (iii) creation of novel filing requirements for a Leave to Construct application by Hydro One.

On December 21, 2017, both NextBridge and Hydro One received interrogatories from the OEB and Intervenors related to their respective Leave to Construct applications. Hydro One submitted its responses by the January 25, 2017 due date.

Other Regulatory Developments

Fair Hydro Plan and First Nations Rate Assistance Program

In March 2017, Ontario's Minister of Energy announced the Fair Hydro Plan, which included changes to the Global Adjustment, the Rural or Remote Electricity Rate Protection (RRRP) Program, the introduction of the First Nations rate assistance program, and improving the allocation of delivery charges across the rural and urban geographies of the province. Hydro One worked collaboratively with the OEB on the First Nations rate assistance program, and was a key stakeholder in providing solutions that address both the Global Adjustment and RRRP elements. The Fair Hydro Plan came into effect on July 1, 2017 and resulted in a reduction of approximately 25% on electricity bills for typical Ontario residential customers. The Province also launched a new Affordability Fund aimed at assisting electricity customers who cannot qualify for low-income conservation programs. Additional enhancements were also made to the existing Ontario Electricity Support Program (OESP).

Hydro One customers saw the full benefits of the Fair Hydro Plan for all electricity consumed after July 1, 2017. A typical rural residential customer using 750 kWh per month will see savings on their monthly bills of 31% on average, or approximately $600 annually. These changes did not have an impact on the net income of the Company.

Hydro One continues to work with First Nations customers living on reserves to help ensure the required applications are submitted to receive the benefits associated with the First Nations rate assistance program which provides a credit on the delivery charge.

OEB Pension and Other Post-Employment Benefits Costs

On September 14, 2017, the OEB issued its final report, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (Report), that establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. The Report also provides for the establishment of a variance account, effective January 1, 2018, to track the difference between the forecasted accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to the differential.

Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers, including a higher cost recovered through rates, more volatility relating to the ability to predict the effect on rates, and the pension offset (cumulative difference between the cash and accrual basis which is $981 million as at December 31, 2017) having to be recovered in rates on an accelerated basis. As the Report establishes that a basis other than the accrual accounting method may be acceptable if resulting in just and reasonable rates, Hydro One believes that the cash basis treatment of pension costs would continue to be supportable.

OTHER DEVELOPMENTS

Strategy

In 2017, the Company's Board of Directors approved Hydro One's strategy which details the Company's goal to become North America's leading utility, centered around three key pillars: (i) optimization and innovation, (ii) diversification, and (iii) growth.

Collective Agreements

On April 7, 2017, Hydro One reached an agreement with the Canadian Union of Skilled Workers (CUSW) for a renewal of the collective agreement. The agreement is for a five-year term, covering May 1, 2017 to April 30, 2022. The agreement was ratified by the CUSW and the Hydro One Board of Directors in May 2017.

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society of Energy Professionals (the Society) and the Power Workers' Union (PWU) to facilitate the insourcing of these services effective March 1, 2018.

The current collective agreement with the PWU expires on March 31, 2018. In January 2018, Hydro One and the PWU commenced collective bargaining with the official exchange of bargaining agendas. Both sides acknowledged their commitment to working towards the timely completion of collective bargaining.

Litigation

Hydro One, Hydro One Networks, Hydro One Remote Communities Inc., and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, an estimate of a possible loss related to this claim cannot be made.

Appointment of Chief Financial Officer

On January 28, 2018, Mr. Paul Dobson was appointed to the position of Chief Financial Officer of Hydro One, effective March 1, 2018. Mr. Dobson was most recently the Chief Financial Officer at Direct Energy Ltd. in Houston, Texas.

HYDRO ONE WORK FORCE

Hydro One has a skilled and flexible work force of approximately 5,300 regular employees and 2,000 non-regular employees province-wide, comprising of a mix of skilled trades, engineering, professional, managerial and executive personnel. Hydro One's regular employees are supplemented primarily by accessing a large external labour force available through arrangements with the Company's trade unions for variable workers, sometimes referred to as "hiring halls", and also by access to contract personnel. The hiring halls offer Hydro One the ability to flexibly utilize highly trained and appropriately skilled workers on a project-by-project and seasonal basis.

The following table sets out the number of Hydro One employees as at December 31, 2017:

	Regular Employees	Non-Regular Employees	Total
PWU[1]	3,344	694	4,038
The Society	1,314	32	1,346
Canadian Union of Skilled Workers (CUSW) and construction building trade unions[2]	—	1,254	1,254
Total employees represented by unions	4,658	1,980	6,638
Management and non-represented employees	665	22	687
Total employees	5,323	2,002	7,325

[1] Includes 575 non-regular "hiring hall" employees covered by the PWU agreement.

[2] The construction building trade unions have collective agreements with the Electrical Power Systems Construction Association (EPSCA).

Share-based Compensation

During 2017 and 2016, the Company granted awards under its Long-term Incentive Plan, consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled. At December 31, 2017 and 2016, 425,120 and 228,890 PSUs, respectively, and 388,140 and 252,440 RSUs, respectively, were outstanding.

NON-GAAP MEASURES

FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to the common shareholder. As such, FFO provides a consistent measure of the cash generating performance of the Company's assets.

Year ended December 31 *(millions of dollars)*	2017	2016
Net cash from operating activities	1,694	1,668
Changes in non-cash balances related to operations	(63)	(168)
Distributions to noncontrolling interest	(6)	(9)
FFO	1,625	1,491

Revenues, net of purchased power

Revenues, net of purchased power is defined as revenues less purchased power. Management believes that revenue, net of purchased power is helpful as a measure of net revenues for the Distribution segment, as purchased power is fully recovered through revenues.

Year ended December 31 *(millions of dollars)*	2017	2016
Revenues	5,947	6,502
Less: Purchased power	2,875	3,427
Revenues, net of purchased power	3,072	3,075

Year ended December 31 *(millions of dollars)*	2017	2016
Distribution revenues	4,366	4,915
Less: Purchased power	2,875	3,427
Distribution revenues, net of purchased power	1,491	1,488

FFO and Revenues, net of purchased power are not recognized measures under US GAAP and do not have a standardized meaning prescribed by US GAAP. They are therefore unlikely to be directly comparable to similar measures presented by other companies. They should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under US GAAP.

RELATED PARTY TRANSACTIONS

Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), the OEB, and Hydro One Telecom, are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One. The following is a summary of the Company's related party transactions during the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2017	2016
IESO	Power purchased	1,583	2,096
	Revenues for transmission services	1,521	1,549
	Amounts related to electricity rebates	357	—
	Distribution revenues related to rural rate protection	247	125
	Distribution revenues related to the supply of electricity to remote northern communities	32	32
	Funding received related to CDM programs	59	63
OPG	Power purchased	9	6
	Revenues related to provision of construction and equipment maintenance services	2	4
	Costs related to the purchase of services	1	1
OEFC	Power purchased from power contracts administered by the OEFC	2	1
OEB	OEB fees	8	11
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	3
Hydro One Limited	Return of stated capital	535	609
	Dividends paid	15	2
	Stock-based compensation costs	23	24
	Cost recovery for services provided	6	—
Hydro One Telecom	Services received - costs expensed	24	24
	Services received - costs capitalized	—	12
	Revenues for services provided	3	3
2587264 Ontario Inc.	Promissory note issued and repaid[1]	486	—
	Preferred shares issued[2]	486	—

[1] On October 17, 2017, Hydro One issued a promissory note to 2587264 Ontario Inc., a subsidiary of Hydro One Limited, totalling $486 million. On November 20, 2017, Hydro One repaid the $486 million promissory note to 2587264 Ontario Inc., as well as interest totalling $1 million.

[2] On November 20, 2017, Hydro One issued 485,870 Class B preferred shares to 2587264 Ontario Inc. for proceeds of $486 million.

RISK MANAGEMENT AND RISK FACTORS

Risks Relating to Hydro One's Business

Regulatory Risks and Risks Relating to Hydro One's Revenues

Risks Relating to Obtaining Rate Orders

The Company is subject to the risk that the OEB will not approve the Company's transmission and distribution revenue requirements requested in outstanding or future applications for rates. Rate applications for revenue requirements are subject to the OEB's review process, usually involving participation from intervenors and a public hearing process. There can be no assurance that resulting decisions or rate orders issued by the OEB will permit Hydro One to recover all costs actually incurred, costs of debt and income taxes, or to earn a particular ROE. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, such as occurred in the September 28, 2017 and November 9, 2017 OEB decisions (details above in "Electricity Rates Applications - Hydro One Networks - Transmission"), may materially adversely affect: Hydro One's transmission or distribution businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the cost and issuance of long-term debt, and other matters, any of which may in turn have a material adverse effect on the Company. In addition, there is no assurance that the Company will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement and cash flows could be impacted.

Risks Relating to Actual Performance Against Forecasts

The Company's ability to recover the actual costs of providing service and earn the allowed ROE depends on the Company achieving its forecasts established and approved in the rate-setting process. Actual costs could exceed the approved forecasts if, for example, the Company incurs operations, maintenance, administration, capital and financing costs above those included in the Company's approved revenue requirement. The inability to obtain acceptable rate decisions or to recover any significant difference between forecast and actual expenses could materially adversely affect the Company's financial condition and results of operations.

Further, the OEB approves the Company's transmission and distribution rates based on projected electricity load and consumption levels, among other factors. If actual load or consumption materially falls below projected levels, the Company's revenue and net income for either, or both, of these businesses could be materially adversely affected. Also, the Company's current revenue requirements for these businesses are based on cost and other assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in the Company's costs.

The Company is subject to risk of revenue loss from other factors, such as economic trends and weather conditions that influence the demand for electricity. The Company's overall operating results may fluctuate substantially on a seasonal and year-to-year basis based on these trends and weather conditions. For instance, a cooler than normal summer or warmer than normal winter can be expected to reduce demand for electricity below that forecast by the Company, causing a decrease in the Company's revenues from the same period of the previous year. The Company's load could also be negatively affected by successful Conservation and Demand Management programs whose results exceed forecasted expectations.

Risks Relating to Rate-Setting Models for Transmission and Distribution

The OEB approves and periodically changes the ROE for transmission and distribution businesses. The OEB may in the future decide to reduce the allowed ROE for either of these businesses, modify the formula or methodology it uses to determine the ROE, or reduce the weighting of the equity component of the deemed capital structure. Any such reduction could reduce the net income of the Company.

The OEB's recent Custom Incentive Rate-setting model requires that the term of a custom rate application be a minimum five-year period. There are risks associated with forecasting key inputs such as revenues, operating expenses and capital, over such a long period. For instance, if unanticipated capital expenditures arise that were not contemplated in the Company's most recent rate decision, the Company may be required to incur costs that may not be recoverable until a future period or not recoverable at all in future rates. This could have a material adverse effect on the Company.

After rates are set as part of a Custom Incentive Rate application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital (including ROE), working capital allowance or sales volumes. If there were an increase in interest rates over the period of a rate decision and no corresponding changes were permitted to the Company's allowed cost of capital (including ROE), then the result could be a decrease in the Company's financial performance.

To the extent that the OEB approves an In-Service Variance Account for the transmission and/or distribution businesses, and should the Company fail to meet the threshold levels of in-service capital, the OEB may reclaim a corresponding portion of the Company's revenues.

Risks Relating to Capital Expenditures

In order to be recoverable, capital expenditures require the approval of the OEB, either through the approval of capital expenditure plans, rate base or revenue requirements for the purposes of setting transmission and distribution rates, which include the impact of capital expenditures on rate base or cost of service. There can be no assurance that all capital expenditures incurred by Hydro One will be approved by the OEB. Capital cost overruns may not be recoverable in transmission or distribution rates. The Company could incur unexpected capital expenditures in maintaining or improving its assets, particularly given that new technology may be required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. There is risk that the OEB may not allow full recovery of such expenditures in the future. To the extent possible, Hydro One aims to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

Any regulatory decision by the OEB to disallow or limit the recovery of any capital expenditures would lead to a lower than expected approved revenue requirement or rate base, potential asset impairment or charges to the Company's results of operations, any of which could have a material adverse effect on the Company.

Risks Relating to Regulatory Treatment of Deferred Tax Asset

As a result of leaving the PILs Regime and entering the Federal Tax Regime in connection with the IPO of the Company, Hydro One recorded a deferred tax asset due to the revaluation of the tax basis of Hydro One's fixed assets at their fair market value and recognition of eligible capital expenditures. The OEB's September 28, 2017 and November 9, 2017 decisions (see details above in "Electricity Rates Applications - Hydro One Networks - Transmission") alter Hydro One's allocation of the tax savings resulting from the deferred tax asset. If this approach is followed (pending the outcome of the Motion and Appeal), the exposure from the potential impairment from the regulatory treatment of the deferred tax asset could be a one-time decrease in net income, resulting in annual decreases to FFO.

Risks Relating to Other Applications to the OEB

The Company is also subject to the risk that it will not obtain, or will not obtain in a timely manner, required regulatory approvals for other matters, such as leave to construct applications, applications for mergers, acquisitions, amalgamations and divestitures, and environmental approvals. Decisions to acquire or divest other regulated businesses licensed by the OEB are subject to OEB approval. Accordingly, there is the risk that such matters may not be approved or that unfavourable conditions will be imposed by the OEB.

Indigenous Claims Risk

Some of the Company's current and proposed transmission and distribution assets are or may be located on reserve (as defined in the *Indian Act* (Canada)) (Reserve) lands, and lands over which Indigenous people have Aboriginal, treaty, or other legal claims. Some Indigenous leaders, communities, and their members have made assertions related to sovereignty and jurisdiction over Reserve lands and traditional territories and are increasingly willing to assert their claims through the courts, tribunals, or by direct action. These claims and/or settlement of these claims could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations, including the development of current and future projects.

The Company's operations and activities may give rise to the Crown's duty to consult and potentially accommodate Indigenous communities. Procedural aspects of the duty to consult may be delegated to the Company by the Province or the federal government. A perceived failure by the Crown to sufficiently consult an Indigenous community, or a perceived failure by the Company in relation to delegated consultation obligations, could result in legal challenges against the Crown or the Company, including judicial review or injunction proceedings, or could potentially result in direct action against the Company by a community or its citizens. If this occurs, it could disrupt or delay the Company's operations and activities, including current and future projects, and have a material adverse effect on the Company.

Risk from Transfer of Assets Located on Reserves

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to assets located on Reserves. The transfer of title to these assets did not occur because authorizations originally granted by the federal government for the construction and operation of these assets on Reserves could not be transferred without required consent. In several cases, the authorizations had either expired or had never been issued.

Currently, the OEFC holds legal title to these assets and it is expected that the Company will manage them until it has obtained permits to complete the title transfer. To occupy Reserves, the Company must have valid permits. For each permit, the Company must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the issuance of a permit. For transmission assets, the Company must negotiate terms of payment. It is difficult to predict the aggregate amount that the Company may have to pay to obtain the required agreements from First Nations. If the Company cannot reach satisfactory agreements with the relevant First Nation to obtain federal permits, it may have to relocate these assets to other locations and restore the lands at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. In either case, the costs relating to these assets could have a material adverse effect on the Company if the costs are not recoverable in future rate orders.

Compliance with Laws and Regulations

Hydro One must comply with numerous laws and regulations affecting its business, including requirements relating to transmission and distribution companies, environmental laws, employment laws and health and safety laws. The failure of the Company to comply with these laws could have a material adverse effect on the Company's business. See also "- Health, Safety and Environmental Risk".

For example, Hydro One's licensed transmission and distribution businesses are required to comply with the terms of their licences, with codes and rules issued by the OEB, and with other regulatory requirements, including regulations of the National Energy Board. In Ontario, the Market Rules issued by the IESO require the Company to, among other things, comply with the reliability standards established by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council, Inc. (NPCC). The incremental costs associated with compliance with these reliability standards are expected to be recovered through rates, but there can be no assurance that the OEB will approve the recovery of all of such incremental costs. Failure to obtain such approvals could have a material adverse effect on the Company.

There is the risk that new legislation, regulations, requirements or policies will be introduced in the future. These may require Hydro One to incur additional costs, which may or may not be recovered in future transmission and distribution rates.

Risk of Natural and Other Unexpected Occurrences

The Company's facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including but not limited to cyber and physical terrorist type attacks, events which originate from third-party connected systems, or any other potentially catastrophic events. The Company's facilities may not withstand occurrences of this type in all circumstances. The Company does not have insurance for damage to its transmission and distribution wires, poles and towers located outside its transmission and distribution stations resulting from these or other events. Where insurance is available for other assets, such insurance coverage may have deductibles, limits and/or exclusions. Losses from lost revenues and repair costs could be substantial, especially for many of the Company's facilities that are located in remote areas. The Company could also be subject to claims for damages caused by its failure to transmit or distribute electricity or costs related to ensuring its continued ability to transmit or distribute electricity.

Risk Associated with Information Technology Infrastructure and Data Security

The Company's ability to operate effectively in the Ontario electricity market is, in part, dependent upon it developing, maintaining and managing complex information technology systems which are employed to operate and monitor its transmission and distribution facilities, financial and billing systems and other business systems. The Company's increasing reliance on information systems and expanding data networks increases its exposure to information security threats. The Company's transmission business is required to comply with various rules and standards for transmission reliability, including mandatory standards established by the NERC and the NPCC. These include standards relating to cyber-security and information technology, which only apply to certain of the Company's assets (generally being those whose failure could impact the functioning of the bulk electricity system). The Company may maintain different or lower levels of information technology security for its assets that are not subject to these mandatory standards. The Company must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information and information regarding consumers, wholesalers, generators and retailers.

Cyber-attacks or unauthorized access to corporate and information technology systems could result in service disruptions and system failures, which could have a material adverse effect on the Company, including as a result of a failure to provide electricity to customers. Due to operating critical infrastructure, Hydro One may be at greater risk of cyber-attacks from third parties (including state run or controlled parties) that could impair or incapacitate its assets. In addition, in the course of its operations, the Company collects, uses, processes and stores information which could be exposed in the event of a cyber-security incident or other unauthorized access or disclosure, such as information about customers, suppliers, counterparties, employees and other third parties.

Security and system disaster recovery controls are in place; however, there can be no assurance that there will not be system failures or security breaches or that such threats would be detected or mitigated on a timely basis. Upon occurrence and detection, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on the Company.

Labour Relations Risk

The substantial majority of the Company's employees are represented by either the PWU or the Society. Over the past several years, significant effort has been expended to increase Hydro One's flexibility to conduct operations in a more cost-efficient manner. Although the Company has achieved improved flexibility in its collective agreements, the Company may not be able to achieve further improvements. The Company reached an agreement with the PWU for a renewal collective agreement with a three-year term, covering the period from April 1, 2015 to March 31, 2018 and an early renewal collective agreement with the Society with a three-year term, covering the period from April 1, 2016 to March 31, 2019. The Company also reached a renewal collective agreement with the Canadian Union of Skilled Workers for a five-year term, covering the period from May 1, 2017 to April 30, 2022. Additionally, the EPSCA and a number of construction unions have reached renewal agreements, to which Hydro One is bound, for a five-year term, covering the period from May 1, 2015 to April 30, 2020. Agreements have also been reached with the Society and the PWU to facilitate the insourcing of customer service operations services effective March 1, 2018. Future negotiations with unions present the risk of a labour disruption and the ability to sustain the continued supply of energy to customers. The Company also faces financial risks related to its ability to negotiate collective agreements consistent with its rate orders. In addition, in the event of a labour dispute, the Company could face operational risk related to continued compliance with its requirements of providing service to customers. Any of these could have a material adverse effect on the Company.

Work Force Demographic Risk

By the end of 2017, approximately 22% of the Company's employees who are members of the Company's defined benefit and defined contribution pension plans were eligible for retirement, and by the end of 2018, approximately 20% could be eligible. These percentages are not evenly spread across the Company's work force, but tend to be most significant in the most senior levels of the Company's staff and especially among management staff. During 2017, approximately 5% of the Company's work force (up from 3% in 2016) elected to retire. Accordingly, the Company's continued success will be tied to its ability to continue to attract and retain sufficient qualified staff to replace the capability lost through retirements and meet the demands of the Company's work programs.

In addition, the Company expects the skilled labour market for its industry will remain highly competitive. Many of the Company's current and potential employees being sought after possess skills and experience that are also highly coveted by other organizations inside and outside the electricity sector. The failure to attract and retain qualified personnel for Hydro One's business could have a material adverse effect on the Company.

Risk Associated with Arranging Debt Financing

The Company expects to borrow to repay its existing indebtedness and to fund a portion of capital expenditures. Hydro One has substantial debt principal repayments, including $752 million in 2018, $731 million in 2019, and $653 million in 2020. In addition, from time to time, the Company may draw on its syndicated bank lines and/or issue short-term debt under Hydro One's $1.5 billion commercial paper program which would mature within approximately one year of issuance. The Company also plans to incur continued material capital expenditures for each of 2018 and 2019. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of the Company's existing indebtedness and capital expenditures. The

Company's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, the Company's results of operations and financial position, market conditions, the ratings assigned to its debt securities by credit rating agencies, an inability of the Corporation to comply with its debt covenants, and general economic conditions. A downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt. Any failure or inability on the Company's part to borrow the required amounts of debt on satisfactory terms could impair its ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on the Company.

Market, Financial Instrument and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated ROE is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk or material foreign exchange risk.

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. The Company estimates that a decrease of 100 basis points in the combination of the forecasted long-term Government of Canada bond yield and the A-rated utility corporate bond yield spread used in determining its rate of return would reduce the Company's transmission business' 2019 net income by approximately $24 million. For the distribution business, after distribution rates are set as part of a Custom Incentive Rate application, the OEB does not expect to address annual rate applications for updates to allowed ROE, so fluctuations will have no impact to net income. The Company periodically utilizes interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. Hydro One monitors and minimizes credit risk through various techniques, including dealing with highly rated counterparties, limiting total exposure levels with individual counterparties, entering into agreements which enable net settlement, and by monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. The Company is required to procure electricity on behalf of competitive retailers and certain local distribution companies for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into the Company's service agreements with these retailers in accordance with the OEB's Retail Settlement Code.

The failure to properly manage these risks could have a material adverse effect on the Company.

Risks Relating to Asset Condition and Capital Projects

The Company continually incurs sustainment and development capital expenditures and monitors the condition of its transmission assets to manage the risk of equipment failures and to determine the need for and timing of major refurbishments and replacements of its transmission and distribution infrastructure. However, the lack of real time monitoring of distribution assets increases the risk of distribution equipment failure. The connection of large numbers of generation facilities to the distribution network has resulted in greater than expected usage of some of the Company's equipment. This increases maintenance requirements and may accelerate the aging of the Company's assets.

Execution of the Company's capital expenditure programs, particularly for development capital expenditures, is partially dependent on external factors, such as environmental approvals, municipal permits, equipment outage schedules that accommodate the IESO, generators and transmission-connected customers, and supply chain availability for equipment suppliers and consulting services. There may also be a need for, among other things, *Environmental Assessment Act* (Ontario) approvals, approvals which require public meetings, appropriate engagement with Indigenous communities, OEB approvals of expropriation or early access to property, and other activities. Obtaining approvals and carrying out these processes may also be impacted by opposition to the proposed site of the capital investments. Delays in obtaining required approvals or failure to complete capital projects on a timely basis could materially adversely affect transmission reliability or customers' service quality or increase maintenance costs which could have a material adverse effect on the Company. Failure to receive approvals for projects when spending has already occurred would result in the inability of the Company to recover the investment in the project as well as forfeit the anticipated return on investment. The assets involved may be considered impaired and result in the write off of the value of the asset, negatively impacting net income. External factors are considered in the Company's planning process. If the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce network capacity, result in customer interruptions, compromise the reliability of the Company's networks or increase the costs of operating and maintaining these assets. Any of these consequences could have a material adverse effect on the Company.

Increased competition for the development of large transmission projects and legislative changes relating to the selection of transmitters could impact the Company's ability to expand its existing transmission system, which may have an adverse effect on the Company. To the extent that other parties are selected to construct, own and operate new transmission assets, the Company's share of Ontario's transmission network would be reduced.

Health, Safety and Environmental Risk

The Company is subject to provincial health and safety legislation. Findings of a failure to comply with this legislation could result in penalties and reputational risk, which could negatively impact the Company.

The Company is subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject the Company to fines or other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties or governmental orders requiring the Company to take specific actions such as investigating, controlling and remediating the effects of these substances. Contamination of the Company's properties could limit its ability to sell or lease these assets in the future.

In addition, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on the Company's balance sheet. The Company does not have insurance coverage for these environmental expenditures.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases. Failure to obtain necessary approvals or permits could result in an inability to complete projects.

Hydro One emits certain greenhouse gases, including sulphur hexafluoride or "SF_6". There are increasing regulatory requirements and costs, along with attendant risks, associated with the release of such greenhouse gases, all of which could impose additional material costs on Hydro One.

Any regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on the Company.

Pension Plan Risk

Hydro One has the Hydro One Defined Benefit Pension Plan in place for the majority of its employees. Contributions to the pension plan are established by actuarial valuations which are required to be filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2016, and was filed in May 2017, covering a three-year period from 2017 to 2019. Hydro One's contributions to its pension plan satisfy, and are expected to satisfy, minimum funding requirements. Contributions beyond 2019 will depend on the funded position of the plan, which is determined by investment returns, interest rates and changes in benefits and actuarial assumptions at that time. A determination by the OEB that some of the Company's pension expenditures are not recoverable through rates could have a material adverse effect on the Company, and this risk may be exacerbated if the amount of required pension contributions increases.

In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers or material negative impacts on the company should recovery of costs be disallowed by the OEB. See "- Other Post-Employment and Post-Retirement Benefits Risks".

Risk of Recoverability of Total Compensation Costs

The Company manages all of its total compensation costs, including pension and other post-employment and post-retirement benefits, subject to restrictions and requirements imposed by the collective bargaining process. Any element of total compensation costs which is disallowed in whole or part by the OEB and not recoverable from customers in rates could result in costs which could be material and could decrease net income, which could have a material adverse effect on the Company.

Other Post-Employment and Post-Retirement Benefits Risks

The Company provides other post-employment and post-retirement benefits, including workers compensation benefits and long-term disability benefits to qualifying employees. In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently maintains the accrual accounting method with respect to OPEBs. If the OEB directed Hydro One to transition to a different accounting method for OPEBs, this could result in income volatility, due to an inability of the company to book the difference between the accrual and cash as a regulatory asset. A determination that some of the Company's post-employment and post-retirement benefit costs are not recoverable could have a material adverse effect on the Company.

Risk Associated with Outsourcing Arrangements

Hydro One has entered into an outsourcing arrangement with a third party for the provision of back office and IT services and call centre services. If the outsourcing arrangement or statements of work thereunder are terminated for any reason or expire before a new supplier is selected and fully transitioned, the Company could be required to transfer to another service provider or insource, which could have a material adverse effect on the Company's business, operating results, financial condition or prospects.

Risk from Provincial Ownership of Transmission Corridors

The Province owns some of the corridor lands underlying the Company's transmission system. Although the Company has the statutory right to use these transmission corridors, the Company may be limited in its options to expand or operate its systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of the Company's systems may increase safety or environmental risks, which could have a material adverse effect on the Company.

Litigation Risks

In the normal course of the Company's operations, it becomes involved in, is named as a party to and is the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to actual or alleged violations of law, common law damages claims, personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company, which could have a material adverse effect on the Company. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company's business operations, which could adversely affect the Company. See also "Other Developments - Litigation".

Transmission Assets on Third-Party Lands Risk

Some of the lands on which the Company's transmission assets are located are owned by third parties, including the Province and federal Crown, and are or may become subject to land claims by First Nations. The Company requires valid occupation rights to occupy such lands (which may take the form of land use permits, easements or otherwise). If the Company does not have valid occupational rights on third-party owned lands or has occupational rights that are subject to expiry, it may incur material costs to obtain or renew such occupational rights, or if such occupational rights cannot be renewed or obtained it may incur material costs to remove and relocate its assets and restore the subject land. If the Company does not have valid occupational rights and must incur costs as a result, this could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations.

Reputational, Public Opinion and Political Risk

Reputation risk is the risk of a negative impact to Hydro One's business, operations or financial condition that could result from a deterioration of Hydro One's reputation. Hydro One's reputation could be negatively impacted by changes in public opinion, attitudes towards the Company's privatization, failure to deliver on its customer promises and other external forces. Adverse reputational events or political actions could have negative impacts on Hydro One's business and prospects including, but not limited to, delays or denials of requisite approvals, such as denial of requested rates, and accommodations for Hydro One's planned projects, escalated costs, legal or regulatory action, and damage to stakeholder relationships.

Risk associated with change in Hydro One Limited capital structure

A change in the capital structure of Hydro One Limited could cause credit rating agencies which rate the outstanding debt obligations of Hydro One to re-evaluate and potentially downgrade their current credit ratings, which could increase the Company's borrowing costs.

Risks Relating to the Company's Relationship with Hydro One Limited and the Province

Indirect Ownership and Continued Influence by the Province and Voting Power

The Province currently owns approximately 47.4% of the outstanding common shares of Hydro One Limited and it is expected to continue to maintain a significant ownership interest in voting securities of Hydro One Limited for an indefinite period.

As a result of its significant ownership of the common shares of Hydro One Limited, the Province has, and is expected indefinitely to have, the ability to determine or significantly influence the outcome of shareholder votes at Hydro One Limited, subject to the restrictions in the governance agreement entered into between Hydro One Limited and the Province dated November 5, 2015 (Governance Agreement; available on SEDAR at www.sedar.com). Despite the terms of the Governance Agreement in which the Province has agreed to engage in the business and affairs of Hydro One Limited as an investor and not as a manager, there is a risk that the Province's engagement in the business and affairs of Hydro One Limited as an investor will be informed by its policy objectives and may influence the conduct of the business and affairs of Hydro One Limited in ways that may not be aligned with the interests of other shareholders of Hydro One Limited. This influence may also extend to Hydro One. As a result, the Province may influence the conduct of the business and affairs of Hydro One, and decisions may be made by the Province as a shareholder of Hydro One Limited which may not be aligned with the interests of the other security holders of Hydro One.

Composition of the Board of Directors of Hydro One

Under the Governance Agreement, Hydro One Limited has agreed that the board of directors of Hydro One and Hydro One Networks will be constituted to have the same members as the board of directors of Hydro One Limited, unless the board of directors of Hydro One Limited determines otherwise. The Governance Agreement contains provisions governing the independence of the members of the board of Hydro One Limited and the ability of the Province to nominate and, in certain circumstances, remove directors, which could indirectly impact the composition of the board of directors of Hydro One in a manner which may not be aligned with the interests of the other security holders of Hydro One. There is a risk that the Province will nominate or confirm individuals who satisfy the independence requirements but who it considers are disposed to support and advance its policy objectives and give disproportionate weight to the Province's interests in exercising their business judgment and balancing the interests of the stakeholders of Hydro One Limited. Those same individuals, to the extent they are also on the board of directors of Hydro One, could similarly give disproportionate weight to the Province's indirect interest in Hydro One in exercising their business judgment and balancing the interests of the stakeholders of Hydro One.

More Extensive Regulation

Although under the Governance Agreement, the Province has agreed to engage in the business and affairs of Hydro One Limited as an investor and not as a manager and has stated that its intention is to achieve its policy objectives through legislation and regulation as it would with respect to any other utility operating in Ontario, there is a risk that the Province will exercise its legislative and regulatory power to achieve policy objectives in a manner that has a material adverse effect on Hydro One Limited, which in turn could have a material adverse effect on Hydro One.

Prohibitions on Selling the Company's Transmission or Distribution Business

The *Electricity Act* prohibits Hydro One Limited from selling all or substantially all of the business, property or assets related to its transmission system or distribution system that is regulated by the OEB. There is a risk that these prohibitions may limit the ability of Hydro One Limited, and in turn, Hydro One, to engage in sale transactions involving a substantial portion of either system, even where such a transaction may otherwise be considered to provide substantial benefits to Hydro One Limited, Hydro One or their security holders.

CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of Hydro One Consolidated Financial Statements requires the Company to make key estimates and critical judgments that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. Hydro One bases its estimates and judgments on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities, as well as identifying and assessing the Company's accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments. Hydro One has identified the following critical accounting estimates used in the preparation of its Consolidated Financial Statements:

Revenues

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Regulatory Assets and Liabilities

Hydro One's regulatory assets represent certain amounts receivable from future electricity customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The regulatory assets mainly include costs related to the pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, share-based compensation costs, and environmental liabilities. The Company's regulatory liabilities represent certain amounts that are refundable to future electricity customers, and pertain primarily to OEB deferral and variance accounts. The regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the amounts have been approved for inclusion in the electricity rates by the OEB, or if such approval is judged to be probable by management. If management judges that it is no longer probable that the OEB will allow the inclusion of a regulatory asset or liability in future electricity rates, the applicable carrying amount of the regulatory asset or liability will be reflected in results of operations in the period that the judgment is made by management.

Environmental Liabilities

Hydro One records a liability for the estimated future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment, and for the assessment and remediation of chemically contaminated lands. There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

Hydro One's employee future benefits consist of pension and post-retirement and post-employment plans, and include pension, group life insurance, health care, and long-term disability benefits provided to the Company's current and retired employees. Employee future benefits costs are included in Hydro One's labour costs that are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets. Changes in assumptions affect the benefit obligation of the employee future benefits and the amounts that will be charged to results of operations or capitalized in future years. The following significant assumptions and estimates are used to determine employee future benefit costs and obligations:

Weighted Average Discount Rate

The weighted average discount rate used to calculate the employee future benefits obligation is determined at each year end by referring to the most recently available market interest rates based on "AA"-rated corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rate at December 31, 2017 decreased to 3.40% (from 3.90% at December 31, 2016) for pension benefits and decreased to 3.40% (from 3.90% at December 31, 2016) for the post-retirement and post-employment plans. The decrease in the discount rate has resulted in a corresponding increase in employee future benefits liabilities for the pension, post-retirement and post-employment plans for accounting purposes. The liabilities are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates.

Expected Rate of Return on Plan Assets

The expected rate of return on pension plan assets is based on expectations of long-term rates of return at the beginning of the year and reflects a pension asset mix consistent with the pension plan's current investment policy.

Rates of return on the respective portfolios are determined with reference to respective published market indices. The expected rate of return on pension plan assets reflects the Company's long-term expectations. The Company believes that this assumption is reasonable because, with the pension plan's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed-income and short-term investment returns. The net result, on a long-term basis, is a lower return than might be expected by investing in equities alone. In the short term, the pension plan can experience fluctuations in actual rates of return.

Rate of Cost of Living Increase

The rate of cost of living increase is determined by considering differences between long-term Government of Canada nominal bonds and real return bonds, which decreased from 1.80% per annum as at December 31, 2016 to approximately 1.60% per annum as at December 31, 2017. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for employee future benefits liability valuation purposes as at December 31, 2017.

Salary Increase Assumptions

Salary increases should reflect general wage increases plus an allowance for merit and promotional increases for current members of the plan, and should be consistent with the assumptions for consumer price inflation and real wage growth in the economy. The merit and promotion scale was developed based on the salary increase assumption review performed in 2017. The review considers actual salary experience from 2002 to 2016 using valuation data for all active members as at December 31, 2016, based on age and service and Hydro One's expectation of future salary increases. Additionally, the salary scale reflect negotiated salary rate increases over the contract period.

Mortality Assumptions

The Company's employee future benefits liability is also impacted by changes in life expectancies used in mortality assumptions. Increases in life expectancies of plan members result in increases in the employee future benefits liability. The mortality assumption used at December 31, 2017 is 95% of 2014 Canadian Pensioners Mortality Private Sector table projected generationally using improvement Scale B.

Rate of Increase in Health Care Cost Trends

The costs of post-retirement and post-employment benefits are determined at the beginning of the year and are based on assumptions for expected claims experience and future health care cost inflation. For the post-retirement benefit plans, a trend study of historical Hydro One experience was conducted in 2017, which resulted in a change in the prescription drug, dental and hospital trends to be used for 2017 year-end reporting purposes. A 1% increase in the health care cost trends would result in a $29 million increase in 2017 interest cost plus service cost, and a $250 million increase in the benefit liability at December 31, 2017.

Valuation of Deferred Tax Assets

Hydro One assesses the likelihood of realizing deferred tax assets by reviewing all readily available current and historical information, including a forecast of future taxable income. To the extent management considers it is more likely than not that some portion or all of the deferred tax assets will not be realized, a valuation allowance is recognized.

Asset Impairment

Within Hydro One's regulated businesses, the carrying costs of most of the long-lived assets are included in the rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through OEB-approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2017, no asset impairment had been recorded for assets within Hydro One's businesses.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Hydro One has concluded that goodwill was not impaired at December 31, 2017. Goodwill represents the cost of acquired distribution and transmission companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure controls and procedures are part of a broad internal control framework integral to ensuring that the Company fairly presents in all material respects the financial condition, results of operations and cash flows of the Company for the periods presented in this MD&A and the Company's Annual Report. Disclosure controls and procedures include processes designed to ensure that information is recorded, processed, summarized and reported on a timely basis to the Company's management, including its Chief Executive and Chief Financial Officers, as appropriate, to make timely decisions regarding required disclosure. At the direction of the Company's Chief Executive Officer and the Senior Vice President, Finance, acting in the capacity of Chief Financial Officer, management evaluated disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, management concluded that the Company's disclosure controls and procedures were effective at a reasonable level of assurance as at December 31, 2017.

Internal control over financial reporting is a subset of the internal control framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with US GAAP. The Company's internal control over financial reporting framework includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and disposition of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with US GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorization of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's consolidated financial statements.

The Company's management, at the direction of the Chief Executive Officer and with the participation of the Senior Vice President, Finance, acting in the capacity of Chief Financial Officer, evaluated the effectiveness of the design and operation of internal control over financial reporting based on the framework and criteria established in the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective at a reasonable level of assurance as at December 31, 2017.

Together, disclosure controls and procedures and internal control over financial reporting provide internal control over reporting and disclosure. Internal control, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and due to its inherent limitations, may not prevent or detect all misrepresentations. Furthermore, the effectiveness of internal control is affected by change and subject to the risk that internal control effectiveness may change over time.

The role of Chief Financial Officer was vacated effective May 19, 2017. Responsibilities of the Chief Financial Officer have been temporarily assigned to other senior executives with full oversight provided by the Chief Executive Officer. This model is expected to remain in place until Paul Dobson assumes the role of the new Chief Financial Officer on March 1, 2018. There were no significant changes in the design of the Company's internal control over financial reporting during the three months ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the operation of the Company's internal control over financial reporting.

Management will continue to monitor its systems of internal control over reporting and disclosure and may make modifications from time to time as considered necessary.

NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13 2017-14	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.
2016-02 2018-01	February 2016 – January 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-04	January 2017	The amendment removes the second step of the current two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

SUMMARY OF FOURTH QUARTER RESULTS OF OPERATIONS

Three months ended December 31 *(millions of dollars, except EPS)*	2017	2016	Change
Revenues			
Distribution	1,049	1,228	(14.6%)
Transmission	380	376	1.1%
	1,429	1,604	(10.9%)
Costs			
Purchased power	662	858	(22.8%)
OM&A			
Distribution	147	162	(9.3%)
Transmission	84	115	(27.0%)
Other	(1)	6	(116.7%)
	230	283	(18.7%)
Depreciation and amortization	213	201	6.0%
	1,105	1,342	(17.7%)
Income before financing charges and income taxes	**324**	**262**	**23.7%**
Financing charges	101	101	0.0%
Income before income taxes	**223**	**161**	**38.5%**
Income taxes	41	28	46.4%
Net income	**182**	**133**	**36.8%**
Net income attributable to common shareholder of Hydro One	**180**	**131**	**37.4%**
Basic and Diluted EPS	$1,265	$921	37.4%
Capital Investments			
Distribution	161	201	(19.9%)
Transmission	267	274	(2.6%)
	428	**475**	**(9.9%)**
Assets Placed In-Service			
Distribution	207	211	(1.9%)
Transmission	522	488	7.0%
	729	**699**	**4.3%**

Net Income

Net income attributable to common shareholder for the quarter ended December 31, 2017 of $180 million is an increase of $49 million or 37.4% from the prior year. Significant influences on net income included:

- increase in distribution revenues due to higher energy consumption;
- higher transmission revenues driven by OEB's decision on the 2017-2018 transmission rates filing;
- transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- lower OM&A costs primarily resulting from a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, insurance proceeds received on failed equipment at two transformer stations, a tax recovery of previous year's expenses, lower support services costs, and reduced vegetation management costs; and
- higher depreciation expense due to an increase in rate base.

Revenues

The quarterly increase of $4 million or 1.1% in transmission revenues was primarily due to higher revenues driven by the OEB's decision on the 2017-2018 transmission rates filing, partially offset by lower OEB-approved transmission rates.

The quarterly increase of $17 million or 4.6% in distribution revenues, net of purchased power, was primarily due to higher energy consumption mainly resulting from colder weather in the fourth quarter of 2017; and higher external revenues related to CDM incentive bonus; partially offset by reduction in 2017 allowed ROE for the distribution business.

OM&A Costs

The quarterly decrease of $31 million or 27.0% in transmission OM&A costs was primarily due to a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, lower support services costs, and insurance proceeds received due to equipment failures at the Fairchild and Campbell transmission stations.

The quarterly decrease of $15 million or 9.3% in distribution OM&A costs was primarily due to lower expenditures for vegetation management programs due to strategic changes to the forestry program scope that resulted in cost efficiency and improved management of the Company's rights of ways; lower bad debt expense attributable to lower write-offs and improved accounts receivable aging; and a tax recovery of previous year's expenses.

A further decrease of $7 million in other OM&A is primarily due to lower corporate organizational costs in the other segment.

Depreciation and Amortization

The increase of $12 million or 6.0% in depreciation and amortization costs for the fourth quarter of 2017 was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

Financing Charges

The financing charges for the fourth quarter of 2017 were comparable to prior year.

Income Taxes

Income tax expense for the fourth quarter of 2017 increased by $13 million compared to 2016, and the Company realized an effective tax rate of approximately 18.4% in the fourth quarter of 2017, compared to approximately 17.4% realized in 2016. The increase in the tax expense is primarily due to higher income before taxes in the fourth quarter of 2017.

Capital Investments

The decrease in transmission capital investments during the fourth quarter was primarily due to the following:

- lower volume and timing of spare transformer equipment purchases;
- timing and substantial completion of major development projects, including Guelph Area Transmission Refurbishment, Midtown Transmission Reinforcement, and Holland and Hawthorne transmission stations; and
- timing of work related to the Clarington Transmission Station project; partially offset by
- timing on work on station refurbishments and equipment replacement projects; and
- timing of work at Leamington transmission station.

The decrease in distribution capital investments during the fourth quarter was primarily due to the following:

- timing of capital contributions for jointly used facilities and lower volume of line relocation work;
- substantial completion of work on the Bolton Operation Centre in the fourth quarter of 2016;
- lower volume of work within distribution station refurbishment programs;
- timing of information technology projects including e-Billing and website redesign;
- lower volume of line refurbishments and replacements work; and
- lower volume of fleet and work equipment purchases; partially offset by
- high volume of work on new connections and upgrades due to increased demand.

Assets Placed In-Service

The increase in transmission assets placed in-service during the fourth quarter was primarily due to the following:

- substantial investments of major development projects at Leamington and Holland transmission stations were placed in-service in the fourth quarter of 2017;
- higher volume of investments for overhead lines and component refurbishments and replacement programs;
- timing of assets placed in-service for sustainment investment projects including the transformer asset replacement project at Overbrook transmission station and the breaker replacement project at Richview transmission station; partially offset by
- a large number of cumulative sustainment investments that were placed in-service in the fourth quarter of 2016 at the Bruce A and Burlington transmission stations;
- timing of investments that were placed in-service for the Advanced Distribution System project; and
- timing of assets that were placed in-service in the fourth quarter of 2016 for certain information technology development projects.

The decrease in distribution assets placed in-service during the fourth quarter was primarily due to the following:

- timing of distribution station refurbishments and spare transformer purchases; and
- lower volume of work on distribution generation connection projects; partially offset by
- higher volume of subdivision connections due to increased demand; and
- substantial investments that were placed in-service in the fourth quarter of 2017 for the Leamington transmission station feeder development project.

FORWARD-LOOKING STATEMENTS AND INFORMATION

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting decisions, rates and expected impacts and timing; the Company's liquidity and capital resources and operational requirements; the standby credit facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects and initiatives, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; the OEB; the Motion and the Appeal; the Anwaatin Motion; the East-West Tie Line Project and related regulatory application; collective agreements; Inergi outsourcing and customer service operations arrangements; the pension plan, future pension contributions, valuations and expected impacts; impacts of OEB treatment of pension and OPEBs costs; dividends; credit ratings; class action litigation; Hydro One's strategy and goals; effect of interest rates; non-GAAP measures; critical accounting estimates, including environmental liabilities, regulatory assets and liabilities, and employee future benefits; occupational rights; internal control over financial reporting and disclosure; the Fair Hydro Plan and First Nations Rate Assistance Program, including expected outcomes and impacts; recent accounting-related guidance; the Company's acquisitions and mergers, including Orillia Power; the appointment of Hydro One's new Chief Financial Officer; cyber and data security; expectations related to work force demographics; and reputational, public opinion and political risk. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's distribution and transmission businesses; continued use of US GAAP; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- risks associated with the Province's share ownership of Hydro One's parent corporation and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets located on reserves (as defined in the *Indian Act* (Canada));
- the risks associated with information system security and maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;

- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section "Risk Management and Risk Factors" in this MD&A.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future investments, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com, the US Securities and Exchange Commission's EDGAR website at www.sec.gov/edgar.shtml, and the Company's website at www.HydroOne.com/Investors.

UNDERTAKING – JT 1.9

Undertaking

To confirm whether the OPEB valuation shows the year end 2017 discount rate.

Response

The OPEB valuation filed as attachment to Exhibit I, Tab 40, Schedule Staff-215 reflected the December 2016 discount rate. However, the OPEB expense projections used to derive the 2018 forecast OPEB costs as noted in Exhibit I, Tab 40, Schedule Staff-215, part (a) were based on the December 2017 discount rate.

UNDERTAKING – JT 1.10

Undertaking

To advise the cost of re-running the Mercer Study and whether it's low enough to proceed.

Response

It will cost $3,000 to $4,000 to rerun the 2016 analysis to reflect the 2017 and 2018 Society base salary increase assumptions. As discussed at the Technical Conference, the 2016 study was conducted to with intention of comparing Hydro One’s total compensation positioning with a peer group. Focusing on base salary will only take into account a portion of the total compensation package. Accordingly, Hydro One does not believe that it is reasonable to re-run the Mercer Study.

Witness: MCDONELL Keith

UNDERTAKING – JT 1.11

Undertaking

To provide the statistical certainty level on the market median estimate.

Response

Hydro One asked Mercer to comment on the statistical certainty level of the market median estimate. Mercer's response is reproduced below.

> *An approach to assessing the certainty level in the data set is to determine the market percentile values at points above and below the median. This provides an indication of the spread and skewness in the data.*
>
> *On an aggregate basis (across all benchmark jobs), the 45th and 55th percentile total compensation values are -3% and +3% respectively in comparison to the market median (50th percentile). This suggests that the overall study result has a relatively low margin of error. We are confident in the findings of the Hydro One Study.*

UNDERTAKING – JT 1.12

Undertaking

The employee pension contributions have increased in 2017 and 2018, and Hydro One will estimate the impact on total pension contributions in those two years for those higher employee contributions.

Response

Since 2013, Hydro One has maintained a steady focus on the sustainability and affordability of Hydro One's defined benefit pension plan by gradually increasing employee contributions paid by the pre-2004 and post-2003 MCP groups. In 2017 and 2018, Hydro One's pension contributions for these two groups decreased by $1.4 million and $1.2 million respectively.

UNDERTAKING – JT 1.13

Undertaking

To explain how the non-capital loss carry forwards are factored into the test period PILS calculation.

Response

As explained in Exhibit I, Tab 3, Schedule Staff-12, Hydro One's 2015 non-capital loss carryforwards arose as a result of the additional tax deductions from the fair market revaluation as a consequence of the IPO and the departure from the PILs regime. For the same reasons as stated in Exhibit I, Tab 3, Schedule Staff-12, Hydro One incurred another $549 million of non-capital losses in 2016 and they were not factored into the test period tax calculations.

UNDERTAKING – JT 1.14

Undertaking

To outline or provide an analysis of significant transition issues for moving from a cash basis of recovery for pensions to an accrual basis.

Response

The most significant transition issue for moving from a cash basis to accrual basis is the recovery of the Pension Regulatory Asset, which represents the historical difference between accrual basis and cash basis costs. The Pension Regulatory Asset had a balance at December 31, 2017 of over $900 Million and would have to be recovered over a period of 10 to 15 years.

If pensions were to transition to the accrual basis, the new USGAAP guidance relating to Pension and OPEBs in Accounting Standards Update (ASU) 2017-07 that Hydro One previously noted as being applicable to OPEBs only would also be applicable to Pensions and Hydro One will book the non-service cost components of accrual basis Pension cost that are no longer eligible for capitalization in the deferral account requested in Exhibit F1, Tab 3, Schedule 1. Hydro One will update the requested account to OPEB & Pension Cost Deferral Account.

Alternatively, as per our response to the Society of Energy Professionals Interrogatory # 22 – Exhibit I, Tab 57, Schedule SEP-22 part C – the suggestion is made for the OEB to consider a regulatory accounting policy decision (similar to what was done by the FERC) to allow for the continued capitalization of ineligible Pension and OPEB costs (as defined by ASU-2017-07). Hydro One would be supportive of such a policy decision, which would eliminate the need for the requested deferral account.

UNDERTAKING – JT 1.15

Undertaking

With reference to Exhibit I, Tab 40, Staff IR 215, page 16 of the OPEB Valuation, (a) to reconcile the expense amounts and (b) to provide the quantum of the expense.

Response

The valuation provided as part Exhibit I, Tab 40, Staff -215, Attachment 1 was for the Post Retirement Benefits Plan (PRB).

OPEB expense amounts in Exhibit I, Tab 40, Schedule Staff-215:

	$ M
Total per Staff IR 215	**104**
PRB (Hydro One + Inergi)	87
PEB (ie LTD)	9
SPP	8
Total 2018 OPEB (ties to Staff IR 215)	**104**

Further details for PRB, PEB and SPP are provided below:

Hydro One Inc. Non-Pension Post Retirement Benefit - Hydro One + Inergi **(PRB)**
Projected 2017 to 2023 Accounting under US GAAP

Figures in $000s

		Projections 2018
D	**Components of Benefit Cost**	
	Employer service cost	40,122
	Interest cost	47,083
	Expected return on plan assets	-
	Net prior service (credit)/cost amortization	-
	Net (gains)/loss amortization	-
	Curtailments	-
	Settlements	-
	Special/contractual termination benefits	-
	Disclosed benefit cost	87,205

Hydro One Inc. Post Employment Benefits **(PEB)**
Projected 2017 to 2023 Accounting under US GAAP

Figures in $000s

		Projections 2018
D	**Components of Benefit Cost**	
	Employer service cost	6,737
	Interest cost	2,190
	Expected return on plan assets	-
	Net prior service (credit)/cost amortization	-
	Net (gains)/loss amortization	-
	Curtailments	-
	Settlements	-
	Special/contractual termination benefits	-
	Disclosed benefit cost	8,927

Hydro One Supplemental Plan **(SPP)**
Projected 2017 to 2023 Accounting Under US GAAP

Figures in $000s

		Projections 2018
D	**Components of Benefit cost**	
	Employer service cost	1,585
	Expected letter of credit fee	402
	Interest cost	4,303
	Expected return on plan assets	-
	Net prior service cost amortization	-
	Net loss/(gain) amortization	1,568
	Curtailments	-
	Settlements	-
	Special/contractual termination benefits	-
	Disclosed benefit cost	7,858

Reconciliation of Post Retirement Benefit Plans Valuation report as provided in Exhibit I, Tab 40, Staff -215, Attachment 1 to the updated expense expected for 2018:

page 16 of the OPEB Valuation for 2018	**$M**
PRB (Hydro One)	88.7
PRB (Inergi)	1.4
PRB (Hydro One + Inergi)	**90.1**
PRB (Hydro One + Inergi) per Staff IR 215	87.2
Decrease due to discount rate update	**2.9**

UNDERTAKING – JT 1.16

Undertaking

To provide the FERC guidelines referred to in Exhibit I, Tab 40, Staff IR 217.

Response

The FERC guidelines referred to in Exhibit I, Tab 40, Staff IR 217 are provided as an attachment. Please refer to item #2 "CAPITALIZAITON OF PENSION AND PBOP COSTS" on page 4 and 5 of the attachment.

Additionally, Hydro One notes that on page 132 of the transcript, Mr. Chhelavda was asked to confirm whether all of the $121.8 million credit is related to non-RPP customers or whether there is a split between RPP and non-RPP customers with respect to this credit.

Hydro One confirms the entire $121.8 million credit is related to non-RPP customers.

FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. AI18-1-000
December 28, 2017

TO ALL JURISDICTIONAL PUBLIC UTILITIES AND LICENSEES, NATURAL GAS COMPANIES, OIL PIPELINE COMPANIES AND CENTRALIZED SERVICE COMPANIES

Subject: Accounting and Financial Reporting for Pensions and Post-retirement Benefits other than Pensions

The Financial Accounting Standards Board (FASB) has issued Accounting Standards Update (ASU) No. 2017-07, *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost.* ASU No. 2017-07 amends FASB Accounting Standards Codification (ASC), Topic 715, *Compensation – Retirement Benefits*, to specify how the amount of pension costs and costs for post-retirement benefits other than pensions (PBOP) should be presented on the income statement under Generally Accepted Accounting Principles (GAAP), and what components of those costs are eligible for capitalization in assets. The Commission has received a number of inquiries from industry regarding clarification of whether and how to apply this ASU for purposes of regulatory accounting and reporting to the Commission. Accordingly, this accounting issuance is intended to provide clarity and certainty to industry on how they should apply the Commission's accounting and reporting requirements over pension and PBOP costs.

Pension and PBOP costs are made up of several components that reflect different aspects of an employer's financial arrangements as well as the cost of benefits earned by employees. Prior to this ASU, companies typically reported all of these components on an aggregate basis, without separating the various components on the financial statements. The amendments in this ASU require that an employer report the service cost component of pension and PBOP costs with other compensation costs arising from services rendered by employees during the period. Additionally, based on this ASU, these costs generally fall under a subtotal of income from operations for GAAP financial reporting. The other components of pension and PBOP costs are required to be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The amendments in this ASU also allow only the service cost component to be eligible for capitalization when all of the other normal criteria for capitalization under GAAP are met.

20171228-3003 FERC PDF (Unofficial) 12/28/2017

Based on the Commission's Uniform System of Accounts, Commission jurisdictional public utilities and licensees, natural gas companies, and centralized service companies recognize pension and PBOP costs in Account 926, Employee Pensions and Benefits,[1] while oil pipeline companies recognize pension and PBOP costs in Account 550, Employee Benefits,[2] if the pension and PBOP costs are not eligible for capitalization. The Commission's longstanding policy is to view these expenses as part of a single line item on the income statement in the Form No. 1, Form No. 1-F, Form No. 2, Form No. 2-A, Form No. 3-Q, Form No. 6, and Form No. 60 (collectively as FERC Forms), and that pension and PBOP costs in their entirety are attributable to the calculation of Net Utility Operating Income on the FERC Forms. The pension and PBOP expenses are recorded to the respective jurisdictional account without separation of the various components making up the pension and PBOP costs.

Regarding capitalization of pension and PBOP costs when the costs are incurred as part of a capital project, the Uniform System of Accounts does not specify whether capitalization of pension and PBOP costs should include or exclude the non-service cost components that make up the pension and PBOP costs. The instructions to Account 926 under the Uniform System of Accounts prescribed for public utilities and licensees, natural gas companies, and centralized service companies state that there shall be credited to this account the portion of pensions and benefits expenses which is charged to construction, and that records in support of this account shall be so kept that the amounts of pensions and benefits expenses transferred to construction or other accounts will be readily available. In practice, companies generally have capitalized both the service cost component and non-service cost components of the pension and PBOP costs in the past, as long as the capitalization of those costs were in compliance with Electric Plant Instruction No. 4, Gas Plant Instruction No. 4, or Service Company Property Instruction No. 367.52, of the Uniform System of Accounts. The instructions for Account 550 under the Uniform System of Accounts prescribed for oil pipeline companies similarly do not discuss service or non-service components of pension and PBOP costs to be transferred to construction.

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[1] *See* 18 C.F.R. Part 101, *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act*; 18 C.F.R. Part 201, *Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act*; and 18 C.F.R. Part 367, *Uniform System of Accounts for Centralized Service Companies Subject to the Provisions of the Public Utility Holding Company Act of 2005*.

[2] *See* 18 C.F.R. Part 352, *Uniform System of Accounts Prescribed for the Oil Pipeline Companies Subject to the Provisions of the Interstate Commerce Act*.

The focus of the Commission's accounting regulations is to ensure that the Commission and other stakeholders have available to them financial information about jurisdictional entities that is useful for the development and monitoring of rates. The uniform application of the Commission's accounting regulations is essential in providing comparability and decision-useful information to the Commission and stakeholders to reach informed rate decisions and conclusions. Accordingly, the objective of this guidance is to provide clarification as to how all jurisdictional entities should account for and report pension and PBOP costs, in response to ASU No. 2017-07.

The guidance is being provided to all jurisdictional entities to ensure proper and consistent application of the Commission's accounting requirements over pension and PBOP costs in response to ASU No. 2017-07 for Commission financial reporting purposes. This guidance is for Commission accounting and reporting purposes only and is without prejudice to the ratemaking practice or treatment that should be afforded the items addressed herein.

1. ACCOUNTING FOR PENSION AND PBOP COSTS ON THE INCOME STATEMENT

Question: How should jurisdictional entities account for pension and PBOP costs on the income statement for Commission accounting and reporting purposes?

Response: Jurisdictional public utilities and licensees, natural gas companies, and centralized service companies should record pension and PBOP costs in their entirety in Account 926, while oil pipeline companies should record pension and PBOP costs in their entirety in Account 550, provided the costs are not transferred to construction.

Pension and PBOP costs are made up of several components: service cost, interest cost, actual return on plan assets, gain or loss, amortization of prior service cost or credit, and amortization of any transition asset or obligation existing at the date of initial application of ASC Subtopic 715-30. Though pension and PBOP costs are computed using the aggregate total of these various components, the Commission's longstanding policy is to consider the amount as a singular cost to the employer. This cost is calculated based on Statement of Financial Accounting Standards (SFAS) No. 106[3] and reported as an accrued expense under net income from continuing operations.

[3] SFAS No. 106 was superseded for GAAP reporting purposes by ASC Topic 715 in 2009 when FASB codified all of the former accounting statements into ASC topics, but the calculations under both SFAS No. 106 and ASC 715 to arrive at the pension and PBOP costs remained the same.

Accordingly, there is one account designated for pension and PBOP costs under each respective Uniform System of Accounts for public utilities and licensees, natural gas companies, centralized service, and oil pipeline companies. This accounting is consistent with the rate treatment of pension and PBOP costs to most jurisdictional entities with cost-of-service rates. While there are some varying rate schemes approved by the Commission and other regulatory bodies to calculate recoverable pension and PBOP costs in cost-of-service rates, the Commission has determined that a uniform requirement for how jurisdictional entities should account for and report pension and PBOP costs are most conducive to promoting comparability and decision-usefulness of the information.[4] As such, we will continue to require all jurisdictional entities to recognize pension and PBOP costs on the income statement, in its entirety without disaggregation of its various components, in the currently existing account designated for pension and PBOP costs under each respective Uniform System of Accounts.

2. CAPITALIZATION OF PENSION AND PBOP COSTS

Question: Is it appropriate for jurisdictional entities to capitalize pension and PBOP costs using the method prescribed under ASU No. 2017-07?

Response: Provided that the pension and PBOP costs are based on appropriate labor costs and have a definite relation to construction as required under Electric Plant Instruction No. 4, Gas Plant Instruction No. 4, and Service Company Property Instruction No. 367.52, jurisdictional entities may continue to capitalize the service cost component and non-service cost components of pension and PBOP costs as it has traditionally been the widely accepted practice, or they may elect to capitalize only the service cost component of pension and PBOP costs, as prescribed by ASU No. 2017-07. Both methods are appropriate and are not precluded by the Commission's accounting requirements.

The Commission's Uniform System of Accounts prescribed for public utilities and licensees, natural gas companies, and centralized service companies do not require any specific method to determine the components of pension and PBOP costs to be included or excluded from capitalization, as long as the capitalization is based on labor costs and have a definite relation to construction. The instructions to Account 926 only requires that records in support of this account shall be so kept that the amounts of pensions and benefits expenses transferred to construction or other accounts will be readily available. Additionally, Electric Plant Instruction No. 4, Gas Plant Instruction No. 4, and Service

[4] *See* California Independent System Operator Corporation, 126 FERC ¶ 61,263 (2009), *order on reh'g*.

Company Property Instruction No. 367.52 require overhead costs allocated to construction and capitalized to have a definite relation to the construction, either based on direct charges using employee time tracking or special studies. The Uniform System of Accounts prescribed for oil pipeline companies similarly do not discuss the service or non-service components of pension and PBOP costs to be included or excluded from capitalization.

Because there is no definitive requirement under the Uniform Systems of Accounts requiring specific identification of pension and PBOP cost components to be capitalized, outside of the requirement for the capitalization to be based on appropriate labor costs and to have a definite relation to construction, jurisdictional entities may elect to follow the capitalization required under ASU No. 2017-07. It is also acceptable to continue capitalizing all of the pension and PBOP costs, as companies have done so prior to the issuance of the ASU. Either approach will not conflict with the existing requirements under the Uniform System of Accounts, provided that the method of capitalization adheres to Electric Plant Instruction No. 4, Gas Plant Instruction No. 4, and Service Company Property Instruction No. 367.52.

Question: How should jurisdictional entities account for deferred income taxes related to property, plant, and equipment which include capitalized pension and PBOP costs, if those amounts of pension and PBOP costs capitalized for regulatory accounting and reporting to the Commission differ from the amounts capitalized for GAAP reporting purposes?

Response: Jurisdictional entities must account for and report deferred income taxes to the Commission based on the temporary differences between the basis of assets reported to the Internal Revenue Service (IRS) and the basis of assets reported to the Commission. Similarly, the amount of deferred income tax reversals in subsequent periods must be based on the difference between the revenues and expenses used for reporting to the IRS and the revenues and expenses recognized for reporting to the Commission. Balances used in GAAP reporting should not be a factor in determining the deferred income tax balances reported to the Commission. Jurisdictional entities must be able to reconcile deferred income tax balances reported on the financial statements filed with the Commission with the respective asset and liability balances on those same set of financial statements.

3. DISCLOSURES AND FUTURE FILINGS TO THE COMMISSION

Question: What are the required disclosures or filings to the Commission related to changes made to a jurisdictional entity's accounting practice in response to ASU No. 2017-07?

Response: Jurisdictional entities should disclose any changes in accounting practice in response to ASU No. 2017-7 in their respective FERC Forms filed to the Commission quarterly and annually, within the Notes to the Financial Statements. Disclosures should include potential rate impacts resulting from these changes, including the effects on rate base and current period expenses. Jurisdictional entities should also make similar disclosures on future rate filings, as applicable.

Question: What are the required procedures for jurisdictional entities that want to change its capitalization policy over pension and PBOP costs after the 2018 reporting period?

Response: While either approach to capitalization of pension and PBOP costs as discussed herein is acceptable, there is a risk that the approach elected by companies will change from one period to the next in order to influence rate outcomes. Accordingly, jurisdictional entities are required to be consistent in all future periods using the capitalization approach elected after effectuation of ASU No. 2017-07 or during the 2018 reporting period. They must write in to the Commission for approval if there is any change of capitalization policy for pension and PBOP costs in the future.

20171228-3003 FERC PDF (Unofficial) 12/28/2017

The Commission delegated authority to act on this matter to the Director of the Office of Enforcement or his designee under 18 C.F.R. § 375.311 (2017). The Director has designated this authority to the Chief Accountant. This letter constitutes final agency action. Your company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2017).

Sincerely,

Bryan K. Craig
Chief Accountant and Director
Division of Audits and Accounting
Office of Enforcement

Document Content(s)

UNDERTAKING – JT 1.17-1

Reference

Exhibit I, Tab 7, Schedule CME-1, part (b)

Undertaking

a) Is it correct that Hydro One proposed to update the cost of capital for 2021 and 2022 for all of the Hydro One distribution assets and not just the distribution assets of the acquired utilities?

b) If the acquitted utilities had been included in the rate base of Hydro One beginning in 2018, would Hydro One still be seeking an update of the cost of capital parameters for 2021 and 2022?

Response

a) Correct. Hydro One is proposing to update the cost of capital for all assets in 2021 and 2022.

b) The need to fairly allocate costs between Hydro One's rate classes when assets of the acquired utilities are added to Hydro One's rate base is the main driver of Hydro One's proposal. That said, there are other valid reasons which would support a mid-term update to a utility's cost of capital parameters. The cost of capital is impacted by interest rates which are influenced by macroeconomic conditions. These are exogenous factors outside a utility's control and are not related to productivity, efficiency of operations or sound planning.

UNDERTAKING – JT 1.17-2

Reference

Exhibit I, Tab 9, Schedule CME-5

Undertaking

Please confirm that based on the response provided, that the capital factor will be set as part of this proceeding for 2019 and 2020 and then for 2021 and 2022, the capital factor will be updated based only on the changes that will be proposed for the short term and long term debt rates and the allowed return on equity, and that there will be change to the rate base or capital additions in 2021 and 2022 from that approved in this proceeding.

Response

Confirmed.

UNDERTAKING – JT 1.17-3

Reference

Exhibit I, Tab 44, Schedule CME-36

The evidence indicates that there is a $21.9 million difference in the depreciation expense in 2018 between using the existing depreciation rates and changing to the 2016 Foster Associates study. Part (c) of the question asked if this would result in rate base being more than $100 million higher by the end of 2022 under the Hydro One proposal to continue to use the existing rates rather than those recommended in the Foster Associates study. The response indicates that this would not be the case.

Undertaking

a) Is this response based on the $21.9 million figure in the evidence, or was it based on the updated information as provided in the response to part (a) of the response, which is based on the Exhibit Q updates?

b) If the response is based on the original evidence, please explain why rate base would not be more than $100 million higher at the end of 2022, given the lower depreciation of $21.9 million in 2018, and comparable reductions in 2019 through 2022.

c) If the response is based on the Exhibit Q updates, what is the approximate increase in rate base at the end of 2022?

Response

a) The response provided in Exhibit I, Tab 44, Schedule CME-36 was based upon the Exhibit Q updated information.

b) Not applicable.

c) The impact on rate base of maintaining the current depreciation rates is $81 million by the end of 2022.

UNDERTAKING – JT 1.17-4

Reference

Exhibit I, Tab 44, Schedule CME-38

In Exhibit Q, the depreciation expense for 2018 has increased by $4.5 million. The interrogatory response indicates that the increase is only related to depreciation and there is no impact on the asset removal costs or capitalized depreciation. The response to part (b) indicates that the in-service additions adjustment triggered a changed in fixed assets.

Undertaking

a) Please confirm that the in-service additions in 2018 were decreased in 2018 in Exhibit Q relative to the original forecast and, therefore, would lead to a reduction in 2018 depreciation expense.

b) Were there any changes in the in-service additions for 2017, and if so, what is the impact on the 2018 depreciation expense?

Response

a) Confirmed, the in-service additions in 2018 were decreased in Exhibit Q relative to the original forecast. Depreciation expense would be effected by the lower in-service but the primary reason which more than offset any reductions to depreciation expense was the updated common depreciation rates as approved by the OEB in EB-2016-0160.

b) No, there were no changes to the 2017 forecast.

UNDERTAKING – JT 1.17-5

Reference
Exhibit I, Tab 44, Schedule CME-38

At page 2 of Exhibit Q, Tab 1, Schedule 1, two drivers of the $4.5 million increase in the 2018 depreciation expense are noted: the reduction in the capital forecast and an update to the rates for general plant to align with the OEB's decision dated September 28, 2017 in the 2017-2018 transmission application (EB-2016-0160).

Undertaking
Please provide the breakdown between these two drivers, including the calculations that result in the net increase of $4.5 million in the 2018 depreciation expense.

Response
Please refer to the table below:

Depreciation Impact	2018
Common Study Depreciation Rate Update	4.5
Reduction in Capital Forecast	(0.0)
Total Depreciation Impact - Exhibit Q	4.5

UNDERTAKING – JT 1.17-6

Reference

Exhibit I, Tab 45, Schedule CME-67

The interrogatory deals with other revenues and requested that Table 3 in Exhibit E1, Tab 1, Schedule 2, Updated be updated with 2017 actuals. The response indicates that 2017 actual data is not yet available, but will be provided once it is available.

Undertaking

a) In addition to providing the actual 2017 data when it is available for Table 3, please also provide an updated Table 1 from Exhibit E1, Tab 1, Schedule 2.

b) For each line item in Tables 1 and 3, please indicate if there is a deferral or variance account that deals with any difference between the forecast and actuals over the forecast horizon.

Response

a) The tables will be updated once the 2017 audited actuals are available.

b) Hydro One does not have variance accounts for distribution external revenue.

UNDERTAKING – JT 1.17-7

Reference

Exhibit I, Tab 34, Schedule CME-48

This interrogatory explains the change since the last lead lag study with respect to the "not assigned" category. The Navigant report states that 6.9% of the customers do not have an assigned billing schedule (Exhibit D1-1-3, Attachment 1, page 7). The response to part (c) of the interrogatory refers to the 6.9% as being the percentage of revenues.

Undertaking

a) Is the 6.9% related to revenues or customers?

b) The response to part (b) has a figure of 5.8% for the not assigned category. Is this 5.8% of revenues or customers?

c) What is the difference between the 6.9% and the 5.8%?

Response

a) The 6.9% represents the not assigned category portion of revenue for the month of December.

b) Part (c) of Exhibit I, Tab 34, Schedule CME-48 references 5.8% which represents the not assigned category portion of revenue for the entire year.

c) The 6.9% is for the month of December whereas the 5.8% is for the entire year.

UNDERTAKING – JT 1.17-8

Reference
Exhibit I, Tab 34, Schedule CME-48

Table 3 in the response to part (a) appears to use a simple average of the three categories used to come up with the mid-point for the not-assigned category.

Undertaking
Please explain why a customer or revenue weighting was not used to calculate the mid-point for the not-assigned category.

Response
Since there is not sufficient data to determine the appropriate billing frequencies of the not assigned category, Navigant decided that it would be prudent to take the simple average of the calculated mid-point of the other categories.

UNDERTAKING – JT 1.17-9

Reference
Exhibit I, Tab 34, Schedule CME-50

The interrogatory deals with Tables 2 and 3 in the Navigant report. In particular, it deals with the impact of the Fair Hydro Act on the retail revenue lag.

The response to part (a) indicates that the retail revenue line would not change and that the only impact is that part of the retail revenue would shifts from the customer to a third party.

Undertaking

a) Who is that third party?

b) While the retail revenue line in Table 2 does not change, why wouldn't there be a different collections lag in Table 3 for the retail revenue that comes from the third party, since payment from the third party will not be identical to that from the distribution customers?

c) In part (b) of the response, it is indicated that based on 2017 data, about 5% of the retail revenues are funded through the IESO for the distribution rate protected residential customers and the delivery credit for on-reserve customers. What is the forecast of retail revenues for 2018?

d) Please confirm that the forecast for the DRP and First Nations credits is $253 million in 2018, which is more than the revenue funded through the RRRP (Exhibit I, Tab 51, Schedule CME-91)

e) Please confirm that based on the response to part (c) of the interrogatory, the DRP and First Nations credit is provided to Hydro One by the IESO through a credit on the cost of power invoice. If this cannot be confirmed, please explain.

f) Part (d) of the response says that the RRRP credit was previously funded by the IESO through its monthly invoice. Please explain the word "previously" and explain how the RRRP credit if funded now.

g) Part (g) of the interrogatory response states that the DRP and FNDC credits will only be reimbursed after they are applied to a customer's invoice which is based on the billing period for each individual customer. If a customer has a billing period that ends on February 15 (meter reading) and there is a 7 or 8 day billing lag, the invoice is created on or about February 22 or 23. That invoice will reflect a credit to the customer of some amount. When does that amount show up as a credit on the IESO invoice to Hydro One?

Response

a) The third party is the Independent Electricity System Operator (IESO).

b) In order to quantify the impacts on the lag days, a new study would have to be commissioned and sufficient actual data with fair hydro implemented would be required. This is not yet available. Also, it is difficult to estimate whether or not the decreased bills as a result of the lower cost of power would affect the lead/lag days significantly.

c) The best estimate for retail revenue forecast for 2018, based on information currently provided in this application would be the sum of Rates Revenue Requirement for 2018 of $1,463.8 million provided in Exhibit I, Tab 33, Schedule Staff-179 and the updated cost of power of $2,994 million provided in Exhibit JT1.17B-13 for 2018.

d) Confirmed that in part (c) of Exhibit I, Tab 51, Schedule CME-91, the sum of R1 and R2 rate classes' revenue funded through DRP or FNDC is greater than the $238.4M identified in the same table for revenue funded by RRRP.

e) Confirmed. However, the IESO reimburses Hydro One only after the eligible customers have been credited on their invoices. This will ultimately result in larger lag and would increase working capital. This was not captured in the fair hydro plan impact updates for any working capital calculations.

f) Previously the process was that the IESO provided the fixed RRRP amount in which Hydro One would credit eligible customers. This essentially means the IESO was funding the program. Going forward, the RRRP credit is no longer funded upfront through the IESO but instead, the amount credited to eligible customers and then settled through the IESO afterwards. This will result in a larger lag and would increase working capital. This was not captured in the fair hydro plan impact updates for any working capital calculations.

g) The reimbursement for this particular example for the DRP and FNDC credit would appear on the March IESO invoice. This invoice would be received on the tenth business day of the month.

UNDERTAKING – JT1.17-10

Reference

Exhibit I, Tab 33, Schedule Staff-176

In the response to part (b), the estimated reduction in the working capital requirement in 2017 is estimated to be about $24 million, which is related to a reduction in the cost of power, largely a result of a decrease to the global adjustment rate.

Undertaking

a) How is the DRP and FNDC related to the decrease to the global adjustment rate?

b) The response then goes on to say that the Navigant study was utilized to estimate the $24 million reduction, but the response does not explain how the amount was calculated or what information from the Navigant study was utilized. Please show how the $24 million figure was derived.

Response

a) The DRP and FNDC are credits applied to eligible customer bills, and are unrelated to the cost of power and therefore do not decrease the global adjustment rate.

b) The estimated cost of power reduction as a result of the fair hydro plan was calculated based on the letter from the Ministry of Energy to the OEB dated April 10, 2017. This letter provides an estimated impact to global adjustment by $17.28/MWh. This cost of power adjustment was estimated to be approximately $354M in 2017. The Navigant study results were then applied to this adjustment which yielded the following results provided in the table below:

Description	Working Capital Factor	Expenses	Working Capital Requirement
A	**B**	**C**	**D = (B X C)**
Cost of Power	5.2%	$354M	$18.4M
HST	12.7%	$46M	$5.8M
Total Impact			**$24.2M**

UNDERTAKING – JT1.17-11

Reference

Exhibit I, Tab 33, Schedule Staff-178

The updated evidence in Exhibit D1, Tab 1, Schedule 1, Table 2 shows the 2018 cash working capital to be $321.2 million along with figure for 2019 through 2022.

Exhibit Q, Tab 1, Schedule 1, Table 7 has the same figure for 2018 and the subsequent years as in the original evidence.

Undertaking

a) Why did the cash working capital not decrease when the OM&A forecast for 2018 decreased by $5.1 million?

b) The response found at Exhibit I, Tab 33, Schedule Staff-178, page 6, there is a new set of numbers for 2018 through 2022 for the cash working capital. In 2018 the figure is $281.0 million, a reduction of $40.2 million. Please confirm that based on the heading in the table this reduction is related solely to the Fair Hydro plan. If this cannot be confirmed, please explain.

c) Please confirm that the impact of the reduction in OM&A on the cash working capital would be in addition to the $40.2 million reduction? If not, please explain fully.

Response

a) The working capital was not updated as part of Exhibit Q as the impact to revenue requirement is immaterial. The $5.1 million decrease in OM&A would impact 2018 cash working capital by less than $375 thousand which would impact revenue requirement by approximately $28 thousand.

b) Confirmed.

c) The reduction in OM&A would be in addition to the $40.2M in 2018. Please refer to part a) as the impact is immaterial to the overall revenue requirement.

Witness: JODOIN Joel

UNDERTAKING – JT1.17-12

Reference

Exhibit I, Tab 3, Schedule CME-65

In the revenue requirement workform provided in the response to Exhibit 1, Tab 3, Schedule CME-65 in the rate base and working capital sheet, the reduction in the allowance for working capital of about $40 million is the result of a reduction in $8 million in controllable expenses and a reduction of $584 million in the cost of power.

Undertaking

a) How does the $577 million in updated controllable expenses in the spreadsheet relate to the $579.6 million in OM&A costs shown in Table 1 in Exhibit Q, Tab 1, Schedule 1? (original figures were $585 in spreadsheet and $584.8 in Table 1, which match)

b) Is the reduction in the cost of power of $584 million shown in the spreadsheet related solely to the Fair Hydro plan? How does it relate to the $253 million provided in Exhibit I, Tab 51, Schedule CME-91?

Response

a) The response in Exhibit I, Tab 33, Schedule Staff-179 indicates that Exhibit Q OM&A figure of $579.6 million was further reduced by $2.9 million as a result of a reduction in bad debt expense related to fair hydro plan impact. Final OM&A figure is $576.7 million. Please note that the spreadsheet is showing the figures rounded to the nearest million.

b) Confirmed, the $584 million is related to the Fair Hydro Plan. There is no correlation to the $253 million this figure refers to the total amount of Hydro One’s distribution tariff revenue that is funded through government subsidies under the Fair Hydro Plan. These amounts are separate from cost of power.

UNDERTAKING – JT1.17-13

Reference

Exhibit I, Tab 34, Schedule CME-61

In the response to part (b) in Exhibit I, Tab 34, Schedule CME-61, the cost of power flow through is shown for 2018 through 2022.

Undertaking

Please update these tables to reflect the impact of the Fair Hydro plan and provide an explanation for any differences from that filed in the interrogatory response.

Response

The updated wholesale cost of power tables provided which reflect the impact of the Fair Hydro Plan. The changes include a lower global adjustment rate, a lower RPP rate, an updated wholesale market service charge rate, and an updated RRRP rate. In addition, a new global adjustment modifier credit was added and the OESP funding adder was removed.

Cost of Power Flow Through Dollars in $M	**2018**	**2019**	**2020**	**2021**	**2022**
RPP Customers Commodity	1,553	1,630	1,725	1,821	1,926
Non-RPP Customers Commodity	267	278	291	305	321
Global Adjustment	705	743	788	834	885
Global Adjustment Modifier	(79)	(78)	(78)	(78)	(78)
WMSC (Incl RRRP)	97	96	96	96	96
Tx Network	239	261	273	288	306
Tx Line Connection	53	58	61	64	68
Tx Transf Connection	147	160	167	176	187
OESP	-	-	-	-	-
SME Charge	12	12	12	12	12
	2,994	**3,159**	**3,336**	**3,520**	**3,723**

Cost of Power Flow Through Rates		2018	2019	2020	2021	2022
RPP Commodity	c/kWh	10.10	10.70	11.33	11.99	12.69
Non- RPP Commodity	c/kWh	3.21	3.37	3.55	3.73	3.91
Global Adjustment	c/kWh	7.33	7.79	8.27	8.78	9.31
Global Adjustment Modifier	c/kWh	(3.29)	(3.29)	(3.29)	(3.29)	(3.29)
WMSC	c/kWh	0.36	0.36	0.36	0.36	0.36
RRRP Funding Adder	c/kWh	0.03	0.03	0.03	0.03	0.03
Tx Network	$/kW	3.79	4.17	4.37	4.62	4.91
Tx Line Connection	$/kW	0.96	1.06	1.11	1.17	1.24
Tx Transformation Connection	$/kW	2.29	2.52	2.64	2.79	2.97
OESP Funding Adder	c/kWh	-	-	-	-	-

Summary of Demand and Consumption		2018	2019	2020	2021	2022
Total Wholesale Volume	GWh	24,987	24,763	24,750	24,682	24,679
Tx Network	MW	63,166	62,568	62,557	62,388	62,219
Tx Line Connection	MW	55,639	55,114	55,107	54,958	54,809
Tx Transformation Connection	MW	63,977	63,372	63,363	63,191	63,108
Global Adjustment Modifier Eligible Volume	GWh	2,405	2,383	2,382	2,376	2,375

UNDERTAKING – JT1.17-14

Reference

Exhibit I, Tab 34, Schedule CME-51

The response indicates that the Navigant report was incorrect in saying that the Inergi payments occur at the end of the month when it now takes place in the middle of the month.

Undertaking

a) Please confirm that this is correct and that the Inergi payments are made in the middle of the month.

b) Why was there a change in the timing of the Inergi payment, accelerating the payment from the end of the month to the middle of the month?

Response

a) Confirmed, Inergi payments based on this new data set are observed to be made closer to the middle of the month.

b) The mix of services provided by Inergi has changed when compared to the prior study. The types of work provided such as base, variable (ad-hoc), and project work have different payment timings depending on when the invoices are issued. Therefore, within this study the middle of the month was most representative of the actual cash outflows observed from the data.

UNDERTAKING – JT1.17-15

Reference

Exhibit I, Tab 34, Schedule CME-55

Undertaking

a) Does Hydro One pay interest on its long term debt instruments semi-annually?

b) Based on the interest table shown in the response to part (a), is it correct that interest is paid in advance of the end of the period? For example, on the first line, Hydro One paid $4.176 million on January 9 and another $4.176 million on July 10. Were both of these payments related to the amount outstanding on the loan for 2014 only? What is the issue date of this particular long debt instrument?

c) The PILS table in part (b) shows equal monthly payments. Why is there no true-up to reflect the actual PILS paid for 2014?

d) Is there any change in moving from the PILS regime to the standard corporate income tax on the timing or amounts of payments made? If yes, please explain fully.

Response

a) Yes, Hydro One makes coupon payments twice a year for its long-term debt issuances.

b) Confirmed. Yes, both payments were made in 2014 for the associated debt outstanding within 2014. The issuance date for this particular example was in 2012.

c) There were no material true-up payments within the 2014 period. The forecasted amount occurs at the beginning of the year and the payment instalments are made equally throughout. Material true-up payments do not normally occur except for when unforeseen tax/accounting changes occur. Therefore, the forecasted payments aligned with the actual yearend tax instalments which resulted in no true-up payments within the 2014 period.

d) No, the timing of instalments and the method of calculation of the amount are similar under both the PILS regime and the standard corporate income tax regime.

UNDERTAKING – JT1.17-16

Reference

Exhibit I, Tab 34, Schedule CME-58

This interrogatory dealt with the HST calculations shown in Table 8 in the Navigant study and the response indicates that there would be too much time and effort required within the time allowed and on the immateriality of the impact on the revenue requirement to provide the requested information.

The cost of power component of the HST shown in Table 8 represents rate base amounts ranging from $59 million to $71 million, and is larger than the total net HST included in the working capital amounts.

Undertaking

a) Please provide the data, assumptions and calculations used to determine the HST lead time for the cost of power only of 46.42 days.

b) Is there any impact on the HST calculations of the fair hydro plan? For example, is there a reduction in the HST due to the reduction in cost of power? Please explain fully.

Response

a) Please see the table below which outlines the HST lead time for cost of power.

Month	Period Beginning	Period Ending	Invoice Date	Payment Amount	Payment Date	Service Lead Time Days	Payment Lead Time Days	Total Lead Time Days	Weighting Factor	Weighted Lead Time	HST Collection Date	HST Lead Time Days
A	B	C	D	E	F	G	H	I	J	K	L	M
Jan-14	1/1/2014	1/31/2014	2/14/2014	$ 237,809,410	2/19/2014	15.50	19.00	34.50	11.16%	3.85	3/31/2014	45.00
Feb-14	2/1/2014	2/28/2014	3/14/2014	$ 250,840,722	3/18/2014	14.00	18.00	32.00	11.77%	3.77	4/30/2014	47.00
Mar-14	3/1/2014	3/31/2014	4/14/2014	$ 176,674,165	4/16/2014	15.50	16.00	31.50	8.29%	2.61	5/31/2014	47.00
Apr-14	4/1/2014	4/30/2014	5/14/2014	$ 230,907,902	5/16/2014	15.00	16.00	31.00	10.84%	3.36	6/30/2014	47.00
May-14	5/1/2014	5/31/2014	6/13/2014	$ 129,025,680	6/17/2014	15.50	17.00	32.50	6.06%	1.97	7/31/2014	48.00
Jun-14	6/1/2014	6/30/2014	7/15/2014	$ 126,096,435	7/17/2014	15.00	17.00	32.00	5.92%	1.89	8/31/2014	47.00
Jul-14	7/1/2014	7/31/2014	8/15/2014	$ 130,904,300	8/19/2014	15.50	19.00	34.50	6.14%	2.12	9/30/2014	46.00
Aug-14	8/1/2014	8/31/2014	9/15/2014	$ 138,049,814	9/17/2014	15.50	17.00	32.50	6.48%	2.11	10/31/2014	46.00
Sep-14	9/1/2014	9/30/2014	10/15/2014	$ 137,086,796	10/17/2014	15.00	17.00	32.00	6.43%	2.06	11/30/2014	46.00
Oct-14	10/1/2014	10/31/2014	11/17/2014	$ 163,262,017	11/19/2014	15.50	19.00	34.50	7.66%	2.64	12/31/2014	44.00
Nov-14	11/1/2014	11/30/2014	12/12/2014	$ 178,819,112	12/16/2014	15.00	16.00	31.00	8.39%	2.60	1/31/2015	50.00
Dec-14	12/1/2014	12/31/2014	1/15/2015	$ 231,246,379	1/19/2015	15.50	19.00	34.50	10.85%	3.74	2/28/2015	44.00
				$ 2,130,722,731					100.00%	32.72		46.42

b) Yes, the HST payments would be impacted as a result of lower cost of power. This is seen in the undertaking JT 1.17B-10 which illustrates the lower HST. However, since the HST collection dates do not change, there will be no effect to the HST lead days.

UNDERTAKING – JT1.17-17

Reference

Ref: Exhibit I, Tab 34, Schedule CME-59

The response appears to indicate that the working capital percentage calculated in Tables 9 through 13 of the Navigant report are outputs and are not used as inputs into the calculation of the cash working capital amounts included in rate base.

Undertaking

a) Please confirm that the cash working capital figures used by Hydro One in the calculation of rate base are the dollar figures taken from each of the five tables (9 through 13) in the Navigant study and the total cash working capital percentages are not used in the calculations. If this is not correct, please explain fully.

Response

a) Confirmed, the percentages are for illustrative purposes only.

UNDERTAKING – JT1.17-18

Reference

Exhibit I, Tab 3, Schedule CME-65

The rate base and working capital sheet in the revenue requirement workform provided in the response to the above noted interrogatory shows an increase in the working capital rate from 7.81% to 7.99%.

Undertaking

a) Please explain the increase in the working capital rate.

b) Please explain why these figures are different from the 7.70% that was derived for 2018 in Table 9 of the Navigant study?

Response

a) The change in working capital % in the workform from 7.8% in the initial application to 8.0% in the application update is due to the mathematical calculation in which the denominator decreases significantly as a result of the cost of power adjustment. The newly calculated cash working capital amount based on Navigant methodology decreases by $40 million.

To illustrate the differences, please refer to the table below which outlines the dollar amounts and its percentage out of the working capital base (Cost of Power and controllable expenses).

2018	Initial Application	Application Update for Fair Hydro Plan
Working Capital Base (COP and controllable expenses) from Revenue Requirement worform	$4,163	$3,571
Navigant Cash Working Capital (A)	$321.2 [1]	$281.0 [2]
Materials and Supply Inventory (B)	$4.1	$4.1
Total Working Capital (A+B)	$325.3	$285.1
Total Working Capital Percent of Base in the Revenue Requirement workform	7.8%	8.0%

[1] Initial Application cash working capital is calculated in Exhibit D1, Tab 1, Schedule 3, Attachment 1, table 9
[2] Application Update for Fair Hydro Plan cash working capital is calculated in Exhibit JT1.17B-19

b) The working capital rate within the revenue requirement workform includes the materials and supply inventory amount which is included in the total working capital amount together with Navigant calculated cash working capital when deriving the percentage of total OM&A and Cost of Power. Therefore, when comparing the initial application amount to the Navigant study there would be no change from the rate calculated if it were on the same basis. Please refer to part a) for the full calculation.

UNDERTAKING – JT1.17-19

Reference

Exhibit I, Tab 33, Schedule Staff-178

It does not appear that there is any information on the record to support the updated cash working capital figures that take into account the Fair Hydro plan as shown in the response to Exhibit I, Tab 33, Schedule Staff-178.

Undertaking

a) Please confirm that the figures shown in the interrogatory response come from an updated calculation based on the Navigant study. If this cannot be confirmed, please explain fully how the numbers have been derived.

b) Please update Tables 9 through 13 in the Navigant study that result in the figures shown in the staff interrogatory, as well as Table 8 (summary of HST) if there are changes in the HST amounts resulting from the Fair Hydro plan.

c) For each of the tables, please explain any changes in the lead or lag days or in the level of the expense to which the working capital factor is applied.

Response

a) Confirmed. Please see Exhibit JT 1.17B-10.

b) Please see the updated working capital requirement tables which reflect the fair hydro plan impact to cost of power for 2018-2022 below:

HONI Distribution Working Capital requirements (2018) – Fair Hydro Plan Update

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirement ($M)
A	B	C	D	E	F	G
Cost of Power	51.82	32.72	19.10	5%	$2,994.02	$156.65
OM&A Expenses	51.82	25.13	26.69	7%	$591.94	$43.28
PILS	51.82	13.67	38.16	10%	$58.01	$6.06
Interest Expense	51.82	-1.93	53.75	15%	$185.55	$27.33
Environmental Remediation	51.82	16.97	34.85	10%	$13.20	$1.26
Removals	51.82	24.39	27.43	8%	$58.65	$4.41
Total					$3,901.37	$238.99
HST						$42.00
Total - Including HST						$280.99
Working Capital as % of OM&A incl COP						7.84%

HONI Distribution Working Capital requirements (2019) – Fair Hydro Plan Update

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirement ($M)
A	B	C	D	E	F	G
Cost of Power	51.82	32.72	19.10	5%	$3,158.99	$165.28
OM&A Expenses	51.82	25.13	26.69	7%	$599.64	$43.85
PILS	51.82	13.67	38.16	10%	$61.33	$6.41
Interest Expense	51.82	-1.93	53.75	15%	$194.66	$28.67
Environmental Remediation	51.82	16.97	34.85	10%	$13.49	$1.29
Removals	51.82	24.39	27.43	8%	$69.52	$5.22
Total					$4,097.63	$250.72
HST						$45.11
Total - Including HST						$295.82
Working Capital as % of OM&A incl COP						7.87%

HONI Distribution Working Capital requirements (2020) – Fair Hydro Plan Update

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirement ($M)
A	B	C	D	E	F	G
Cost of Power	51.82	32.72	19.10	5%	$3,336.34	$174.08
OM&A Expenses	51.82	25.13	26.69	7%	$607.43	$44.29
PILS	51.82	13.67	38.16	10%	$62.60	$6.53
Interest Expense	51.82	-1.93	53.75	15%	$205.01	$30.11
Environmental Remediation	51.82	16.97	34.85	10%	$13.80	$1.31
Removals	51.82	24.39	27.43	8%	$70.06	$5.25
Total					$4,295.24	$261.58
HST						$46.93
Total - Including HST						$308.50
Working Capital as % of OM&A incl COP						7.82%

HONI Distribution Working Capital requirements (2021) – Fair Hydro Plan Update

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirement ($M)
A	B	C	D	E	F	G
Cost of Power	51.82	32.72	19.10	5%	$3,519.64	$184.15
OM&A Expenses	51.82	25.13	26.69	7%	$615.33	$44.99
PILS	51.82	13.67	38.16	10%	$68.17	$7.13
Interest Expense	51.82	-1.93	53.75	15%	$214.44	$31.58
Environmental Remediation	51.82	16.97	34.85	10%	$14.11	$1.35
Removals	51.82	24.39	27.43	8%	$69.22	$5.20
Total					$4,500.90	$274.40
HST						$49.49
Total - Including HST						$323.89
Working Capital as % of OM&A incl COP						7.83%

HONI Distribution Working Capital requirements (2022) – Fair Hydro Plan Update

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirement ($M)
A	B	C	D	E	F	G
Cost of Power	51.82	32.72	19.10	5%	$3,722.92	$194.79
OM&A Expenses	51.82	25.13	26.69	7%	$623.33	$45.58
PILS	51.82	13.67	38.16	10%	$68.96	$7.21
Interest Expense	51.82	-1.93	53.75	15%	$223.96	$32.98
Environmental Remediation	51.82	16.97	34.85	10%	$14.42	$1.38
Removals	51.82	24.39	27.43	8%	$70.07	$5.27
Total					$4,723.67	$287.20
HST						$52.79
Total - Including HST						$339.99
Working Capital as % of OM&A incl COP						7.82%

HONI Distribution Summary of HST Working Capital Amounts – Fair Hydro Plan Update

Description	HST Lead Time	Working Capital Factor	2018	2019	2020	2021	2022
A	B	C	D	E	F	G	H
Revenues	-8.97	-2.46%	(16.24)	(16.92)	(17.59)	(18.39)	(19.19)
Cost of Power	46.42	12.72%	49.50	52.22	55.01	58.19	61.55
OM&A Expenses	43.31	11.87%	3.42	3.46	3.50	3.55	3.60
Removals	41.76	11.44%	0.10	0.12	0.12	0.12	0.12
Environmental Remediation	41.76	11.44%	0.07	0.07	0.08	0.08	0.08
Capital	41.76	11.44%	5.15	6.15	5.82	5.94	6.64
Total			**42.00**	**45.11**	**46.93**	**49.49**	**52.79**

c) Please see Exhibit JT 1.17B-9, part b).

Witness: JODOIN Joel

UNDERTAKING – JT 1.19

Undertaking

To point out the derivation of the numbers from the Black & Veach study and the breakdown; to explain how that may be the same or different from the calculation in attachment 6 to C1 to 10.

Response

The purpose of this undertaking is to reconcile (a) the application of the Labour Content Method in Hydro One's compensation evidence on page 7 of Attachment 6 to Exhibit C1, Tab 2, Schedule 1, with (b) Exhibit I-40-SEC-083.

This response provides a step-by-step explanation of the allocation of the dollar difference between the weighted average total compensation for Hydro One's employees allocated to its distribution business and the P50 median used in the Mercer compensation study.

1. In Exhibit I-40-SEC-083, Hydro One first obtained the total dollar amount above market median from Mercer.

2. Subsequently, Hydro One applied the Labour Content Method to allocate this figure to Hydro One Transmission OM&A, Hydro One Transmission capital, Hydro One Distribution OM&A and Hydro One Distribution capital (TDOC). The labour splits detailed in Table 1 are consistent with those used in the Labour Content Method for the Black & Veatch report "Review of Overhead Capitalization Rates" (provided as Attachment 1 to Exhibit D1, Tab 3, Schedule 1).

Table 1: Labour Splits

	2016	**2017**	**2018**	**Row Reference**
Tx OM&A (%)	12.3%	17.6%	16.4%	A
Dx OM&A (%)	27.4%	26.0%	24.7%	B
Tx Capital (%)	32.6%	31.0%	30.3%	C
Dx Capital (%)	27.7%	25.3%	28.6%	D

In completing this response, Hydro One found an error in the "Total OM&A Distribution Comp" and "Total Capital Distribution Comp" figures provided on page 7 of Attachment 6 to Exhibit C1, Tab 2, Schedule 1. They were calculated incorrectly using the transmission labour splits, instead of the distribution labour splits set out in

Table 1. Note that the total "Distribution Compensation" figures remain unchanged. The corrected distribution OM&A and capital figures are provided below in Table 2.

Table 2: Corrected Allocation of Dx Compensation to OM&A and Capital

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Total Capital Dx Comp	169,193,807	330,855,675	321,004,661	299,243,081	342,404,569	347,815,408	333,225,316	324,634,686	327,669,257
Total OM&A Dx Comp	459,493,279	294,441,835	317,999,965	307,505,404	295,373,937	294,715,310	298,050,034	291,614,056	294,339,962
Total Dx Compensation	**628,687,087**	**625,297,510**	**639,004,626**	**606,748,484**	**637,778,506**	**642,530,718**	**631,275,350**	**616,248,742**	**622,009,219**

a) In deriving total compensation in the tables filed in evidence, figures are first allocated to Hydro One Transmission and Hydro One Distribution. The allocation employs two methodologies: (a) the Black & Veatch methodology for all regular employees and (b) the application of management expertise for casual employees. This is outlined in Exhibit C1, Tab 2, Schedule 1, Attachment 7, Page 4, Table 1. The allocation of casual employees to Hydro One Transmission and Hydro One Distribution does not reconcile with the Black & Veatch TDOC splits provided in Table 1 of this Exhibit. As a result, a direct reconciliation between Exhibit I-40-SEC-083 and Table 2 of this Exhibit is not possible.

b) Once the allocations to Hydro One Transmission and Hydro One Distribution are complete, amounts are further allocated to OM&A and capital following the Labour Content Method precisely. The supporting calculations are provided in Table 3.

Table 3: Reconciling Table 1 & Table 2

	2016	**2017**	**2018**	**Row Reference**
Dx OM&A (%)	27.4%	26.0%	24.7%	B (table 1)
Dx Capital (%)	27.7%	25.3%	28.6%	D (table 1)
% OM&A	49.76%	50.68%	46.31%	B / (B+D)
% Capital	50.24%	49.32%	53.69%	D / (B+D)
Dx Comp ($m)	$639.0	$606.7	$637.8	See Table 2
Dx Comp ($m - OM&A)	$318.0	$307.5	$295.4	= Dx Comp x B
Dx Comp ($m - Capital)	$321.0	$299.2	$342.4	= Dx Comp x D

UNDERTAKING – JT 1.20

Undertaking

To provide an explanation showing the acquired's effect on that year vis-a-vis the normal as you were doing each year as a fact; and to take out that piece of information separately.

Response

Table 1 from Exhibit Q has been reproduced below to exclude the Acquired LDCs integration starting in 2021. This results in lower OM&A and capital related revenue requirement due to lower rate base. Overall the revenue requirement in 2021 is lower by $25.5 million and in 2022 the revenue requirement is lower by $26.2 million.

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base	D1-1-1	7,666.4	8,026.9	8,430.5	8,791.7	9,152.4
2	Return on Debt	E1-1-1	199.0	208.4	218.9	228.3	237.6
3	Return on Equity	E1-1-1	276.0	289.0	303.5	316.5	329.5
4	Depreciation	C1-6-2	397.1	418.2	433.1	447.8	461.4
5	Income Taxes	C1-7-2	65.4	69.0	71.5	78.4	78.9
6	Capital Related Revenue Requirement		937.5	984.5	1,026.9	1,071.0	1,107.4
7	Less Productivity Factor (0.45%)			(4.4)	(4.6)	(4.8)	(5.0)
8	**Total Capital Related Revenue Requirement**		**937.5**	**980.1**	**1,022.3**	**1,066.1**	**1,102.4**
9	OM&A	C1-1-1	579.6	584.0	588.3	592.8	597.2
10	Integration of Acquired Utilities	A-7-1					
11	**Total Revenue Requirement**		**1,517.1**	**1,564.1**	**1,610.7**	**1,658.9**	**1,699.6**
12	Increase in Capital Related Revenue Requirement			42.6	42.2	43.8	36.3
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.81%	2.70%	2.72%	2.19%
14	Less Capital Related Revenue Requirement in I-X			0.46%	0.47%	0.48%	0.48%
15	**Capital Factor**			**2.34%**	**2.23%**	**2.24%**	**1.71%**

UNDERTAKING – JT 1.21

Undertaking

To clarify what is included in the 2016 distribution financial statements and what is included in what was filed in the application.

Response

Hydro One's response to Exhibit I, Tab 28, Schedule VECC-51, part (a) confirmed that OM&A costs relating to the acquired utilities are not included in two exhibits referred to in the question.

Hydro One Networks Distribution Financial Statements would reflect balances relating to the acquired utilities from the date that they are operationally integrated into Hydro One Networks Distribution. For the acquired utilities in question, operational integration occurred on September 1, 2015 for Norfolk and on September 1, 2016 for Haldimand and Woodstock. Therefore, the 2016 Hydro One Networks Distribution Financial Statements would reflect balances including OM&A for the full year relating to Norfolk and from the integration date of September 1, 2016 for Haldimand and Woodstock.

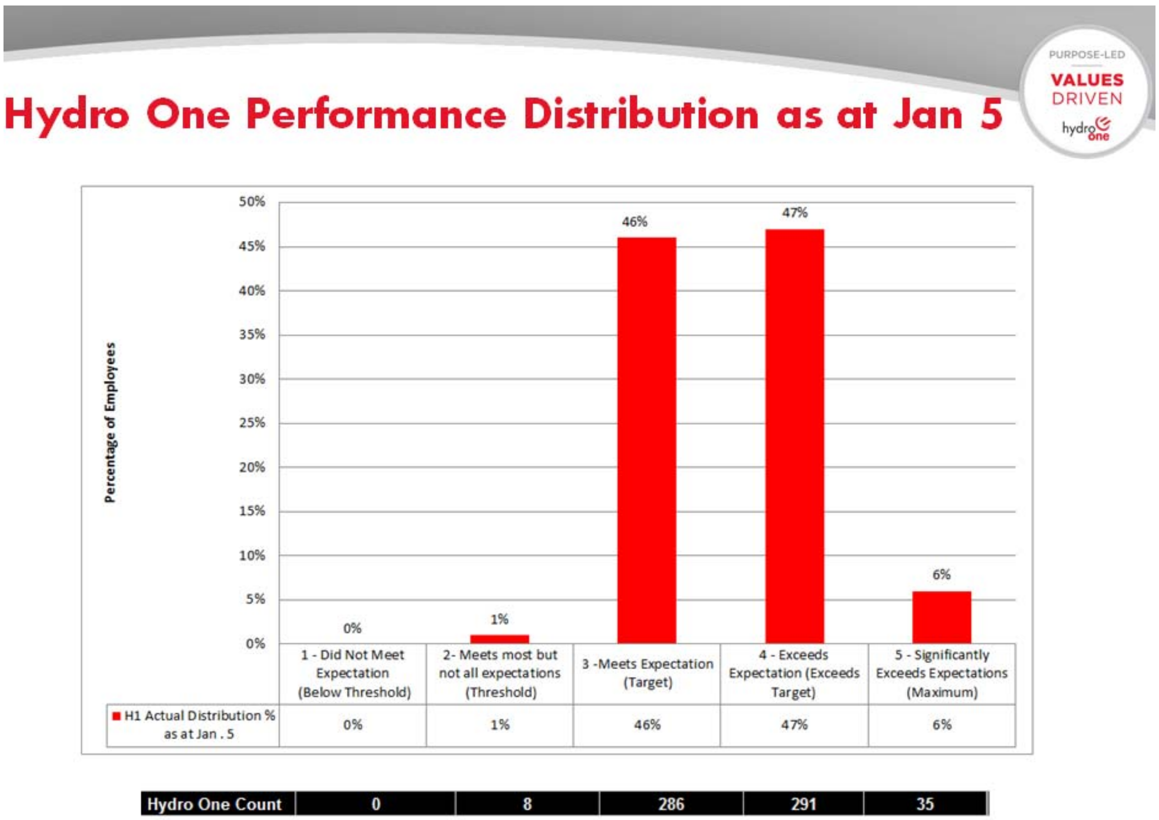
UNDERTAKING – JT 2.1

Undertaking

To provide the original ratings.

Response

Please see the figure below.



Witness: MCDONELL Keith

UNDERTAKING – JT 2.2

Undertaking

To calculate the impact of backfilling on labour costs.

Response

This undertaking is related to the issue of the vacancy rate and whether Hydro One could provide data to show the labour costs incurred while vacancies were being filled. Unfortunately, neither Hydro One's pay nor finance systems track costs to any specific vacancy. Open vacancies can be managed in a variety of ways that would result in costs being incurred, including temporary resourcing strategies such as temporary contracts, internal rotations, overtime, contracting out, and hiring casual labour (e.g. PWU Hiring Hall).

UNDERTAKING – JT 2.3

Undertaking

To make best efforts to advise the level of spending on contract staff, 2018 to 2022.

Response

Starting in 2016, Hydro One's supply chain department began reporting on contract staff spending for the Corporate Common groups. As stated in Exhibit I, Tab 40, Schedule AMPCO-47, the historical spending for 2016 and 2017 was $18.9 million and $ 20.8 million annually for contract staff.

When developing the Dx Business Plan, the Corporate Common groups were asked to provide the forecast for "contract spend", which includes both contract staff and contractors/consultants and their deliverables (such as reports or studies). The lines of business do not separate theses cost into (a) contract staff and (b) contractors/consultants. In order to be responsive to this undertaking, the forecasts for "contract spend" for the Corporate and Common groups are shown below.

	2017	2018	2019	2020	2021	2022
Contract Spend	27,717,509	27,332,773	26,182,612	23,778,339	23,399,356	23,639,040

UNDERTAKING – JT 2.4

Undertaking

To provide the total non-overtime hours of work, plus hours of overtime, on a best efforts basis, with a business plan forecast for overtime for the test period; and to provide total billable hours excluding overtime.

Response

As stated in Exhibit I Tab 40 AMPCO 47 (f), Hydro One does not budget for overtime as part of its business planning process. On a best efforts basis, Hydro One has forecasted overtime and non-overtime hours for the test period in Table 1. It should be noted that overtime forecasts are difficult to make since the majority of overtime hours within field operations is due to storm activity and the resulting restoration efforts.

Table 1

Year	Regular Hours	Overtime Hours Worked at Straight Time	Overtime Hours Worked at 1.5	Overtime Hours Worked at 2.0	Total Overtime Hours Worked
2012	13,503,501	7,908	220,370	767,249	995,526
2013	13,533,619	20,826	240,919	978,466	1,240,212
2014	13,746,075	9,188	236,621	858,416	1,104,225
2015	13,370,407	6,855	212,701	817,101	1,036,657
2016	13,812,981	11,763	160,705	830,654	1,003,122
2017	13,271,988	11,998	153,430	837,086	1,002,514
2018	14,199,900	10,253	183,216	761,286	954,755
2019	14,033,250	10,198	182,225	757,168	949,590
2020	14,005,200	10,171	181,748	755,186	947,104
2021	13,982,100	10,148	181,338	753,483	944,969
2022	13,970,550	10,126	180,942	751,835	942,903

Witness: MCDONELL Keith

UNDERTAKING – JT 2.5

Undertaking

To provide the excel version of the table showing the breakdown of FTEs, as found in part h) of AMPCO-47.

Response

Please see Attachment 1.

		2012	2013	2014	2015	2016	2017
Regular	MCP	655	634	605	597	611	679
	Society	1342	1318	1291	1282	1267	1375
	PWU	3476	3396	3342	3356	3391	3480
	Total	**5473**	**5348**	**5238**	**5235**	**5269**	**5534**
Non-Regular	MCP	19	23	29	29	33	29
	Society	56	55	56	55	47	51
	PWU	259	321	328	212	230	165
	Total	**334**	**399**	**413**	**296**	**310**	**245**
Casual	PWU HH	1301	1330	1338	1188	1383	1374
	Casual Cor	1104	1116	1319	1358	1402	1428
Total FTE's		**8212**	**8193**	**8308**	**8077**	**8364**	**8581**

UNDERTAKING – JT 2.6

Undertaking

To advise if there were some other allowances within the Society and PWU; if not, to update that table, and if it is in "burdens", to break it out.

Response

“Other Allowances” have been included in the base pay amount for PWU and Society represented employees.

UNDERTAKING – JT 2.7

Undertaking

To provide specifics on the corporate relations group.

Response

This undertaking was a follow up in response to interrogatory response filed in Exhibit I-38-CCC-36 with respect to the accountabilities of the External Relations (formerly "corporate relations") department. With respect to the detailed accountabilities of this particular department, please refer to Exhibit A, Tab 4, Schedule 1, Page 6, Section G.

UNDERTAKING – JT 2.8

Undertaking

To provide an update on finalized STIP and LTIP numbers.

Response

The 2018 STIP (for performance year 2017) was paid on February 22, 2018. The following table shows the percentage of employees receiving an STIP payment by performance rating.

Overall Performance Rating	**Number of Employees**	**%**
Significantly Exceeds	13	2%
Exceeds	177	28%
Meets	391	61%
Meets Most but not all	51	8%
Does not meet	8	1%

The 2018 LTIP grant was finalized on March 1, 2018. All regular Directors and above received a LTIP grant that will vest February 28, 2021.

UNDERTAKING – JT 2.9

Undertaking

To provide materials that were presented during the calibration session.

Response

Please see Attachment 1.

Witness: JESUS Bruno

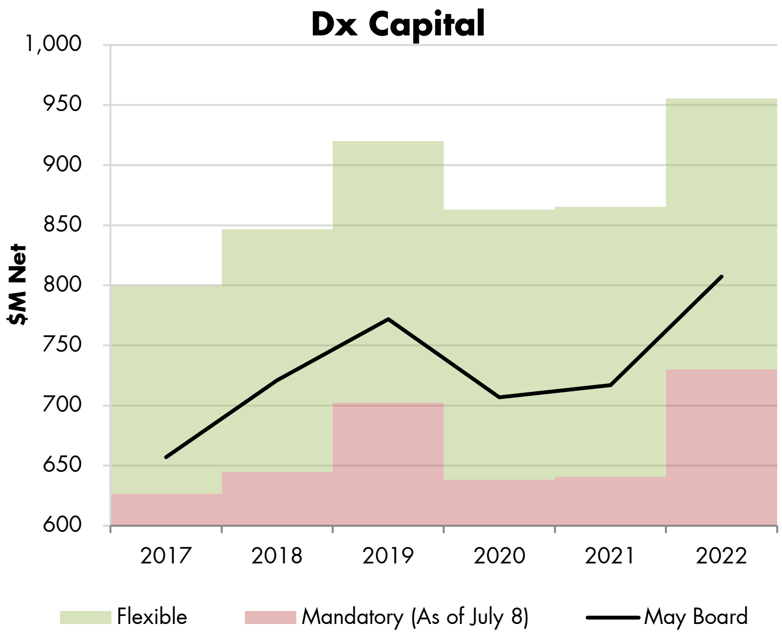
2017-22 Dx
Investment Calibration Session

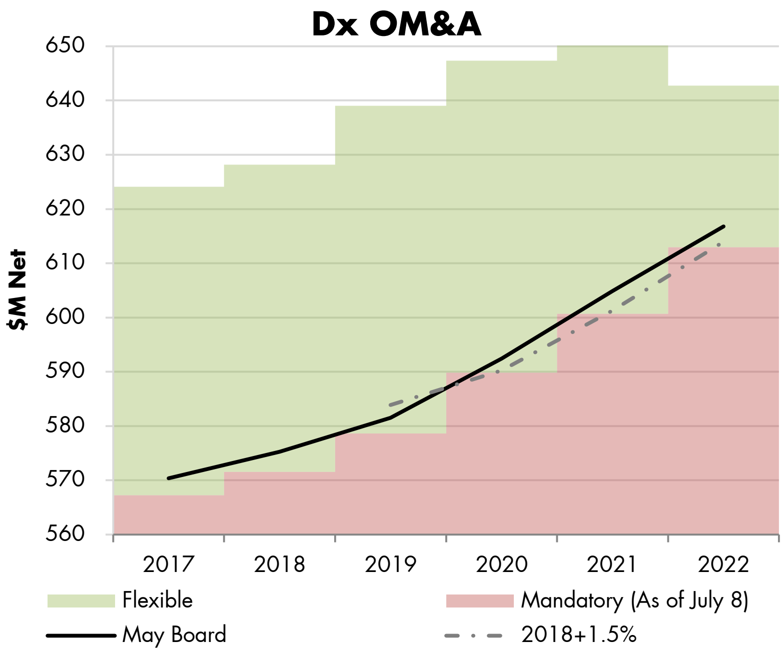
July 12, 2016

Agenda (Planned)

From	To	Subject Area	Presenter
8:30 AM	8:45 AM	Opening Remarks	Randy Church
8:45 AM	9:20 AM	Customer Service	Imran Merali
9:20 AM	9:40 AM	Corporate Projects	JJ Blais
9:40 AM	**10:00 AM**	**Break**	
10:00 AM	10:35 AM	Enterprise IT	Lincoln Frost-Hunt
10:35 AM	10:55 AM	Facilities and Real Estate	Lou Fortini
10:55 AM	12:00 PM	Dx Asset Management	Sinisa Grkovic for Paul Brown
12:10 PM	**12:40 PM**	**Lunch**	
12:40 PM	1:00 PM	*Dx Asset Management (if req'd)*	*Sinisa Grkovic for Paul Brown*
1:00 PM	1:20 PM	Network Operating	Tom Irvine
1:20 PM	1:40 PM	Fleet Services	Mark Binkley for Mike Piggott
1:40 PM	1:55 PM	Security Operations	Rick Haier
1:55 PM	**2:15 PM**	**Break**	
2:15 PM	2:30 PM	Tx AM	CK Ng
2:30 PM	2:45 PM	Health, Safety & Environment	Bill Welch
2:45 PM	3:00 PM	Reliability Standards and Compliance	Janet Eby for Luis Marti
3:00 PM	3:15 PM	Planning Optimization	Scot Mclachlan
3:15 PM	3:45 PM	Wrap-Up and Action Items	Kevin Mancherjee

Investment Levels





Some flexibility vs. May Board levels

If we optimized today…

- Would likely to result in mix of proposed/optimal and minimum levels
- Only $30M available for flexible investments in 2017, but ~$70 - 75M/year available 2018-22

Minimal flexibility vs. May Board levels

If we optimized today…

- Would likely to result in minimum levels being selected
- Only ~$3M/year available for flexible investments (vs. May Board)
- Only ~$3 - 5M/year available for flexible investments in 2017-19 and no incremental spend in 2020+ (vs. Regulatory modelling)

Return to Agenda

Investment Calibration

Customer Service

Imran Merali

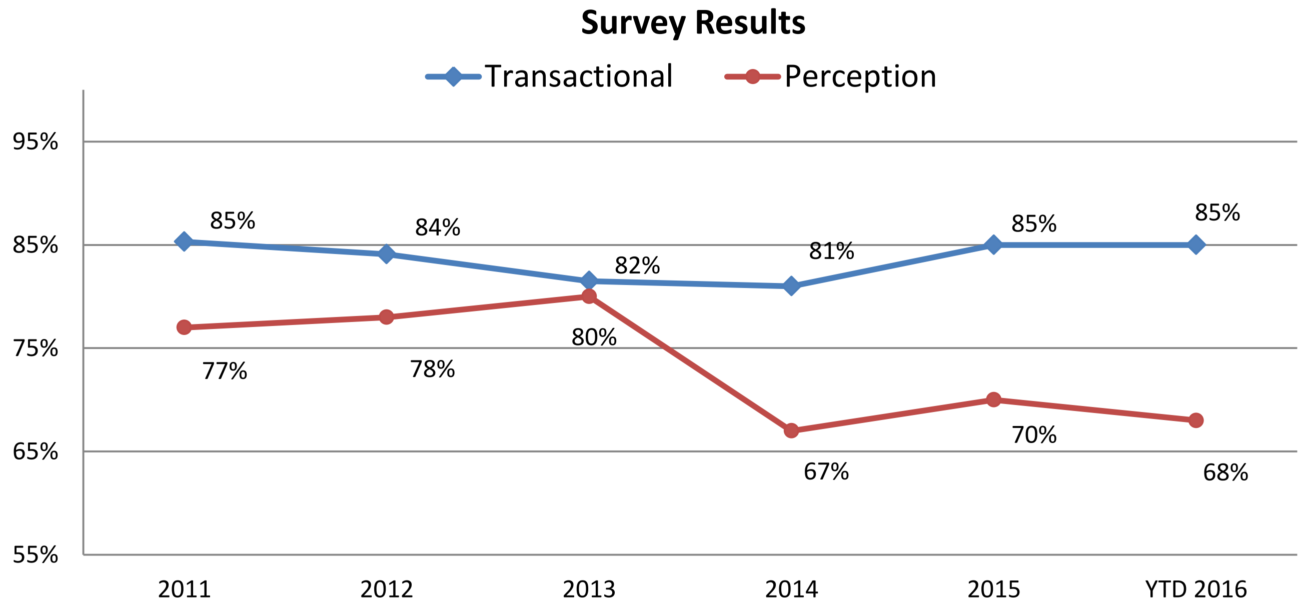
July 12, 2016

Customer Satisfaction

Overview

- Hydro One currently conducts approximately 20 ongoing customer surveys, which includes a combination of *Perception and Transactional surveys.*
- The perception-based surveys measure overall customer satisfaction and sentiment towards Hydro One. They tell us how we are performing in key areas of Customer Service, Image, Price/Billing, and Product/Reliability.
- Our transactional surveys tell us how we are doing across the various communication channels and customer touch-points. These surveys are conducted (within 3 – 5 days) following a customer interaction and focus on feedback about the overall customer experience.

Results



Investment Flexibility: OM&A

Investment Flexibility = Limited

- The majority of costs are either determined through a competitive RFP or requirements/service levels that are dictated by the OEB.

Mandatory/Non-Discretionary Overview

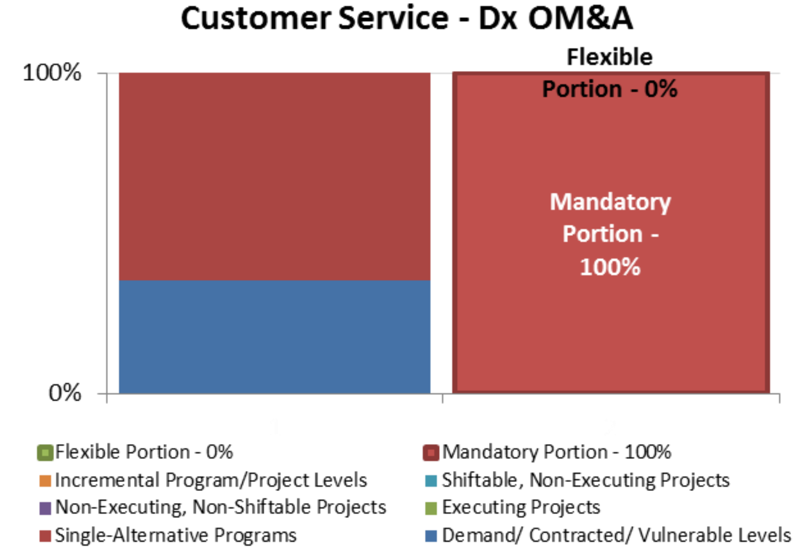
Outsourcing Contract:

- This expenditure reflects Hydro One's outsourcing agreement with Inergi to deliver call center, billing, collections, and settlement services.
- The amounts were derived from a competitive RFP process.
- Some of Inergi's Service Levels align with best practices and exceed the OEB's requirements.

Billing:

- The majority of this expenditure relates to Canada Post charges to mail customers their electricity bills and collection letters.
- Although the postage rates are set by Canada Post, we've included an aggressive eBilling plan with approximately $15M of postage savings included over the planning period.

Continued on next slide …



Expenditure ($M)	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	2022 Plan
Customer Service & Settlements Outsourcing	57	43	43	43	43	44	45	45
Billing	11	12	13	13	13	13	13	13
Manual Meter Reading	13	14	13	13	13	13	13	13
Smart Meter & Interval Meter Reading	10	10	10	10	10	10	10	10
Collections	13	8	8	8	9	9	10	10
Contact Handling	1	1	1	1	1	1	1	1
TOTAL	**104**	**89**	**89**	**89**	**89**	**90**	**92**	**92**

Investment Flexibility: OM&A

Mandatory/Non-Discretionary Overview

SMNO:

- This expenditure contains funding for Stations to operate the Smart Meter Network to obtain Time-of-Use reads for the majority of customers using Advanced Metering Infrastructure and interval meter reads for Hydro One's large commercial and industrial customers.
- Unit costs are provided by Stations, and the volume of work is determined by Customer Service and the OEB's Billing Accuracy targets.

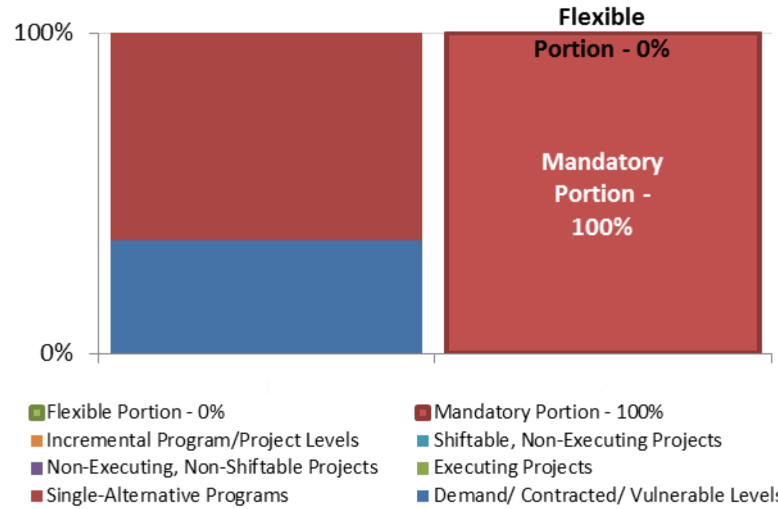
Manual Meter Reading:

- This expenditure contains funding for Provincial Lines to obtain manual meter reads.
- Although the majority of our customers are read automatically via the smart meter network, approximately 230,000 manual reads are required on an annual basis for areas with no/limited network communication.

Collections:

- This expenditure allows Provincial Lines resources to execute field collections activities, such as disconnections for non-payment.
- Savings of $3M per year associated with remote disconnect functionality has been included in the plan.
- Although significant improvements have been made to Hydro One's collections performance (including Net Bad Debt), Hydro One still lags behind several top quartile utilities.
- This expenditure also includes funding for the Ontario Energy Board's Low-Income Energy Assistance Program (LEAP).

Customer Service - Dx OM&A



Expenditure ($M)	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	2022 Plan
Customer Service & Settlements Outsourcing	57	43	43	43	43	44	45	45
Billing	11	12	13	13	13	13	13	13
Manual Meter Reading	13	14	13	13	13	13	13	13
Smart Meter & Interval Meter Reading	10	10	10	10	10	10	10	10
Collections	13	8	8	8	9	9	10	10
Contact Handling	1	1	1	1	1	1	1	1
TOTAL	104	89	89	89	89	90	92	92

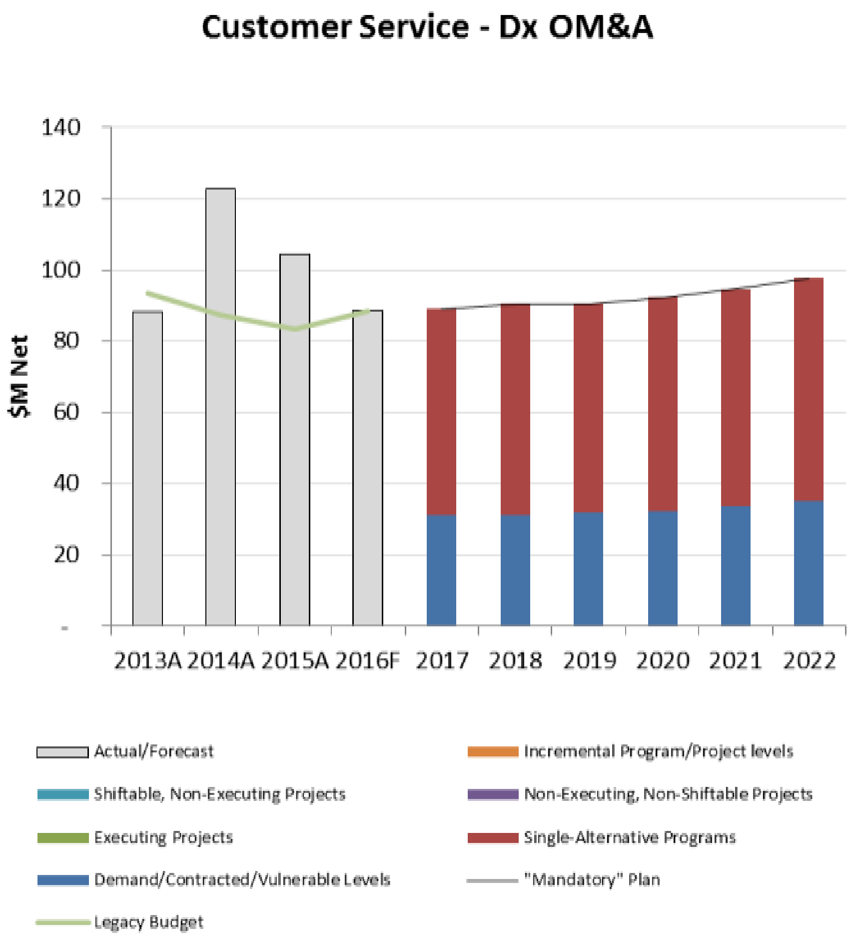
Investment Flexibility: OM&A

Consistency with historic delivery/budget

- 2014 and 2015 expenditure increased due to CIS and Customer Service Recovery. Our 2017 to 2022 plan aligns with pre-CIS expenditure.
- Although Customer Service has implemented and planned several initiatives to reduce costs, total expenditure increases over the planning period primarily due to upward pressure on unit costs (due to inflation provisions in the outsourcing contract, higher labour rates for field activities, postage rate increases), and due to changing regulatory requirements affecting billing.
- Adjusted for inflation, most of our costs have declined.

Funding Reduction Risks and Implications

- A funding reduction would severely compromise Hydro One's customer service and customer satisfaction targets.
- In addition, Hydro One would not be able to meet the OEB's minimum standards with respect to calls answered on time, first call resolution, billing accuracy, and customer satisfaction.



Risk Assessments: Customer Service

Approach

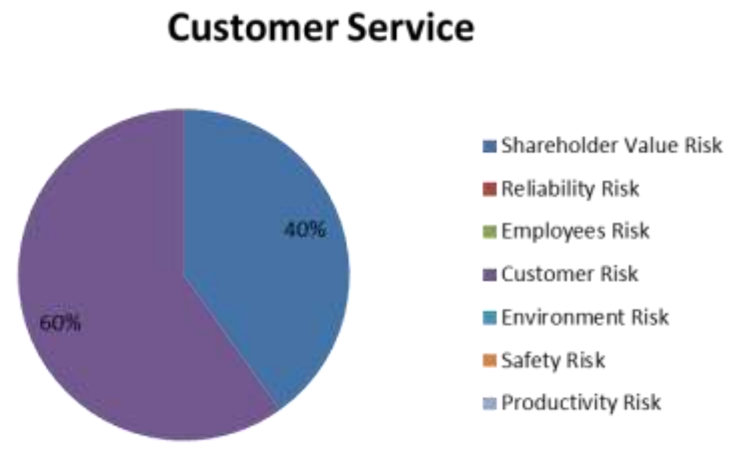
- Customer Service's business plan affects two of Hydro One's core values: Customer Service and Shareholder Value.

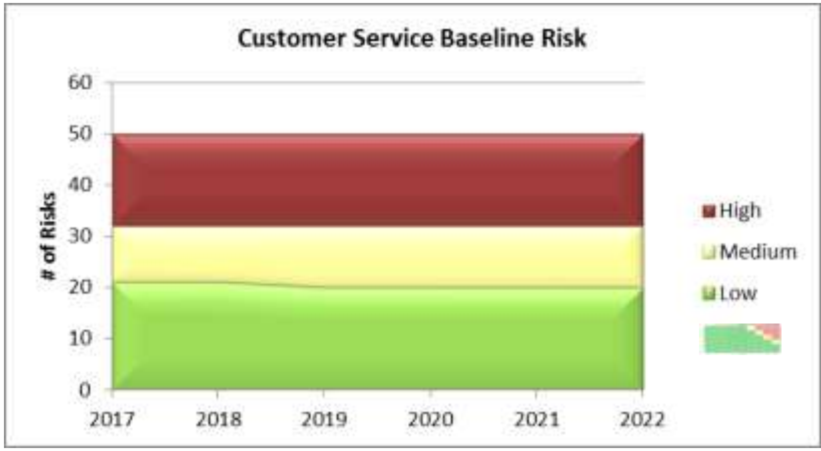
Customer Service:

- This business plan allows Hydro One to serve the needs of our customers by providing timely and accurate bills, responding to customer inquiries when they contact us, and managing a collections program to recover revenue.
- The expenditure ultimately allows Hydro One to deliver value to our customers and improve customer satisfaction (both perception and transactional).

Shareholder:

- This business plan allows Hydro One to serve the needs of our executive team, including corporate scorecard targets and growth aspirations, while ensuring compliance with Ontario Energy Board regulations.
- A degradation in Customer Service would likely reduce our ability to successfully acquire other utilities.
- The plan is also based of early findings from the Dx consultation process.





Investment Calibration

Corporate Projects
JJ Blais
July 12, 2016

Return to Agenda

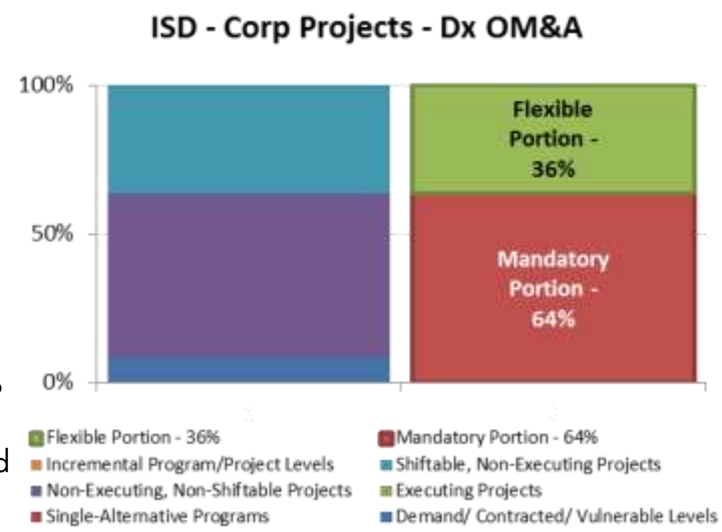
Investment Flexibility: OM&A (1/2)

Investment Flexibility

- **36% Flexible** The investments in the Corporate Projects area support the business technology roadmap. Our investments deliver expanded business capability through the introduction of new enabling technologies as well as protecting our current technology by addressing end of life replacements of business applications. The OMA portion of the investment covers communication, training, process, change management & data conversion.

Mandatory/Non-Discretionary Overview

- **Mandatory Overview -** Majority of the investments are 'projects' (as opposed to 'programs'). By default, project investments are deemed mandatory except when explicitly selected as a shiftable project. Examples of projects that are deemed mandatory are: CTI Replacement, GIS Roadmap, Funding for OEB Regulatory Compliance
- **Approach to Mandatory -** Projects that are either in-flight or OEB mandated must proceed. Those that have a higher risk of operational impact (CTI & GIS) should proceed. Other projects (Bill redesign) that will have a customer impact should also proceed. The remaining projects should then be measured on their strategic value and benefits and ranked for delivery according to available funding.
- **Mandatory Drivers -** The bulk of investments classified as mandatory is in response to the level of risk (deemed unacceptable risk to delay the investment further) as well as delayed benefit to Hydro One if the investment were pushed out. There were also some investments related to regulatory compliance (ex. Demand Interval Conversion, Critical Peak Pricing, Dynamic Pricing).
- **Discretionary Opportunities -** The bulk of investments classified as mandatory is due to the risk assessed as unacceptable. As this is a subjective exercise, depending on the risk appetite, there may be an opportunity to reclassify some investments from mandatory to discretionary.



Mandatory Driver	Approx. %
Legal Regulatory/ Compliance	18%
Other – Please Specify (Weighed the risk & the impact of delaying the benefit if the project were to shift)	82%

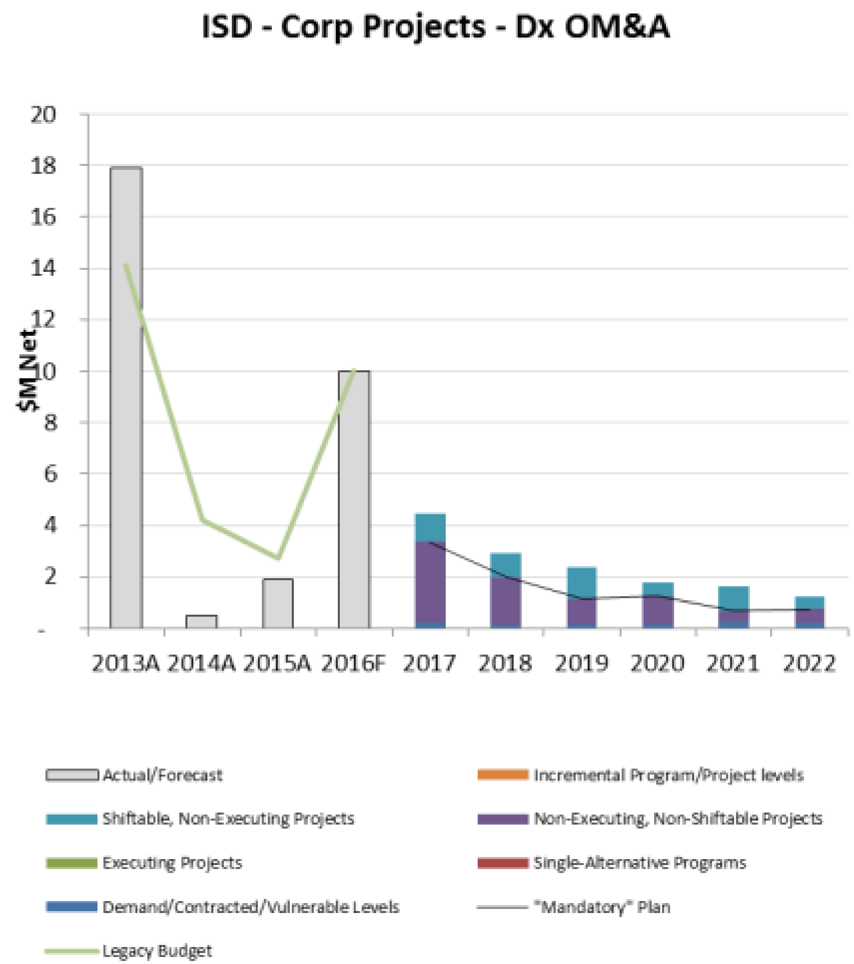
Investment Flexibility: OM&A (2/2)

Consistency with historic delivery/budget

- Cornerstone CIS was in flight in 2013 which explains the unusually high OMA actuals during that year. In 2016, OMA funding is also high due to an increased volume of Customer initiatives. Going forward, the level of funding requested is substantially lower. As a rule of thumb, we use 10% of the CAP spend.
- For OMA, Corporate Projects typically delivers lower than what was budgeted.

Funding Reduction Risks and Implications

- For most of the investments, reducing the funding requested will delay the achievement of benefits associated with those investments. It will also impact the quality & user adoption of what will be implemented since OMA funding covers for training, communication, data conversion & process.
- For most of the investments, pushing out the funding requested by 1 to 2 years will increase the risk associated with those investments. The bulk of the risk relates to customers & reduction in customer satisfaction followed by productivity risk & risk to shareholder value. Benefits will also be delayed.



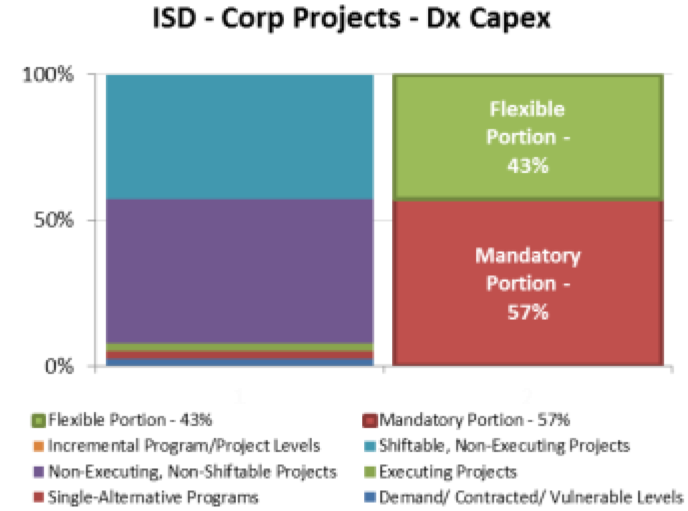
Investment Flexibility: Capital (1/2)

Investment Flexibility

- **43% Flexible** The investments in the Corporate Projects area support the business technology roadmap. Our investments deliver expanded business capability through the introduction of new enabling technologies as well as protecting our current technology by addressing end of life replacements of business applications.

Mandatory/Non-Discretionary Overview

- **Mandatory Overview -** Majority of the investments are 'projects' (as opposed to 'programs'). By default, project investments are deemed mandatory except when explicitly selected as a shiftable project. Examples of projects that are deemed mandatory are: CTI Replacement, GIS Roadmap, Funding for OEB Regulatory Compliance
- **Approach to Mandatory -** Projects that are either in-flight or OEB mandated must proceed. Those that have a higher risk of operational impact (CTI & GIS) should proceed. Other projects (Bill redesign) that will have a customer impact should also proceed. The remaining projects should then be measured on their strategic value and benefits and ranked for delivery according to available funding.
- **Mandatory Drivers -** The bulk of investments classified as mandatory is in response to the level of risk (deemed risky to delay the investment further) as well as delayed benefit to Hydro One if the investment were pushed out. There were also some investments related to regulatory compliance (ex. Demand Interval Conversion, Critical Peak Pricing, Dynamic Pricing).
- **Discretionary Opportunities -** The bulk of investments classified as mandatory is due to the risk assessed as unacceptable. As this is a subjective exercise, depending on the risk appetite, there may be an opportunity to reclassify some investments from mandatory to discretionary.



Mandatory Driver	Approx. %
Legal Regulatory/ Compliance	12%
Released Project	10%
Other – Please Specify (Weighed the risk & the impact of delaying the benefit if the project were to shift)	78%

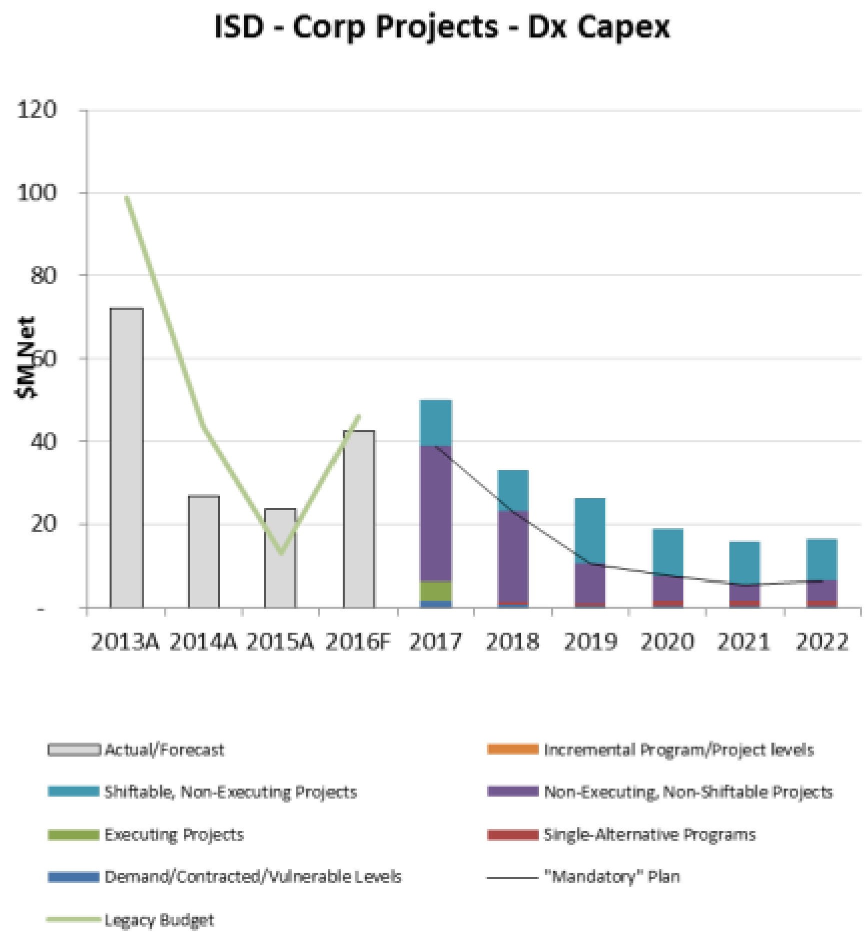
Investment Flexibility: Capital (2/2)

Consistency with historic delivery/budget

- Cornerstone CIS was in flight in 2013 which explains the unusually high CAP spend during that year. Forecasted CAP spend in 2016 is also relatively high with a number of initiatives carried over from 2015 – in addition to what was planned for this year. The spike in funding requested in 2017 is attributed to the Demand to Interval Project which runs through until 2019.
- For CAP projects, Corporate Projects typically delivers more than what was budgeted / planned. It's not uncommon for unplanned projects to be added which Corporate Projects need to deliver.

Funding Reduction Risks and Implications

- For most of the investments, reducing the funding requested will delay OR even reduce the achievement of benefits associated with those investments. It may also impact the quality of what will be delivered – ex. reduced funding resulting in reduced testing.
- For most of the investments, pushing out the funding requested by 1 to 2 years will increase the risk associated with those investments. The bulk of the risk relates to customers & reduction in customer satisfaction followed by productivity risk & risk to shareholder value. Benefits will also be delayed.



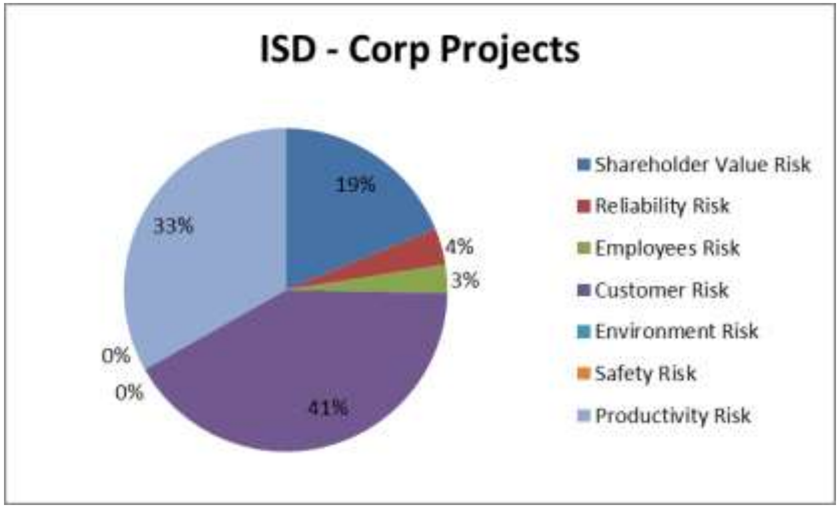
Risk Assessments: Corporate Projects (1/4)

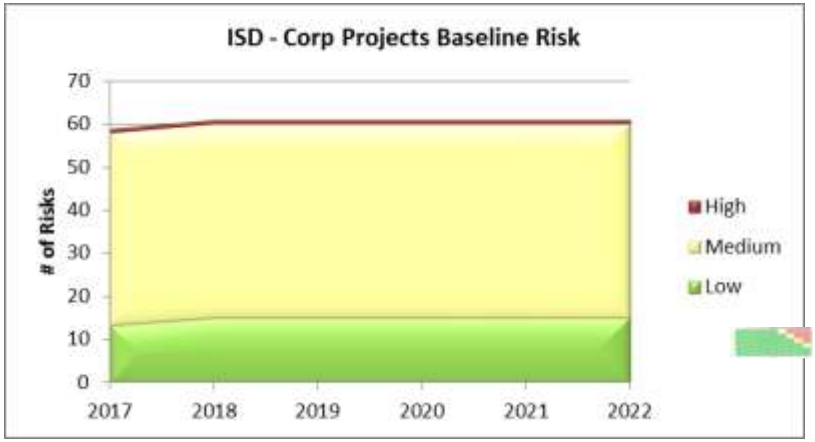
Approach

- Our approach for assessing risk is to first determine which corporate values will be impacted by the investment. Most of our investments are associated with Customer Risk followed by Productivity risk & Shareholder Value Risk. Planners then collaborated with the LOB to come up with the appropriate level of consequence & used best judgment to determine the likelihood using the corporate risk consequence matrix.

Risk Sources

- **Significant Hazards/ Threats / Vulnerabilities –** Dissatisfied Customers, Loss of Productivity, Disengaged Employees, Weakened Shareholder Confidence
- **Significant Baseline Risk Consequences –** The risk of status quo includes increased in call volumes at the call center, regulatory non-compliance, higher cost to do work, dis-engaged employees.
- **Baseline Risk Trend –** The baseline risk trend is fairly consistent across the planning period with majority of the baseline risk classified as 'Medium' risk.





Data updated July 8

Risk Assessments: Corporate Projects (2/4)

Top 6 Highest Risk Investments

N.C.C.2.60	Executing	Move to Mobile - Provincial Lines - Capital	AIP000065	8.278857779	73
N.C.M.2.60	Short Term Planning	Move to Mobile - Provincial Lines - OMA	AIP005742	8.278857779	73
N.C.C.2.60	Executing	Corporate Support Optimization	AIP000060	6.213026476	91
N.D.C.2.60	Short Term Planning	CTI Replacement, IVR, Call Recording, Speech Analytics	AIP000213	4.659769857	111
N.D.C.2.60	Short Term Planning	E-Customer Replacement	AIP000214	4.659769857	111
N.C.C.2.60	Executing	Enterprise GIS Integration	AIP000061	4.659769857	111

Top 6 Lowest Risk Investments

Driver	Stage	Description	Investment Code	Baseline Value	Rank
N.C.C.2.10	Executing	Cornerstone Phase 3 - EDT CAP	AIP000053	0.006197494	363
N.C.M.2.10	Executing	Cornerstone Phase 3 - EDT OM&A	AIP000098	0.006197494	363
N.C.C.2.10	Executing	Cornerstone Phase 3 - Workflow of the Future	AIP000056	0.00465977	365
N.D.M.2.10	Executing	Cornerstone Phase 4 - CIS - OM&A	AIP000307	0.003122046	371
N.C.M.2.60	Short Term Planning	Engineering Design Transformation - OM&A Portion	AIP005767	0.001094014	373
N.C.C.2.60	Short Term Planning	Engineering Design Transformation	AIP005762	0.000438916	376

Notes:
Includes only Dx/Common Investments
Excludes Investments without a risk assessment

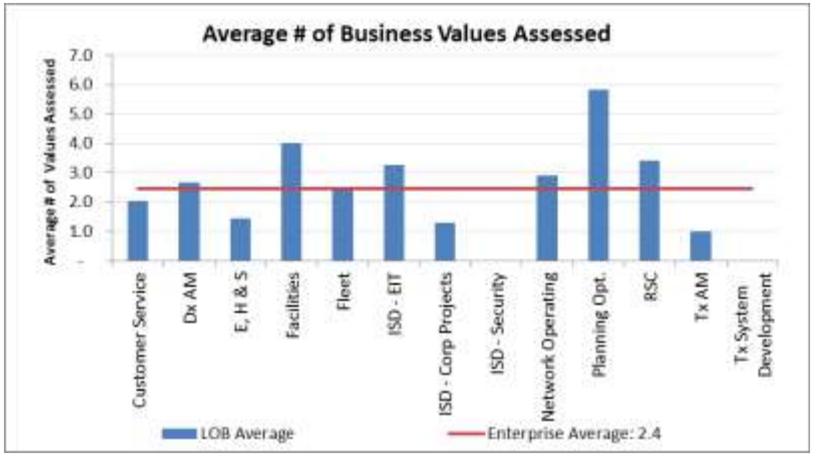
Risk Assessments: Corporate Projects (3/4)

Investment Portfolio

- **Corporate Projects**

Alignment with Other LOBs

- **Scope of Risk Assessments** - We determined the number of risk to evaluate based on the investment proposed. For instance, for Customer Projects, the risk is typically associated with Customer Risk, Shareholder Risk (particularly if regulatory related) & Productivity Risk.
- **Changing Risk Profile**; The risk profile for Corporate Projects is fairly consistent across the planning period with majority of the risk assessed as medium.



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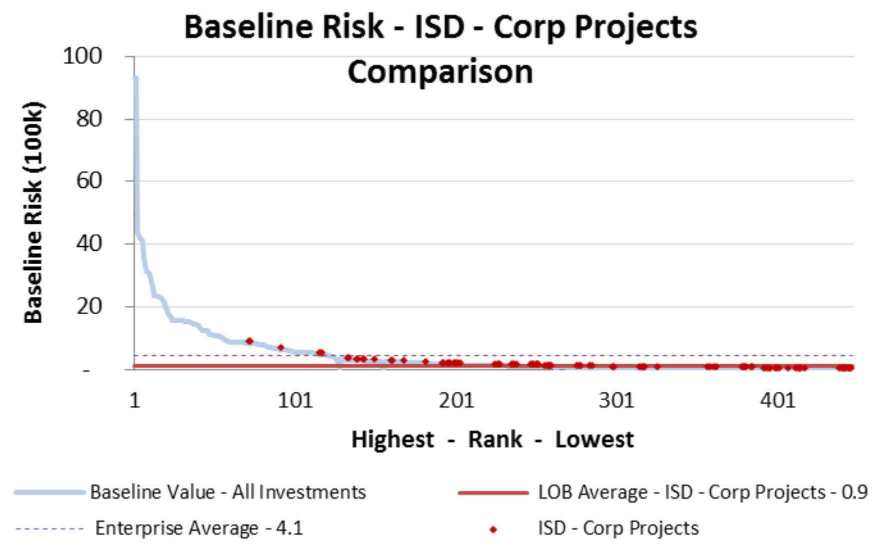
Risk Assessments: Corporate Projects (4/4)

Investment Portfolio

- **Corporate Projects**

Alignment with Other LOBs

- **Relativity of Risk Assessments -** Relative to other LOBs, majority of the investments in Corporate Projects had risks which were below the enterprise average. The risks may therefore be skewed low however the projects in question do not have the same on/off impact as a major asset for example. Therefore perhaps our risk rating is ok as long as we understand that in-flight projects and Regulatory projects must be allowed to proceed as planned.



	First Quartile	Second Quartile	Third Quartile	Fourth Quartile
	Most Baseline Risk			Least Baseline Risk (or no assessment)
LOB Investments	3	27	27	45
LOB - % of Quartile	2.6%	22.9%	22.7%	38.5%
LOB - Quartile Distribution	3.0%	26.4%	26.2%	44.4%

Risk-Based Investment Walkthrough- Computer Telephony Integration (CTI) Replacement (1/3)

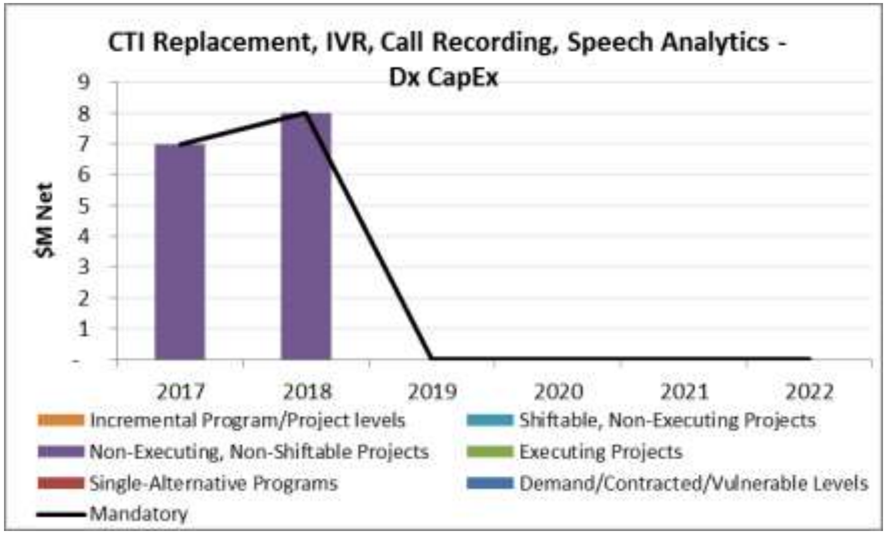
Investment Code / Description

- AIP000213 / CTI Replacement

  Computer telephony system is used at Hydro One for Call information display; Automatic dialing and computer controlled dialing; Phone control; Coordinated phone and data transfers between two parties; Call routing, reporting functions, automation of desktop activities, and multi-channel blending of phone, e-mail, and web requests; Call control for Quality Monitoring & Call Recording software.

Mandatory Level and Alternatives Considered

- The Computer Telephony System used at our Call Center has already reached end-of-life. It requires replacement to accommodate tighter integration between CTI and our work force scheduling technologies. This investment will make our telephony system an integrated, multi-channeled solution to keep up with the demands of the customers and their preferred channel of interaction. This new integration will allow calls to be routed, scheduled and dispatched in a more efficient manner with the end result being better customer service. It will also allow us to scale up in a cost effective way in the event of a natural occurring disaster such as storm etc.
- Replacing the current system was initially targeted for 2014 but due to funding constraints, it was pushed out to 2017. If the replacement is delayed any further, it may contribute to an increase in customer dissatisfaction, increased calls to the call center & reputational risk to Hydro One. In view of all these, this particular investment is deemed mandatory & non-shiftable.



Data updated July 8

Risk-Based Investment Walkthrough-
CTI Replacement (2/3)

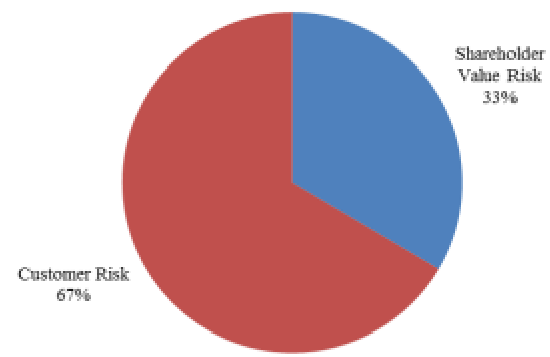
Investment Code / Description

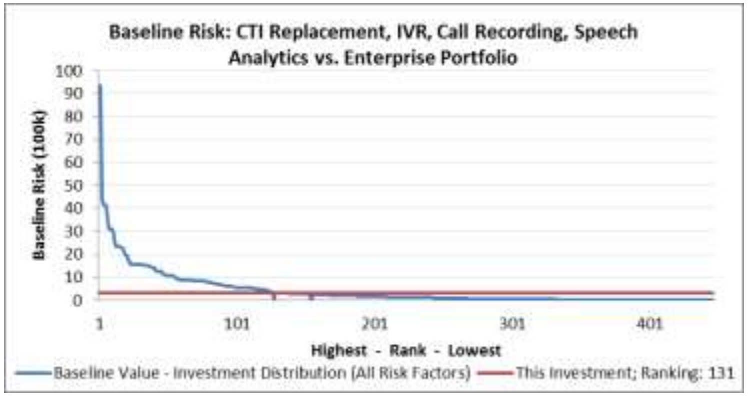
- AIP000213 / CTI Replacement

Baseline Risk Assessment

- Since this investment relates to the telephony system used by our Hydro One customers, the key business values related to this investment is customer (associated with customer satisfaction & lower call volumes at the call center) and shareholder value (reputation of Hydro One).
- Given our existing Computer Telephony System has already reached end of life, baseline risk was assessed as 'Major' for customer value as failure in the telephony system can result in an increase in customer dissatisfaction & higher call volumes. It was also assessed as 'Major' in terms of shareholder value as failure in the telephony system can result in reputational risk to Hydro One & negative media attention.
- Relative to other investments within Corporate Project, CTI is ranked among the highest risks. This is appropriate given the reasons stated above. Across Hydro One, as the telephony system does not have a direct impact on the reliability of transmitting & delivering electricity to our customers, the investment is medium risk.

CTI Replacement, IVR, Call Recording, Speech Analytics Baseline Risk Drivers





Data updated July 8

Risk-Based Investment Walkthrough- CTI Replacement (3/3)

Investment Code / Description

- AIP000213 / CTI Replacement

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Customer	**Major**	Large and Mid Customers (Industrials, LDCs, Generators)	Large and Mid Customers (Industrials, LDCs, Generators): Increase in customer dissatisfaction with Hydro One	One "large" customer experiences significant production losses (restart time on production lines, etc.) due to Hydro One actions/inaction; High level (CEO, COO, etc.) calls to Hydro One CEO's office; Significant increase in number of customers falling outside of "delivery point performance standards"; Sharp deterioration in large and mid customer satisfaction survey results (as measured by scorecard) in a single segment.
		OEB Service Quality Indices	Failure to meet Service Quality Indices	Achieve only 80% (to 89%) of Overall Expected Performance
		Residential and Small Business Customers	Residential and Small Business Customers: Increase in customer dissatisfaction with Hydro One service quality	Call centre volumes increase (not storm related) noticeably (15-30%); Noticeable increase in complaints received by field staff doing work on customer premises; Modest deterioration in mass market customer satisfaction as per survey response (as measured by scorecard).
Shareholder Value	**Major**	Net Income	Net Income Shortfall	$25M-$100M
		Shareholder Confidence	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Material erosion in confidence; Shareholder Agreement rewritten to include approval of major investment & operating decisions; One or more Senior Managers replaced by the Board
		Public Profile /Confidence re effective stewardship of assets	Public Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	Significant local attention; Several opinion leaders/customers publicly critical
		Meet Licence Conditions and obtain required rates maintain credibility with regulators	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities including non- compliance.	Some Concerns re: Competence; Difficult Demands
		Regulatory/Legal Compliance	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction	Conviction or regulatory finding of non-compliance with minor fine ("minor" meaning <30% of maximum fine under relevant legislation or regulation, and one that is not unusually high/unprecedented amount for the industry).

Data updated July 8

Benefit-Driven Investment Walkthrough – Project Portfolio Management (1/1)

Investment Code / Description

- AIP005672 / Project Portfolio Management for ISD

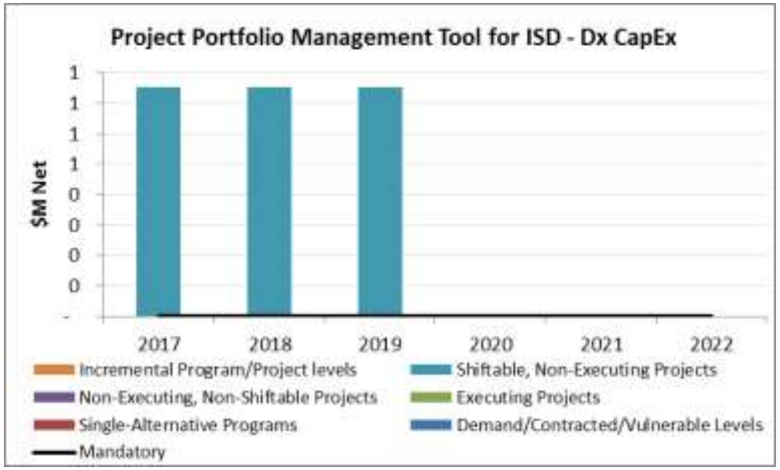
  This investment will implement a Project and Portfolio Management tool that will provide visibility, oversight and management tools to help our business prioritize and manage project delivery & resource assignments.

Mandatory Level and Alternatives Considered

- The mandatory level was determined by looking at the various PPM tool options. The options range significantly, from what we believe to be the most expensive; the SAP PPM module to cloud/hosted offerings (i.e. a model of $/user/month). All options are on the table and will be assessed in the RFP we have undertaken.

Benefits Analysis

- Efficiency Savings was determined through time savings as a result of having easy access to project information. The PPM portal will allow external parties to access and enter project information directly. This increases overall efficiency. The manual effort required to produce regular monthly project status reports will also be reduced.



Name	2017	2018	2019	2020	2021	2022
Activity	$ 0.80	$ 0.80	$ 0.80	$ 0.80	$ 0.80	$ 0.80
Activity Time Savings - External resource access to project information						
Reporting	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06	$ 0.06
Reporting Savings - Monthly - Monthly reporting effort reduction						

Data updated July 8

Investment Calibration

Enterprise IT
Lincoln Frost-Hunt
July 12, 2016

Return to Agenda

Investment Flexibility: OM&A (1/2)

Investment Portfolio

- **Enterprise IT**

Investment Flexibility

- 6%

Mandatory/Non-Discretionary Overview

- **Mandatory Overview**

Outsourcing Contracts - Inergi and Telecom Service Providers, IT 3rd Party Contracts, IT Application Upgrades, IT Security , Infrastructure Refresh, IT Business Improvements / Enhancements.

- **Approach to Mandatory**

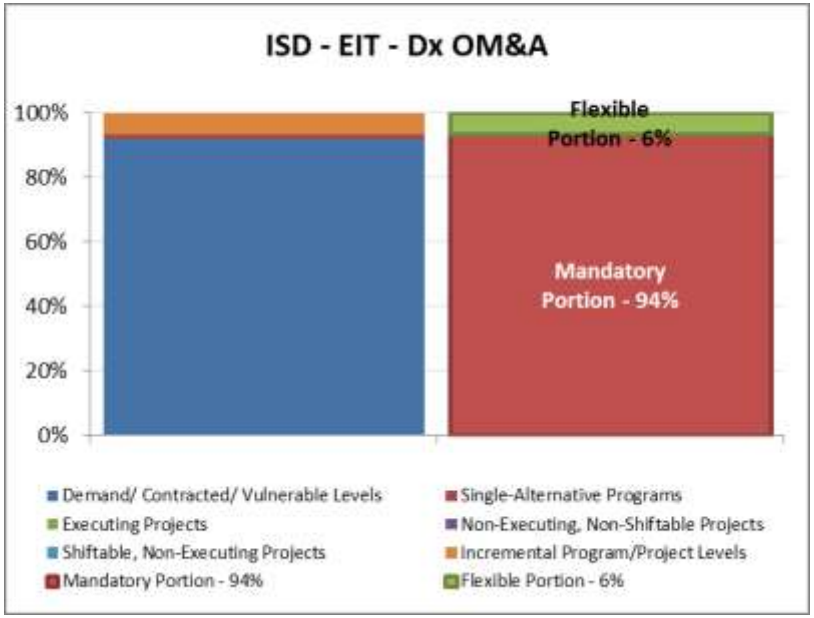
Contractual commitment, maintain warranties / vendor supported standards, red zone risk, compliance, multi-year average.

- **Mandatory Drivers**

Outsourced delivery of IT services (Inergi). Licensing and maintenance of our enterprise software. Voice and data services to support Hydro One business operations (H1 Telecom, Bell Canada, 3rd party telecom providers). Ensure ongoing reliability of our IT assets. Remediate and improve IT security capabilities. Implement OEB mandated enhancements associated with Customer. Increased LOB focus on enhancing customer experience and delivering operational efficiencies *as identified in Good to Great Program.*

- **Discretionary Opportunities**

Any shortfall in funding related to LOB driven Business Improvements and Enhancements (including Customer) will have to be transferred from H1 LOB drivers.



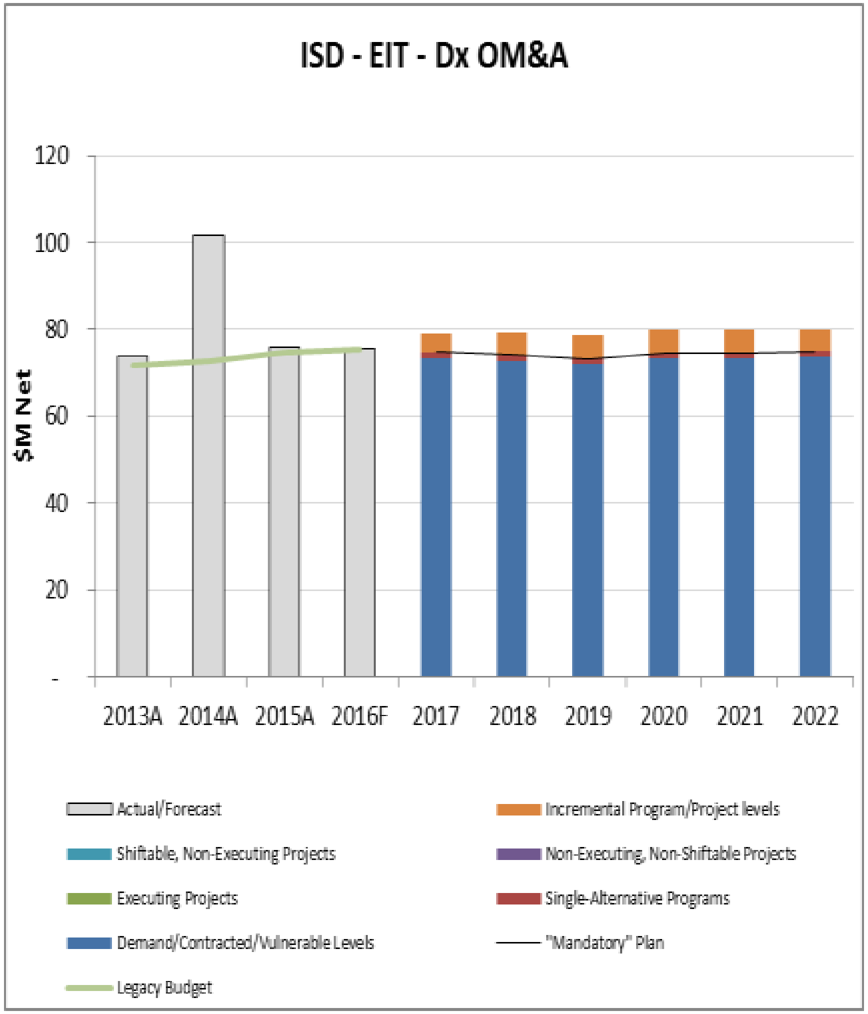
Mandatory Driver	Approx. %
Contractual Commitment	80.7
Obligation to upgrade – IT Infrastructure & Apps	6.8
Other – Business Improvements / Enhancements	5.8
Other – IT Security risk considerations, Business continuity	2.8
Regulatory / Compliance	1.9
Released Project / Un-Released Project	1.7
Policy Responsiveness	0.3
License Condition	
Other - Demand	

Investment Flexibility: OM&A (2/2)

Investment Portfolio
- **Enterprise IT**

Consistency with historic delivery/budget
- *Level of funding in-line with historic for Demand / Contracted / Vulnerable levels and Single –Alternative Programs.*
- *Portfolio delivery generally consistent with budget.*
- *Portfolio redirection related to CSO enhancements.*
- *Delivery shortfalls related to Non-CSO enhancements and Client Tech Refresh Services due to redirections to be within Portfolio approved budget.*

Funding Reduction Risks and Implications
- *New Inergi contract (starting in 2015) achieved 3% savings plan over plan. Reflected in the 2016 - 2020 BP.*
- *Additional savings opportunities identified in 2017 ($3.1M) and 2018 ($3.7M) as part of BCG review/Good to Great Program. Reflected in 2017- 2022BP.*
- *IT security - Increase over historic levels ($ 2M each year)* costs to
  - Remediate and improve security capabilities based on lessons learned from past incidents, audit reviews, and industry practices.
  - Implement governance and compliance protocols, reflecting legal requirements (such as Bill 198 and NERC CIP) and corporate standards, to prevent unauthorized access to data and IT systems.
- *Additional funding required for Implementing:*
  - *Increased LOB focus on enhancing customer experience and delivering operational efficiencies as identified in Good to Great Program.*
  - *3rd Party Contracts – Increase over historic levels ($1.9M each year) related to IT Projects / Good to Great Program – CSO initiatives /projects, Ariba, Taulia etc.*
  - *OEB mandated enhancements associated with Customer. Additional $1M in 2019 for Seasonal rate class elimination.*



Investment Flexibility: Capital (1/2)

Investment Portfolio
- **Enterprise IT**

Investment Flexibility
- 13%

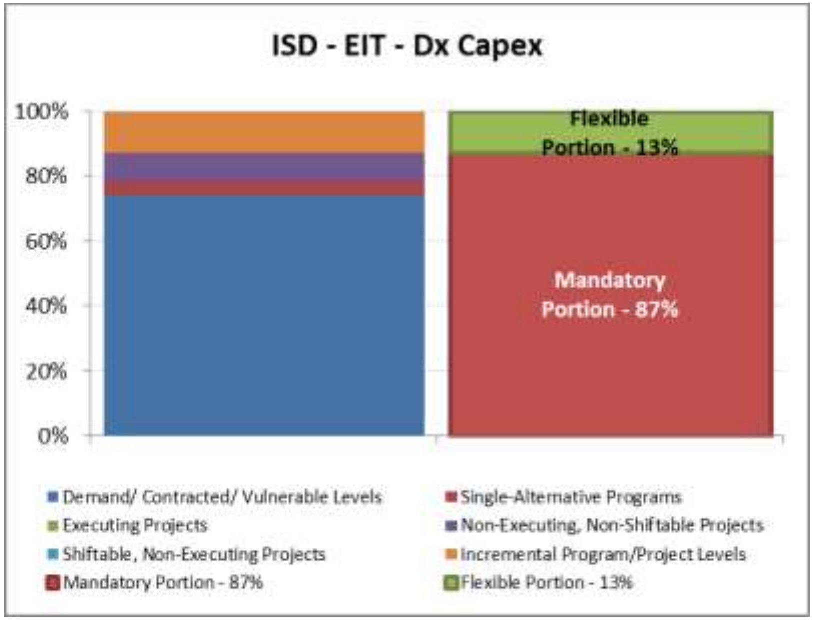
Mandatory/Non-Discretionary Overview
- **Mandatory Overview**

IT MFA, Infrastructure Refresh , IT Application Upgrades, IT Security, IT Project support, Replacement of end-of-life equipment.
- **Approach to Mandatory**

Application and infrastructure asset replacement, growth in demand for IT services, capacity limitations, maintain hardware and software currency at vendor supported levels, *MFA related funding for IT projects, compliance, red zone risk.*
- **Mandatory Drivers**

Ensure the ongoing reliability of our IT assets - Infrastructure refresh in order to maintain warranties within an acceptable level, Applications upgrades to ensure support from outsourcing partner and OEM vendor. Build out capacity on demand capability to provide hosting for new or expanded IT services and H1 LOB driven IT capital projects. New/advanced IT security capabilities .
- **Discretionary Opportunities**

None



Mandatory Driver	Approx. %
Obligation to upgrade – IT Infrastructure & Apps	53.5
Released Project / Un-Released Project	34.3
Other - Demand	4.8
Policy Responsiveness	3.3
Regulatory / Compliance	2.1
Other – IT Security Risk considerations, Business continuity	2.0
Contractual Commitment	
Other – Business Improvements / Enhancements	
License Condition	

Investment Flexibility: Capital (2/2)

Investment Portfolio

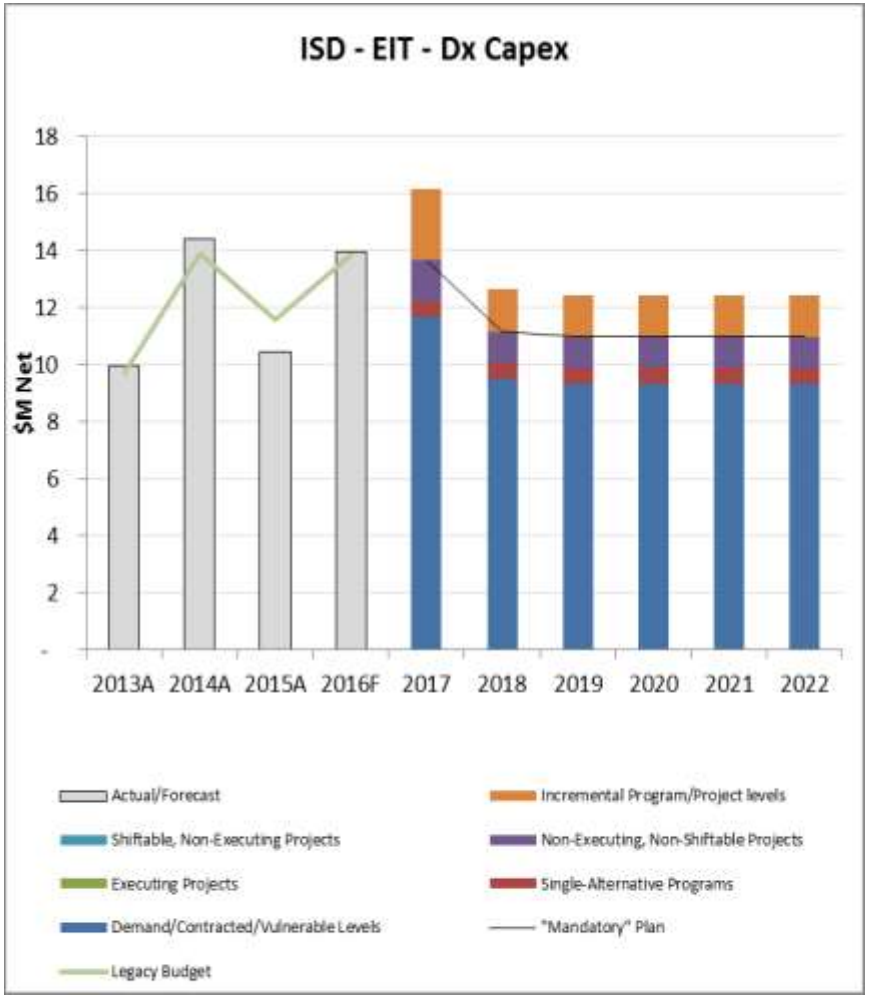
- **Enterprise IT**

Consistency with historic delivery/budget

- *Increase over historic levels.*
- *Portfolio delivery not always consistent with budget.*
- *Delivery shortfalls related to Infrastructure Refresh and associated MFA.*

Funding Reduction Risks and Implications

- *Incremental Program level funding required for Infra Tech Refresh Program and IT MFA for*
  - *Datacenter of Future Initiative to realize the additional opportunities /savings identified as part of the BCG analysis/Good to GREAT program.*
  - *Maintain warranties within expectable levels ; Replace end-of-life equipment*
  - *Ensure support from outsourcing partner and OEM Vendor*
  - Build out capacity on demand capability to provide hosting for H1 LOB driven IT capital projects.
- *IT security - Increase over historic levels ($ 2.8M in 2017 and $1.3M each year thereafter).*
  - *One –time investment $1.5M in 2017,* consolidation of enterprise and power system security event for purposes of Security monitoring.
  - Data loss prevention solution to monitor data being emailed, printed, uploaded to the internet or downloaded to a thumb drive.
  - Application security review annually selects an application such as SAP, to assess the code of practice application and coding security requirements.



Risk Assessments: Enterprise IT (1/4)

Investment Portfolio

- **Enterprise IT**

Approach

- *IT Outsourced Contractual Commitments (Inergi, Telecom Service Providers, 3rd Party contracts).*
- *Address H1 LOB IT needs, support new or existing business processes, enhancing customer experience and delivering operational efficiencies identified as part of Good to Great Program.(LOB meetings/workshops, IT Roadmap, Incremental sustainment costs assessment)*
- *Existing hardware and application investments coming to maturity.(CMDB, Configuration Mgmt. Database. Analytics of data to determine priority , Program scope, Technology Debt /Obsolescence versus Business Needs etc.)*
- *Demand capability limitations with respect to provide hosting to H1 business driven IT capital projects.(Capacity Planning Report. Analytics of data)*
- *Reduce OMA costs associated to end of life hardware and legacy application/OS/DB.(CMDB , Configuration Mgmt. Database)*
- *Maintain hardware and software currency at vendor supported levels (SLIM, Software licensing Information mgmt. Analytics of data to determine priority , Program scope, Technology Debt /Obsolescence versus Business Needs etc.)*
- *Compliance /Standards and Regulatory requirements*

Risk Sources

- **Significant Hazards/ Threats / Vulnerabilities**

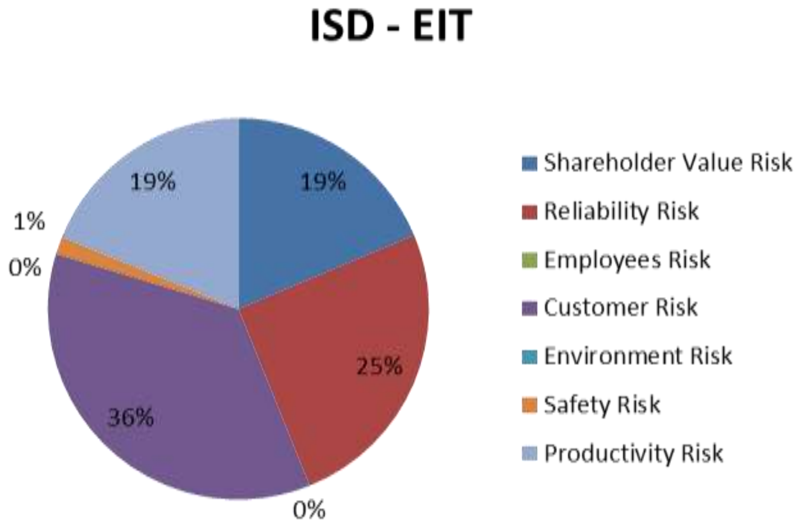
No outsourcing partner and OEM vendor support, IT service degradation, IT asset conditions, customer satisfaction, lower productivity/inefficiencies, compliance, increased sustainment/OMA costs.

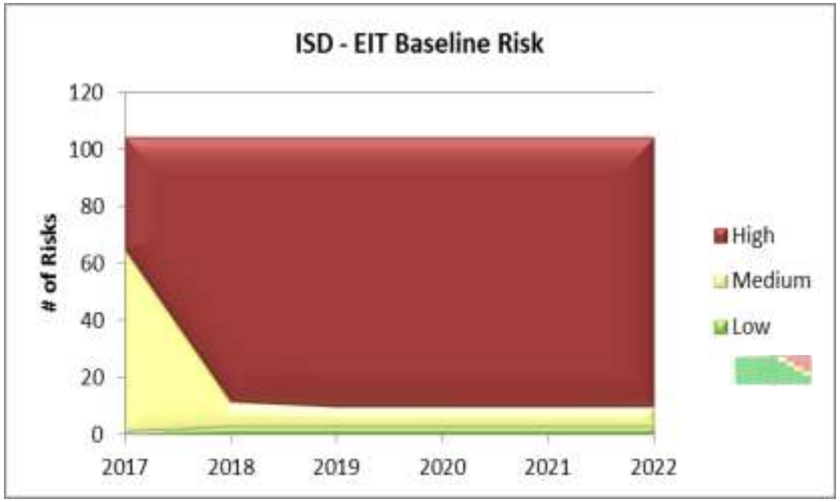
- **Significant Baseline Risk Consequences**

Outsourcer will not provide the contracted service and Hydro One will not be able to enforce the Service Level Agreements (SLAs), as per the outsourcing contract. Imminent stoppage of Applications / Hardware that are critical to operating the business operations and performance degradation due to unsupported applications/hardware. Contractual payments to third party carriers to lease circuits and equipment will not be made resulting in severe network performance degradation and can not address Hydro One's communication needs. Outsourced Base IT related to Applications Maintenance, Data Center Services, Distributed Server Sustainment and Help Desk & Desk side support will not be delivered to Hydro One and its employees. This will result in disruptions to the work that employees have to perform daily resulting in no productivity as the required business applications and hardware will not be operating. The risks as noted will have a direct impact on 1. delivery of our Customer Service Programs and Customer Satisfaction (as key systems and the data generated will not be available to our customers), 2. Hydro One's reputation and shareholder value.

- **Baseline Risk Trend**

Critical systems are not highly available and cannot survive the failure of any single supporting technology component. Applications are run on obsolete versions that are not supported by the vendors so employees cannot use and/or perform duties without interruptions due to unplanned downtime. Poor Customer experience and ineffective delivery of our Customer Service Programs linked to H1 Customer Satisfaction goals due to lower response times and inadequate infrastructure that would have a visible impact to the service provided. Limits implementation of Regulatory/Compliance related system changes and enhancements to support customers and operational efficiencies. Processes and systems cannot keep up with changing business requirements . Hydro One will not be able to adhere to an IT industry standard practice of managing its assets through a lifecycle program .





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Risk Assessments: Enterprise IT (2/4)

Top 5 Highest Risk Investments

Driver	Stage	Description	Investment Code	Baseline Value -	Rank
N.C.M.1.70	Short Term Planning	3rd Party Contracts	AIP000090	93.19539714	1
N.C.M.1.70	Short Term Planning	Inergi Sustainment	AIP000091	93.19539714	1
N.C.M.1.25	Short Term Planning	Telecom Data	AIP000082	31.06513238	8
N.C.M.1.25	Short Term Planning	Telecom Voice	AIP000084	31.06513238	8
N.C.M.2.70	Short Term Planning	Infrastructure Refresh	AIP000108	14.39457636	39

Top 5 Lowest Risk Investments

Driver	Stage	Description	Investment Code	Baseline Value -	Rank
N.C.M.1.70	Short Term Planning	Allocation HOT/Remotes	AIP000092	6.213026476	91
N.C.M.1.25	Short Term Planning	Recovery from HOT/REM	AIP000080	6.213026476	91
N.C.M.2.70	Short Term Planning	Compliance Monitoring & Reporting Program	AIP005741	4.924717536	109
N.C.C.1.75	Short Term Planning	ADS MFA	AIP000043	4.659769857	111
N.C.M.2.70	Short Term Planning	Data Security	AIP005722	0.697169886	253

Notes:
Includes only Dx/Common Investments
Excludes Investments without a risk assessment

Risk Assessments: Enterprise IT (3/4)

Investment Portfolio

- **Enterprise IT**

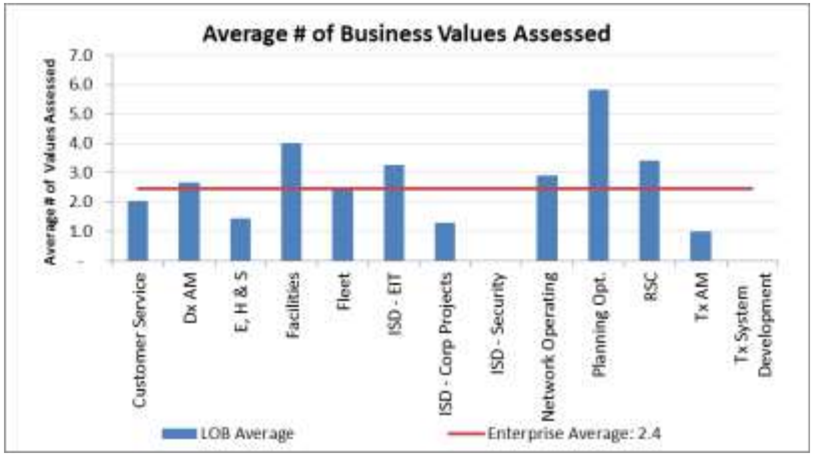
Alignment with Other LOBs

- **Scope of Risk Assessments**

IT is the enabler of the expanded customer service strategy and operational efficiencies as identified in Good to Great program. Employees have to be able to use systems to perform their daily work plan without interruptions. Systems and data generated needs to be made available without causing information gaps for our customers and loss of customer/ other H1 confidential data. Ensure the ongoing maintenance and sustainment of existing and newly commissioned systems, policies, practices, standards and regulatory requirements.

- **Changing Risk Profile**

Risk associated with IT Contractual Commitments (69% of total 6 year - EIT Dx Capital+OMA) is high across all six years. Risk associated with rest of the investments primarily had an increasing risk profile i.e. initially the risk profile is medium and it changes to high at the end of 6 years, with No IT investments.



Risk Assessments: Enterprise IT (4/4)

Investment Portfolio

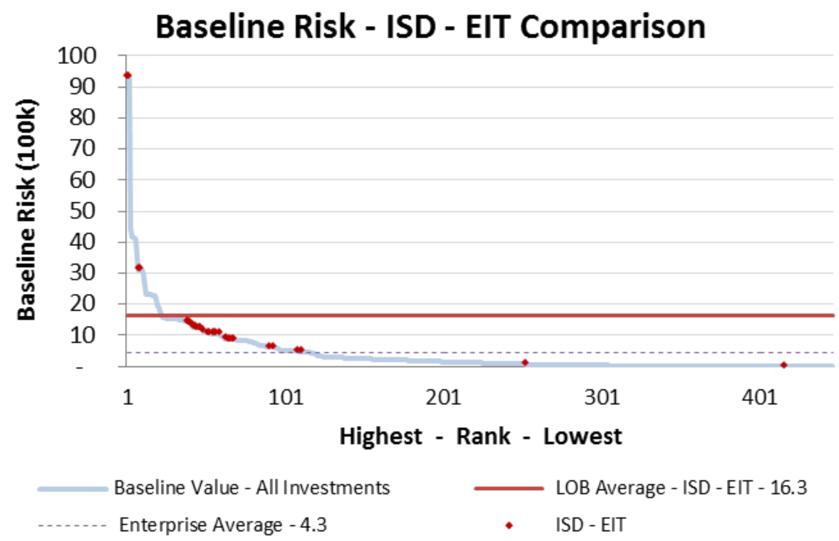
- **Enterprise IT**

Alignment with Other LOBs

- **Relativity of Risk Assessments**

Baseline risk for EIT investments is higher compared to Enterprise average and other LOBs.

- IT Contractual commitment investments (Inergi Outsourcing, 3rd Party and Telecom Service Providers) account for 69% of EIT- Dx Capital+OMA , have a baseline risk of 90k and 30k resp. This skewed EIT overall baseline average higher.
- Obligation to Upgrade, Released projects and Demand investments account for 21% of EIT- Dx Capital+OMA.
- Business Improvements / Enhancements investments account for 5% of EIT- Dx Capital+OMA.
- Compliance/Regulatory/Policy Responsiveness investments account for 3% of EIT- Dx Capital+OMA.



	First Quartile	Second Quartile	Third Quartile	Fourth Quartile
	Most Baseline Risk			Least Baseline Risk (or no assessment)
LOB Investments	28	1	1	1
LOB - % of Quartile	25.5%	0.9%	0.9%	0.9%
LOB - Quartile Distribution	90.5%	3.1%	3.2%	3.2%

Risk-Based Investment Walkthrough – Third Party Contracts (1/4)

Investment Code / Description

- AIP000090 / Third Party Contracts

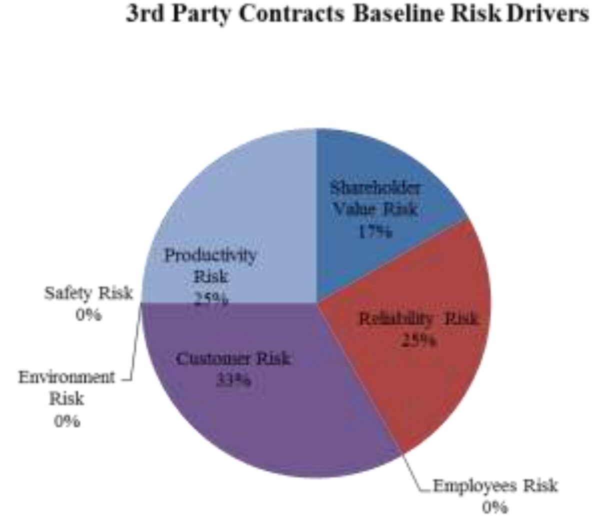
Mandatory Level and Alternatives Considered

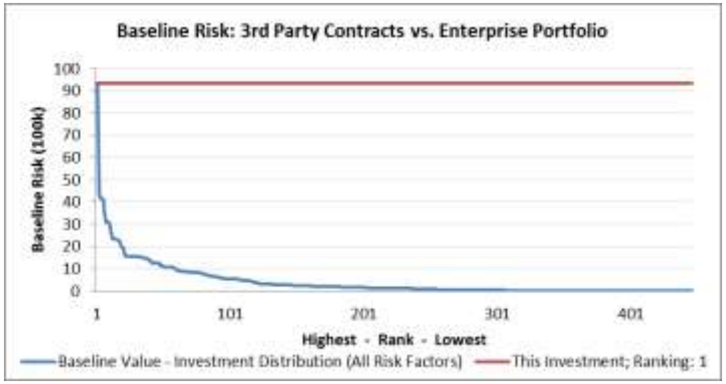
- No alternative's were provided. All dollars in this bucket relate to mandatory signed contracts.
- IT 3rd Party Contracts are the costs for hardware and software maintenance agreements to support existing and new applications. License or maintenance agreements are usually subject to annual increases as part of the contractual terms with the vendor. These fees are subject to annual audits by third party vendors to confirm the fees match the services provided.
- Top 10 contracts include:
  - SAP
  - Microsoft
  - Oracle
  - Trilliant
  - ESRI
  - HP
  - Success Factors
  - Itron
  - CDW
  - VmWare

Risk-Based Investment Walkthrough – Third Party Contracts (2/4)

Investment Code / Description
- AIP000090 / Third Party Contracts

Baseline Risk Assessment
- There would be an impact to our end customers as our critical infrastructure and business applications would experience a decline in reliability and availability.
- Shareholder value will be diminished due to a halt in improvements to key applications and infrastructure.
- Productivity will be impacted due to a drop in a level of service (more frequent and/or longer service interruptions) affecting reliability and availability. Potential for critical information systems being unavailable therefore causing information gap for our customers. Software and hardware maintenance contracts not maintained to vendor supported level will result in Inergi not being accountable to contracted Service Level Agreements (SLA's). Hardware maintenance contracts may not be renewed resulting in possible out of plan spend to resolve hardware problems.





Risk-Based Investment Walkthrough – Third Party Contracts (3/4)

Investment Code / Description

- AIP000090 / Third Party Contracts

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Customer	**Catastrophic**	Large and Mid Customers (Industrials, LDCs, Generators)	Large and Mid Customers (Industrials, LDCs, Generators): Increase in customer dissatisfaction with Hydro One	Numerous Large & Mid Customers initiate action such as by-pass or relocation; Exponential increase in customer lawsuits for direct and/or collateral damage believed to be caused by Hydro One; Complaints to provincial government increase dramatically
		OEB Service Quality Indices	Failure to meet Service Quality Indices.	Achieve only 25% (to 66%) of Overall Expected Performance.
		Residential and Small Business Customers	Residential and Small Business Customers: Increase in customer dissatisfaction with Hydro One service quality	Letters and complaints to MPPs escalate exponentially; significant numbers of customers begin to default on bill payments
Shareholder Value	**Catastrophic**	Net Income	Net Income Shortfall	>$300M
		Shareholder Confidence	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Complete loss of confidence; Shareholder Agreement rewritten to include active involvement in all business operations; CEO and Board replaced by the owner; Shareholder imposes substantial reduction in Hydro One scope and mandate
		Public Profile /Confidence re effective stewardship of assets	Public Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	National media attention; opinion leaders/customers nearly unanimous in public criticism
		Meet Licence Conditions and obtain required rates maintain credibility with regulators	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities including non- compliance.	General loss of Credibility; Intrusive Involvement;
		Regulatory/Legal Compliance	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction	Conviction with Incarceration of Staff

Risk-Based Investment Walkthrough – Third Party Contracts (4/4)

hydro one

Investment Code / Description

- AIP000090 / Third Party Contracts

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Reliability	**Catastrophic**	Reliable Delivery of Electricity	Transmission Unsupplied Energy (due to single acute event or outage) Measured in MWh	>10,000 MWh
			Deterioration in Transmission System reliability (over the next 5 years, compared to benchmarked comparable).	Deterioration to third quartile at any time in 5 year period.
			Transmission Lost Redundancy Power supplied without expected redundancy measured in MWh	> 200,000 MWh
			Equipment Unavailability (Incremental %): The extent to which the transmission equipment is not available for use due to outages	> 1% (100,000 asset-hours, for an asset class with 1000 assets)
			Improve Tx Worst Served Customers Number of outliers significantly impacted by investment	Impact 10 or more chronic outliers
			Duration of Distribution Outages Measured in Interruption Hours (Number of customers impacted * Expected duration of Outage)	>15 Million Customer Interruption Hours (equivalent to SAIDI of >12.5 hrs)
			Frequency of Distribution Outages Number of customers interrupted for > 1 minute	>7.5 Million Interruptions
Productivity	**Catastrophic**	Productivity	Failure meet Unit Cost targets per plan	Unit Costs increase by >10%

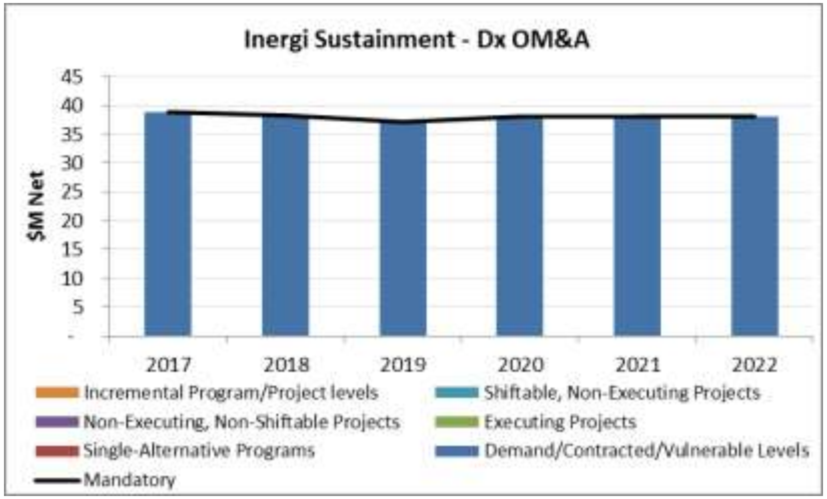
Risk-Based Investment Walkthrough – Inergi IT Sustainment (1/4)

Investment Code / Description

- AIP000091 / Inergi Sustainment

Mandatory Level and Alternatives Considered

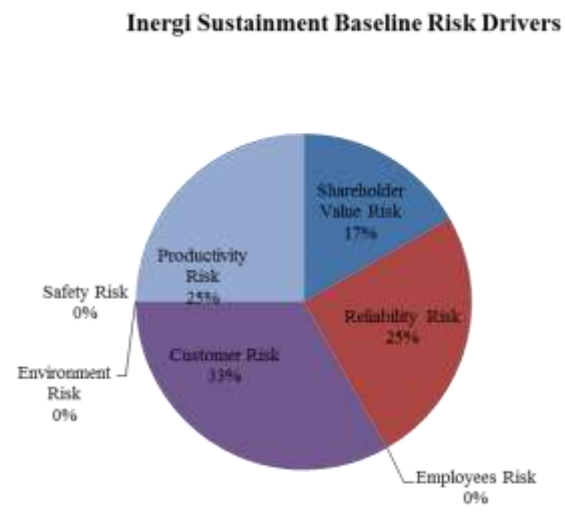
- No alternative's were provided. All dollars in this bucket relate to Inergi Outsourcing Contract signed in March 2015. Contract goes till end of 2019 with two additional option years.
- Outsourcing contract will :
  - Maintain current service levels for the infrastructure and applications.
  - Support new business applications via a planned implementation program.
  - Our critical infrastructure and business applications will be reliable and available. So there would be no negative impact to our end customers.

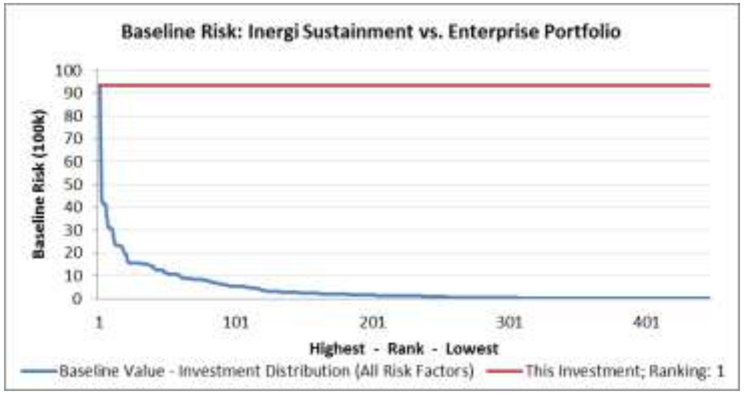


Risk-Based Investment Walkthrough – Inergi IT Sustainment (2/4)

Investment Code / Description
- AIP000091 / Inergi Sustainment

Baseline Risk Assessment
- There would be an impact to our end customers as our critical infrastructure and business applications would experience a decline in reliability and availability.
- Shareholder value will be diminished due to a halt in improvements to key applications and infrastructure.
- Productivity will be impacted due to a drop in a level of service (more frequent and/or longer service interruptions) affecting reliability and availability. Potential for critical information systems being unavailable therefore causing information gap for our customers. Software and hardware maintenance contracts not maintained to vendor supported level will result in Inergi not being accountable to contracted Service Level Agreements (SLA's). Hardware maintenance contracts may not be renewed resulting in possible out of plan spend to resolve hardware problems.





Risk-Based Investment Walkthrough – Inergi IT Sustainment (3/4)

hydro one

Investment Code / Description

- AIP000091 / Inergi Sustainment

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Customer	**Catastrophic**	Large and Mid Customers (Industrials, LDCs, Generators)	Large and Mid Customers (Industrials, LDCs, Generators): Increase in customer dissatisfaction with Hydro One	Numerous Large & Mid Customers initiate action such as by-pass or relocation; Exponential increase in customer lawsuits for direct and/or collateral damage believed to be caused by Hydro One; Complaints to provincial government increase dramatically
		OEB Service Quality Indices	Failure to meet Service Quality Indices.	Achieve only 25% (to 66%) of Overall Expected Performance.
		Residential and Small Business Customers	Residential and Small Business Customers: Increase in customer dissatisfaction with Hydro One service quality	Letters and complaints to MPPs escalate exponentially; significant numbers of customers begin to default on bill payments
Shareholder Value	**Catastrophic**	Net Income	Net Income Shortfall	>$300M
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		Meet Licence Conditions and obtain required rates maintain credibility with regulators	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities including non- compliance.	General loss of Credibility; Intrusive Involvement;
		Regulatory/Legal Compliance	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction	Conviction with Incarceration of Staff

Risk-Based Investment Walkthrough – Inergi IT Sustainment (4/4)

Investment Code / Description

- AIP000091 / Inergi Sustainment

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Reliability	**Catastrophic**	Reliable Delivery of Electricity	Transmission Unsupplied Energy (due to single acute event or outage) Measured in MWh	>10,000 MWh
			Deterioration in Transmission System reliability (over the next 5 years, compared to benchmarked comparable).	Deterioration to third quartile at any time in 5 year period.
			Transmission Lost Redundancy Power supplied without expected redundancy measured in MWh	> 200,000 MWh
			Equipment Unavailability (Incremental %): The extent to which the transmission equipment is not available for use due to outages	> 1% (100,000 asset-hours, for an asset class with 1000 assets)
			Improve Tx Worst Served Customers Number of outliers significantly impacted by investment	Impact 10 or more chronic outliers
			Duration of Distribution Outages Measured in Interruption Hours (Number of customers impacted * Expected duration of Outage)	>15 Million Customer Interruption Hours (equivalent to SAIDI of >12.5 hrs)
			Frequency of Distribution Outages Number of customers interrupted for > 1 minute	>7.5 Million Interruptions
Productivity	**Catastrophic**	Productivity	Failure meet Unit Cost targets per plan	Unit Costs increase by >10%

Investment Calibration

Facilities and Real Estate
Lou Fortini
July 12, 2016

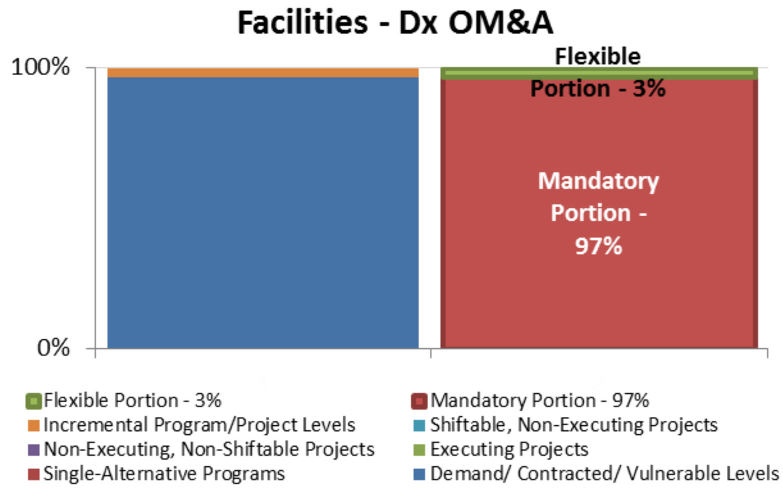
Investment Flexibility: OM&A

Investment Flexibility

- Real Estate costs are pre-dominantly fixed

Mandatory/Non-Discretionary Overview

- **Mandatory Overview** – Provides for employee work space and housing for materials and equipment)
- **Approach to Mandatory** – To meet minimum obligations to maintain existing workspace.
- **Mandatory Drivers** – Provide workspace and housing facilities for materials and equipment.
- **Discretionary Opportunities** – No existing funding for discretionary expenditures – reduction only by elimination of existing workspace



in $M	Actuals			Projection	2017 - 2022 Proposal					
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
NCM150	44	44	50	49	49	50	52	52	52	52

Investment Flexibility: OM&A

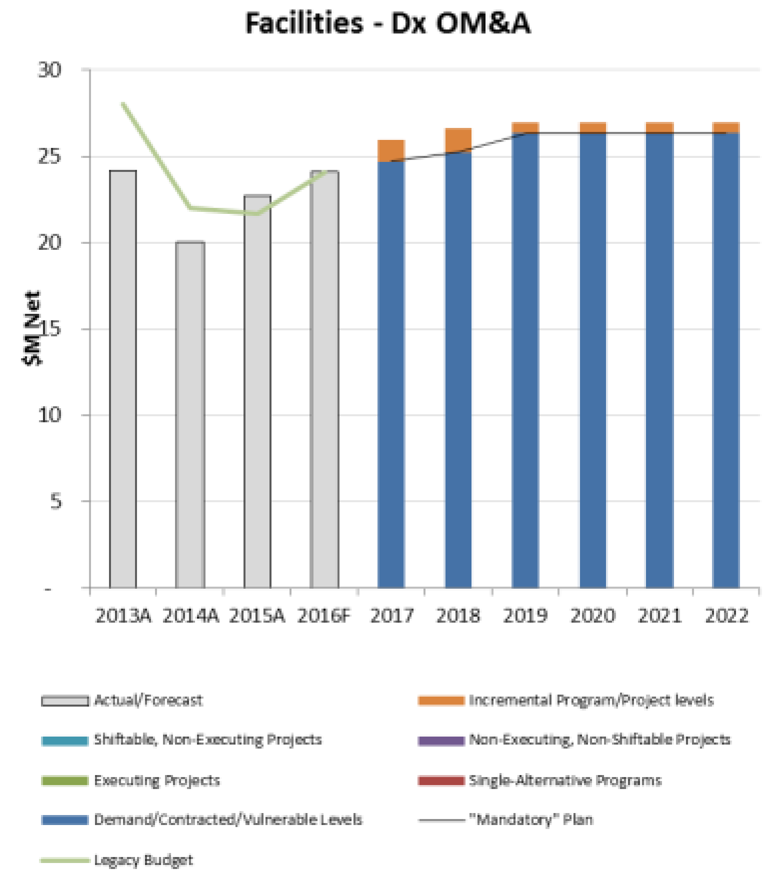
Consistency with historic delivery/budget

- The funding is at the minimum . Expected 2016 expenditures beyond current budget

Funding Reduction Risks and Implications

- Elimination of employee workspace and /or housing facilities (Warehouses, Garages, Operation Centres)

- Eliminated workplace for employees and / or no available housing for company equipment , materials and fleet resulting with lost operational ability, limited or no access to assets and equipment failure.



*shows Dx allocation only

in $M	Actuals			Projection	2017 - 2022 Proposal					
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
NCM150	44	44	50	49	49	50	52	52	52	52

Investment Flexibility: Capital

hydro one

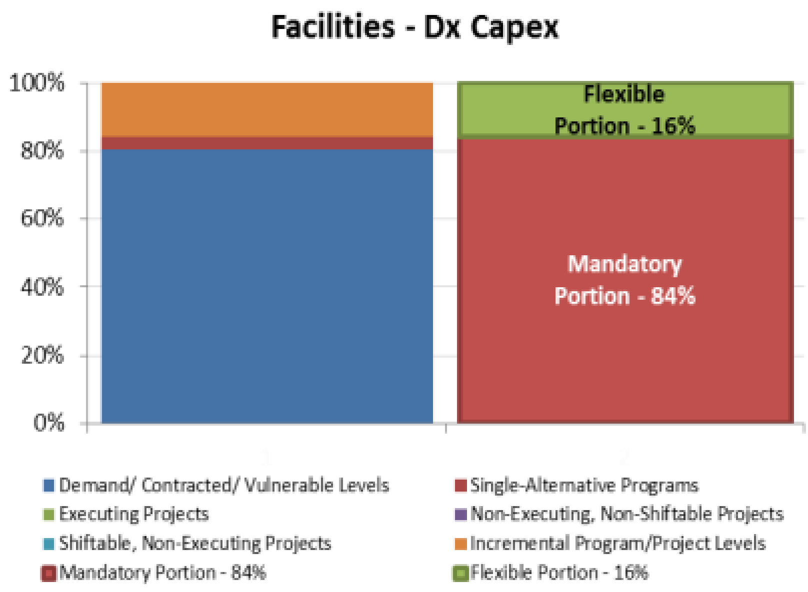
Mandatory/Non-Discretionary Overview

- This investment is addressing funding requirements for space and operational accommodation needs in terms of new facilities, building additions and capital sustainment activities: such as replacement of major building components including roof structures, windows, heating, ventilating and air conditioning (HVAC) systems and other structural elements.
- Funding covers only - Must do = priority one Facilities Improvements and additions

Mandatory Drivers:

- End of Life Facilities, H&SE Issues, LOB Requirements and Corporate Initiatives / Strategy e.g. (LDC)

Discretionary Opportunities – not covered under current level of funding.



in $M	Actuals			Projection	2017 - 2022 Proposal					
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
NCC150 *	15	26	27	35	35	40	40	45	45	45
NDC150					7	21	22	16	16	13
Total	15	26	27	35	42	61	62	61	61	58

Investment Flexibility: Capital

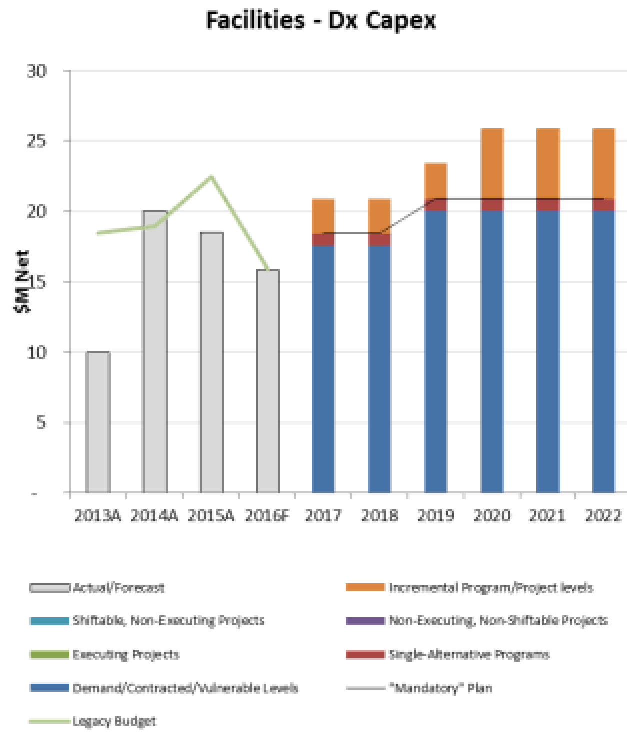
hydro one

Consistency with historic delivery/budget

- The historic delivery was focus on must do capital sustainment work and deferral of Facilities Investments. Now the investments are needed to address new and need fo replacement facilities and urgent renovations of existing buildings.

Funding Reduction Risks and Implications

- Further reduction of "must do" capital work will likely result in facilities accommodations not being able to meet either due to lack of capacity or failed facilities physical conditions company operational requirements.
- Eliminated workplace for employees and / or no available housing for company equipment , materials and fleet resulting with lost operational ability, limited or no access to assets and equipment failure.



*shows Dx allocation only

in $M	Actuals			Projection	2017 - 2022 Proposal					
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
NCC150 *	15	26	27	35	35	40	40	45	45	45
NDC150					7	21	22	16	16	13
Total	15	26	27	35	42	61	62	61	61	58

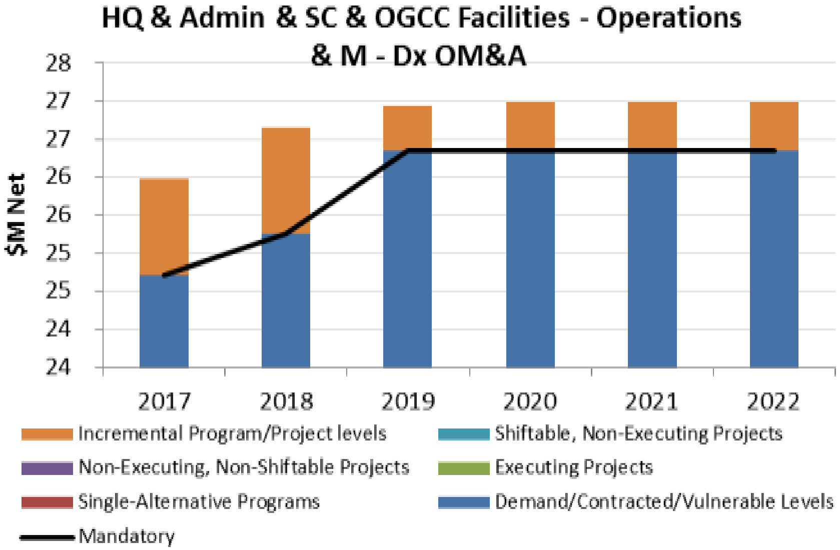
Risk-Based Investment Walkthrough – Facilities OM&A

Investment Code / Description

- **AIP000086 / HQ & Admin & SC & OGCC Facilities OM&A**

Mandatory Level and Alternatives Considered

- To meet minimum requirements to maintain existing facilities.
- The Mandatory funding level will see lease contract (e.g. rent, operating expenses, taxes), Administrative Service Centre utility and similar cost obligations met in accordance with legal agreement requirements. As well, operations / maintenance activities would continue to include taking all necessary steps to ensure legislative and regulatory requirements are met with respect to facility operations. Service levels will be provided based on currently mandated and/ or fixed obligations.



*shows Dx allocation only

Risk-Based Investment Walkthrough – Facilities OM&A

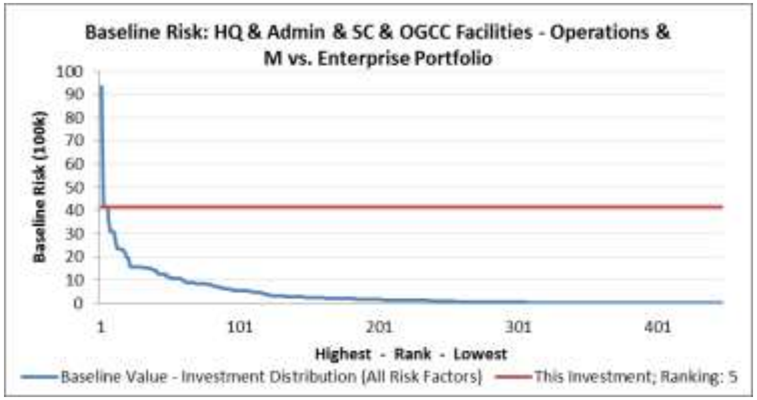
Investment Code / Description

- **AIP000086 / HQ & Admin & SC & OGCC Facilities OM&A**

Baseline Risk Assessment

- The program provides for employee workspace, storage facilities and facilities housing work equipment.

- The Facilities work program is fixed in terms of operating cost and is predominately driven by Company work program space requirements, which also reflects regulatory environment, health & safety and staff levels. The program is subjected to local real estate markets conditions throughout the Province and economic factors effecting fixed contractual obligations including utility prices. The program funding has direct correlation to employee workspace that is provided and potential reduction in funding would ultimately result in reduction / elimination of existing workspace.



Risk Assessments: Facilities and Real Estate Capital

Investment Portfolio

- **Facilities and Real Estate- Capital**

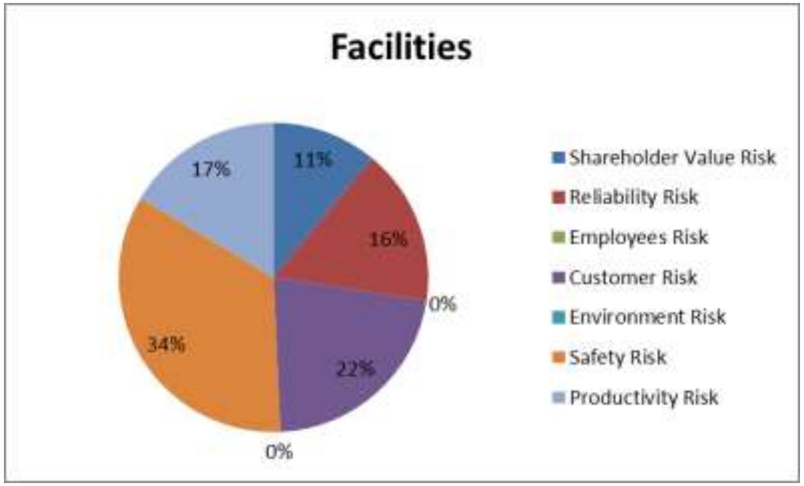
Approach

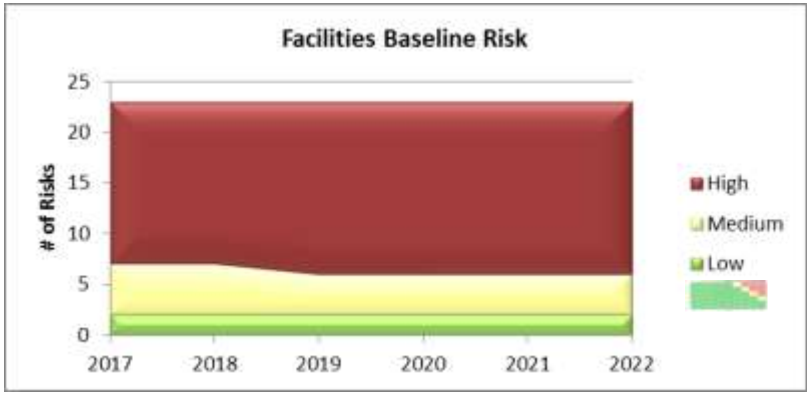
- Asset Conditions Assessments of existing Facilities and Company current and future operational requirements.

Risk Sources

- The aging facilities asset base in conjunction with operational needs of the business units requires capital investment in order to continue to provide adequate accommodation space. Approximately 40% of Administrative and Service Centres facilities infrastructure are estimated to be more than 40 years old. This issue is being addressed now through facilities improvements & accommodation strategy initiative, which will continue over the planning period.

- **Baseline Trend:**
- The investments are done on priority bases with work the most urgent going forward first.





Risk-Based Investment Walkthrough – Facility Accommodations and Improvements - Capital

Investment Code / Description

- **AIP001215 / Dx Facility Accommodations and Improvements**

Mandatory Level and Alternatives Considered

- Must do – priority one investments only
- This funding level will address 'must do' capital work levels, addressing only emergency repairs, high priority improvements, significantly limiting response to identified estimates of facilities improvement work over the planning period of 2017-2022.

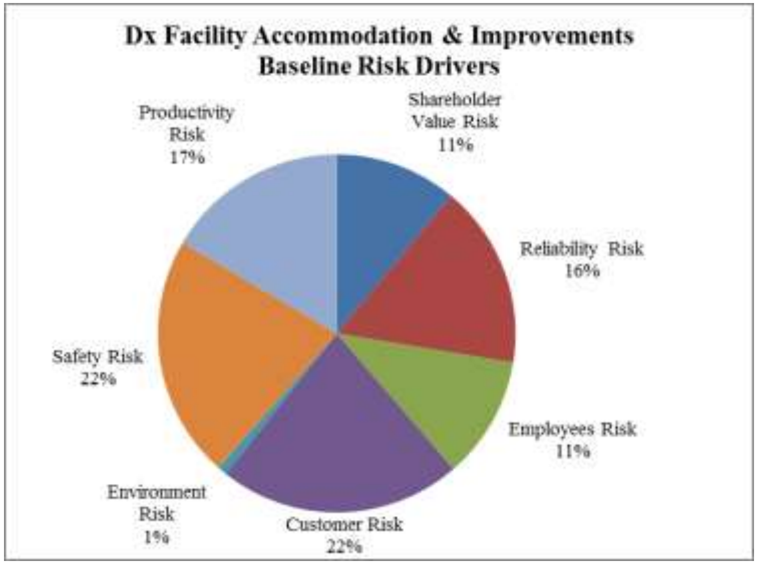
Risk-Based Investment Walkthrough – Facility Accommodations and Improvements Capital

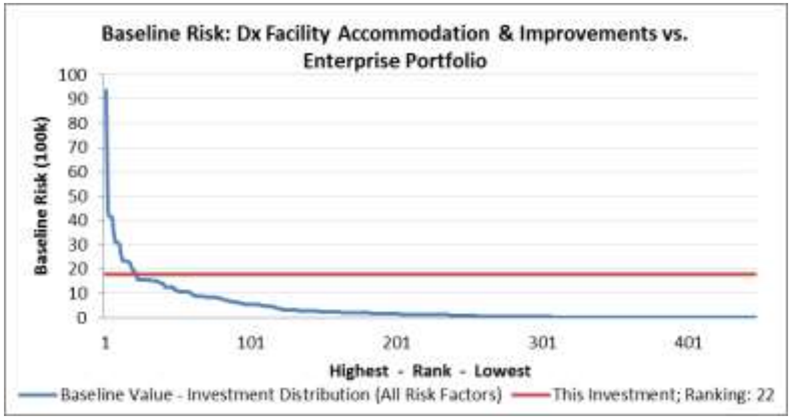
Investment Code / Description

- **AIP001215 / Dx Facility Accommodations and Improvements**

Baseline Risk Assessment

- Facilities not available or in conditions not acceptable to accommodate for employee workspace, housing of company assets and equipment. Facilities not being able to meet LOB operational requirements.





Risk Assessments: Facilities and Real Estate

Top 5 Highest/Lowest Risk Investments

Driver	Stage	Description	Investment Code	Baseline Risk - Investment Distribution (All Risk Factors)	Rank
N.C.M.1.50	Short Term Planning	HQ & Admin & SC & OGCC Facilities - Operations & M	AIP000086	41.3942889	5
N.C.C.1.50	Short Term Planning	Facility Accommodation & Improvements Service Centres & Admin	AIP000027	22.75520947	18
N.D.C.1.50	Short Term Planning	Dx Facility Accommodation & Improvements	AIP001215	17.615592	22
N.C.C.1.50	Short Term Planning	Facility Improvements HQ, GTA Admin & CSO Faciliti	AIP000028	8.730383907	69
N.C.C.1.55	Short Term Planning	Facilities & Real Estate MFA	AIP000029	0.238175855	314

Notes:
Includes only Dx/Common Investments
Excludes Investments without a risk assessment

Investment Calibration

Distribution Asset Management
Sinisa Grkovic (for Paul Brown)
July 12, 2016

Return to Agenda

Investment Flexibility: OM&A (1/2)

Investment Portfolio

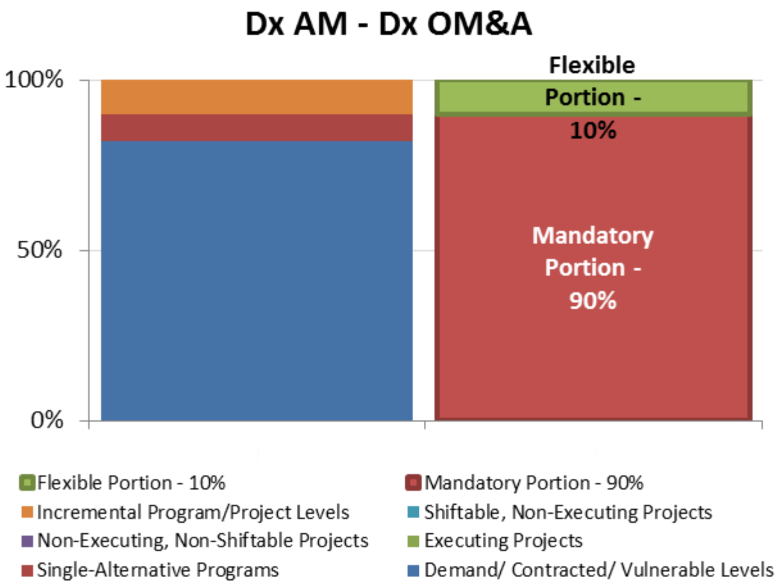
- **Distribution Asset Management**

Investment Flexibility

- **10**% [corresponds to graph on the side; based on 6 yr total]

Mandatory/Non-Discretionary Overview

- **Mandatory Overview** *i.e. Storm Response, Customer Connections, Metering Reading, Electrical Code Requirements, Environmental Code Requirements, etc.*
- **Approach to Mandatory**; *i.e. compliance*
- **Mandatory Drivers** *i.e. compliance, break/fix, obligation to connect, license condition, etc.*
- **Discretionary Opportunities** *i.e. VM, Defect Corrections, Equipment Replacement Program, DSs Maintenance, etc*.



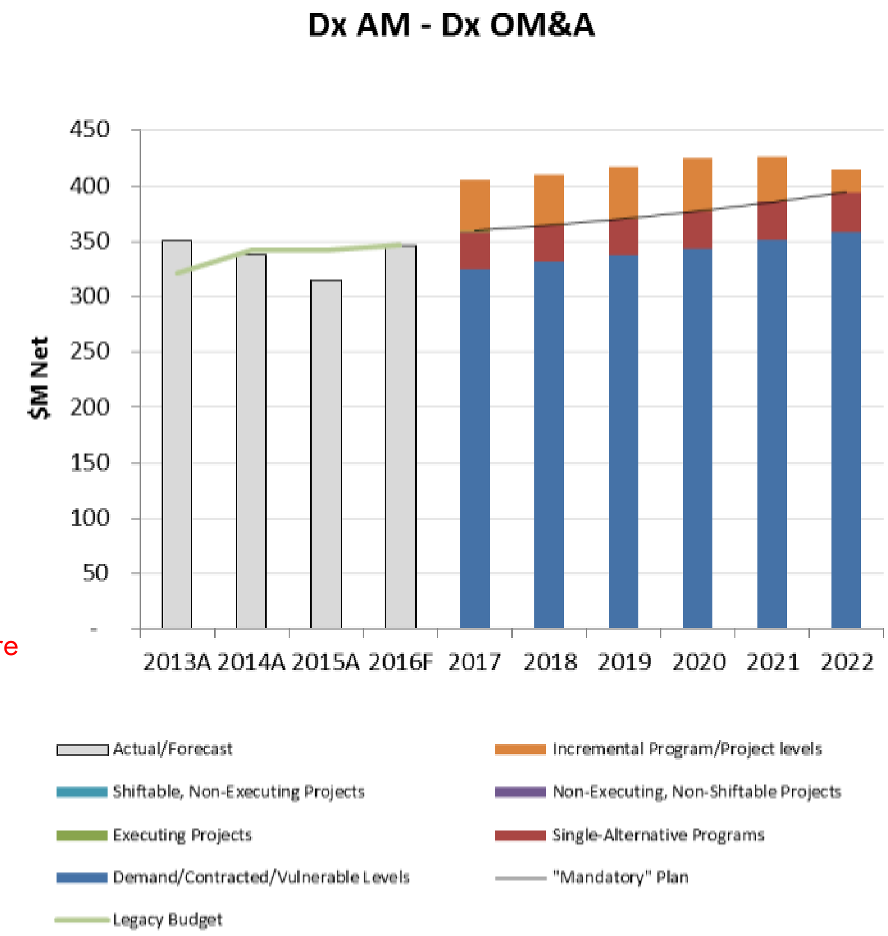
Mandatory Driver	Approx. %
Emergency Break/ Fix	70%
Legal Regulatory/ Compliance	9%
Obligation to connect/ upgrade/ modify	7%
License Condition	10%
Contractual Commitment	
Policy Responsiveness	3%
Released Project	

Investment Flexibility: OM&A (2/2)

Investment Portfolio
- **Distribution Asset Management**

Consistency with historic delivery/budget
- Increase over historic values *(unit costs trending upwards, investment base is larger – LDC acquisitions)*
- DX OM&A redirection to manage corporate envelope is common

Funding Reduction Risks and Implications
- Main incremental Risk of a +/- 10% mandatory program change or 1-2 year project deferral is seen in not meeting mandatory compliance targets, inability to maintain asset conditions and maintain/improve reliability
- Reduction/deferral will result in backlog and increase of future investments (on VM), non-compliance (on Dx Patrols and PCB Testing) and reliability deteriotion (on Dx Maintenance)



Investment Flexibility: Capital (1/2)

Investment Portfolio

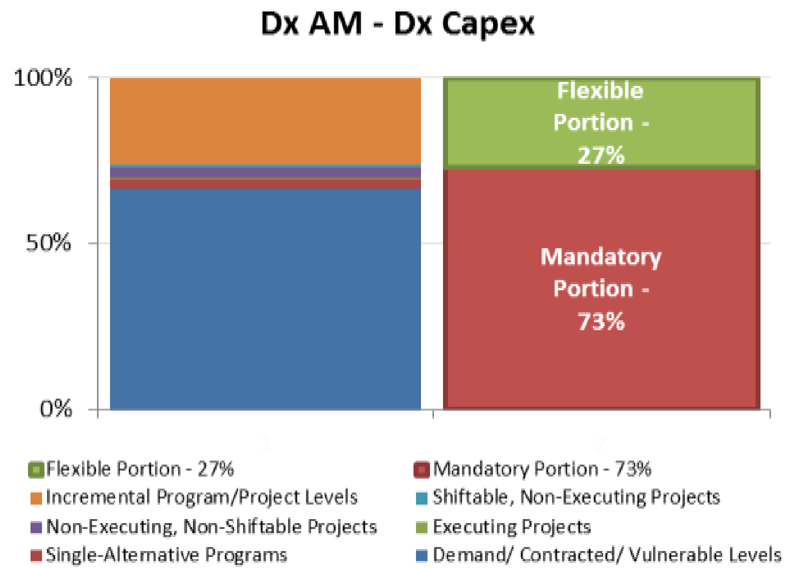
- **Distribution Asset Management**

Investment Flexibility

- **[47]**% [corresponds to graph on the side; based on 6 yr total]
- NOTE: Mandatory portion is 53% for CapEX (graph to be updated)

Mandatory/Non-Discretionary Overview

- **Mandatory Overview** *i.e. Storm Response, Customer Connections, Joint use, Line Relocations, PCB Transformer Replacement, etc.*
- **Approach to Mandatory** *i.e. compliance, red zone risk, rolling multi-year average (related to storm/new connects), etc.*
- **Mandatory Drivers** *i.e. compliance (PCB Tx Replacement, Gen Cxns, Load Expectations), break/fix (Trouble, Storm), in-execution (Leamington Cost Contribution), etc.*
- **Discretionary Opportunities** *i.e. funding levels within the compliance window can be adjusted (PCB Tx Repl), system upgrades triggered by load growth (System Capability Reinforcement), etc.*



Mandatory Driver	Approx. %
Emergency Break/ Fix	34%
Legal Regulatory/ Compliance	12%
Obligation to connect/ upgrade/ modify	46%
License Condition	
Contractual Commitment	
Policy Responsiveness	1%
Released Project	8%

Investment Flexibility: Capital (2/2)

Investment Portfolio

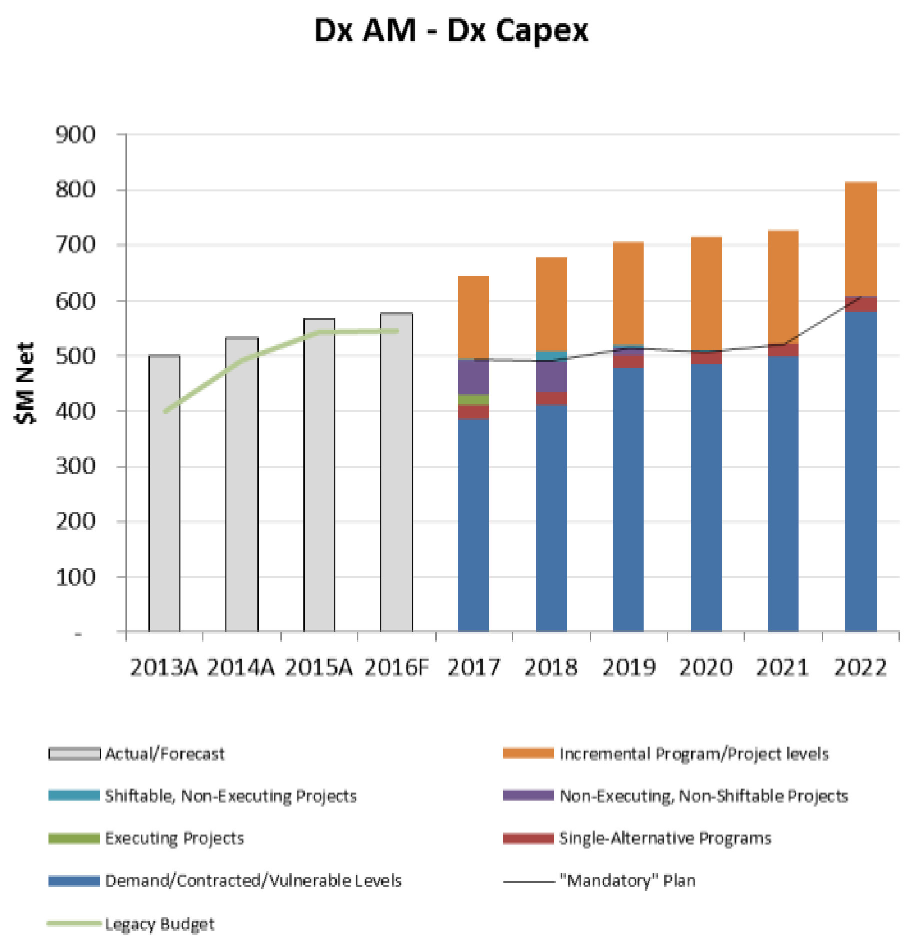
- **Distribution Asset Management**

Consistency with historic delivery/budget

- *i.e. increase over historic levels (Pole Replacement, Component Replacement, PCB Replacement, etc.)*
- *i.e. portfolio generally consistent with budget*

Funding Reduction Risks and Implications

- *Inability to respond to storm events and restoration, deteriorated asset condition leading to failure and reliability degradation, inability to meet capacity requirements, inability to connect new customers, non-compliance to environmental policies, etc.*



Risk Assessments: Dx AM (1/4)

Investment Portfolio

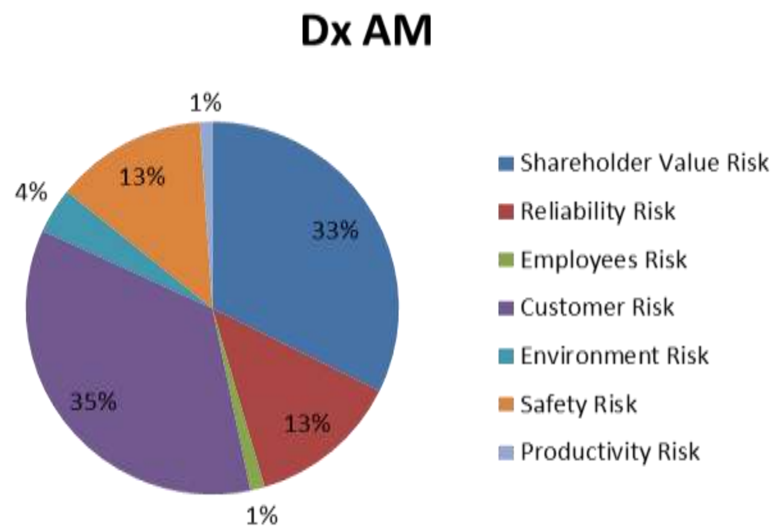
- **Distribution Asset Management**

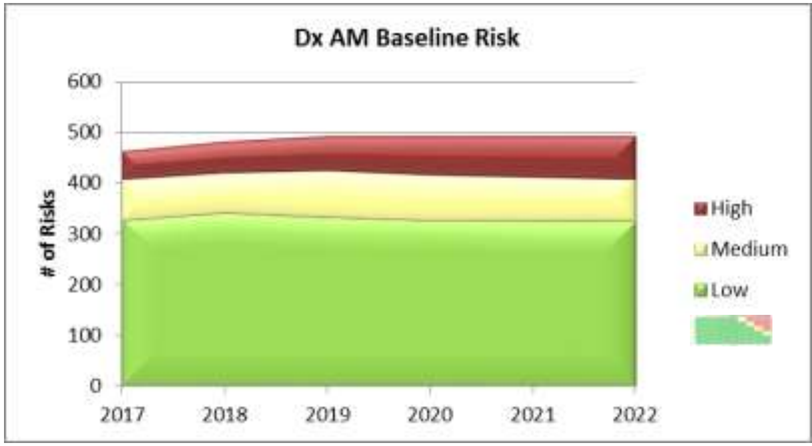
Approach

- Discussed primary business value drivers for investments within DX AM (specific teams for projects vs programs).
- Data considered: condition and demographics data from SAP/AA, loading data form NMS and ERAs, utilization of CYME for modeling, review of historical reliability data, customer impact data;

Risk Sources

- **Significant Hazards/ Threats / Vulnerabilities** *i.e. unexpected natural events, non clarity on data considered identified above*
- **Significant Baseline Risk Consequences** *i.e. service delivery impacts, customer satisfactions, compliance, etc.*
- **Baseline Risk Trend** *i.e. deterioration because renewal efforts do not keep up with replacements, etc.*





Risk Assessments: Dx AM (2/4)

Top 5 Highest Risk Investments

Driver	Stage	Description	Investment Code	Baseline Value ·	Rank
N.D.C.2.03	Short Term Planning	Micro Embedded Generation Connections	AIP000198	23.29884928	13
N.D.C.2.03	Short Term Planning	Net Metered Embedded Generation	AIP000200	23.29884928	13
N.D.C.2.03	Short Term Planning	Small Embedded Generation	AIP000191	23.29884928	13
N.D.C.1.06	Short Term Planning	Storm Damage	AIP000137	21.48153904	19

Top 5 Lowest Risk Investments

Driver	Stage	Description	Investment Code	Baseline Value ·	Rank
N.D.C.2.02	Short Term Planning	Beckwith DS F3 Feeder Development	AIP005425	0.003253655	369
N.D.C.2.02	Short Term Planning	Manotick DS F3	AIP005427	0.003253655	369
N.D.M.2.02	Short Term Planning	ArcFM Business Process Support	AIP000288	0.002329885	372
N.D.M.1.17	Short Term Planning	DX P&C Corrective	AIP000282	0.000698965	374
N.D.M.1.17	Short Term Planning	P&C Distribution Support	AIP000283	0.000698965	374

Notes:
Includes only Dx/Common Investments
Excludes Investments without a risk assessment

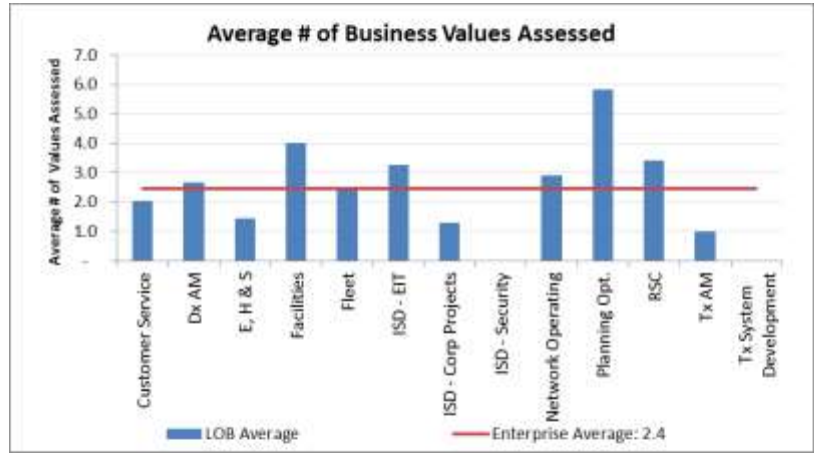
Risk Assessments: Dx AM (3/4)

Investment Portfolio

- **Distribution Asset Management**

Alignment with Other LOBs

- **Scope of Risk Assessments**; Majority of Dx AM investments will impact Reliability, Customer and Shareholder value (compliance and public image). Some investments will impact safety and environment.
- **Changing Risk Profile**; *Risk profile degrades if no investments are undertaken (baseline risk). However the change is significantly less than presented by other LOBs*



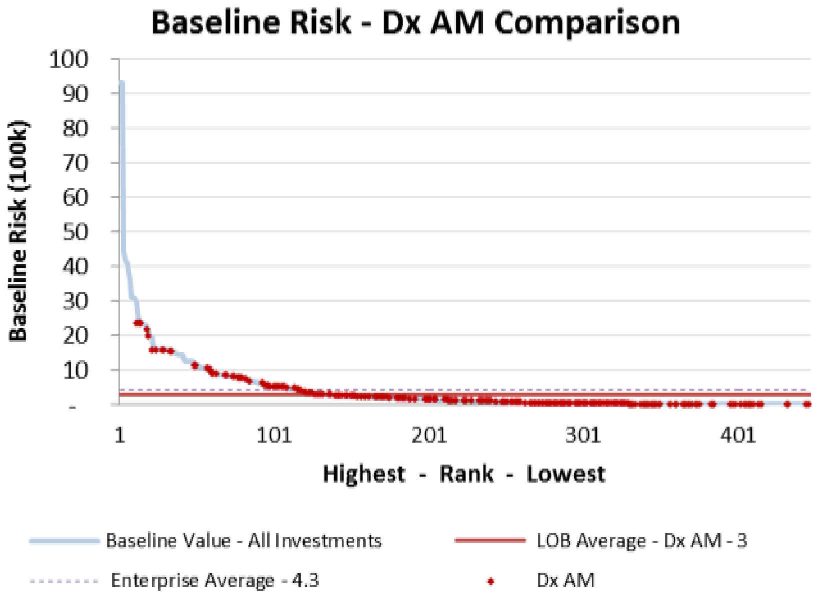
Risk Assessments: Dx AM (4/4)

Investment Portfolio

- **Distribution Asset Management**

Alignment with Other LOBs

- **Relativity of Risk Assessments;** Risk is slightly below enterprise average. It should be noted that DX AM contains large portion of DX related investments hence has high impact on the enterprise average. Compared to most other LOBs our baseline risk assessment is relatively low.



	First Quartile	Second Quartile	Third Quartile	Fourth Quartile
	Most Baseline Risk			Least Baseline Risk (or no assessment)
LOB Investments	43	62	87	44
LOB - % of Quartile	39.1%	54.4%	78.4%	39.3%
LOB - Quartile Distribution	18.5%	25.8%	37.1%	18.6%

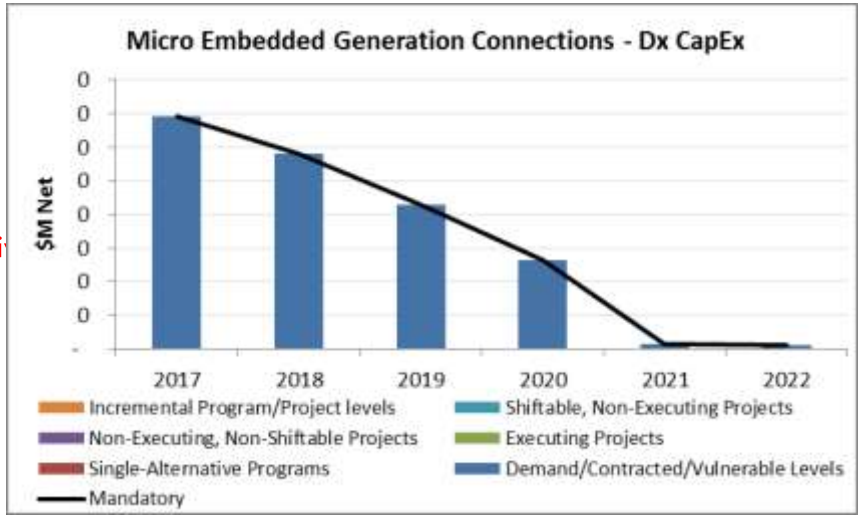
Risk-Based Investment Walkthrough-MicroFit (1/4)

Investment Code / Description

- AIP000198 / Micro Embedded Generation Connections

Mandatory Level and Alternatives Considered

- Due to the mandatory nature of this investment only one alternative is considered.



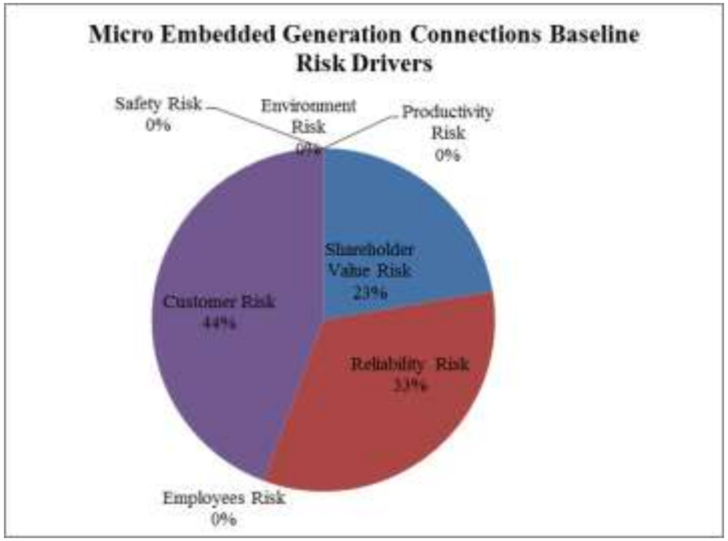
Risk-Based Investment Walkthrough-MicroFit (2/4)

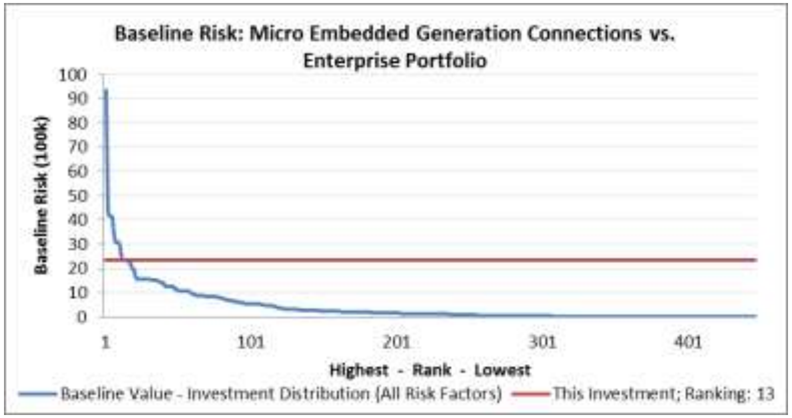
Investment Code / Description

- AIP000198 / Micro Embedded Generation Connections

Baseline Risk Assessment

- Shareholder value and customer are the primary business value drivers for this investment. Ability to connect micro embedded generation is high profile and effects specifically customers that are looking to connect these generators.
- Reliability risk for this investments was recognized as not one of the main drivers and will need to be removed.





Risk-Based Investment Walkthrough-MicroFit (3/4)

Investment Code / Description

- AIP000198 / Micro Embedded Generation Connections

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Customer	**Severe**	Large and Mid Customers (Industrials, LDCs, Generators)	Large and Mid Customers (Industrials, LDCs, Generators): Increase in customer dissatisfaction with Hydro One	Customer associations (AMPCO, etc.) step up lobbying efforts for stricter penalties against Hydro One; Increase in customer lawsuits for direct and/or collateral damage believed to be caused by Hydro One; Complaints to provincial government increase significantly; Sharp deterioration in large and mid customer satisfaction survey results (as measured by scorecard) across multiple segments.
		OEB Service Quality Indices	Failure to meet Service Quality Indices.	Achieve only 67% (to 79%) of Overall Expected Performance.
		Residential and Small Business Customers	Residential and Small Business Customers: Increase in customer dissatisfaction with Hydro One service quality	Exponential increase (>30%) in: - call centre volumes (not storm related); - complaints received by field staff; - time and effort to resolve; Sharp deterioration in mass market customer satisfaction as per survey responses (as measured by scorecard).
Shareholder Value	**Severe**	Net Income	Net Income Shortfall	$100-$300M
		Shareholder Confidence	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Extensive loss of confidence; Shareholder Agreement rewritten to include approval of all investment and operating decisions; CEO or several Sr. Managers replaced
		Public Profile /Confidence re effective stewardship of assets	Public Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	Provincial media attention; most opinion leaders/customers publicly critical
		Meet Licence Conditions and obtain required rates maintain credibility with regulators	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities including non- compliance.	Some loss of Credibility; Excessive Involvement;
		Regulatory/Legal Compliance	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction	Conviction or regulatory finding of non-compliance with major fine ("major" meaning >30% of maximum fine under relevant legislation or regulation, or an unusually high/unprecedented amount for the industry).

Risk-Based Investment Walkthrough-MicroFit (4/4)

Investment Code / Description

- AIP000198 / Micro Embedded Generation Connections

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Reliability	**Severe**	Reliable Delivery of Electricity	Transmission Unsupplied Energy (due to single acute event or outage) Measured in MWh	5000-10,000MWh
			Deterioration in Transmission System reliability (over the next 5 years, compared to benchmarked comparable).	Deterioration to second quartile for more than one year in the 5 year period.
			Transmission Lost Redundancy Power supplied without expected redundancy measured in MWh	100,000 MWh-200,000 MWh
			Equipment Unavailability (Incremental %): The extent to which the transmission equipment is not available for use due to outages	0.5 - 1% (40,000 to 100,000 asset-hours, for an asset class with 1000 assets)
			Improve Tx Worst Served Customers Number of outliers significantly impacted by investment	Impact 5 to 10 chronic outliers
			Duration of Distribution Outages Measured in Interruption Hours (Number of customers impacted * Expected duration of Outage)	10 Million to 15 Million Customer Interruption Hours (equivalent to SAIDI of 8.3 to 12.5 hrs)
			Frequency of Distribution Outages Number of customers interrupted for > 1 minute	3.75 Million to 7.5 Million Interruptions

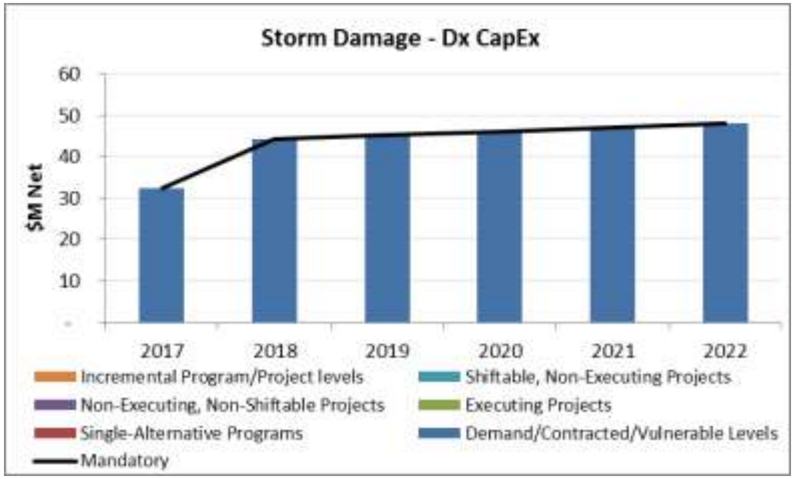
Risk-Based Investment Walkthrough- Storm Damage (1/4)

Investment Code / Description

- AIP000137 / Storm Damage

Mandatory Level and Alternatives Considered

- Only investment level considered based on historic spent (2018 and onwards). 2017 was constrained due to corporate budgets.



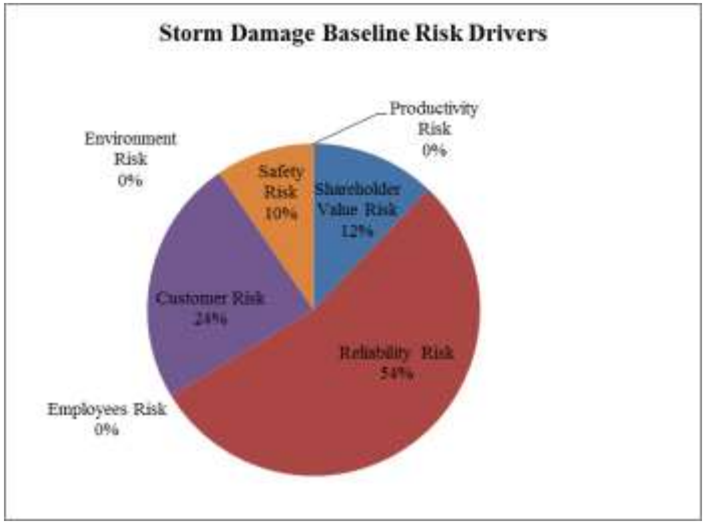
Risk-Based Investment Walkthrough- Storm Damage (2/4)

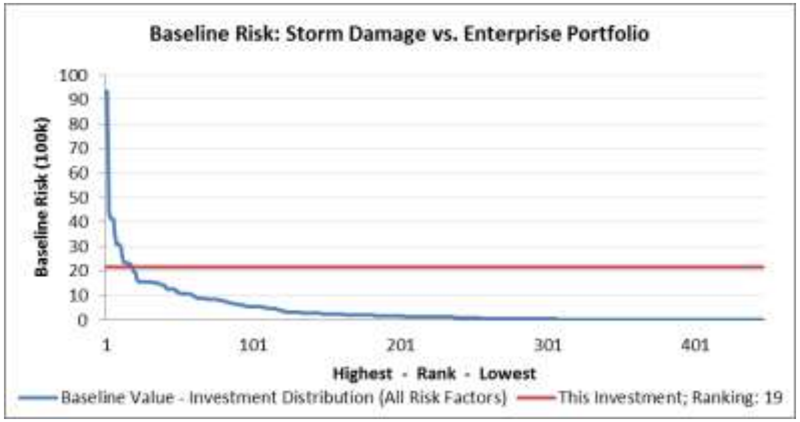
Investment Code / Description

- AIP000137 / Storm Damage

Baseline Risk Assessment

- Followed AIP supplied risk matrix that was provided as part of AIP offered training.
- Risk was calculated based on AIP selections for severity and likelihood.
- Storm Damage is within top 20 highest risk investments.





Risk-Based Investment Walkthrough- Storm Damage (3/4)

Investment Code / Description

- AIP000137 / Storm Damage

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Customer	**Severe**	Large and Mid Customers (Industrials, LDCs, Generators)	Large and Mid Customers (Industrials, LDCs, Generators): Increase in customer dissatisfaction with Hydro One	Customer associations (AMPCO, etc.) step up lobbying efforts for stricter penalties against Hydro One; Increase in customer lawsuits for direct and/or collateral damage believed to be caused by Hydro One; Complaints to provincial government increase significantly; Sharp deterioration in large and mid customer satisfaction survey results (as measured by scorecard) across multiple segments.
		OEB Service Quality Indices	Failure to meet Service Quality Indices.	Achieve only 67% (to 79%) of Overall Expected Performance.
		Residential and Small Business Customers	Residential and Small Business Customers: Increase in customer dissatisfaction with Hydro One service quality	Exponential increase (>30%) in: - call centre volumes (not storm related); - complaints received by field staff; - time and effort to resolve; Sharp deterioration in mass market customer satisfaction as per survey responses (as measured by scorecard).
Shareholder Value	**Severe**	Net Income	Net Income Shortfall	$100-$300M
		Shareholder Confidence	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Extensive loss of confidence; Shareholder Agreement rewritten to include approval of all investment and operating decisions; CEO or several Sr. Managers replaced
		Public Profile /Confidence re effective stewardship of assets	Public Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	Provincial media attention; most opinion leaders/customers publicly critical
		Meet Licence Conditions and obtain required rates maintain credibility with regulators	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities including non- compliance.	Some loss of Credibility; Excessive Involvement;
		Regulatory/Legal Compliance	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction	Conviction or regulatory finding of non-compliance with major fine ("major" meaning >30% of maximum fine under relevant legislation or regulation, or an unusually high/unprecedented amount for the industry).

Risk-Based Investment Walkthrough- Storm Damage (4/4)

Investment Code / Description

- AIP000137 / Storm Damage

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Safety	**Severe**	Employee/Contractor Workforce/Health and safety	Workforce Health and Safety: Fatality or serious employee/contractor injuries/illness; failure to meet targeted reduction in OSHA Recordable injuries.	Employee/contractor critical injury due to failure of managed system. Significant deterioration in health and safety performance.
		Public Safety	Public Injuries (with Hydro One at fault)	Significant Increase in Number of Injuries
Reliability	**Catastrophic**	Reliable Delivery of Electricity	Transmission Unsupplied Energy (due to single acute event or outage) Measured in MWh	>10,000 MWh
			Deterioration in Transmission System reliability (over the next 5 years, compared to benchmarked comparable).	Deterioration to third quartile at any time in 5 year period.
			Transmission Lost Redundancy Power supplied without expected redundancy measured in MWh	> 200,000 MWh
			Equipment Unavailability (Incremental %): The extent to which the transmission equipment is not available for use due to outages	> 1% (100,000 asset-hours, for an asset class with 1000 assets)
			Improve Tx Worst Served Customers Number of outliers significantly impacted by investment	Impact 10 or more chronic outliers
			Duration of Distribution Outages Measured in Interruption Hours (Number of customers impacted * Expected duration of Outage)	>15 Million Customer Interruption Hours (equivalent to SAIDI of >12.5 hrs)
			Frequency of Distribution Outages Number of customers interrupted for > 1 minute	>7.5 Million Interruptions

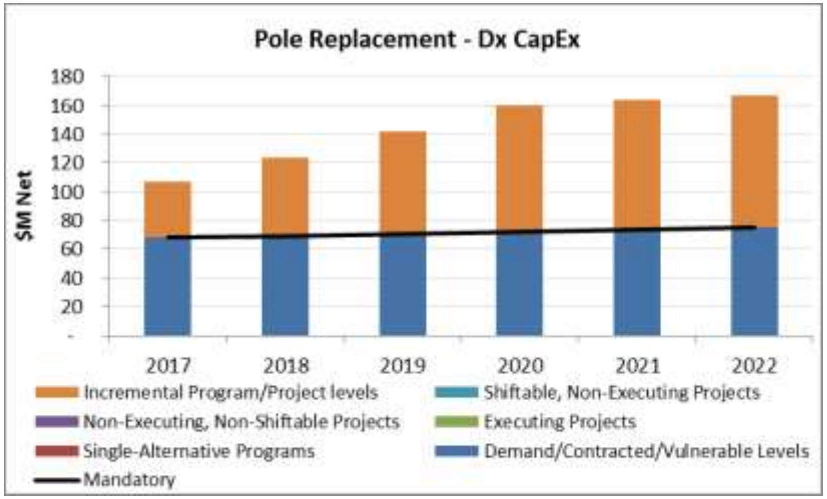
Risk-Based Investment Walkthrough-Pole Replacement (1/4)

Investment Code / Description

- AIP000128 / Pole Replacement

Mandatory Level and Alternatives Considered

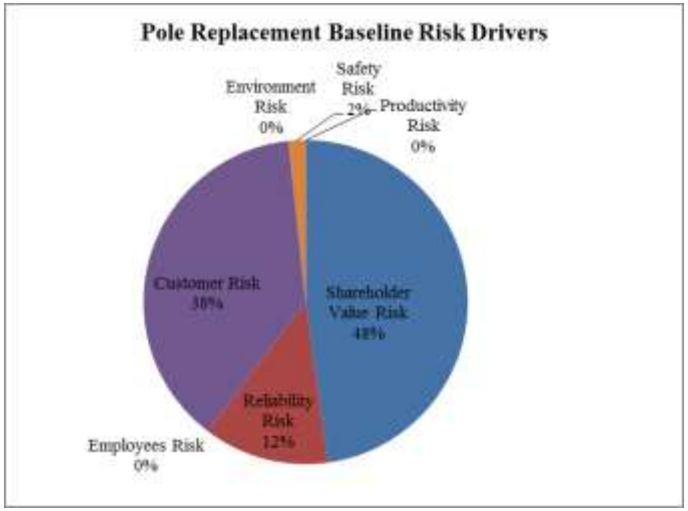
- Currently a backlog of 60,000 poles in poor condition that require replacement. 40,000 substandard treated poles.
- Vulnerable investment level maintains the current backlog of poles in poor condition and will not proactively address substandard poles.
- Intermediate investment level increases over the plan at a rate which is able to be resourced. The substandard treated poles will be replaced proactively over the next 12 years and the backlog of poles in poor condition will be reduced.
- Asset optimal investment level increases planned replacements at a rate which may not be resource able. Substandard treated poles will be replaced proactively over the next 12 years and the backlog of poles in poor condition will be eliminated by 2025.

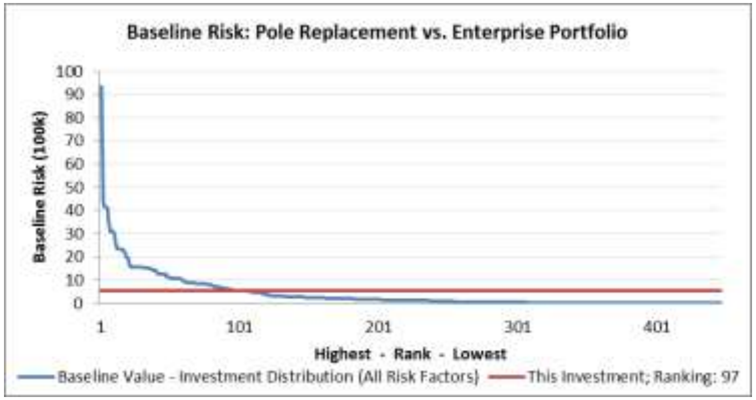


Risk-Based Investment Walkthrough-Pole Replacement(2/4)

Investment Code / Description
- AIP000128 / Pole Replacement

Baseline Risk Assessment
- Customer: Large customers will experience production losses and residential customers will experience more frequent outages
- Reliability: *On average about 200 customers are affected each time a pole failure occurs. Based on number of poles in poor condition and anticipated number of poles that will deteriorate over the course of the plan, assuming that only have of these poles will fail and result in customer interruptions, the impact would be approximately 1.9million customer interruptions per year.*
- Safety: poles are in the public domain and not replacing poor condition poles increases risk of failure and results in a moderate risk to public safety
- Shareholder: pole failures province wide resulting in significant outages can lead to significant negative media attention for Hydro One.
- The ranking of this program seems low relative to other investments, but it is believed that this program was evaluated fairly given the corporate risk matrix





Risk-Based Investment Walkthrough-Pole Replacement(3/4)

Investment Code / Description

- AIP000128 / Pole Replacement

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Customer	**Major**	Large and Mid Customers (Industrials, LDCs, Generators)	Large and Mid Customers (Industrials, LDCs, Generators): Increase in customer dissatisfaction with Hydro One	One "large" customer experiences significant production losses (restart time on production lines, etc.) due to Hydro One actions/inaction; High level (CEO, COO, etc.) calls to Hydro One CEO's office; Significant increase in number of customers falling outside of "delivery point performance standards"; Sharp deterioration in large and mid customer satisfaction survey results (as measured by scorecard) in a single segment.
		OEB Service Quality Indices	Failure to meet Service Quality Indices.	Achieve only 80% (to 89%) of Overall Expected Performance
		Residential and Small Business Customers	Residential and Small Business Customers: Increase in customer dissatisfaction with Hydro One service quality	Call centre volumes increase (not storm related) noticeably (15-30%); Noticeable increase in complaints received by field staff doing work on customer premises; Modest deterioration in mass market customer satisfaction as per survey response (as measured by scorecard).
Shareholder Value	**Severe**	Net Income	Net Income Shortfall	$100-$300M
		Shareholder Confidence	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Extensive loss of confidence; Shareholder Agreement rewritten to include approval of all investment and operating decisions; CEO or several Sr. Managers replaced
		Public Profile /Confidence re effective stewardship of assets	Public Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	Provincial media attention; most opinion leaders/customers publicly critical
		Meet Licence Conditions and obtain required rates maintain credibility with regulators	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities including non- compliance.	Some loss of Credibility; Excessive Involvement;
		Regulatory/Legal Compliance	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction	Conviction or regulatory finding of non-compliance with major fine ("major" meaning >30% of maximum fine under relevant legislation or regulation, or an unusually high/unprecedented amount for the industry).

Risk-Based Investment Walkthrough-Pole Replacement(4/4)

Investment Code / Description

- AIP000128 / Pole Replacement

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Safety	**Moderate**	Employee/Contractor Workforce/Health and safety	Workforce Health and Safety: Fatality or serious employee/contractor injuries/illness; failure to meet targeted reduction in OSHA Recordable injuries.	Less than planned improvement in health and safety performance
		Public Safety	Public Injuries (with Hydro One at fault)	Small Increase in Number of Injuries
Reliability	**Major**	Reliable Delivery of Electricity	Transmission Unsupplied Energy (due to single acute event or outage) Measured in MWh	1500-5000 MWh
			Deterioration in Transmission System reliability (over the next 5 years, compared to benchmarked comparable).	Deterioration to second quartile for only one year in the 5 year period.
			Transmission Lost Redundancy Power supplied without expected redundancy measured in MWh	30,000 MWh-100,000MWh
			Equipment Unavailability (Incremental %): The extent to which the transmission equipment is not available for use due to outages	0.1 - 0.5% (10,000 to 40,000 asset-hours, for an asset class with 1000 assets)
			Improve Tx Worst Served Customers Number of outliers significantly impacted by investment	Impact 2 to 5 chronic outliers
			Duration of Distribution Outages Measured in Interruption Hours (Number of customers impacted * Expected duration of Outage)	8 Million to 10 Million Customer Interruption Hours - note: current performance is 8.8 hrs.. and 5 year average is 8.4 hrs. (equivalent to SAIDI of 6.7 to 8.3 hrs.)
			Frequency of Distribution Outages Number of customers interrupted for > 1 minute	1.25 Million to 3.75 Million Interruptions

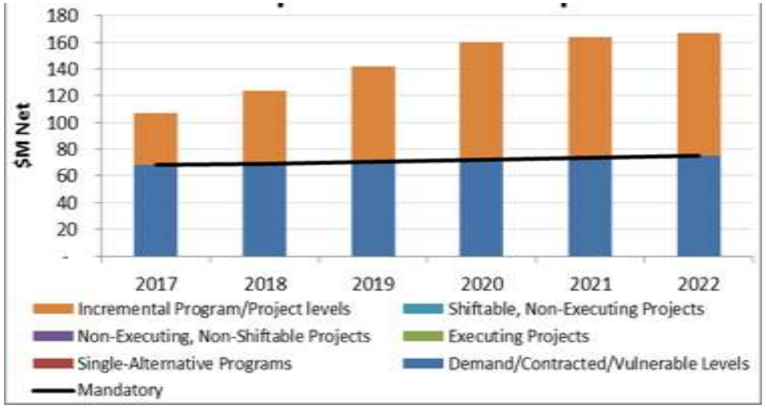
Risk-Based Investment Walkthrough-Veg Management (1/4)

Investment Code / Description

- AIP005662 / Cyclical Vegetation Management

Mandatory Level and Alternatives Considered

- Vulnerable level defined as investment that will manage specific feeders with large number of customers or critical customers on a set cycle.



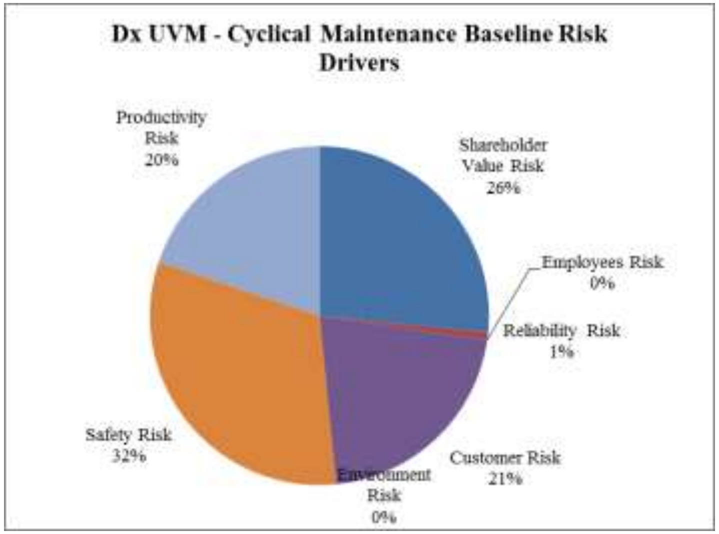
Risk-Based Investment Walkthrough-Veg Management(2/4)

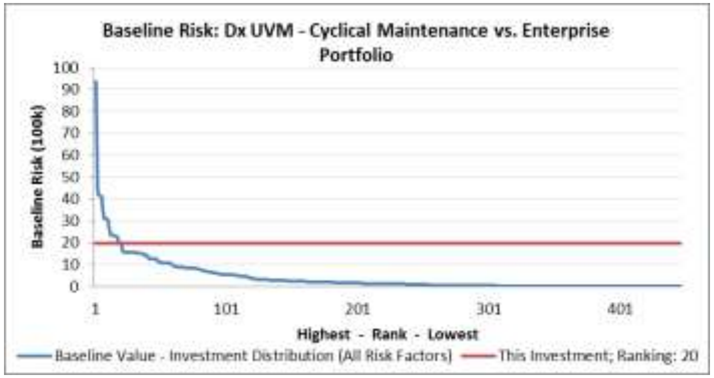
Investment Code / Description

- AIP005662 / Cyclical Vegetation Management

Baseline Risk Assessment

- Baseline risk was assessed based on a risk consequence matrix and an understanding of a how vegetation related outage can have an impact on our system and customers.





Risk-Based Investment Walkthrough-Veg Management(3/4)

Investment Code / Description

- AIP005662 / Cyclical Vegetation Management

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Customer	**Major**	Large and Mid Customers (Industrials, LDCs, Generators)	Large and Mid Customers (Industrials, LDCs, Generators): Increase in customer dissatisfaction with Hydro One	One "large" customer experiences significant production losses (restart time on production lines, etc.) due to Hydro One actions/inaction; High level (CEO, COO, etc.) calls to Hydro One CEO's office; Significant increase in number of customers falling outside of "delivery point performance standards"; Sharp deterioration in large and mid customer satisfaction survey results (as measured by scorecard) in a single segment.
		OEB Service Quality Indices	Failure to meet Service Quality Indices.	Achieve only 80% (to 89%) of Overall Expected Performance
		Residential and Small Business Customers	Residential and Small Business Customers: Increase in customer dissatisfaction with Hydro One service quality	Call centre volumes increase (not storm related) noticeably (15-30%); Noticeable increase in complaints received by field staff doing work on customer premises; Modest deterioration in mass market customer satisfaction as per survey response (as measured by scorecard).
Shareholder Value	**Severe**	Net Income	Net Income Shortfall	$100-$300M
		Shareholder Confidence	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Extensive loss of confidence; Shareholder Agreement rewritten to include approval of all investment and operating decisions; CEO or several Sr. Managers replaced
		Public Profile /Confidence re effective stewardship of assets	Public Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	Provincial media attention; most opinion leaders/customers publicly critical
		Meet Licence Conditions and obtain required rates maintain credibility with regulators	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities including non- compliance.	Some loss of Credibility; Excessive Involvement;
		Regulatory/Legal Compliance	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction	Conviction or regulatory finding of non-compliance with major fine ("major" meaning >30% of maximum fine under relevant legislation or regulation, or an unusually high/unprecedented amount for the industry).

Risk-Based Investment Walkthrough-Veg Management(4/4)

Investment Code / Description

- AIP005662 / Cyclical Vegetation Management

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Safety	**Catastrophic**	Employee/Contractor Workforce/Health and safety	Workforce Health and Safety: Fatality or serious employee/contractor injuries/illness; failure to meet targeted reduction in OSHA Recordable injuries.	Employee/contractor fatality or major permanent disability due to failure of managed system
		Public Safety	Public Injuries (with Hydro One at fault)	Fatality or Major Permanent Disability
Reliability	**Minor3**	Reliable Delivery of Electricity	Transmission Unsupplied Energy (due to single acute event or outage) Measured in MWh	30-120 MWh
			Deterioration in Transmission System reliability (over the next 5 years, compared to benchmarked comparable).	No deterioration in reliability relative to current performance in the 5 year period.
			Transmission Lost Redundancy Power supplied without expected redundancy measured in MWh	600-2400 MWh
			Equipment Unavailability (Incremental %): The extent to which the transmission equipment is not available for use due to outages	0.0025-0.006% (200 asset-hours - 500 asset-hours, for an asset class with 1000 assets)
			Improve Tx Worst Served Customers Number of outliers significantly impacted by investment	No impact to chronic outliers
			Duration of Distribution Outages Measured in Interruption Hours (Number of customers impacted * Expected duration of Outage)	50,000 to 500,000 Customer Interruption Hours
			Frequency of Distribution Outages Number of customers interrupted for > 1 minute	25,000 to 100,000 Interruptions
Productivity	**Severe**	Productivity	Failure meet Unit Cost targets per plan	Unit Costs increase by 6% - 10%

Investment Calibration

Network Operating
Tom Irvine
July 12, 2016

Investment Flexibility: OM&A (1/2)

Investment Portfolio

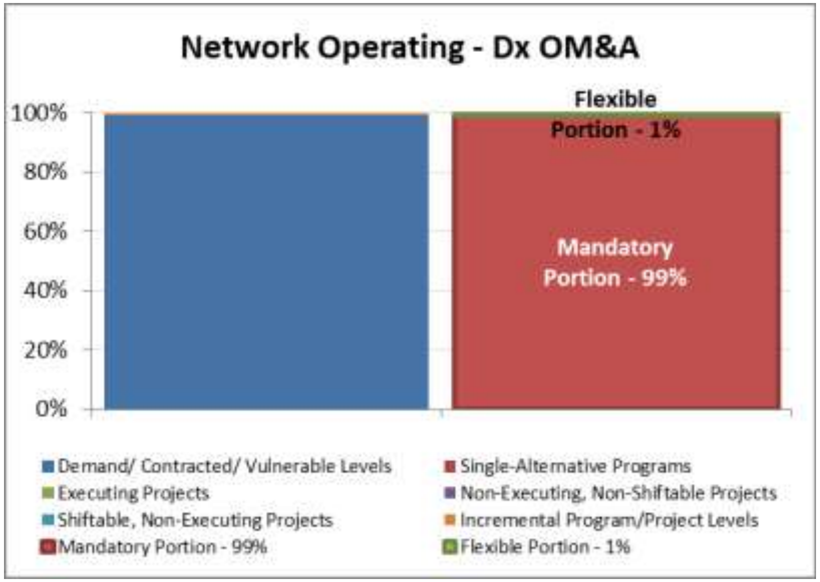
- **Network Operating**

Investment Flexibility

- **[1]**% Customer Satisfaction Surveys (multiple funding levels)
- **Limited flexibility**
- **Critical system support,** software patching, first level support , licensing etc.
- **Demand based** programs to support Operations

Mandatory/Non-Discretionary Overview

- **Mandatory Overview**.
- ***Critical System Support :*** *Power System IT, Voice support*
- ***Demand Programs*** *: Storm Response, Dx verification and information updates and Emergency Preparedness.*
- **Approach to Mandatory**
- Compliance (SAIDI, CAIDI (OEB)) **customer impacts**, outage planning, storm & outage response risk**, reliability targets** and **availability of critical system and tools** (ORMS, NOMS).
- **Mandatory Drivers**
- ***Lifecycle Management– Reliability /Availability*** *including Supportability (software patching)*
- ***Compliance & Customer Sat.*** *- Interruption Duration / Frequency Indices, Service Level Obligations (response)*
- **Discretionary Opportunities**
- *No Discretionary investments.*



Mandatory Driver	Approx. %
Emergency Break/ Fix	0
Legal Regulatory/ Compliance	1
Obligation to connect/ upgrade/ modify	0
License Condition	0
Contractual Commitment	0
Policy Responsiveness	0
Other – Critical Systems Support	62
Other – Demand (Information Updated / Verification)	36
Other – Major Tools Assessment	1

Investment Flexibility: OM&A (2/2)

Investment Portfolio
- **Network Operating**

Consistency with historic delivery/budget
- ***Decrease from historic driver budget.***
  - *Voice Support increase (new technology) ~$85k*
  - *PSIT Oracle DB increase ~$200k*
  - *Major Tools Assessment (NEW - $300k)*
  - *DOM Maps & Information Updates decrease $-0.5M*

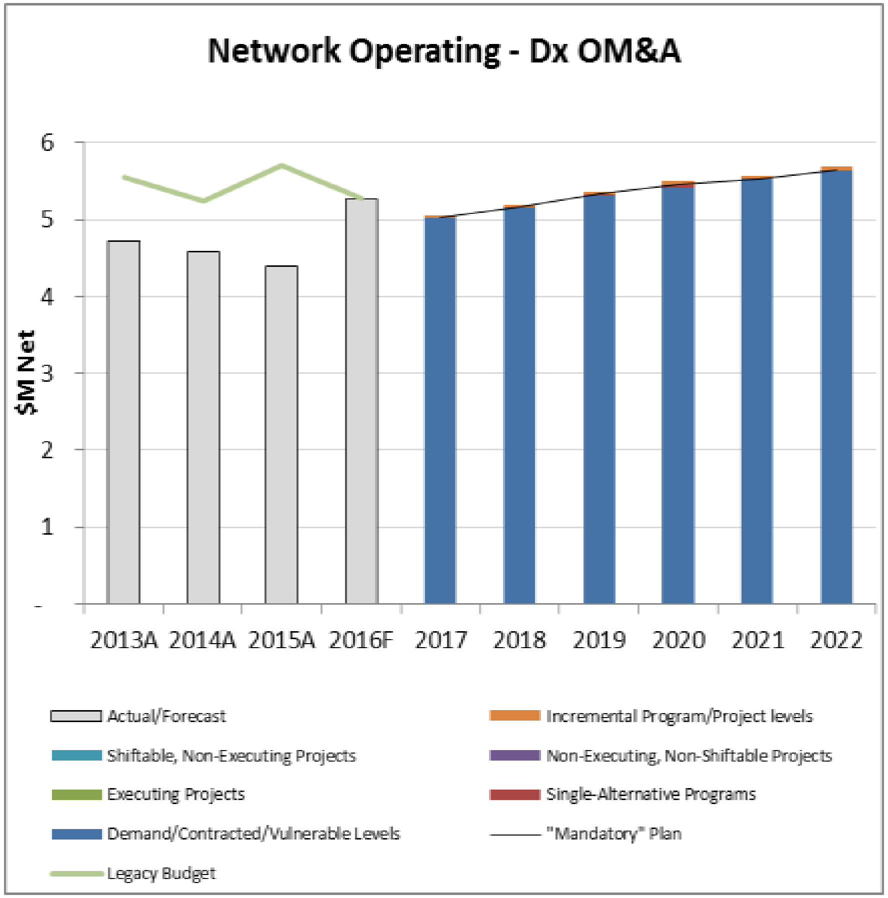
- **Portfolio delivery vs. budget:.**
- ***Below Driver budget historically*** *:*
  - *DOM Mts & DS Operating Diagrams(~$500k)*
  - *Field Verification of Ds Op. Diagrams ($~120k)*
  - *OGCC Data Collection & Info Updates ($~200k)*

  *** Reductions to future plans have been made.**
  *** Variable – demand nature.**

Funding Reduction Risks and Implications

10% reduction will pose the following incremental risk:
- *Service quality indicator targets (response & Cust. Sat.)*
- *Deteriorated asset condition*
- *Reduced availability*
- *Data and diagram integrity*

Implication of reduction/deferral
- ***Increased system availability / reliability risk***
  - *Unsupported systems and critical infrastructure*
- ***Reduced accuracy of information***
  - *connectivity models (diagrams, data etc.), customer info.*



Investment Flexibility: Capital (1/2)

Investment Portfolio

- **Network Operating**

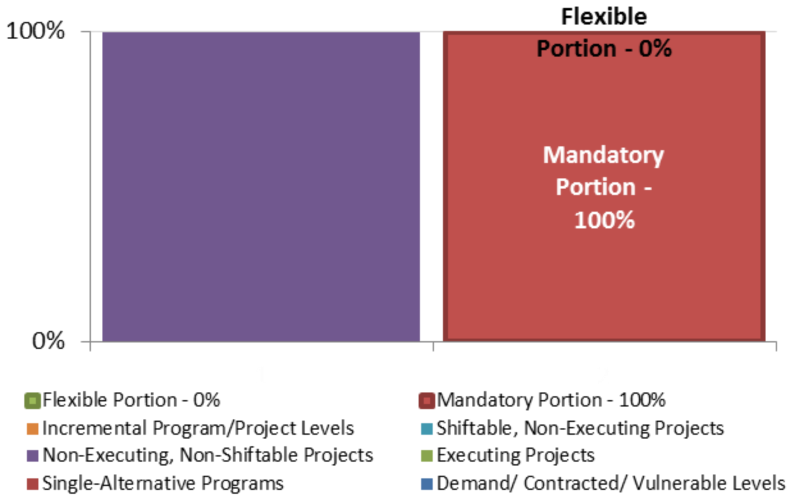
Investment Flexibility

- **[0]**% **Limited flexibility - End of life replacement**, Manufacturer lifecycle schedules, need for continued supportability and software patching and need to ensure reliability of systems for Operations.

Mandatory/Non-Discretionary Overview

- **Mandatory Overview (All)**
- Integrated System Operations Centre – New Facility (in flight)
- Operating Hardware, Application, Infrastructure and facilities lifecycle maintenance mandatory for compliance (OM), reliability and availability of critical systems.
- **Approach to Mandatory**
- Disruption to Operations, customer impacts, Compliance - SAIDI, CAIDI (OEB), outage planning, storm & response risk, reliability targets and availability of critical system and tools (ORMS, NOMS).
- **Mandatory Drivers**
- *Lifecycle Management– Availability Requirements, Supportability (software patching)*
- *Compliance & Customer Sat. - Interruption Duration / Frequency Indices, Service Level Obligations (response)*
- **Discretionary Opportunities**
- ORMS Enhancements– reviewed in light of customer satisfaction, benefits and productivity. *

Network Operating - Dx Capex



Mandatory Driver	Approx. %
Emergency Break/ Fix	2
Legal Regulatory/ Compliance (ISOC)	53
Obligation to connect/ upgrade/ modify	0
License Condition	0
Contractual Commitment	0
Policy Responsiveness	0
Released Project	7
Other – Critical System Upgrades	34
Other – Enhancements (ORMS / Express Power)	2

Investment Flexibility: Capital (2/2)

Investment Portfolio

- **Network Operating**

Consistency with historic delivery/budget

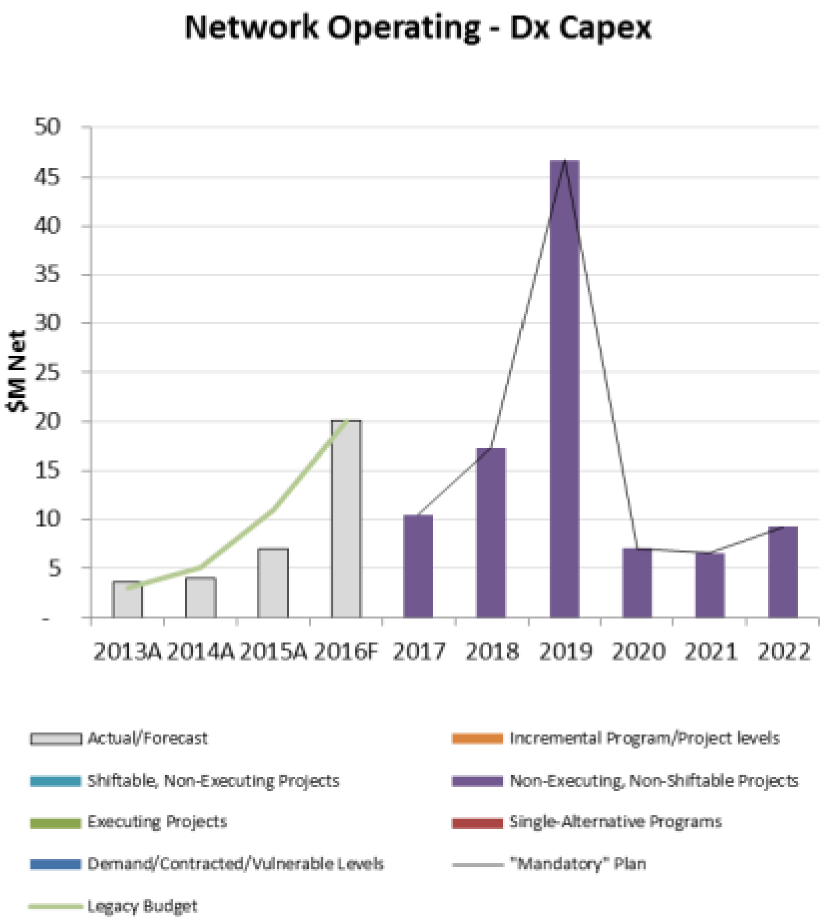
- *Increase over historic due to ISOC and Data Centre Remediation.*
- *Trend consistent with lifecycle upgrade cycles for critical systems, hardware and infrastructure support facilities.*

- **Portfolio delivery vs. budget**
- *Investment delays (ORMS) = under budget 2014/15*
- *Corporate redirection for emergent / unplanned investment*
  - Richview BUCC flood, UPS fire OGCC

Funding Reduction Risks and Implications

- **10% reduction will pose the following incremental risk:**
  - *Inability to maintain all lifecycle upgrade schedules*
  - *Deteriorated asset condition, reduced availability*
  - In-flight project risks

- **Implication of reduction/deferral**
  - *Unsupported systems and support infrastructure,*
  - *Increased failure risk, and*
  - *Several investments have already been deferred i.e. ISOC (BUCC), ORMS, NOMS (Regulatory Risk i.e. OEB)*



Risk Assessments: Network Operating (1/4)

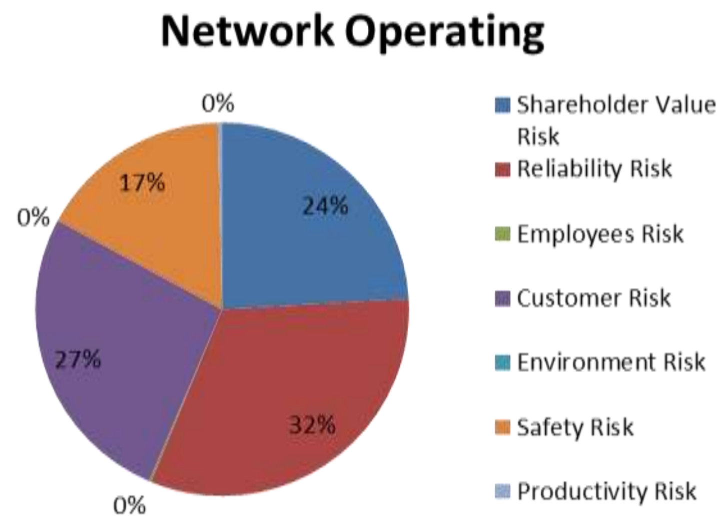
Investment Portfolio
- **Network Operating**

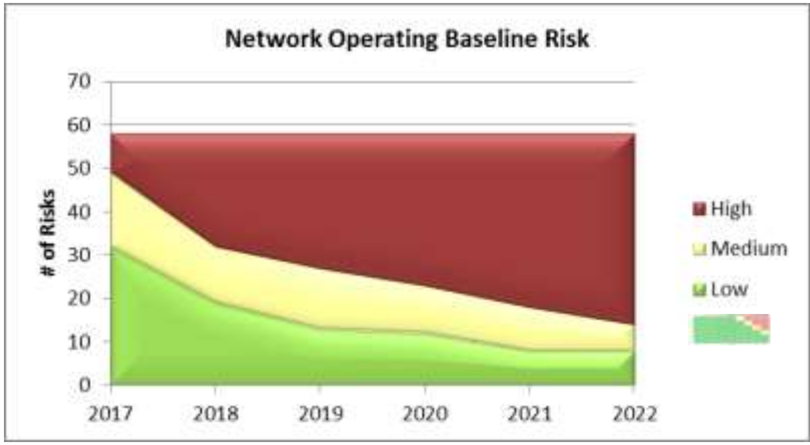
Approach
- *Risk is based on availability and reliability of the Systems and tools required to maintain 24/7 Operations. (Impact of loss of system)*
- *Secondarily, demand based programs are assessed based on the impact to Operations , Hydro One's work program and ultimately our customers (including Shareholders).*
- *Risk is informed / based on vendor support cycles, failure rate /defect reporting, industry best practices, customer satisfaction indices and outage info.*

- **Risk Sources**
- **Significant Hazards/ Threats / Vulnerabilities**
- *Asset condition, lifecycle maintenance, inaccuracy of information.*
  - *Richview BUCC, OGCC Data Centre and Customer Responsiveness.*

- **Significant Baseline Risk Consequences**
- *Increase in failure rates of critical systems (hardware, support infrastructure, application layer etc.)*
- *Customer responsiveness and potential for increased duration for response*
- *Shareholder value , due to above consequences.*

- **Baseline Risk Trend**
- *Deterioration occurs due to sustainment / upgrade cycles not keeping up with vendor manufacturer lifecycle, reducing or eliminating support, software patching and increasing risk of hardware failure etc.*
- *Failure to maintain information updates and verification increases inaccuracies over time ,creating customer, Operations and safety risks.*
- *Impacts to Operations is a direct impact to Hydro One Customers and therefore Shareholder value with decreased customer satisfaction , and responsiveness.*





Risk Assessments: Network Operating (2/4)

Top 5 Highest Risk Investments

Driver	Stage	Description	Investment Code	Baseline Value ·	Rank
N.C.M.3.01	Short Term Planning	Operating Power Systems IT Support	AIP000116	44.07365656	3
N.D.M.3.01	Short Term Planning	Dx Storm Management Customer Satisfaction Surveys	AIP005237	41.89623028	4
N.C.C.3.01	Short Term Planning	Integrated System Operations Centre - New Facility Development	AIP000071	41.04432801	6
N.C.C.3.01	Executing	OGCC Storage Area Network Upgrade	AIP000075	35.74744635	7
N.C.C.3.01	Executing	Voice Communications Upgrade	AIP000079	30.94173219	10

Top 5 Lowest Risk Investments

Driver	Stage	Description	Investment Code	Baseline Value ·	Rank
N.C.C.3.01	Executing	Control Room Display Refresh	AIP000072	3.883141547	120
N.C.C.3.01	Short Term Planning	OGCC Office Remediation	AIP005431	2.55946364	147
N.C.C.3.01	Short Term Planning	Display Technology Capital Replacement	AIP005369	2.285210881	162
N.C.C.3.01	Short Term Planning	OGCC Storage Area Network	AIP005705	1.968109209	177
N.C.M.3.01	Short Term Planning	OGCC Major Tools Assessment/RFI	AIP005360	0.492260071	269

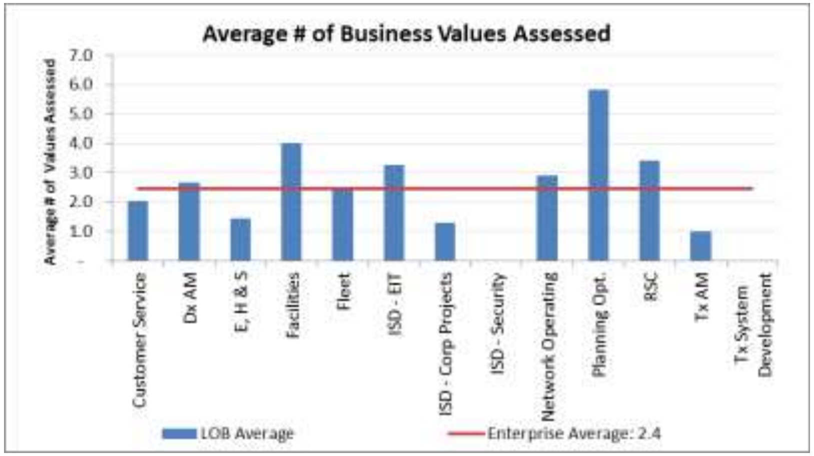
Notes:
Includes only Dx/Common Investments
Excludes Investments without a risk assessment

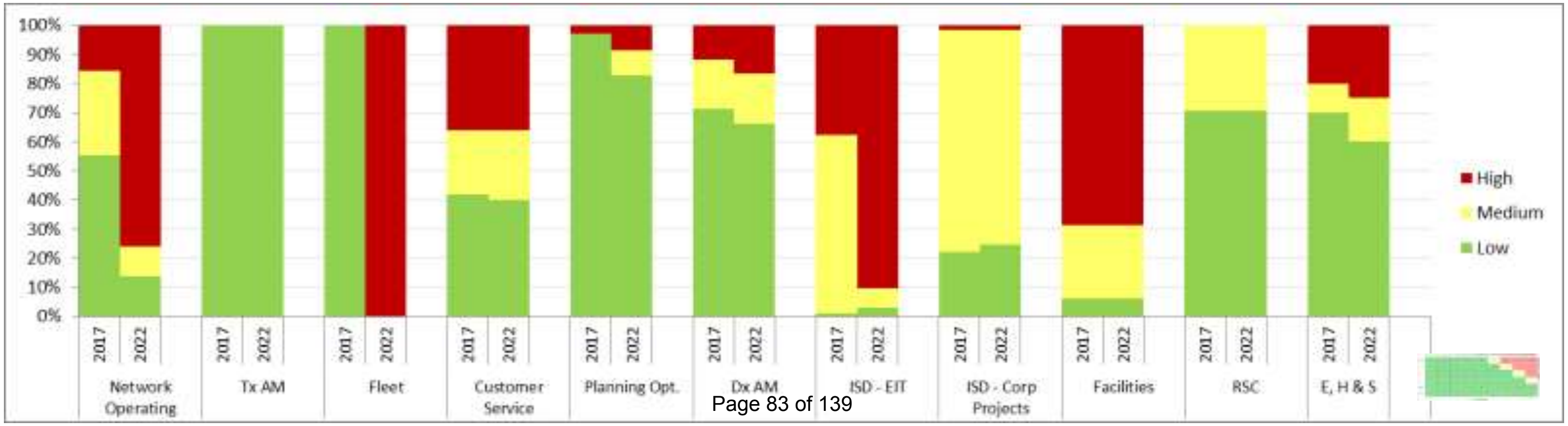
Risk Assessments: Network Operating (3/4)

Investment Portfolio
- **Network Operating**

Alignment with Other LOBs
- **Scope of Risk Assessments**; Impacts on Operations is a cascading impact model i.e. Operational outages / failures impact customers and Hydro One's work programs (delivery and safety) and therefore has a direct link with Shareholder value. NOD is the first level for dispatch & outage response.

- **Changing Risk Profile**;
- IT has a relatively short lifecycle compared to other LoB's. Lack of lifecycle maintenance increases risk rapidly over time.
- Demand based programs are essential for safety (internal and external customers) and Operational proficiency, accuracy.
- Critical infrastructure and facilities are essential in maintaining computing environments





Risk Assessments: Network Operating (4/4)

Investment Portfolio

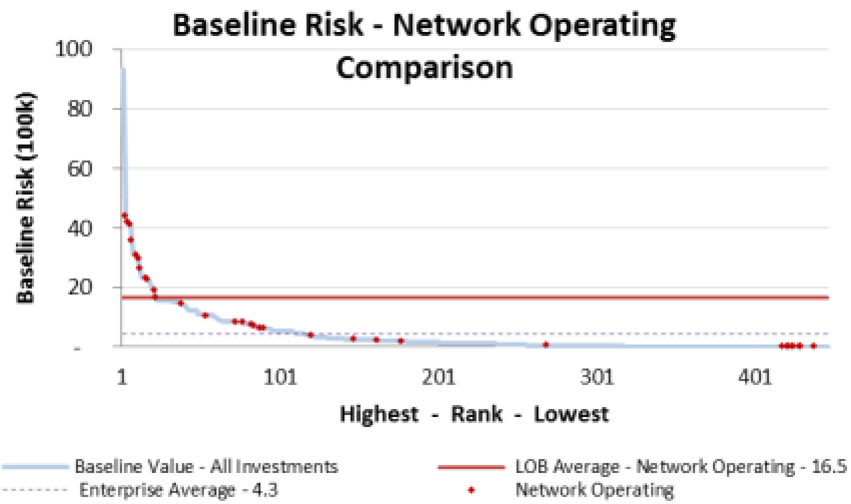
- **Network Operating**

Alignment with Other LOBs

- **Relativity of Risk Assessments;**

NOD Investments have a higher baseline risk when compared to other LOBs for the following reasons:

- Direct impacts to dispatch and customer responsiveness if Outages in critical systems (i.e. ORMS, NOMS, Voice etc.)
- Direct impacts to Hydro One's work program execution i.e. Outage Planning and Response.
- Heavy in IT investments – steeper risk profile over time i.e. shorter lifecycles. (Servers 5 yrs. Vs. Transformers 50 yrs.)



	First Quartile	Second Quartile	Third Quartile	Fourth Quartile
	Most Baseline Risk			Least Baseline Risk (or no assessment)
LOB Investments	19	4	1	8
LOB - % of Quartile	17.3%	3.5%	0.9%	7.1%
LOB - Quartile Distribution	59.9%	12.2%	3.1%	24.8%

Risk-Based Investment Walkthrough – Storm Management Surveys (1/3)

Investment Code / Description
- AIP005237 / Dx Storm Management Customer Satisfaction Surveys

Mandatory Level and Alternatives Considered
- Customer Satisfaction in DOMC has historically been below acceptable levels. This investment strives to seek better statistical information about our customers, measuring planned, unplanned and storm event outage management performance conducted by DOMC. Levels were derived from varying service level offerings as provided in an independent RFP process (Vendor : Forum)

- $95 -$134k annually renewed.

Dx Storm Management Surveys	Alt. 1	Alt. 2	Alt. 3
- Planned, Short Notice outages;	X	X	X
- Unplanned/forced outages;	X	X	X
- Major storm events;	X	X	X
- Online Outage Map Users;	X	X	X
- Up to 1200 (600) user surveys for mobile messaging/SMS applications.	1200	1200	600
- Local geographic events;	X		
- Unplanned auto-call transactional surveys;	X		
- Short planned auto-call transactional surveys;	X		
- Quali-Quant telephone interviews.	X		
Cost ($k)	**$ 955**	**$ 714**	**$ 568**

Risk-Based Investment Walkthrough – Storm Management Surveys (2/3)

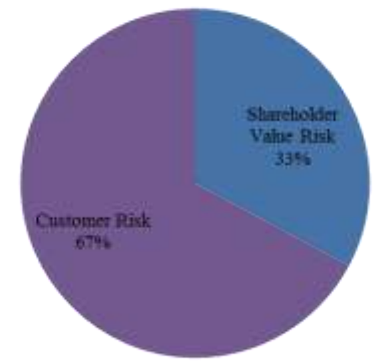
Investment Code / Description

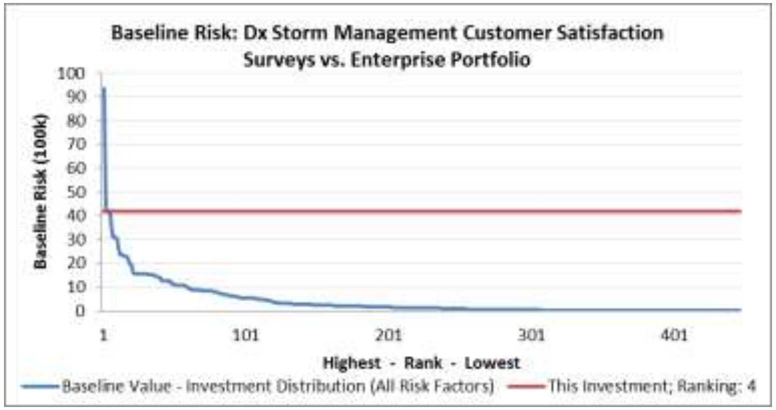
- AIP005237 / Dx Storm Management Customer Satisfaction Surveys

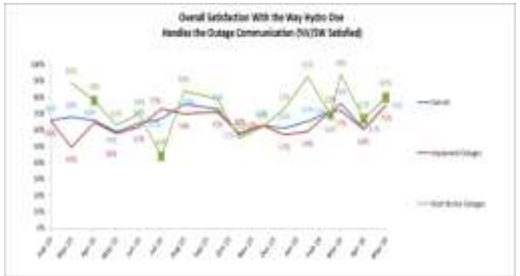
Baseline Risk Assessment

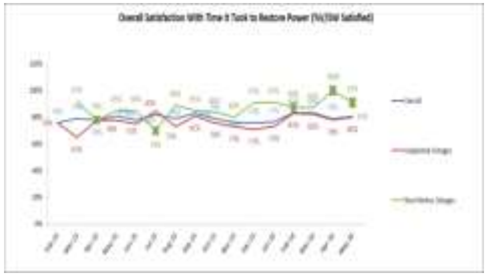
- Business objectives based on current customer satisfaction indices around DOMC / Hydro One's communication on Outages and responsiveness (time to restore).
- Media Attention on customer experience is increasing.
- Customer risk and risk for shareholder value degradation if customer outage experiences don't improve.
- Risk of customer satisfaction decreasing without identification of the cause.
- NOD is a customer facing LOB impacting Hydro One's reputation.
- Small investment will large potential benefit.
- January, 2015 - **66%** -> May, 2016 - **75%** **Target <85%**

Dx Storm Management Customer Satisfaction Surveys Baseline Risk Drivers









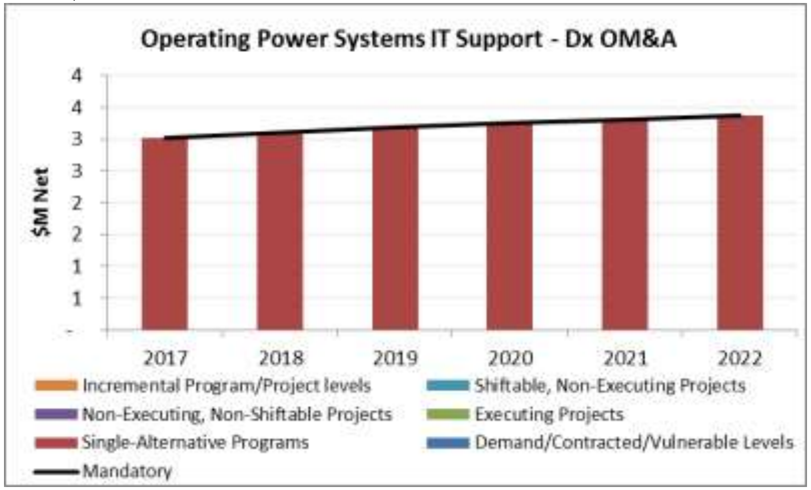
Risk-Based Investment Walkthrough – Storm Management Surveys (3/3)

Investment Code / Description

- AIP005237 / Dx Storm Management Customer Satisfaction Surveys

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Customer	**Catastrophic**	Large and Mid Customers (Industrials, LDCs, Generators)	Large and Mid Customers (Industrials, LDCs, Generators): Increase in customer dissatisfaction with Hydro One	Numerous Large & Mid Customers initiate action such as by-pass or relocation; Exponential increase in customer lawsuits for direct and/or collateral damage believed to be caused by Hydro One; Complaints to provincial government increase dramatically
		OEB Service Quality Indices	Failure to meet Service Quality Indices.	Achieve only 25% (to 66%) of Overall Expected Performance.
		Residential and Small Business Customers	Residential and Small Business Customers: Increase in customer dissatisfaction with Hydro One service quality	Letters and complaints to MPPs escalate exponentially; significant numbers of customers begin to default on bill payments
Shareholder Value	**Catastrophic**	Net Income	Net Income Shortfall	>$300M
		Shareholder Confidence	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Complete loss of confidence; Shareholder Agreement rewritten to include active involvement in all business operations; CEO and Board replaced by the owner; Shareholder imposes substantial reduction in Hydro One scope and mandate
		Public Profile /Confidence re effective stewardship of assets	Public Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	National media attention; opinion leaders/customers nearly unanimous in public criticism
		Meet Licence Conditions and obtain required rates maintain credibility with regulators	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities including non- compliance.	General loss of Credibility; Intrusive Involvement;
		Regulatory/Legal Compliance	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction	Conviction with Incarceration of Staff

Risk-Based Investment Walkthrough – Power System IT Support (1/4)



Investment Code / Description

- AIP000116 / Power System IT Support

Mandatory Level and Alternatives Considered

- Mandatory level was predicated on a host of Support Level Agreements, Reliability Targets, Licenses and vendor contracts.
- Informed based on historic spend and future planned technology change and capacity expansions (ex. more users, more licenses).
- Considered the minimum to achieve reliability / Operational availability targets.
  - Critical Application Support (ORMS, NOMS, EL, CRIS, IS&R, XSW , Voice Communications etc.)
  - Vendor Support Contracts
  - Vendor Licenses
  - Data Services
  - Architecture & Infrastructure Management
  - Voice Communication Systems Support
  - Building Facilities Management (computer rooms, control room etc.)
  - Shift Control Engineer (on-site first level support & trouble)
  - Performance Monitoring and Reporting

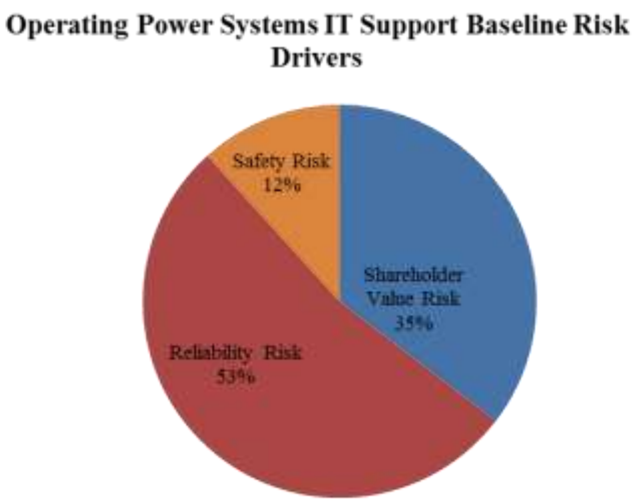
Risk-Based Investment Walkthrough – Power System IT Support (2/4)

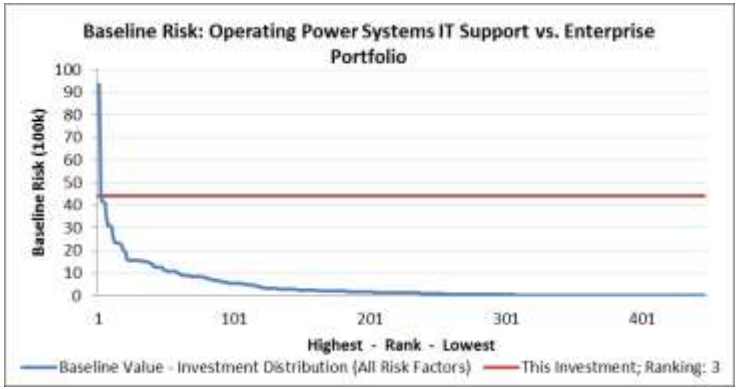
Investment Code / Description
- AIP000116 / Power System IT Support

Baseline Risk Assessment

- Impacted business objectives were determined based on the functional reliability, availability and serviceability of the Critical systems and infrastructure required for 24 / 7 Operations and the associated impact if functionality is lost. (OGCC & BUCC)
- Impacts on reliability is a direct correlation to support activities and asset lifecycle management. If decreased, or deferred, reliability of Business functions follows with direct impacts on customers and Hydro One's work programs.
- Shareholder value risk is predicated on an inability to perform daily Operations, the resulting impact on customers and work programs and the inability to meet our Mandate. Results , reputational impacts and media attention.
- Safety risk was based on the loss of ORMS and support tools required for SkyWatch, Emergency Dispatch, customer communications and response etc. and the resulting loss of safety processes and procedure. Results in heightened risk to employee and customer safety.

The risk profile is appropriate given the central role and criticality of Network Operating business functions on the daily Operation and Dispatch for Hydro One Networks.





Risk-Based Investment Walkthrough – Power System IT Support (3/4)

Investment Code / Description

- AIP000116 / Power System IT Support

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Shareholder Value	**Catastrophic**	Net Income	Net Income Shortfall	>$300M
		Shareholder Confidence	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Complete loss of confidence; Shareholder Agreement rewritten to include active involvement in all business operations; CEO and Board replaced by the owner; Shareholder imposes substantial reduction in Hydro One scope and mandate
		Public Profile /Confidence re effective stewardship of assets	Public Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	National media attention; opinion leaders/customers nearly unanimous in public criticism
		Meet Licence Conditions and obtain required rates maintain credibility with regulators	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities including non- compliance.	General loss of Credibility; Intrusive Involvement;
		Regulatory/Legal Compliance	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction	Conviction with Incarceration of Staff

Risk-Based Investment Walkthrough – Power System IT Support (4/4)

Investment Code / Description

- AIP000116 / Power System IT Support

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Safety	**Severe**	Employee/Contractor Workforce/Health and safety	Workforce Health and Safety: Fatality or serious employee/contractor injuries/illness; failure to meet targeted reduction in OSHA Recordable injuries.	Employee/contractor critical injury due to failure of managed system. Significant deterioration in health and safety performance.
		Public Safety	Public Injuries (with Hydro One at fault)	Significant Increase in Number of Injuries
Reliability	**Catastrophic**	Reliable Delivery of Electricity	Transmission Unsupplied Energy (due to single acute event or outage) Measured in MWh	>10,000 MWh
			Deterioration in Transmission System reliability (over the next 5 years, compared to benchmarked comparable).	Deterioration to third quartile at any time in 5 year period.
			Transmission Lost Redundancy Power supplied without expected redundancy measured in MWh	> 200,000 MWh
			Equipment Unavailability (Incremental %): The extent to which the transmission equipment is not available for use due to outages	> 1% (100,000 asset-hours, for an asset class with 1000 assets)
			Improve Tx Worst Served Customers Number of outliers significantly impacted by investment	Impact 10 or more chronic outliers
			Duration of Distribution Outages Measured in Interruption Hours (Number of customers impacted * Expected duration of Outage)	>15 Million Customer Interruption Hours (equivalent to SAIDI of >12.5 hrs)
			Frequency of Distribution Outages Number of customers interrupted for > 1 minute	>7.5 Million Interruptions

Investment Calibration

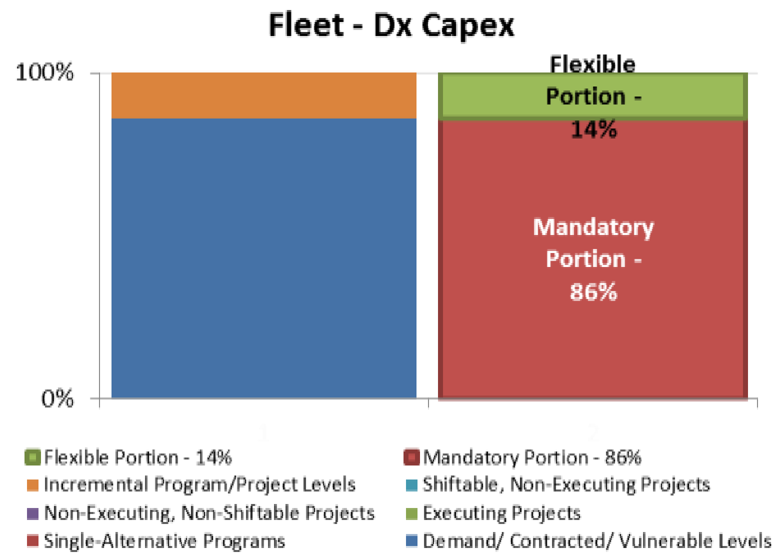
Fleet Services
Mark Binkley for Mike Piggott
July 12, 2016

Investment Flexibility: Capital (1/2)

Investment Portfolio
- **Fleet**

Investment Flexibility
- **14%**

Mandatory/Non-Discretionary Overview
- **Mandatory Overview**
  - Fleet Capital Replacement Program, and Capital investment to fulfill additional LOB requirements.
- **Approach to Mandatory**
  - Life cycle expectancy
  - NBV to OCV ratio
  - Operating cost drivers
  - Additional LOB requirements
- **Mandatory Drivers**
  - *To maintain SLA requirements with LOB*
- **Discretionary Opportunities**
  - *No discretionary opportunities*



Mandatory Driver	Approx. %
TWE Capital Replacement Program	78.9%
Incremental Requirements – Forestry Mechanical Brushing Program	3.2%
Incremental Requirements – Provincial Lines Pole Replacement Program	4.5%
TWE Capital Adjustment based on USD$ Forecast of $0.74	5.5%
Helicopter	5.6%
TWE Service Equipment (Forestry, Provincial Lines, Constructions)	2.4%

Investment Flexibility: Capital (2/2)

Investment Portfolio

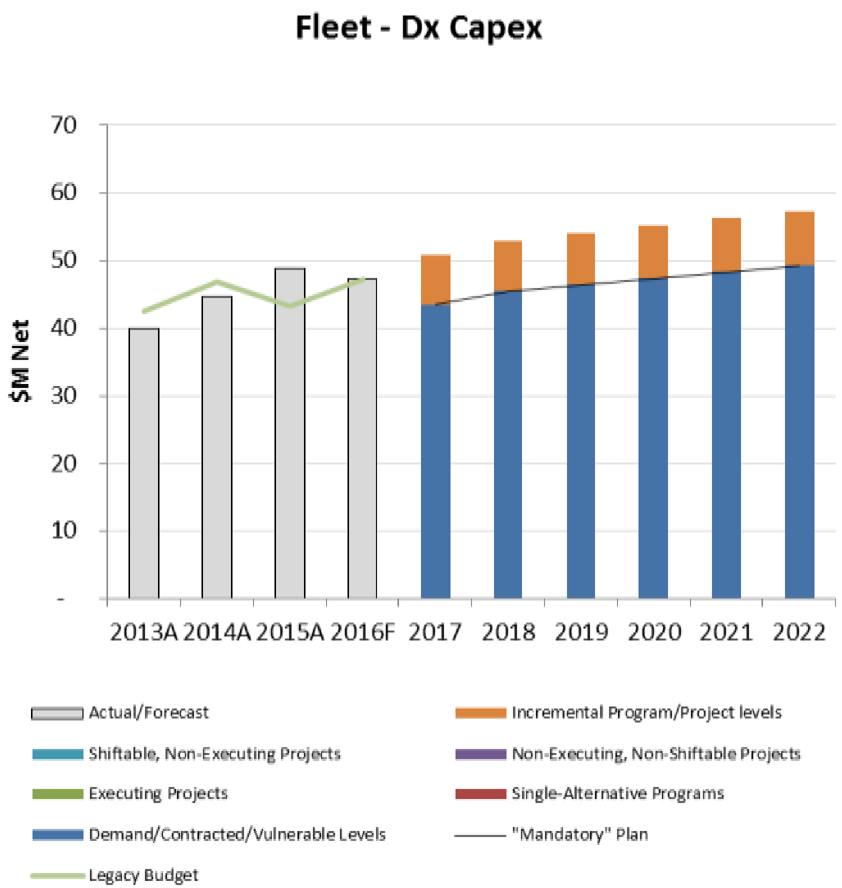
- **Fleet**

Consistency with historic delivery/budget

- In-line with historic
- Consistent with budget and approved business plan

Funding Reduction Risks and Implications

- *Deteriorated asset (TWE) condition, decline in NBV to OCV ratio indicator, Reduced total available TWE hours, enhance safety risk due to aging assets, increased TWE downtime*
- *Leading to higher maintenance costs, potential delays to work programs due to absence of TWE, Increase in rental costs to support shortfall of additional fleet requirements by lines of businesses, higher exposure to potential safety incidents.*

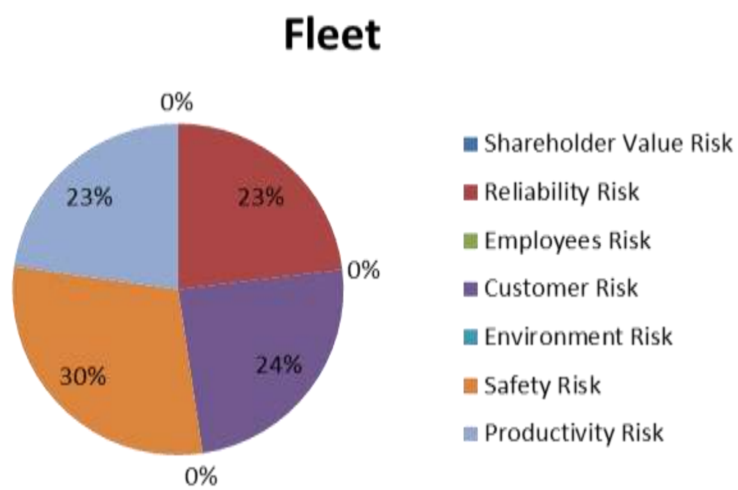


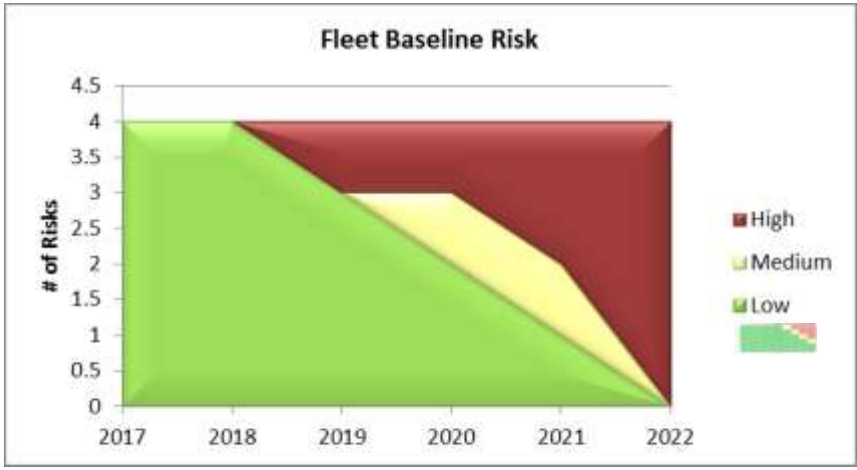
Risk Assessments: Fleet (1/4)

Investment Portfolio
- **Fleet**

Approach
- Productivity
  - Maintenance, labour, rental costs
- Reliability
  - Downtime
- Safety
  - Vehicles determined to be a safety risk (annual inspections, etc.) are not put on the road.
- Customer
  - Utilization Reports, Total available fleet hours

Risk Sources
- Asset condition, Asset availability, SLA requirements
- SLA requirement not fulfilled, Increase Maintenance costs and Increase headcount requirement, Increased rental costs
- *Deterioration because capital requirements do not keep up with end of life replacements program for TWE, increase in maintenance cost due to higher potential downtime of aging assets, Increase in rental costs to fulfill additional line of businesses requirements, Lack of capital would result in increase in possibility of major or serious accident (LTI, LTD, Fatality).*





Return to Agenda

Risk Assessments: Fleet (2/4)

Top 1 Highest Risk Investments

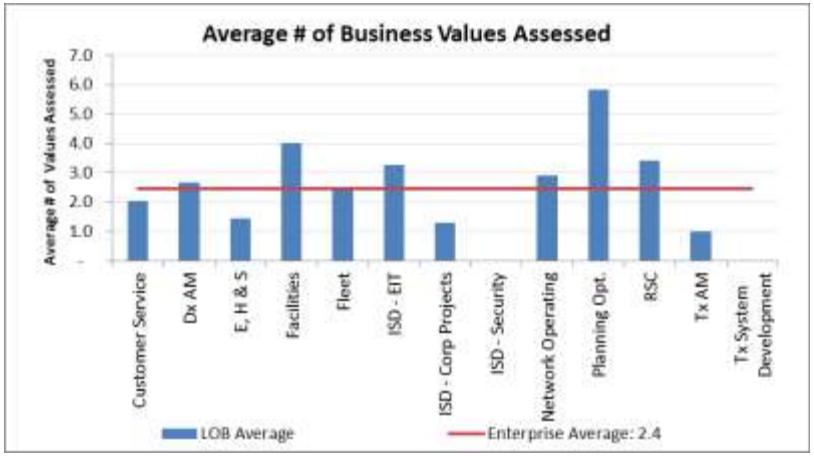
Driver	Stage	Description	Investment Code	Baseline Value ·	Rank
N.C.C.1.30	Short Term Planning	Transport and Work Equipment (TWE) Capital Requirements	AIP000014	14.7308398	37

Notes:
Includes only Dx/Common Investments
Excludes Investments without a risk assessment

Risk Assessments: Fleet (3/4)

Investment Portfolio
- **Fleet**

Alignment with Other LOBs
- **Scope of Risk Assessments**;
  - Productivity Risk
  - Safety Risk
  - Reliability Risk
  - Customer Risk
- **Changing Risk Profile**;
  - Low Short-term impact
  - High medium and long term impact.



Risk Assessments: Fleet (4/4)

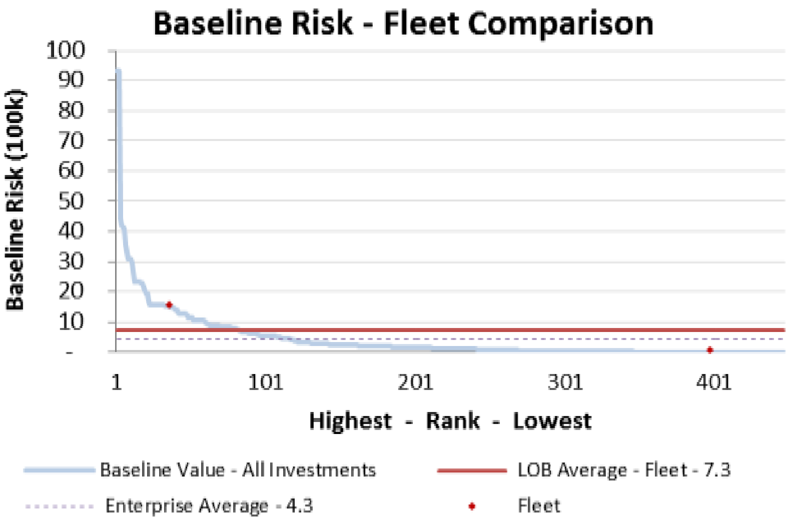
Investment Portfolio
- **Fleet**

Alignment with Other LOBs
- **Relativity of Risk Assessments;**

- **Fleet higher than enterprise Average:**
  - Productivity
    - Maintenance, labour, rental costs
  - Reliability
    - Downtime
  - Safety
    - Vehicles determined to be a safety risk (annual inspections, etc.) are not put on the road.
  - Customer
    - Utilization Reports, Total available fleet hours
- Asset condition, Asset availability, SLA requirements

- SLA requirement not fulfilled, Increase Maintenance costs and Increase headcount requirement, Increased rental costs

- *Deterioration because capital requirements do not keep up with end of life replacements program for TWE, increase in maintenance cost due to higher potential downtime of aging assets, Increase in rental costs to fulfill additional line of businesses requirements, Lack of capital would result in increase in possibility of major or serious accident (LTI, LTD, Fatality).*



	First Quartile	Second Quartile	Third Quartile	Fourth Quartile
	Most Baseline Risk			Least Baseline Risk (or no assessment)
LOB Investments	1	0	0	1
LOB - % of Quartile	0.9%	0.0%	0.0%	0.9%
LOB - Quartile Distribution	50.5%	0.0%	0.0%	49.5%

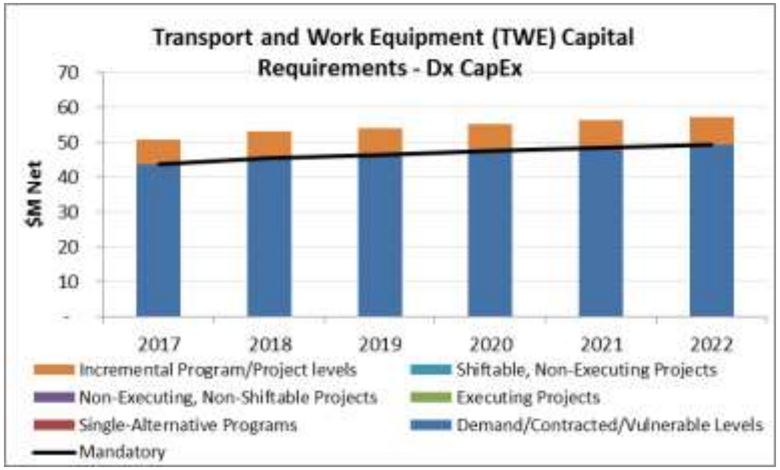
Risk-Based Investment Walkthrough- TWE (1/4)

Investment Code / Description

- AIP000014 / Transportation and Work Equipment

Mandatory Level and Alternatives Considered

- Safety and Regulatory Compliance
- Improve NBV to OCV ratio to align with industry best practices.
- Satisfy the incremental Fleet requirements to support LOB programs and staffing.
- Ensure the Fleet Vehicle Replacement program, which measures the optimum equipment life expectancy from both the fleet operating cost and LOB customer equipment reliability, safety and productivity perspective, is executed effectively.



Risk-Based Investment Walkthrough- TWE (2/4)

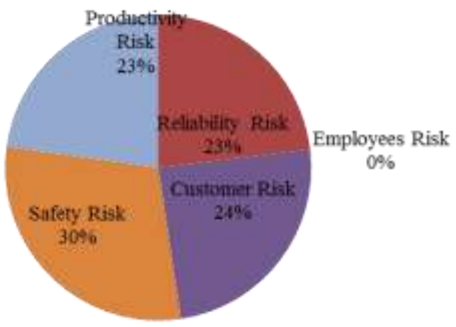
Investment Code / Description

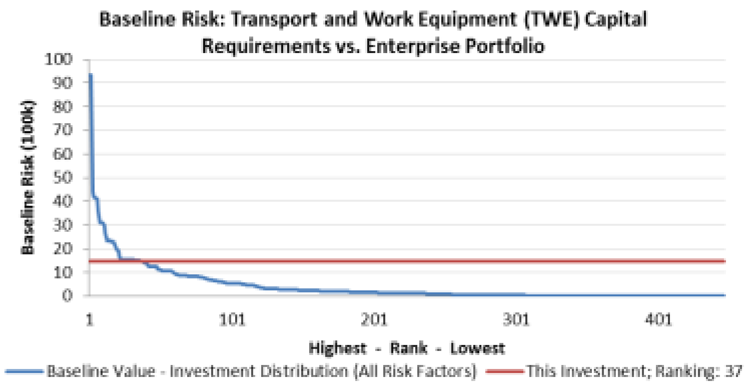
- AIP000014 / Transportation and Work Equipment

Baseline Risk Assessment

- Productivity
  - Maintenance, labour, rental costs
- Reliability
  - Downtime
- Safety
  - Vehicles determined to be a safety risk (annual inspections, etc.) are not put on the road.
- Customer
  - Utilization Reports, Total available fleet hours

Transport and Work Equipment (TWE) Capital Requirements Baseline Risk Drivers





Risk-Based Investment Walkthrough- TWE (4/4)

Investment Code / Description

- AIP000014 / Transportation and Work Equipment (Modified to match Fleet business requirements)

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Safety	**Severe**	Employee/Contractor Workforce/Health and safety	Workforce Health and Safety: Fatality or serious employee/contractor injuries/illness; failure to meet targeted reduction in OSHA Recordable injuries.	• Employee/contractor critical injury due to failure of managed system. • Significant deterioration in health and safety performance.
		Public Safety	Public Injuries (with Hydro One at fault)	• Significant Increase in Number of Injuries
Customer	**Severe**	Service Quality & Work Program Completion	Failure to meet all LoB work program requirements.	• Significant deterioration of Fleet assets. • Achieve only ~77% of work program requirements.
Reliability	**Catastrophic**	Reliability of Fleet Vehicles	Equipment Unavailability (Incremental %): The extent to which equipment is not available for use due to deteriorating assets.	• >50% of Fleet vehicles past end of life, resulting in significant spike of downtime hours and unit unavailability (13.2% of available hours resulting in downtime)
Productivity	**Catastrophic**	Productivity	Impact on Fleet OM&A	• OM&A budget increase ~14%

Investment Calibration

Security Operations
Rick Haier
July 12, 2016

Investment Flexibility: OM&A (1/2)

Investment Portfolio

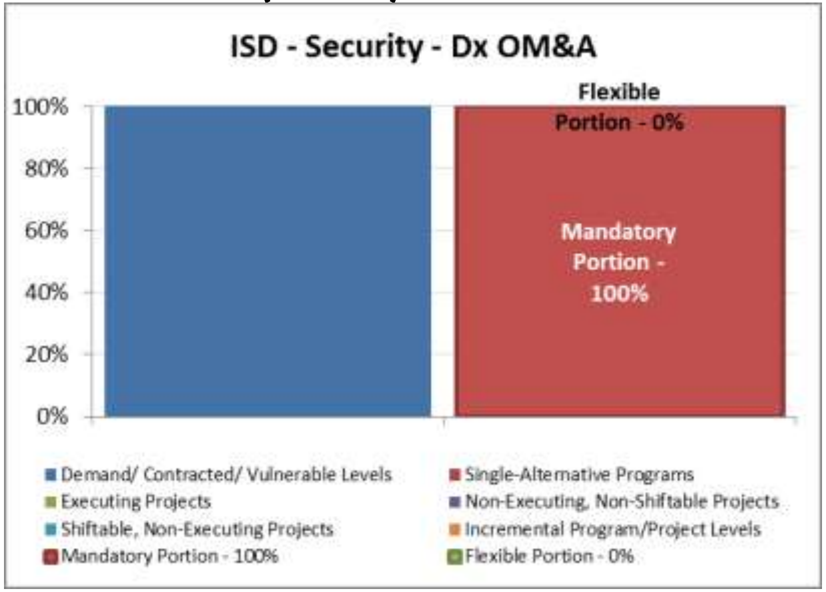
- **Security Operations**

Investment Flexibility

- **[0]**%

Mandatory/Non-Discretionary Overview

- **Mandatory Overview:** The work is to provide on demand security services to safeguard Hydro One Employees, Equipment and Facilities as dictated by events or requests from business lines. *i.e. Guard Services during planned outages at PSPs, Protection Services during AGM, Guard Services to protect Hydro One Vehicles and Equipment during Emergency Restoration, Other services to support criminal investigations etc.*
- **Approach to Mandatory** based on historical spend levels over last 1-3 years.
- **Mandatory Drivers:** On Demand, Risk Reduction
- **Discretionary Opportunities** No



Mandatory Driver	Approx. %
Other – Please Specify (i.e. - risk considerations)	100%

Investment Flexibility: OM&A (2/2)

Investment Portfolio

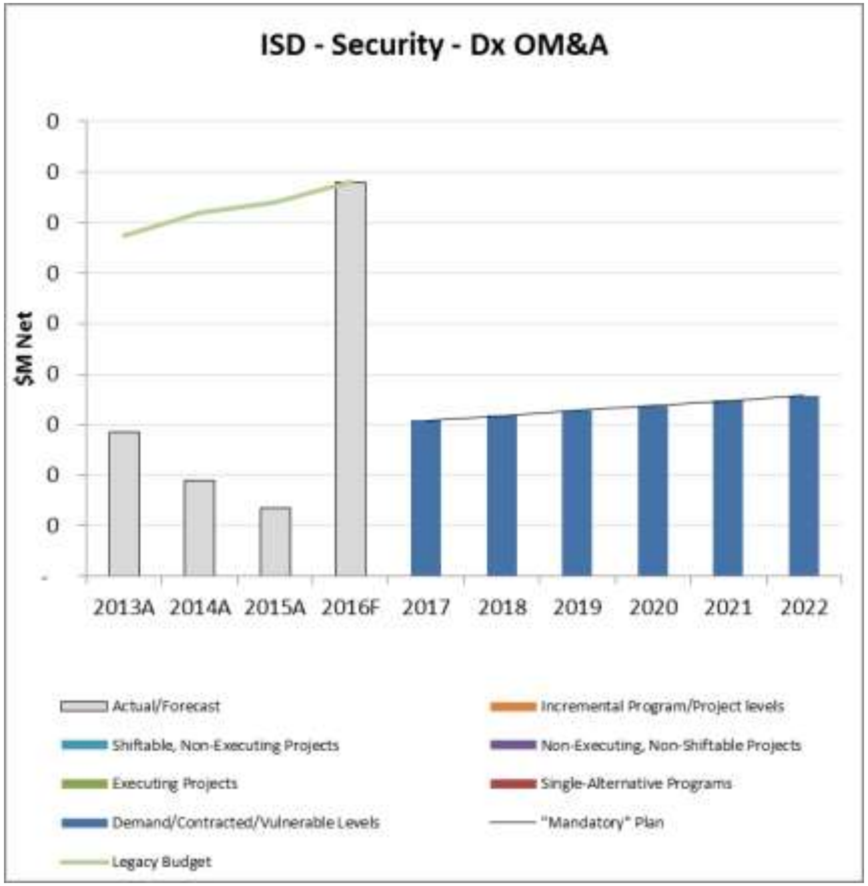
- **Security Operations**

Consistency with historic delivery/budget

- Budget and Forecast are calibrated to spend levels over the last 2 years.
- **[Provide comment on portfolio delivery vs. budget]** N/A - see above

Funding Reduction Risks and Implications

- If spend is deferred or reduced to 0, no protection services will be provided exposing Hydro One Employees, Equipment and Facilities to Higher Levels of Risk. Additionally, NERC Compliance may be at risk of services are not available to support planned outages at PSPs.



Risk Assessments: Security Operations (1/4)

Investment Portfolio

- **Security Operations**

Approach

- Risk Assessments are based on historical experience and risk assessments from business lines or risk of being non-compliance with NERC CIP

Risk Sources

- **Significant Hazards/ Threats / Vulnerabilities**
- *i.e. theft, safeguarding of Hydro One Equipment etc.*
- **Significant Baseline Risk Consequences** *i.e. Potential non- compliance, theft of Hydro One Equipment etc.*
- **Baseline Risk Trend** *NA*

Investment Calibration

Health, Safety & Environment
Bill Welch
July 12, 2016

Return to Agenda

Investment Flexibility: OM&A (1/2)

Investment Portfolio

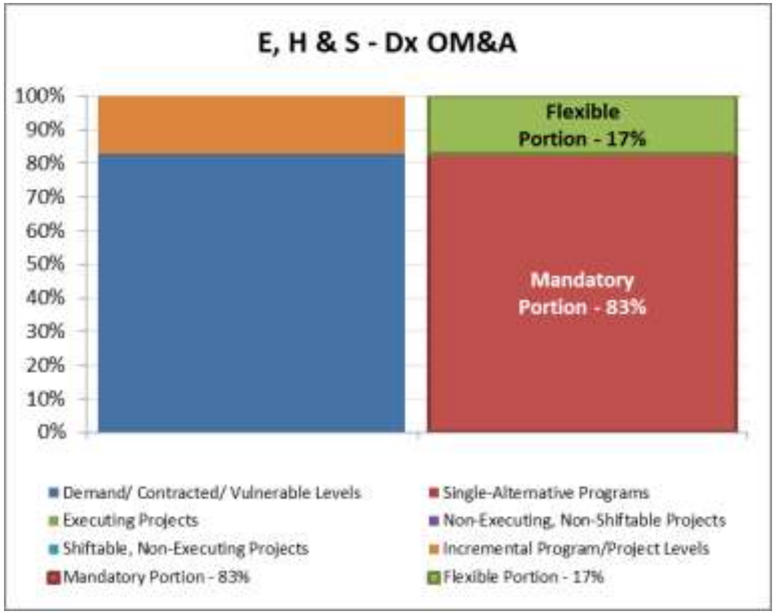
- **Health, Safety & Environment**

Investment Flexibility

- **17**%

Mandatory/Non-Discretionary Overview

- **Mandatory Overview:** *programs are required for Hydro One to meet legal obligations, improve employee safety performance and prevent injury or loss, to fulfill due diligence requirements and provide up to date technical & safety training .*
- **Approach to Mandatory:** *Compliance with Regulations and Hydro One policies (Health & Safety and Public)*
- **Mandatory Drivers:** *Hydro One Health & Safety Policy, Hydro One Public Safety Policy, Hydro One Environment Policy, Hydro One's 18001 Registration, Requirements to meet regulatory requirements associated with health and safety,*
- **Discretionary Opportunities:** *no discretionary opportunities for legal compliance items. Limited discretionary opportunities for some program elements.*



Mandatory Driver	Approx. %
Legal Regulatory/ Compliance	70
Contractual Commitment	25
Other – Demand based on LoB Requests	5

Investment Flexibility: OM&A (2/2)

Investment Portfolio

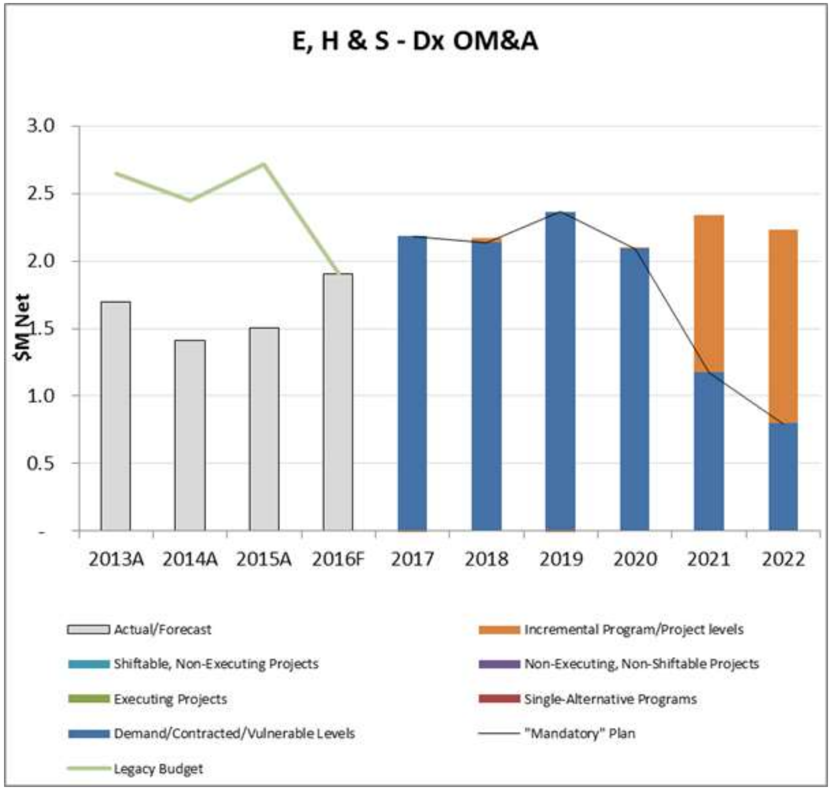
- **Health, Safety & Environment**

Consistency with historic delivery/budget

- *In line with historic funding requests although spending history has helped to refine budget requests.*
- *Certain programs have historically been underspent but this has allowed better alignment of budget requests.*

Funding Reduction Risks and Implications

- *Some of the HSE programs have defined contracts for delivery of service but is based on demand (e.g., care management, hearing conservation, wellness, ice/water rescue) .*
- *If program elements are reduced or deferred, there may be risk of Hydro One not meeting our legal obligations under the Occupational H&S Act and regulations or not being compliant with Hydro One policy.*

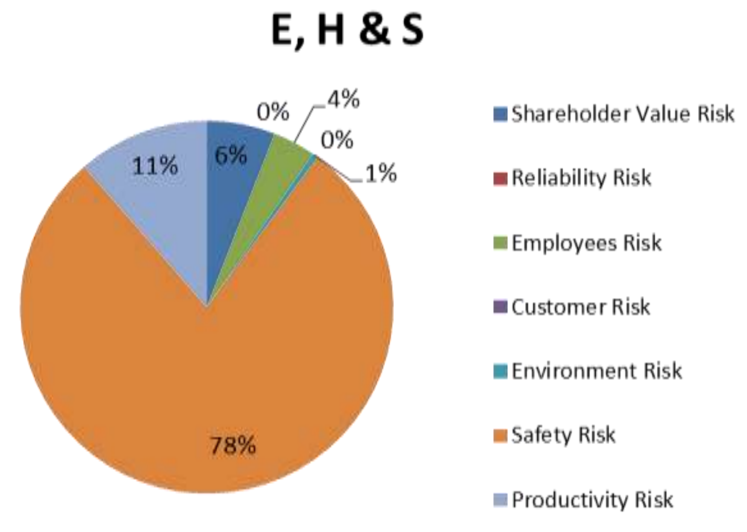


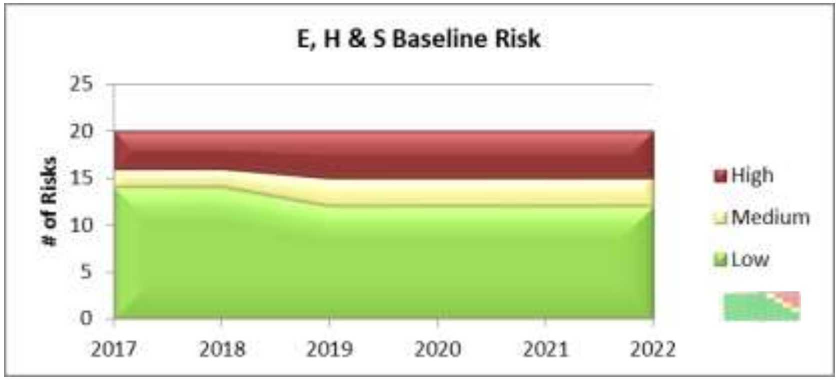
Risk Assessments: Health, Safety & Environment (1/4)

Investment Portfolio
- **Health, Safety & Environment**

Approach
- Safety performance data, public safety data, regulatory requirements.

Risk Sources
- **Significant Hazards/ Threats / Vulnerabilities**
  - *employee health and safety and public safety*
- **Significant Baseline Risk Consequences**
  - *employee and public safety performance, employee heath performance.*
- **Baseline Risk Trend**
  - *trend is for maintaining performance.*





Risk Assessments: Health, Safety & Environment (2/4)

Top 7 Highest/Lowest Risk Investments

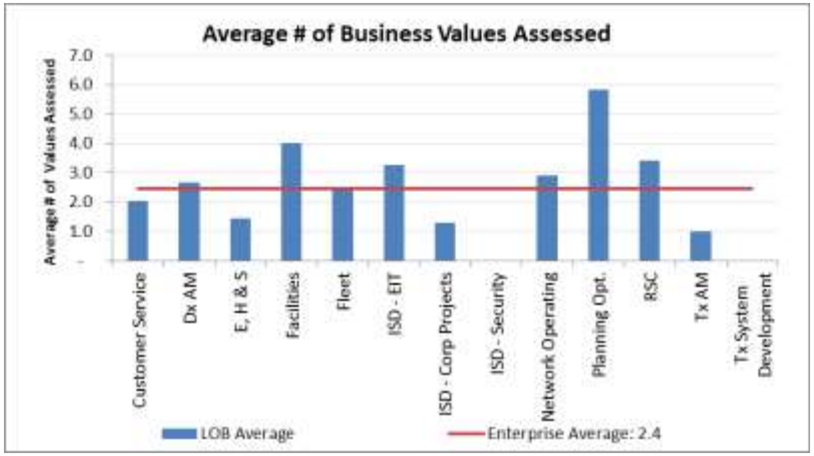
Driver	Stage	Description	Investment Code	Baseline Value ·	Rank
N.C.M.3.03	Short Term Planning	Strategy & Technical Services	AIP000125	15.39917625	32
N.C.M.3.03	Short Term Planning	Public Electrical Safety Presentations	AIP000122	6.315450438	89
N.C.M.3.03	Short Term Planning	Health & Rehab Services	AIP000118	4.166063994	118
N.C.M.3.03	Short Term Planning	Specialist HSE Resources	AIP000124	2.326326683	159
N.C.M.2.50	Short Term Planning	Greener Choices	AIP000101	0.292610553	305
N.C.M.3.03	Short Term Planning	Journey to Zero	AIP000120	0.087128068	337
N.C.M.3.03	Short Term Planning	S&E Contractor Pre-Qualification Process	AIP000123	0.043891583	353

Notes:
Includes only Dx/Common Investments
Excludes Investments without a risk assessment

Risk Assessments: Health, Safety & Environment (3/4)

Investment Portfolio
- **Health, Safety & Environment**

Alignment with Other LOBs
- **Scope of Risk Assessments**; Reviewed each program within the drivers and applied the most appropriate objectives from the risk matrix
- **Changing Risk Profile**; Risk profile is fairly consistent over the planning period



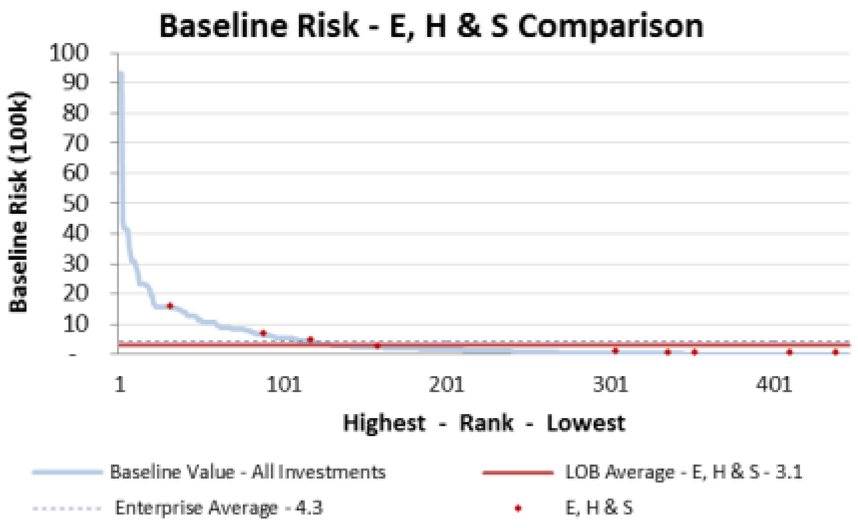
Risk Assessments: Health, Safety & Environment (4/4)

Investment Portfolio

- **Health, Safety & Environment**

Alignment with Other LOBs

- **Relativity of Risk Assessments;** EH&S programs are at or below the baseline average.



	First Quartile	Second Quartile	Third Quartile	Fourth Quartile
	Most Baseline Risk			Least Baseline Risk (or no assessment)
LOB Investments	2	2	1	4
LOB - % of Quartile	1.8%	1.8%	0.9%	3.6%
LOB - Quartile Distribution	22.6%	21.8%	11.2%	44.4%

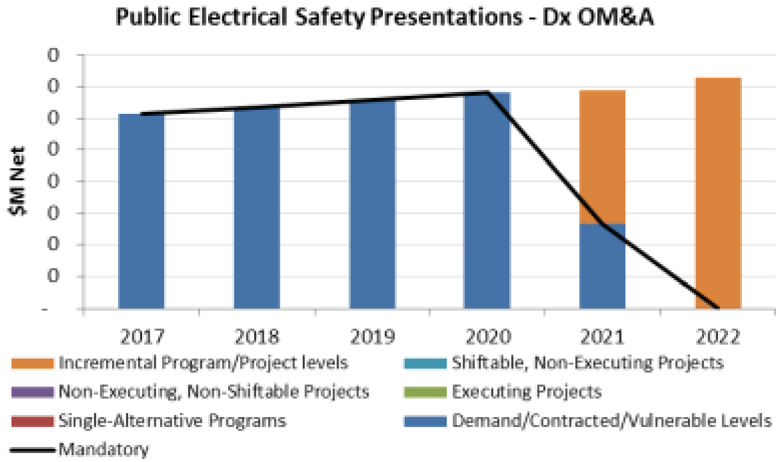
Risk-Based Investment Walkthrough (1/4)

Investment Code / Description

- AIP000122 / Public Safety Presentations

Mandatory Level and Alternatives Considered

- The level of funding requested is based on making safety presentations to elementary school children across Hydro One's service territory once every 4-5 years. Hydro One also makes presentations to 30+ community events and proactively plans its participation in 7-8 fairs annually including the International Plowing Match. The program is delivered by Provincial Lines staff.
- Although reduced delivery of presentations was considered, it was not entered into the AIP tool. Given the expanse of the Hydro One service territory, reduced presentations would make it very difficult to meet the Hydro One Public Safety Policy.



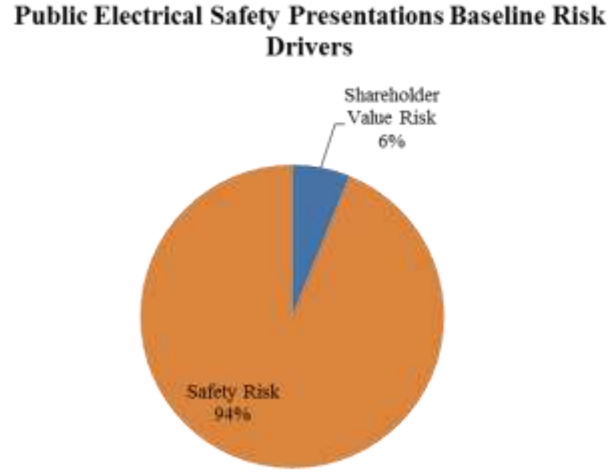
Risk-Based Investment Walkthrough (2/4)

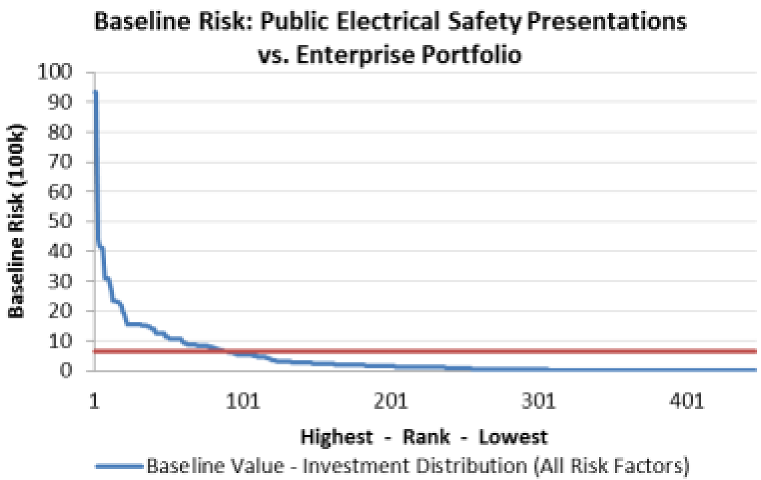
Investment Code / Description

- AIP000122 / Public Safety Presentations

Baseline Risk Assessment

- Two objectives identified: Safety risk is highest business objective for this program. Because public safety is monitored by regulatory bodies (ESA scorecard) and is in the public eye/media Shareholder Value was the second objective identified.
- Each objective was evaluated using the matrix (safety relates to our public safety statistics (e.g., fatalities) and Shareholder relates to potential media attention as well as scorecard monitoring by ESA.
- The number of electrical fatalities and serious injuries involving children is low and while it is impossible to prove that the program is saving children from harm, the aim is to educate children to protect them both now and in the future as adults. This supports the fact that there are riskier investments above this program.





Risk-Based Investment Walkthrough (3/4)

Investment Code / Description

- AIP000122 / Public Safety Presentations

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Shareholder Value	**Major**	Net Income	Net Income Shortfall	$25M-$100M
		Shareholder Confidence	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Material erosion in confidence; Shareholder Agreement rewritten to include approval of major investment & operating decisions; One or more Senior Managers replaced by the Board
		Public Profile /Confidence re effective stewardship of assets	Public Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	Significant local attention; Several opinion leaders/customers publicly critical
		Meet Licence Conditions and obtain required rates maintain credibility with regulators	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities including non- compliance.	Some Concerns re: Competence; Difficult Demands
		Regulatory/Legal Compliance	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction	Conviction or regulatory finding of non-compliance with minor fine ("minor" meaning <30% of maximum fine under relevant legislation or regulation, and one that is not unusually high/unprecedented amount for the industry).

Risk-Based Investment Walkthrough (4/4)

Investment Code / Description

- AIP000122 / Public Safety Presentations

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Safety	**Catastrophic**	Employee/Contractor Workforce/Health and safety	Workforce Health and Safety: Fatality or serious employee/contractor injuries/illness; failure to meet targeted reduction in OSHA Recordable injuries.	Employee/contractor fatality or major permanent disability due to failure of managed system
		Public Safety	Public Injuries (with Hydro One at fault)	Fatality or Major Permanent Disability

Investment Calibration

Reliability Studies, Standards and Compliance
Luis Marti
July 12, 2016

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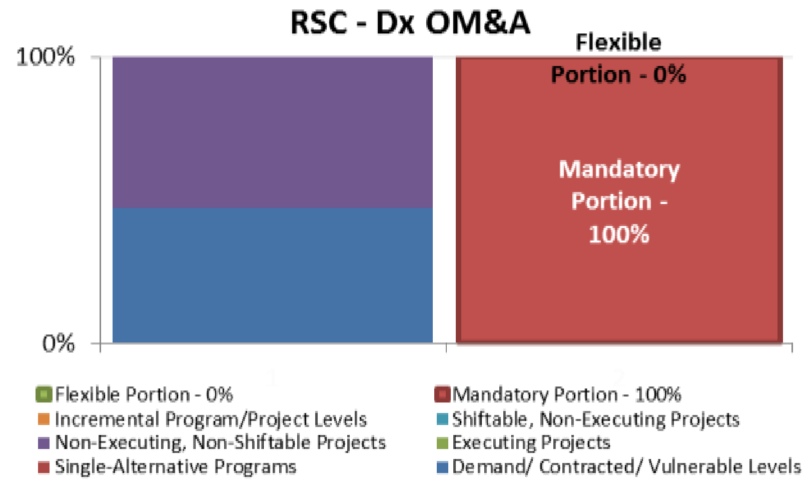
Investment Flexibility: OM&A (1/2)

Investment Portfolio
- **Reliability Studies, Standards and Compliance**

Investment Flexibility
- **0**%

Mandatory/Non-Discretionary Overview
- **Mandatory Overview:** Participation in research and development projects (including demonstrations) and programs; conducting power quality audits and investigations.
- **Approach to Mandatory:** The power quality program – including investigations and audits - is critical to customer satisfaction. Most large RD&D projects are associated with business development and Hydro One's ability to compete, and maintaining shareholder value. EPRI has elements of power quality in its programs that are part of the company's power quality strategy. Participation in EPRI and CEATI are essential to maintaining/upgrading information related to asset sustainment, health and safety, customer satisfaction, reliability, etc.
- **Mandatory Drivers:** As mentioned above
- **Discretionary Opportunities:** Different opportunities or selections are possible within our drivers (e.g. sites may be selected for particular focus), and these are prioritized according to greatest need or benefit.



Mandatory Driver	Approx. %
Emergency Break/Fix	
Legal/Regulatory, Compliance	10%
Obligation to connect/ upgrade/ modify	
License Condition	
Contractual Commitment	
Policy Responsiveness	
Released Project	
Strategic/Business Development/Competitive Advantage	50%
Reliability/Power Quality/H&S	40%

hydro one

Investment Flexibility: OM&A (2/2)

Investment Portfolio

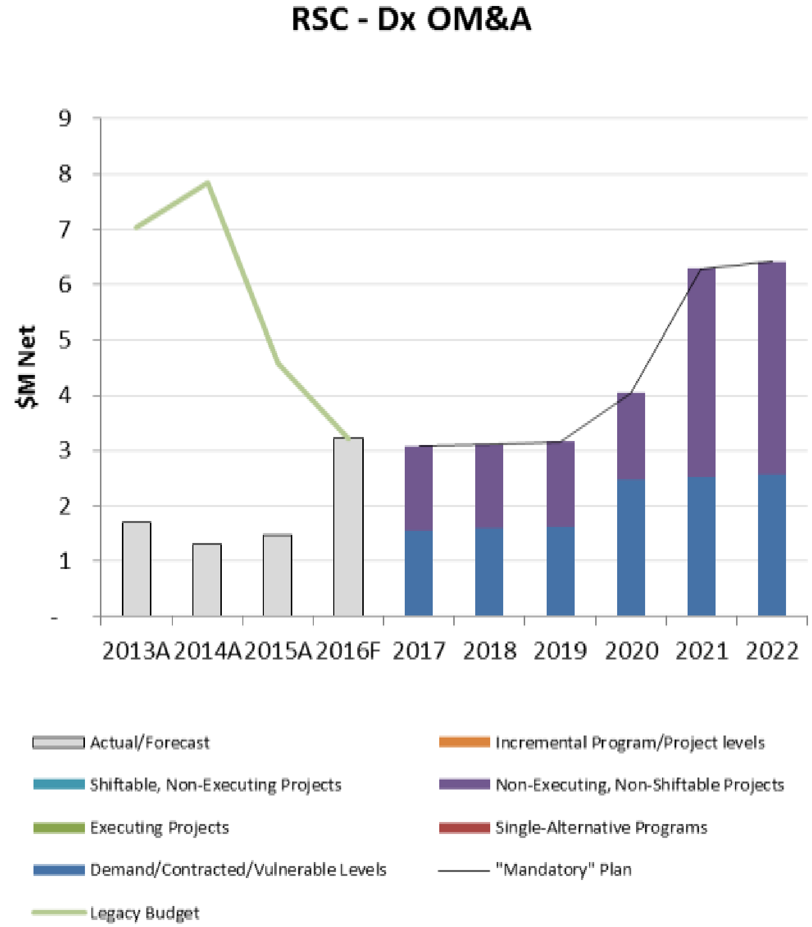
- **Reliability Studies, Standards and Compliance**

Consistency with historic delivery/budget

- RD&D has been rationalizing involvement in its projects and programs, and redirecting focus throughout 2015 and 2016.
- Greater need is seen in the future for projects with strategic implications/benefits.
- Some types of demonstration projects (e.g. microgrids) will require more funding than the current budget allows.
- There is increasing demand for power quality audits and investigations to address customer satisfaction issues, and more funding will be required for this.

Funding Reduction Risks and Implications

- There are implications related to customer satisfaction and public image if power quality investigations are not funded adequately.
- The largest impact of reduction in funding for RD&D projects and programs would be the loss of competitive advantage for Hydro One. This is critical to the company's ability to thrive.
- Reducing access to EPRI and CEATI project/program funding will result in lost opportunities to reduce OM&A, increase reliability and increase health and safety .



Risk Assessments: Reliability Studies, Standards and Compliance (1/4)

Investment Portfolio

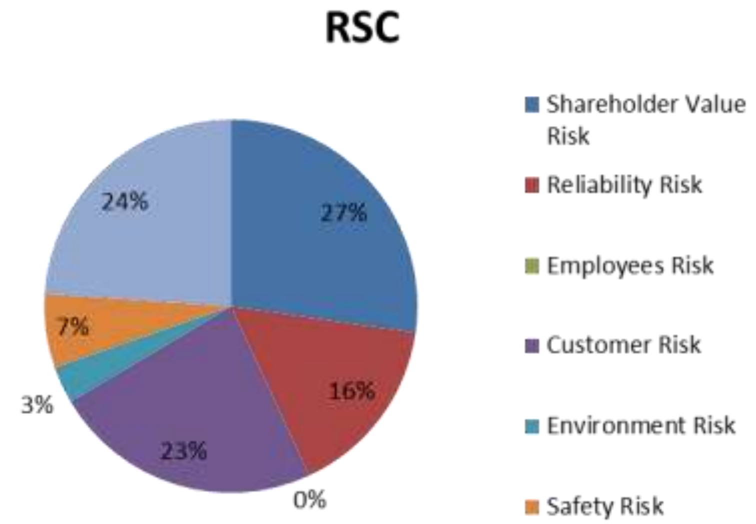
- **Reliability Studies, Standards and Compliance**

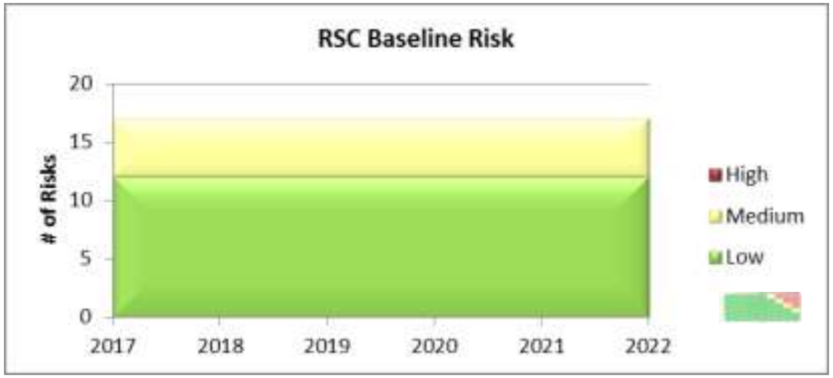
Approach

- Risk is assessed based on historical risk assessments (e.g. the risks and benefits assessed for previous programs and projects) and an estimation of future risks, especially for strategic opportunities and disruptive technologies.
- Risk is also assessed based on the anticipated impact to customer satisfaction.

Risk Sources

- **Significant Hazards/ Threats / Vulnerabilities**
  Shareholder Value (strategic value and ability to compete); Customer Satisfaction; Reliability; Productivity; HS&E.
- **Significant Baseline Risk Consequences**
- Inability to compete with other LDCs with regards to new technologies; decreased customer satisfaction related to poor power quality and reliability; decreased productivity
- **Baseline Risk Trend**
- The graph is not representative of the trend in risk. Risk is increasing substantially. The risk to the company's ability to compete with other LDCs is at high levels and growing rapidly. The need to provide customers with solutions to power quality issues is becoming more urgent. The pressure on us to find more cost-effective solutions for asset maintenance, and ways to decrease OM&A, is increasing.





Risk Assessments: Reliability Studies, Standards and Compliance (2/4)

Top 5 Highest/Lowest Risk Investments

Driver	Stage	Description	Investment Code	Baseline Value -	Rank
N.C.M.2.21	Short Term Planning	R&D Program - EPRI	AIP005490	3.343384872	123
N.C.M.2.21	Short Term Planning	R&D Program - CEATI	AIP005493	2.411430901	150
N.D.M.2.21	Short Term Planning	RD&D Project - Grid Modernization and Energy Storage	AIP005498	1.866237828	179
N.D.C.2.23	Short Term Planning	Customer Power Quality (Dx) - Capital	AIP005533	1.052331359	227
N.D.M.2.23	Short Term Planning	Customer Power Quality (Dx) - OMA	AIP005534	1.052331359	227

Notes:
Includes only Dx/Common Investments
Excludes Investments without a risk assessment

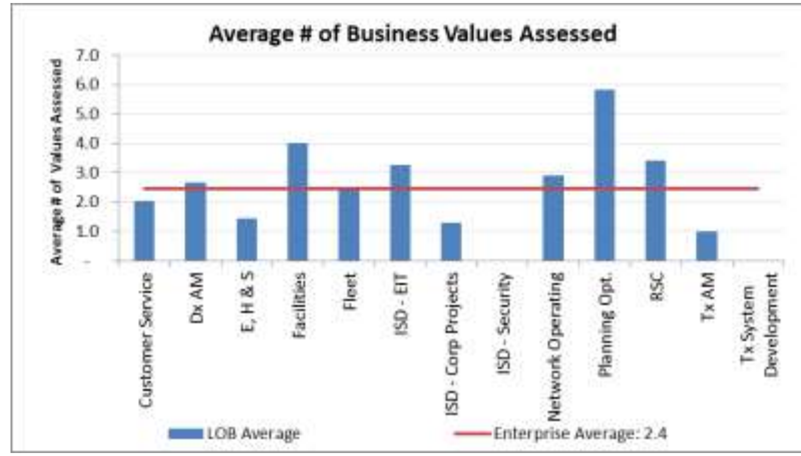
Risk Assessments: Reliability Studies, Standards and Compliance (3/4)

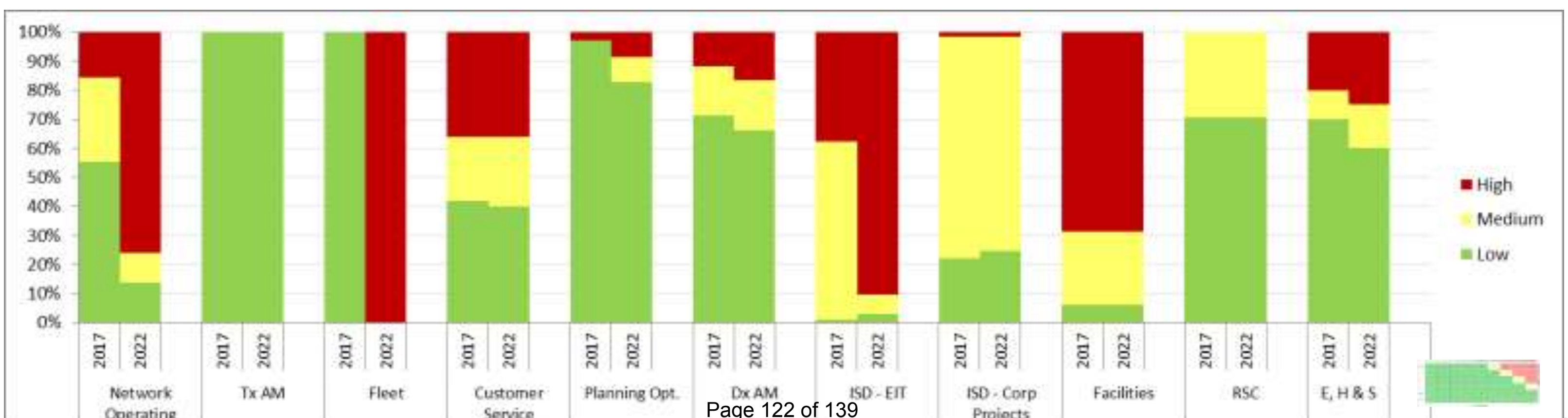
Investment Portfolio

- **Reliability Studies, Standards and Compliance**

Alignment with Other LOBs

- **Scope of Risk Assessments**; See above. Our primary risks include Shareholder Value and Customer Satisfaction. This is tied to RD&D's role in assessing and demonstrating new (especially disruptive) technologies, and Special Studies' role in conducting power quality audits and investigations.
- **Changing Risk Profile**; Although it appears that our risk profile is static and low/medium, this is not true. We feel that the risk associated with RD&D is increasing, with the evolution and adoption of new disruptive technologies, and the need for Hydro One to compete in a way that was unknown in the past. Also, the attention to power quality and customer satisfaction issues is significant and growing. Risk levels will be adjusted accordingly.





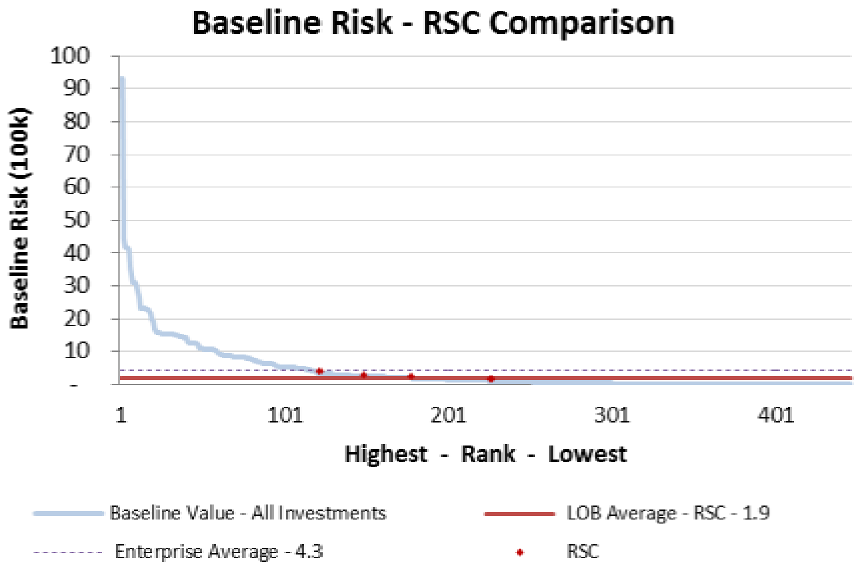
Risk Assessments: Reliability Studies, Standards and Compliance (4/4)

Investment Portfolio

- **Reliability Studies, Standards and Compliance**

Alignment with Other LOBs

- **Relativity of Risk Assessments;** No comment.



	First Quartile	Second Quartile	Third Quartile	Fourth Quartile
	Most Baseline Risk			Least Baseline Risk (or no assessment)
LOB Investments	0	3	2	0
LOB - % of Quartile	0.0%	2.6%	1.8%	0.0%
LOB - Quartile Distribution	0.0%	59.4%	40.6%	0.0%

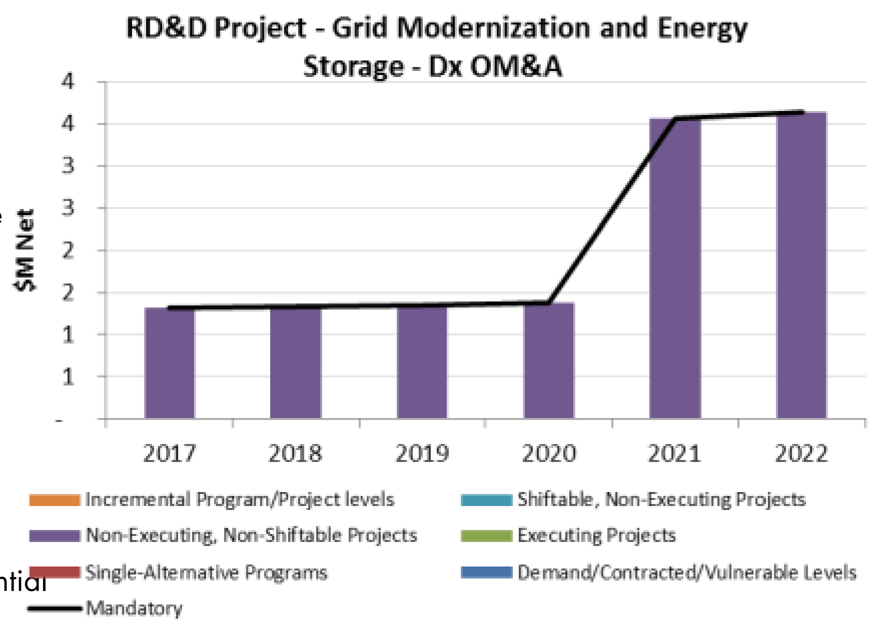
Risk-Based Investment Walkthrough – RD&D – Grid Modernization and Energy Storage (1/4)

Investment Code / Description

- AIP005498 / RD&D – Grid Mod and Energy Storage

Mandatory Level and Alternatives Considered

- This driver encompasses the non-CEATI/non-EPRI projects done within RD&D, including such projects as:
  - Electric Vehicle Charging
  - Electrification of Transit (Bus and Train Charging)
  - Energy Storage
  - Smart Grid Fund Projects (e.g. "Shawanaga" microgrid)
  - Pelee Island Microgrid
- Opportunities to collaborate with others are sought (e.g. Electrification of Buses; Shawanaga) to share cost/reduce risk.
- In some cases, this is not possible, as one objective is the potential for future business prospects.
- The "do nothing" alternative is not feasible if Hydro One is to maintain any competitive toehold at all.

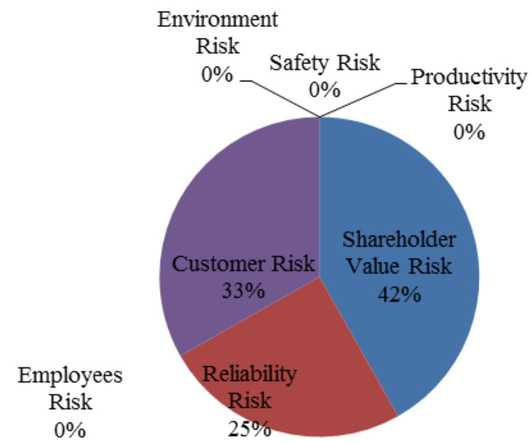


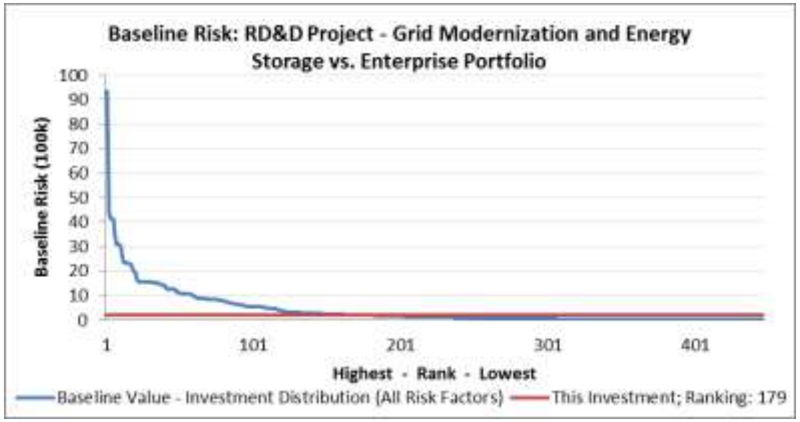
Risk-Based Investment Walkthrough – RD&D – Grid Modernization and Energy Storage (2/4)

Investment Code / Description
- AIP005498 / RD&D – Grid Mod and Energy Storage

Baseline Risk Assessment
- Risk associated with project cost and technology is ameliorated in some projects by cooperative research and demonstrations with partners such as other LDCs (e.g. Electrification of Buses).
- Demonstration projects in some cases (e.g. EV Charging) are a way to test not only new technology, but the ability of Hydro One to compete in new ventures; potentially unregulated areas. In these cases, cooperative ventures may not be prudent. These types of projects support the government's initiatives (e.g. climate change strategy) and boost the company's image.
- Some projects are developed to not only help us compete with other LDCs that are further ahead on the curve, and assess new technologies, but resolve other risks. They may address issues associated with customer satisfaction, a significant public issue for our largest shareholder (e.g. Shawanaga microgrid), or a technique that can reduce costs (capital or OM&A) or improve safety (Pelee Island microgrid/submarine cable; UAVs).
- Hydro One would encounter significantly higher risk in several strategic categories by underfunding RD&D.

RD&D Project - Grid Modernization and Energy Storage Baseline Risk Drivers





Risk-Based Investment Walkthrough – RD&D – Grid Modernization and Energy Storage (3/4)

Investment Code / Description

- AIP005498 / RD&D – Grid Mod and Energy Storage

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Customer	**Minor5**	Large and Mid Customers (Industrials, LDCs, Generators)	Large and Mid Customers (Industrials, LDCs, Generators): Increase in customer dissatisfaction with Hydro One	Less than planned improvement in customer satisfaction survey results (as measured by scorecard).
		OEB Service Quality Indices	Failure to meet Service Quality Indices.	Achieve only 95% (to 100%) of Overall Expected Performance
		Residential and Small Business Customers	Residential and Small Business Customers: Increase in customer dissatisfaction with Hydro One service quality	Less than planned improvement in mass market customer satisfaction as per survey responses (as measured by scorecard).
Shareholder Value	**Moderate**	Net Income	Net Income Shortfall	\$5M-\$25M
		Shareholder Confidence	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Confidence in question; Owner requests significant changes to business plan; Chair and CEO required to meet with owner to explain
		Public Profile /Confidence re effective stewardship of assets	Public Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	Credible letter(s) to Premier, to Minister of Energy, to Minister of Environment, or to Chair of OEB that require action
		Meet Licence Conditions and obtain required rates maintain credibility with regulators	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities including non- compliance.	Increase in Reporting Detail and Frequency (for HOI only)
		Regulatory/Legal Compliance	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction	Regulatory Order and/or financial sanction that is small, symbolic in nature or acknowledged as routine by the regulator and the industry.

Risk-Based Investment Walkthrough – RD&D – Grid Modernization and Energy Storage (4/4)

Investment Code / Description

- AIP005498 / RD&D – Grid Mod and Energy Storage

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Reliability	**Minor5**	Reliable Delivery of Electricity	Transmission Unsupplied Energy (due to single acute event or outage) Measured in MWh	250-600 MWh
			Deterioration in Transmission System reliability (over the next 5 years, compared to benchmarked comparable).	Deterioration in reliability relative to current performance (but still within 1st quartile) for only one year in the 5 year period.
			Transmission Lost Redundancy Power supplied without expected redundancy measured in MWh	5000 MWh-12,000 MWh
			Equipment Unavailability (Incremental %): The extent to which the transmission equipment is not available for use due to outages	0.015-0.04% (1000 asset-hours - 4000 asset-hours, for an asset class with 1000 assets)
			Improve Tx Worst Served Customers Number of outliers significantly impacted by investment	No impact to chronic outliers
			Duration of Distribution Outages Measured in Interruption Hours (Number of customers impacted * Expected duration of Outage)	5 Million to 7 Million Customer Interruption Hours (equivalent to SAIDI of 3.8 to 5.4 hrs)
			Frequency of Distribution Outages Number of customers interrupted for > 1 minute	200,000 to 500,000 Interruptions

Investment Calibration

Planning Optimization
[Scott McLachlan]
July 12, 2016

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Investment Flexibility: OM&A (1/2)

Investment Portfolio

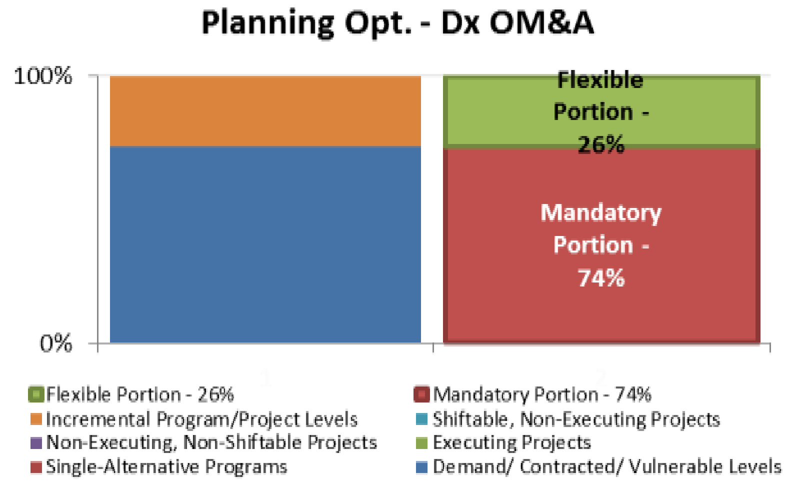
- **Planning Optimization**

Investment Flexibility

- **22**% [2017-22 total = $14M, mandatory = $11M, does not include ESA annual fees - ~$800k/yr]

Mandatory/Non-Discretionary Overview

- **Mandatory Overview *[Reg 22-04 compliance]***; *i.e. Storm Response, Customer Connections, Metering Reading, etc.*
- **Approach to Mandatory *[Consistent with historical Dx standards program needs]***; *i.e. compliance, red zone risk, rolling multi-year average, etc.*
- **Mandatory Drivers *[Compliance based needs];*** *i.e. compliance, break/fix, contractual commitments, in-execution, etc. Suggest providing details such as "License fees for critical business application," "For non-communicating smart meters, OEB allows a maximum of 2 estimated bills per year" , etc.*
- **Discretionary Opportunities *[No]*** *i.e. funding includes base requirements and X service enhancement initiatives, etc.*



Mandatory Driver	Approx. %
Emergency Break/ Fix	
Legal Regulatory/ Compliance	100
Obligation to connect/ upgrade/ modify	
License Condition	
Contractual Commitment	
Policy Responsiveness	
Released Project	
Other – Please Specify (i.e. - risk considerations)	
Other – Please Specify (i.e. - Demand)	

Investment Flexibility: OM&A (2/2)

Investment Portfolio

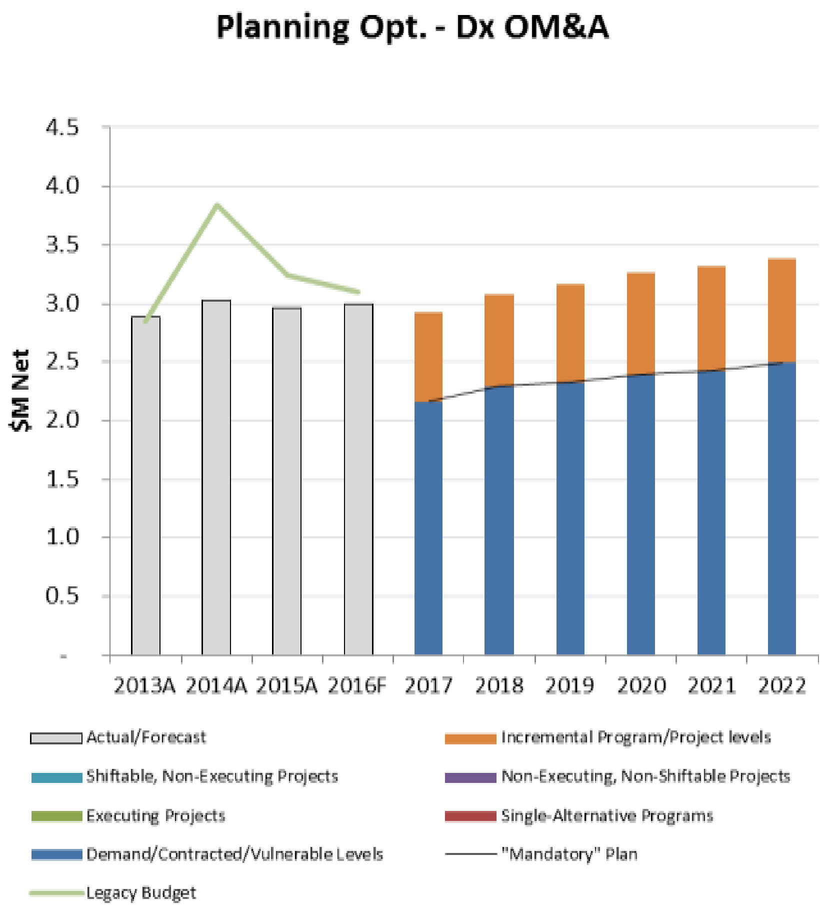
- **Planning Optimization**

Consistency with historic delivery/budget

- **[Consistent with historical spend levels, shown to the right – but these include ESA annual fees of ~$800k/yr]** *i.e. in-line with historic, increase over historic levels , etc.*
- **[Actuals vs budget are normally on plan]** *i.e. generally consistent with budget; portfolio redirection to manage corporate envelope; delivery shortfalls; overage to do demand, etc.*

Funding Reduction Risks and Implications

- **[Risk will increase to equipment standardization and capital program delivery]**; *i.e. inability to meet service quality indicator targets (calls answered on time), deteriorated asset condition leading to failure, contract break penalty, etc.*
- **[Same as above]** *i.e. deferral of renewal investments will result in backlog and increased future investment; contract break fees; non-compliance with Section x.y.z of DSC, etc.*



Risk Assessments: Planning Optimization (1/4)

Investment Portfolio

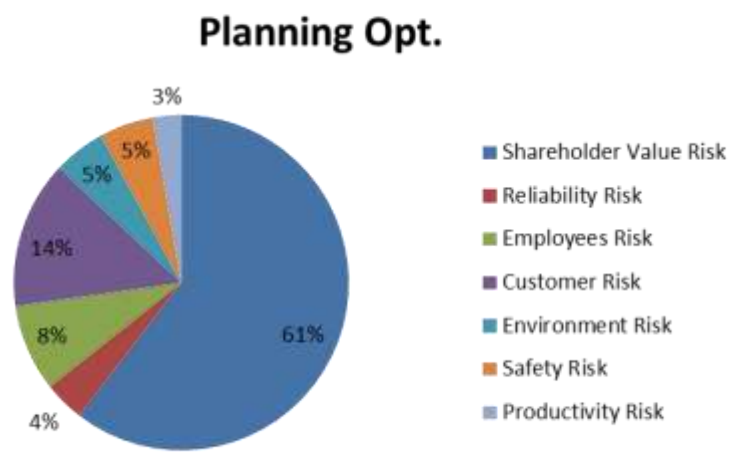
- **Planning Optimization**

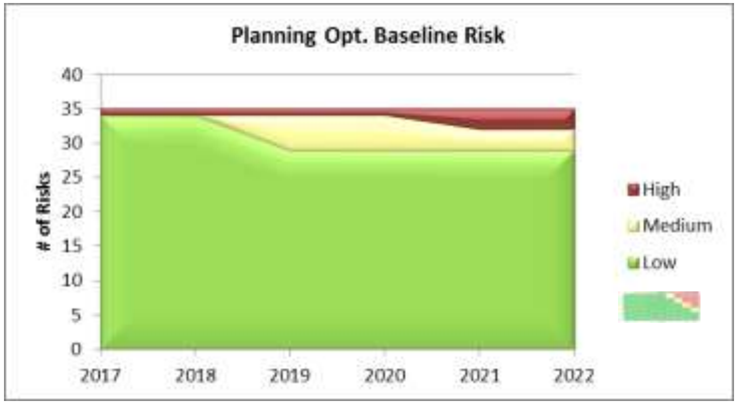
Approach

- [Without proper standards in place, capital programs can be at risk in not being completed and not in compliance with Reg 22-04]

Risk Sources

- **Significant Hazards/ Threats / Vulnerabilities [Compliance, design deficiencies]**; *i.e. asset conditions, customer responsiveness, etc.*
- **Significant Baseline Risk Consequences [Non-compliance, and risk of delivery of capital work]**; *i.e. service delivery impacts, customer satisfactions, compliance, etc.*
- **Baseline Risk Trend[Capital program not executed to standard designs]**; *i.e. deterioration because renewal efforts do not keep up with replacements, etc.*





Risk Assessments: Planning Optimization (2/4)

Top 5 Highest/Lowest Risk Investments

Driver	Stage	Description	Investment Code	Baseline Value ·	Rank
N.D.M.2.20	Short Term Planning	Dx - TECHS-LINES-Standards	AIP000309	6.712282932	87
N.D.M.2.20	Short Term Planning	DX TECHS-Stations Standards Development	AIP000310	2.311559273	161
N.D.M.2.20	Short Term Planning	Dx - AM Standards Development	AIP000308	2.099834903	166
N.D.M.2.20	Short Term Planning	Dx - Engineering Standards	AIP000311	2.005042563	175
N.D.M.2.20	Short Term Planning	Dx - External Standards Development ?	AIP000313	0.182006149	319

Notes:
Includes only Dx/Common Investments
Excludes Investments without a risk assessment

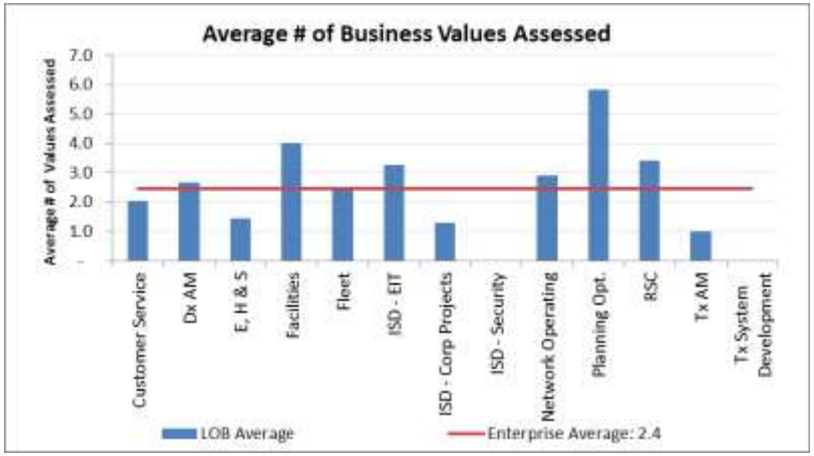
Risk Assessments: Planning Optimization (3/4)

Investment Portfolio

- **Planning Optimization**

Alignment with Other LOBs

- **Scope of Risk Assessments**; [Rationale for reviewing all values – standards impact all values – without them in place we WILL negatively impact upon each and every value, from Shareholder value right thru to employees and safety.]
- **Changing Risk Profile**; [*Non-compliance risk increases along with risk to all corporate values.*]



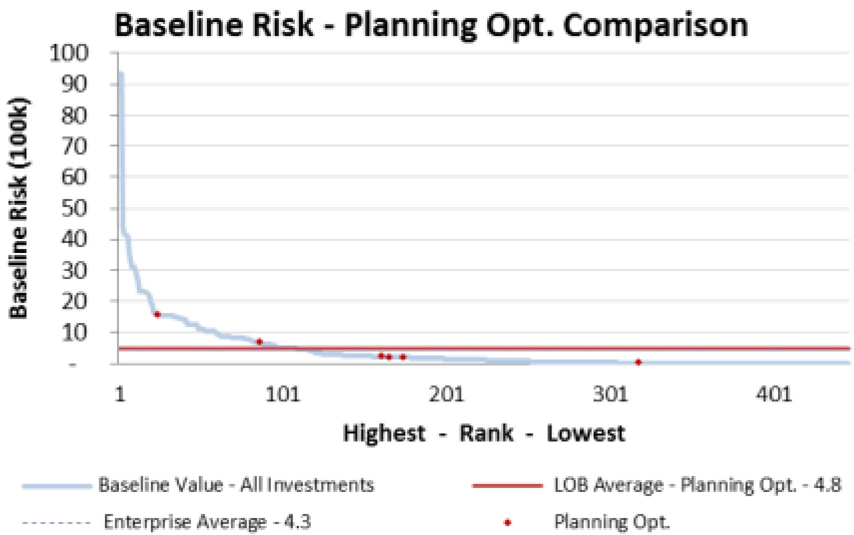
Risk Assessments: Planning Optimization (4/4)

Investment Portfolio

- **Planning Optimization**

Alignment with Other LOBs

- **Relativity of Risk Assessments; [**Yes, in line with corporate average, but slightly higher due to the Compliance impacts of not having standards in place.]



	First Quartile	Second Quartile	Third Quartile	Fourth Quartile
	Most Baseline Risk			Least Baseline Risk (or no assessment)
LOB Investments	2	3	1	0
LOB - % of Quartile	1.8%	2.6%	0.9%	0.0%
LOB - Quartile Distribution	34.0%	49.2%	16.8%	0.0%

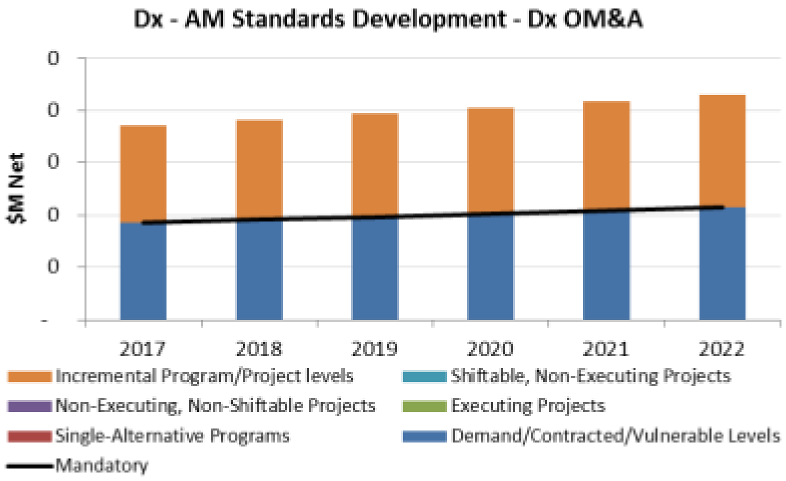
Risk-Based Investment Walkthrough –Technical Standards (1/4)

Investment Code / Description

- AIP000308 / Dx Technical Standards (AM)

Mandatory Level and Alternatives Considered

- [Level arrived at based on historical funding needs, however resourcing shortfalls have prevented actual costs incurred]



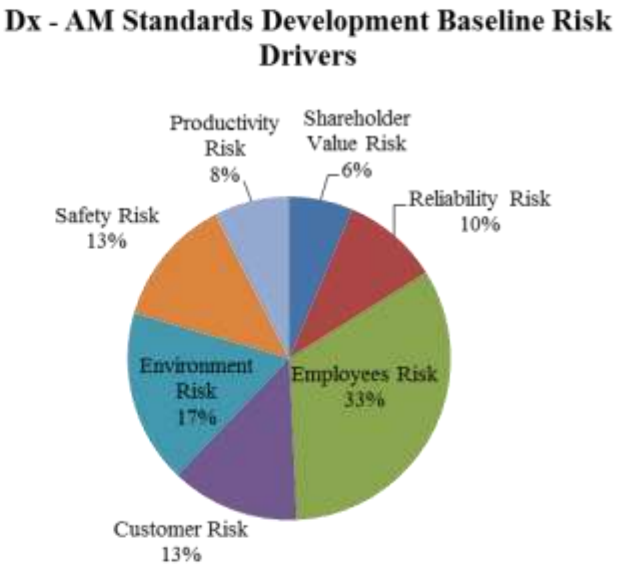
Risk-Based Investment Walkthrough –Technical Standards (2/4)

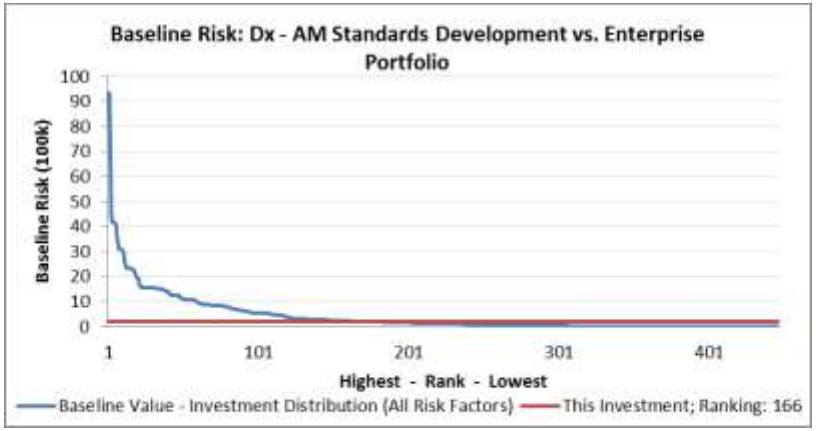
Investment Code / Description

- AIP000308 / Dx Technical Standards (AM)

Baseline Risk Assessment

- [Determined by Dx AM for functional standards reqts]
- [Appropriately assigned at the mid-point level due to the compliance implications and relatively low cost risk]





Risk-Based Investment Walkthrough –Technical Standards (3/4)

Investment Code / Description

- AIP000308 / Dx Technical Standards (AM)

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Customer	**Moderate**	Large and Mid Customers (Industrials, LDCs, Generators)	Large and Mid Customers (Industrials, LDCs, Generators): Increase in customer dissatisfaction with Hydro One	Increase in number of customer complaints; Some increase in number of customers falling outside of "delivery point performance standards"; Moderate deterioration in large and mid customer satisfaction survey results (as measured by scorecard) in at least one segment.
		OEB Service Quality Indices	Failure to meet Service Quality Indices.	Achieve only 90% (to 94%) of Overall Expected Performance
		Residential and Small Business Customers	Residential and Small Business Customers: Increase in customer dissatisfaction with Hydro One service quality	Slight deterioration in mass market customer satisfaction as per survey responses (as measured by scorecard).
Shareholder Value	**Moderate**	Net Income	Net Income Shortfall	$5M-$25M
		Shareholder Confidence	Shareholder Confidence: Owner/ shareholder involvement in Hydro One operations	Confidence in question; Owner requests significant changes to business plan; Chair and CEO required to meet with owner to explain
		Public Profile /Confidence re effective stewardship of assets	Public Profile/Confidence: Negative Media Attention; Opinion leader and Public Criticism	Credible letter(s) to Premier, to Minister of Energy, to Minister of Environment, or to Chair of OEB that require action
		Meet Licence Conditions and obtain required rates maintain credibility with regulators	Maintain Credibility With Regulators: Lack of Credibility or poor relationships with Regulators & Reliability Authorities including non- compliance.	Increase in Reporting Detail and Frequency (for HOI only)
		Regulatory/Legal Compliance	Compliance: Failure to Meet Legal, Regulatory, Health Safety, Environmental Compliance Requirements or Sanction	Regulatory Order and/or financial sanction that is small, symbolic in nature or acknowledged as routine by the regulator and the industry.

Risk-Based Investment Walkthrough –Technical Standards (4/4)

Investment Code / Description

- AIP000308 / Dx Technical Standards (AM)

Business Value	2022 Impact Consequence	Attribute	Consequence Table Event	Event Description (Based on Consequence Assessment)
Safety	**Moderate**	Employee/Contractor Workforce/Health and safety	Workforce Health and Safety: Fatality or serious employee/contractor injuries/illness; failure to meet targeted reduction in OSHA Recordable injuries.	Less than planned improvement in health and safety performance
		Public Safety	Public Injuries (with Hydro One at fault)	Small Increase in Number of Injuries
Reliability	**Moderate**	Reliable Delivery of Electricity	Transmission Unsupplied Energy (due to single acute event or outage) Measured in MWh	600-1500 MWh
			Deterioration in Transmission System reliability (over the next 5 years, compared to benchmarked comparable).	Deterioration in reliability relative to current performance (but still within 1st quartile) for more than one year in the 5 year period.
			Transmission Lost Redundancy Power supplied without expected redundancy measured in MWh	12,000 MWh-30,000 MWh
			Equipment Unavailability (Incremental %): The extent to which the transmission equipment is not available for use due to outages	0.04-0.1% (4000 asset-hours - 10,000 asset-hours, for an asset class with 1000 assets)
			Improve Tx Worst Served Customers Number of outliers significantly impacted by investment	Impact 1 or 2 chronic outliers
			Duration of Distribution Outages Measured in Interruption Hours (Number of customers impacted * Expected duration of Outage)	7 Million to 8 Million Customer Interruption Hours (equivalent to SAIDI of 5.4 to 6.7 hrs)
			Frequency of Distribution Outages Number of customers interrupted for > 1 minute	500,000 to 1.25 Million Interruptions
Employee	**Moderate**	Employee skills and engagement: developing, retaining, attracting and competencies	Change in employee engagement survey results.	Much Less-than-planned improvement achieved in employee survey results.
Productivity	**Major**	Productivity	Failure meet Unit Cost targets per plan	Unit Costs increase by < 5%
Environment	**Major**	Environmental Performance	Adverse Environmental Impact	Significant local offsite Impact (e.g.. a public thoroughfare) e.g. >5,000 - 10,000 L non-PCB material released or >25% - 50% increase in non-recoverable spills/leaks above historical levels
		Environmental Performance	Adverse Emissions (carbon footprint / greenhouse gas)	No real improvement relative to work program in carbon footprint / greenhouse gas initiatives.

Action Items

Session	Actions/Follow-ups

UNDERTAKING – JT 2.10

Undertaking

To provide a further explanation of the above-discussed matter after reviewing the transcript.

Response

As part of the exchange between Mr. Oakley and Mr. Jesus on March 2, 2018, three topics were discussed:

A. the risk assessment process and Exhibit I-24-Staff-100; and
B. the difference between Hydro One's optimization process and a forced rank order prioritization; and
C. The investment plan's risk profile and placement of the capital budget line.

These three topics are addressed in Part A, Part B and Part C, respectively.

Part A: Risk Assessment Process

Once investment candidate options are identified, as discussed in Section 2.1 of the DSP, they are assessed based on the value created by mitigating risks or their ability to enhance productivity/produce financial benefits.

The risk assessment process incorporates a probability and consequence of outcome to determine the impact on each business objective, as applicable. Based on identified sources of risk, an assessment is made on (a) the worst credible consequence/impact of a given risk on a specific business objective, as measured on a nine-point risk tolerance scale from "minor 1" to "catastrophic" and (b) the likelihood that a given consequence/impact will materialize over the planning period, as measured on a six-point likelihood scale, from "unexpected" to "very likely."

The risk assessment includes: (a) a baseline risk evaluation, representing the risk of not proceeding with the investment: and (b) a residual risk evaluation, representing the remaining risk after the investment is put into service. The difference between the baseline risk and residual risk is the risk mitigation value created by the investment. An example of the output of these baseline and residual risk assessments is included in Exhibit I-24-Staff-100.

Part B: Optimization vs. Prioritization

Based on Hydro One’s understanding of Mr. Oakley’s line of questioning, a typical forced rank order investment prioritization exercise produces a ranked list of possible investments based on a set of decision criteria resulting in a fixed score (for example absolute risk mitigation). The overall portfolio is ranked using the fixed score, and funding is allocated from highest to lowest priority until all available funding has been allocated, resulting in funded list of investments.

Hydro One’s optimization process uses a weighted multi-criteria assessment of the risk mitigated for each of the business values and considers three elements not typically incorporated in a forced rank order prioritization including: (a) alternate project timing, (b) alternate program pacing, and (c) the ability to address multiple constraints, including financial and non-financial constraints and investment dependencies.

Part C: Developing the final Budget Line

The output of the optimization process is an optimized investment portfolio or draft investment plan. This draft plan is then reviewed as part of Operational Stakeholder Engagement as described in section 2.1.5.2 of the DSP to achieve enterprise alignment for meeting business outcomes and objectives. This review may necessitate changes to the draft plan.

The factors that inform and influence the final budget envelope and investment plan include: (a) strategic direction and business outcomes including requirements for performance and additional cost constraints/productivity; (b) customer needs and preferences; (c) asset risks and system needs, including condition and reliability of the distribution system; and (d) the effect on customer rates.

In preparing the Dx Business Plan underpinning this Application, Hydro One considered alternate funding envelopes for its capital plan as described in Exhibit A, Tab 3, Schedule 1, each of which provided different outcomes and different levels of risk mitigation.

UNDERTAKING – JT 2.11

Undertaking

To provide a sample monthly report to the management level on projects and programs for the last year; the most recent month available.

Response

Please refer to Attachment 1 of this undertaking.

PP-177 - Schedules A & C Net, Fiscal Year/Period: 2017/12, Report Date: 2018.01.17

Distribution OM&A

		Financial - Net			Units		
	Primary Unit	YTD Act	YTD Budget	YTD Var	YTD Act	YTD Budget	YTD Var
N.D.M.1.01 - TROUBLE CALLS CUSTOMER LOCATES & DISCONN							
Trouble Call	# of Calls	55.3	61.8	(6.6)	41,106	42,645	(1,539)
Cable Locates	# of locates	12.1	13.8	(1.7)	216,986	200,000	16,986
Disconnect/Reconnect	# of disconnect/reco	14.2	12.4	1.7	15,651	14,250	1,401
O&M Costs - Storm Response	# of Storms	13.1	13.4	(0.3)	0	0	0
Total N.D.M.1.01 - TROUBLE CALLS CUSTOMER LOCATES & DISCO		**95**	**101**	**(7)**			
N.D.M.1.02 - LINE MAINTENANCE & REPAIR							
Distribution Patrols	# of poles/inspectio	5.5	9.8	(4.3)	316,578	350,000	(33,422)
CM: Defect Corrections	# of defects	4.2	3.7	0.5	7,474	7,050	424
PM: Insulator Washing	# of insulators	0.2	0.3	(0.1)	2,986	6,000	(3,014)
PM: Recloser & Regulator Maintenance	# of regulators/recl	0.0	0.1	(0.1)	1	75	(74)
PM: Switch Maintenance (ABS & LBS)	# of Switches	0.9	1.3	(0.4)	189	215	(26)
Sentinel Light Maintenance	# of lights	0.5	1.1	(0.5)	911	2,000	(1,089)
Material Failure Investigations	Investigations	0	0.1	(0.1)	0	0	0
Total N.D.M.1.02 - LINE MAINTENANCE & REPAIR		**11**	**16**	**(5)**			
N.D.M.1.03 - VEGETATION MANAGEMENT							
Unplanned Maintenance	-	17.8	9.9	8.0	0	0	0
Program Development, Management, & Auditing	-	1.3	0.1	1.2	0	0	0
DX Hazard Tree Removal	Trees removed	8.2	3.9	4.3	12,779	8,500	4,279
DX UVM - Tactical Maintenance	# of km	19.0	47.1	(28.0)	3,615	3,500	115
DX UVM - Cycle Maintenance	# of km	82.5	79.9	2.7	10,767	8,500	2,267
Total N.D.M.1.03 - VEGETATION MANAGEMENT		**129**	**141**	**(12)**			
N.D.M.1.04 - DISTRIBUTING & REGULATING STATION							
DX Herbicide Application	# of Orders	0.5	0.7	(0.2)	2,222	2,295	(73)
DS Corrective Maintenance - Demand - Station	# of Orders	2.6	3.2	(0.6)	676	0	676
DS Corrective Maintenance - Planned - Station	# of Orders	7.0	5.7	1.2	983	0	983
DS Misc Mtce & Support - PCB Oil Retrofill	# of Retrofills	0.3	0.7	(0.3)	34	43	(9)
DS Misc Mtce & Support - PCB Oil Sampling	# of Tests	0.4	0.6	(0.2)	757	558	199
DS Preventive Maintenance - Ground and Sites	# of Orders	1.5	1.8	(0.3)	3,783	3,521	262
DS Preventive Maintenance - Station	# of Orders	3.8	4.4	(0.6)	6,180	6,234	(54)
DS Transformer Overhaul Program	# of Transformers	0.8	1.3	(0.5)	7	6	1
Dx Infrastructure Corrective Maintenance Demand	# of Orders	0.2	0.1	0.1	85	0	85
Dx Infrastructure Corrective Maintenance Planned	# of Orders	0.9	0.5	0.5	351	0	351
DS Operating Spare Mtce & Inspection	# of Orders	0.1	0.1	(0.0)	127	166	(39)
DS Operating Spare Corrective Maintenance	# of Orders	0.3	0.1	0.2	45	0	45
DS Misc Mtce & Support - Technical Support	-	0.9	1.1	(0.2)	0	0	0
Total N.D.M.1.04 - DISTRIBUTING & REGULATING STATION		**19**	**20**	**(1)**			
N.D.M.1.05 - CUSTOMER METERS							
Meter Replacement Services	# of meters	6.2	3.6	2.6	18,296	8,000	10,296
Sustaining	-	7.4	7.3	0.1	0	401	(401)
Total N.D.M.1.05 - CUSTOMER METERS		**14**	**11**	**3**			
N.D.M.1.06 - PCB TEST & DESTRUCTION							
PCB Inspection & Testing	Transformers	7.3	9.4	(2.1)	19,728	27,595	(7,867)
Environmental Services	-	5.4	5.4	(0.0)	0	0	0
Total N.D.M.1.06 - PCB TEST & DESTRUCTION		**13**	**15**	**(2)**			
N.D.M.1.07 - OTHER SERVICES							
Data Collection	# of occurrence	1.1	0.6	0.6	0	0	0
Joint Use Audits	# of audits	0.2	0.1	0.1	19	10	9
SQI Measures	# of occurrence	1.0	1.0	0.0	12	0	12
Small External Demand Requests	# of occurrence	9.8	7.7	2.1	5,757	0	5,757
Community Events	# of Events	1.0	0.2	0.8	0	0	0
Tx Idle Line Rental Payments	-	3.9	3.9	(0.0)	0	0	0
Small External Demand Request Recoverable	# of occurrence	0.3	0	0.3	0	0	0
Not assigned	-	0.9	0.9	(0.0)	0	0	0
Pole Rentals & Joint Use Audits	# of Poles	0.8	0.7	0.2	0	0	0
Distribution Document Management	-	0.1	0.2	(0.1)	1,282	0	1,282
Misc Engineering & Environmental Support	Retainer	0.1	0.1	0.0	0	0	0
Total N.D.M.1.07 - OTHER SERVICES		**19**	**15**	**4**			
N.D.M.1.08 - LAND ASSESSMENT & REMEDIATION							
Environmental Services	-	5.0	5.1	(0.1)	0	4	(4)
Total N.D.M.1.08 - LAND ASSESSMENT & REMEDIATION		**5**	**5**	**(0)**			
N.D.M.1.09 - TELECOM MONITORING AND CONTROL							
HONI-HOT Smart Meter Sustainment	Retainer	1.3	1.6	(0.3)	0	0	0
Retail Settlements	Retainer	3.8	4.9	(1.1)	0	0	0
Total N.D.M.1.09 - TELECOM MONITORING AND CONTROL		**5**	**7**	**(1)**			
N.D.M.1.17 - PROTECTION,CONTROL AND TELECOM MAIN							
DX P&C Corrective	-	0.0	0.3	(0.2)	0	0	0
P&C Distribution Support	-	0.2	0.3	(0.1)	0	0	0
Total N.D.M.1.17 - PROTECTION,CONTROL AND TELECOM MAIN		**0**	**1**	**(0)**			

Filed: 2018-03-29
EB-2017-0049
Exhibit JT 2.11
Attachment 1

PP-177 - Schedules A & C Net, Fiscal Year/Period: 2017/12, Report Date: 2018.01.17

Distribution CAPTL

	Primary Unit	Financial - Net YTD Act	Financial - Net YTD Budget	Financial - Net YTD Var	Units YTD Act	Units YTD Budget	Units YTD Var
N.D.C.1.02 - WOOD POLE REPLACEMENT							
Pole Replacement	# of poles	72.4	95.8	(23.5)	9,769	12,458	(2,689)
Total N.D.C.1.02 - WOOD POLE REPLACEMENT		**72**	**96**	**(23)**			
N.D.C.1.03 - JOINT USE & RELOCATIONS							
Joint Use & Line Relocations < 75k	# of projects	16.1	21.9	(5.7)	1,722	0	1,722
Total N.D.C.1.03 - JOINT USE & RELOCATIONS		**16**	**22**	**(6)**			
N.D.C.1.04 - PCB TRANSFORMER REPLACEMENT							
PCB Transformers Replacement	# of transformers	0.0	0.1	(0.0)	0	0	0
Total N.D.C.1.04 - PCB TRANSFORMER REPLACEMENT		**0**	**0**	**(0)**			
N.D.C.1.06 - TROUBLE CALLS & STORM DAMAGE							
Equipment Replaced (Trouble Call)	# of equipment piece	19.0	23.9	(4.9)	3,039	3,376	(337)
Storm Damage	# of storms	44.5	43.5	1.0	89	0	89
Post Trouble and Power Quality	# of occurrence	15.2	6.6	8.6	790	0	790
Damage Claims	# of claims	2.7	2.6	0.1	442	0	442
UG Sub Replace Trouble	# of cables	5.6	5.1	0.5	4,245	0	4,245
Farm Stray Voltage	# of occurrence	0.9	0.5	0.4	28	0	28
Total N.D.C.1.06 - TROUBLE CALLS & STORM DAMAGE		**88**	**82**	**6**			
N.D.C.1.07 - LINES							
Large Sustainment Initiatives	# of projects	13.8	10.7	3.1	0	0	0
Small Sustainment Initiatives	# of projects	3.7	3.9	(0.2)	0	0	0
Component Replacement - Crossarms	# of crossarms	1.3	1.4	(0.2)	810	1,000	(190)
Component Replacement - Sentinel Lights	# of lights	1.2	0.5	0.7	2,112	1,400	712
Conductor Replacement - Overhead	# of incidents	0.0	0.6	(0.6)	1,800	0	1,800
Conductor Replacement - Submarine	# of incidents	7.3	7.5	(0.2)	73,285	0	73,285
Component Replacement - Regulators/Reclosers	# of regulators/recl	0.4	4.6	(4.2)	42	250	(208)
Component Replacement - Switches	# of Switches	0.2	1.3	(1.1)	7	30	(23)
Component Replacement - Transformers	# of transformers	0.0	1.1	(1.1)	0	30	(30)
Component Replacement - Nest Platforms	# of platforms	0.1	0.1	(0.0)	12	15	(3)
Idle Line Removal	# of projects	0.1	0	0.1	31,764	0	31,764
Total N.D.C.1.07 - LINES		**28**	**32**	**(4)**			
N.D.C.1.08 - DISTRIBUTING & REGULATING STATIONS							
Spill Containment Program	# of Stations	0.6	0.6	0.0	0	1	(1)
DS Component Replacement	# of Stations	0.9	2.3	(1.4)	0	50	(50)
DS MUS Refurbishment_Purchase Program	# of MUSs	2.8	1.7	1.1	0	1	(1)
DS Recloser Upgrade Program	# of Reclosers	2.6	2.6	0.0	6	38	(32)
DS Spare Transformers	# of Transformers	5.2	2.0	3.2	9	3	6
DS Station Refurbishment Program	# of Stations	13.1	18.1	(5.1)	5	14	(9)
iMDS Station Refurbishments	-	6.7	11.3	(4.6)	0	6	(6)
DS MUS Purchase Program	-	0.1	2.8	(2.6)	0	1	(1)
DS Demand Capital	# of Demand replacem	3.5	2.5	1.0	0	0	0
Total N.D.C.1.08 - DISTRIBUTING & REGULATING STATIONS		**36**	**44**	**(8)**			
N.D.C.1.09 - METERING							
Field Meter Service	# of meters	16.7	21.1	(4.4)	21,222	27,232	(6,010)
Wholesale to Retail Standard (New meter w TCP/IP)	# of Meter Installat	0	0.1	(0.1)	0	20	(20)
Meter Inventory Sustainment	# of Meters	9.0	6.2	2.7	0	25,835	(25,835)
Remote Disconnect/Reconnect	# of meters	1.3	4.1	(2.8)	3,412	8,500	(5,088)
Not assigned	-	0	0.5	(0.5)	0	0	0
Total N.D.C.1.09 - METERING		**27**	**32**	**(5)**			

UNDERTAKING – JT 2.12

Undertaking

To provide a ranking of the considerations in the emergency preparedness risk consideration list.

Response

Emergency Preparedness risk considerations:

1. Adjacent to a major transformer station which exposes the BUCC to the following emergency preparedness risk: electrical hazards, environmental hazards such as fire, oil spills and other asset failure hazards.

2. In a congested area in the event of wide spread emergencies i.e. civil unrest, blackout, natural disaster, terrorism at Pearson International Airport, which would negatively affect the mandated two-hour activation timeline.
    a. Given physical location, high level of congestion, limited access routes (travel would most likely be along the 400 Highway) and physical distance between sites, travelling to the alternate location can be extremely hampered particularly in an emergency and / or catastrophic situation where these emergency travel risks would be further compounded. This would result in significant delay in regaining operational control of the grid and add further risk to overall reliability of the power system.

3. Between two major highways (Hwy 427 & Hwy 401)
    a. Richview TS is adjacent or close to multiple highways (Hwy 401, Hwy 409 and Hwy 27) so any spills or major motor vehicle accidents could lead to an evacuation.

4. Adjacent to public storage facilities.
    a. Risk of terrorism and other disturbances as there is insufficient setback with neighboring businesses.
    b. The nature of high profile neighbouring businesses poses additional risk to Hydro One's ability to access and maintain a prolonged activation without further disruption (E.g. 1982 bombing of Litton Industries).

5. Gas pipelines located underneath property.
    a. A pipeline failure leading to an explosion or a leak resulting in an evacuation is an example of very high consequence event, but carries a low probability.

6. In a flight path (Pearson International Airport).
    a. There are over 1,100 daily flights in and out of Pearson International Airport.
    b. Given the proximity to the runway, an airplane crash during take-off or landing is an example of a very high consequence event, which could render the BUCC inoperable, but carries a low probability.

UNDERTAKING – JT 2.13

Undertaking

To provide an estimate of average savings from automated meter reading with 5,000 customers per year added.

Response

Meters that become suitable for migration to time-of-use (TOU) billing are typically meters that already have some connectivity to the existing AMI network. The reinforcement/expansion of the cellular network improves the reliability of these meters, to the point where they are suitable for migration to TOU.

When AMI communication network expansion occurs, it typically only picks up a portion of the meter locations in a local geographic area and most often picks up meters that are closest to each other and closest to the area already covered by the AMI network.

Since driving time between meters is the largest component of Hydro One's manual meter reading costs (accounting for approximately 96% of a meter reader's time), the reduction in the volume of meters manually read only marginally reduces driving time (approximately 5%). This is due to the ongoing need to manually read a smaller number of meters that are widely dispersed amongst a sparsely populated customer base in the same geographic area.

For these reasons, the average savings tied to the migration of 5000 customers to TOU is approximately $72,000 per annum, which is already included in the 2018 test year forecast.

UNDERTAKING – JT 2.14

Undertaking

To provide a copy of the study of costs of bringing customer care function in-house.

Response

As outlined in Exhibit C1, Tab 1, Schedule 5, Hydro One's Customer Care organization anticipated spending $44.5 million in 2018 to support Customer Service Operations (CSO).

In early 2017, Hydro One conducted a high-level analysis to evaluate the cost of bringing the CSO in-house. At the time, the estimated cost to run CSO in-house was similar to the cost of outsourcing the operations to Inergi, as noted below. Note that 2018 costs will be higher than anticipated due to transition costs that will be incurred in the first half of 2018.

2018 Test Year ($M)	**CSO Outsourced**
Customer Service Operations (CSO)	40.4
Settlements (SET)	4.1
Total	**44.5**
2018 Test Year ($M)	**CSO Insourced**
Agents (Part Time & Full Time)	26.2
Analysts / Support / Team Leads	7.9
Management	3.2
Third Party Support [1]	3.6
CSO (Insourced)	**40.9**
SET (Outsourced)	**4.1**
TOTAL	**45.0**

[1] *This funding is required for third party services, including: bill print, voice recording, and auto-dialer functionality to support CSO.*

Witness: MERALI Imran

UNDERTAKING – JT 2.15

Undertaking

To provide the name of the federal funding program that support green energy and greenhouse gas-reducing energy projects.

Response

The name of the federal program is: Green Infrastructure Phase II – Smart Grid Demonstration and Deployment Program. Additional information about this program can be found at the following website:
https://www.nrcan.gc.ca/energy/science/programs-funding/19793.

UNDERTAKING – JT 2.16

Undertaking

a) To provide a copy of the submission to NRCAN for the proposed Christian Island funding.
b) To provide presentations, handout materials, and summary report prepared for first nation engagement sessions held February 9 and 10, 2017.

Response

a) Hydro One has only one application of funding for Christian Island at the federal level. The federal funding application for Christian Island is to the Green Infrastructure II Smart Grid Demonstration and Deployment Program through the Department of Natural Resources Canada.

Upon reviewing the confidentiality terms and agreement of the application, only Section 1 of the proposal can be released without obtaining permission from the Department of Natural Resources Canada.

Section 1 of the Christian Island proposal through the aforementioned application is included below.

Section 1: Non-Confidential Applicant Information and Project Summary

1.1 Applicant Information	
Organization:	Hydro One Networks Inc.
Applicant Type (private/investor-owned utility or public utility/operator or government/agency):	Shareholder-owned utility.
Contact Name:	Manager, Strategy and RD&D
Project Manager:	Manager, Distribution Investment Planning
Mailing Address:	483 Bay Street, 13th Floor, North Tower, Toronto, M5G 2P5

1.2 Project Information Summary	
Project Title:	Christian Island Project
Project Location(s):	Beausoleil First Nation Community, Christian Island, Ontario
Project Start Date:	July 1, 2018
Project End Date:	December 31, 2021
Total Project Cost ($):	$6.2M
Funding Requested from Smart Grid Program ($):	$2.5M
Project Type Designation (Demonstration/ Deployment/Hybrid):	Demonstration
[Deployment projects only] **Will the deployment project reduce GHG emissions as a project outcome?**	Please indicate one: Yes

1.2 Project Description Summary

Please note: this information could be used on NRCan's public facing website. Keep the information brief, non-technical, and non-confidential.

Problem Statement (150 words maximum)

What issue or problem is this project trying to address? In what context is this project being introduced?

This project is required to improve reliability of electricity supply for the 750 members of the Beausoleil First Nation (Chimnissing), who are Hydro One customers living on reserve, on Christian Island in Ontario. Based on last the 4 years of data, the system average interruption duration for customers is 50.3 hours annually, and the system average interruption frequency is 7.7. For the customer who has experienced outages, the customer average interruption duration is 6.5 hours.

Christian Island is currently supplied by three submarine cables which are 40 years old, and considered close to end-of-life. Although plans are in preparation to replace them, this is not expected to completely address reliability issues. The duration of outages is very long for the customers affected, as it can take hours to locate problems affecting the cables under the water, and then the cables must be brought to the surface, repaired, and returned to the water.

Project Summary (150 words maximum)

This project involves the installation of a microgrid (incorporating an energy storage battery) on Christian Island, to reduce the duration of outages for the Beausoleil First Nations community.

In determining the sizing and location of the energy storage battery, Hydro One will demonstrate the use of new software developed recently by Hydro One and the Electric Power Research Institute. The project will also demonstrate the resulting benefits to SAIDI and CAIDI resulting from the application of energy storage.

The battery will charge from the submarine cable(s) providing electrical supply to Christian Island, and in the event of an outage will provide continuing service to residents for a period of 4 hours or possibly more.

This project will also demonstrate the ability to incorporate off-the-shelf vendor products and platforms.

Benefit to Canadians and Stakeholders (150 words maximum)

The ultimate result will be the demonstration of a more reliable, environmentally-friendly and affordable alternative for supplying electricity to this community, that could potentially be deployed to other similar communities in the future.

- The installation of a storage battery will reduce the duration of outages for the Beausoleil First Nation, improving the residents' quality of life.
- It will reduce greenhouse gas emissions resulting from the use of customer-owned generators on Christian Island.
- Once successfully demonstrated, this concept can be applied in other remote or northern communities, or islands supplied by submarine cables, where additional supply for reliability purposes is not practical or economically feasible.

b) All presentations, handout materials, and summary report prepared for First Nation engagement sessions held February 9 and 10, 2017 are publicly available and can be found on Hydro One's corporate website at the following web address: https://www.hydroone.com/about/indigenous-relations/first-nations-engagement-sessions.

UNDERTAKING – JT 2.17

Undertaking

To confirm whether the presentation at Attachment 6 of Exhibit I, Tab 6, Schedule Anwaatin 1, would have been given to a First Nations and Métis engagement session on February 18th, 2018.

Response

This is confirmed.

The First Nations Engagement Session held on February 21, 2018 focused on: Customer Service including Affordability; Procurement & Business Partnerships; Employment and Training; and Transmission & Distribution Planning & Reliability Performance.

Three presentations are attached which were delivered at the First Nations Engagement session in February 2018:

1. Diversity & Inclusion at Hydro One;
2. First Nations Reliability Performance Overview; and
3. Customer Programs – Get Local, First Nations Delivery Credit, Ontario Energy Support Program.

The overall tone of the engagement session was cordial and the feedback heard by First Nations at the February 21, 2018 engagement session focused on: the need to continue open dialogue with Hydro One to address business and revenue generation opportunities within First Nations' traditional territories, and distribution and transmission reliability performance issues impacting First Nations communities. The participating First Nations also expressed an interest to plan and develop jointly with Hydro One, through the Chiefs of Ontario's Committee on Energy, the next Hydro One's First Nations provincial engagement session. A copy of the February 21, 2018 First Nations engagement session report will be filed once finalized.

The second attachment has been redacted for non-distribution-related content.

Diversity & Inclusion at Hydro One

Overview

- Diversity & Inclusion Strategy
- Diversity & Inclusion Effectiveness Review
- Indigenous Leadership Training
- Indigenous Network Circle Workshop
- Company Commitments

Diversity & Inclusion Strategy

hydro one

- Organizational benefits of Diversity & Inclusion
  - Higher productivity
  - Safety in the workplace
  - Engagement and trust
  - Better decision making
  - Creativity and innovation

- 3 main goals:
  - To build a diverse workforce
  - Create a culture of inclusion
  - Be a leader in diversity and inclusion in the energy sector.

Diversity & Inclusion Strategy

- We will consider our partners perspectives to help us achieve our goals and deliver them value. Our key partners are:
- Unions
- Customers
- Communities
- Employees & leaders
- Shareholders

5 Paths to Achieving our Strategy

Workforce Planning

- Work with business leaders to identify where diversity and inclusion can enhance their business
- Establish a set of measures that are discussed and actioned with the business

Recruitment

- Develop a recruitment strategy that will attract diverse candidates
- Select diverse candidates and ensure our selection process is not biased

Succession Planning

- Identify and promote diverse candidates

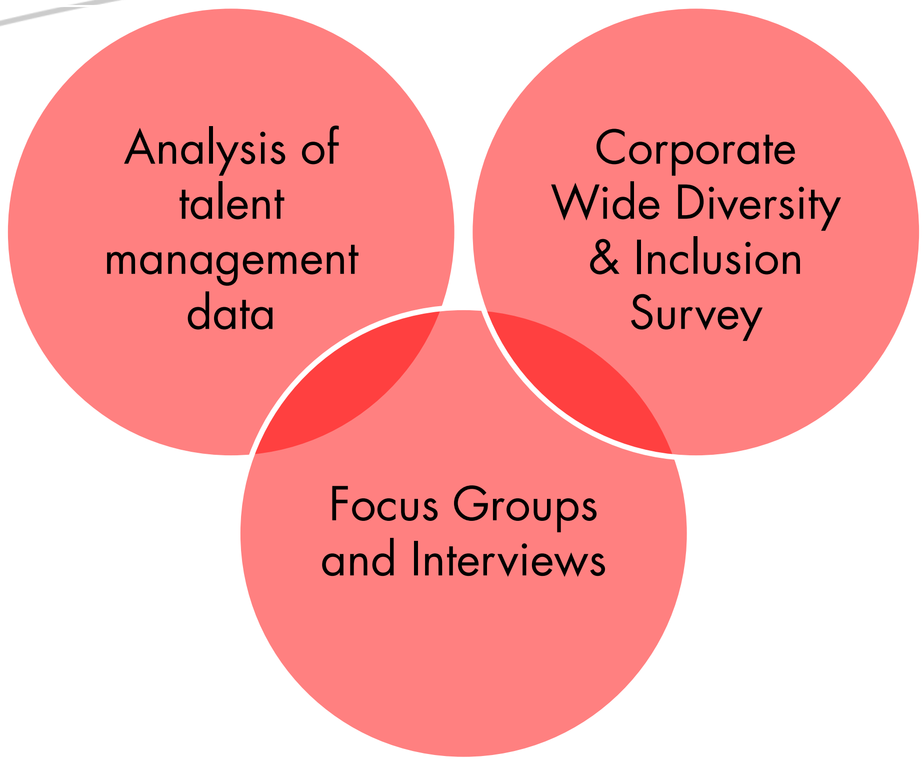
Education and Leadership Development

- Develop a Women in Leadership program
- Roll out Indigenous Leadership Learning program
- Integrate diversity and inclusion principles into training and development programs
- Deliver specialized diversity and inclusion programs

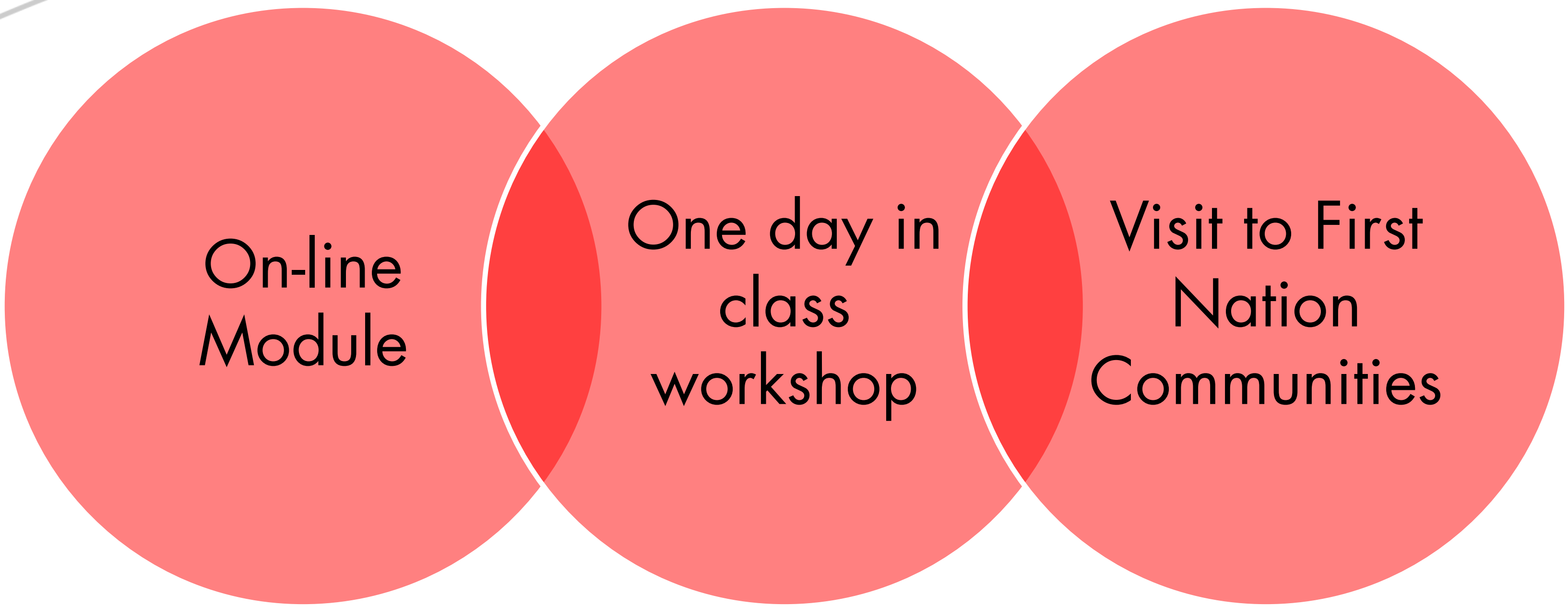
Cultural Guidance and Outreach

- Conduct a diversity and inclusion effectiveness review
- Create and promote employee resource groups including an Indigenous Network Circle
- Develop strategic community partnerships and sponsor community and industry initiatives
- Create a Diversity Leadership Council

Diversity & Inclusion Review



Indigenous Leadership Training



Indigenous Network Circle Workshop

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Shared insights and personal experiences

1-day workshop

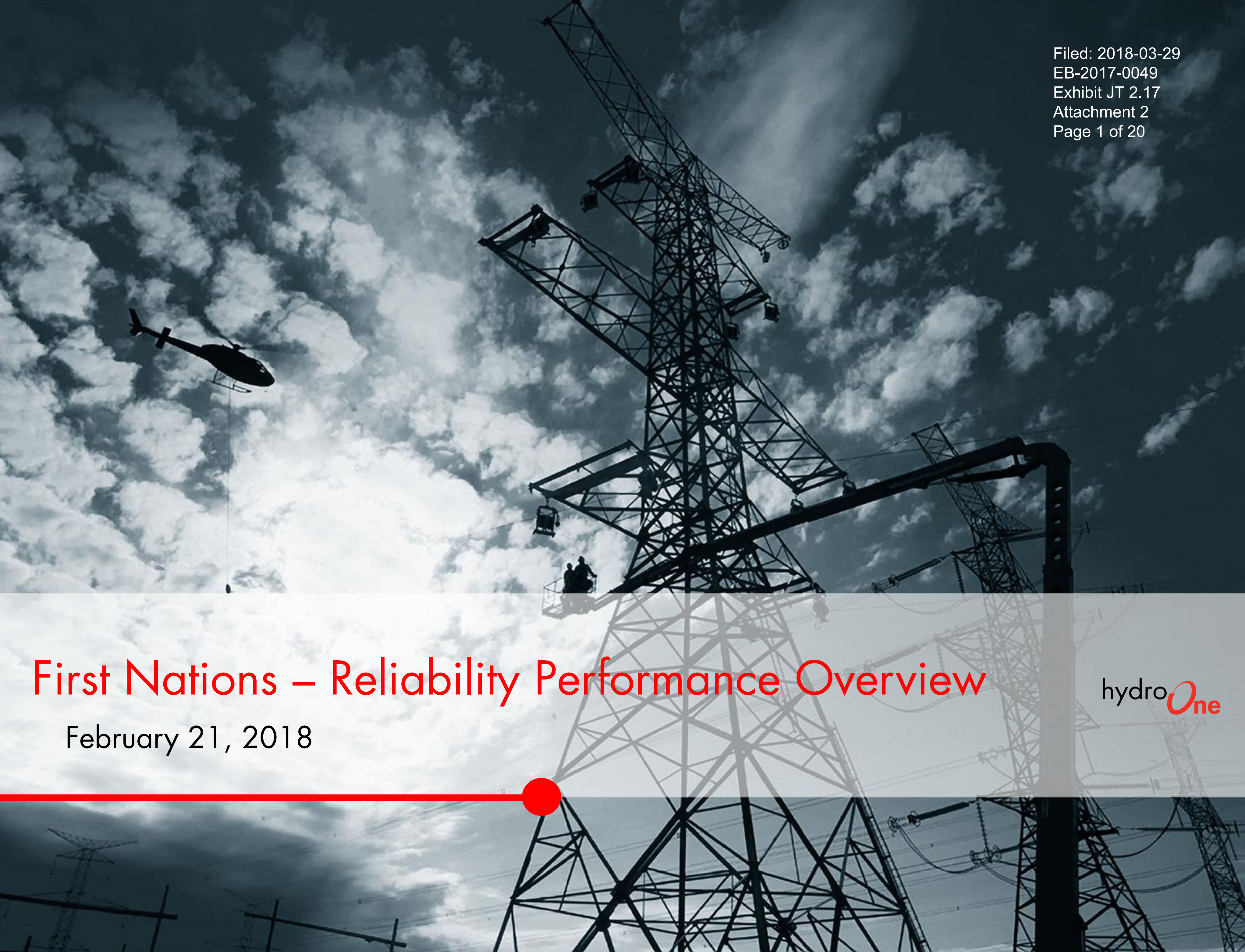
30 Indigenous Employees

Unanimously agreed to develop a Network

Company Commitments

- Hire a Diversity & Inclusion Consultant to focus on Indigenous Outreach, Recruitment and Inclusion
- Hire more Indigenous employees:
  - Regular hires
  - Co-op/Internship
  - New Grad
  - Summer Outreach Program
- Visit communities across the province sharing information about recruitment requirements and career opportunities
- Work with Hydro One Indigenous employees to educate and raise cultural awareness within the organization
- Engage Indigenous communities in a dialogue regarding training and development partnerships
- Research and adopt as required Indigenous employment and retention industry best practices

Questions?



First Nations – Reliability Performance Overview

February 21, 2018

hydro One

Agenda

- Hydro One Operations Review
- Historical Reliability Performance
- First Nations Communities Supply
- 2017 Transmission Reliability
- Transmission Reliability Improvements
- 2017 Distribution Reliability
- Distribution Grid Modernization
- Planned Work on Assets Serving First Nations Communities

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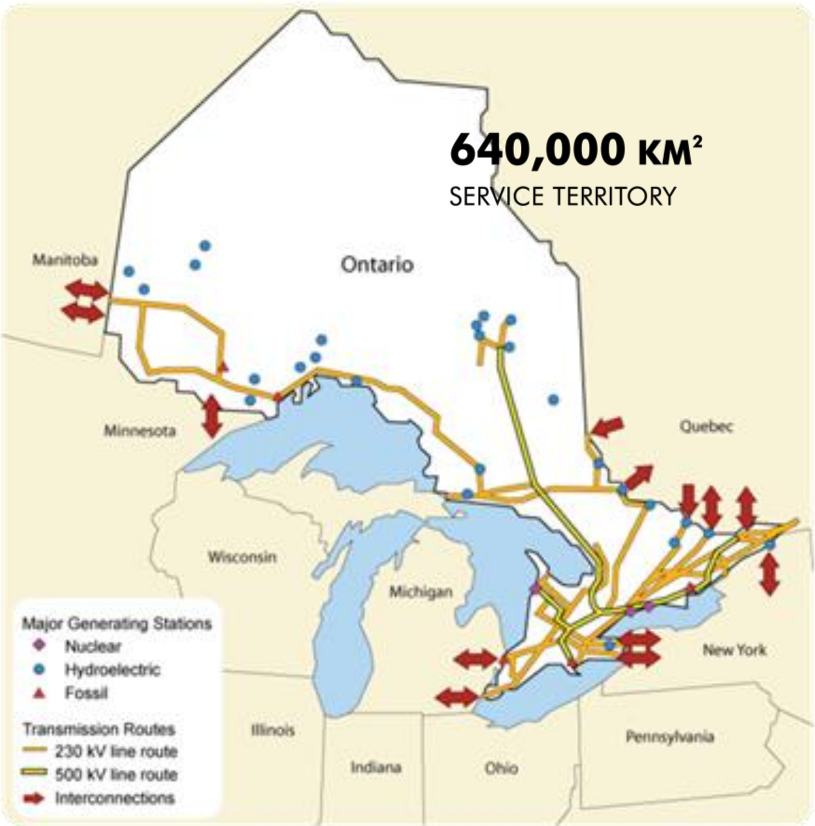
HYDRO ONE OPERATIONS REVIEW



640,000 KM²
SERVICE TERRITORY

30,000 KM
OF HIGH-VOLTAGE TRANSMISSION LINES

308
TRANSMISSION STATIONS

1.6 MILLION
DISTRIBUTION POLES

123,000 KM
OF LOCAL DISTRIBUTION LINES

1.3 MILLION
RESIDENTIAL AND BUSINESS CUSTOMERS ACROSS ONTARIO

1005
Distribution Stations

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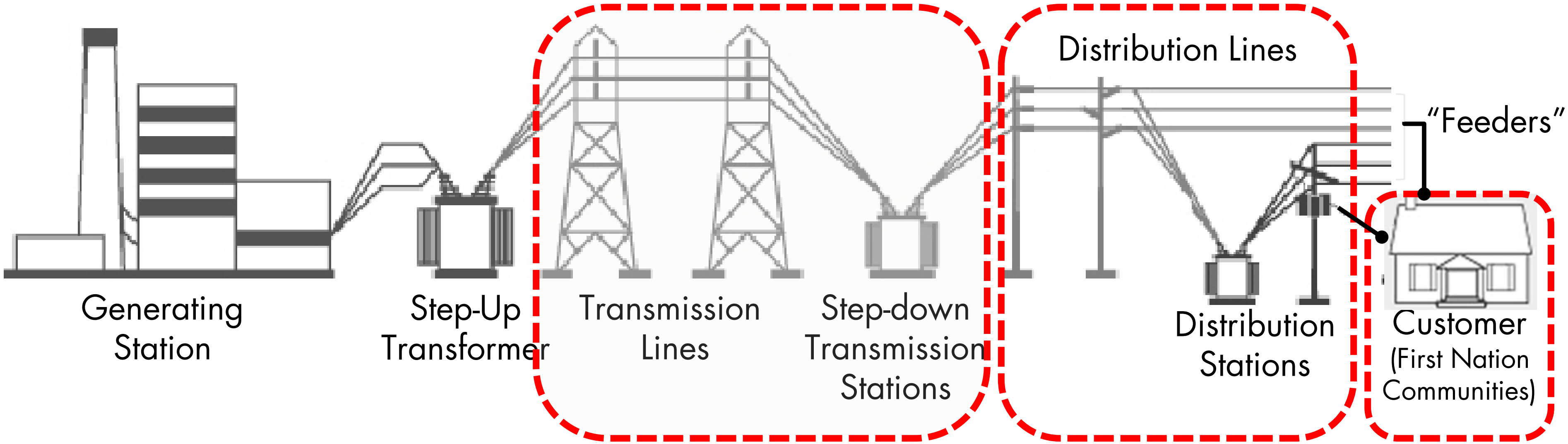
First Nations Communities Supply



First Nations Communities: Supplied from 68 Transmission Lines, 59 Transmission Delivery Points and 109 Distribution Feeders

2017 Transmission System Reliability Performance

[redacted]

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Tx System – Primary Causes of Interruptions:

[redacted]

First Nations: Transmission Connections

[redacted]

How Is Hydro One Improving Tx Reliability

[redacted]

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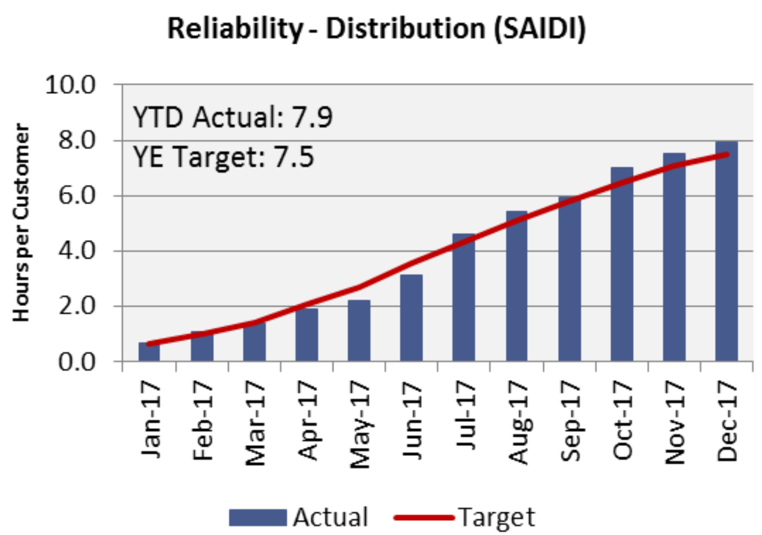
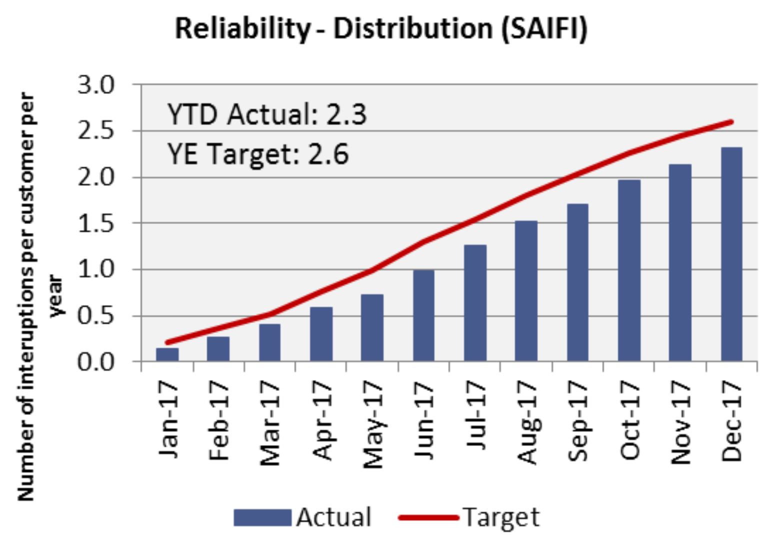
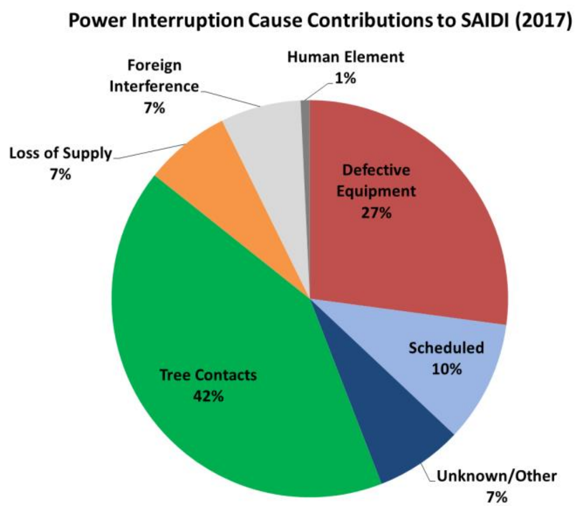
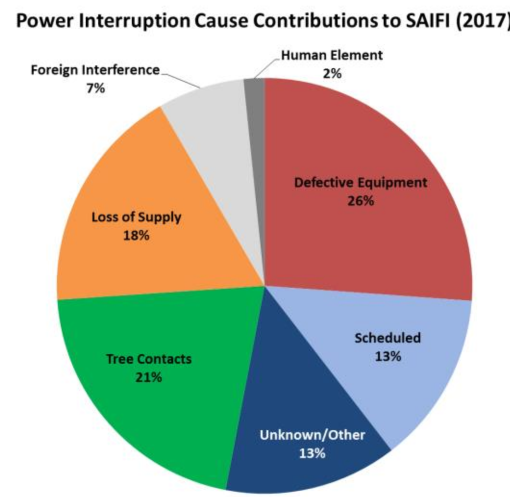
2017 Distribution System Reliability Performance

2017 Year End Overall Distribution Performance: SAIDI was 7.9 hrs and SAIFI was 2.3 interruptions per customer. Main causes of these interruptions are 1) Defective Equipment 2) Tree Contacts 3) Loss of Supply









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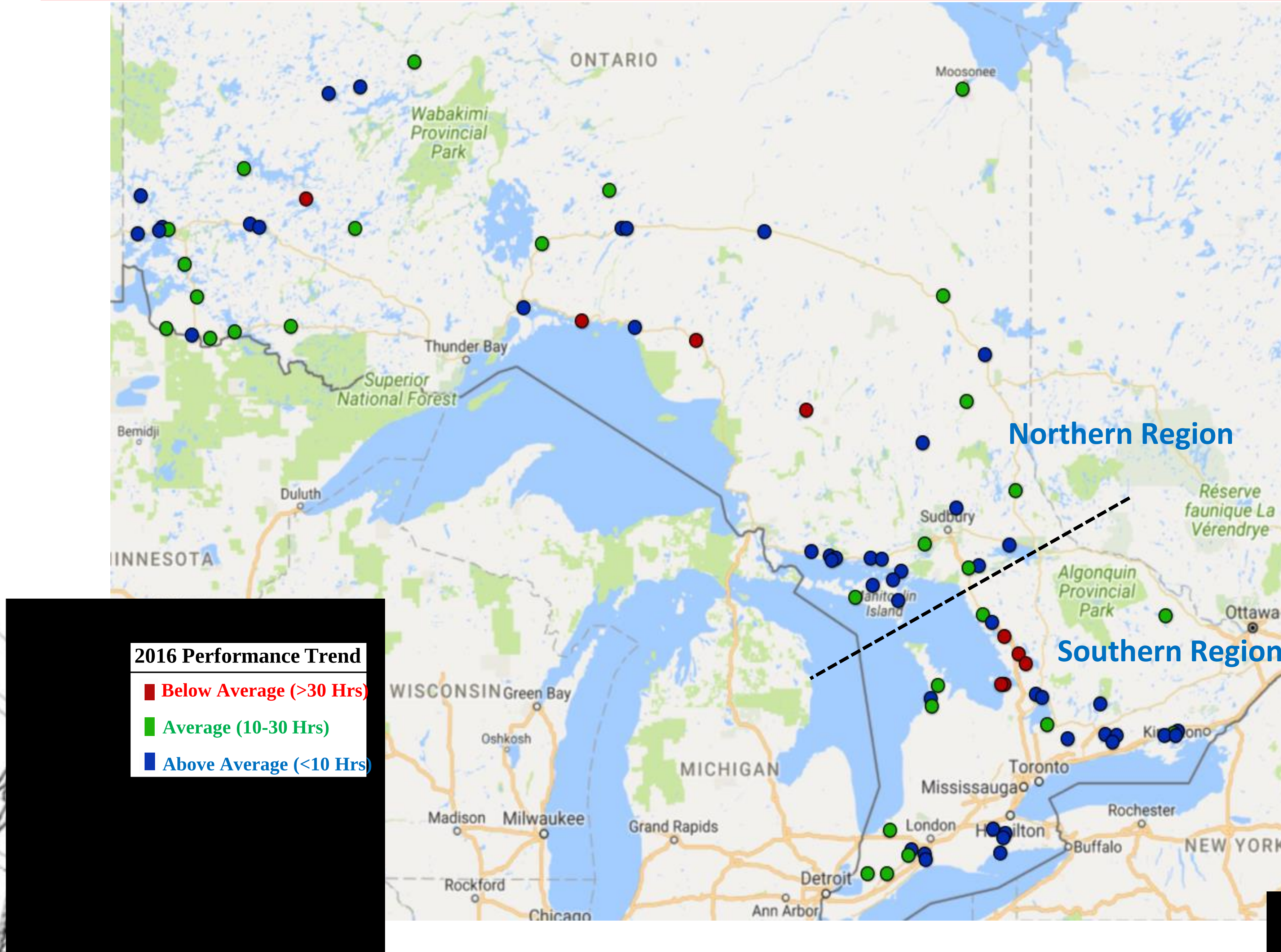
Dx System – Primary Causes of Interruptions:
(~47% occurs from Tree Contacts & Equipment Failures)

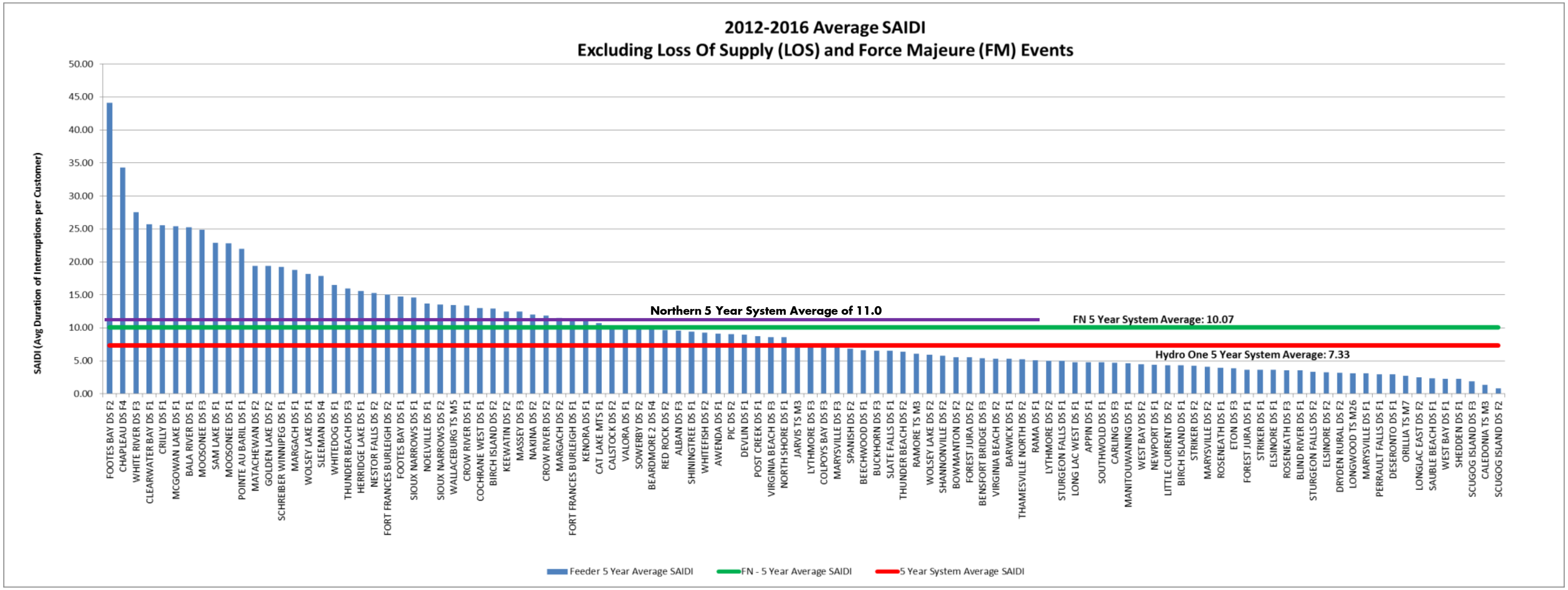
Power outage causes (2017)

Equipment failure	**26%**	Poles, transformers, lines failures can cause an outage.
Tree Contacts	**21%**	Trees fall on lines during storms.
Loss of Supply	**18%**	Transmission caused outage events that result in distribution system loss of supply
Scheduled outages	**13%**	Occasionally, Hydro One needs to schedule power outages to safely replace or update equipment.
Unconfirmed causes	**13%**	Sometimes Hydro One crews can't determine the exact cause of an outage.
Animal or vehicle damage to equipment	**7%**	Animal contacts with Hydro One's equipment and car accidents that damage poles.

First Nations: Distribution Connections



Dx Feeders Supply to First Nations Communities: 5 Year Average SAIDI Excluding Loss of Supply (LOS) and Force Majeure (FM) Events



The First Nations 5 Year average SAIDI performance is about 9% better than the Hydro One Northern system average. The primary SAIDI cause contributor is Tree Contacts. The secondary contributor is Defective Equipment.

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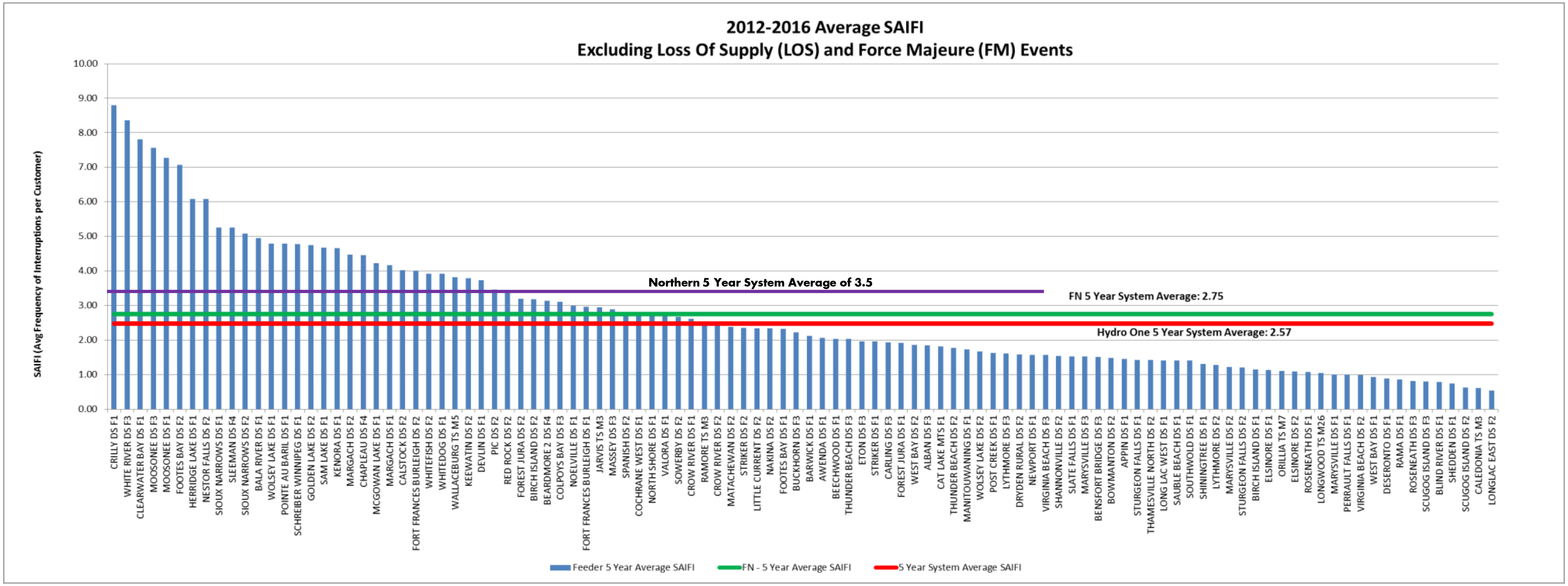
Dx Feeders Supply to First Nations Communities: 5 Year Average SAIFI Excluding Loss of Supply (LOS) and Force Majeure (FM) Events



The First Nations 5 year average SAIFI performance is 27% better than the Hydro One Northern system average. The primary SAIFI cause contributor is Tree Contacts. The secondary contributor is Scheduled outages.

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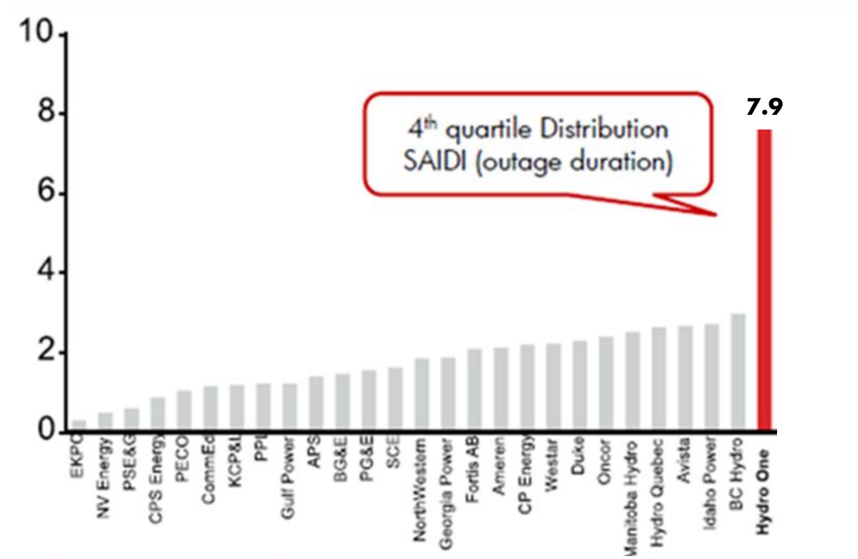
DISTRIBUTION GRID MODERNIZATION

Our plan to tackle Distribution Reliability:

- New vegetation management strategy (20-40% improvement)
- Focusing on 30% worst performing feeders by deploying automation, self-healing, smart sectionalization, fault indicators and remote sensors (20 to 40% improvement)
- Storm prediction tools and processes to improve response and restoration (CAIDI) including leveraging smart meters (10% improvement)
- Grid Modernization and deployment of new technologies (i.e. energy storage, micro grids, electric vehicles) and non-wires solutions for addressing reliability and power quality.

AVERAGE SAIDI FROM 2013 – 2017	AVERAGE SAIFI FROM 2013 - 2017
7.53	2.51



Note: *Peer comparison shows 2016 Hydro One result with 2015 results for peers
Source: EIA 861 data; SNL; Company public disclosures; IEEE

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DISTRIBUTION GRID MODERNIZATION

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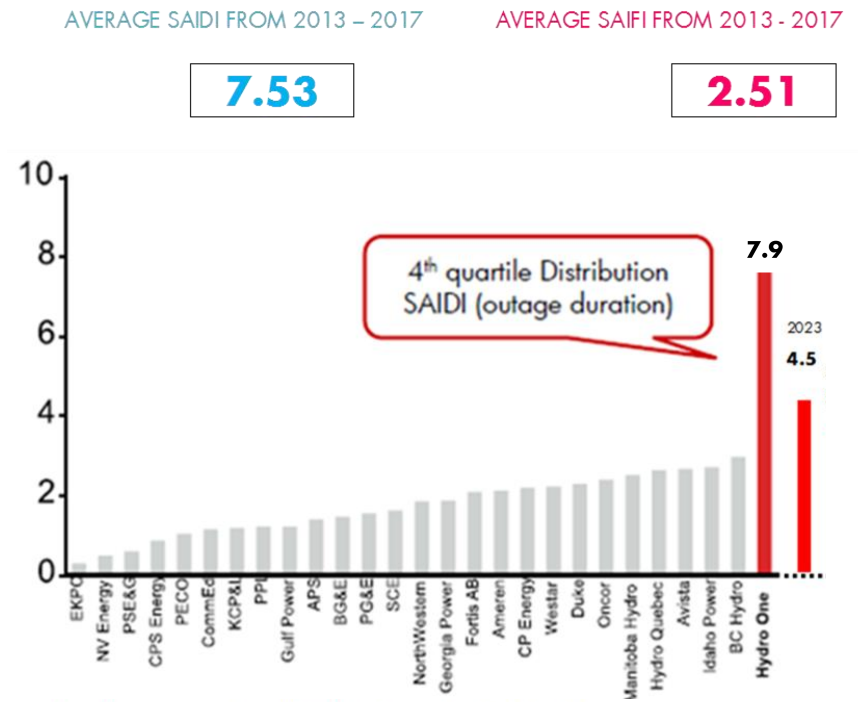

Note: *Peer comparison shows 2016 Hydro One result with 2015 results for peers
Source: EIA 861 data; SNL; Company public disclosures; IEEE

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Planned Work on Assets Serving First Nations Communities (Page 1)

Communities	Zone	Op Centre	Supply Station	Feeder	Upstream TS	TS Circuit	TS Feeder	Work Planned 2018-2023	Year In-Service
Alderville First Nation	3A	Peterboroug	Bowmanton DS	F2	PORT HOPE TS DESN1	P4S / P3S	M15	TS Staton Refurbishment	2025
	3A		Roseneath DS	F1	PORT HOPE TS DESN1	P4S / P3S	M15	TS Staton Refurbishment	2025
	3A		Roseneath DS	F3	PORT HOPE TS DESN1	P4S / P3S	M15	TS Staton Refurbishment	2025
Algonquins of Pikwakanagan	3B	Cobden	Golden Lake DS	F2	COBDEN TS	X2Y / X6	M6	Cobden TS M6 - Install 6 smart switches under worst performing feeder + Tx Line Refurb X2Y	2018 - 19
Animakee Wa Zhing #37	7	Kenora	Sioux Narrows DS	F2	Transmission Circuit	K6F	K6F		
Animbigoo Zaagiigan Anishinaabek (AZA)	7	Thunder Bay	Jellicoe DS #3	F1	Transmission Circuit	A4L		3ph expansion to connect new AZA subdivision + Tx Line Refurbishment	Pending customer signed agreement+ 2021
Anishinaabeg of Naongashiing	7	Fort Frances	Sleeman DS	F4	BARWICK TS	K6F	M2	Sleeman DS Rebuild and voltage conversion to 25 kV	2023
Anishinabe of Wauzhushk Onigum (Rat Portage)	7	Kenora	Margach DS	F1	Transmission Circuit	K6F	K6F	Extend Keewatin DS F2 to pick up portion of Margach DS F1 (Rat Portage FN)	2019
Aroland First Nation	7	Thunder Bay	Nakina DS	F2	LONGLAC TS M2	A4L	A4L	Longlac TS to be relocated (customer driven project) + Tx Line Refurbishment	2021
Asubspeeschoseewagong Netum Anishinabek (Grassy Narrows)	7	Kenora	Margach DS	F2	Transmission Circuit	K6F	K6F		
Aundeck-Omni-Kaning	6	Manitoulin	Little Current DS	F2	MANITOULIN TS	S2B	M26	Worst Performing Feeder Investment S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2018 2017
Beausoloeil First Nation	5	Penetang	Thunder Beach DS	F2	WAUBAUSHENE TS	E26 / E27	M7	Waubashene M7 we are installing 7 remote operable switches and automating the existing recloser.	2018 for switches
	5		Thunder Beach DS	F3	WAUBAUSHENE TS	E26 / E27	M7	Waubashene M7 we are installing 7 remote operable switches and automating the existing recloser.	2018 for switches
	5		Awenda DS	F1	WAUBAUSHENE TS	E26 / E27	M7	Waubashene M7 we are installing 7 remote operable switches and automating the existing recloser. On Awanda DS-F1 we are planning to upgrade the supply to Christian Island	2019 for the upgrades
Big Grassy First Nation	7	Fort Frances	Sleeman DS	F4	BARWICK TS	K6F	M2	Sleeman DS Rebuild and voltage conversion to 25 kV	2023
Biinjitiwaabik Zaaging Anishinaabek (BZA) (aka Rocky Bay First Natior	7	Thunder Bay	Beardmore DS #2	F4	Transmission Circuit	A4L	A4L	Tx Line Refurbishment	
Brunswick House, Chapleau Cree FN , Chapleau Ojibway FN	6	Timmins	Chapleau DS	F4	Transmission Circuit	W2C	W2C		
Caldwell First Nation	1A	Essex	Kingsville TS	-	Kingsville TS	K2Z / K6Z	K2Z	Leamington TS feeder development + New Leamington TS + Kingsville Refurbishment	2018-20
	1A	Essex	Kingsville TS	-	Kingsville TS	K2Z / K6Z	K6Z	Leamington TS feeder development + New Leamington TS + Kingsville Refurbishment	2018-20
Cat Lake FN	7	Dryden	Cat Lake DS	F1	Transmission Circuit	E1C	E1C	Station Refurbishment on site (weather and ice road dependent, was deferred for two years due to warm weather) + Tx Line Refurbishment + Watay Line_to_Pickle Lake Connection	2018
Chippewas of Georgina Island First Nation	3A	Fenelon Falls	Virginia Beach DS	F2	BEAVERTON TS	M80B / M81B	M27	TS Station Work	2023
	3A		Virginia Beach DS	F3	BEAVERTON TS	M80B / M81B	M27	TS Station Work	2023
Chippewas of Kettle and Stony Point First Nation	1A	Lambton	Forest Jura DS	F1	Transmission Circuit	S2N	S2N	Tx Line Refurb S2N	2019
	1A		Forest Jura DS	F2	Transmission Circuit	S2N	S2N	Tx Line Refurb S2N	2019
Chippewas of Nawash Unceded First Nation	1B	Owen Sound	Colpoys Bay DS	F3	OWEN SOUND TS	B27S / B28S	M23	Mar DS and Feeder Development	2021
Chippewas of Rama First Nation	5	Orillia	Rama DS	F1	ORILLIA TS	M6E / M7E	M7	Sectionalizing M6E/M7E Switches + Tx Line Refurb M6E/M7E + TS station work	2017 - 21
	5		Orillia TS	M7	Transmission Circuit	M6E / M7E	M7E	Sectionalizing M6E/M7E Switches + Tx Line Refurb M6E/M7E + TS station work	2017 - 21
Chippewas of The Thames First Nation	1A	Strathroy	Longwood TS	M26	Transmission Circuit	L24L / L26L	L24L	Longwood TS Station Work	2023
	1A					L24L / L26L	L26L	Longwood TS Station Work	2023
	1A		Appin DS	F1	LONGWOOD TS	L24L / L26L	M26	Longwood TS Station Work	2023

Planned Work on Assets Serving First Nations Communities (Page 2)

Communities	Zone	Op Centre	Supply Station	Feeder	Upstream TS	TS Circuit	TS Feeder	Work Planned 2018-2023	Year In-Service
Constance Lake First Nation	6	Kapuskasing	Calstock DS	F2	Transmission Circuit	H2N	H2N		
Couchiching First Nation	7	Fort Frances	Burleigh DS	F1	Transmission Circuit	F1B	F1B		
Curve Lake First Nation	3A	Peterboroug	Buckhorn DS	F3	OTONABEE TS DESN2	C28C / H24C	M27	On Otonabee M27, install 3 DMS operable switches and upgrade existing recloser to improve reliability as part of worse performing feeders + Tx Line Refurb C28C	2018 -23
Delaware Nation	1A	Kent	Thamesville North DS	F2	KENT TS DESN2	L28C / L29C	M24	TS Station Refurb	2025
Dokis	6	Sudbury	Noelville DS	F1	MARTINDALE TS	S21N / F2SP	M5	Transformer Replacement Martindale M5 Rebuild + Martindale TS Refurbishment	2018 - 21
Eagle Lake	7	Dryden	Eton DS	F3	Transmission Circuit	K3D	K3D		
Ginoogaming First Nation	7	Thunder Bay	Longlac East DS	F2	LONGLAC TS	A4L	M1	Longlac TS to be relocated (customer driven project) + Tx Line Refurbishment	2021
Henvey Inlet	6	Sudbury	Alban DS	F3	MARTINDALE TS	S21N / F2SP	M5	Wind Farm Connection Martindale M5 Rebuild + Martindale TS Station Refurbishment	2019 2018 - 21
Hiawatha First Nation	3A	Peterboroug	Bensfort Bridge DS	F3	OTONABEE TS DESN2	C28C / H24C	M28	Relocation of Otonabee M28 from off-road to road allowance + Tx Line Refurb C28C	2019 - 23
Iskatewizaagegan #39 Independent First Nation	7	Kenora	Clearwater Bay DS	F1	Transmission Circuit	SK1	SK1		
Lac La Croix	7	Fort Frances	Crilly DS	F1	Transmission Circuit	M1S	M1S	Crilly DS rebuild	2020
Lac Seul First Nation	7	Dryden	Sam Lake DS	F1	Transmission Circuit	K3D	K3D		
Long Lake No. 58 First Nation	7	Thunder Bay	Longlac West DS	F1	LONGLAC TS	A4L	M1	Longlac TS to be relocated (customer driven project)	2021
Magnetawan First Nation	5	Parry Sound	Pointe Au Baril DS	F1	PARRY SOUND TS	E26 / E27	M1	TS Station Work	2022
Matachewan	6	Kirkland Lake	Matachewan DS	F2	KIRKLAND LAKE TS	K2 / A8K	G3K	G3K - Line Relocation + Tx Line Refurbishment A8K & K2 + Kirkland Lake TS Refurbishment	2020 - 23
Mattagami	6	Timmins	Shiningtree DS	F1	Transmission Circuit	T61S	T61S	Worst Performing Feeder Investment + Install Sectionalizing Switch for Shiningtree DS + Tx Line Refurb T61S	2018 -24
M'Chigeeng First Nation	6	Manitoulin	West Bay DS	F1	MANITOULIN TS	S2B	M25	Station Refurbishment & Line Work Worst Performing Feeder Investment	2022 2018
	6		West Bay DS	F2	MANITOULIN TS	S2B	M25	Station Refurbishment & Line Work Worst Performing Feeder Investment S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2022 2018 2017
Mishkeegogamang	7	Dryden	Crow River DS	F1	Transmission Circuit	E1C	E1C	Tx Line Refurbishment + Watay Line_to_Pickle Lake Connection	2022
	7		Crow River DS	F2	Transmission Circuit	E1C	E1C	Tx Line Refurbishment + Watay Line_to_Pickle Lake Connection	2022
Mississauga	6	Algoma	North Shore DS	F1	Transmission Circuit	T1B	T1B		
	6		Blind River DS	F1	STRIKER DS	T1B	F1	Voltage Conversion Project	2021
	6		Striker DS	F1	Transmission Circuit	T1B	T1B		
	6		Striker DS	F2	Transmission Circuit	T1B	T1B		
Mississaugas of Scugog Island First Nation	3A	Bowmanville	Scugog Island DS	F2	WILSON TS DESN2	B23C / E29C	M12	New line build to off load part of M12 to the new Enfield TS + Tx Line Refurbishment B23C + Wilson TS Station Work	2019 - 23
	3A		Scugog Island DS	F3	WILSON TS DESN2	B23C / E29C	M12	New line build to off load part of M12 to the new Enfield TS + Tx Line Refurbishment B23C + Wilson TS Station Work	2019 - 23
Mississaugas of The New Credit First Nation	2	Simcoe	Lythmore DS	F2	CALEDONIA TS	N1M / N5M	M3	Lythmore Relief Project	2018
	2		Lythmore DS	F3	CALEDONIA TS	N1M / N5M	M3	Lythmore Relief Project	2018
	2		Jarvis TS	M3	Transmission Circuit	N21J / N22J	N21J	New lighting arrestors	2018

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Planned Work on Assets Serving First Nations Communities (Page 3)

Communities	Zone	Op Centre	Supply Station	Feeder	Upstream TS	TS Circuit	TS Feeder	Work Planned 2018-2023	Year In-Service
MoCreebec Eeyoud aka Moose Cree FN	6	Kapuskasing	Moosonee DS	F1 & F2	Transmission Circuit	M9K / T7M / T8M	M9K	New circuit T8M parallel to T7M was placed I/S in 2015 which will improve performance to Moosonee DS	2015
Mohawks of the Bay of Quinte	3B	Picton	Deseronto DS	F1	NAPANEE TS	X21 / X22	M4		
	3B		Shannonville DS	F2	BELLEVILLE TS	B23C /H23B	M6	Tx Line Refurbishment B23C + TS Station Work	2021 - 23
	3B		Marysville DS	F1	NAPANEE TS	X21 / X22	M4		
	3B		Marysville DS	F2	NAPANEE TS	X21 / X22	M4		
	3B		Marysville DS	F3	NAPANEE TS	X21 / X22	M4		
	3B		Beechwood DS	F1	NAPANEE TS	X21 / X22	M4		
Moose Cree First Nation	6	Kapuskasing	Moosonee DS	F1	Transmission Circuit	M9K / T7M / T8M	M9K	New circuit T8M parallel to T7M was placed I/S in 2015 which will improve performance to Moosonee DS.	2015
	6		Moosonee DS	F3	Transmission Circuit	M9K / T7M / T8M	M9K		
Moose Deer Point First Nation	5	Parry Sound	Footes Bay DS	F2	PARRY SOUND TS	E26 / E27	M2	TS Station Work	2022
Munsee-Delaware Nation	1A	Strathroy	Appin DS	F1	LONGWOOD TS	L24L / L26L	M26	Longwood TS Station Work	2023
	1A		Longwood TS	M26	Transmission Circuit	L24L / L26L	L26L	Longwood TS Station Work	2023
	1A						L24L	Longwood TS Station Work	
Naicatchewenin	7	Fort Frances	Devlin DS	F1	BARWICK TS	K6F	M1	Devlin DS HV Fuse upgrade, and inline reclosers OCR 906 and 953 upgrade on F1	2018
Naotkamegwanning	7	Kenora	Sioux Narrows DS	F1	Transmission Circuit	K6F	K6F		
	7		Sioux Narrows DS	F2	Transmission Circuit	K6F	K6F		
Nigigoonsiminikaaning First Nation (aka Red Gut First Nation)	7	Fort Frances	Burleigh DS	F2	Transmission Circuit	F1B	F1B	Burleigh DS F2 1ph to 3ph conversion	2020
Nipissing First Nation	6	Nipissing	Sturgeon Falls DS	F1	CRYSTAL FALLS TS	H23S / H24S	M2		
	6		Sturgeon Falls DS	F2	CRYSTAL FALLS TS	H23S / H24S	M2		
Northwest Angle No. 33 / Whitefish Bay 33A	7	Kenora	Sioux Narrows DS	F2	Transmission Circuit	K6F	K6F		
Obashkaandagaang	7	Kenora	Keewatin DS	F2	Transmission Circuit	SK1	SK1	Extend Keewatin DS F2 to pick up portion of Margach DS F1 (Rat Portage FN)	2019
Ochiichagwe'babigo'ining First Nation	7	Kenora	Kenora DS	F1	Transmission Circuit	T1L / T2L	T2L	Station Refurbishment on site	2021
Ojibway Nation of the Saugeen	7	Dryden	Valora DS	F1	Transmission Circuit	29M1	29M1		
Ojibways of Onigaming First Nation	7	Fort Frances	Nestor Falls DS	F2	Transmission Circuit	K6F	K6F		
Oneida Nation of the Thames	1A	Strathroy	Southwold DS	F1	EDGEWARE TS	W44LC / W45LS	M2	Aylmer TS new feeder + Edgeware Station Work	2018 - 21
	1A		Shedden DS	F1	EDGEWARE TS	W44LC / W45LS	M2	Aylmer TS new feeder + Edgeware Station Work	2018 - 21
Pays Plat	7	Thunder Bay	Schreiber Winnipeg D	F1	Transmission Circuit	A5A	A5A	-Schreiber Winnipeg DS Regulator replacement and MUS facility installation -Schreiber town rebuild	2018 -2020
Pic Mobert	7	Thunder Bay	White River DS	F3	Transmission Circuit	M2W	M2W	F1 and F2 station recloser upgrade to Viper, protection coordination update on F1	2018
Pic River First Nation (Biigtigong Nishnaabeg First Nation)	7	Thunder Bay	Pic DS	F2	Transmission Circuit	M2W	M2W		
Rainy River First Nation	7	Fort Frances	Barwick DS	F1	BARWICK TS	K6F	M2		
Red Rock (aka Lake Helen First Nation)	7	Thunder Bay	Red Rock DS	F2	Transmission Circuit	56M1	56M1		
Sagamok Anishnawbek	6	Algoma	Massey DS	F3	Transmission Circuit	S2B	S2B	S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2017
Saugeen First Nation	1B	Owen Sound	Elsinore DS	F1	OWEN SOUND TS	B27S / B28S	M25	Worst Performing Feeder Investment	2018
	1B		Elsinore DS	F2	OWEN SOUND TS	B27S / B28S	M25	Worst Performing Feeder Investment	2018
	1B		Sauble Beach DS	F1	OWEN SOUND TS	B27S / B28S	M25	Worst Performing Feeder Investment	2018

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Planned Work on Assets Serving First Nations Communities (Page 4)

Communities	Zone	Op Centre	Supply Station	Feeder	Upstream TS	TS Circuit	TS Feeder	Work Planned 2018-2023	Year In-Service
Seine River First Nation	7	Fort Frances	Crilly DS	F1	Transmission Circuit	M1S	M1S	Crilly DS rebuild	2020
Serpent River	6	Algoma	Spanish DS	F2	Transmission Circuit	S2B	S2B	S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2017
Shawanaga First Nation	5	Parry Sound	Carling DS	F3	PARRY SOUND TS	E26 / E27	M1	Carling DS - Nobel Rd & Avro Arrow Rd Line Relocate Pt 1 + TS Station Work	2018 - 22
Sheguiandah	6	Manitoulin	Little Current DS	F2	MANITOULIN TS	S2B	M26	Worst Performing Feeder Investment S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2018 2017
Sheshegwaning	6	Manitoulin	Wolsey Lake DS	F1	MANITOULIN TS	S2B	M25	Station Refurbishment Worst Performing Feeder Investment	2022 2018
	6		Manitouwaning DS	F1	MANITOULIN TS	S2B	M26	Transformer Replacement Worst Performing Feeder Investment	2018 2018
	6		West Bay DS	F2	MANITOULIN TS	S2B	M25	Station Refurbishment & Line Work Worst Performing Feeder Investment S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2022 2018 2017
Shoal Lake No. 40	7	Kenora	Clearwater Bay DS	F1	Transmission Circuit	SK1	SK1		
Six Nations of the Grand River	2	Simcoe	Lythmore DS	F2	CALEDONIA TS	N1M / N5M	M3	Lythmore Relief Project	2018
	2		Lythmore DS	F3	CALEDONIA TS	N1M / N5M	M3	Lythmore Relief Project	2018
	2		Jarvis TS	M3	Transmission Circuit	N21J / N22J	N21J	New lighting arrestors	2018
	2						N22J	New lighting arrestors	2018
	2		Caledonia TS	M3	Transmission Circuit	N1M / N5M	N5M	Lythmore Relief Project	2018
	2						N1M	Lythmore Relief Project	
	2		Newport DS	F1	BRANTFORD TS	M32W / M33W	M27	Newport DS Conversion	2018
Slate Falls First Nation	7	Dryden	Slate Falls DS	F1	Transmission Circuit	E1C	E1C	Tx Line Refurbishment + Watay Line_to_Pickle Lake Connection	2020-23
Stanjikoming/Mitaanjigamiing First Nation	7	Fort Frances	Burleigh DS	F1	Transmission Circuit	F1B	F1B		
Taykwa Tagmou Nation	6	Kapuskasing	Cochrane West DS	F1	Transmission Circuit	A4H	A4H	Station Refurbishment + Tx Line Refurbishment	2019 -21
Temagami First Nation	6	New Liskeard	Herridge Lake DS	F1	Transmission Circuit	D2L	D2L	Demand Enhancement - Line Regulator + Tx Line Refurb D2L	2018
Thessalon	6	Algoma	Sowerby DS	F2	Transmission Circuit	T1B	T1B	Station Refurbishment	2019
Wabaseemoong Independent Nations	7	Kenora	Whitedog DS	F1	WHITEDOG FALLS GS	FP3H	FP3H	Station Refurbishment on site	2020
Wabauskang First Nation	7	Dryden	Perrault Falls DS	F1	Transmission Circuit	E4D	E4D	E4D - Upgrade to operate at Higher Temperature	2018
Wabigoon Lake Ojibway Nation	7	Dryden	Dryden Rural DS	F2	DRYDEN TS	FP25A1A2	M1	Dryden TS Station Refurbishment	2018
Wahgoshig	6	Kirkland Lake	Ramore TS	M3	Transmission Circuit	A9K	A9K	Demand Enhancement - Line Regulator	2018
Wahnapitae	6	Sudbury	Post Creek DS	F1	MARTINDALE TS	S21N / F2SP	M7	Martindale TS station refurbishment	2021
Wahta Mohawks First Nation	5	Bracebridge	Bala River DS	F1	MUSKOKA TS	M6E / M7E	M1	Muskoka M1- relocating 10km of line, and installing DMS operable switches + Tx Line Refurb + TS Station Refurbishment	2018 for switches, 201
	5	Parry Sound	Footes Bay DS	F1	PARRY SOUND TS	E26 / E27	M2	TS Station Work	2022
	5		Footes Bay DS	F2	PARRY SOUND TS	E26 / E27	M2	TS Station Work	2022
Walpole Island	1A	Kent	Wallaceburg TS	M5	Transmission Circuit	N5K	N5K	N5K - Connect Otter Creek Generation	2019
Wasauksing First Nation	5	Parry Sound	McGowan Lake DS	F1	PARRY SOUND TS	E26 / E27	M3	TS Station Work	2022
Whitefish Lake (Atikameksheng Anishnawbek)	6	Sudbury	Whitefish DS	F2	Transmission Circuit	S2B	S2B	Regulator Replacement S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2018 2017

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Planned Work on Assets Serving First Nations Communities (Page 5)

Communities	Zone	Op Centre	Supply Station	Feeder	Upstream TS	TS Circuit	TS Feeder	Work Planned 2018-2023	Year In-Service
Whitefish River	6	Manitoulin	Birch Island DS	F1	MANITOULIN TS	S2B	M26	Worst Performing Feeder Investment	2018
	6		Birch Island DS	F2	MANITOULIN TS	S2B	M26	Worst Performing Feeder Investment	2018
								S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2017
Wikwemikong	6	Manitoulin	Manitouwaning DS	F1	MANITOULIN TS	S2B	M26	Worst Performing Feeder Investment	2018
	6		Wolsey Lake DS	F2	MANITOULIN TS	S2B	M25	Worst Performing Feeder Investment	2018
								S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2017
Zhiibaahaasing First Nation	6	Manitoulin	Wolsey Lake DS	F1	MANITOULIN TS	S2B	M25	Station Refurbishment	2022
								Worst Performing Feeder Investment	2018
								S2B-e shield-wire, poles, switches, insulators are being replaced. Surge arresters being installed at S2B-w	2017

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Customer Programs

Get Local
First Nations
Delivery Credit,
Ontario Electricity
Support Program

2017 By The Numbers

TURN ON THE POWER OF POSSIBILITY

Get Local

- To date, we've visited over 1,500 customers in 35 Communities across the province.

Customers In Arrears

- There has been a reduction of customers in arrears by 2,400 since January 2017, a reduction from 8,900 to 6,500.

First Nations Delivery Credit (FNDC)

- Hydro One launched a blitz in August 2017 to reach out to customers who were not receiving the First Nations Delivery Credit. Since then, we have reduced that number by 1,600 to a total of 4,891. Included in the 4,891 are 2,470 seasonal properties.

Ontario Electricity Support Program (OESP)

- We have doubled OESP enrollments for First Nations customers through our get local efforts from 1,600 to 3,400.

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Top 10 Communities Who Can Benefit from the First Nations Delivery Credit

Below are the number of customers, by Community, that are not currently enrolled in the First Nations Delivery Credit, as well as the number of seasonal properties included in the total.

Community	# Customers Not Enrolled	Seasonal Properties
Saugeen 29FN	1180	1135
Kettle Point 44FN	453	246
Nipissing FN	296	30
Parry Island 16FN	245	209
Christian IS 30FN	243	224
Curve Lake 35FN	227	61
Moose Factory	210	0
West Bay 22FN	194	0
Six Nations 40FN	173	0
Georgina Is 33FN	155	122

*** We need your help in identifying if the accounts classified as seasonal are inhabited by First Nations customers**

FNDC – Next Steps to 100% Enrollment

TURN ON THE POWER OF POSSIBILITY

Hydro One will be attempting to have 100% enrollment in FNDC by the end of 2018 to ensure all customers are receiving the full benefit of the credit.

How we plan to achieve 100% enrollment

- We need your support! Average customer savings of 50%!
- Increase the number of Get Local Community visits to 60
- Provide detailed maps to Band Offices to help identify seasonal properties and properties not inhabited by First Nations customers
- Door to door visits to meet with customers to assist with the enrollment process
- Social Media campaigns, marketing campaigns (radio, newspaper)

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Benefits of FNDC

TURN ON THE POWER OF POSSIBILITY

Below is an example of a customer's bill pre Fair Hydro Plan and post Fair Hydro Plan for the same time period in 2017 and 2018:

- Feb. 2017 Bill:
  - Consumption: 4,100 kwh
  - Total charges: $650
- Feb. 2018 Bill:
  - Consumption: 6,000 kwh
  - Total charges: $399

- There is a $250 difference between 2017 and 2018 and in the case of this customer, consumption increased by one third from 4,100 kwh to 6,000 kwh

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Get Local 2018

TURN ON THE POWER OF POSSIBILITY

Hydro One plans to continue to grow this program by expanding Get Local from 35 Communities to 60 Communities in 2018.

Has Hydro One been to your Community?

Would you like to schedule a Get Local session in your Community?

We'd love to meet with you!

To request a Get Local session in your Community, please call us at 1-866-994-9909 x 5821 or email us at FNMCustomer@HydroOne.com

- One-on-One meetings with Hydro One and our customers
- Assist with enrollments in FNDC, OESP and other various programs
- Provide dedicated and knowledgeable staff to answer any questions or concerns our customers may have

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TURN ON THE POWER OF POSSIBILITY

Thank You!

UNDERTAKING – JT 2.18

Undertaking

To confirm that a presentation shown at Attachment 7 of Exhibit I, Tab 6, Schedule Anwaatin 1 would have been given at the First Nations and Métis of Ontario engagement session on February 21st, 2018.

Response

This is confirmed. Note that the February 21, 2018 session was only a First Nations engagement session. A Métis session will be planned for later in 2018.

UNDERTAKING – JT 2.19

Undertaking

Of the commitments made at the February 9 and 10, 2017 First Nations engagement sessions, the 5 percent of the commitments that were not addressed throughout the year, why they were not addressed and what their current status is when they will be addressed.

Response

As referenced in Exhibit I, Tab 6, Schedule Anwaatin-1, Hydro One made 35 specific commitments at the February 9 and 10, 2017 First Nation engagement session, of which 95% were addressed throughout the year. The 5% of commitments not yet addressed relate to tax exemption off reserve. Tax exemption off reserve has already been brought forward and must be addressed by the Canada Revenue Agency and not by Hydro One.

UNDERTAKING – JT 2.20

Undertaking

To provide the list of communities scheduled to receive the First Nations conservation program in 2018.

Response

The First Nation communities listed below are scheduled to participate in the First Nations Conservation Program in 2018. Note that not all communities have agreed to participate or provided Band Council resolution yet.

1. Mohawks of the Bay of Quinte
2. Wahta Mohawks
3. Ochiichagwe'babigo'ining (Dalles)
4. Wauzhushk Onigum (Rat Portage)
5. Lac La Croix
6. Wabeseemong
7. Cat Lake
8. Ojibway Nation of Saugeen
9. Wabauskang
10. Washagmis Bay
11. Shoal Lake # 40
12. North West Angle #37
13. Big Grassy
14. Naicatchewenin
15. Rainy River
16. Mitaanjigamiing
17. Mishkeegogaming
18. Slate Falls
19. Seine River
20. Temagami

Witness: MERALI Imran

UNDERTAKING – JT 2.21

Undertaking

TO FILE HYDRO ONE'S BROCHURES ON OESP, LEAP AND HAP PROGRAMS.

Response

Please see Attachments 1-5.

ONTARIO ENERGY BOARD

More help for more households

$35 TO $75 OFF YOUR ELECTRICITY BILL EACH MONTH

ONTARIO ELECTRICITY SUPPORT PROGRAM

To apply online or learn more about the program, visit:

OntarioElectricitySupport.ca

For questions please call:

1-855-831-8151 (toll-free)

1-800-855-1155 (TTY to TTY)
Or contact your local electricity utility

Who qualifies and what support can you receive?

If you are a customer of an electricity utility, and in a lower-income home, you may qualify.

The Ontario Electricity Support Program (OESP) applies a credit directly to your electricity bill **every month.**

The amount of each monthly credit you receive depends on two factors:

- How many people live in your home
- Your household's combined income

Effective May 1, 2017, the OEB increased the credit available by 50 per cent and expanded the eligibility criteria so that more lower-income households can benefit. If you are already enrolled, the increased credit will be automatically applied to your bill.

OESP monthly credit amounts by household income level

Level of household income (after tax)	Household size (number of people living in household)						
	1	2	3	4	5	6	7+
$28,000 or less	$45	$45	$51	$57	$63	$75	$75
$28,001 – $39,000		$40	$45	$51	$57	$63	$75
$39,001 – $48,000			$35	$40	$45	$51	$57
$48,001 – $52,000					$35	$40	$45

For example, a household with four people and an annual income of $39,000 will receive an on-bill credit of $51 each month.

If you live in a home heated with electricity, rely on certain medical devices requiring a lot of power or are part of an Indigenous community, you could qualify for a higher level of assistance.

Ready to apply?

1. Gather up the following:
   - Your electricity bill
   - Birthdates and names of all residents in your home as registered with the Canada Revenue Agency (CRA)
   - Social Insurance Numbers or Temporary Tax Numbers for all household members 18 and older
2. Fill out the application online at **OntarioElectricitySupport.ca** or call 1-855-831-8151 to have an application form mailed to you or to find an agency to help you.
3. CRA needs your consent to verify your income. Remember to print, sign and mail in the consent form that can be found online or with your paper application form. You'll find the mailing address on the consent form.

You will be notified of eligibility about four to six weeks after your completed application and signed consent form have been received.

Once approved, the credit will start to appear directly on your electricity bill.

You will receive OESP for two years before having to reapply.

Please note: If you have not filed an income tax return recently, or if your situation has changed since you last filed, you can apply for OESP through a designated agency listed on our website. You will need to bring all of the documents listed in Step 1 above, plus proof of your household income.

COMMISSION
DE L'ÉNERGIE
DE L'ONTARIO

Plus d'aide pour plus de ménages

ÉCONOMISEZ DE 35 $ À 75 $ SUR VOTRE FACTURE D'ÉLECTRICITÉ CHAQUE MOIS

PROGRAMME ONTARIEN D'AIDE RELATIVE AUX FRAIS D'ÉLECTRICITÉ

Pour vous inscrire ou pour en apprendre davantage sur le programme :

AideElectriciteOntario.ca

Si vous avez des questions, composez le :

1-855-831-8151 (sans frais)

1-800-855-1155 (ATS à ATS)
Vous pouvez aussi communiquer avec votre service public d'électricité

Qui est admissible et quelle est l'aide que vous pouvez recevoir?

Si vous êtes client d'un service public d'électricité et dans un ménage à faible revenu, vous pourriez être admissible.

Le Programme ontarien d'aide relative aux frais d'électricité (POAFE) applique un crédit directement sur votre facture d'électricité **chaque mois.**

Le montant du crédit mensuel que vous recevrez dépendra de deux facteurs :

- le nombre de personnes vivant dans votre foyer;
- le revenu combiné de votre ménage.

À compter du 1er mai 2017, la CEO a augmenté le crédit disponible de 50 pour cent et a élargi les critères d'admissibilité afin que davantage de ménages à faible revenu puissent en profiter. Si vous êtes déjà inscrit au programme, le crédit accru sera automatiquement appliqué sur votre facture.

Montant du crédit mensuel du POAFE selon le niveau de revenu du ménage

Niveau de revenu du ménage (après impôt)	Taille du ménage (nombre de personnes vivant au domicile)						
	1	2	3	4	5	6	7+
28 000 $ ou moins	45 $	45 $	51 $	57 $	63 $	75 $	75 $
28 001 $ – 39 000 $		40 $	45 $	51 $	57 $	63 $	75 $
39 001 $ – 48 000 $			35 $	40 $	45 $	51 $	57 $
48 001 $ – 52 000 $					35 $	40 $	45 $

Par exemple, un ménage de quatre personnes ayant un revenu annuel de 39 000 $ recevra un crédit sur sa facture d'électricité de 51 $ chaque mois.

Si votre domicile est chauffé à l'électricité, que vous avez besoin d'appareils médicaux consommant beaucoup d'énergie, ou que vous êtes membre d'une communauté autochtone, vous pourriez être admissible à un niveau d'aide plus grand.

Prêt à vous inscrire?

1 Réunissez les documents qui suivent :

- votre facture d'électricité;
- le nom et la date de naissance de tous ceux qui résident dans votre foyer, comme il est inscrit auprès de l'Agence du revenu du Canada (ARC);
- les numéros d'assurance sociale ou les numéros d'imposition temporaire de tous les membres de votre ménage âgés de 18 ans et plus.

2 Remplissez la demande en ligne à **AideElectriciteOntario.ca** ou composez le 1 855 831-8151 pour recevoir par la poste un formulaire de demande ou pour trouver un organisme qui peut vous aider.

3 L'ARC a besoin de votre consentement pour vérifier votre revenu. N'oubliez pas d'imprimer, de signer et de poster le formulaire de consentement disponible en ligne ou avec votre formulaire de demande papier. Vous trouverez l'adresse postale sur le formulaire de consentement.

Vous serez avisé de votre admissibilité environ de quatre à six semaines après que votre formulaire dûment rempli et votre formulaire de consentement signé auront été reçus.

Une fois que vous êtes approuvé, le crédit commencera à apparaître sur votre facture d'électricité.

Vous recevrez le crédit du POAFE pendant deux ans, après quoi vous devrez vous réinscrire.

Remarque : Si vous n'avez pas produit une déclaration de revenus récemment, ou si votre situation a changé depuis votre dernière déclaration de revenus, vous pouvez présenter une demande au POAFE par l'entremise d'un organisme désigné dont le nom apparaît sur notre site Web. Vous devrez avoir en votre possession tous les documents inscrits à l'étape n° 1 décrite ci-dessus, ainsi qu'une preuve des revenus de votre ménage.

MORE HOUSEHOLDS NOW QUALIFY

For special assistance programs

HEATING & COOLING REBATES

Now save up to $4,000 on upgrades

NO OVEN NECESSARY

Simple, no-energy dessert recipe

NEW!

Introducing Save on Energy DEAL DAYS

Instant discounts in stores or online

hydro one

Partners in Powerful Communities

CHANGE is in the air

From new energy-saving technology and gadgets to rebates big and small, simple actions and major makeovers, you can find it all here! Because lower home energy use isn't just a smart way to save on bills (though we all love that!) – it's also how we strengthen our communities, sustain our shared power system and protect the beauty of Ontario.

Hydro One Named Regional Utility of the Year

We're honoured to receive ENERGY STAR® Canada's 2017 Regional Utility of the Year award for demonstrated excellence in advancing energy efficiency.

4 THREE CHEERS
Instant discounts are here!

12 YUM! YUM!
Try this energy-wise recipe

6 MEET THE EXPERTS
Get great deals and expert advice at participating retailers near you

14 GOING OUT OF TOWN?
Protect your home from power surges

7 FLIP THE SWITCH
See how we're changing to serve you better

15 SMALL BUSINESS OWNER?
Find out if you're eligible for free lighting upgrades

8 RED-HOT REBATES
For furnace, AC, air-source heat pump upgrades

16 CRAFT WITH KIDS
Frugal fun with a Halloween theme

10 MAKING ENDS MEET
Help for households in need

18 BANISH PHANTOMS
Stop devices from draining power

19 GRILL N' CHILL SWEEPSTAKES
Sign up for AutoPay for a chance to win

Introducing

SAVE ON ENERGY DEAL DAYS

GREAT. BIG. SAVINGS.

OCTOBER 6 – NOVEMBER 5

NEW! No coupons needed – get instant discounts on these and many more energy-efficient products. Multipack discounts also available! Shop in store or online. For a complete list of retailers, visit **HydroOne.com/DealDays**

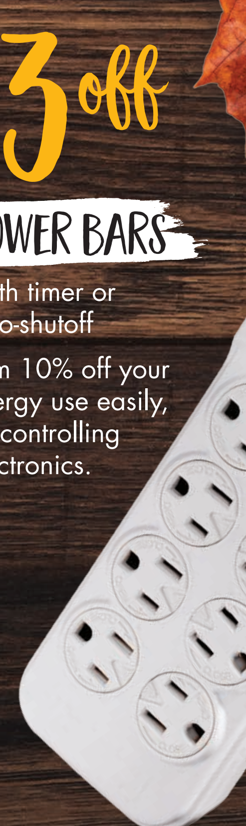
Instant savings now.
Energy savings year after year.

$8 off

ENERGY STAR® certified

LIGHT FIXTURES

Use 75% less electricity than standard fixtures.



$3 off

POWER BARS

With timer or auto-shutoff

Trim 10% off your energy use easily, by controlling electronics.

up to $2 off PER BULB

ENERGY STAR® certified

LED BULBS

Use up to 75% less energy and choose from a rainbow of hues.

$8 off

ENERGY STAR® certified

CEILING FANS

50% more energy-efficient than non-certified fans.

$4 off

DIMMER SWITCHES

Match lighting to your task and mood, and save energy too.

MEET THE EXPERTS

Stop by a store near you during Save on Energy Deal Days and chat with Hydro One's energy experts. They'll be on hand at selected stores to share energy-saving tips and help you choose the best products for your home.

ONE MONTH ONLY!
OCTOBER 6 – NOVEMBER 5

Visit **HydroOne.com/DealDays** for dates and locations.

Shop and save at these select stores and many more:

- HOME HARDWARE
- LOWE'S
- RONA
- THE HOME DEPOT
- TSC
- WALMART

4 ENERGY MYTHS OUR EXPERTS LOVE BUSTING

MYTH #1 HEAT PUMPS ONLY HEAT

Not only do heat pumps cut heating costs by up to 50%, they provide energy-efficient home cooling and dehumidifying in summer months! Check out our heat pump rebates on page 8.

MYTH #2 LEDS ARE EXPENSIVE

LED prices have come down so much in recent years, their value is clearer than ever. They pay for themselves quickly by using up to 75% less energy and lasting 25 times longer than standard incandescents.

MYTH #3 CRANK THE THERMOSTAT FOR FASTER HEATING

This only wastes energy. Enjoy better temperature control with a programmable or adaptive thermostat that you can adjust from any location for comfort.

MYTH #4 WHEN ELECTRONICS ARE OFF, THEY'RE OFF

If they're plugged in, many devices continue to use small amounts of power even after they've been turned off. This is known as "phantom power," and we have tips to help you fight it! See page 18.

SERVING YOU BETTER

We're making changes where it matters most for our customers.

1 FAIR HYDRO PLAN

Now in effect! Customers are seeing lower monthly bills with Ontario's new **Fair Hydro Plan**. We advocated for these changes because we heard your concerns.

2 MANAGE YOUR ACCOUNT

Get 24/7 access to your account from any device, sign up for paperless billing and manage high usage with tailored alerts.

3 ELIMINATING SECURITY DEPOSITS

All residential security deposits have been eliminated, existing deposits returned and business security deposits reduced.

4 MORE FINANCIAL ASSISTANCE

Now, more eligible low-income customers with past due bills can get emergency relief grants up to $600 (see page 10 for details).

5 CUSTOMER SERVICE GUARANTEES

From now on, if we fail to meet any of our service guarantees, we will credit your account $75.

6 GET LOCAL

We're travelling the province to provide better service and have opened three locations to serve customers face to face during regular business hours.

FLIP THE SWITCH Learn more at **HydroOne.com/FlipTheSwitch**

Stay connected to see how we're improving to serve customers better.

COME HOME TO Cozy

Switch to a heat pump and reduce heating costs. Get rebates up to **$4,000**.*

UPGRADE TO A HIGH-EFFICIENCY FURNACE AND GET $250

Reduce heating costs by up to 25% when you install a quieter, more efficient furnace with an electronically commutated motor (ECM). This offer ends December 31, 2017.

UPGRADE TO AN 18+ SEER ENERGY STAR® CERTIFIED CENTRAL AIR CONDITIONER AND GET $600

Use up to 20% less energy and improve indoor air quality when you install a high-performing central air conditioner.

SPECIAL OFFER FOR ELECTRICALLY HEATED HOMES

Install an air-source heat pump and save up to 50% on your heating costs, plus get rebates up to $4,000.

HOW TO QUALIFY FOR REBATES

1. Find a participating contractor near you – they will guide you through the program and complete the paperwork.
2. Buy and install your new system.
3. Submit your invoice.

See all heating and cooling rebates at **HydroOne.com/Rebates**

A CHANCE TO Win YOUR UPGRADES

Install your new furnace or AC by **December 31, 2017** and you'll be automatically entered to win** up to $5,000 toward the cost of your upgrade.

**Chances of winning depend on the number of entries received. The winner has to answer a skill-testing question and sign a release. Contest closes December 31, 2017 at 11:59 p.m. Last day for eligible installations is December 31, 2017. See full contest terms and conditions at www.HydroOne.com/Rebates.

PUMP UP COMFORT

Heat AND cool for less!

IS AN AIR-SOURCE HEAT PUMP WORTH IT?

If your electric heating system is 10+ years old or in need of repair, you may want to consider switching to an air-source heat pump – the electricity savings can be up to 50%.

HOW DO I CHOOSE THE RIGHT ONE?

Working with a qualified contractor will make it easy to find the right air-source heat pump for your home's size, age and condition. They can also help you apply for up to $4,000 in rebates when you upgrade.

WHAT IS INVOLVED IN INSTALLATION?

Heat pumps come in a wide variety of installation options – ask your contractor which one is best for your home.

HOW LONG CAN I EXPECT IT TO LAST?

With proper maintenance, most heat pumps last 15 to 20 years.

HOW DOES A HEAT PUMP WORK?

Heat pumps transfer air between outdoors and indoors by compressing and expanding a refrigerant. On the heating cycle, they collect heat from the outside air and deliver it inside. For cooling, they do the opposite, just like your refrigerator. Plus, they dehumidify indoor air in summer, too!

More help for MORE HOUSEHOLDS

If you're struggling to make ends meet, you may qualify for one or more of these programs.

Get a FREE in-home energy assessment – and energy-efficient appliances, light bulbs, weatherstripping, power bars and more – installed at no cost with the **Home Assistance Program** if you meet ONE of these requirements:

OPTION 1

Your annual household income after tax is less than or equal to:

HOUSEHOLD SIZE (PERSONS)	HOUSEHOLD INCOME†
1	$21,773
2	$30,792
3	$37,712
4	$43,546
5	$48,686
6	$53,333
7	$57,606
8	$61,583
9	$65,319
10	$68,852

† After-tax income of all household members aged 18 and older. Subject to change to align with Low Income Measures (LIM) updates.

OPTION 2

You have received **one** of the following in the past 12 months:

- Ontario Electricity Support Program
- Low-Income Energy Assistance Program (LEAP)
- Guaranteed Income Supplement
- National Child Benefit Supplement
- Allowance for Seniors
- Ontario Works
- Ontario Disability Support Program
- Allowance for the Survivor
- Healthy Smiles Ontario Child Dental Program
- Natural Gas (DSM) Low-Income Program

For details and complete eligibility requirements, visit **HydroOne.com/HAP** or call **1-855-591-0877**.

FIXED OR MODEST INCOME?

Lower-income households can receive $35 to $75 per month towards their bill through the **Ontario Electricity Support Program (OESP)**. Higher credits are available if your home is electrically heated and/or you rely on medical devices that use a lot of electricity.

Learn more at **HydroOne.com/OESP**

DIFFICULTY PAYING PAST DUE BILLS?

Get a one-time emergency grant up to $600 to help with past due electricity bills with the **Low-Income Energy Assistance Program (LEAP)**.

Learn more at **HydroOne.com/LEAP** or call **1-855-487-5327**.

AFFORDABILITY FUND

The Government of Ontario established a $100M Affordability Fund to help customers in financial need, and who may not be eligible for other programs based on income criteria.

Eligible customers will benefit from upgrades to their home to make it more energy-efficient and reduce their electricity bills. Each level of support is based on customer eligibility.

For more program details and to see if you qualify, visit: **HydroOne.com/AffordabilityFund**

Scrumptious PUMPKIN

NO-BAKE CHEESECAKE

So easy to make and deliciously light on electricity, this pumpkin cheesecake is just the ticket for holiday gatherings.

PREP TIME: 10 minutes
MAKES: 6–8 servings

1 (9-inch) ready-to-use or homemade **graham cracker crumb pie crust**

250 g (½ lb.) softened **cream cheese**

Pinch of **cinnamon**

118 ml (½ cup) **sugar**

250 ml (1 cup) **canned pumpkin**

2.5 ml (½ tsp) **pumpkin pie spice**

710 ml (3 cups) **canned real whipped cream**

DIRECTIONS

1. Combine cream cheese, pumpkin, sugar and pumpkin pie spice in a large bowl. Gently stir in 2½ cups of canned real whipped cream.
2. Spoon mixture into crust and spread evenly.
3. Refrigerate cheesecake and remaining whipped cream for at least 3 hours. Serve cheesecake topped with remaining whipped cream. Sprinkle with cinnamon, if desired.

TOP TIP: HOLIDAY CLEANUP

Use your dishwasher's controls to save

- Run only when full
- Choose the shortest wash cycle
- Let dishes air-dry

Want more energy-saving tips?
Visit **HydroOne.com/ForHome**

GOING AWAY FOR Thanksgiving OR the holidays?

Severe weather is a common cause of power surges, which can overload circuits and damage appliances and electronics.

Use these pre-trip tips to safeguard against surges:

1. Unplug all non-essential appliances like TVs, microwave oven and stereo before leaving.
2. Plug major appliances and sensitive electronics like computers into a power bar and turn the master switch off
3. Many advanced power bars have surge protectors built in – look for the words “surge protection” and “fused strip” or "interrupter switch"

SAVE ON ENERGY DEAL DAYS

Shop for power bars with surge protectors and more great energy-saving products.

October 6 – November 5

See page 4 for details.

DO YOU HAVE THESE ENERGY CULPRITS?

If your small business uses any of these outdated lights, you’re likely a good candidate for a FREE energy assessment and up to $2,000 in lighting upgrades with our **Small Business Lighting** program. Book your free assessment today by calling **1-866-932-8283**.

Incandescent light bulbs | Pot lights | Halogen bulbs | Track lighting | High bay lighting

WHY SWITCH TO LEDS?

1 Save up to 75% on your lighting costs

2 Rated bulb life of up to 50,000 hours

3 Fewer failed bulbs

4 Lower maintenance costs

Eligible small businesses can get up to $2,000 in upgrades on us!

You decide how much you want done and when!

HOW THE PROGRAM WORKS

- FREE assessment
- Professional installation
- State-of-the-art equipment
- Ongoing savings

See if you qualify! Take our two-minute lighting checkup at **HydroOne.Com/Checkup**

MASON JAR Mummies

Turn jars into a simple seasonal craft

Wicked fun to make with kids, this DIY Halloween decoration is easy on the wallet and the planet.

BENEFITS OF LED TEA LIGHTS

- Flameless and smokeless
- No wax drips or soot
- Long-lasting
- Zero carbon emissions

Why don't mummies go on holiday?

THEY DON'T LIKE TO UNWIND!

YOU'LL NEED JUST A FEW BASIC SUPPLIES:

- Mason jars
- 2.5 cm (1″) gauze bandage (or cheesecloth, cut into 2.5 cm (1″) strips)
- Googly eyes with adhesive backs
- LED tea lights
- Glue

STEP 1

Wind gauze around the entire mason jar, starting from the bottom

STEP 2

Secure the end of the gauze with glue

STEP 3

Stick on googly eyes as desired

STEP 4

Place an LED tea light inside the jar to bring your mummy to life

These mummies look great clustered in a group on a mantle or windowsill, or you can line your front steps on Halloween night to greet trick-or-treaters!

MULTICOLOUR MUMMIES

LED tea lights now come in a variety of fun colours – make a rainbow!

Is your home HAUNTED?

Turned off or idle, your home's devices and appliances continue to draw power. It's called "phantom" or "standby" power, and it could be costing you up to $150 every year in electricity.

TOP 8 PLACES PHANTOMS LURK

These energy-slurping electronics may be raising your usage every month.

1 Personal video recorder
2 Desktop PC
3 Satellite cable box
4 Video game console
5 Compact stereo system
6 Laptop/notebook
7 Computer speaker
8 Speaker dock

THE SIMPLE SOLUTION?

Unplug them! Or use advanced power bars with built-in timers or auto-shutoff, that prevent electronics from wasting power when they're not in use.

Find more ways to save on phantom power at **HydroOne.com/PhantomPower**

FAST AND SECURE. SAVE TIME AND MONEY. STAY IN CONTROL.

You could WIN!‡

The GRILL n' CHILL Sweepstakes

Set up AutoPay and put bill payments on the back burner

YOU COULD WIN:

A BBQ prize pack ($1,000 value!), including a new Weber BBQ and grill set

One of 10 $100 RONA gift cards!

DOUBLE YOUR CHANCES!

Get an additional chance to win when you sign up for **paperless billing**!

Don't miss out! Contest ends **December 10, 2017**.
Sign up through *my*Account at **HydroOne.Com/myAccount**.

‡AutoPay is the pre-authorized payment program. Contest runs from 12:01 p.m. ET on September 8, 2017 until 11:59 p.m. ET on December 10, 2017. Prize may not be as shown. Chances of winning depend on the number of entries received. The winner has to answer a skill-testing question and sign a release. See full terms and conditions at www.hydroone.com/myaccount/autopay-grill-n-chill/terms-and-conditions-v2.

WE'RE HERE TO HELP

Have a question about your bill or simply want to learn more about reducing your energy usage? Drop in and meet with us one-on-one at these locations:

Markham Office
185 Clegg Road
Markham, Ontario
Monday to Friday
8 a.m. – 4 p.m.

London Office
727 Exeter Road
London, Ontario
Monday to Friday
8 a.m. – 4 p.m.

Sudbury Office
500 Barry Downe Road
Sudbury, Ontario
Monday to Friday
8 a.m. – 4 p.m.

VISIT US ONLINE

Access your information 24/7 by registering for ***myAccount***. Take advantage of self-serve options, manage your usage and sign up for paperless billing.

WE'RE COMING TO YOU!

We're travelling the province to provide better service to all customers. See all the communities we're visiting at **HydroOne.com/GetLocal**

FOLLOW US

@HydroOneOfficial
@HydroOne
@HydroOneOfficial

OUTAGE REPORTING & UPDATES

1-800-434-1235
24 hours a day,
7 days a week

MORE ONLINE TIPS & TOOLS TO HELP YOU SAVE ELECTRICITY

HydroOne.com/SaveEnergy

CUSTOMER COMMUNICATIONS CENTRE

1-888-664-9376
Monday to Friday
7:30 a.m. – 8 p.m. ET
CustomerCommunications@HydroOne.com

TIME-OF-USE RATES

TIMING IS EVERYTHING

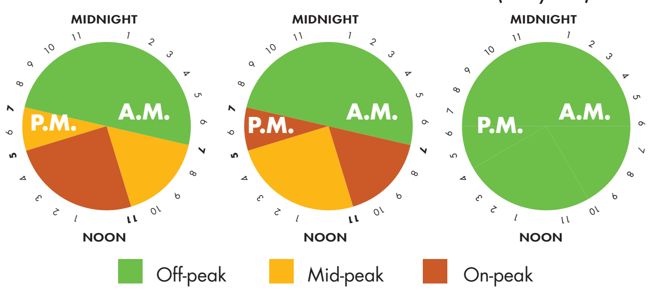
With time-of-use (TOU) rates, shifting your electricity usage to off-peak hours helps you save.

It's easy to track your TOU usage – simply log in to *my*Account at **HydroOne.com/myAccount**

Summer Hours
May 1 – Oct. 31

Winter Hours
Nov. 1 – Apr. 30

Weekends/ Holidays
(All year)



SAVE ON ENERGY
POWER WHAT'S NEXT

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Subject to additional terms and conditions found at www.HydroOne.com/SaveEnergy. *Incentives are available for installation of eligible equipment completed between January 1 and December 31, 2017 and submitted no later than February 28, 2018. Equipment must be purchased from and installed by a participating contractor. $250 incentive with the purchase and installation of an eligible furnace. $600 incentive with the purchase and installation of an eligible central air conditioning system. Up to $4,000 incentive with the purchase and installation of an eligible air-source heat pump.

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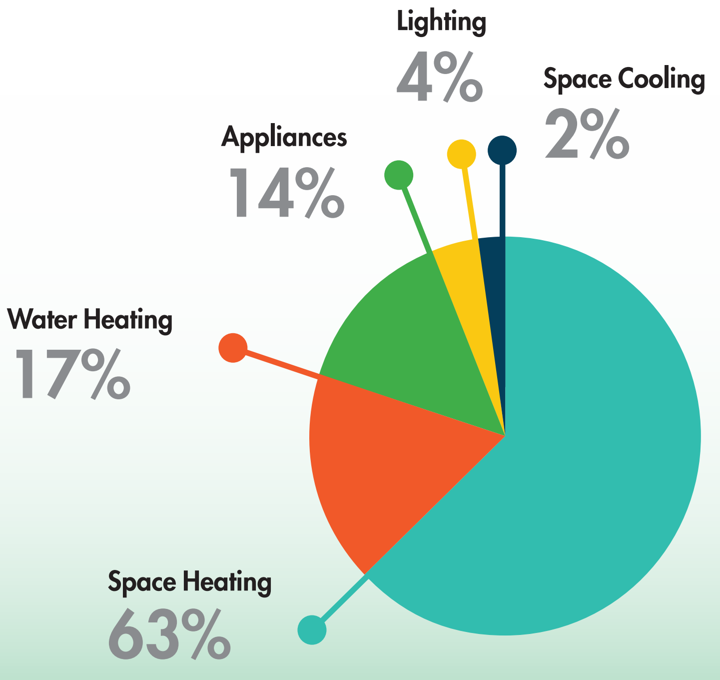
Filed: 2018-03-29
EB-2017-0049
Exhibit: JT 2.21
Attachment 3
Page 1 of 2

Your home energy use at-a-glance

Here's how a typical home's energy use breaks down, by activity:



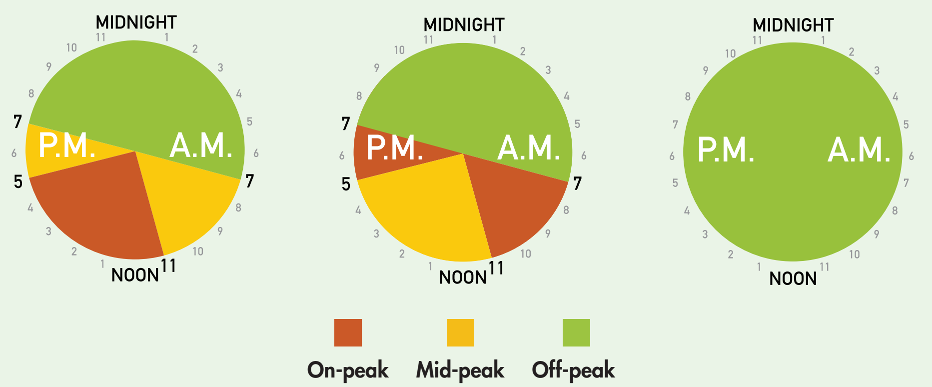
Understanding how your daily habits affect your electricity use can help you look for opportunities to save.

Over the course of a year, the largest energy user in a typical household is space heating, followed by water heating, appliances, lighting and air conditioning. But other factors such as the size, age and condition of your home can also increase energy use, as can extreme weather and higher occupancy (more people living in the home than normal). Because heating accounts for more than half of your annual energy use, it's a smart place to start using energy more efficiently.

Read on for tips and programs to help you better control heating costs and more.

Time-of-use checklist

- ☑ Pay the lowest rate by running your dishwasher, clothes washer and dryer **before 7:00 a.m., after 7:00 p.m.,** or anytime on **weekends**, when electricity prices drop.
- ☑ Off-peak rates are **half the cost** of on-peak rates
- ☑ Weekends and statutory holidays are also off-peak



Rebates, tips and more ways to save are here!

Explore more: **HydroOne.com/ForHome**

Get real, live answers: **1-888-664-9376**
(7:30 a.m. – 8:00 p.m. ET, Monday to Friday)

@HydroOneOfficial **@HydroOne** **@HydroOneOfficial**

SAVE ON ENERGY
POWER WHAT'S NEXT

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MY HOME

energy savings tips made easy

Heat & cool **for less**

Time-of-use **checklist**

Enlightened **lighting**

Manage your **appliances**

16 everyday **energy secrets**

hydro one
Partners in Powerful Communities

Looking for easy savings at home?

In this guide, you'll find helpful tips to make energy-efficient choices and cost-efficient upgrades around your home. Knowing where to look is the best way to get started.

HOT WATER

Save energy from going down the drain.

1 Fix leaky taps
A simple rubber washer stops leaks that can add up to 75 litres of water each week.

2 Wash with cold
85-90% of the energy used to wash clothes is from heating the water. Wash in cold water to save.

3 Hot water tank wrap
Wrap a blanket around your electric hot water tank to reduce energy loss by up to 40%.

4 Sparkling dishwasher savings
Always run full loads, use the shortest cycle and select air dry for up to 50% savings.

LIGHTING & ELECTRONICS

Bright ideas for better bulbs and busting phantoms.

5 Upgrade to LEDs
ENERGY STAR® certified LED bulbs last up to 25 times longer, produce no excess heat and are 75-90% more energy efficient than traditional incandescent bulbs.

6 Install sensors and dimmers
Garages, basements and outdoor lights are ideal for automatic lighting sensors, while easy-to-install dimmers also help reduce indoor lighting costs.

7 Fight phantom power
Plug PCs, game consoles, TVs and other electronics into a power bar with a timer or auto-shutoff to help save up to 20% in phantom power.

8 Lamp timers
Who left the lights on? Not you! Timers can also go on fans, so they don't run all night.

APPLIANCES

Big appliances are big users.

9 Seal your fridge
Try closing a $5 bill in your fridge door. Does it stay in place? If not, you may need to replace the seal.

10 Avoid overheating
Preheating ovens is only necessary for baking; roasts and casseroles can skip it.

11 Avoid freezer fatigue
Freezers work best when they are two-thirds full and set at -18°C (0°F).

12 Upgrade your old appliances to save
ENERGY STAR® certified fridges are 20% more efficient; front-loading washing machines use up to 65% less energy compared to conventional top loaders.

Consider the "second price tag"
The sticker price is just one cost when you're buying new. Remember to factor in the cost of operating the product over its lifetime. Find ENERGY STAR® certified models at:
www.nrcan.gc.ca/energy/products/energystar/12519

HEATING & COOLING

About **65%** of costs come from heating and cooling.

13 Test for air tightness
Hold a lit incense stick next to windows to detect air leaks. A strong leak will blow smoke away; a small leak will draw it in.

14 Reduce electricity use by up to 20%
Inexpensive caulking and weatherstripping for windows, doorframes, attic hatches and more can reduce your heating and cooling needs by up to 20%.

15 Wall outlets
Get pre-cut foam gaskets to seal indoor and outdoor switch plates — they're a big source of air leaks.

16 Program your thermostat
Automatically regulate heating and cooling to save up to 10%.

Time for a new furnace or a central air conditioner?
The latest models are quieter, more reliable and use less energy.
It may be time to upgrade if:

- Your system is more than 10 years old
- You need major parts replaced
- You had more than one maintenance call this year
- Your system is unusually noisy

CONTACT US

Indigenous Relations
+1.877.955.1155

Supply Chain Services
Hydro One Networks Inc.
483 Bay Street
South Tower, 6th Floor
Toronto, Ontario, M5P 2G5

New Vendor Inquiries
NewVendorInquiries@HydroOne.com

Ariba System Help Desk
SupplierContact@HydroOne.com

HydroOne.com
Hydro One Supply Chain Services
& Indigenous Relations

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DOING BUSINESS WITH HYDRO ONE

A guide for Indigenous suppliers and contractors in Ontario

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Partners in Powerful Communities

TABLE OF CONTENTS

HYDRO ONE NETWORKS INC.

Owns and operates 98% (30,000 kilometres) of Ontario's high-voltage transmission grid that delivers electricity from generators to major industries and large local distribution companies (LDCs).

Low-voltage distribution network spans more than 123,000 kilometres and 1.6 million poles, serving 1.3 million customers, mostly in rural areas.

Employs more than 5,300 highly-skilled and professional employees (¾ in field operations).

HYDRO ONE'S INDIGENOUS RELATIONS DEPARTMENT

Hydro One's Indigenous Relations Department has employees dedicated to each region of the province. We are committed to continue working together to build our relationships based on trust with Indigenous communities.

Hydro One has facilities in 23 ~~Indigenous communities~~ and directly serves 88 communities.

Hydro One Remote Communities Inc., operates and maintains the generation and distribution assets used to supply electricity to 21 communities across northern Ontario that are not connected to the province's electricity grid, 15 of which are ~~Indigenous communities~~.

INDIGENOUS RELATIONS POLICY

Hydro One owns assets on reserve lands and within the traditional territories of Indigenous Peoples. Hydro One recognizes their lands are unique to Canada, with distinct legal, historical and cultural significance.

Hydro One is committed to working with Indigenous Peoples in a spirit of co-operation and shared responsibility. Forging relationships with Indigenous ~~communities~~ based upon trust, confidence and accountability is vital to achieving our corporate objectives.

Hydro One's Indigenous policy enhances and complements other corporate policies and will guide Hydro One in its relationships with Indigenous Peoples.

Hydro One is committed to developing and maintaining relationships with Indigenous ~~communities~~ that demonstrate mutual respect for one another.

WORKFORCE DEVELOPMENT

Indigenous People are an important part of Hydro One's workforce. We are committed to increasing the representation of qualified Indigenous employees at all levels in our workforce.

Visit the careers section at **www.HydroOne.com/careers** or email: **Indigenous.Recruitment@HydroOne.com**

WHAT DOES HYDRO ONE PURCHASE

Hydro One purchases a variety of materials and services for use at our sites all throughout Ontario. The following are some examples of the type of services and materials procured.

- Heavy duty equipment with or without operators (floats, trucks, backhoes, cranes, etc.)
- Construction services and materials including aggregate, concrete, fencing, pole digging and rock drilling services
- Forestry/vegetation management services
- Electrical equipment
- Security Services
- IT Software and Hardware

HOW TO DO BUSINESS WITH HYDRO ONE

Hydro One is committed to developing and maintaining relationships with Indigenous Peoples that demonstrate mutual respect for one another. We support procurement opportunities for qualified Indigenous-owned businesses and the development and capacity of Indigenous contractors who can provide goods and services to Hydro One.

If you would like more information on how to participate in Hydro One procurement opportunities, please see the Procurement at Hydro One: A Guide for Indigenous Businesses document, available at **www.HydroOne.com/about/indigenous-relations** and click on Business Opportunities.

INDIGENOUS BUSINESS DIRECTORY

If you would like your company identified on the Hydro One website as an Indigenous-owned business with an interest in working with Hydro One and having an interest in doing business with Hydro One, please contact **NewVendorInquiries@HydroOne.com.**

HOW IT WORKS

AN OVERVIEW OF HYDRO ONE'S PROCUREMENT PROCESS

1. Supplier registers on Hydro One's SAP Ariba system through **hydroone.supplier.ariba.com/register**
2. Supplier receives invitations via email to participate in RFx
3. Supplier views the event details
    - Event details show how much time is remaining to submit your response (when the event will start accepting responses and when it will close)
    - Supplier can review and accept Bidder Agreement
4. Supplier prepares response as per the requirement specified in the FTx event
    - Suppliers will be able to communicate with the Hydro One buyer via the Ariba message board
    - Suppliers are required to regularly monitor their message board for the duration of the event for notes/instruction from the buyer
5. Supplier submits proposal to Hydro One
6. Hydro One evaluates proposals
7. Hydro One awards the contract

SAP ARIBA SYSTEM

1. **REGISTRATION**
   To register for the Ariba System, using Internet Explorer or Chrome, go to **hydroone.supplier.ariba.com/register**. After successfully registering as a supplier, you will receive invitations via email to participate in sourcing events.
2. **LOG IN**
   To access a sourcing event and the pertaining documentation available, click the "Log In to Ariba" button located in **HydroOne.com/about/suppliers**
3. **SOURCING EVENT**
   To view and/or participate in a sourcing event, please follow the instructions provided in the invitation email.
4. **USER GUIDES**
   The following user guides are available at **HydroOne.com/about/suppliers** for instructions on steps 1-13:
    - User Guide – Supplier Registration
    - User Guide – Responding to a Sourcing Event
    - User Guide – DocUSign

The supplier registration process is a one-time free process. If you need assistance registering, please contact **SupplierContact@HydroOne.com**

2017 Leonard S. (Tony) Mandamin Scholarship Winners

LEONARD S. (TONY) MANDAMIN SCHOLARSHIP

Our annual **Leonard S. (Tony) Mandamin Scholarship** supports First Nations, Métis and Inuit students from Ontario enrolled at a recognized college or university. Scholarship winners are granted a financial award of $5,000.00. In addition to the financial award, winners may also have an opportunity to complete a paid developmental work term with Hydro One. For more information on how to apply, eligibility and deadlines, please visit: **www.HydroOne.com/careers/one-awards**

BIG STORIES

Kevin Hill

Oneida Nation of the Thames
Regional Maintainer Forester II

Shekoli, I am TE WA TLU HYA LUNI meaning 'does fancy things' in Haudenosaunee and I come from the Bear Clan in Oneida Nation of the Thames. My English name is Kevin Richard Hill, Regional Maintainer Forester II for Hydro One.

My most memorable event with Hydro One was removing a burning limb from a power line during an ice storm with freezing rain pelting off my face and hard hat while I went up 50 feet to clear the power line. I could see a glow coming from the front window of this tiny house, with hands in front of a woodstove fire attempting to keep warm. The power was out for kilometers, we were in total darkness, and I was incredibly proud to get the limb cleared so that the family could have their power back.

My trade is exciting and challenging every single day, with many gratifying accomplishments by the end of each day. Now at Hydro One, I will do ALL I can to help my people to improve their lives and the lives of our future generations.

Yaw^ ko

Kevin Hill

STORIES BROUGHT TO LIGHT

Work with us and help power all the things that brighten our lives.

www.HydroOne.com/Careers

hydro one

Partners in Powerful Communities

OUR COMMITMENT

Indigenous peoples are an important part of Hydro One's workforce. This is why we are dedicated to Indigenous employment outreach. We have many resources available for you to learn about our workplace and how to join our team. If you have questions related to employment, please e-mail:
Aboriginal.Recruitment@HydroOne.com

For more information on careers with Hydro One and to view our current opportunities, please visit: www.HydroOne.com/Careers

STUDENTS & NEW GRADS

COLLEGE COLLABORATIONS

We have partnered with Ontario Colleges to keep our workforce growing and evolving with new skills and technical training. We support curriculum development and work collaboratively to ensure graduates have industry-ready skills and technical training.

CO-OP & INTERNSHIPS

Hydro One provides the opportunity for students to complement their classroom learning with real, hands-on experience in the office or field. There are a range of opportunities available—from electrical to engineering, to business or finance. To apply, students must be currently enrolled in a registered co-op or internship program at a recognized college or university and be scheduled to return at the conclusion of their work term.

Students may be eligible to apply for either:
- co-op work term: 4 to 8 months
- internship position: 12 to 16 months

POST-SECONDARY SUMMER STUDENT OUTREACH PROGRAM

Hydro One designates a portion of its summer positions to students of First Nation, Métis or Inuit descent. This program runs from May to August and employs current students who will be returning to a recognized college or university in the fall. These positions are posted annually in February.

Kim Trimble, Protection & Control Engineer

Chris Atkinson, Protection & Control Trainee

NEW GRAD TRAINING PROGRAM

The New Grad Program is designed to help recent university graduates learn and try new skills and roles. Our new grads are mentored by talented and experienced industry leaders. The two-year training program is tailored to both technical and corporate grads, which includes on-the-job coaching and multi-department rotations. These positions are posted annually in September.

APPRENTICESHIPS

Skilled trades make up a large portion of Hydro One's workforce. The Power Workers' Union represents the majority of the skilled trades working at Hydro One. Our skilled trades employees are widely regarded as the industry's best—this program offers candidates the opportunity to learn on the job, directly from Hydro One employees.

Hydro One typically hires the following trades:
- Powerline Technician
- Utility Arborist/Forester
- Construction and Maintenance Electrician
- Truck and Coach Technician

In order to qualify for one of our four skilled trades, the requirements are:
- completion of Ontario Secondary School Diploma
- completion of Grade 12 math and Grade 12 english (or equivalent)
- completion of one senior Science or a senior Electrical Shop for the Construction and Maintenance Electrician course
- a valid Ontario driver's licence
- updated resume (mandatory) and cover letter (optional)
- copies of your high school transcripts
- a current e-mail address

All requirements must be completed at the time of application. No exceptions.

Powerline Technicians, Thunder Bay

APPRENTICESHIP REMINDERS

- You will be required to work and travel across the Province—it is unlikely you will be working in your home community.
- For roles such as Powerline Technician and Utility Arborist, you should be comfortable with heights as the bulk of the work is in the air, on top of transmission towers, poles, and helicopter stairs.
- You will be working outdoors in all types of weather conditions.
- The job is very physically demanding.
- You will be required to wear protective equipment, which can be heavy and constricting.

Our standards are high, our training is challenging, but our work environment is rewarding and consistently brings out the best in our employees!

For more detailed information on our skilled trades, please visit: **www.TradeUp.ca**

UNDERTAKING – JT 3.1-1

Reference

I-23-AMPCO-7 (c)

Preamble: HONI's response references the new Large Customer Interruption Frequency metric which is included on HONI's Distribution Scorecard at Q-1-1 Attachment #1.

Undertaking

Please provide 2017 actuals for this metric and the targets for each of the years 2018 to 2022

Response

Measure	2017	2018	2019	2020	2021	2022
Large Customer Interruption Frequency (LDA) - frequency of outages	227	216	245	267	286	305

This measure was started in 2016 to identify the frequency of LDA interruptions. However, this measure was reported as the number of interruptions as opposed to a normalized frequency based on the total number of LDAs. The corrected measure is presented below as the frequency of interruptions normalized by the total number of LDAs. This will be the measure reported going forward as part of HONI's Distribution OEB Scorecard.

Proposed New Measure:	2017	2018	2019	2020	2021	2022
Large Distribution Accounts (LDA) - Interruptions per LDA	1.7	1.6	1.6	1.6	1.6	1.6

Witness: JESUS Bruno

UNDERTAKING – JT 3.1-2

Reference

I-24-AMPCO-6 (j)

Preamble: AMPCO asked that HONI complete a table to show spending in three areas: Proactive, Maintenance and Demand-Driven programs. HONI's response indicates that HONI does not characterize investments as "proactive" so it is not possible to provide actual or planned funding levels for proactive investments. HONI makes assumptions about what "Maintenance Programs" and "Demand-Driven" Programs might be referring to.

AMPCO wishes to clarify that HONI's evidence at B1-1-1 DSP Section 1.1 Page 12 states the following:

> Hydro One has a number of proactive investment programs that aim to pre-emptively address critical assets where a failure would impact a large number of customers. Hydro One has maintenance programs to address less pervasive assets and to quickly respond to events such as asset failures on a reactive basis. Finally, Hydro One has comprehensive demand-driven programs that react to unforeseen incidents that affect the entire system, such as storms or other external factors.

Undertaking

From the above it appears that HONI characterizes its investments in three key program areas: Proactive, Maintenance and Demand-Driven. AMPCO asks that HONI please complete the table to show the actual spending in these three areas from 2012 to 2017 and the forecast for the years 2019 to 2022.

Response

In the cited reference, "proactive" programs are defined as all capital investments not included under "demand-driven" programs. The table below was completed using this definition for "proactive" and the definitions for "maintenance" and "demand-driven" programs given in part j) of Exhibit I-24-AMPCO-6.

Investments	**2012 $ (Note 1)**	**2013 $**	**2014 $**	**2015 $**	**2016 $**	**2017 $**	**2018 $**	**2019 $**	**2020 $**	**2021 $**	**2022 $**
Proactive Programs	NA	358.5	374.4	398.9	411.2	365.9	379.1	494.8	454.9	469.1	551.2
Maintenance Programs	NA	335.7	325.7	304.6	323.7	334.5	346.7	A forecast is only provided for 2018 as per Exhibit C1-1-2			
Demand-driven Programs	NA	278.5	273.1	279.3	282.9	267.6	254.8	262.0	264.1	271.6	276.0

Note 1: The breakdown between the different program work for 2012 is not readily available.

UNDERTAKING – JT 3.1-3

Reference

I-23-AMPCO-11 (a)

Undertaking

Please update the table of "Power Outage Causes" excluding Force Majeure and Loss of Supply events.

Response

Power Outage Causes	**2013**	**2014**	**2015**	**2016**	**2017**
Tree damage	18%	18%	19%	24%	25%
Equipment failure	25%	27%	29%	25%	32%
Unconfirmed causes	25%	23%	22%	21%	17%
Scheduled outages	25%	23%	22%	22%	16%
Animal or vehicle damage	7%	9%	8%	8%	10%

UNDERTAKING – JT 3.1-4

Reference
I-24-AMPCO-13 (i)

Preamble: HONI does not use Adverse Weather and Lightning as Cause Codes.

Undertaking

i. Please provide the rationale for not using Adverse Weather and Lightning as Cause Codes.

ii. Does HONI have the data related to the contribution of Adverse Weather and Lightning to SAIDI and SAIFI? If yes, please provide.

iii. If data is not available, does HONI have a sense if the contribution of adverse weather and lightning to SAIDI and SAIFI is material in its service territory.

Response

i. Hydro One does not use Adverse Weather and Lightning as Cause Codes because we incorporate those causes into our existing Cause Codes. For example, Tree Contacts and Defective Equipment would capture Adverse Weather or Lightning causes. We do this to provide more meaningful insight in supporting our investment planning process.

ii. No

iii. Please see i.

UNDERTAKING – JT 3.1-5

Reference

I-24-AMPCO-13 (j)

Preamble: Tables 13, 14 and 15 include the outage code "Loss of Supply".

Undertaking

Please confirm Loss of Supply event data is not included under other cause codes.

Response

Loss of Supply event data is not included under the other cause codes.

Witness: JESUS Bruno

UNDERTAKING – JT 3.1-6

Reference
I-24-AMPCO-20 (a)

Preamble: The response indicates that HONI does not track the age an asset fails for every asset category.

Undertaking
Please provide the asset groups where HONI has data on the age an asset fails.

Response
Hydro One tracks asset age of failures for station transformers and mobile unit substations asset groups.

UNDERTAKING – JT 3.1-7

Reference

I-24-AMPCO-21 (a)

Preamble: HONI provides thresholds for cost, schedule and scope variances.

Undertaking

i. Please provide HONI's variance policy document.
ii. Please provide any internal documents that govern the preparation of Business Cases.
iii. Please provide any internal documents that govern internal project controls.
iv. The Schedule Variance Threshold references a material impact of the benefit of the scope of work. How is a material impact on the benefit of the scope of work evaluated?

Response

i. Please see Attachment 1 for the variance policy document.
ii. Please see Attachment 1 and Attachment 2.
iii. Please refer to Attachment 1, Section 1.5 (Project & Program Variance Approvals) for guidance on project controls and Attachment 3 for guidance on the preparation of variance approvals.
iv. Please refer to Attachment 1, Section 1.5 (Project & Program Variance Approvals).

Witness: JESUS Bruno

Filed: 2018-03-29
EB-2017-0049
Exhibit JT 3.1-7
Attachment 1
Page 1 of 11

Program and Project Approval Procedure

Purpose and Scope

This document describes the procedure required to be followed to approve expenditures including Corporate Common Costs, Programs and Projects as per Element 2.0 of the Expenditure Authority Register (EAR) and the procedure to approve variances to modify the scope, schedule or cost of either Projects or Programs as per Element 3.0 of the EAR.

Revision Statement

This procedure combined the requirements and relevant guidance in SP0976 Project Variance Approval, SP0738 Project Management Policy and SP1078 EAR/OAR Guidance. Both SP0738 and SP1078 have been removed as a result. This update also extends variance approval procedures to Programs.

Contents

1.0 Requirements

1.1 Role of the Consolidated Business Plan

a. The Consolidated Business Plan provides a detailed operational and financial outlook including financial and non-financial targets.

b. Approval of the Consolidated Business Plan by the Board of Directors provides the following expenditure approvals:

   i. Approval of Corporate Common Costs for business functions that provide shared operational, strategic and/or policy support. For example, Finance, Regulatory Affairs, Planning, People and Culture are considered Corporate Costs. As per SP0804 Shared Corporate Services Cost Allocation and Transfer Pricing Policy, a portion of these costs are allocated to each subsidiary. After this allocation occurs, a portion is then allocated to capital Programs or Projects as an overhead charge, or remain in OM&A within common corporate costs, consistent with the business model.

   ii. Approval of Programs' expenditures, scope and targeted results for the first year of the business plan. Subsequent years Programs' expenditures, scope and targeted results are approved in subseqent years' business plans.

iii. Establishment of total Project expenditures and in-service for that year. This consists of:

1. Expenditures related to multi-year Projects previously approved by management in accordance with a Business Case.
2. Expenditures for planned Projects which require further analysis to define scope, costs and benefits. The approval of these individual Projects must be sought separately in accordance to the EAR with a Business Case post Consolidated Business Plan approval.

3. Unplanned work related to customer requests and other reactive work. Approval of these individual expenditures must be sought separately in accordance with the EAR with a Business Case post Consolidated Business Plan approval.

1.2 Corporate Common Costs

c. All Corporate Common Cost expenditures must be included, identified and allocated within the Consolidated Business Plan.

d. Corporate Common Cost expenditures are considered approved by the Consolidated Business Plan if the need for the expenditure, scope of work (e.g. area of accountability), total gross and unit costs (e.g. FTEs), and accomplishments are detailed with supporting documentation (often referred to as a "Corporate Common Cost Template") and included as a supporting document to the Consolidated Business Plan at the time that it receives Board of Directors' approval.

e. Corporate Common Cost expenditures not utilized in a fiscal year do not automatically roll over into the following year. If these expenditures are still required, the required funding must be included as part of the Corporate Common Cost approval process in the next Consolidated Business Plan.

f. Explanation of the variances to the Corporate Common Costs' annual expenditures and the impact upon the business are the accountability of the Line of Business' Executive Vice President or higher.

1.3 Program Approval

g. All Programs must be included and identified within the Consolidated Business Plan by the accountable Planning Unit.

h. A Program is considered approved by the Consolidated Business Plan if:

i. The need, scope of work (including type and total units of work if applicable), results, gross and net expenditures are detailed and documented.

ii. The program is reviewed and approved by Planning Unit's leader (manager level or above) prior to the Consolidated Business Plan submission.

iii. This documentation is included as supporting information to the Consolidated Business Plan at the time that it receives Board of Directors' approval

i. Program expenditures not utilized in a fiscal year do not automatically roll over into the following year. If these expenditures are still required, the funding request must be included as part of the Program approval process in the next Consolidated Business Plan.

j. If a Program was not identified and not included in the annual Consolidated Business Plan, the first year's approval and expenditures will require that the Project Approval process be followed. Subsequent years' approval and expenditures must be included as part of the Program approval process in the next Consolidated Business Plan.

1.4 Project Approval

k. All Projects are subject to management review and approval. Review and approval is documented by the Planning Unit within a Business Case and approved in accordance with the authority limits in the EAR.

l. Projects approval phases are typically categorized as Development, Long Lead, Partial and Full Approval

  i. Development approvals typically used to provide funding and resources to scope and estimate a project

  ii. Long Lead approvals typically utilized to order material prior to the execution phase

  iii. Partial approvals are utilized to initiate the work execution phase prior to development phase being sufficiently completed. This type of approval is typically granted only under exceptional circumstances.

  iv. Full Approval is to approve the full scope of work and complete the work execution phase of a Project.

m. A single Business Case may be utilized to approve any combination of Development, Long Lead, Parital and Full Approval. For example, a single business case may be utilized to approve both the Development and Long Lead phase of a project.

n. The Business Case must include the approved total gross and net expenditures, the need for the investment, scope, the expected result, other alternatives, regulatory implications and potential material risks.

o. Long Lead and/or Development approval is for a limited scope of expenditures associated with a Project prior to full approval.

  i. Development approval is limited to expenditures related to:

    a) Engineering, Design and other necessary work to determine the overall Project scope.

    b) Verifying site conditions.

    c) Conducting investigations and producing an estimation of costs.

  ii. Long Lead approval is limited to expenditures related to:

a) Obtaining materials.

b) Initiating work with lengthy lead time, i.e. site preparation, requiring approval in advance of the main Project if the overall in-service date is to be met.

iii. A Project may have multiple Development and/or Long Lead approvals prior to seeking final approval. Each Development and/or Long Lead approval requires a Business Case. Approval must be sought for the cumulative total expenditures including previous long lead and development work.

i.e.: *Planning has a complex multi-year Project of which the scope and requirements are uncertain. Planning can approve a development Business Case to provide the necessary approval of expenditures to complete the engineering and estimation for the completion of the final business case. Assume the engineering and estimation work are expected to cost $1 million. Management with expenditure authority limit of $1 million under the EAR can approve the first Development Business Case. Subsequently, the line of business is required to order materials in advance of the final approval (i.e. $10M for transformers and other equipment). An additional Business Case must be approved to order these material as a Long Lead approval, which must be approved by Management with sufficient expenditure authority for the total cumulative expenditures to date, which is $11 million ($10 million for the material plus $1 million for the initial engineering).*

iv. All Development and/or Long Lead Business Cases must identify the time to complete the development phase, the cost of the development work, the expected cost of the total Project and the expected time of seeking the next approval.

v. Each Development and/or Long Lead Business Case must add additional development or long lead scope that meets the criteria in 1.4e i) and/or ii) above.

vi. If additional expenditures are required to meet the approved scope of the Development and/or Long Lead Business Case, variance approval and documentation is required as per section 1.5 Project & Program Variance Approvals below.

p. If approval is required for limited scope of expenditures that does not meet the criteria in 1.4e above for Long Lead and/or Development (for example: initiating construction of an asset), the approval is considered to be a Partial Approval.

i. A Business Case is to be used to provide Partial Approval for a limited scope of expenditures associated with a Project prior to full approval.

ii. An explanation of the exceptional circumstances why work execution must proceed prior to seeking Full Approval is required to be provided

iii. Partial Approval can only be granted by an individual holding a position with sufficient authority as per the EAR to approve the entire Project expenditures based on the current total estimated gross expenditure of the entire Project.

iv. All Partial Approval Business Cases must identify the limited scope and expenditures approved, the expected gross expenditures of the entire Project and the expected time of seeking the next approval.

v. A Project may have multiple Partial Approvals prior to seeking final approval.

q. Full approval for a Project must include the cumulative total of previous Partial Approval(s), Development and/or Long Lead approvals. The full approval can only be grandted by an individual holding a position with sufficient authority as per the EAR to approve the entire Project expenditures.

r. A Business Case may be deferred under emergency conditions.

i. Emergency conditions exist when immediate action is required to:

a) safeguard corporate assets.

b) prevent personal injury.

c) restore service.

ii. After emergency conditions are resolved, it is still necessary to follow up after the emergency with documentation and formal approval in accordance with 1.4a.

s. Projects which were identified with insufficient funding or not identified in the Business Plan must have the source of funding identified and approved for redirection.

1.5 Project & Program Variance Approvals

t. A variance is a material change from the approved cost, schedule, or scope of a Project or Program.

u. Variance review and approval is required as soon as there is a reasonable expectation that a variance in cost, scope and/or schedule from the previous approval is identified; this review and approval is required even if there is sufficient funding to meet requirements into the foreseeable future or the Project is completed and in-service / Program is at year end.

v. Any material variance (as defined in A, B and C below) is subject to management review and approval, which is documented with the Variance Approval Form and approved in accordance with the EAR.

w. Approval levels for expenditure variances are based on the cumulative total of all expenditure variances between the original approved and the total requested amount, regardless of previously approved variances. The first variance is always calculated against the approved Business Case or Program documentation. When a second variance is required, the materiality thresholds are calculated against the current approved amount inclusive of the proceeding variances, but approval authority is required for the total expenditure variance from the original approval amount.

x. Variances can be categorized as cost variances, schedule variances, scope variances or a combination of the three:

i. A cost variance is a material increase or decrease in spending based on the approved scope.

ii. A schedule variance is a business impactive change from the approved In-Service (IS) Date with or without changes in scope and/or costs.

iii. A scope variance is a material change to features or functions of the requested product.

y. Each type of variance is measured independently. ***i.e.*** *A Project experiencing a cost variance of $5 million offset by a scope decrease of $5 million would require Variance Approval despite no increase or decrease to the approved expenditures.*

z. Variances must have the source of funding identified and and approved for redirection.

aa. Previously unrecognized material variances discovered at the conclusion of a Project or at the end of the year for a Program also require documentation and approval in accordance with the EAR. The Variance Approval Form may be included in a Project close out process for this purpose.

A. Cost Variances

a. A Cost Variance is a material expenditure increase or decrease from the approved Project or Program expenditures. There are two potential triggers for determining a cost variance:

1. variance in expenditures more than $5 million

OR

2. variance greater of 10% of currently approved expenditures **and** greater than $0.5 million

b. Cost Variances are calculated in gross dollars - total costs including interest, overhead, and before any reduction for external capital contributions.

c. Cost Variances for Projects are calculated based upon the entire approved expenditures and can span multiple years.

d. Cost Variances for Programs are measured against the individual Program approved expenditures for the current fiscal year.

e. Program cost variances in future fiscal years are not to be approved via a variance approval; but are to be incorporated in the following year's Consolidated Business Plan. The original approval for a Program is considered to be a corresponding Program documentation prepared during the Consolidated Business Plan cycle.

B. Schedule Variances

a. Schedule variances are business impactive changes to planned In-Service dates.

b. The Planning Unit's leader (manager level or above) will determine whether the schedule delay is business impactive. The first variance is always calculated against the original approved In-Service date. If a further variance is required, the business impactive threshold is calculated against the current approved In-Service date.

c. Business impactive schedule variances are those that materially affect the value or benefit of the scope of work. Examples include:

- Missing critical commitments to customers, external stakeholders or the Board of Directors.
- Failure to meet a key system need, i.e. an i/s date slips past the shoulder months (spring or fall), thereby missing the intended facility capacity increase for summer or winter peaks.
- Material delays the realization of benefits, i.e. IT system deployment delay results in process improvement not occurring in time.
- Failure to meet a schedule set by an external regulator.
- When the delay will require a material adjustment to the annual work plan.
- Schedule change that results in $10 million capital or greater being placed into service in rate or fiscal year other than that planned and approved in the Business Case, Program documentation or prior Variance Approval.

d. Approval levels for schedule variances requires approval by the equivalent authority as the original approver.

C. Scope Variances

a. A Project or Program is deemed to have variance in scope if either of the following events occur:

i. The deliverables are modified.

ii. Planning Specifications at the functional or performance levels are modified.

b. Judgement needs to be exercised in determining whether the scope variance is material, the following guidelines should be applied:

i. The required result has changed by more than 20*%, i.e. a Project to build a 100,000 square foot building is changed to build a 125,000 or 75,000 square foot building;*

ii. The features or functions included in the product or service providing benefits have been removed or added. *i.e. a software solution will not be delivering a component of its promised benefits or functionality;* or

iii. A new alternative is selected. *i.e., the decision to repair a transformer instead of replacing a transformer.*

c. A project cancellation is considered to be a 100% scope reduction and may require variance approval.

d. The Planning Unit's leader (manager level or above) determines whether the scope variance is material.

e. Scope variance approvals are not driven by the change in expenditures. Project scope variances needs to be approved by the equivalent authority as the original approver. Program scope variances requires a minimum of Line of Business VP to approval *i.e. VP of Planning*.

D. Immaterial Variances

a. For changes from the approved cost, schedule, or scope that do not meet the materiality thresholds; it is the responsibility of the Planning Unit's Management to prepare sufficient documentation of the cause and required remedial action to support future regulatory filings. Dependent upon the nature of the variance, a project closing report may be sufficient for this purpose.

b. This documentation does not change the officially approved costs, scope or in-service.

c. Variance Approval Form is not required for variances that do not meet the materiality thresholds.

E. Variance Accountabilities

a. It is the responsibility of the Work Execution Unit to regularly monitor and control the Program or Project; and to forecast any variance.

b. The accountable Work Execution Unit will record the projections of cost, schedule, and scope variances into the reporting process on a monthly basis.

c. The Work Execution Unit will update the Planning Unit on a monthly basis of all actual and forecasted variances including variances not requiring Variance Approval.

d. Business Planning and Financial Support is accountable for preparing and notifying the Planning Unit and senior management of all potential variance approvals recorded into system on a monthly basis and on a quarterly basis respectively.

e. If a cost or schedule variance approval is required, the Work Execution Unit will be accountable for preparing the explanation. The Planning Unit will confirm the that the scope is the most appropriate solution with the revised expenditures and/or schedule.

f. If a scope variance is required, the Work Execution Unit will be accountable for providing support and information to assist the Planning unit in preparing the documentation.

g. The Planning Unit is accountable for ensuring the Variance Approval form is completed and submitted for approval.

h. The Planning Unit should submit material variances for approval within three months, of being informed of such a variance by the Work Execution Unit .

i. Variance Approval forms must be submitted with Original Business Case or Program documentation and previously approved variance documentation.

2.0 Definitions

Term	Definition
Consolidated Business Plan	Annual document approved by the Board of Directors setting out Hydro One's future objectives and the plans, investments, budget and strategies for achieving those objectives
Business Case	Summary document for the approval of Projects that details total cost, need for the investment, scope, expected result, other alternatives, regulatory impact and potential material risks
Development Approval	Project/Program expenditure approval limited to defining the scope and estimating the expenditures of the execution phase
Full Approval	Project/Program approval to execute the entire scope of work.
Long Lead Approval	Project/Program approval limited to order material or complete preparatory work required prior to the execution phase
Partial approvals	Approval utilized to initiate the work execution phase prior to development phase being sufficiently completed. This type of approval is typically granted only under exceptional circumstances.
Planning Unit	Unit accountable for identifying a Project or Program's need, the appropriate solution and overseeing the solution's implementation throughout delivery phase.
Program	A specific body of work where the type of work is repetitive and recurs year over year. The extent of the work executed in any particular year, may change from year to year depending on its ranking in the prioritized Programs and the overall availability of funds. Alternative approaches do not exist to achieve the objective. An example of a Program would be Pole Replacements
Project	A specific body of work that is a one-time event that occurs during a specific time period. This period may cover more than one fiscal year. Alternative approaches can be taken to achieve the objective and there is a greater level of risk. An example of a Project would be refurbishment of a Transmission Station.
Work Execution Unit	Unit accountable for delivering the Project or Program
Variance Approval form	Approval document for a material change in the approved cost, schedule, or scope of a Project or Program.

3.0 References

Expenditure Authority Register (EAR)

SP1210 Program and Project Cancellation Procedure

SP0804 Shared Corporate Services Cost Allocation and Transfer Pricing Policy

4.0 Document Management

Owner/Functional Responsibility	Director, Business Planning and Decision Support
Approver	Senior Vice President, Finance
Approval Date	December 13, 2017
Effective Date	January 1st, 2018
Last Reviewed Date	December 13, 2017
Next Review Date	December , 2018

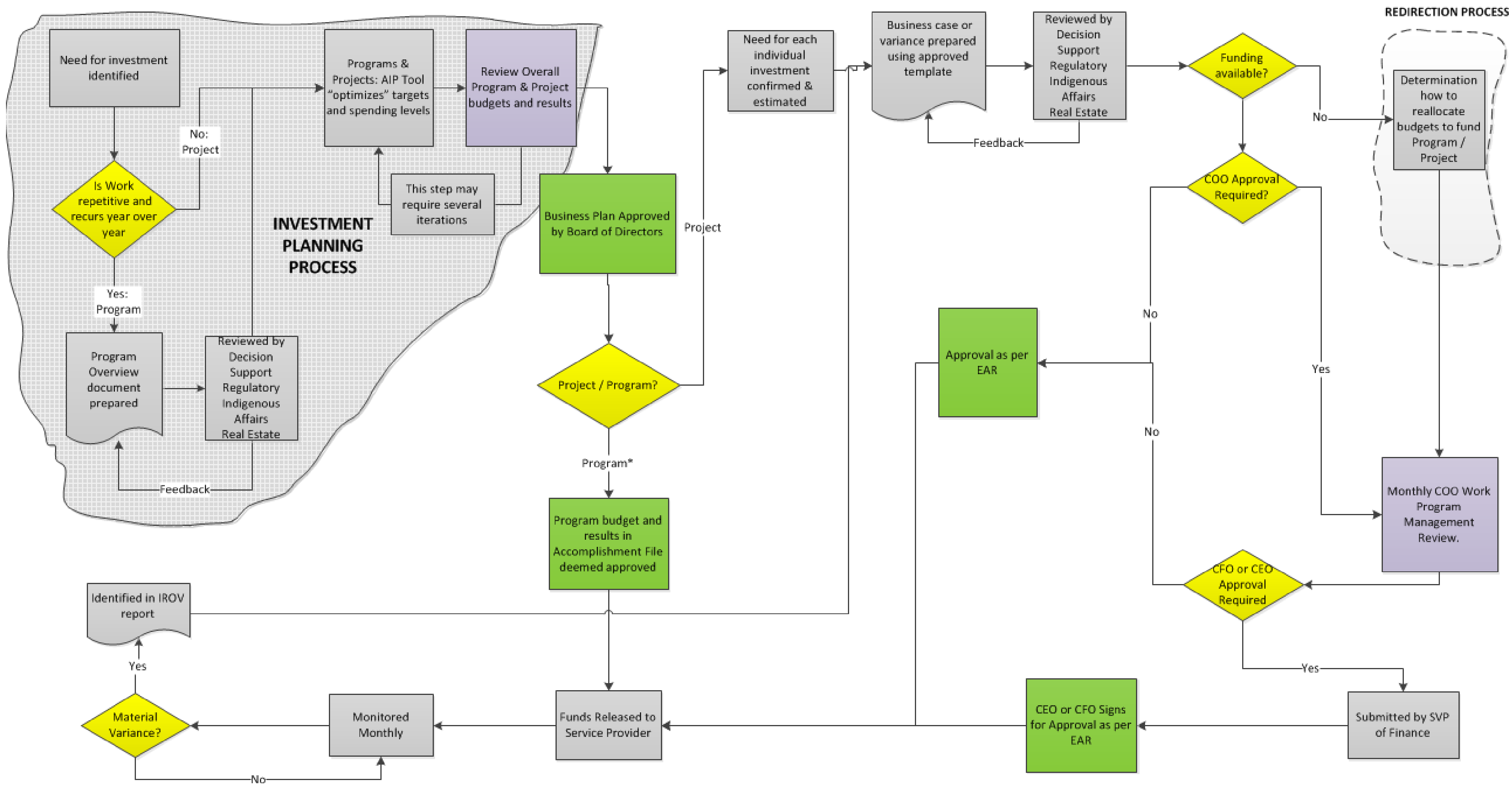
5.0 Appendices

Appendix A: Business Case Summary Template w/Guidance

Appendix B: Variance Approval Form

Appendix C: Process Flow of Project & Program Expenditure Procedure

Appendix C: Process Flow of Project & Program Expenditure Procedure



* If a Program was not identified and not included in the annual Consolidated Business Plan, the first year's approval and expenditures will require that the Project Approval process be followed.

Filed: 2018-03-29
EB-2017-0049
Exhibit JT 3.1-7
Attachment 2
Page 1 of 7

Insert Investment Name

Delete all red guidance text before submitting and change text font to black (including the names, dates etc in the header and footer). For Board of Directors BCS presented in a Board Memo, contact Decision Support for appropriate format. Be concise and avoid repetition in the BCS; if it is stated once, there is no requirement to state it again with the exception of the Overview. Also, do not use acronyms for any BCS at COO or higher level.

It is recommended that you ensure that you have the most recent copy of the BCS Template on the Decision Support website at: http://hydronet.hydroone.com/LoB/CFO/BPFS/DS/Pages/default.aspx

Presentation of dollar amounts throughout the BCS should follow the following convention:

- Investments >= $5.0M, in $M, 1 decimal
- Investments < $5.0M, in $k, no decimals

Overview of Recommended Alternative: (2 – 3 sentences)

A short summary of the requested approval (cost and scope) as well as the expected result of the project. (i.e. Requesting approval of $XM for XYZ system enhancement with an annual savings of $YM resulting in a Net Present Value of $XM.) The total expenditures being approved, both current and prior approvals, must be stated in this section.

Investment Details:

In-service: Enter I/S Date

When completing a business case submission, consider the following guidance and requirements.

The first paragraph should provide a concise background driving the need for this particular investment (i.e. what is the business problem being solved or the opportunity being taken advantage of? For example, if an asset is in poor condition, stating that it is at end of life is insufficient. Required to state why it is considered to be end of life. For example; field testing, visual inspection, poor customer reliability etc that the asset is been determined to be at end of life.)

Explain the importance of this system / program and the implications of not doing the work (e.g. How it will improve Hydro One execution of its Corporate Strategy or improving reliability statistics or customer value etc)

Detail the scope of work to be completed by this approval and how the project will be executed (e.g. build x km of a new 230kcml line from X to Y)

Please insert a picture(s)/diagram(s) if determined to be helpful in understanding the project. If a picture/diagram is included, it should have a brief description (2 or 3 word caption) below it. Note, the picture should be formatted not to dominate the page (e.g. should not be ½ the front page).

Explain why this investment (solution) is the recommended alternative and given priority over other projects (e.g. highest NPV of potential solutions, studies, field assessments, improved productivity, positive customer experience, reduces Hydro One's corporate risk profile etc), "Alt. 1 is recommended because of x,y,and z".

For a Productivity BCS or a need that has more than one feasible alternative, a statement on the expected NPV and/or IRR of the investment are required. Contact Decision Support for assistance

- Note: All productivity BCS should have a productivity spreadsheet completed for assessment and tracking purposes. The template can be located on the Decision Support website at **http://hydronet.hydroone.com/LoB/CFO/BPFS/DS/Pages/default.aspx**

- For Distribution & Transmission sustainment and development investments, it is required to complete the Investment Planning Scoring template for tracking and verification. This template can be located on the Decision Support website at: **http://hydronet.hydroone.com/LoB/CFO/BPFS/DS/Pages/default.aspx**
  For assistance for completing this template, please contact the Strategy and Integrated Planning Department.

For a Development or Long Lead BCS the Scope required is to be limited to determining overall project scope, verify site conditions, conduct investigations, produce an estimate of costs, obtain materials and/or perform work requiring a lengthy lead time such that approval in advance of the main project is required if the overall in-service date is to be met. The following information is required in the Investment Details as per SP1078:

- Expected cost of the entire project and the expected time of seeking the next approval.
- Why Development or Long Lead approval is required and why approval of the main project is not feasible at this time
- For Long Lead, identify how recovery is sufficiently assured (contractual guarantee / alternative use elsewhere in the system etc)

If Connection & Cost Recovery Agreement (CCRA) is required, include

- Approval to proceed with the project is contingent upon <Customer> signing the CCRA.. The <Title> of <Department> will execute the CCRA on behalf of HONI.

If a proposal does not qualify as a Development BCS, but is for a limited scope of expenditures associated with a Project prior to full approval, it is a Partial Approval

- Partial Approval can only be granted a position with sufficient authority as per the EAR to approve the entire Project expenditures based on the current total estimated gross expenditure of the entire Project. (e.g. $3M to initiate construction of a $20M project requires approval from a position with sufficient authority to approval $20M)
- All Partial Approval Business Cases must identify the limited scope and expenditures approved, the business reason for partial approval, the expected gross expenditures of the entire Project and the expected time of seeking the next approval.

Benefits:

Detail the expected benefits and results of the investment (e.g. improve reliability such as SAIDI results or improved productivity). Results must link to addressing the need identified in the Investment Details section.

Estimated Costs & In-service:

Include one or two sentences describing in-servicing of the asset (e.g. "No capital will be placed in-service during the development phase of the project" or "This is a multi-year project, with expenditures planned over XYZ years. However, we are able to segregate and measure discrete elements of the project to enable capital to be placed in service throughout the project duration" or "The majority of the assets will go in service at project completion".

The cost breakdown is as follows:

Category	Cost ($k or $M)
Contingency	
Interest & Overhead	
Total	

Examples of Categories are Engineering & Design, Materials, Construction, Project Management, Change Management, Commissioning, Consultants etc. Note Project Management, Engineering and Commission should be distinct line items and not combined.

Some commentary on the engineering estimate tolerances (e.g. estimate is based upon detailed (conceptual, preliminary etc) engineering) as well as background on the contingency (e.g. contingency is for construction and materials). If the AACE level is known, it needs to be disclosed. If the estimate quality is not within the standard error range, state the business reasons why the project should be approved with a lower quality estimate (e.g. approval is to allow construction to commence immediately to take advantage of an outage, or due to customer requirements etc).

For example: The estimate was completed based upon completion of detailed engineering with the contingency primarily for construction and commissioning to cover any deviation from the original design during execution.

Required Additional Information:

1. Whether the estimated project/program expenditures by year were included in the approved Business Plan. If not, a discussion on how this project/program will be funded via Redirection (e.g. will another project be cancelled or are other projects spending under planned forecast etc).
2. A statement if further ongoing sustainment expenditures are required (e.g. increase in licensing fees etc)

If the project requires customer *Capital Contribution* (detailed on Recoverable line), describe why recovery is being applied (e.g. If Hydro One is attempting to recover the expenditure from a third party capital contribution as per 6.5 of the Transmission System Code),

Other Alternatives Considered

If there is more than one feasible alternative, an NPV analysis is required if decision is based on economic factors. Even if primarly reason is not economic, NPV analysis may still be required. Contact Decision Support for advice and to perform the analysis.

Status Quo or Do nothing Alternative
This should only be used for the do nothing or status quo alternative. A fulsome description of the implications of not doing this work and the reasons this is not a viable alternative.

(Insert Name of each Other Alternative)
List each potential alternative that was not selected. Briefly describe the scope of work to be done under each alternative, potential costs and benefits as well as feasibility A brief description of why this alternative was not selected when compared to the recommended alternative needs to be provided (e.g. this alternative was not feasible from a technical perspective as it did not address the reliability concerns, or this alternative would result in expenditures 50% greater than recommended alternative and has a lower NPV etc)

Regulatory Considerations

The section should contain a description if the investment was included in the most recent rate filing, OEB approved project costs and in-service date. If there are any regulatory risks or concerns (e.g. risks to recovery of costs, compliance with codes, OEB approval required) associated with the investment, they should also be included and a discussion on how Hydro One will avoid these risks being realized.

Risks and Mitigation

List only risks considered to be at medium risk or greater. These can include risks effecting the execution of the project/program and/or potential impact to corporate risks at a project level. All risks discussed in the section require a discussion on the mitigation plan.

All proposals requiring COO, CFO or CEO approval require a risk assessment. If a Risk Workshop has not been completed, a risk questionnaire must be completed. To obtain a questionnaire, please contact Corporate Risk (CorporateRisk@HydroOne.com) for assistance.

Examples of Risks are:
CHANGE MANAGEMENT – How dependent upon successful change management is each major component of benefits?
FIRST NATIONS – Are First Nation consultations required?
OUTAGES – Is there a significant potential that the required outage be cancelled?
REAL ESTATE – Is there a significant potential that Hydro One may have to expropriate property?
APPROVALS & AGREEMENTS – e.g. Is an Environmental Approval required for this project?
RESOURCING – Are sufficient field resources available?
RELIABILITY – Are there potential impacts or risks to the system from the recommended alternative

SAFETY – Are there aspects of this project that may have greater safety issues than usual?
CUSTOMER – Is there aspects to the project that may adversely impact customers?

Any project risks that does not appear in the list above that applies to a particular project should be added. If no risks are considered to be medium risk or greater; a simple statement that no major risks are considered significant is required.

This Approval ($):	**Previous Approval ($):**	**Total Approval ($):**
Signature Block:		
Approved by:	**Title:**	**Date:**
Approved by: (Insert Required Financial Reviewer)	**Title:**	**Date:**
Approved by: (Insert final approver with sufficient authority as per EAR)	**Title:**	**Date:**

Required Signatures for SVP/VP or lower approvals

Consistent with the new Expenditure Authority Register the first individual approving must be the Direct Report of the final approver within the Operational Group. The only exception is when the final approver is a Manager in Planning, then no signed submission from the planner is required. Approval by a Finance representative is required for all investments as per the EAR. The final approver, at the bottom of the signature block, must have sufficient authority to approve the investment as per the Expenditure Authority Register. If other stakeholder approval is required, as the investment is to meet the requirements of another line of business (e.g. CIO approval for SAP system investment to improve customer service would require approval from a management representative of customer service), insert new rows into table to facilitate signatures.

Examples: A Manager in Planning approving a $1.5M investment would only require the Manager of the Decision Support and the Manager as the final approver (only two signatures required). A SVP investment of $6M would require the Director reporting to that SVP approving the investment first, followed by the Director of Business Planning, with final approval by the SVP (three signatures required).

Required Signatures for COO or greater level approvals

Consistent with the Expenditure Authority Register the first individual approving must be the SVP/VP followed by approval by a Finance representative as per the EAR. This is to be followed by COO, CFO and/or CEO dependent upon the approval authority required. The final approver, at the bottom of the signature block, must have sufficient authority as per the Expenditure Authority Register. If other stakeholder approval is required (e.g. CIO approval for SAP system investment), insert new rows into table to facilitate signatures.

Appendix: Required information for SAP data input

This appendix must be on a separate page.

Yearly Expenditures

	2016($k or $M)	2017($k or $M)	2018($k or $M)	Total ($k or $M)
Capital* and MFA				
OM&A and Removals				
Gross Investment Cost*				
Recoverable				
Net Investment Cost				

*Includes capitalized interest and overhead at current rates

Note: Recoverable is usually a capital contribution(s) from external customer(s) as required under the Transmission System Code or the Distribution System Code. Hydro One distribution capital contributions to Transmission should not be included in this line.

Yearly expenditures should include both previous and current approval values. E.g. if estimate and design was approved in a development BCS during 2015, please include those prior approvals

Rate base additions

	2016($k or $M)	2017($k or $M)	2018($k or $M)	Total ($k or $M)
In-Service $ Additions from estimate				
In-Service $ Additions included in Tx/Dx Rate Case (include EB #)				
Variance				
Redirection Required?	(Yes/No)	(Yes/No)	(Yes/No)	

The In-service $ additions to rate base is the forecast of in-service adds to account for potential partial in-servicing. Does not include OM&A. If asset is disclosed in Distribution and Transmission rate case, may require further rows.

In-service Date:	Enter I/S Date
Business Case Summary #:	Enter BCS #
Appropriation Request #:	Enter AR #
Subject ID #	Insert Subject ID #
Investment Driver:	Insert relevant Investment Driver #

Investment Summary Document	Investment Summary Document Name and Number, as included to support the relevant Regulatory Rate Filings to the OEB
Redirection Required?	Yes / No
Productivity Savings	No / If Yes, embed or link to the document detailing productivity impacts. Note, contact Decision Support if you require assistance on the required level of documentation
Estimate	Embed a copy or link to the PDR or estimate here
Other Supporting documents	Insert Investment Planning Scoring template as well as other required documents if required. Note: All proposals requiring COO, CFO or CEO approval require completion of risk assessment questionnaire if a Risk Workshop has not been completed and included in the PDR. To obtain a questionnaire, please contact Corporate Risk (CorporateRisk@HydroOne.com) for assistance.
Director	Insert Business Case Originator Director name
Planner	Insert Business Case Originator Planner name

Scientific Research & Experimental Development Tax Credits (SR&ED): ***_CONFIRM WITH TAX IF REQUIRED***

- Do you anticipate that an initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? Select from list

A technological advancement is new technical knowledge that is not publicly available, goes beyond routine practice, solves a scientific or technological barrier, and is acquired through experimentation. Extending existing programming environments, or overcoming their limitations, may give rise to a technological advancement. Smart Grid Investments may qualify.

- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? Select from list

A Technological Uncertainty arises when the solution, or the method of achieving it, is not readily apparent to appropriately skilled and experienced persons, i.e., all known approaches are inadequate, resolution increases company knowledge, it can arise from functional, cost or time targets, methodologies and system integration. This could also arise if the proposed solution has not been implemented in an environment or scale similar to Hydro One and there is technical uncertainty as to whether it can be modified to work in our environment. Technological uncertainty could also exist due to the unavailability of third-party proprietary information.
IF THE ANSWER IS "YES" TO EITHER OF THE ABOVE QUESTIONS OR YOU ARE UNSURE, PLEASE CALL THE TAX DEPARTMENT @ 416-345-6778

PROGRAM/PROJECT VARIANCE APPROVAL FORM

Check All Applicable Boxes to Show Variances Requiring OAR Approval

☐ **Cost Variance** ☐ **Schedule (Business Impactive)** ☐ **Scope Change (Significant)**

AR	Driver	Asset Owner *(LOB)*	Service Provider *(LOB)*	Date

Investment Title			
		Currently Approved Cost	$0 K
		Total Cost Approved plus Requested	$0 K
Currently approved in-service date	Proposed new in-service date	% of Total Costs Requested vs Approved Cost	

Background Situation:

Brief description and purpose of the original program / project. In addition, the following items are required to be provided:
1. Initial Approval date and scope
2. Initial quality of estimate (e.g. +/- 20%)
3. Total Spend to date
4. Amounts in-serviced (if any)
5. Major events subsequent to approval (e.g. previous variance approvals etc).

Note: all this information should be in a single paragraph of 4 - 5 sentences.

Variance Explanation: *(Discussion of significant cost, schedule, and scope changes, and an explanation of root causes.)*

Guidance:

A brief description of a variance including an explanation of root causes and impacts on Hydro One. Questions to ask: a) does it increase risks exposure?; b) was the original investment approved in a previous rate case and is already in ratebase which will cause a Regulatory issue at future hearings?; c) are benefits not expected to be realized (e.g. reliablility improvement not expected to be realized in time for OEB reporting?); etc.

An itemized listing of the individual components of each type of variances should not be included in this section, but on the "IROV Form" (page 2) under Item/Description. However, cost/schedule/scope variances should be identified and discussed seperately. Schedule variance should be identified as material or not with the ISA $'s provided.

Should be logical as to why costs, schedule and/or the scope changed.

Lessons Learned:

Planned Action:

Provide remedial actions that will be taken to implement the improvements identified as required in the Lessons Learned and explain how these improvements will be executed. In the boxes below, state which Line of Business will be accountable for executing the required remedial actions and the proposed completion date

Accountable LOB for Planned Action		Proposed Completion Date for Planned Action	Note: for Planned action

Approvals

Approved by:	Signature	Date
Submitted to Direct Report of Final Approver		
Approved by	Signature	Date
Work Execution Management Signature		
Approved by	Signature	Date
Finance Approval as per EAR		
Approved by	Signature	Date
Final Approval by Planning Unit as per EAR		

IROV Author	
Date Prepared	
Date Submitted	

PROGRAM/PROJECT VARIANCE APPROVAL FORM

AR	IROV Claim #	Driver	Asset Owner (LOB)	Service Provider *(LOB)*	Date *(mm/dd/yy)*

Investment Title		
	5. Currently Approved Cost *(Line 2)*	$0 K
	6. Total Cost Approved Plus Requested *(line 4)*	$0 K

Project Manager	Planner	% of Total Costs Requested vs Approved Cost	

			Original approved in-service date *(as per line 1)*
1. Original approved cost	1.1 OM&A	$0 K	
	1.2 CAPITAL	$0 K	
	1.3 REMOVALS	$0 K	
	TOTAL	**$0 K**	

			Current approved in-service date *(as per line 2)*
2. Total $ currently approved *(Original plus previous IROVs awards)*	2.1 OM&A	$0 K	
	2.2 CAPITAL	$0 K	
	2.3 REMOVALS	$0 K	
	TOTAL	**$0 K**	

		Total (A + B)	(A) Cost of Scope Variance	(B) Cost of "In-Scope" Project Variances
3. Revision now requested	3.1 OM&A	$0 K	$0 K	$0 K
	3.2 CAPITAL	$0 K	$0 K	$0 K
	3.3 REMOVALS	$0 K	$0 K	$0 K
	TOTAL	**$0 K**	**$0 K**	**$0 K**

			Proposed new in-service date *(as per line 3)*
4. Total Cost including OH & AFUDC *(Line 2 plus line 3)*	4.1 OM&A	$0 K	
	4.2 CAPITAL	$0 K	
	4.3 REMOVALS	$0 K	
	TOTAL	**$0 K**	

Summary of Variance:

Provide a description of the main drivers impacting expenditures. Use the Item / Description lines below to itemize significant expenditure increases or decreases. Note for Programs, only the current fiscal year can be varied.

#	Item / Description	Cost of Scope Variance $K	In-Scope Variance $K
1			
2			
3			
4			
5			
6			
7			
8			
9			
10			
	Total Variance Costs	**$0 K**	**$0 K**

Program / Project Cashflow Detail by Year

Description		2014	2015	2016	2017	2018	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	CAPITAL	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	REMOVALS	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	TOTAL	**$0 K**	**$0 K**	**$0 K**	**$0 K**	**$0 K**	**$0 K**

UNDERTAKING – JT 3.1-8

Reference

I-24-AMPCO-21 (b)

Preamble: HONI indicates there were five Variance Proposals in recent years with EOY cost impacts.

Undertaking

Please provide the original Business Case, any subsequent Business Cases and the Variance Proposals for each of the five projects.

Response

Please see the following attachments:

1. Business Case: Brant TS M14 St George Loop
2. Variance Approval: Brant TS M14 St George Loop
3. Business Case: Sturgeon Falls DS F2 Generator Connection
4. Variance Approval: Sturgeon Falls DS F2 Generator Connection
5. Business Case: Striker HVDS F2 Generator Connection
6. Variance Approval: Striker HVDS F2 Generator Connection
7. Business Case: Warren HVDS F2 Generator Connection
8. Variance Approval: Warren HVDS F2 Generator Connection
9. Estimating Business Case: Brown Hill TS M4 Generator Connection
10. Business Case: Brown Hill TS M4 Generator Connection
11. Variance Approval: Brown Hill TS M4Generator Connection

Witness: JESUS Bruno

Investment Driver: N.D.C.2.02 Date: January 03,2014

AR Number: 23131 Title: Brant TS M14 St George Loop Feed

Hydro One Networks - Business Case Summary - 50003532

Brant TS M14 St George Loop Feed

Investment Driver: **In-Service date:** December 13,2015

N.D.C.2.02 - System Capability Reinforcement (2015-$87.39M)

Investments in System Capability Reinforcement provide for new or modified distribution system facilities to accommodate (1) increases in customer load; (2) improvements in system reliability; (3) improved operational efficiency and asset life cycle planning; and (4) contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This Approval: $400K **Previous Approval:** $0 **Project Total:** $400K

Need:

A loop feed supply to the village of St George is recommended to assist with power restoration effort and improve supply reliability.

Not doing the work will result in the longer duration of power outages and will generate increased complaints from both HONI and LDC customers due to the poor reliability.

Investment Summary:

St George is a fast growing community of 3000 people radially supplied by the Brant TS M14 feeder. The village is expected to attract 2400 new customers or 6000 people by year 2031. Two existing industrial parks are also proposed for expansion.

In past years, St George has experieced several power interruptions of 3 to 6 hours in duration. Creating a loop feed supply to St George will provide a backup line which will help restore power and reduce the outage duration.

Results:

Provide a backup supply to St George Improve power restoration to St George

Costs:

	2015 K	Total K
Capital* and MFA	400	400
OM&A and Removals	0	0
Gross Investment Cost*	400	400
Recoverable	0	0
Net Investment Cost	400	400

Investment Driver: N.D.C.2.02 Date: January 03,2014

AR Number: 23131 Title: Brant TS M14 St George Loop Feed

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

Do nothing presents serious risks on power restoration time resulting in adverse reliability indexes and damage to the corporate image

ALTERNATIVES CONSIDERED FURTHER

Alternative One

Alternative one is considered further since it provides the solution to the need for improved reliability to the village of St George and surrounding areas.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

Alternative one involving an extension of 27.6kV for 2km from Hwy 24 along German School Road to make a loop feed around St George.

Project Risk and Mitigation:

Cost:

The project cost is based upon a Class C estimate from Lines, which is accurate in the range of +/- 50%. Sufficient work has been done on the Class C section to have good confidence in the cost.

Business Planning:

This investment is included in the 2014-2019 Business Plan under AIP000185 with sufficient funding.

Regulatory Considerations:

This investment is included in the 2015-2019 Distribution Rate Filling (EB-2013-0416, Exhibit D2-2-3, Reference D-06) with a 2015 gross cost of $1.7M. The current estimate for the 2015 work is $0.4M since the amount of work required is less than initially anticipated. There is no significant regulatory issues anticipated other than standard need and prudence justification.

Funds Included in Business Plan: Y	**Director:** Paul Brown	**Planner:** Charlie Lee
This Approval($K): 400	**Previous Approval($K):** 0	**Current Est. of Total Cost($K):** 400
Signature Block:		
Submitted by: Charlie Lee	**Title:** Planner	**Date:** MAR 21/14
Reviewed by:	**Title:**	**Date:**
Recommended by:	**Title:**	**Date:**
Approved by: Lyla Garzouzi (for)	**Title:** Manager	**Date:** March 21/14

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

PROGRAM/PROJECT VARIANCE APPROVAL FORM

Check All Applicable Boxes to Show Variances Requiring OAR Approval

☑ Cost Change ☑ Schedule (Business Impactive) ☐ Scope Change (Significant)

AR	Driver	Asset Owner *(LOB)*	Service Provider *(LOB)*	Date
23131	N.D.C.2.02	Dx Asset Management	Quality Assurance & Operations Support	20-Apr-17

Investment Title		Original Approved Cost	$400 K
Brant TS M14 St George Loop Feed		Total Cost Approved plus Requested	$1,110 K
Original approved in-service date	Proposed new in-service date	% of Total Costs Requested vs Approved Cost	278%
December 13, 2015	December 1, 2018		

Background Situation:

This project covers the construction of approximately 2km of 27.6kV feeder on the Brant TS M14 to create a loop to St. George village. St. George Village, located in Dundas OPS, is a fast growing community of 3000 people radially supplied by the Brant TS M14 feeder. The village is expected to attract 2400 new customers or 6000 people by year 2031. Two existing industrial parks are also proposed to expand. In the past, the St. George community has experienced several power interruptions of 3 to 6 hours in duration. Creating a loop feed of 27.6 kV supply to St. George village will provide a backup line which will help improve reliability and reduce power outage durations.

The original investment of $400k was approved in March 2014 based on a Class C estimate provided by Provincial Lines. Variance from estimates originally developed are substantial from a cost and timelines perspective. As of April 2017, approximately 21% of the approved funding has been spent.

Variance Explanation: *(Discussion of significant cost, schedule, and scope changes, and an explanation of root causes.)*

Cost Variance

The detailed design and class A estimate were completed in January 2016 by Provincial Lines and the total cost of the project increased by $710k totaling $1.11M. The incremental costs include $156k materials and labour, $227k Transport and Work Equipment (TWE), $81k Contractor/Sundry/Easement, $117k removals, $86k contingencies, and $43k in overhead and interest.

This investment is not included in the 2017-2022 Business Plan. The additional $710k required in 2018 and deferral of ISA will be updated in the 2018-2023 Business Plan to be developed later this year.

Schedule Variance

The project was placed on hold after the forecasted cost overrun was identified in 2016. After reviewing the alternatives, Distribution Asset Management recommends to proceed with the work and defer the project in-service date to December 1, 2018 based on project priorities.

Lessons Learned:

1) Releasing a project of this magnitude (i.e. >$300k) for construction based on a Class C estimate is not appropriate, as it does not adequately consider challenges which would be identified during a detailed design estimate.
2) The process for Provincial Lines to review estimates, identify cost overruns in excess of IROV criteria, and only proceed with the work once appropriate approvals were in place, did not exist at the time of this release.

Planned Action:

1) A new DX lines work release process has been implemented since this investment was released and requires all Dx lines projects >$300k to be released for construction based on a Class A estimate.
2) A process has now been established with Provincial Lines to identify, review and approve cost overruns in excess of IROV criteria prior to the execution of work.
3) Dx Asset Management is receiving regular forecast and LTD spend information from Provincial Lines to identify the need for an IROV. Furthermore a regular IROV tracking report is now prepared by Decision Support, and reviewed by Dx Asset Management.

Accountable LOB Implementing Planned Action	Provincial Lines and Asset Management	Proposed Planned Action Completion Date	Completed

Approvals

Approved by:	Signature	Date
Lyla Garzouzi, Director, Dx Asset Management	[signature]	April 20, 2017
Approved by:	**Signature**	**Date**
Kathy Moulton, Director, Qual Assur & OP Support	[signature]	April 24, 2017
Approved by:	**Signature**	**Date**
Wade Frost, Manager, Decision Support	[signature]	April 20/17
Approved by *(As per EAR/OAR)*:	**Signature**	**Date**
Darlene Bradley, VP, Planning	[signature]	April 20/17

IROV Author	Helen Guo
Date Prepared	20-Apr-17

PROGRAM/PROJECT VARIANCE APPROVAL FORM

AR	IROV Claim #	Driver	Asset Owner (LOB)	Service Provider *(LOB)*	Date *(mm/dd/yy)*
23131	41001557	N.D.C.2.02	Dx Asset Management	Quality Assurance & Operations Support	April 20, 2017

Investment Title		
Brant TS M14 St George Loop Feed	5. Original Approved Cost *(Line 1)*	$400 K
	6. Total Cost Approved Plus Requested *(line 4)*	$1,110 K

Project Manager	Planner	% of Total Costs Requested vs Approved Cost
Jeff Battaglia	Helen Guo	278%

1. Original approved cost	1.1 OM&A	$0 K	**Original approved in-service date** *(as per line 1)*
	1.2 CAPITAL	$400 K	December 13th, 2015
	1.3 REMOVALS	$0 K	
	TOTAL	$400 K	
2. Total $ currently approved *(Original plus previous IROVs awards)*	2.1 OM&A	$0 K	**Current approved in-service date** *(as per line 2)*
	2.2 CAPITAL	$400 K	December 13th, 2015
	2.3 REMOVALS	$0 K	
	TOTAL	$400 K	

		Total (A + B)	(A) Cost of Scope Increases	(B) Cost of "In-Scope" Project Variances
3. Revision now requested	3.1 OM&A	$0 K	$0 K	$0 K
	3.2 CAPITAL	$593 K	$0 K	$593 K
	3.3 REMOVALS	$117 K	$0 K	$117 K
	TOTAL	$710 K	$0 K	$710 K

4. Total Cost including OH & AFUDC *(Line 2 plus line 3)*	4.1 OM&A	$0 K	**Proposed new in-service date** *(as per line 3)*
	4.2 CAPITAL	$993 K	December 1, 2018
	4.3 REMOVALS	$117 K	
	TOTAL	$1,110 K	

Summary of Variance:

The original approved investment of $400k was based on a Class C estimate provided by Provincial Lines in 2014. The detailed design and Class A estimate were completed in January 2016 by Provincial Lines and the total cost of the project increased by $710k. The incremental costs include $156k materials and labour, $227k Transport and Work Equipment (TWE), $81k Contractor/Sundry/Easement, $117k removals, $86k contingencies, and $43k in overhead and interest.

The in-service date was deferred until December 2018 based on project priorities.

#	Item / Description	Cost of Scope increase $K	In-Scope Variance $K
1	Materials, Labour		$156 K
2	Overhead and Interest		$43 K
3	TWE		$227 K
4	Contractor/Sundry/Easement		$81 K
5	Removals		$117 K
6	Contingencies		$86 K
7			
8			
10			
	Total Variance Costs	$0 K	$710 K

Program / Project Cashflow Detail by Year

Description		2014	2015	2016	2017	2018	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	CAPITAL	$11 K	$27 K	$47 K	$0 K	$908 K	$993 K
	REMOVALS	$0 K	$0 K	$0 K	$0 K	$117 K	$117 K
	TOTAL	$11 K	$27 K	$47 K	$0 K	$1,025 K	$1,110 K

hydro one

Investment Driver: N.D.C.2.03 Date: June 10,2014

AR Number: 23294,23315 Title: Sturgeon Falls DS - F2 - ID 24720 - AGRIS Solar Garden 12

Hydro One Networks - Business Case Summary - 50003676

Sturgeon Falls DS - F2 - ID 24720 - AGRIS Solar Garden 12

Investment Driver: **In-Service date:** October 01,2014

N.D.C.2.03 - Distribution Generation Connections (2014-$48.7M) Investments in the Distribution Generation Connection Driver modify/upgrade the Distribution system including distribution line transfers requested by the Customers and supply stations to connect new generation facilities to Hydro One's Distribution System. Capital contributions from the Customers are based on Hydro One's connection policy and are in accordance with the DSC, under which the Customer is responsible for a portion of the cost to connect to Hydro One's Distribution System, and other portions are paid for by Hydro One Distribution.

N.T.C.2.19 - P&C Enablement for Generation Connections (2014-$24M) This investment driver funds the development of standards, enhancements, modifications, and replacement of protection and control equipment to allow mass deployment of Distributed Generators to HONI's system at all voltage levels.

This Approval: $958K **Previous Approval:** $0 **Project Total:** $958K

Need:

This investment is required to connect AGRIS Solar Garden 12 to the Hydro One Networks Inc. (HONI) system. Not proceeding with this investment would present customer, reputation and regulatory risks through the violation of our License requirements. AGRIS Solar Co- operative Inc. has requested that HONI proceed with the connection work that is required to connect AGRIS Solar Garden 12 to the HONI system.

Investment Summary:

AGRIS Solar Co-operative Inc. is planning to connect a 480 kW solar generation project to Sturgeon Falls DS 12.5 kV F2 feeder downstream of Crystal Falls TS 44 kV M2. The 480 kW solar generation facility is located at Springer/West Nipissing/Nipissing, E ¼ Lot 6, Concession B , Ontario. The distribution work covered by this BCS includes Transfer Trip (TT) from the F2 feeder recloser at Sturgeon Falls DS and M2 feeder protection, and new F2 line voltage regulator set.

Hydro One has carried out the connection studies including a Connection Impact Assessment (CIA) study and a class C type cost estimate. IESO assessment (SIA) is not required. The CIA indicates that there are no significant impacts to HONI customers. Project Development has determined an estimate of cost. The in-service date will be negotiated with the Customer at the Project Management kick-off meeting. Approval is requested to proceed with the CCA and the project. The HONI connection work will start once AGRIS Solar Co-operative Inc. has signed the CCA and paid all the required deposits. Costs of common elements (DS/line recloser) will be shared by ID 24660 in BCS 50003677. Transmission costs will be incurred as a result of these connections. Separate ARs have been created for the Transmission (AR # 23315) and Distribution (AR # 23294) portion of the work.

Results:

This investment will enable the connection of the 480 kW AGRIS Solar Garden 12.

Costs:

	2014 K	Total K
Capital* and MFA	958	958
OM&A and Removals	0	0
Gross Investment Cost*	958	958
Recoverable	715	715
Net Investment Cost	243	243

Costs include AFUDC and overheads at current rates

Investment Driver: N.D.C.2.03 Date: June 10,2014

AR Number: 23294,23315 Title: Sturgeon Falls DS - F2 - ID 24720 - AGRIS Solar Garden 12

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

Do Nothing - The do nothing alternative is not a viable option as the generation facility would not be connected to Hydro One's system, would not satisfy our license requirements nor meet our stakeholder expectations to connect generation facilities when possible.

ALTERNATIVES CONSIDERED FURTHER

Alternative One

Connect new AGRIS Solar Garden 12 to HONI system as per license requirements while maintaining customer connection reliability and system security.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

Alternative 1 is recommended as the generation facility would be connected to Hydro One's system, would satisfy our license requirements and meet our stakeholder expectations to connect generation facilities when possible.

Alternatives Compared

	Project Level Risk		
Business Value	**Current Risk**	**Alt1**	**Comparison**
Reliability	N/A	N/A	Not influential in the investment decision.
Customer	HIGH	LOW	Alternative 1 mitigates the risk of customer dissatisfaction with Hydro One.
Competitiveness	N/A	N/A	Not influential in the investment decision.
Safety and environment	N/A	N/A	Not influential in the investment decision.
Regulatory / Legal	HIGH	LOW	Alternative 1 mitigates the risks of not complying with our license requirements.
Reputation	HIGH	LOW	Not meeting our license requirements would result in deterioration of public image of HONI
Initial Cost ($K)		958	
Financial: PV Cost / NPV ($K)			NPV was not calculated as there is only one viable alternative and this investment is not primarily driven by financial factors.

Project Risk and Mitigation:

Cost:

The project cost is based upon a Class C estimate from Project Development, which is accurate in the range of +/- 50%, and includes a contingency for in-scope variances of $64K.

The estimated total cost for the HONI connection work is $958K

This includes:

Connection Assets - $68K

Expansions - $151K

Renewable Enabling Improvements (REI) - $224K

Upstream Work - $515K

Costs of common elements (DS and line recloser upgrade) were estimated to be $136K and were approved in BCS 50003677 (ID 24660) and therefore not included in the project total for approval in this BCS. AGRIS Solar Garden 12 will contribute to common elements as per the Distribution System Code and the terms of the CCA.

Investment Driver: N.D.C.2.03 | Date: June 10,2014

AR Number: 23294,23315 | Title: Sturgeon Falls DS - F2 - ID 24720 - AGRIS Solar Garden 12

Cost Contribution:

The terms and conditions in the CCA mitigate the risks associated with timing, cost level, scope and recovery of the actual cost of the HONI connection work per the Distribution System Code.

It is expected that AGRIS Solar Co-operative Inc. will contribute $715333 calculated in accordance with the Distribution System Code. The remaining expenditures, $242,667 will be borne by Hydro One.

The proponent's contribution incorporates a reduction of $18,667. This reduction is the net of the impact from the economic evaluation and the Distributor Funded Expansion of $43,200.

Business Planning:

Dx costs of $443K are included in the (2014-2019) Business Plan under DC 203 as AIP # 000199. Re-direction is not required.

Tx costs of $515K are included in the (2014-2019) Business Plan under AIP # 000931. Re-direction is not required.

Others:

Timing & Scope of Work:

The terms and conditions in the CCA mitigate the risks associated with timing and scope of the HONI connection work.

Customer Withdrawal:

The terms of the CCA mitigate the financial risks should AGRIS Solar Garden 12 withdraw once the project has started.

Execution:

Approvals	N/A
S.92	N/A
EA	N/A
Outages	Med
Resourcing	High
First Nations	N/A
Real Estate	N/A
Agreements	Low
Technology	Low

Outage needs continue to be a risk that could delay the in-service date of the project. Releasing the work well ahead of the proposed October 1, 2014 in-service date should help with outage and resource planning.

Resourcing continues to be a significant concern, but bundling the work with other connections on same station and feeder lessens internal resourcing needs and further enables contracting of some engineering elements.

Regulatory Considerations:

The costs for this generation facility connection are allocated as per the Distribution System Code and any portions recoverable will be recovered consistent with HONI Policy.

No significant regulatory issues anticipated other than standard need and prudence justification.

Investment Driver: N.D.C.2.03

Date: June 10,2014

AR Number: 23294,23315

Title: Sturgeon Falls DS - F2 - ID 24720 - AGRIS Solar Garden 12

Funds Included in Business Plan: Y	**Director:** Paul Brown	**Planner:** Gert Alikaj
This Approval($K): 958	**Previous Approval($K):** 0	**Current Est. of Total Cost($K):** 958

Signature Block:		
Submitted by: Gert Alikaj	**Title:** Planner	**Date:** June 12 2014
Reviewed by:	**Title:**	**Date:**
Recommended by:	**Title:**	**Date:**
Approved by: Peter Faltaous	**Title:** Manager	**Date:** June 13 2014

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

INTERIM REVIEW OF VARIANCE (IROV)

40002441

Check All Applicable Boxes to Show Variances Requiring OAR Approval

☑ Cost Increase ☑ Schedule (Business Impactive) ☐ Scope Change (Significant)

AR	Driver	BCS Originator (LOB)	Service Provider (LOB)	Date
23315 23294	N.D.C.2.03 N.T.C.2.19	Asset Management	Engineering and Construction	25-Nov-15

Investment Title		
Sturgeon Falls DS - F2 - ID 24720 - AGRIS Solar Garden 12	Original Approved Cost (as per BCS)	$958 K
	Total Cost Approved plus Requested	$2,299 K

Original approved in-service date	Proposed new in-service date	Current Cost ratio	240%
October 1, 2014	January 15, 2016		

Background Situation:

The BCS was approved with total funding of $958K, including a customer contribution of 715k for the connection of DG project 24,720 (Agris Solar Garden 12) in June, 2014. The cost of Renewable Enablement Improvement work on this project will enable the connection of four other projects (ID 24830, 24810, 24660 and 24670). The release was based on a Class 'C' estimate with no preliminary engineering or site visits. Once a site visit was completed with the project team, it was determined that significant extra work would be required to support the necessary outage plan. The project is in the Construction phase with an in-service date of January 15, 2016 due to customer deferral.

Variance Explanation: *(Discussion of significant cost, schedule, and scope changes, and an explanation of root causes.)*

The Customer funded portion is expected to decrease from $715K to $478K, primarily due to the removal of station work that the Customer was responsible to pay for. The Hydro One funded portion of the work is expected to increase from $243k to $1,821k, as a result of the increased cost of the REI work, which is non-recoverable from the Customer (section 3.3.2 of the DSC). The root casues for the total cost variance are as follows:

1. Cost increase to accommodate outage requirements

Upon review of the outage plan, it was determined that a full station outage would be required to complete the necessary recloser upgrade, and hence, the need to install new facilities to support connection of an MUS. This solution provides additional flexibility for future feeder and station upgrades.

2. Reduction to upstream work at Crystal Falls TS due to pre existing equipment

The Class 'C' estimate did not reflect site conditions at Crystal Falls TS as there was no site visit or detailed estimate prepared. Due to a previous DG connection, modernized equipment suitable for the connection of a DG was already in place. Therefore, the required upgrades at the station were significantly reduced.

Lessons Learned:

Hydro One is regulated to provide the Customer with a completed CIA within 60 days (DSC 6.2.12-13,16). In addition, Hydro One provides an estimate at the same time to allow the Customer to make an informed decision about their project. As a result of the compressed timeline, only 5 days are allocated to produce the estimate, which is of Class "C" accuracy. In most cases to-date, these estimates have been of sufficient quality.

> Distribution Asset Management and Project Delivery to undertake review of the DG Connection Process in the following areas:
- Class C estimate variance control process for cost, scope, and schedule.
- Required estimate detail for projects with atypical scope.
- Estimate quality and timing for business case approval.

Approvals

	Signature	Date
Submitted by:		
Chris Cooper Director, Project Delivery	Chris Cooper	Dec 2, 2015
Recommended by:		
Brad Bowness VP, Construction Services	B. Bowness	Dec 2/2015
Reviewed by:		
Mike Penstone VP, Planning	M. Penstone.	Dec 2/2015
Financial Review: *(If President Approval Required)*		
Approved by *(As per EAR/OAR)*:		
Sandy Struthers COO and EVP Strategic Planning		Dec 2/2015

INTERIM REVIEW OF VARIANCE (IROV)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date *(mm/dd/yy)*
23315 23294	N.D.C.2.03 N.T.C.2.19	Asset Management	Engineering and Construction	November 25, 2015

Investment Title	
Sturgeon Falls DS - F2 - ID 24720 - AGRIS Solar Garden 12	
	5. Original Approved Cost *(Line 1)*	$958 K
	6. Total Cost Approved Plus Requested *(line 4)*	$2,299 K

Project Manager	Planner	Current Cost ratio *(Box 6/Box 5)*	240%
Sara Fatima	Gert Alikaj		

1. Original approved cost *(per BCS)*	1.1 OM&A	$0 K	Original approved in-service date *(as per line 1)*	
	1.2 CAPITAL	$958 K	October 1, 2014	
	1.3 REMOVALS	$0 K		
	TOTAL	$958 K		
2. Total $ currently approved *(Original plus previous IROVs awards)*	2.1 OM&A	$0 K	Current approved in-service date *(as per line 2)*	
	2.2 CAPITAL	$958 K	October 1, 2014	
	2.3 REMOVALS	$0 K		
	TOTAL	$958 K		
3. Revision now requested		Total (A + B)	(A) Cost of Scope Increases	(B) Cost of "In-Scope" Project Variances
	3.1 OM&A	$0 K	$0 K	$0 K
	3.2 CAPITAL	$1,341 K	$0 K	$1,341 K
	3.3 REMOVALS	$0 K	$0 K	$0 K
	TOTAL	$1,341 K	$0 K	$1,341 K
4. Total Cost including OH & AFUDC *(Line 2 plus line 3)*	4.1 OM&A	$0 K	Proposed new in-service date *(as per line 3)*	
	4.2 CAPITAL	$2,299 K	January 15, 2016	
	4.3 REMOVALS	$0 K		
	TOTAL	$2,299 K		

Summary of Variance:

1/2. Additional work required to support the necessary outage plan that was not considered in original estimate.
3/4. Reduction of work required at Crystal Falls TS due to pre existing equipment that was installed under another project.

#	Item / Description	Cost of Scope increase $K	In-Scope Variance $K
1	REI: 3 MUS LV Structures to be installed including trenching, cabling and egress poles at Sturgeon Falls DS to enable outage required to upgrade the DS.		$1,535 K
2	REI: Addition of station service transformer required on LV Bus at Sturgeon Falls DS as a result of outage requirement.		$43 K
3	Upstream TX: VT installation at Crystal Falls TS that was included in the Class 'C' estimate was found not to be required after detailed engineering and site visit.		-$137 K
4	Upstream TX: Protection equipment upgrade at Crystal Falls TS that was captured in the Class 'C' Estimate was found not to be required after detailed engineering and site visit.		-$100 K
5			
6			
7			
8			
9			
10			
	Total Variance Costs	$0 K	$1,341 K

Project Cashflow Detail by Year

Description		2012	2013	2014	2015	2016	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	CAPITAL	$0 K	$0 K	$30 K	$1,969 K	$300 K	$2,299 K
	REMOVALS	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	TOTAL	$0 K	$0 K	$30 K	$1,969 K	$300 K	$2,299 K

IROV Form 11B July 18, 2011

hydro one

Investment Driver: N.D.C.2.03 Date: September 26,2014

AR Number: 23485,23486 Title: Striker HVDS F2 ID25180 Solvation-S

Hydro One Networks - Business Case Summary - 50003765

Striker HVDS F2 ID25180 Solvation-S

Investment Driver: **In-Service date:** September 25,2015

N.D.C.2.03 # Distribution Generation Connections (2014-$48.7M, 2015- $48.5M) Investments in this Driver modify/upgrade the Distribution system including distribution line transfers requested by the Customers and supply stations to connect new generation facilities to Hydro One's Distribution System. Capital contributions from the Customers are based on Hydro One's connection policy and are in accordance with the DSC, under which the Customer is responsible for a portion of the cost to connect to Hydro One's Distribution System, and other portions are paid for by Hydro One Distribution.

N.T.C.2.19 # P&C Enablement for Generation Connections (2014-$24M, 2015-$23.6M) This investment driver funds the development of standards, enhancements, modifications, and replacement of protection and control equipment to allow mass deployment of Distributed Generators to HONI's system at all voltage levels.

This Approval: $1097K **Previous Approval:** $0 **Project Total:** $1097K

Need:

This investment is required to connect Solvation-S to the Hydro One Networks Inc. (HONI) system. Not proceeding with this investment would present customer, reputation and regulatory risks through the violation of our License requirements. 1544656 Ontario Ltd. has requested HONI to proceed with the work that is required to connect Solvation-S to HONI system.

Investment Summary:

1544656 Ontario Ltd. is planning to connect 0.48 MW solar generation to Striker HVDS 25 kV F2 feeder. The generation facility is located at Lot 8, Con. 1, Town of Blind River, ON. Hydro One has carried out a CIA study and a class C cost estimate. The CIA indicates that there are no significant impacts to HONI customers. The HONI work includes installation of HV transfer trip (TT) and Distributed Generator End Open (DGEO) scheme between the 115 kV T1B circuit and the F2 feeder protection as well as installation of Line Back-up Protection at Striker HVDS. There is also a HONI common cost of $903k approved under BCS 50003705 which will enable the connection of this project and three other generation projects (ID 25090, 25150 and 25200). The in service date will be negotiated with the Customer at the Project Management kick-off meeting.

Approval is requested to proceed with the CCA and the project. The HONI connection work will start once 1544656 Ontario Ltd. has signed the CCA and paid all the required deposits. 1544656 Ontario Ltd. will be executing the CCA for the HONI connection work. The Director - Customer Care will sign the CCA on behalf of HONI. Transmission costs will be incurred as a result of this connection. Separate ARs have been created for the Tx (AR # 23486) and Dx (AR # 23485) portions of the work.

Results:

This investment will enable the connection of Solvation-S and will mitigate potential customer, reputation and regulatory risks.

Costs:

	2014 K	2015 K	Total K
Capital* and MFA	110	987	1097
OM&A and Removals	0	0	0
Gross Investment Cost*	110	987	1097
Recoverable	59	533	592
Net Investment Cost	51	454	505

The cost estimate includes AFUDC and overheads at current rates.

Investment Driver: N.D.C.2.03 Date: September 26,2014

AR Number: 23485,23486 Title: Striker HVDS F2 ID25180 Solvation-S

Alternatives

ALTERNATIVES CONSIDERED FURTHER

Alternative One

Connect new Solvation-S to HONI system as per license requirements while maintaining customer connection reliability and system security.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

Alternative 1 is recommended as the generation facility would be connected to HONI's system, would satisfy HONI license requirements and meet HONI stakeholder expectations to connect generation facilities when possible.

Alternatives Compared

	Project Level Risk		
Business Value	**Current Risk**	**Alt1**	**Comparison**
Reliability	N/A	N/A	Not influential in the investment decision.
Customer	HIGH	LOW	Alternative 1 mitigates the risk of customer dissatisfaction with Hydro One.
Competitiveness	N/A	N/A	Not influential in the investment decision.
Safety and environment	N/A	N/A	Not influential in the investment decision.
Regulatory / Legal	HIGH	LOW	Alternative 1 mitigates the risks of not complying with our license requirements.
Reputation	HIGH	LOW	Not meeting our license requirements would result in deterioration of public image of HONI.
Initial Cost ($K)		1097	
Financial: PV Cost / NPV ($K)			NPV was not calculated as there is only one viable alternative and this investment is not primarily driven by financial factors.

Project Risk and Mitigation:

Cost:

The project cost is based upon a Class C estimate which is accurate in the range of +/- 50%, and includes 15% contingency for in-scope variances.

The estimated total cost for the HONI connection work is $2,000,000 including the common cost of $903k for Renewable Enabling Improvements (REI).
The cost breakdown is as follows:

Connection Assets (Dx) - $67,000
REI (Dx) - $1,408,000
Upstream Station Work (Tx) - $118,000
Upstream Telecom Work (Tx) - $407,000

Hydro One cost of common elements; the installation of Line Back-up protection and HVTT work at Striker HVDS and the replacement of Striker HVDS F2 feeder reclosers has been estimated to be $903,000 under REI and has already been approved under BCS 50003705. This REI common cost of $903,000 is not included in this BCS but is an enabler for this investment.

Cost Contribution:

The terms and conditions in the CCA mitigate the risks associated with recovery of the actual cost of the HONI connection work per the Distribution System Code.

It is expected that 1544656 Ontario Ltd. will contribute $592,000 calculated in accordance with the Distribution System Code. The remaining expenditures $505,000 will be borne by Hydro One in addition to the common cost of $903k which is already approved under BCS 50003705.

Business Planning:

Dx costs are included in the 2014-2019 Business Plan under N.D.C.2.03 as AIP 000195. Re-direction is not required.

Tx costs are included in the 2014-2019 Business Plan under N.T.C.2.19 as AIP 000931. These costs are fully recoverable. Re-direction is not required.

Others:

Timing & Scope of Work:

The terms and conditions in the CCA mitigate the risks associated with timing and scope of the HONI connection work.

Execution:

Approvals	N/A
S.92	N/A
EA	N/A
Outages	Med
Resourcing	Med
First Nations	N/A
Real Estate	N/A
Agreements	Low
Technology	Low

Outage needs continue to be a risk that could delay the in-service date of the project. Releasing the work well ahead of the proposed September 25, 2015 in-service date should help with outage planning. Resourcing continues to be a concern, but bundling the work with other connections on same station and feeder lessens internal resourcing needs and further enables contracting of some engineering elements.

Regulatory Considerations:

The costs for this generation facility connection are allocated as per the Distribution System Code and any portions recoverable will be recovered consistent with HONI Policy.

No significant regulatory issues anticipated other than standard need and prudence justification. No ISD for this investment was included in the 2014 Dx rate case EB-2013-0141 as it was not required to be filed in the IRM application. In 2015, $0.5M of distribution expenditure for the Striker HVDS F2 ID25180 Solvation-S project was included in the currently submitted Dx rate filing (EB-2013-0416) for years 2015-2019 under Development Capital in the category 'Development projects/programs less than $1M'.

Investment Driver: N.D.C.2.03

Date: September 26,2014

AR Number: 23485,23486

Title: Striker HVDS F2 ID25180 Solvation-S

Funds Included in Business Plan: Y	Director: Paul Brown		Planner: Mansab Ali	
This Approval($K): 1097	Previous Approval($K): 0		Current Est. of Total Cost($K): 1097	
Signature Block:				
Submitted by: Mansab Ali		Title: Planner		Date: Oct 03/14
Reviewed by: Natalia Gaydukevych		Title: Manager Decision Support		Date: Oct 03/14
Recommended by: Peter Faltaous		Title: Manager		Date: Oct 3, 2014
Approved by: Paul Brown	J Fuenth for	Title: Director		Date: Oct 3, 2014

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

INTERIM REVIEW OF VARIANCE (IROV)

H0002450

Check All Applicable Boxes to Show Variances Requiring OAR Approval

☐ Cost Increase ☐ Schedule (Business ☑ Scope Change

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date
23485, 23486	DC203, TC219	Distribution Asset Management	E&PD	19-Nov-15

Investment Title		Original Approved Cost *(as per BCS)*	$1,097 K
Striker HVDS F2 ID 25180 Solvation-S		Total Cost Approved plus Requested	$330 K
Original approved in-service date	Proposed new in-service date	Current Cost ratio	30%
September 25, 2015	November 30, 2015		

Background Situation:

This investment is required for the connection of 480 kW solar project ID 25,180 to Striker HVDS 25 kV F2 feeder. The BCS (50003765) dated October 3, 2014, included a cost of $511k for the installation of HV Transfer Trip (HVTT) from Algoma TS to Striker HVDS in order to prevent islanded operation. This upstream transmission upgrade cost was intended to enable the connection of this and three other generation projects (ID 25090, 25150 and 25200) for a total capacity of 1.8 MW. These projects are Capacity Allocation Exempt (CAE) projects with allocated capacity for each project ≤ 500 kW. The requirements of HVTT from Algoma TS to Striker HVDS and Line Backup Protection at Striker HVDS were proposed based on the cumulative size of the four projects, which is 1.8 MW. Upon later review of the HVTT criteria, it was determined that HVTT would not be required for any individual project up to and including 500kW. As a result, the CIA and planning spec for the project ID 25,180 were revised by eliminating HVTT and Line Backup Protection requirement from the scope of work and the project cost has been decreased from $1,097K to $330K as per revised class C estimate revision 2 dated November 5, 2015.

Additionally, a new $133k line expansion is required to connect the generator at the new location to Hydro One's existing feeder. The cost for the line expansion is divided into either work that is eligible or not eligible for alternative bid. Work eligible for alternative bid is work that may be done by the customer, instead of Hydro One. $115k of this expansion is work eligible for alternative bid. The rest, $18k, is work that must be done by Hydro One. The customer has confirmed intent to do the work eligible for alternative bid, therefore the costs in this IROV exclude this work and only consider the expansion work of $18k to be done by Hydro One.

Variance Explanation: *(Discussion of significant cost, schedule, and scope changes, and an explanation of root causes.)*

The total estimated project cost has been decreased from $1,097K to $330K due to removal of HVTT and line backup protection. The cost decrease was slightly offset by the addition of line expansion. The capital contribution from the customer has been decreased from $592K to $110K and HONI contribution decreased from $505K to $220K as per revised class C estimate revision 2 dated November 5, 2015.

Approval is being requested for the scope and dollar variance due to removal of HVTT and line backup protection, addition of line expansion and in-scope variances as per revised class C estimate revision 2 dated November 5, 2015. The customer has been notified of the scope change. An amending CCA will be executed following the approval of this IROV.

Lessons Learned:

The criteria for high voltage transfer trip has been updated for projects <= 500kW and is being applied for all new CIA applications.

Approvals

Submitted by:	Signature	Date
Peter Faltaous, Manager - Distribution Investment Planning	Peter Fal	Dec. 10, 2015
Recommended by:	Signature	Date
Paul Brown, Director - Distribution Asset Management	Paul	DEC 10/15
Reviewed by:	Signature	Date
Brad Bowness, VP - Construction Services	B. Bowness	Dec 11/15
Financial Review: *(If President Approval Required)*	Signature	Date
N/A		
Approved by *(As per EAR/OAR)*:	Signature	Date
Mike Penstone, VP - Planning	M. Penstone	Dec 14, 2015

INTERIM REVIEW OF VARIANCE (IROV)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date *(mm/dd/yy)*
23485, 23486	DC203, TC219	Distribution Asset Management	E&PD	November 19, 2015

Investment Title		
Striker HVDS F2 ID 25180 Solvation-S	5. Original Approved Cost *(Line 1)*	**$1,097 K**
	6. Total Cost Approved Plus Requested *(line 4)*	**$330 K**

Project Manager	Planner	Current Cost ratio *(Box 6/Box 5)*	**30%**
Thomas Tang	Gert Alikaj		

1. Original approved cost *(per BCS)*	1.1 OM&A	$0 K	Original approved in-service date *(as per line 1)*	
	1.2 CAPITAL	$1,097 K	September 25, 2015	
	1.3 REMOVALS	$0 K		
	TOTAL	**$1,097 K**		
2. Total $ currently approved *(Original plus previous IROVs awards)*	2.1 OM&A	$0 K	Current approved in-service date *(as per line 2)*	
	2.2 CAPITAL	$1,097 K	September 25, 2015	
	2.3 REMOVALS	$0 K		
	TOTAL	**$1,097 K**		
3. Revision now requested		Total (A + B)	(A) Cost of Scope Increases	(B) Cost of "In-Scope" Project Variances
	3.1 OM&A	$0 K	$0 K	$0 K
	3.2 CAPITAL	-$767 K	-$763 K	-$4 K
	3.3 REMOVALS	$0 K	$0 K	$0 K
	TOTAL	**-$767 K**	**-$763 K**	**-$4 K**
4. Total Cost including OH & AFUDC *(Line 2 plus line 3)*	4.1 OM&A	$0 K	Proposed new in-service date *(as per line 3)*	
	4.2 CAPITAL	$330 K	November 30, 2015	
	4.3 REMOVALS	$0 K		
	TOTAL	**$330 K**		

Summary of Variance:

The project ID 25,180 is proposed for connection to Striker HVDS F2 feeder. The original requirements for HVTT and Line Backup Protection have been removed in alignment with the new criteria. Additionally, a new line expansion is required to connect the generator at the new location to Hydro One's existing feeder. The net effect is that the project cost is decreasing as compared to BCS approval cost.

#	Item / Description	Cost of Scope increase $K	In-Scope Variance $K
1	Upstream TS Work (Station & Telecom) - Removed HVTT	-$485 K	-$26 K
2	REI - Removed work at Striker HVDS for line backup protection and cascading of HV transfer trip from upstream TS to DG.	-$296 K	-$4 K
3	Connection Assets - No scope change	$0 K	$26 K
4	Expansion - new line (work not eligible for alternative bid)	$18 K	$0 K
5			
6			
7			
8			
9			
10			
	Total Variance Costs	**-$763 K**	**-$4 K**

Project Cashflow Detail by Year

Description		2014	2015	2016	2017	2018	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	CAPITAL	$1,097 K	-$767 K	$0 K	$0 K	$0 K	$330 K
	REMOVALS	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	TOTAL	**$1,097 K**	**-$767 K**	**$0 K**	**$0 K**	**$0 K**	**$330 K**

hydro one

Investment Driver: N.D.C.2.03 Date: July 15,2014

AR Number: 23382,23383 Title: Warren HVDS-F2-ID25080-Gengrowth Garden 03 Giroux

Hydro One Networks - Business Case Summary - 50003715

Warren HVDS-F2-ID25080-Gengrowth Garden 03 Giroux

Investment Driver: **In-Service date:** December 01,2014

N.D.C.2.03 # Distribution Generation Connections (2014-$48.7M) Investments in this Driver modify/upgrade the Distribution system including distribution line transfers requested by the Customers and supply stations to connect new generation facilities to Hydro One's Distribution System. Capital contributions from the Customers are based on Hydro One's connection policy and are in accordance with the DSC, under which the Customer is responsible for a portion of the cost to connect to Hydro One's Distribution System, and other portions are paid for by Hydro One Distribution.

N.T.C.2.19 # P&C Enablement for Generation Connections(2014-$24M) This investment driver funds the development of standards, enhancements, modifications, and replacement of protection and control equipment to allow mass deployment of Distributed Generators to HONI's system at all voltage levels.

This Approval: $761K **Previous Approval:** $0 **Project Total:** $761K

Need:

This investment is required to connect Gengrowth Garden 03 Giroux to the Hydro One Networks Inc. (HONI) system. Not proceeding with this investment would present customer, reputation and regulatory risks through the violation of our License requirements. Gengrowth Solar Inc. has requested that HONI proceed with the connection work that is required to connect Gengrowth Garden 03 Giroux to the HONI system.

Investment Summary:

Gengrowth Solar Inc. is planning to connect 0.5 MW solar generation to Warren HVDS 12.5 kV F2 feeder. The generation facility is located at 61 Robert Road W ½ LOT 2 CON 2 in the township of River Valley/West Nipissing/Nipissing. The distribution work covered by this BCS includes Transfer Trip (TT) from the F2 feeder recloser to DG facility and installation of 3 new 1-phase line voltage regulators with CL6 controller on Warren HVDS F2 feeder.

Hydro One has carried out the connection studies including a Connection Impact Assessment (CIA) study and a class C type cost estimate. IESO assessment (SIA) is not required. The CIA indicates that there are no significant impacts to HONI customers. Project Development has determined an estimate of cost. The in-service date will be negotiated with the Customer at the Project Management kick-off meeting. Approval is requested to proceed with the CCA and the project. The HONI connection work will start once Gengrowth Solar Inc. has signed the CCA and paid all the required deposits. Gengrowth Solar Inc. will be executing the CCA for the HONI connection work. The Director - Customer Care will sign the CCA on behalf of HONI. Transmission costs will be incurred as a result of this connection. Separate ARs have been created for the Transmission (AR # 23382) and Distribution (AR # 23383) portion of the work.

Results:

This investment will enable the connection of Generator Gengrowth Garden 03 Giroux.

Costs:

	2014 K	Total K
Capital* and MFA	761	761
OM&A and Removals	0	0
Gross Investment Cost*	761	761
Recoverable	214	214
Net Investment Cost	548	548

The cost estimate includes AFUDC and overheads at current rates.

Investment Driver: N.D.C.2.03 Date: July 15,2014

AR Number: 23382,23383 Title: Warren HVDS-F2-ID25080-Gengrowth Garden 03 Giroux

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

Do Nothing - The do nothing alternative is not a viable option as the generation facility would not be connected to HONI's system, would not satisfy HONI license requirements nor meet our stakeholder expectations to connect generation facilities when possible.

ALTERNATIVES CONSIDERED FURTHER

Alternative One

Connect new Gengrowth Garden 03 Giroux to HONI system as per license requirements while maintaining customer connection reliability and system security.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

Alternative 1 is recommended as the generation facility would be connected to HONI's system, would satisfy HONI license requirements and meet HONI stakeholder expectations to connect generation facilities when possible.

Alternatives Compared

	Project Level Risk		
Business Value	**Current Risk**	**Alt1**	**Comparison**
Reliability	N/A	N/A	Not influential in the investment decision.
Customer	HIGH	LOW	Alternative 1 mitigates the risk of customer dissatisfaction with Hydro One.
Competitiveness	N/A	N/A	Not influential in the investment decision.
Safety and environment	N/A	N/A	Not influential in the investment decision.
Regulatory / Legal	HIGH	LOW	Alternative 1 mitigates the risks of not complying with our license requirements
Reputation	HIGH	LOW	Not meeting our license requirements would result in deterioration of public image of HONI.
Initial Cost ($K)		761	
Financial: PV Cost / NPV ($K)			NPV was not calculated as there is only one viable alternative and this investment is not primarily driven by financial factors.

Project Risk and Mitigation:

Cost:

The project cost is based upon a Class C estimate from Project Development, which is accurate in the range of +/- 50%, and includes a contingency of 15% for in-scope variances.

The estimated total cost for the HONI connection work is $761,000.

This includes:

Connection Assets (Dx) - $68,000

Expansions (Dx) - $153,000

Renewable Enabling Improvements (Dx) - $527,000

Upstream Telecom Work (Tx) - $13,000

Investment Driver: N.D.C.2.03

AR Number: 23382,23383

Date: July 15,2014

Title: Warren HVDS-F2-ID25080-Gengrowth Garden 03 Giroux

Cost Contribution:

The terms and conditions in the CCA mitigate the risks associated with timing, scope and recovery of the actual cost of the HONI connection work per the Distribution System Code.

It is expected that Gengrowth Solar Inc. will contribute $213,509 calculated in accordance with the Distribution System Code. The remaining expenditures, $547,491 will be borne by Hydro One.

The proponent's contribution incorporates a reduction of $20,490. This reduction is the net of the impact from the economic evaluation and the Distributor Funded Expansion of $45,000.

Business Planning:

Dx costs of $748,000 are included in the (2014-2019) Business Plan under DC 203 as AIP000199. Re-direction is not required.

Tx costs of $13,000 are included in the (2014-2019) Business Plan under AIP000931. Re-direction is not required.

Others:

Timing & Scope of Work:

The terms and conditions in the CCA mitigate the risks associated with timing and scope of the HONI connection work.

Customer Withdrawal:

The terms of the CCA mitigate financial risks should Gengrowth Solar Inc. withdraw once the project has started.

Execution:

Approvals	N/A
S.92	N/A
EA	N/A
Outages	Med
Resourcing	Med
First Nations	N/A
Real Estate	N/A
Agreements	Low
Technology	Low

Outage needs continue to be a risk that could delay the in-service date of the project. Releasing the work well ahead of the proposed December 1, 2014 in-service date should help with outage and resource planning.

Regulatory Considerations:

The costs for this generation facility connection are allocated as per the Distribution System Code and any portions recoverable will be recovered consistent with HONI Policy.

No significant regulatory issues anticipated other than standard need and prudence justification.

Investment Driver: N.D.C.2.03

Date: July 15,2014

AR Number: 23382,23383

Title: Warren HVDS-F2-ID25080-Gengrowth Garden 03 Giroux

Funds Included in Business Plan: Y	Director: Paul Brown	Planner: Gaurav Behal
This Approval($K): 761	**Previous Approval($K):** 0	**Current Est. of Total Cost($K):** 761

Signature Block:

Submitted by: Gaurav Behal	**Title:** Planner	**Date:** July 28, 2014
Reviewed by:	**Title:**	**Date:**
Recommended by:	**Title:**	**Date:**
Approved by: Peter Faltaous	**Title:** Manager	**Date:** July 28, 2014

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

INTERIM REVIEW OF VARIANCE (IROV)

Check All Applicable Boxes to Show Variances Requiring OAR Approval

☐ Cost Increase ☐ Schedule (Business Impactive) ☑ Scope Change (Significant)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date
23382, 23383	DC203, TC219	Distribution Asset Management	was E&PD, changed to Lines	19-Oct-15

Investment Title		Original Approved Cost *(as per BCS)*	$761 K
Warren HVDS F2 ID 25080 Gengrowth Garden 03 Giroux		Total Cost Approved plus Requested	$272 K
Original approved in-service date	Proposed new in-service date	Current Cost ratio	36%
December 1, 2014	November 26, 2015		

Background Situation:

This investment is required for the connection of 0.5 MW solar project ID 25,080 to Warren HVDS F2 feeder. The BCS 50003715 dated July 28, 2014 was approved for $761K based on the original class C estimate dated April 24, 2014. Back in 2014, Hydro One received approximately 60 - 70 solar project applications (each ≤ 500 kW) under Micro-FIT relocation program from a couple of proponents. Although, the subject project was the only project proposed for connection to Warren HVDS F2 feeder, transfer trip was identified as a requirement based on planner discretion since the project is above the 50% generation/minimum load ratio. Following this, a review was done of the transfer trip criteria to be applied for a single project vs. a cluster of projects. Based on this review, the criteria for transfer trip changed and transfer trip was no longer a requirement for this single project. As a result, the transfer trip requirement was removed from the revised CIA and planning spec and the project cost has been decreased from $761k to $272k as per revised class C estimate dated April 28, 2015.

Variance Explanation: *(Discussion of significant cost, schedule, and scope changes, and an explanation of root causes.)*

The total estimated project cost has been decreased from $761K to $272K due to removal of TT and some in-scope variances. The capital contribution from the customer has been decreased from $214K to $186K and HONI contribution from $548K to $115K as per revised class C estimate revision 1 dated April 28, 2015.

Approval is being requested for the scope and dollar variance due to removal of TT and in-scope variance to the connection costs as per revised class C estimate revision 1 dated April 28, 2015. The customer has been notified of the scope change. An amending CCA will be executed following the approval of this IROV.

Lessons Learned:

The criteria for transfer trip has been updated for projects <= 500kW and is being applied for all new CIA applications. Revision to the DG Technical Interconnection Requirements document is in progress to reflect this new criteria.

Approvals

	Signature	Date
Submitted by:		
Gert Alikaj, Planner - Distribution Investment Planning	Gert Alikaj	December, 10, 2015
Recommended by:		
N/A		
Reviewed by:		
Peter Faltaous, Manager - Distribution Investment Planning	Peter Faltaous	December 10, 2015
Financial Review: *(If President Approval Required)*		
N/A		
Approved by *(As per EAR/OAR)*:		
Paul Brown, Director - Distribution Asset Management	[signature]	Dec 10/15

INTERIM REVIEW OF VARIANCE (IROV)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date *(mm/dd/yy)*
23382, 23383	DC203, TC219	Distribution Asset Management	was E&PD, changed to Lines	October 19, 2015

Investment Title		
Warren HVDS F2 ID 25080 Gengrowth Garden 03 Giroux	5. Original Approved Cost *(Line 1)*	**$761 K**
	6. Total Cost Approved Plus Requested *(line 4)*	**$272 K**

Project Manager	Planner	Current Cost ratio *(Box 6/Box 5)*	**36%**
Jim Perfitt (was Byron Downton)	Gert Alikaj		

1. Original approved cost *(per BCS)*	1.1 OM&A	$0 K	Original approved in-service date *(as per line 1)*	
	1.2 CAPITAL	$761 K	December 1, 2014	
	1.3 REMOVALS	$0 K		
	TOTAL	**$761 K**		
2. Total $ currently approved *(Original plus previous IROVs awards)*	2.1 OM&A	$0 K	Current approved in-service date *(as per line 2)*	
	2.2 CAPITAL	$761 K	December 1, 2014	
	2.3 REMOVALS	$0 K		
	TOTAL	**$761 K**		
3. Revision now requested		Total (A + B)	(A) Cost of Scope Increases	(B) Cost of "In-Scope" Project Variances
	3.1 OM&A	$0 K	$0 K	$0 K
	3.2 CAPITAL	-$489 K	-$449 K	-$40 K
	3.3 REMOVALS	$0 K	$0 K	$0 K
	TOTAL	**-$489 K**	**-$449 K**	**-$40 K**
4. Total Cost including OH & AFUDC *(Line 2 plus line 3)*	4.1 OM&A	$0 K	Proposed new in-service date *(as per line 3)*	
	4.2 CAPITAL	$272 K	November 26, 2015	
	4.3 REMOVALS	$0 K		
	TOTAL	**$272 K**		

Summary of Variance:

Project ID 25,080 is to be connected to Warren HVDS F2 feeder. The original requirement for transfer trip is being removed. As a result, the project cost is decreasing compared to original BCS approval.

#	Item / Description	Cost of Scope increase $K	In-Scope Variance $K
1	Upstream TS Work (Station & Telecom) - No scope change	$0 K	$7 K
2	REI - Removed transfer trip from DS	-$449 K	-$8 K
3	Connection Assets - No scope change	$0 K	-$26 K
4	Expansion - No scope change	$0 K	-$13 K
5			
6			
7			
8			
9			
10			
	Total Variance Costs	**-$449 K**	**-$40 K**

Project Cashflow Detail by Year

Description		2014	2015	2016	2017	2018	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	CAPITAL	$761 K	-$489 K	$0 K	$0 K	$0 K	$272 K
	REMOVALS	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	TOTAL	**$761 K**	**-$489 K**	**$0 K**	**$0 K**	**$0 K**	**$272 K**

Filed: 2018-03-29
EB-2017-0049
Exhibit JT 3.1-8
Attachment 9
Page 1 of 2

Hydro One Networks - Business Case Summary - 50001684

Request for Class A Estimate # Project ID 15,950 - BeamLight LP

Investment Driver:

In-Service date: June 04,2013

N.D.C.2.03 # Distribution Generation Connections (2011- $151.5M) Investments in the Distribution Generation Connection Driver modify/upgrade the Distribution system including distribution line transfers requested by the generators and supply stations to connect new generation facilities to Hydro One's Distribution System. Capital contributions from the generators are based on Hydro One's connection policy and are in accordance with the DSC, under which the generator is responsible for a portion of the cost to connect to Hydro One's Distribution System, and other portions are paid for by Hydro One Distribution.

This Approval: $111K **Previous Approval:** $0 **Project Total:** $111K

Need:

This investment is required to obtain the Class A estimate for Project ID 15,950 - BeamLight LP. Hydro One Networks Inc received the request for CCE from SkyPower Ltd. on August 3rd 2011

Not proceeding with this investment would present customer, reputation and regulatory risks through the violation of our License requirements.

Investment Summary:

The subject generation project is proposed to be connected to Brown Hill TS M4 feeder. The generating facility includes 20 x 500kW Solar Inverters for a total of 10,000kW.

The fee for Class A estimate is $111,000 and the developer SkyPower Ltd. has made 100% payment of the total fee.

Approval is requested to provide a Class A estimate to SkyPower Ltd.

AR(21753) has been created for this scope of the work.

Results:

The cost estimate class A type shall be provided so that SkyPower Ltd. may deposit the necessary funding to proceed with the connection of BeamLight LP.

Costs:

	2011 K	Total K
Capital* and MFA	111	111
OM&A and Removals	0	0
Gross Investment Cost*	111	111
Recoverable	111	111
Net Investment Cost	0	0

HST is not included in this amount

Investment Driver: N.D.C.2.03

AR Number: 21753

Date: August 18,2011

Title: Request for Class A Estimate # Project ID 15,950 - BeamLight LP

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

The status quo alternative is not a viable option as the generator would not be connected to Hydro One's system, would not satisfy our license requirements nor meet our stakeholder expectations to connect generators when possible.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

Alternative 1 is recommended as the generator would be connected to Hydro One's system, would satisfy our license requirements and meet our stakeholder expectations to connect generators when possible.

Funds Included in Business Plan: Y	**Redirection Required:** N	**Planner:** Muhammed Ali
This Approval($K): 111	**Previous Approval($K):** 0	**Current Est. of Total Cost($K):** 111
Signature Block:		
Submitted by: Muhammed Ali	**Title:** Planner	**Date:** 22 AUG 2011
Reviewed by:	**Title:**	**Date:**
Recommended by: Ryan Boudreau	**Title:** Manager	**Date:** Aug 22/2011
Approved by: Ayesha Sabouba	**Title:** Manager	**Date:** Aug 22, 2011

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a **Technological Advancement**? N
- Do you anticipate that the initiative will resolve a **Technological Uncertainty**? N

Investment Driver: N.D.C.2.03

Date: August 21,2012

AR Number: 21753,21740

Title: Brown Hill TS M4 ID 15950 - BeamLight LP

Hydro One Networks - Business Case Summary - 50002572

Brown Hill TS M4 ID 15950 - BeamLight LP

Investment Driver:

In-Service date: June 04,2013

N.D.C.2.03 # Distribution Generation Connections (2012-$56.6M, 2013- $56.9M)Investments in the Distribution Generation Connection Driver modify/upgrade the Distribution system including distribution line transfers requested by the generators and supply stations to connect new generation facilities to Hydro One's Distribution System. Capital contributions from the generators are based on Hydro One's connection policy and are in accordance with the DSC, under which the generator is responsible for a portion of the cost to connect to Hydro One's Distribution System, and other portions are paid for by Hydro One Distribution.

N.T.C.2.19 # P&C Enablement for Generation Connections (2012-$41.0M, 2013-$27.9M)This investment driver funds the development of standards, enhancements,modifications, and replacement of protection and control equipment to allow mass deployment of Distributed Generators to HONI's system at all voltage levels.

This Approval: $3.8M **Previous Approval:** $0 **Project Total:** $3.8M

Need:

This investment is required to connect BeamLight LP to the Hydro One Networks Inc. (HONI) system. Not proceeding with this investment would present customer, reputation and regulatory risks through the violation of our License requirements.

Investment Summary:

The original BCS (dated August 15, 2011) was based on a planning specification that did not have any line expansion. Due to the addition of line expansion, the original BCS was cancelled and replaced by this BCS. BeamLight LP (The Generator) is planning to connect a 10 MW solar power generation facility to the 44kV Brownhill TS M4 feeder. The work to be done includes building a 5.5 km new line, installing transfer trip and upgrading feeder protections. We have carried out the connection studies including a Connection Impact Assessment (CIA) study and a class A type cost estimate. IESO assessment (SIA) is not required. The CIA indicates that there are no significant impacts to HONI customers. E&PD has determined an estimate of cost,schedule and detailed scope for the HONI connection work. The in-service date will be negotiated with the customer at the E&PD kick-off meeting. The customer entered into a connection cost agreement (CCA) with Hydro One prior to completion of the Class A estimate. The terms of the CCA allow Hydro One to perform the engineering portion of the connection work, and to stop any other connection work until authorized by the customer. Conditional approval is being requested to proceed with project work. Release of funds for execution of the connection work is contingent upon the customer entering into an amended CCA with Hydro One for the total amount cited in the Class A estimate. Transmission costs will be incurred as a result of these connections.Separate ARs have been created for the Transmission (AR #21740) and Distribution (AR# 21753)portion of the work.

Results:

This investment will enable the connection of 15950 BeamLight LP to the Brown Hill TS M4 Feeder.

Costs:

	2012 M	2013 M	Total M
Capital* and MFA	1.0	2.8	3.8
OM&A and Removals	0.0	0.0	0.0
Gross Investment Cost*	1.0	2.8	3.8
Recoverable	0.8	2.1	2.9
Net Investment Cost	0.2	0.7	0.9

The cost estimate includes AFUDC and overheads at current rates.

Investment Driver: N.D.C.2.03 Date: August 21,2012

AR Number: 21753,21740 Title: Brown Hill TS M4 ID 15950 - BeamLight LP

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

Do Nothing - The do nothing alternative is not a viable option as the generator would not be connected to Hydro One's system, would not satisfy our license requirements nor meet our stakeholder expectations to connect generators when possible.

ALTERNATIVES CONSIDERED FURTHER

Alternative One

Connect new BeamLight LP to HONI system as per license requirements while maintaining customer connection reliability and system security.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

Alternative 1 is recommended as the generator would be connected to Hydro One's system, would satisfy our license requirements and meet our stakeholder expectations to connect generators when possible.

Alternatives Compared

	Project Level Risk		
Business Value	**Current Risk**	Alt1	Comparison
Reliability	N/A	N/A	Not influential in the investment decision.
Customer	H!GH	LOW	Alternative 1 mitigates the risk of customer dissatisfaction with Hydro One.
Competitiveness	N/A	N/A	Not influential in the investment decision.
Safety and environment	N/A	N/A	Not influential in the investment decision.
Regulatory / Legal	HIGH	LOW	Alternative 1 mitigates these risks of not complying with our license requirements.
Reputation	HIGH	LOW	Not meeting our license requirements would result in deterioration of public image of HONI
Initial Cost ($M)		3.8	
Financial: PV Cost / NPV ($M)			NPV was not calculated as there is only one viable alternative and this investment is not primarily driven by financial factors.

Project Risk and Mitigation:

Cost:

The project cost is based upon a Class A estimate from E&PD, which is accurate in the range of +/- 10%, and includes a contingency of 10% of the direct project cost.

HONI has completed on June 8, 2012 a Class A cost estimate based on the planning specifications of this project. Also, the terms and conditions in the CCA mitigate the risks associated with timing, cost level, scope and recovery of the actual cost of the HONI connection work per the Distribution System Code.

hydro one

Investment Driver: N.D.C.2.03

Date: August 21,2012

AR Number: 21753,21740

Title: Brown Hill TS M4 ID 15950 - BeamLight LP

Cost Contribution:
The estimated total cost for the HONI connection work is $3,796,000
This includes:
Connection Cost Estimate - $111,000
Connection Costs - $44,000
Expansions - $2,702,000
Renewable Enabling Improvements (REI) - $9,000
Upstream Station Work - $779,000
Upstream Telecom Work - $151,000

It is expected that BeamLight LP will contribute $2,892,120 (which includes the cost of the Class A estimate $111,000) calculated in accordance with the Distribution System Code. The remaining expenditures, $903,880 will be borne by Hydro One.

The variance to the original BCS in cost is attributable to the addition of 5.5 km of over-building an existing distribution line, install a 3 phase gang operated disconnect switch and the cost for completing a Class A estimate. The proponent's contribution incorporates a reduction of $895K of which $900K is the Distributor Funded Expansion and the remainder is the net impact from the economic evaluation.

Business Planning:
Dx costs of $2,866,000 are included in the (2012-2016) Business Plan under DC 203 as accomplishment ID # 2. Re-direction is not required.

Tx costs of $930,000 are not included in the (2012-2016) Business Plan under accomplishment ID # 282. All Tx costs are recoverable, re-direction is not required.

Others:
Timing & Scope of Work:
The terms and conditions in the CCA mitigate the risks associated with timing and scope of the HONI connection work.

Customer Withdrawal:
The terms of the CCA mitigate financial risks should BeamLight LP withdraw once the project has started.

Execution:

Approvals	N/A
S.92	N/A
EA	N/A
Outages	Med
Resourcing	High
First Nations	N/A
Real Estate	N/A
Agreements	Low
Technology	Low

Outage needs continue to be a risk that could delay the in-service date of the project. Releasing the work well ahead of the proposed June 4, 2013 in-service date should help with outage and resource planning.

Resourcing continues to be a significant concern, but bundling the work with other connections on same station and feeder lessens internal resourcing needs and further enables contracting of some engineering elements.

Investment Driver: N.D.C.2.03

Date: August 21,2012

AR Number: 21753,21740

Title: Brown Hill TS M4 ID 15950 - BeamLight LP

Regulatory Considerations:

The connection asset costs and upstream costs for this generator connection are fully recoverable as per the Distribution System Code and will be recovered consistent with HONI Policy. No significant regulatory issues anticipated other than standard need and prudence justification.

Funds Included in Business Plan: Y	**Redirection Required:** N	**Planner:** Muhammed Ali
This Approval($M): 3.8	**Previous Approval($M):** 0	**Current Est. of Total Cost($M):** 3.8

Signature Block:

Submitted by: Ayesha Sabouba	**Title:** Manager	**Date:** Oct 17, 2012
Reviewed by: Michael Satchell	**Title:** Manager Decision Support	**Date:** Oct 17/12
Recommended by: William Meeker	**Title:** Director	**Date:** Oct 19, 2012
Approved by: Rick Stevens	**Title:** Vice President	**Date:** Oct 24, 2012

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

INTERIM REVIEW OF VARIANCE (IROV)

40002340

☐ Cost ☐ Schedule (Business ☑ Scope Change

Check All Applicable Boxes to Show Variances Requiring OAR Approval

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date
21753, 21740	N.D.C.2.03, N.T.C.2.19	Asset Management - GCD	Engineering & Construction	1-Oct-14

Investment Title			
Brown Hill TS M4 ID 15,950 - BeamLight LP		Original Approved Cost *(as per BCS)*	**$3,796 K**
		Total Cost Approved plus Requested	**$4,521 K**
Original approved in-service date	**Proposed new in-service date**	Current Cost ratio	**119%**
June 4, 2013	May 14, 2015		

Background Situation:

This investment is required to connect the distributed generation (DG) project ID 15,950 "Sutton-BeamLight" to Brown Hill TS 44 kV M4 feeder. The facility consists of 13 x 769 KW solar generators, for a total of 10 MW. The original BCS 50002572 dated August 21, 2012 was approved for $3796K based on the class C estimate revision 2 dated December 14, 2011.

Variance Explanation: *(Discussion of significant cost, schedule, and scope changes, and an explanation of root causes.)*

The original BCS 50002572 for the project ID 15,950 included the cost for upstream station work and cost for building a new line expansion of 5.5 km from the Point of Connection (POC) to the Point of Common Coupling (PCC). BeamLight LP (the "Customer") submitted a revised Form B on December 3, 2013 by proposing a new PCC on Frog Street instead of Snodden Road. This new proposed PCC resulted in an increase of 1.7 km in new Line Expansion length from the original 5.5 km to 7.2 km. Consequently, the addition of 1.7 km of new line expansion caused an increase in the project estimated cost for the expansion work by $725k as per revised class C estimate revision 3 dated May 21, 2014. The Customer contribution is increased by $809,261 and Hydro One contribution decreased by $84,261 from the original $903,880 to new $819,619 due to the economic evaluation.

Approval is being requested for the scope and dollar variance due to the additional cost of 1.7 km of Line Expansion as per revised class C estimate revision 3 dated May 21, 2014.

Lessons Learned:

None. There is no mechanism in the DSC that prevents the customers from changing the project location / PCC unless doing so causes a material impact on other Customers.

Approvals

Submitted by:	Signature	Date
Peter Faltaous, Manager Distribution Investment Planning	[signature]	Oct. 3, 2014
Recommended by:	**Signature**	**Date**
Paul Brown, Director Distribution Asset Management	[signature] J Fuerth for PB	Oct 3/14
Reviewed by:	**Signature**	**Date**
Brad Bowness, Director Project Management	B. Bowness	Oct 6/14
Financial Review: *(If President Approval Required)*	**Signature**	**Date**
N/A		
Approved by *(As per EAR/OAR)*:	**Signature**	**Date**
Mike Penstone, VP Planning	M Penstone	Oct 7/14

INTERIM REVIEW OF VARIANCE (IROV)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date *(mm/dd/yy)*
21753, 21740	N.D.C.2.03, N.T.C.2.19	Asset Management - GCD	Engineering & Construction	October 1, 2014

Investment Title		
Brown Hill TS M4 ID 15,950 - BeamLight LP	5. Original Approved Cost *(Line 1)*	**$3,796 K**
	6. Total Cost Approved Plus Requested *(line 4)*	**$4,521 K**

Project Manager	Planner	Current Cost ratio *(Box 6/Box 5)*	**119%**
Alex Yang	Mansab Ali		

1. Original approved cost *(per BCS)*	1.1 OM&A	$0 K	Original approved in-service date *(as per line 1)*	
	1.2 CAPITAL	$3,796 K	June 4, 2013	
	1.3 REMOVALS	$0 K		
	TOTAL	$3,796 K		
2. Total $ currently approved *(Original plus previous IROVs awards)*	2.1 OM&A	$0 K	Current approved in-service date *(as per line 2)*	
	2.2 CAPITAL	$3,796 K	June 4, 2013	
	2.3 REMOVALS	$0 K		
	TOTAL	$3,796 K		
3. Revision now requested		Total (A + B)	(A) Cost of Scope Increases	(B) Cost of "In-Scope" Project Variances
	3.1 OM&A	$0 K	$0 K	$0 K
	3.2 CAPITAL	$725 K	$725 K	$0 K
	3.3 REMOVALS	$0 K	$0 K	$0 K
	TOTAL	$725 K	$725 K	$0 K
4. Total Cost including OH & AFUDC *(Line 2 plus line 3)*	4.1 OM&A	$0 K	Proposed new in-service date *(as per line 3)*	
	4.2 CAPITAL	$4,521 K	May 14, 2015	
	4.3 REMOVALS	$0 K		
	TOTAL	$4,521 K		

Summary of Variance:

The work for project 15,950 has been expanded to include the estimated cost for building an additional 1.7 km of new Line expansion due to a change in the point of common coupling requested by the customer.

#	Item / Description	Cost of Scope increase $K	In-Scope Variance $K
1	The cost for building additional 1.7 km of new line expansion due to change in PCC requested by the Customer.	$725 K	
2			
3			
4			
5			
6			
7			
8			
9			
10			
	Total Variance Costs	$725 K	$0 K

Project Cashflow Detail by Year

Description		2012	2013	2014	2015	2016	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	CAPITAL	$1,000 K	$2,796 K	$0 K	$725 K	$0 K	$4,521 K
	REMOVALS	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	TOTAL	$1,000 K	$2,796 K	$0 K	$725 K	$0 K	$4,521 K

UNDERTAKING – JT 3.1-9

Reference
I-25-Energy Probe-38

Preamble: The response lists the Variance Proposals for projects with budgets greater than $1 million.

Undertaking
Please provide the original Business Case, any subsequent Business Cases and the Variance Proposals for each of the projects listed.

Response
Please see the following attachments:

1. Business Case: Commerce Way TS M1 Generator Connection
2. Variance Approval: Commerce Way TS M1 Generator Connection

3. Estimating Business Case: Beckwith DS T2 and F3
4. Business Case: Beckwith DS T2 and F3
5. Variance Approval: Beckwith DS T2 and F3

6. Business Case: Purchasing and Installation of Pilot IMDS
7. Variance Approval: Purchasing and Installation of Pilot IMDS

8. Business Case: Commerce Way TS Feeder Extension
9. Variance Approval: Commerce Way TS Feeder Extension

10. Estimating Business Case: Bob-Lo DS Voltage Conversion
11. Business Case: Bob-Lo DS Voltage Conversion
12. Variance Approval: Bob-Lo DS Voltage Conversion

13. Estimating Business Case: Belle River DS Voltage Conversion
14. Business Case: Belle River DS Voltage Conversion
15. Variance Approval: Belle River DS Voltage Conversion

16. Estimating Business Case: Nebo TS M12 Extension to Hamilton Airport
17. Business Case: Nebo TS M12 Extension to Hamilton Airport
18. Variance Approval: Nebo TS M12 Extension to Hamilton Airport

Witness: JESUS Bruno

19. Estimating Business Case 1: Nobleton DS T1 – New Transformers and Feeders
20. Estimating Business Case 2: Nobleton DS T1 – New Transformers and Feeders
21. Business Case: Nobleton DS T1 – New 27.6 kV Transformer and Feeder
22. Variance Approval: Nobleton DS T1 – New 27.6kV Transformer and Feeder

Investment Driver: N.D.C.2.03

Date: March 26,2014

AR Number: 23210,23211

Title: Commerce Way TS M1 ID 22500 Gunn's Hill Wind Farm.

Hydro One Networks - Business Case Summary - 50003622

Commerce Way TS M1 ID 22500 Gunn's Hill Wind Farm.

Investment Driver:

In-Service date: July 05,2014

N.D.C.2.03 - Distribution Generation Connections (2014-$48.7M) Investments in the Distribution Generation Connection Driver modify/upgrade the Distribution system including distribution line transfers requested by the Customers and supply stations to connect new generation facilities to Hydro One's Distribution System. Capital contributions from the Customers are based on Hydro One's connection policy and are in accordance with the DSC, under which the Customer is responsible for a portion of the cost to connect to Hydro One's Distribution System, and other portions are paid for by Hydro One Distribution. N.T.C.2.19 -P&C Enablement for Generation Connections (2014-$24M) This investment driver funds the development of standards, enhancements, modifications, and replacement of protection and control equipment to allow mass deployment of Distributed Generators to HONI's system at all voltage levels.

This Approval: $1522K

Previous Approval: $0

Project Total: $1522K

Need:

This investment is required to connect Gunn's Hill Wind Farm to the Hydro One Networks Inc. (HONI) system. Not proceeding with this investment would present customer, reputation and regulatory risks through the violation of our License requirements. Gunn's Hill Windfarm Inc has requested that HONI proceed with the connection work that is required to connect Gunn's Hill Wind Farm to the HONI system.

Investment Summary:

The subject generation project is proposed for connection to Commerce Way TS on the 27.6 kV, M1 feeder. The generating facility located at 485044 Firehall Rd, Township of Norwich, Oxford County would include 10 x 1880 kW generators, for a total of 18 MW. Hydro One has carried out the connection studies including a Connection Impact Assessment (CIA) study and a class C type cost estimate. IESO assessment (SIA) has been completed. Distribution system major work includes reconductoring of 2.5 km of existing line from 3/0 ACSR to 556AL conductors. The CIA indicates that there are no significant impacts to HONI customers. The Customer's proposed in-service date is so close and difficult to meet, the new date will be negotiated with the Customer at the Project Management kick-off meeting. Approval is requested to proceed with the CCA and the project. The HONI connection work will start once Gunn's Hill Windfarm Inc has signed the CCA and paid all the required deposits. The Director - Customer Care will sign the CCA on behalf of HONI. Transmission costs (station protection and telecom cost) be incurred as a result of these connections. Separate ARs have been created for the Transmission (AR # 23211) and Distribution (AR # 23210) portion of the work.

Results:

This investment will enable the connection of Generator Gunn's Hill Wind Farm.

Costs:

	2014 K	Total K
Capital* and MFA	1522	1522
OM&A and Removals	0	0
Gross Investment Cost*	1522	1522
Recoverable	766	766
Net Investment Cost	756	756

The cost estimate include AFUDC and overheads at current rates.

Investment Driver: N.D.C.2.03 Date: March 26,2014

AR Number: 23210,23211 Title: Commerce Way TS M1 ID 22500 Gunn's Hill Wind Farm.

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

Do Nothing - The do nothing alternative is not a viable option as the generation facility would not be connected to Hydro One's system, would not satisfy our license requirements nor meet our stakeholder expectations to connect generation facilities when possible.

ALTERNATIVES CONSIDERED FURTHER

Alternative One

Connect new ID-22500 Gunn's Hill Wind Farm to HONI system as per license requirements while maintaining customer connection reliability and system security.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

Alternative 1 is recommended as the generation facility would be connected to Hydro One's system, would satisfy our license requirements and meet our stakeholder expectations to connect generation facilities when possible.

Alternatives Compared

	Project Level Risk		
Business Value	**Current Risk**	**Alt1**	**Comparison**
Reliability	N/A	N/A	Not influential in the investment decision.
Customer	HIGH	LOW	Alternative 1 mitigates the risk of customer dissatisfaction with Hydro One.
Competitiveness	N/A	N/A	Not influential in the investment decision.
Safety and environment	N/A	N/A	Not influential in the investment decision.
Regulatory / Legal	HIGH	LOW	Alternative 1 mitigates these risks of not complying with our license requirements.
Reputation	HIGH	LOW	Not meeting our license requirements would result in deterioration of public image of HONI
Initial Cost ($K)		1522	
Financial: PV Cost / NPV ($K)			NPV was not calculated as there is only one viable alternative and this investment is not primarily driven by financial factors.

Project Risk and Mitigation:

Cost:

The project cost is based upon a Class C estimate from Project Development, which is accurate in the range of +/-50%, and includes a contingency for in-scope variances of $96,000 which is 15% of the direct project cost.

The estimated total cost, for the HONI connection work is $1522K.

This includes:

Connection Assets - $75K

Expansions - $742K

Renewable Enabling Improvements (REI) - $14K

Upstream Station Work - $539K

Upstream Telecom Work - $152K

Investment Driver: N.D.C.2.03 Date: March 26,2014

AR Number: 23210,23211 Title: Commerce Way TS M1 ID 22500 Gunn's Hill Wind Farm.

Cost Contribution:

The terms and conditions in the CCA mitigate the risks associated with timing, cost level, scope and recovery of the actual cost of the HONI connection work per the Distribution System Code.

Gunn's Hill Wind Farm will contribute $766K calculated in accordance with the Distribution System Code. The remaining expenditures, $756K will be borne by Hydro One.

The proponent's contribution incorporates a reduction of $50,993. This reduction is the net of the impact from the economic evaluation and the Distributor Funded Expansion of $835,201.

Business Planning:

Dx costs of $831K are included in the (2014-2019) Business Plans under DC 203 as AIP #000199. Re-direction is not required
Tx costs of $691K are included in the (2014-2019) Business Plan under AIP #000931. Re-direction is not required.

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Others:

Timing & Scope of Work:

The terms and conditions in the CCA mitigate the risks associated with timing and scope of the HONI connection work.

Customer Withdrawal:

The terms of the CCA mitigate financial risks should Gunn's Hill Wind Farm withdraw once the project has started.

Execution:

Approvals N/A
S.92 N/A
EA N/A

Outages Med

Outage needs continue to be a risk that could delay the in-service date of the project. Releasing the work well ahead of the proposed 7/5/2014 in-service date should help with outage and resource planning.

Resourcing High

The Customer originally requested an in-service date of July 5, 2014 and the Customer has had delays on their end. Since a new in-service date is still to be negotiated. The risk of having resource availability is still high.

First Nations N/A
Real Estate N/A
Agreements Low
Technology Low

Others:

Regulatory Considerations

The costs for this generation facility connection are allocated as per the Distribution System Code and any portions recoverable will be recovered consistent with HONI Policy.

No significant regulatory issues anticipated other than standard need and prudence justification.

hydro one

Investment Driver: N.D.C.2.03 Date: March 26,2014

AR Number: 23210,23211 Title: Commerce Way TS M1 ID 22500 Gunn's Hill Wind Farm.

Funds Included in Business Plan: Y	**Director:** Paul Brown	**Planner:** Muhammad Sabir
This Approval($K): 1522	**Previous Approval($K):** 0	**Current Est. of Total Cost($K):** 1522
Signature Block:		
Submitted by: Muhammad Sabir	**Title:** Planner	**Date:** April 2/2014
Reviewed by: for William Chan Viktor	**Title:** Manager	**Date:** April 2/2014
Recommended by: John Fuerth	**Title:** Manager	**Date:** Apr 2/2014
Approved by: Paul Brown	**Title:** Director	**Date:** APRIL 2/14

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

INTERIM REVIEW OF VARIANCE (IROV)

40002440

Check All Applicable Boxes to Show Variances Requiring OAR Approval

☑ Cost Increase ☑ Schedule (Business Impactive) Scope Change (Significant)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date
23210 23211	N.D.C.2.03 N.T.C.2.19	Asset Management	Engineering and Construction	25-Nov-15

Investment Title		Original Approved Cost *(as per BCS)*	$1,522 K
Commerce Way TS M1 ID 22500 Gunn's Hill Wind Farm		Total Cost Approved plus Requested	$2,251 K
Original approved in-service date	**Proposed new in-service date**	Current Cost ratio	148%
July 5, 2014	July 14, 2016		

Background Situation:

The BCS was approved with total funding of **$1,522K**, including a customer contribution of **$766k**, for the connection of DG project 22,500 (Gunn's Hill Wind Farm) in April, 2014. The release was based on the accepted risk of a Class "C" estimate with no preliminary engineering or site visits. Once Provincial Lines completed their detailed design, it was discovered that the route would have to change, resulting in a significant increase in the line expansion cost. The Customer was notified immediately of this change and potential cost impact to them.

An in-service date of November 2015 was negotiated with the Customer at the project kick-off meeting in March 2015 as per the current DG process. The Customer has since deferred their in-service date to July 2016 as a result of their facility not being ready to connect.

Variance Explanation: *(Discussion of significant cost, schedule, and scope changes, and an explanation of root causes.)*

The Customer funded portion is expected to decrease from **$766k** to **$558k**, primarily due to the removal of station work that the Customer was responsible to pay for. The Hydro One funded portion of the work is expected to increase from **$756k** to **$1,693k**, as a result of the increased cost of the line expansion, as Hydro One pays $90k/MW of the line expansion cost. The root casues for the total cost variance are as follows:

1. Original estimate for line expansion did not consider actual site conditions and route

The original Class 'C' estimate prepared for the project was not based on actual site conditions, and assumed that reconductoring was possible with minimal pole replacement. Upon completion of the detailed design in May 2015, it was determined that the planned route would require complete pole replacement (overbuilding) and migration of the line from private property onto the road allowance, resulting in a significant design change and cost variance. An revised estimate was prepared in September 2015 incorporating this change.

2. Reduction to station work due to PCT in a box at Commerce Way

The Class C estimate did not reflect site conditions at Commerce Way TS as there was no site visit or detailed estimate prepared. Due to a new PCT building with modernized equipment in place, the required upgrades at the station were significantly reduced. This change was also incorporated in the revised estimate to the Customer.

Lessons Learned:

Hydro One is regulated to provide the Customer with a completed CIA within 60 days (DSC 6.2.12-13,16). In addition, Hydro One provides an estimate at the same time to allow the Customer to make an informed decision about their project. As a result of the compressed timeline, only 5 days are allocated to produce the estimate, which is of Class "C" accuracy. In most cases to-date, these estimates have been of sufficient quality.

> Distribution Asset Management and Project Delivery to undertake review of the DG Connection Process in the following areas:
- Class C estimate variance control process for cost, scope, and schedule.
- Required estimate detail for projects with atypical scope.
- Estimate quality and timing for business case approval.

Approvals

Submitted by:	Signature	Date
Chris Cooper Director, Project Delivery	Chris Cooper	Dec 2, 2015
Recommended by:	**Signature**	**Date**
Brad Bowness VP, Construction Services	B. Bowness	Dec 2/2015
Reviewed by:	**Signature**	**Date**
Mike Penstone VP, Planning	M Penstone	Dec 2/2015
Financial Review: *(If President Approval Required)*	**Signature**	**Date**
Approved by *(As per EAR/OAR)*:	**Signature**	**Date**
Sandy Struthers COO and EVP Strategic Planning		Dec 2/2015

INTERIM REVIEW OF VARIANCE (IROV)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date *(mm/dd/yy)*
23210 23211	N.D.C.2.03 N.T.C.2.19	Asset Management	Engineering and Construction	November 25, 2015

Investment Title		
Commerce Way TS M1 ID 22500 Gunn's Hill Wind Farm	5. Original Approved Cost *(Line 1)*	$1,522 K
	6. Total Cost Approved Plus Requested *(line 4)*	$2,251 K

Project Manager	Planner	Current Cost ratio *(Box 6/Box 5)*	148%
Anthony Manna	Muhammad Sabir		

1. Original approved cost *(per BCS)*	1.1 OM&A	$0 K	**Original approved in-service date** *(as per line 1)*
	1.2 CAPITAL	$1,522 K	July 5, 2014
	1.3 REMOVALS	$0 K	
	TOTAL	$1,522 K	
2. Total $ currently approved *(Original plus previous IROVs awards)*	2.1 OM&A	$0 K	**Current approved in-service date** *(as per line 2)*
	2.2 CAPITAL	$1,522 K	July 5, 2014
	2.3 REMOVALS	$0 K	
	TOTAL	$1,522 K	

		Total (A + B)	(A) Cost of Scope Increases	(B) Cost of "In-Scope" Project Variances
3. Revision now requested	3.1 OM&A	$0 K	$0 K	$0 K
	3.2 CAPITAL	$729 K	$0 K	$729 K
	3.3 REMOVALS	$0 K	$0 K	$0 K
	TOTAL	$729 K	$0 K	$729 K

4. Total Cost including OH & AFUDC *(Line 2 plus line 3)*	4.1 OM&A	$0 K	**Proposed new in-service date** *(as per line 3)*
	4.2 CAPITAL	$2,251 K	July 14, 2016
	4.3 REMOVALS	$0 K	
	TOTAL	$2,251 K	

Summary of Variance:

1. Design change for line expansion portion of work.
2/3. Reduction to work required at station due to project actuals and use of existing equipment at Commerce Way TS (PCT-in-a-box).

Total cost forecast breakdown: Dx $1,991k | Tx $260k

#	Item / Description	Cost of Scope increase $K	In-Scope Variance $K
1	Design change resulting in cost variance due to change in route and from reconductoring to overbuild of existing pole line.		$1,160 K
2	Reduction to protection station work due to PCT in a box at Commerce Way TS.		-$414 K
3	Reduction to telecom station work by utilizing existing lighting tower for antenna mounting at Commerce Way TS.		-$17 K
4			
5			
6			
7			
8			
9			
10			
	Total Variance Costs	$0 K	$729 K

Project Cashflow Detail by Year

Description		2012	2013	2014	2015	2016	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	CAPITAL	$0 K	$0 K	$0 K	$2,151 K	$100 K	$2,251 K
	REMOVALS	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	TOTAL	$0 K	$0 K	$0 K	$2,151 K	$100 K	$2,251 K

Investment Driver: N.D.C.2.02 Date: September 24,2013

AR Number: 22725 Title: Beckwith DS T2 and F3

Hydro One Networks - Business Case Summary - 50003287

Beckwith DS T2 and F3

Investment Driver: **In-Service date:** May 15,2015

N.D.C.2.02 - System Capability Reinforcement (2014-$71.09 M)

Investments in System Capability provide for new or modified system facilities to accommodate (1) increases in customer load; (2) improvements in system reliability; (3) improved operational efficiency and asset life cycle planning; and (4) contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This Approval: $20K **Previous Approval:** $0 **Project Total:** $20K

Need:

Beckwith DS is a 44-27.6/16 kV station that is projected to exceed its Planned Loading Limit (PLL) due to load growth in its supply area.

Not remedying this situation will result in transformer overload conditions leading to increased risk of load restriction, equipment damage, failure, and associated outages.

Investment Summary:

The growth areas that Beckwith DS supplies offer no load transfer opportunities. There are no other opportunities for load relief.

This investment proposes to add a second transformer bank, together with one additional feeder position, to provide reliable capacity to supply existing and new customers in the growing suburban area outside Ottawa.

Approval of a $20 k expenditure to provide a Class A estimate of costs is requested.

Results:

Eliminate overloading and risk of outages by bringing Beckwith DS within its load rating specification and providing capacity to supply future growth in and around Carleton Place. Optimize alternate supply and emergency backup. Reduce reliance on MUS for station transformer failures and maintenance.

Costs:

	2014 K	Total K
Capital* and MFA	20	20
OM&A and Removals	0	0
Gross Investment Cost*	20	20
Recoverable	0	0
Net Investment Cost	20	20

*Cost includes AFUDC and overheads at current rates

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

Continuing to overload equipment beyond its ratings, risking prolonged customer outages is unacceptable. Therefore this alternative is rejected.

Alternative Two

Select a new site and construct a new DS complete with feeders, and supply facilities (44 kV). This alternative was judged at the development stage to be at least twice as expensive as Alternative One and was therefore rejected.

ALTERNATIVES CONSIDERED FURTHER

Alternative One

Add a second bank and one additional feeder position at Beckwith DS.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

Alternative One is recommended as it provides relief to the overloaded equipment and offers substantial ability of alternate supply to this growing urban area. Risks to reliability, customer loads, and Hydro One's reputation will be eliminated. Projected growth will be able to be reliably supplied for at least the next 10 years.

Project Risk and Mitigation:

Business Planning:

The funds are included in the Business Plan for 2013-2017 under Accomplishment ID 3780. No redirection is required.

Execution Risks:

S.92	N/A
EA	N/A
Outages	Low
Resourcing	Low
First Nations	N/A
Real Estate	N/A
Agreements	Low
Technology	Low

Regulatory Considerations:

No ISD for this investment was included in the 2013 Dx rate case EB-2012-0136 as it is not required to be filed in this IRM application.

No significant regulatory issues are anticipated other than the standard need and prudence justification.

Investment Driver: N.D.C.2.02 Date: September 24,2013

AR Number: 22725 Title: Beckwith DS T2 and F3

Funds Included in Business Plan: Y	**Director:** Paul Brown		**Planner:** Ashley LeBel	
This Approval($K): 20	**Previous Approval($K):** 0		**Current Est. of Total Cost($K):** 20	
Signature Block:				
Submitted by: Ashley LeBel		Title: Planner		Date: 26/9/13
Reviewed by:		**Title:**		**Date:**
Recommended by:		Title:		Date:
Approved by: Lyla Garzouzi		Title: Manager		Date: Sept 26, 2013

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

hydro one

Investment Driver: N.D.C.2.02 Date: January 12,2015

AR Number: 22725 Title: Beckwith DS T2 and F3

Hydro One Networks - Business Case Summary - 50003915

Beckwith DS T2 and F3

Investment Driver: **In-Service date:** May 15,2016

N.D.C.2.02 - System Capability Reinforcement (2016-$102.88 M)

Investments in System Capability provide for new or modified system facilities to accommodate (1) increases in customer load; (2) improvements in system reliability; (3) improved operational efficiency and asset life cycle planning; and (4) contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This Approval: $3.0M **Previous Approval:** $0.0M **Project Total:** $3.0M

Need:

Beckwith DS is a 44-27.6/16 kV station that is projected to exceed its Planned Loading Limit (PLL) due to load growth in its supply area.

Not remedying this situation will result in transformer overload conditions leading to increased risk of load restriction, equipment damage, failure, and associated outages. The area serviced by Beckwith DS is also bordering the service territory with Hydro Ottawa and the insufficient station capacity will increase the risk of customer complaints and risk unfavorable utility comparisons.

Investment Summary:

Beckwith DS currently supplies 8.5MVA of load and is a hub to developing areas such as Carleton Place and south of Highway 7. The growth areas that Beckwith DS supplies offer no load transfer opportunities. There are no other opportunities for load relief from adjacent stations.

An area study entitled Beckwith DS Area Study, updated in March of 2015 provides the analysis and supports this business case. In the study, forecasted load growth for Beckwith DS will exceed the planned loading limit of the station by 2017 and relief is required. This investment proposes to add a second transformer bank, together with one additional feeder position, to provide reliable capacity to supply existing and new customers in the growing suburban area outside Hydro Ottawa service territory. Approval of a $2957k expenditure is requested to complete the recommended investment proposal.

Results:

Eliminate overloading and risk of outages by bringing Beckwith DS within the station Planned Loading Limit and providing capacity to supply future growth in and around Carleton Place. Move towards grid modernization by increasing visibility and controllability through installation of programmable reclosers. Reduce the risks associated with insufficient supply capacity for customers near the Hydro Ottawa service territory. Provide an alternate supply and emergency backup for the existing station transformer. Reduce reliance on MUS for station transformer failures and maintenance.

Costs:

	2015 M	2016 M	Total M
Capital* and MFA	1.0	2.0	3.0
OM&A and Removals	0.0	0.0	0.0
Gross Investment Cost*	1.0	2.0	3.0
Recoverable	0.0	0.0	0.0
Net Investment Cost	1.0	2.0	3.0

Cost includes AFUDC and overhead at current rates.

Investment Driver: N.D.C.2.02 Date: January 12,2015

AR Number: 22725 Title: Beckwith DS T2 and F3

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

Continuing to overload equipment beyond its ratings, risking prolonged customer outages is unacceptable. Therefore this alternative is rejected.

Alternative Two

Select a new site and construct a new DS complete with feeders, and supply facilities 44 kV. This alternative was rejected at the development stage because the total upfront capital cost is substantially higher (almost double) than the proposed alternative.

Alternative Three

Switch Drummond DS F4 to pick up Beckwith DS F1 and extend F1 by upgrading existing pole structures. There are operational concerns in addition to reliability concerns associated with this option. This option relieves the station in the short term and does not meet the planning requirement for load growth over 10 years and therefore is rejected.

ALTERNATIVES CONSIDERED FURTHER

Alternative One

Add a second bank and one additional feeder position at Beckwith DS.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

Alternative One is recommended as it provides relief to the overloaded equipment and offers substantial ability for alternate supply to this growing urban area. Risks to reliability, customer loads, and Hydro One's reputation will be reduced. Projected growth will be able to be reliably supplied for at least the next 10 years.

Alternatives Compared

	Project Level Risk		
Business Value	**Current Risk**	**Alt1**	**Comparison**
Reliability	HIGH	LOW	Alternative 1 reduces the risk of overloaded equipment failure avoiding prolonged customer outages.
Customer	HIGH	LOW	Alternative 1 will increase the system capacity to serve more customers.
Competitiveness	N/A	N/A	Not influential in the investment decision.
Safety and environment	N/A	N/A	Not influential in the investment decision.
Regulatory / Legal	MED	LOW	A constrained system, with Hydro One refusal of customer requests, could result in a Board investigation of Hydro One's system management practices and fairness in its decision-making between customers.
Reputation	HIGH	LOW	Hydro One will be seen to address system capacity needs in a timely manner.
Initial Cost ($M)		3.0	
Financial: PV Cost / NPV ($M)			NPV was not calculated as the investment is not driven by financial factors

hydro one

Investment Driver: N.D.C.2.02

Date: January 12,2015

AR Number: 22725

Title: Beckwith DS T2 and F3

Project Risk and Mitigation:

Cost:

The project cost is based upon a Class B estimate from Project Development, which is accurate in the range of +/- 20%, and includes a contingency for in-scope variances of $302k, which is 12% of the direct project cost.

Business Planning:

This investment is included in the 2015-2019 Business Plan as AIP000183 with sufficient funding.

Execution Risks:

Approvals - N/A
Section 92 - N/A
EA - N/A
Outages - Low
Resourcing - Low
First Nations - N/A
Real Estate - N/A
Agreements - Low
Technology - Low

Regulatory Considerations:

No significant regulatory issues are anticipated other than the standard need and prudence justification.

Funds Included in Business Plan: Y	**Director:** Paul Brown	**Planner:** Donald Lau
This Approval($M): 3.0	**Previous Approval($M):** 0.0	**Current Est. of Total Cost($M):** 3.0
Signature Block:		
Submitted by: John Fuerth	**Title:** ~~Planner~~ Manager	**Date:** Apr 30/15
Reviewed by: Wade Frost	**Title:** Manager	**Date:** Apr 30/15
Recommended by: Paul Brown	**Title:** Director	**Date:** MAY 1/15
Approved by: Mike Penstone	**Title:** Vice President	**Date:** May 4/15

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

INTERIM REVIEW OF VARIANCE (IROV)

40002391

Check All Applicable Boxes to Show Variances Requiring OAR Approval

☐ Cost Increase ☐ Schedule (Business Impactive) ☑ Scope Change (Significant)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date
22725	N.D.C.2.02	DX Asset Management	Engineering	14-Sep-15

Investment Title		Original Approved Cost *(as per BCS)*	$3,000 K
Beckwith DS T2 and F3		Total Cost Approved plus Requested	$2,700 K
Original approved in-service date	Proposed new in-service date	Current Cost ratio	90%
May 15, 2016	May 15, 2016		

Background Situation:

The original investment (BCS# 50003915) was approved to add another transformer bank and an additional feeder position, at Beckwith DS, to provide additional station supply capacity. During recent reviews of spare transformers at CMS, a suitable transformer was found for this project, which avoids the cost of purchasing a new transformer for the Beckwith DS project. Additionally, the project scope has been revised to include the installation of telecom so that Beckwith DS feeder reclosers can be monitored and controlled by DMS, including the two existing feeder reclosers. This requires upgrading the two existing reclosers to meet the current standard for such devices.

Variance Explanation: *(Discussion of significant cost, schedule, and scope changes, and an explanation of root causes.)*

The cause for the variance in scope are:
- A recent review of the CMS spare pool for the required transformer has shown we have a spare suitable for this project and would not need to buy a new one (-$500k)
- A recent DX AM decision was made to revise 2016 station project scopes to include the installation of telecom so that feeder reclosers can be monitored and controlled by DMS. This requires upgrading the F1 and F2 feeder reclosers to electronic reclosers ($100k) and adding telecom connections ($100k).

Lessons Learned:

Before requesting an Engineering cost estimate for a project, DX AM Planner needs to confirm needs for purchase of a new transformer. Due to recent initiatives to address CMS spare transformer inventories, information is now readily available.

Approvals

	Signature	Date
Submitted by:	Signature	Date
Donald Lau	Donald Lau	September 14, 2015
Recommended by:	Signature	Date
John Fuerth		September 14, 2015
Reviewed by:	Signature	Date
John Fuerth		September 14, 2015
Financial Review: *(If President Approval Required)*	Signature	Date
N/A		
Approved by *(As per EAR/OAR)*:	Signature	Date
Paul Brown		September 14, 2015

INTERIM REVIEW OF VARIANCE (IROV)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date *(mm/dd/yy)*
22725	N.D.C.2.02	DX Asset Management	Engineering	September 14, 2015

Investment Title		
Beckwith DS T2 and F3	5. Original Approved Cost *(Line 1)*	$3,000 K
	6. Total Cost Approved Plus Requested *(line 4)*	$2,700 K

Project Manager	Planner	Current Cost ratio *(Box 6/Box 5)*	90%
Saad Hameed	Donald Lau		

1. Original approved cost *(per BCS)*	1.1 OM&A	$0 K	Original approved in-service date *(as per line 1)*		
	1.2 CAPITAL	$3,000 K	May 15, 2016		
	1.3 REMOVALS	$0 K			
	TOTAL	$3,000 K			
2. Total $ currently approved *(Original plus previous IROVs awards)*	2.1 OM&A	$0 K	Current approved in-service date *(as per line 2)*		
	2.2 CAPITAL	$3,000 K	May 15, 2016		
	2.3 REMOVALS	$0 K			
	TOTAL	$3,000 K			
3. Revision now requested		Total (A + B)	(A) Cost of Scope Increases	(B) Cost of "In-Scope" Project Variances	
	3.1 OM&A	$0 K	$0 K	$0 K	
	3.2 CAPITAL	-$300 K	$200 K	-$500 K	
	3.3 REMOVALS	$0 K	$0 K	$0 K	
	TOTAL	-$300 K	$200 K	-$500 K	
4. Total Cost including OH & AFUDC *(Line 2 plus line 3)*	4.1 OM&A	$0 K	Proposed new in-service date *(as per line 3)*		
	4.2 CAPITAL	$2,700 K	May 15, 2016		
	4.3 REMOVALS	$0 K			
	TOTAL	$2,700 K			

Summary of Variance:

Recent review of our spare pool has shown we have a spare transformer that could be used for this project and would not need to purchase a new transformer (-$500k). Preparing for grid modernization it is benificial to replace the exisiting F1 and F2 oil recloser to G&W viper at this time as we are already on site ($200k).

#	Item / Description	Cost of Scope increase $K	In-Scope Variance $K
1	10MVA 44-27.6kV non-ULTC transformer		-$500 K
2	2 x G&W vipers	$100 K	
3	DMS control equipment	$100 K	
4			
5			
6			
7			
8			
9			
10			
	Total Variance Costs	$200 K	-$500 K

Project Cashflow Detail by Year

Description		2015	2016	2017	2018	2019	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	CAPITAL	$0 K	$2,700 K	$0 K	$0 K	$0 K	$2,700 K
	REMOVALS	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	TOTAL	$0 K	$2,700 K	$0 K	$0 K	$0 K	$2,700 K

Investment Driver: N.D.C.1.08 Date: September 12, 2012
AR Number: 22268 Title: Purchasing and Installation of Pilot iMDS's

Hydro One Networks - Business Case Summary - 50002351

Purchasing and Installation of Pilot iMDS's

Investment Driver: **In-Service date:** July 01, 2013

N.D.C.1.08 - Distributing and Regulating Stations (2012-$20.4M, 2013- $58.2M)

Distribution and Regulating Stations provide facilities that transform and regulate voltages to distribution levels and facilitate switching, protection and distribution feeder connections to load customers.

This Approval: $3.9M **Previous Approval:** $0 **Project Total:** $3.9M

Need:

This investment is needed for Hydro One to realize its accomplishment and financial goals in distribution station refurbishments in 2013 and beyond. This investment will help Hydro One realize a standardized/modular solution to Distribution Stations which has the potential to result in lower cost per unit installations. Not proceeding with this investment would limit Hydro One's ability to increase the number of station refurbishments leading to decreased reliability and health and safety risks.

Investment Summary:

The Hydro One distribution system utilizes approximately 1000 in-service distribution and regulating stations. Hydro One will be promoting significant increases in its distribution capital replacement program over the next five years. Historically Hydro One has refurbished 3-5 Distribution Stations per year, through program work, while future investment plans call for 30 refurbishments per year to manage existing and long term pressures of an aging infrastructure. A change in approach is required to reach this increased accomplishment. The iMDS (integrated Modular Distribution Station) is a streamlined, innovative method to station design, construction and commissioning which will help Hydro One realize this objective. The iMDS will allow Hydro One to achieve considerable cost savings in distribution station refurbishments as well as Greenfield stations. Hydro One will be buying a product (iMDS) from a vendor catalogue. This will allow Hydro One to tap into market innovation, install a more reliable distribution station and realize aggessive accomplishment goals set out in the business plan. The iMDS's will be installed at four distribution stations that are at end of life as pilot projects. Upon successful completion of the pilot project, Hydro One will be able to quantify the cost savings achieved with the iMDS, detail timelines required for construction, receive a standard design package and the iMDS will be available for application in both Sustainment and Development investments.

Results:

Complete pilot project at selected end of life distribution stations throughout the province.

Costs:

	2012 M	2013 M	Total M
Capital* and MFA	1.8	1.9	3.7
OM&A and Removals	0.0	0.2	0.2
Gross Investment Cost*	1.8	2.1	3.9
Recoverable	0.0	0.0	0.0
Net Investment Cost	1.8	2.1	3.9

* Costs include AFUDC and overhead at current rates

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

Status quo would be to refurbish the four distribution stations using Hydro One standard practices. This will result in an insufficient number of distribution stations being refurbished relative to future investment plans, resulting in an increase in on site repairs which would significantly increase outage durations. Also, the current expenditure for a distribution station refurbishment is in the range of $1.5M - $3.0M. This was rejected due to cost and that this would not allow Hydro One to achieve efficiency gains.

ALTERNATIVES CONSIDERED FURTHER

Alternative One

Purchase 4 iMDS's and install at 4 predetermined distribution stations that are at end of life and require refurbishment. This pilot project will provide Hydro One with data on cost, installation time, maintenance requirements, procedures and provide a standardized design for distribution stations.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

Alternative one is recommended because purchasing and installing 4 iMDS's is the start of Hydro One implementing an innovative, more reliable distribution station, which will eventually enable Hydro One to realize accomplishment goals. The chances of accomplishing desired units in station refurbishments increases as the iMDS is a pre-engineered, pre manufactured distribution station.

The four pilot locations were chosen because each station is at end of life, they are in the same geographical location which enables the use of the same work crews for the installations, each station can be off loaded within its respective town eliminating the need for two iMDS's and each candidate has no tap changing requirements. Four locations is ideal for the pilot project as it allows Hydro One the option of leveraging innovative ideas from more than one vendor.

The iMDS concept is already in use in western Canada (Saskatchewan Power, Oil and Mining companies)

Investment Driver: N.D.C.1.08 Date: September 12, 2012

AR Number: 22268 Title: Purchasing and Installation of Pilot iMDS's

Alternatives Compared

	Project Level Risk		
Business Value	**Current Risk**	**Alt1**	**Comparison**
Reliability	MED	LOW	Installing 4 iMDS's will maintain reliability as end of life assets are being replaced. A successful pilot will reduce future reliability risk
Customer	MED	LOW	Distribution station outages have direct impact on customers, can be long duration events and can attract local media. The success of this pilot program will help maintain reliability to customers and reduce the risk of outages as aging, end of life assets are replaced
Competitiveness	MED	LOW	The iMDS is expected to reduce its cost per unit when refurbishing distribution stations.
Safety and environment	MED	LOW	The iMDS design is a much safer station as there is no exposed energized equipment and conductors, which will eliminate copper theft and animal outages as well as provide a safer work environment for Hydro One staff.
Regulatory / Legal	N/A	N/A	Not influential in the investment decision.
Reputation	MED	LOW	If no action is taken to address the high number of end of life distribution stations, the company reputation will be damaged
Initial Cost ($M)		3.9	
Financial: PV Cost / NPV ($M)			NPV was not calculated as there is only one viable alternative and this investment is not primarily driven by financial factors

Project Risk and Mitigation:

Cost:

The installation costs associated with this investment are based on a class "C" estimate from Grid Operations which is accurate in the range of +/- 50%. The estimate from Grid Operations contains a contingency of 10%. The costs of purchasing and installing 4 iMDS's throughout the province were estimated based on extensive budgetary discussions with possible vendors. Actual procurement will be conducted through a competitive RFP process, and is expected to be within the requested amount. The contingency for in scope variance is $0.4M, which is 13% of the direct project cost.

Business Planning:

This investment is included in the 2012-2016 Business Plan within Accomplishment Id# 3 with sufficient funding.

hydro one

Investment Driver: N.D.C.1.08

Date: September 12, 2012

AR Number: 22268

Title: Purchasing and Installation of Pilot iMDS's

Execution Risks: ___

Approvals - N/A
Section 92 - N/A
EA - N/A
Outages - Low
Resourcing - Low (Engineering, assembly, commissioning will be completed by external vendor)
First Nations - N/A
Real Estate - N/A
Agreements - N/A
Technology - N/A

Regulatory Considerations:

No significant regulatory issues anticipated other than standard need and prudence justification. This investment was included in the 2013 IRM Distribution Rate application

Funds Included in Business Plan: Y	**Redirection Required:** N	**Planner:** Ryan DOCHERTY
This Approval($M): 3.9	**Previous Approval($M):** 0	**Current Est. of Total Cost($M):** 3.9

Signature Block:

Submitted by: Andrew Spencer		Title: Manager, Station Sustainment Prgm	Date: SEPT 19/2012
Reviewed by: Michael Satchell	M Satchell	Title: Manager Decision Support	Date: Sept 21/12
Recommended by: Darlene Bradley	Darlene Bradley	Title: Director, Sustainment Investment Plng	Date: Sept 26/12
Approved by: Rick Stevens	R Stevens	Title: Vice President, Asset Management	Date: Sept 27/12

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

INTERIM REVIEW OF VARIANCE (IROV)

40002370

Check All Applicable Boxes to Show Variances Requiring OAR Approval

☑ Cost Increase ☑ Schedule (Business Impactive) ☐ Scope Change (Significant)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date
22268	N.D.C1.08	Distribution Asset Management	Station Services / E&C	29-Jan-15

Investment Title		Original Approved Cost *(as per BCS)*	$3,900 K
Purchasing and Installation of Pilot iMDS's		Total Cost Approved plus Requested	$7,600 K
Original approved in-service date	Proposed new in-service date	Current Cost ratio	195%
July 1, 2013	August 15, 2015		

Background Situation:

The iMDS project was approved on September 12, 2012 (BCS# 500023251) and its objective was to rebuild or refurbish 4 distribution stations using an iMDS design (integrated Modular Distribution Station) at each station. The project includes work at Havelock Industrial DS , Brockville Parkdale DS, Trenton Frankford DS and Campbellford Industrial DS. Construction at Havelock started in August 2013 and was completed in December 2013. Construction at Brockville Parkdale DS started in December 2013 and was completed in August 2014. Construction at Trenton was completed in Jan 2015. Construction at Campbellford will be completed in 2015.

Variance Explanation: *(Discussion of significant cost, schedule, and scope changes, and an explanation of root causes.)*

The cause for the variance in cost and schedule are:
- Civil design of the underground vaults and concrete slab proved to be challenging for civil construction to implement resulting in increased construction labour costs and schedule delays.
- The decision to assign the same construction crews for all four pilot projects has resulted in a schedule delay as the projects could not be constructed in parallel, rather one after another. Additional storage charges were incurred to house the units.
- The iMDS unit for Havelock DS was not compatible due to over voltage issues and needed to be replaced with a different unit. The unit at Havelock will be utilized at another Distribution station requiring refurbishment.
- Additional interest and other costs due to the extended schedule
- Overhead rate increase
- Additional Engineering as a wooden station fence was installed at Brockville Parkdale DS; and, actual commissioning hours were more than the estimated amount.

Lessons Learned:

Lessons Learned:
- Efficiencies can be gained by installing a smaller, simpler civil structure which will reduce installation time and costs.
- Multiple construction crews can be assigned so that they work in parallel in order to accomplish more projects
- Additionally, when a variance is flagged, it should be raised to the appropriate OAR (Director, SVP, EC) so that risks are known and approval to continue can be given to the project team.
- A "one team working together" approach will be used to complete the pilot project and to move forward with more iMDS installations; because this approach leads to more efficient and effective resolution of issues. Much has been learned from this pilot project, but beyond this project, there are further opportunities to improve the design and to look for even more affordable installations.

$500k savings per station is confidently realizable over conventional designs.

Approvals

Submitted by:	Signature	Date
Paul Brown, Director DX Asset Management		FEB 19, 2015
Recommended by:	**Signature**	**Date**
Mike Penstone, VP Planning		Feb 19/15.
Reviewed by:	**Signature**	**Date**
Andy Stenning, VP Stations & Operating		Feb. 27/15
Financial Review: *(If President Approval Required)*	**Signature**	**Date**
N/A	N/A	N/A
Approved by *(As per EAR/OAR)*:	**Signature**	**Date**
Sandy Struthers, COO & EVP Strategic Planning		March. 3/15

INTERIM REVIEW OF VARIANCE (IROV)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date *(mm/dd/yy)*
22268	N.D.C1.08	Distribution Asset Management	Station Services / E&C	January 29, 2015

Investment Title		
Purchasing and Installation of Pilot iMDS's	5. Original Approved Cost *(Line 1)*	**$3,900 K**
	6. Total Cost Approved Plus Requested *(line 4)*	**$7,600 K**

Project Manager	Planner	Current Cost ratio *(Box 6/Box 5)*	**195%**
Satish Saini	Daniel Weisser		

1. Original approved cost *(per BCS)*	1.1 OM&A	$0 K	**Original approved in-service date** *(as per line 1)*	
	1.2 CAPITAL	$3,700 K	July 1, 2013	
	1.3 REMOVALS	$200 K		
	TOTAL	**$3,900 K**		
2. Total $ currently approved *(Original plus previous IROVs awards)*	2.1 OM&A	$0 K	**Current approved in-service date** *(as per line 2)*	
	2.2 CAPITAL	$3,700 K	July 1, 2013	
	2.3 REMOVALS	$200 K		
	TOTAL	**$3,900 K**		
3. Revision now requested		Total (A + B)	(A) Cost of Scope Increases	(B) Cost of "In-Scope" Project Variances
	3.1 OM&A	$0 K	$0 K	$0 K
	3.2 CAPITAL	$3,500 K	$0 K	$3,500 K
	3.3 REMOVALS	$200 K	$0 K	$200 K
	TOTAL	**$3,700 K**	**$0 K**	**$3,700 K**
4. Total Cost including OH & AFUDC *(Line 2 plus line 3)*	4.1 OM&A	$0 K	**Proposed new in-service date** *(as per line 3)*	
	4.2 CAPITAL	$7,200 K	August 15, 2015	
	4.3 REMOVALS	$400 K		
	TOTAL	**$7,600 K**		

Summary of Variance:

The original estimate was undertaken as a class C+/-50% and did not have sufficient funds for interest and overheads. Construction and design costs were much higher than originally estimated due to the use of concrete vaults for the Brockville and Havelock stations. In the Brockville station, a wooden fence was added to the scope. In Havelock station, the iMDS unit had to be removed and a new unit installed because of over voltage issues. Scheduling delays resulted in additional unit storage charges. Actual commissioning hours were more than the estimated amount. Additional engineering charges were incurred due to scope changes.

#	Item / Description	Cost of Scope increase $K	In-Scope Variance $K
1	Cost to design, construct, and commission four stations.		$3,500 K
2	Removals		$200 K
3	OM&A		$0 K
4			
5			
6			
7			
8			
9			
10			
	Total Variance Costs	**$0 K**	**$3,700 K**

Project Cashflow Detail by Year

Description		2012	2013	2014	2015	2016	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	CAPITAL	$1,700 K	$1,900 K	$2,600 K	$1,000 K	$0 K	$7,200 K
	REMOVALS	$0 K	$200 K	$100 K	$100 K	$0 K	$400 K
	TOTAL	**$1,700 K**	**$2,100 K**	**$2,700 K**	**$1,100 K**	**$0 K**	**$7,600 K**

Memo

To: Sandy Struthers, COO & EVP Strategic Planning

From: Paul Brown, Director – Distribution Asset Management

CC:

Date: February 2015

Re: AR 22268 – Purchase and Installation of Pilot iMDS Units

Purpose

The purpose of this memorandum is to provide information in support of the IROV for this project.

Project Overview

Historically Hydro One has refurbished 3-7 Distribution stations per year, through program work, while future investment plans call for 30 - 35 refurbishments per year to manage existing and long term pressures of aging infrastructure. A change in approach was required to reach this increased accomplishment. The iMDS (integrated Modular Distribution Station) is a streamlined, innovative method to station design, construction and commissioning that was conceptualized to help Hydro One reach this objective.

The iMDS should allow Hydro One to achieve considerable cost savings in distribution station refurbishments as well as greenfield stations. Hydro One has purchased a product (iMDS) from a vendor catalogue. This should allow Hydro One to tap into market innovation and realize aggressive accomplishment goals set out in the business plan. The iMDS's were planned for installation at four different distribution stations that are at end of life as pilot projects. Sufficient understanding of costs from the pilot to date we are confident of achievable cost savings and timelines over conventional designs. We are working on a standard design package. We are continuing with the plan to implement this design in both Sustainment and Development DS investments.

The objective of the iMDS Pilot Project (AR 22268) is to refurbish four (4) Distribution Stations with an iMDS unit at each station. All four stations have been identified at end of life and require replacement. Every asset at each station will be replaced. The four stations are: Havelock Industrial DS, Brockville Parkdale DS, Campbellford Industrial DS and Trenton Frankford DS.

This project received VP approval September 12, 2012 for an estimated cost of $3.9M with an in-service date of July 1, 2013. A $0.4M contingency allowance (11% of Base Cost) was included.

Of the four stations to be completed in this project, three have been completed to date. The request for additional funding is to complete the remaining station. Originally an estimate was produced where each station would cost $875k, resulting in four stations at $3500k. The revised project cost, for which approval is being requested, is based on the costs to complete the first three stations - $5650k, in total - plus the Grid Operations and Power System Project Management estimated cost for the fourth station.

Although the actual costs of completion for the first three stations are over the estimated budget, Hydro One did realize cost savings as the unit cost for a similar project utilizing a standard U-90 design is $2470k.

The first two stations were designed using three large cement vaults for the underground cables as well as a poured cement block to support the structure. In an effort to simplify installation and reduce installation cost, a slab on grade structure will be used on the remaining two stations. The cost savings expected by using a slab on grade foundation has not been quantified in the estimate for the remaining two stations. Execution of the project was managed by Grid Operations for the first three stations, and, Power System Project Management will manage the fourth station.

Current Project Status

Havelock Industrial DS
Equipment in-service: December, 2013. Station on potential and not carrying load as replacement unit is ordered to correct the system voltage issue

Brockville Parkdale DS
Equipment in-service: July 16, 2014

Trenton Frankford DS
Construction started in October 2014
Equipment in-service: Jan 2015

Campbellford Industrial DS
Power System Project Management forecast in-service date: July 2015

Schedule Delay

The original in-service was July 1, 2013. All major equipment is scheduled to be in-service in July 2015. The following are the main contributing factors to the schedule delay:

1) The same construction crew has been assigned to all four stations. Therefore no work can happen in parallel.
2) There have been multiple project managers throughout the pilot project and therefore delays attributed with transition to new people.
3) Construction time has taken a lot longer than anticipated due to the installation of three large concrete vaults under each iMDS. Also, a wooden fence was installed at Brockville Parkdale DS, while the functional specification of the iMDS calls for no station fence.

Cost Variances

Estimate Variances: $3700k

On a per station basis, the variance, based on an original estimate of $875 per station plus contingency of $100 k per station, is as follows:

First station – Havelock Industrial DS – actual cost of $1800 k or variance of $825 k
Second station – Brockville P DS – actual cost of $2200 k or variance of $1225 k
Third station – Trenton F DS – actual cost of $1650 k or variance of $675 k
Fourth station – Campbellford I DS – forecast cost of $1950 k or variance of $975 k

The main reasons for the potential over-expenditures are:

1) Additional facilities were installed at Brockville Parkdale DS. A wooden station fence was installed following request from engineering.
2) Original estimates were only a class C and did not include sufficient interest and overheads
3) The installed unit at Havelock Industrial DS is non compatible due to the system voltage at that station. The estimated variance will cover the cost to remove the existing unit and install new unit.
4) Storage fees to house the manufactured units. Originally planned that each site would be ready to install iMDS once the vendor had finished manufacturing
5) Additional engineering to deal with changing requirements
6) Large concrete vaults under the iMDS were difficult to install and increased construction time
7) Increased commissioning man-hours

Contingency Use

The $400k contingency budgeted for the project has been applied to cover a portion of the variances.

Root Causes and Recommendation

We have determined that the root causes of the project variances are attributed to the facilities not included in the estimate and the quality of the original estimate. The increased work resulted in longer construction durations. This factor together with the fact that the same construction crew has been assigned to all four stations places the project 30 months behind schedule.

Going forward, the iMDS design will utilize a "slab on grade" style civil structure with the intent of lowering the installation cost, design cost as well as construction time.

Additionally, providing early warning of variance needs improvement. Changes have been made to the Project Progress Tracking Report (PP190 in SAP BI) to flag up-to-date costs as a percentage of the total budget. This can then be compared to the approved/forecast in service dates and costs, and subsequent actions initiated. When such early warning is flagged, the suspected variance will be raised to the appropriate OAR (Director, SVP, EC) so that risks are known and approval to continue work can be explicitly given to the project team. It is important to understand that the realizable cost savings over conventional designs is confidently $500k/station and this is reflected in the Value Card for this program going forward. We therefore recommend continuing with iMDS installations as per our Investment Plan.

In Jan 2015, project management accountabilities, for the iMDS pilot project and for the complete distribution station (DS) refurbishment program, moved from Grid Operations to Power System Project Management. Equipment tendering is underway for the installation of five more iMDS units, under the DS refurbishment program, by the end of 2015.

In Nov 2014, monthly meetings were initiated so that the lines of business are better able to work together as one team. Attending these monthly meetings are Power System Project Management, Stations Engineering, and DX Asset Management. Issues are discussed such as timelines for work scoping and equipment tendering, the development of standard documents, design concerns, and potential outsourcing of EPC.

Concerning the development of standards, functional specifications will be developed by DX AM, by April 2015; and, these specifications will be followed by the development of Engineering design standards and equipment tendering documents, by Sept 2015.

The development of standards will also include the necessary features for the implementation of DMS or NMS distribution monitoring and control. These features will align with the overall strategy for grid modernization, which will allow us to provide our Customers with better reliability and power quality, and, allow us to deliver more affordable electricity.

From 2016 through 2019, there are plans to install an additional 26 iMDS units.

It is recommended that the IROV be approved for the additional required $3700k and a revised in-service of July 2015.

Submitted by:

Paul Brown
Director of Distribution Asset Management

Investment Driver: N.D.C.2.02 Date: February 17,2014

AR Number: 23166 Title: Commerce Way New Feeder Extension

Hydro One Networks - Business Case Summary - 50003553

Commerce Way New Feeder Extension

Investment Driver: **In-Service date:** December 01,2014

N.D.C.2.02 - System Capability Reinforcement (2014-$67.48M)

Investments in System Capability Reinforcement provide for new or modified distribution system facilities to accommodate (1) increases in customer load; (2) improvements in system reliability; (3) improved operational efficiency and asset life cycle planning; and (4) contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This Approval: $2250K **Previous Approval:** $0 **Project Total:** $2250K

Need:

This investment is needed to improve supply reliability and load capacity to the Hydro One service area located at north and east Woodstock.

Not doing this work will result in inability to meet the growth in the area leading to customer and reliability risks.

Investment Summary:

New transformer station called Commerce Way TS was built to relieve Woodstock TS in 2012. The first two new feeders have been constructed and connected to Commerce Way TS. The two feeders are currently supplying customers located in southeast of Woodstock.

There has been significant growth in north Woodstock. The area is currently supplied by an 8 kV feeder Zorra DS F3. The City of Woodstock also has plans for a business park on the east side of the city. With the amount of development in the area, the existing electricity system will be inadequate from both capacity and reliability perspectives. Extending the 27.6 kV feeder to this area is required to meet the load growth and provide adequate reliability.

This investment covers the Commerce Way TS feeder M2 construction to the development area. The work is requested for completion by Dec 1, 2014.

Results:

Provide 27.6 kV supply from Commerce Way TS new feeder M2 into the development area of north and east Woodstock for reliability and capacity improvement.

Costs:

	2014 K	Total K
Capital* and MFA	2009	2009
OM&A and Removals	241	241
Gross Investment Cost*	2250	2250
Recoverable	0	0
Net Investment Cost	2250	2250

*Includes overhead and AFUDC at current rates

Investment Driver: N.D.C.2.02

AR Number: 23166

Date: February 17,2014

Title: Commerce Way New Feeder Extension

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

The 'Do-Nothing' alternative will result in inability to meet the growth in the area leading to customer and reliability risks. Therefore this is not a desired alternative.

Extend both Woodstock TS M9 and Commerce Way TS M2

This alternative includes 3.9 km extension from Woodstock TS M9 to supply North Woodstock area and 4 km extension from Commerce Way TS M2 to supply East Woodstock area. The disadvantage of this alternative includes: 1) Higher line losess; 2) Poor reliability on the Woodstock TS M9 due to longer feeder; 3) Woodstock TS loading would eventually exceed HONI assigned capacity. Therefore this alternative is not recommended.

ALTERNATIVES CONSIDERED FURTHER

Alternative One

Extend Commerce Way TS M2 4 km north then 3.9 km west to the development area. The new extension will tie with Woodstock TS M9 to provide a loop feed.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

This is the recommended alternative as it improves supply reliability and load capacity to the development area.

Alternatives Compared

	Project Level Risk		
Business Value	**Current Risk**	**Alt1**	**Comparison**
Reliability	HIGH	LOW	Reliability risks due to potential failure of overloaded equipment will be mitigated.
Customer	HIGH	LOW	Risk of customer dissatisfaction due to inadequate supply capacity and reliability will be mitigated.
Competitiveness	N/A	N/A	Not influential in the investment decision.
Safety and environment	N/A	N/A	Not influential in the investment decision.
Regulatory / Legal	N/A	N/A	Not influential in the investment decision.
Reputation	HIGH	LOW	Hydro One will be seen to take proactive action to improve system supply reliability and load capacity.
Initial Cost ($K)		2250	
Financial: PV Cost / NPV ($K)			PV was not calculated as there is only one viable alternative and the investment is not driven by financial factors.

Project Risk and Mitigation:

Cost:

The project cost is based upon a Class C estimate from investment planner based on historical actuals from similar projects, which is accurate in the range of +/-50%.

Business Planning:

This investment is included in the 2014-2019 business plan as accomplishment ID AIP000183 with sufficient funding.

Investment Driver: N.D.C.2.02

AR Number: 23166

Date: February 17,2014

Title: Commerce Way New Feeder Extension

Execution Risks:

S.92 N/A
EA N/A
Outages Low
Resourcing Low
First Nations N/A
Real Estate N/A
Agreements N/A
Technology N/A

Regulatory Considerations:

This investment is included in the 2015-2019 Distribution Rate Filing (EB-2013-0416) for 2015 but is being advanced to 2014 due to availability of resources and a more urgent need to meet new load conections expected in 2014.

No significant regulatory issues anticipated other than standard need and prudence justification.

Funds Included in Business Plan: Y	**Director:** Paul Brown	**Planner:** Helen Guo
This Approval($K): 2250	**Previous Approval($K):** 0	**Current Est. of Total Cost($K):** 2250

Signature Block:		
Submitted by: Helen Guo	**Title:** Planner	**Date:** March 4/14
Reviewed by: Michael Satchell	**Title:** Manager Decision Support	**Date:** Mar 4/14
Recommended by: Lyla Garzouzi (for)	**Title:** Manager	**Date:** March 4/14
Approved by: Paul Brown	**Title:** Director	**Date:** MAR 4/14

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

INTERIM REVIEW OF VARIANCE (IROV)

Check All Applicable Boxes to Show Variances Requiring OAR Approval

☑ Cost Increase ☐ Schedule (Business Impactive) ☐ Scope Change (Significant)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date
23166	N.D.C.2.02	Dx Asset Management	Qual Assurance and OP Support	Sept 7th, 2016

Investment Title		Original Approved Cost *(as per BCS)*	$2,250 K
Commerce Way New Feeder Extension		Total Cost Approved plus Requested	$2,979 K
Original approved in-service date	**Proposed new in-service date**	Current Cost ratio	132%
December 1 2014	March 1, 2016		

Background Situation:

The Woodstock TS and M9 feeder require offloading. An area study was completed in late 2013 by the Investment Planner. The recommended approach was to build a new feeder from Commerce Way TS to offload Woodstock TS and the M9 feeder.
The original Investment was approved in March, 2014 based on a Class C estimate. Variance from estimates originally developed are substantial from a cost and timelines perspective.
The project was completed in March, 2016 and approximately 132% of the approved funding has been spent.

Variance Explanation: *(Discussion of significant cost, schedule, and scope changes, and an explanation of root causes.)*

Cost Variance (resulting in $729k in additional cost)
The Investment Planner's Class C estimate for the original investment was $2.25M. The project was released for construction in March, 2014 based on this Class C estimate.
In March 2015, the detailed design was completed for this project by Provincial Lines. The Class A estimated cost for the Dx lines work increased by $729k mostly due to inclusion of interest, overhead and removal costs in the detailed estimate. In March 2015, this project started construction prior to Dx Asset Management variance approvals to proceed given the significant cost variance. In June 2015, Dx Asset Management identified the cost overrun, reviewed the alternatives and recommended proceeding with this work as it remained the lowest cost alternative.

Schedule Variance
The in-service date was deferred until March, 2016 due to insufficient availability of Lines resources to complete the project. This resulted in immaterial additional carrying costs

Lessons Learned:

1) Releasing a project of this magnitude (i.e. >$1M) for construction based on a Class C estimate is not appropriate, as it does not adequately consider challenges which would be identified during a detailed design estimate.
2) The process for Provincial Lines to review estimates, identify cost overruns in excess of IROV criteria, and only proceed with the work once appropriate approvals were in place, did not exist at the time of this release.
3) A new process for oversight of all IROV's did not exist to ensure IROV completion in a timely manner.
4) Estimates will now be signed off by the appropriate Line of Business prior to Investment Approval.

Planned Action:

1) A new DX lines work release process has been implemented since this investment was released and requires all Dx lines projects >$1M to be released for construction based on a Class A estimate.
2) Also, under the new process, cost overruns in excess of $500k require Provincial Lines to notify Dx AM of the cost overrun, and follow proper corporate IROV processes.
3) Dx Asset Management is receiving regular forecast and LTD spend information from Provincial Lines to identify the need for an IROV. Furthermore a regular IROV tracking report is now prepared by Decision Support, and reviewed by Dx Asset Management.
4) Quality Assurance and Operating Support will present to Dx AM on their estimating practices.

Accountable LOB	Qual Assurance & Op Support	Proposed Completion Date	Fall, 2016

Approvals

Approved by:	Signature	Date
Paul Brown, Director, Dx Asset Management		Sept 8, 2016
Approved by:	**Signature**	**Date**
Kathy Moulton, Director, Qual Assur & OP Support		Sept 8, 2016
Approved by:	**Signature**	**Date**
Wade Frost, Mgr, Decision Support Natalia Gaydukov on behalf of		Sept 9, 2016
Approved by *(As per EAR/OAR)*:	**Signature**	**Date**
Mike Penstone, VP, Planning		Sept 12, 2016

IROV Author	Alexander Hamlyn
Date Prepared	Sept 7th, 2016

INTERIM REVIEW OF VARIANCE (IROV)

AR	IROV Claim #	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date *(mm/dd/yy)*
23166	41000568	N.D.C.2.02	Dx Asset Management	Qual Assurance and OP Support	Sept 7th, 2016

Investment Title		
Commerce Way New Feeder Extension	5. Original Approved Cost *(Line 1)*	$2,250 K
	6. Total Cost Approved Plus Requested *(line 4)*	$2,979 K

Project Manager	Planner	Current Cost ratio *(Box 6/Box 5)*
Jeff Battaglia	Alexander Hamlyn	132%

1. Original approved cost *(per BCS)*	1.1 OM&A		**Original approved in-service date** *(as per line 1)*
	1.2 CAPITAL	$2,009 K	December 1 2014
	1.3 REMOVALS	$241 K	
	TOTAL	$2,250 K	
2. Total $ currently approved *(Original plus previous IROVs awards)*	2.1 OM&A		**Current approved in-service date** *(as per line 2)*
	2.2 CAPITAL	$2,009 K	December 31, 2014
	2.3 REMOVALS	$241 K	
	TOTAL	$2,250 K	

		Total (A + B)	(A) Cost of Scope Increases	(B) Cost of "In-Scope" Project Variances
3. Revision now requested	3.1 OM&A	$0 K	$0 K	$0 K
	3.2 CAPITAL	$623 K	$112 K	$511 K
	3.3 REMOVALS	$106 K	$0 K	$106 K
	TOTAL	$729 K	$112 K	$617 K

4. Total Cost including OH & AFUDC *(Line 2 plus line 3)*	4.1 OM&A	$0 K	**Proposed new in-service date** *(as per line 3)*
	4.2 CAPITAL	$2,632 K	March 1, 2016
	4.3 REMOVALS	$347 K	
	TOTAL	$2,979 K	

Summary of Variance:

The Investment Planner's class C estimate for the original investment was $2.25M.

In March, 2015, the detailed design was completed for this project by Provincial Lines. The Class A estimated cost for the Dx lines work increased by $729k due to inaccuracy in the Class C estimate.

#	Item / Description	Cost of Scope increase $K	In-Scope Variance $K
1	Scope was updated to add a second 27.6 kV circuit • Expand the 27.6 kV Commerce Way TS new feeder north along Oxford Rd 4 by overbuilding on the 8 kV circuit. Add second 27.6 kV circuit along this section. (approx. 6km).	$112 K	
2	Cost increase due to inaccuracy of Class C estimate		$617 K
3			
4			
5			
6			
7			
8			
9			
10			
	Total Variance Costs	$112 K	$617 K

Project Cashflow Detail by Year

Description		2015	2016	2017	2018	2019	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	CAPITAL	$2,632 K	$0 K	$0 K	$0 K	$0 K	$2,632 K
	REMOVALS	$347 K	$0 K	$0 K	$0 K	$0 K	$347 K
	TOTAL	$2,979 K	$0 K	$0 K	$0 K	$0 K	$2,979 K

Investment Driver: N.D.C.2.02 Date: March 18,2013

AR Number: 22733 Title: Bob-Lo DS Voltage Conversion

Hydro One Networks - Business Case Summary - 50002956

Bob-Lo DS Voltage Conversion

Investment Driver: **In-Service date:** December 01,2014

N.D.C.2.02 - System Capability Reinforcement (2013-$64.83M)

Investments in System Capability Reinforcement provide for new or modified distribution system facilities to accommodate (1) increases in customer load; (2) improvements in system reliability; (3) improved operational efficiency and asset life cycle planning; and (4) contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This Approval: $30K **Previous Approval:** $0 **Project Total:** $30K

Need:

To address end-of-life issue at station and improve supply reliability.

Not doing this work will result in risks of inadequate supply.

Investment Summary:

Bob-Lo DS is considered at end-of-life and therefore requires major work. Converting sections of 8kV feeder to 27.6kV and rabbits installation are required in order to decommission Bob-Lo DS.

This release covers the preperation of a Class A estimate for the project.

Results:

Address end-of-life issue at station and improve supply reliability.

Costs:

	2013 K	Total K
Capital* and MFA	30	30
OM&A and Removals	0	0
Gross Investment Cost*	30	30
Recoverable	0	0
Net Investment Cost	30	30

hydro one

Investment Driver: N.D.C.2.02

Date: March 18,2013

AR Number: 22733

Title: Bob-Lo DS Voltage Conversion

Project Risk and Mitigation:

Business Planning:

This investment is included in the 2013-2017 business plan as accomplishment ID 3876 with sufficient funding.

Funds Included in Business Plan: Y	**Redirection Required:** N	**Planner:** Helen Guo
This Approval($K): 30	**Previous Approval($K):** 0	**Current Est. of Total Cost($K):** 30
Signature Block:		
Submitted by: Helen Guo	**Title:** Planner	**Date:** March 18/13
Reviewed by:	**Title:**	**Date:**
Recommended by:	**Title:**	**Date:**
Approved by: Lyla Garzouzi	**Title:** Manager	**Date:** March 18, 2013

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

hydro one

Investment Driver: N.D.C.2.02 Date: December 12,2013

AR Number: 22733 Title: Bob-Lo DS Voltage Conversion

Hydro One Networks - Business Case Summary - 50003491

Bob-Lo DS Voltage Conversion

Investment Driver: **In-Service date:** December 01,2014

N.D.C.2.02 - System Capability Reinforcement (2014-$61.8M)

Investments in System Capability Reinforcement provide for new or modified distribution system facilities to accommodate (1) increases in customer load; (2) improvements in system reliability; (3) improved operational efficiency and asset life cycle planning; and (4) contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This Approval: $2020K **Previous Approval:** $80K **Project Total:** $2100K

Need:

The purpose of this investment is to remove the underutilized station and reconfigure feeder sections to improve supply reliability. This investment will also improve customer satisfaction for the customers of both Hydro One and Essex Power.

Not doing this work would increase risks to safety, reliability, and corporate reputation.

Investment Summary:

Bob-lo DS and its feeders are in poor condition and require major rehabilitation. Essex Power is removing its load from this DS. The station will be underutilized at approximately 1.5 MVA, well below its station PLL of 6.25 MVA. The station is located within Essex Power's service territory, making it inefficient from operating perspective. Feeder reconfiguration between Hydro One and Essex Power was agreed to improve end-use customer satisfaction in the Town of Amhurstburg. Converting sections of the 8kV feeders to 27.6kV and rabbits installation are required in order to decommission the station.

This is the continuation of Malden M12 extension work (AR20804) to improve end-use customer satisfaction at Town of Amhurstburg. The project is part of the overall strategic plan for the area.

This release covers the construction of both voltage conversion and the station removal. The work is requested for completion by Dec 1, 2014, this means that the lines portion should be completed by this date.

Results:

Address deteriorated assets and improve supply reliability.

Costs:

	2014 K	Total K
Capital* and MFA	1239	1239
OM&A and Removals	780	780
Gross Investment Cost*	2020	2020
Recoverable	0	0
Net Investment Cost	2020	2020

*Includes overhead and AFUDC at current rates

Investment Driver: N.D.C.2.02 Date: December 12,2013

AR Number: 22733 Title: Bob-Lo DS Voltage Conversion

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

The 'Do-Nothing' alternative would pose safety, reliability, and customer risks. Given the age and condition assessment, there is a high likelihood of failure. Therefore this is not a desired alternative.

Alternative Two

Rebuild Bob-Lo DS and reconfigure its feeders

In this Alternative, Bob-Lo DS will be refurbished with the same transformer size. The 8 kV feeders close to Bob-Lo DS will be rebuilt to Dx standard. This alternative does not meet the long term strategic plans for the area. It does not allow for the feeder reconfiguration between HONI and Essex Power Lines as previously agreed. This alternative also carries higer O&M costs and therefore is not recommended.

ALTERNATIVES CONSIDERED FURTHER

Alternative One

Convert load by installing step down pole top transformers and remove Bob-Lo DS.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

This is the recommended alternative as it removes the assets in poor condition and allows for further feeder reconfiguration between HONI and Essex Power Lines.

Alternatives Compared

	Project Level Risk		
Business Value	**Current Risk**	**Alt1**	**Comparison**
Reliability	HIGH	LOW	Reliability risks due to potential failure of deteriorated assets will be mitigated.
Customer	HIGH	LOW	Risk of customer dissatisfaction due to a lengthy outage will be mitigated.
Competitiveness	N/A	N/A	Not influential in the investment decision.
Safety and environment	HIGH	LOW	On-site arsenic contaminated soil will be removed and disposed of to an approved hazardous waste storage facility. Safety concerns with existing equipment will be eliminated.
Regulatory / Legal	HIGH	LOW	Not influential in the investment decision.
Reputation	HIGH	LOW	Hydro One will be seen to take proactive action to address deteriorated assets that are posing reliability risks.
Initial Cost ($K)		2093	
Financial: PV Cost / NPV ($K)			PV was not calculated as there is only one viable alternative and the investment is not driven by financial factors.

Project Risk and Mitigation:

Cost:

The project cost is based upon a Class C estimate from the investment planner, which is accurate in the range of +/-50%, and includes a contingency for in-scope variances of $120k, which is 10% of the direct project cost.

Business Planning:

This investment is included in the 2014-2019 business plan as accomplishment ID AIP000184A with sufficient funding.

hydro one

Investment Driver: N.D.C.2.02

Date: December 12,2013

AR Number: 22733

Title: Bob-Lo DS Voltage Conversion

Execution Risks:
No execution risks have been identified. There are sufficient resources available to complete this work.

Regulatory Considerations:

No significant regulatory issues anticipated other than standard need and prudence justification.

Funds Included in Business Plan: Y	**Director:** Paul Brown	**Planner:** Helen Guo
This Approval($K): 2020	**Previous Approval($K):** 80	**Current Est. of Total Cost($K):** 2100

Signature Block:		
Submitted by: Helen Guo	**Title:** Planner	**Date:** Dec 19/13
Reviewed by: MICHAEL SATCHELL	**Title:** MGR DECISION SUPPORT	**Date:** Dec. 23, 2013
Recommended by: Lyla Garzouzi	**Title:** Manager	**Date:** Dec 19, 2013
Approved by: Paul Brown	**Title:** Director	**Date:** Dec 19/13

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

INTERIM REVIEW OF VARIANCE (IROV)

Check All Applicable Boxes to Show Variances Requiring OAR Approval

☑ Cost Increase ☐ Schedule (Business Impactive) ☐ Scope Change (Significant)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date
22733	N.D.C.2.02	Dx Asset Management	Qual Assurance and OP Support	Sept 7th, 2016

Investment Title			
Bob-Lo DS Voltage Conversion		Original Approved Cost *(as per BCS)*	$2,100 K
		Total Cost Approved plus Requested	$3,032 K
Original approved in-service date	**Proposed new in-service date**	Current Cost ratio	144%
December 1 2014	June 30th, 2017		

Background Situation:

Bob Lo DS transformer is near end-of-life, and is in need of replacement. An area study was completed in October 2013 by the Investment Planner. The recommended approach was to offload Bob Lo DS via conversion, in lieu of refurbishment.
The original Investment was approved in December 2013 based on a Class C estimate. Variance from estimates originally developed are substantial from a cost and timelines perspective.
As of Aug 23, 2016, approximately 122% of the approved funding has been spent.

Variance Explanation: *(Discussion of significant cost, schedule, and scope changes, and an explanation of root causes.)*

Cost Variance (resulting in $1M in additional cost)

The Investment Planner's Class C estimate for the original investment was $2.1M, which included $600k in stations removal work, and $1.5M Dx line and voltage conversion work. The project was released for construction in January 2014 based on this Class C estimate.
In June 2015, the detailed design was completed for this project by Provincial Lines. The Class A estimated cost for the Dx lines work increased by $930k mostly due to inclusion of interest, overhead and removal costs in the detailed estimate. In June 2015, this project started construction prior to Dx Asset Management variance approvals to proceed given the significant cost variance. In August 2015, Dx Asset Management identified the cost overrun, reviewed the alternatives and recommended proceeding with this work as it remained the lowest cost alternative.

Schedule Variance

The in-service date was deferred until June, 2017 due to insufficient availability of Lines and Stations resources to complete the project. This resulted in immaterial additional carrying costs.

Lessons Learned:

1) Releasing a project of this magnitude (i.e. >$1M) for construction based on a Class C estimate is not appropriate, as it does not adequately consider challenges which would be identified during a detailed design estimate.
2) The process for Provincial Lines to review estimates, identify cost overruns in excess of IROV criteria, and only proceed with the work once appropriate approvals were in place, did not exist at the time of this release.
3) A new process for oversight of all IROV's did not exist to ensure IROV completion in a timely manner.
4) Estimates will now be signed off by the appropriate Line of Business prior to Investment Approval.

Planned Action:

1) A new DX lines work release process has been implemented since this investment was released and requires all Dx lines projects >$1M to be released for construction based on a Class A estimate.
2) Also, under the new process, cost overruns in excess of $500k require Provincial Lines to notify Dx AM of the cost overrun, and follow proper corporate IROV processes.
3) Dx Asset Management is receiving regular forecast and LTD spend information from Provincial Lines to identify the need for an IROV. Furthermore a regular IROV tracking report is now prepared by Decision Support, and reviewed by Dx Asset Management.
4) Quality Assurance and Operating Support will present to Dx AM on their estimating practices.

Accountable LOB	Qual Assurance and OP support	Proposed Completion Date	Fall, 2016

Approvals

Approved by:	Signature	Date
Paul Brown, Director, Dx Asset Management		Sept 8, 2016
Approved by:	**Signature**	**Date**
Kathy Moulton, Director, Qual Assur & OP Support		Sept 8, 2016
Approved by:	**Signature**	**Date**
Wade Frost, Mgr, Decision Support Natalia Gaydukevych on behalf of		Sept 9, 2016
Approved by *(As per EAR/OAR)*:	**Signature**	**Date**
Mike Penstone, VP, Planning		Sept 12, 2016

IROV Author	Alexander Hamlyn
Date Prepared	Sept 7th, 2016

INTERIM REVIEW OF VARIANCE (IROV)

AR	IROV Claim #	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date *(mm/dd/yy)*
22733	41000564	N.D.C.2.02	Dx Asset Management	Qual Assurance and OP Support	Sept 7th, 2016

Investment Title		
Bob-Lo DS Voltage Conversion	5. Original Approved Cost *(Line 1)*	$2,100 K
	6. Total Cost Approved Plus Requested *(line 4)*	$3,032 K

Project Manager	Planner	Current Cost ratio *(Box 6/Box 5)*
Jeff Battaglia	Alexander Hamlyn	144%

1. Original approved cost *(per BCS)*	1.1 OM&A	$0 K	**Original approved in-service date** *(as per line 1)*
	1.2 CAPITAL	$1,320 K	December 1 2014
	1.3 REMOVALS	$780 K	
	TOTAL	$2,100 K	
2. Total $ currently approved *(Original plus previous IROVs awards)*	2.1 OM&A	$0 K	**Current approved in-service date** *(as per line 2)*
	2.2 CAPITAL	$1,320 K	December 1 2014
	2.3 REMOVALS	$780 K	
	TOTAL	$2,100 K	

		Total (A + B)	(A) Cost of Scope Increases	(B) Cost of "In-Scope" Project Variances
3. Revision now requested	3.1 OM&A	$0 K	$0 K	$0 K
	3.2 CAPITAL	$932 K	$0 K	$932 K
	3.3 REMOVALS	$0 K	$0 K	$0 K
	TOTAL	$932 K	$0 K	$932 K

4. Total Cost including OH & AFUDC *(Line 2 plus line 3)*	4.1 OM&A	$0 K	**Proposed new in-service date** *(as per line 3)*
	4.2 CAPITAL	$2,252 K	June 30th, 2017
	4.3 REMOVALS	$780 K	
	TOTAL	$3,032 K	

Summary of Variance:

The Investment Planner's Class C estimate for the original investment was $2.1M, which included $600k in stations removal work, and $1.5M Dx line and voltage conversion work.

In June 2015, the detailed design was completed for this project by Provincial Lines. The Class A estimated cost for the Dx lines work increased by $930k mostly due to inclusion of interest, overhead and removal costs in the detailed estimate.

The in-service date was deferred until June, 2017 due to insufficient availability of Lines and Stations resources to complete the project.

#	Item / Description	Cost of Scope increase $K	In-Scope Variance $K
1	Cost increase due to inaccuracy of Class C estimate		$932 K
2			
3			
4			
5			
6			
7			
8			
9			
10			
	Total Variance Costs	$0 K	$932 K

Project Cashflow Detail by Year

Description		2015	2016	2017	2018	2019	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	CAPITAL	$2,252 K	$0 K	$0 K	$0 K	$0 K	$2,252 K
	REMOVALS	$180 K	$600 K	$0 K	$0 K	$0 K	$780 K
	TOTAL	$2,432 K	$600 K	$0 K	$0 K	$0 K	$3,032 K

Investment Driver: N.D.C.2.02

Date: March 18,2013

AR Number: 22732

Title: Belle River DS Voltage Conversion

Hydro One Networks - Business Case Summary - 50002955

Belle River DS Voltage Conversion

Investment Driver:

In-Service date: December 01,2014

N.D.C.2.02 - System Capability Reinforcement (2013-$64.83M)

Investments in System Capability Reinforcement provide for new or modified distribution system facilities to accommodate (1) increases in customer load; (2) improvements in system reliability; (3) improved operational efficiency and asset life cycle planning; and (4) contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This Approval: $30K **Previous Approval:** $0 **Project Total:** $30K

Need:

To address issues of off road lines and end-of-life station. Improve supply reliability.

Not doing this work will result in risks of inadequate supply.

Investment Summary:

Belle River DS transformer is listed as one of the worst transformers in the Province. The DS also has the spill risk ranking of #15 on the Conestoga Rovers and Associates list. It is proposed to remove the station by voltage conversion and rabbit installations. Converting the DS will also eliminate sections of off road 27.6kV and 8kV lines.

This release covers the preperation of a Class A estimate for the project.

Results:

Remove end-of-life station and off road lines. Improve supply reliability.

Costs:

	2013 K	Total K
Capital* and MFA	30	30
OM&A and Removals	0	0
Gross Investment Cost*	30	30
Recoverable	0	0
Net Investment Cost	30	30

Investment Driver: N.D.C.2.02 Date: March 18,2013

AR Number: 22732 Title: Belle River DS Voltage Conversion

Project Risk and Mitigation:

Business Planning:

This investment is included in the 2013-2017 business plan as accomplishment ID 3876 with sufficient funding.

Funds Included in Business Plan: Y	**Redirection Required:** N		Planner: Helen Guo	
This Approval($K): 30	**Previous Approval($K):** 0		**Current Est. of Total Cost($K):** 30	
Signature Block:				
Submitted by: Helen Guo		**Title:** Planner		**Date:** March 18/13
Reviewed by:		**Title:**		**Date:**
Recommended by:		**Title:**		**Date:**
Approved by: Lyla Garzouzi		**Title:** Manager		**Date:** Mar 18, 2013

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

Investment Driver: N.D.C.2.02 Date: December 13,2013

AR Number: 22732 Title: Belle River DS Voltage Conversion

Hydro One Networks - Business Case Summary - 50003500

Belle River DS Voltage Conversion

Investment Driver: **In-Service date:** June 30,2015

N.D.C.2.02 - System Capability Reinforcement (2015-$81.4M)

Investments in System Capability Reinforcement provide for new or modified distribution system facilities to accommodate (1) increases in customer load; (2) improvements in system reliability; (3) improved operational efficiency and asset life cycle planning; and (4) contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This Approval: $1810K **Previous Approval:** $30K **Project Total:** $1840K

Need:

Belle River DS has reached end-of-life (EOL). The F2 feeder is running along the railway track with accessibility issue. The purpose of this investment is to address the EOL station and the off road feeder section to improve supply reliability.

Not doing this work would pose safety, reliability, customer, and environmental risks.

Investment Summary:

Belle River DS has reached EOL and is planned for refurbishment by Station Sustainment. The station has one of the worst transformers in the Province with the transformer at 64 years of age. The DS also has a high likelihood of spill. Converting sections of the 8kV feeder to 27.6kV and rabbits installation are required in order to decommission Belle River DS.

This release covers the construction of both voltage conversion and the station removal. The work is requested for completion by June 30, 2015, this means that the lines portion should be completed by this date.

Results:

Address end-of-life issue at station and improve supply reliability.

Costs:

	2015 K	Total K
Capital* and MFA	1061	1061
OM&A and Removals	749	749
Gross Investment Cost*	1810	1810
Recoverable	0	0
Net Investment Cost	1810	1810

*Includes overhead and AFUDC at current rates

Investment Driver: N.D.C.2.02

Date: December 13,2013

AR Number: 22732

Title: Belle River DS Voltage Conversion

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

The 'Do-Nothing' alternative would pose safety, reliability, customer, and environmental risks. Given the age, condition assessment and spill assessment, there is a high likelihood of failure. Therefore this is not a desired alternative.

Alternative Two

Rebuild Belle River DS. In this Alternative, Belle River DS will be refurbished with larger transformer. The disadvantage of this alternative includes: 1). Higher initial capaital costs; 2). Higher O &M costs; 3). Higher line losess; 4) Lower power carrying capacity for the same percentage voltage drops. Therefore this alternative is not recommended.

ALTERNATIVES CONSIDERED FURTHER

Alternative One

Convert load by installing step down pole top transformers and remove Belle River DS.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

This is the recommended alternative as it resolves the EOL issue at Belle River DS and allows for the removal of the off road feeder along the railway track.

Alternatives Compared

	Project Level Risk		
Business Value	**Current Risk**	Alt1	**Comparison**
Reliability	HIGH	LOW	Reliability risks due to potential failure of end-of-life equipment will be mitigated.
Customer	HIGH	LOW	Risk of customer dissatisfaction due to a lengthy outage will be mitigated.
Competitiveness	N/A	N/A	Not influential in the investment decision.
Safety and environment	HIGH	LOW	On-site arsenic contaminated soil will be removed and disposed of to an approved hazardous waste storage facility. Safety concerns with existing equipment will be eliminated.
Regulatory / Legal	N/A	N/A	Not influential in the investment decision.
Reputation	HIGH	LOW	Hydro One will be seen to take proactive action to address equipment EOL issues.
Initial Cost ($K)		1840	
Financial: PV Cost / NPV ($K)			PV was not calculated as there is only one viable alternative and the investment is not driven by financial factors.

Project Risk and Mitigation:

Cost:

The project cost is based upon a Class C estimate from the investment planner, which is accurate in the range of +/-50%, and includes a contingency for in-scope variances of $100k, which is 10% of the direct project cost.

Business Planning:

This investment is included in the 2014-2019 business plan as accomplishment ID AIP000184 with sufficient funding.

Execution Risks:

No execution risks have been identified. There are sufficient resources available to complete this work.

Investment Driver: N.D.C.2.02

Date: December 13,2013

AR Number: 22732

Title: Belle River DS Voltage Conversion

Regulatory Considerations:

No significant regulatory issues anticipated other than standard need and prudence justification.

Funds Included in Business Plan: Y	**Director:** Paul Brown	**Planner:** Helen Guo
This Approval($K): 1810	**Previous Approval($K):** 30	**Current Est. of Total Cost($K):** 1840

Signature Block:

Submitted by: Helen Guo	**Title:** Planner	**Date:** Dec 19/13
Reviewed by: MICHAEL SATCHELL	**Title:** MGR, DECISION SUPPORT	**Date:** Dec 23/13
Recommended by: Lyla Garzouzi	**Title:** Manager	**Date:** Dec 19.2013
Approved by: Paul Brown	**Title:** Director	**Date:** DEC 19/13

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

INTERIM REVIEW OF VARIANCE (IROV)

Check All Applicable Boxes to Show Variances Requiring OAR Approval

☑ Cost Increase ☑ Schedule (Business Impactive) ☐ Scope Change (Significant)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date
22732	N.D.C.2.02	Dx Asset Management	Qual Assurance and OP Support	Sept 7th, 2016

Investment Title		Original Approved Cost *(as per BCS)*	$1,840 K
Belle River DS Voltage Conversion		Total Cost Approved plus Requested	$2,871 K
Original approved in-service date	**Proposed new in-service date**	Current Cost ratio	156%
June 30, 2015	June 30, 2017		

Background Situation:

Belle River DS transformer is near end-of-life, and is in need of replacement. An area study was completed in early 2013 by the Investment Planner. The recommended approach was to offload Belle River DS via conversion, in lieu of refurbishment.
The original Investment was approved in December 2013 based on a Class C estimate to offload Belle River DS, and remove it from service. Variance from estimates originally developed are substantial from a cost and timelines perspective.
As of Aug 23rd, 2016, approximately 95% of the approved funding has been spent.

Variance Explanation:

Cost Variance (resulting in $1M in additional cost)

The Investment Planner's Class C estimate for the original investment was $1.84M, which included $600k in stations removal work, and $1.24M Dx line and voltage conversion work. The project was released for construction in January 2014 based on this Class C estimate.
In February 2015, the detailed design was completed for this project by Provincial Lines. The Class A estimated cost for the Dx lines work increased by $1031k mostly due to inclusion of interest, overhead and removals in the detailed estimate . In January 2016, this project started construction prior to Dx Asset Management variance approvals to proceed given the significant cost variance. In March 2016, Dx Asset Management identified the cost overrun, reviewed the alternatives and recommended proceeding with this work as it remained the lowest cost alternative.

Schedule Variance

The in-service date was deferred until June, 2017 due to insufficient availability of Lines and Stations resources to complete the project. This resulted in immaterial additional carrying costs.

Lessons Learned:

1) Releasing a project of this magnitude (i.e. >$1M) for construction based on a Class C estimate is not appropriate, as it does not adequately consider challenges which would be identified during a detailed design estimate.
2) The process for Provincial Lines to review estimates, identify cost overruns in excess of IROV criteria, and only proceed with the work once appropriate approvals were in place, did not exist at the time of this release.
3) A new process for oversight of all IROV's did not exist to ensure IROV completion in a timely manner.
4) Estimates will now be signed off by the appropriate Line of Business prior to Investment Approval.

Planned Action:

1) A new DX lines work release process has been implemented since this investment was released and requires all Dx lines projects >$1M to be released for construction based on a Class A estimate.
2) Also, under the new process, cost overruns in excess of $500k require Provincial Lines to notify Dx AM of the cost overrun, and follow proper corporate IROV processes.
3) Dx Asset Management is receiving regular forecast and LTD spend information from Provincial Lines to identify the need for an IROV. Furthermore a regular IROV tracking report is now prepared by Decision Support, and reviewed by Dx Asset Management.
4) Quality Assurance and Operating Support will present to Dx AM on their estimating practices.

Accountable LOB	Dx AM / Qual Assurance and Op Support	Proposed Completion Date	Fall, 2016

Approvals

Approved by:	Signature	Date
Paul Brown, Director, Dx Asset Management	[signature]	Sept 8, 2016
Approved by:	**Signature**	**Date**
Kathy Moulton, Director, Qual Assur & OP Support	[signature]	Sept 8, 2016
Approved by:	**Signature**	**Date**
Wade Frost, Mgr, Decision Support Natalie Gaul-Kenzel on behalf of	[signature]	Sept 9, 2016
Approved by *(As per EAR/OAR)*:	**Signature**	**Date**
Mike Penstone, VP, Planning	[signature]	Sept 12, 2016

IROV Author	Alexander Hamlyn
Date Prepared	Sept 7th, 2016

INTERIM REVIEW OF VARIANCE (IROV)

AR	IROV Claim #	Driver	BCS Originator (LOB)	Service Provider (LOB)	Date (mm/dd/yy)
22732	41000566	N.D.C.2.02	Dx Asset Management	Qual Assurance and OP Support	Sept 7th, 2016

Investment Title		
Belle River DS Voltage Conversion	5. Original Approved Cost (Line 1)	$1,840 K
	6. Total Cost Approved Plus Requested (line 4)	$2,871 K

Project Manager	Planner	Current Cost ratio (Box 6/Box 5)
Jeff Battaglia	Alexander Hamlyn	156%

1. Original approved cost (per BCS)	1.1 OM&A	$0 K	Original approved in-service date (as per line 1)
	1.2 CAPITAL	$1,091 K	June 30, 2015
	1.3 REMOVALS	$749 K	
	TOTAL	$1,840 K	
2. Total $ currently approved (Original plus previous IROVs awards)	2.1 OM&A	$0 K	Current approved in-service date (as per line 2)
	2.2 CAPITAL	$1,091 K	June 30, 2015
	2.3 REMOVALS	$749 K	
	TOTAL	$1,840 K	

		Total (A + B)	(A) Cost of Scope Increases	(B) Cost of "In-Scope" Project Variances
3. Revision now requested	3.1 OM&A	$0 K	$0 K	$0 K
	3.2 CAPITAL	$1,031 K	$0 K	$1,031 K
	3.3 REMOVALS	$0 K	$0 K	$0 K
	TOTAL	$1,031 K	$0 K	$1,031 K

4. Total Cost including OH & AFUDC (Line 2 plus line 3)	4.1 OM&A	$0 K	Proposed new in-service date (as per line 3)
	4.2 CAPITAL	$2,122 K	June 30, 2017
	4.3 REMOVALS	$749 K	
	TOTAL	$2,871 K	

Summary of Variance:

The Investment Planner's class C estimate for the original investment was $1.84M, which included $600k in stations removal work, and $1.24M Dx line and voltage conversion work.

In February, 2015, the detailed design was completed for this project by Provincial Lines. The Class A estimated cost for the Dx lines work increased by $1031k mostly due to inclusion of Interest, Overhead and Removals in the detailed estimate.

The in-service date was deferred until June, 2017 due to insufficient availability of Lines and Stations resources to complete the project.

#	Item / Description	Cost of Scope increase $K	In-Scope Variance $K
1	Cost increase due to inaccuracy of Class C estimate		$1,031 K
2			
3			
4			
5			
6			
7			
8			
9			
10			
	Total Variance Costs	$0 K	$1,031 K

Project Cashflow Detail by Year

Description		2013	2014	2015	2016	2017	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	CAPITAL	$30 K	$0 K	$0 K	$2,092 K	$0 K	$2,122 K
	REMOVALS	$0 K	$0 K	$0 K	$749 K	$0 K	$749 K
	TOTAL	$30 K	$0 K	$0 K	$2,841 K	$0 K	$2,871 K

Investment Driver: N.D.C.2.02 Date: March 27,2013

AR Number: 22368 Title: Nebo TS M12 extension to Hamilton Airport - Class A Cost Estimate

Hydro One Networks - Business Case Summary - 50002938

Nebo TS M12 extension to Hamilton Airport - Class A Cost Estimate

Investment Driver: **In-Service date:** December 31,2014

N.D.C.2.02- System Capability Reinforcement (2013- $60.61M)

Investments in System Capability Reinforcement provide for new or modified distribution system facilities to accommodate (1) increases in customer load; (2) improvements in system reliability; (3) improved operational efficiency and asset life cycle planning; and (4) contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This Approval: $10K **Previous Approval:** $0 **Project Total:** $10K

Need:

The existing Nebo TS feeders M6 and M7 require load relief because the existing load is over the planning limit. The loading is expected to increase due to the airport expansion.

Not proceeding with this work will increase the risk of feeder failure due to thermal loading and decrease ability for feeders to back up each other during emergency. The situation can lead to wide spread power outages and inability to add any new loads.

Investment Summary:

The existing 27.6 kV feeders M6, M7 and M8 are heavily loaded requiring load relief. In paritcular, both Nebo TS M6 and M7 were at 430 amps and 490 amps respectively which is over the normal Planning Load Limit (PLL) of 350 Amps or 17 MVA for 27.6 kV feeder.

Extension of the new Nebo TS M12 feeder is proposed to the Hamilton Airport area and connect with the existing M6 and M7 feeder to provide the load relief.

This investment requests for a Class A cost estimate for the required M12 feeder extension for a distance of 6km. The funds for this work will be provided under the Accomplishment ID#3873.

Results:

Provide a reliable supply to Ancaster Industrial Park and enable the feeder tie/backup with Dundas M6 feeder.

Costs:

	2013 K	Total K
Capital* and MFA	10	10
OM&A and Removals	0	0
Gross Investment Cost*	10	10
Recoverable	0	0
Net Investment Cost	10	10

Investment Driver: N.D.C.2.02

Date: March 27,2013

AR Number: 22368

Title: Nebo TS M12 extension to Hamilton Airport - Class A Cost Estimate

Funds Included in Business Plan: Y	**Redirection Required:** N	**Planner:** Charlie Lee
This Approval($K): 10	**Previous Approval($K):** 0	**Current Est. of Total Cost($K):** 10

Signature Block:		
Submitted by: Charlie Lee	**Title:** Planner	**Date:** MAR 28/13
Reviewed by:	**Title:**	**Date:**
Recommended by:	**Title:**	**Date:**
Approved by: Lyla Garzouzi	**Title:** Manager	**Date:** April 1 2003

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

hydro one

Investment Driver: N.D.C.2.02 Date: May 06,2015

AR Number: 22368 Title: Nebo TS M12 Extension to Hamilton Airport- Work Execution

Hydro One Networks - Business Case Summary - 50004024

Nebo TS M12 Extension to Hamilton Airport- Work Execution

Investment Driver: **In-Service date:** December 21,2015

N.D.C.2.02- System Capability Reinforcement (2015 - $63.34M)

Investment in System Capability Reinforcement provide for new or modified distribution system facilities to accommodate (1) increases in customer load; (2) improvements in system reliability; (3) improved contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This Approval: $4.1M **Previous Approval:** $0.0M **Project Total:** $4.1M

Need:

Provide load relief to existing Nebo TS feeders M6, M7 and M8 that are currently loaded above the planning limit of 350 A. The loading is expected to increase due the development around the Hamilton airport and Ancaster.

Not proceeding with this work will increase the risk of line component (connectors, switches, etc...) failure due to thermal loading and decrease ability for feeders to back up each other during emergency. This may result to wide spread power outages and inability to add any new loads.

Investment Summary:

The Hamilton Airport is located in the southeastern part of City of Hamilton. The airport and the surrounding area of Ancaster are supplied by Nebo TS M6, M7 and M8 feeders. Nebo TS M7 and M8 are currently over its planning load limit (PLL) of 350 amps (or 17 MVA for 27.6 kV feeder). Nebo TS M6 is 96% of its PLL of 350 amps. An area study was completed in 2012 for the Ancaster and Glanbrook areas. The area study identified a supply shortfall due to large customer connections in the short term as well as the long term forecast load growth of 1.8% annually. It is confirmed through recent re-analysis that this need still exists. The investment will include a new 27.6 kV M12 feeder from Nebo TS on Nebo and Dickensen Rd. to the Hamilton airport area on Hwy 6 and Airport Rd., approximately 10 km. The extension of a new feeder from Nebo TS to the Hamilton Airport area will provide load relief to Nebo TS M6, M7 and M8 by transfering and balancing load among the four feeders. The new feeder will also provide improved supply reliability to the airport since it is a shorter feeder than the existing Nebo TS M7 feeder by 43%. The new feeder will provide capacity for the area until 2025. The planned in-service date for this investment is December 21st, 2015.

Results:

Provide load relief to Nebo TS M6, M7 and M8 by building new Nebo TS M12 feeder and balancing load among the feeders. Improve supply reliability to the Hamilton airport area.

Costs:

	2015 M	Total M
Capital* and MFA	3.6	3.6
OM&A and Removals	0.5	0.5
Gross Investment Cost*	4.1	4.1
Recoverable	0.0	0.0
Net Investment Cost	4.1	4.1

*Costs include AFUDC and overheads at current rates.

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

Not doing anything will result overloading of existing facilities, increasing the risk of feeder failure due to thermal loading. In addition, not doing anything will decrease the ability for feeders to back up each other during emergency; this can lead to wide spread power outages and inability to add new loads in the future. This does not reflect good utility practice and presents customer, reputation, reliability risks. This alternative is rejected.

Alternative Two

Construct new feeder from Dundas TS to Ancaster area (near the Ancaster West DS area)- about 10 km of distance. This option is expected to cost two times more than the alternative one as this line will have to cross the highway 403, Niagara Escarpment and built up commercial and residential areas. For this reason this alternative is rejected.

ALTERNATIVES CONSIDERED FURTHER

Alternative One

The extension of a new 27.6 kV feeder from Nebo TS (M12) to the Hamilton Airport area (about 10 km in distance) will provide load relief to Nebo TS M6, M7 and M8 feeders of about 13 MVA. The new feeder will also improve supply reliability to the Hamilton Airport area.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

Alternative one is recommended to provide load relief to Nebo TS M6, M7 and M8 feeders and to improve supply reliability to the Hamilton airport area. In addition, this alternative is the most cost effective option.

Alternatives Compared

	Project Level Risk		
Business Value	**Current Risk**	**Alt1**	**Comparison**
Reliability	HIGH	LOW	Alt 1 will improve supply reliabity to Hamilton airport and Ancaster area by 0.017 hour SAIDI to distribution network in case of feeder failure (M6/M7/M8) in the Hamilton airport and Ancaster.
Customer	HIGH	LOW	Alt 1 will provide capacity to service existing and new customers in the Hamilton Airport and Ancaster area.
Competitiveness	N/A	N/A	Not influential in the investment decision.
Safety and environment	MED	LOW	Alt 1 will lower the risk of equipment overload which may pose a danger to public and employees' safety.
Regulatory / Legal	MED	LOW	Not proceeding with Alt 1 means Hydro One will not meet its obligation (under DSC) to maintain the reliability of the Distribution System.
Reputation	HIGH	LOW	Alt 1 will address reputation risks with overloaded assets and system capacity needs.
Initial Cost ($M)		4.1	
Financial: PV Cost / NPV ($M)			NVP was not calculated as the investment is not primarily driven by financial factors.

Investment Driver: N.D.C.2.02
AR Number: 22368

Date: May 06,2015
Title: Nebo TS M12 Extension to Hamilton Airport- Work Execution

Project Risk and Mitigation:

Cost:
The project cost is based upon a Class A estimate from Customer Operations- Lines and Forestry (L&FS), which is accurate in the range of +/-10%, and includes a contingency for in-scope variances of $317,178 ,which is 10% of the direct project cost.

Project Management:
Customer Operations- Lines and Forestry are ready to start this work and complete by year end.

Business Planning:
This investment is not included in the 2015-2019 Business Plan. However, this work can be managed within the Distribution Capital Driver through redirection of funds from other delayed projects.

Execution Risks:
Approvals- N/A
Section 92- N/A
EA- N/A
Outages- Low
Resourcing- Low L&FS are ready to start this work and complete by year end.
First Nations- N/A
Real Estate- N/A
Agreements- N/A
Technology- N/A

Regulatory Considerations:
The 2015 Dx Capital expenditures for the 'Nebo TS M12 Extension to Hamilton Airport- Work Execution' project are included in the OEB approved Distribution rate filing (EB-2013-0416) for years 2015 to 2017 within the Development Capital area under the sub-category 'System Capability Reinforcement' and specifically against ISD line 'D2-System Upgrades Driven by Load Growth'.

No significant regulatory issue is anticipated other than standard need and prudence justification.

Funds Included in Business Plan: N	**Director:** Paul Brown	**Planner:** Isabel Victal
This Approval($M): 4.1	**Previous Approval($M):** 0.0	**Current Est. of Total Cost($M):** 4.1

Signature Block:			
Submitted by: John Fuerth	[signature]	**Title:** ~~Planner~~ Manager Investment Planning	**Date:** June 23/15
Reviewed by: Wade Frost	[signature]	**Title:** Manager Decision Support	**Date:** Jun 24/15
Recommended by: Paul Brown	[signature]	**Title:** Director	**Date:** JUN 23/15
Approved by: Mike Penstone	[signature]	**Title:** Vice President	**Date:** June 24/15

Scientific Research & Experimental Development Tax Credits (SR&ED)
- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

INTERIM REVIEW OF VARIANCE (IROV)

Check All Applicable Boxes to Show Variances Requiring OAR Approval

☑ Cost Increase ☑ Schedule (Business Impactive) ☐ Scope Change (Significant)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date
22368	N.D.C2.02	Dx Asset Management	Qual Assurance and OP support	14-Apr-16

Investment Title			
Nebo TS M12 Extension to Hamilton Airport		Original Approved Cost *(as per BCS)*	$4,100 K
		Total Cost Approved plus Requested	$5,634 K
Original approved in-service date	**Proposed new in-service date**	Current Cost ratio	137%
December 21, 2015	June 30, 2016		

Background Situation:

This project addresses the feeder capacity need in the vicinity of the Hamilton Airport and surrounding area as the existing feeders from Nebo TS are at their capacity limits. In April 2013, the detailed design was requested. In January 2014, the scope was revised as per field request. The final design estimate was received for this project from Provincial Lines in April 2015. The project was subsequently approved and released in June of 2015 for in-service of year-end 2015. The construction started in June 2015.

Variance Explanation: *(Discussion of significant cost, schedule, and scope changes, and an explanation of root causes.)*

The original line design by the Lines technician was inaccurate and therefore had to be re-designed and re-estimated. The original design did not provide enough pole space to complete the task for stringing the new circuit. This resulted in delay of the work execution and the updated design resulted in a higher expected cost. This IROV is therefore requesting for the approval of the increased cost of $1,534k (approx 11,471 hours) and a proposed in-service date change to Jun 30, 2016. The cost increase will impact the project cashflow for 2016 however it can be managed within the Dx Capital Driver through redirection of funds from other delayed projects.

Lessons Learned:

Designs and estimates for lines projects needs to be verified for accuracy before submitting to Asset Management for approval.

Planned Action:

The Lines organization is requested to provide a 'reviewed by' sign-off sheet with the cost estimate return. The sign-off should be done by the management level that is equivalent to the Asset Management EAR. Furthermore, it is required that the Lines organization monitor construction progress and spending and provide AM with earlier notification of any forecast cost overruns. To help achieve this, Lines have instituted bi-monthly reporting of spending to date, forecasted spending, forecasted in-service date etc. on all projects. An IROV, if required, would then be prepared and approved in a timely manner.

Accountable LOB	Qual Assurance and OP Support	Proposed Completion Date	30-Jun-16

Approvals

Approved by:	Signature	Date
Paul Brown, Director, Dx Asset Management	~~[illegible]~~ on behalf of Paul Brown	July 6, 2016
Approved by:	**Signature**	**Date**
Wade Frost, Manager, Decision Support	[signature]	July 6/16
Approved by:	**Signature**	**Date**
Kathy Moulton, Director, QA and OP Support	[signature]	July 6, 2016
Approved by *(As per EAR/OAR)*:	**Signature**	**Date**
Mike Penstone, VP, Planning	[signature]	July 6, 2016

IROV Author	Charlie Lee
Date Prepared	28-Jun-16

41000719

INTERIM REVIEW OF VARIANCE (IROV)

AR	IROV Claim #	Driver	BCS Originator (LOB)	Service Provider (LOB)	Date (mm/dd/yy)
22368	~~50004024~~	N.D.C2.02	Dx Asset Management	Qual Assurance and OP support	April 14, 2016

Investment Title	
Nebo TS M12 Extension to Hamilton Airport	
5. Original Approved Cost *(Line 1)*	**$4,100 K**
6. Total Cost Approved Plus Requested *(line 4)*	**$5,634 K**
Current Cost ratio *(Box 6/Box 5)*	**137%**

Project Manager	Planner
Jeff Battaglia	Isabel Victal

1. Original approved cost *(per BCS)*	1.1 OM&A	$100 K	**Original approved in-service date** *(as per line 1)*	
	1.2 CAPITAL	$3,600 K	December 21, 2015	
	1.3 REMOVALS	$400 K		
	TOTAL	**$4,100 K**		
2. Total $ currently approved *(Original plus previous IROVs awards)*	2.1 OM&A	$100 K	**Current approved in-service date** *(as per line 2)*	
	2.2 CAPITAL	$3,600 K	December 21, 2015	
	2.3 REMOVALS	$400 K		
	TOTAL	**$4,100 K**		
3. Revision now requested		Total (A + B)	(A) Cost of Scope Increases	(B) Cost of "In-Scope" Project Variances
	3.1 OM&A	$101 K	$0 K	$101 K
	3.2 CAPITAL	$1,154 K	$0 K	$1,154 K
	3.3 REMOVALS	$279 K	$0 K	$279 K
	TOTAL	**$1,534 K**	**$0 K**	**$1,534 K**
4. Total Cost including OH & AFUDC *(Line 2 plus line 3)*	4.1 OM&A	$201 K	**Proposed new in-service date** *(as per line 3)*	
	4.2 CAPITAL	$4,754 K	June 30, 2016	
	4.3 REMOVALS	$679 K		
	TOTAL	**$5,634 K**		

Summary of Variance:

The original line design by the Lines technician was inaccurate and therefore had to be re-designed and re-estimated. This resulted in the delay in the work execution and the updated design is higher in costs. The tech design hours increased from 1450 to 1800 hours. The line construction hours is increasing from the original estimate of 10879 to 22000 hours. The total combined increase for this IROV is 11,471 hours.

	Item / Description	Cost of Scope increase $K	In-Scope Variance $K
1	redesign and construct (around 11471 hours)	$0 K	$1,534 K
2			
3			
4			
5			
6			
7			
8			
9			
10			
	Total Variance Costs	**$0 K**	**$1,534 K**

Project Cashflow Detail by Year

Description		2012	2013	2014	2015	2016	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$100 K	$101 K	$201 K
	CAPITAL	$0 K	$0 K	$0 K	$3,600 K	$1,154 K	$4,754 K
	REMOVALS	$0 K	$0 K	$0 K	$400 K	$279 K	$679 K
	TOTAL	**$0 K**	**$0 K**	**$0 K**	**$4,100 K**	**$1,534 K**	**$5,634 K**

ALMEIDA Lee

From: BROWN Paul
Sent: Monday, July 04, 2016 8:25 AM
To: ALMEIDA Lee
Subject: Automatic reply: Time Exception for me

Vacation Alert - Please note that I am on vacation until Sunday July 17th, 2016.
For items related to:
Distribution Investment Planning Strategy, please call Sinisa Grkovic at 416 345-6760 office and 905 399-9846 cell.
Distribution Investment Planning North, please call Peter Faltaous at 416 345-5853 office and 416 669-8059 cell.
Distribution Investment Planning South, please call Ted Lyberogiannis at 416 345-5994 office and 647 588-7290 cell.
Distribution Program Integration, please call John Boldt at 888 332-2249 x3214 office and 613 264-2557 cell.
Administration matters please contact Lee Almeida at 416 345-6407.
Otherwise I will reply to your email upon my return.

This email and any attached files are privileged and may contain confidential information intended only for the person or persons named above. Any other distribution, reproduction, copying, disclosure, or other dissemination is strictly prohibited. If you have received this email in error, please notify the sender immediately by reply email and delete the transmission received by you. This statement applies to the initial email as well as any and all copies (replies and/or forwards) of the initial email.

LACORTE Raffaella

From:	ALMEIDA Lee
Sent:	Friday, July 08, 2016 12:13 PM
To:	LACORTE Raffaella
Cc:	FALTAOUS Peter; BROWN Paul
Subject:	Nebo TS IROV_FW: Signing Authority

Regards,

Lee Almeida
416-345-6407

From: BROWN Paul
Sent: Friday, July 08, 2016 12:08 PM
To: ALMEIDA Lee
Cc: FALTAOUS Peter; LYBEROGIANNIS Ted; GRKOVIC Sinisa; BOLDT John
Subject: Signing Authority

Peter has my signing Authority while I am on vacation. Thx

Paul Brown
Director, Distribution Asset Management
Hydro One Networks
416 345-4534 office
705 727-7197 mobile

Sent from my Samsung device over Bell's LTE network.

This email and any attached files are privileged and may contain confidential information intended only for the person or persons named above. Any other distribution, reproduction, copying, disclosure, or other dissemination is strictly prohibited. If you have received this email in error, please notify the sender immediately by reply email and delete the transmission received by you. This statement applies to the initial email as well as any and all copies (replies and/or forwards) of the initial email.

Investment Driver: N.D.C.2.02 | Date: March 28,2014

AR Number: 22380,23220 | Title: Nobleton DS T1: New Transfomer and Feeders

Hydro One Networks - Business Case Summary - 50003641

Nobleton DS T1: New Transfomer and Feeders

Investment Driver: | **In-Service date:** December 31,2015

N.D.C.2.02 - System Capability Reinforcement (2014 - $61M , 2015 - $81M)

Investments in System Capability Reinforcement provide for new or modified distribution system facilities to accommodate (1) increases in customer load;(2) improvements in system reliability; (3) improved operational efficiency and asset life cycle planning; and (4) contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This Approval: $40K | **Previous Approval:** $0 | **Project Total:** $40K

Need:

This investment is required to obtain the Class A cost estimate to add a new 12 MVA transformer T1, build 2 new 27.6 kV feeders from Nobleton DS T1, and convert voltages of feeder sections on Nobleton DS to 27.6 kV. The new transformer and new feeders are required to relieve the overloaded Kleinburg TS M5 feeder as well as increasing 27.6 kV capacities in the Nobleton and Bolton areas.

Not proceeding with this investment would lead to overloaded assets and the inability to serve new load presenting reliability, customer, and regulatory risks.

Investment Summary:

This investment is to request Class A cost estimate for the scope of work including a new 12 MVA transformer, 2 new 27.6 kV feeders and voltage conversion to existing feeder sections.

Currently, the Nobleton community is supplied by Kleinburg TS M5 feeder, which extends a long distance from the Bolton Area. Kleinburg TS M5 feeder is loaded beyond its loading limit and requires immediate attention. Kleinburg TS M5 feeder is no longer sufficient to supply both Bolton and Nobleton Areas.

To address the overloading concern and increasing overall capacity, this investment proposes to add a 12 MVA 44/27.6 kV transformer with 2 feeders. The new transformer will pick up loads currently supplied by the M5 feeder from Kleinburg TS. Nobleton DS F4 and F5 feeder sections south of and along 15th Side Road will be converted from 8.32 kV to 27.6 kV. The converted feeders will pick up the current Kleinburg TS M5.

Results:

The two new 27.6 kV feeders along with the new T1 transformer at Nobleton DS would increase 27.6 kV capacity in both Nobleton Community and the Bolton Area. Nobleton DS T1 can accommodate the existing loads in the Nobleton Community with capacity remaining for future load growth. At the same time, Kleinburg TS feeder M5 would be relieved and has capacity to accommodate load growth in Bolton Area.

Costs:

	2014 K	Total K
Capital* and MFA	40	40
OM&A and Removals	0	0
Gross Investment Cost*	40	40
Recoverable	0	0
Net Investment Cost	40	40

The cost estimate includes AFUDC and overheads at current rates.

Investment Driver: N.D.C.2.02

Date: March 28,2014

AR Number: 22380,23220

Title: Nobleton DS T1: New Transfomer and Feeders

Project Risk and Mitigation:

Business Planning:

This investment is included in the 2014-2019 Business Plan under AIP000184 with sufficient funding.

Regulatory Considerations:

There are no significant regulatory issues anticipated other than standard need and prudence justification.

Funds Included in Business Plan: Y	Director: Paul Brown	Planner: Cecilia Pang
This Approval($K): 40	**Previous Approval($K):** 0	**Current Est. of Total Cost($K):** 40
Signature Block:		
Submitted by: Cecilia Pang	**Title:** Planner	**Date:** Apr 2/2014
Reviewed by:	**Title:**	**Date:**
Recommended by:	**Title:**	**Date:**
Approved by: Peter Faltaous	**Title:** Manager	**Date:** Apr 2/2014

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

hydro one

Investment Driver: N.D.C.2.02 Date: September 15,2014

AR Number: 22380 Title: Cost Estimate- Nobleton DS T1: New Transfomer and Feeders

Hydro One Networks - Business Case Summary - 50003772

Cost Estimate- Nobleton DS T1: New Transfomer and Feeders

Investment Driver: **In-Service date:** December 15,2015

N.D.C.2.02 - System Capability Reinforcement (2014 - $61M , 2015 - $81M)

Investments in System Capability Reinforcement provide for new or modified distribution system facilities to accommodate (1) increases in customer load;(2) improvements in system reliability; (3) improved operational efficiency and asset life cycle planning; and (4) contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This Approval: $40K **Previous Approval:** $40K **Project Total:** $80K

Need:

Additional funds is required by Engineering and Construction in order to complete the cost estimate. The previous release of $40k was not adequate. The scope of work requires a new 12 MVA transformer T1, 2 new 27.6 kV feeders from Nobleton DS T1, and convert voltages of feeder sections on Nobleton DS to 27.6 kV.

Not proceeding with this investment would lead to overloaded assets and the inability to serve new load presenting reliability, customer, and regulatory risks.

Investment Summary:

This investment of additional $40k is required to complete the cost estimate initiated by BCS50003641. The original BCS requests for cost estimate to build new T1 and and 2 new 27.6 kV feeders at Nobleton DS.

The new transformer and new feeders are required to relieve the overloaded Kleinburg TS M5 feeder as well as increasing 27.6 kV capacities in the Nobleton and Bolton areas.

To address the overloading concern and increasing overall capacity, this investment proposes to add a 12 MVA 44/27.6 kV transformer with 2 feeders. The new transformer will pick up loads currently supplied by the M5 feeder from Kleinburg TS. Nobleton DS F4 and F5 feeder sections south of and along 15th Side Road will be converted from 8.32 kV to 27.6 kV. The converted feeders will pick up the current Kleinburg TS M5.

Results:

Complete cost estimate work for the project

Costs:

	2014 K	Total K
Capital* and MFA	40	40
OM&A and Removals	0	0
Gross Investment Cost*	40	40
Recoverable	0	0
Net Investment Cost	40	40

Investment Driver: N.D.C.2.02 Date: September 15,2014

AR Number: 22380 Title: Cost Estimate- Nobleton DS T1: New Transfomer and Feeders

Project Risk and Mitigation:

Business Planning:

This investment is included in the 2014-2019 Business Plan under AIP005267 with sufficient funding.

Regulatory Considerations:

There are no significant regulatory issues anticipated other than standard need and prudence justification.

Funds Included in Business Plan: Y	**Director:** Paul Brown	**Planner:** Charlie Lee	
This Approval($K): 40	**Previous Approval($K):** 40	**Current Est. of Total Cost($K):** 80	
Signature Block:			
Submitted by: Charlie Lee		**Title:** Planner	**Date:** Sept 15/14
Reviewed by:		**Title:**	**Date:**
Recommended by:		**Title:**	**Date:**
Approved by: John Fuerth		**Title:** Manager	**Date:** Sept 15/14

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

Investment Driver: N.D.C.2.02 Date: December 30,2014

AR Number: 22380 Title: Nobleton DS T1-new 27.6 kV transformer and feeder

Hydro One Networks - Business Case Summary - 50003899

Nobleton DS T1-new 27.6 kV transformer and feeder

Investment Driver: **In-Service date:** November 30,2016

N.D.C.2.02 - System Capability Reinforcement (2015-$63.3M, 2016-$102.9M)

Investments in System Capability Reinforcement provide for new or modified distribution system facilities to accommodate (1) increases in customer load;(2) improvements in system reliability; (3) improved operational efficiency and asset life cycle planning; and (4) contributions to the cost of new or upgraded transmission facilities required to accommodate load growth.

This Approval: $3.5M **Previous Approval:** $0.1M **Project Total:** $3.6M

Need:

This investment is required to address overloading concern and to increase supply capacity and reliability for 27.6 kV feeders (Kleinburg TS M5, M7 and M8) servicing Bolton and Nobleton areas.

Not proceeding with this investment would lead to overloaded assets presenting reliability and customer risks.

Investment Summary:

Bolton area is supplied through Kleinburg TS 27.6 kV feeders M5, M7 and M8. Nobleton area is supplied through Kleinburg TS M5, which is ranked # 34 worst performing feeder in the Province in terms of SAIFI. The area has over 1000 new homes planned in the next few years. The forecasted load growth from residential, commercial and industrial developments for the two areas is 8 MW over the next 10 years. These three feeders (M5, M7 & M8) are currently at or over the planned loading limit of 17 MVA.

To address the overloading concern and to increase supply capacity and reliability, this investment proposes to add a 12 MVA 44/27.6 kV transformer with one feeder at Nobleton DS. The new transformer will pick up 8 MW of load currently supplied by the M5 feeder from Kleinburg TS. Nobleton DS F4 feeder section along 15th Side Road and HWY 27 will be converted from 8.32 kV to 27.6 kV and connected to the new transformer to provide enough capacity on M5 for further load relief to Kleinburg TS M7 & M8. Minor switching work will be done to transfer loads between M5, M7 & M8. The 8 MW load transfer off the M5 feeder will remove, from the M5, over 2000 Customer connections and associated branch lines resulting in a reduction in M5 feeder faults. Also the new transformer provides a backup supply for the M5 feeder.

Results:

Provide load relief to Kleinburg TS M5, M7 and M8 by bringing all feeders within the planned loading limit of 17 MVA. The addtional 27.6 kV supply feeder will remove 8 MW of residential load from the M5 feeder and improve supply reliability both Bolton and Nobleton areas.

Costs:

	2015 M	2016 M	Total M
Capital* and MFA	1.0	2.4	3.4
OM&A and Removals	0.0	0.1	0.1
Gross Investment Cost*	1.0	2.5	3.5
Recoverable	0.0	0.0	0.0
Net Investment Cost	1.0	2.5	3.5

*Includes overhead and AFUDC at current rates

Alternatives

ALTERNATIVES CONSIDERED AND REJECTED

Status Quo or Do nothing Alternative

The 'Do-Nothing' alternative will result in continuing heavy loading and overloading of existing facilities. Customer reliability will further deteriorate. Therefore this alternative is rejected.

ALTERNATIVES CONSIDERED FURTHER

Alternative One

Add a 12 MVA 44/27.6 kV transformer with one feeder at Nobleton DS. The new transformer will pick up loads currently supplied by the M5 feeder from Kleinburg TS. Nobleton DS F4 feeder section along 15th Side Road and HWY 27 will be converted from 8.32 kV to 27.6 kV. The converted feeder will pick up portion of Kleinburg TS M5 loads (approximately 8 MW) and provide enough capacity on M5 for further load relief to Kleinburg TS M7 & M8. M5 will become the backup supply to Nobleton area. Only minor switching work will be required in order to transfer loads between M5, M7 & M8.

Alternative Two

Add one 27.6 kV feeder at Kleinburg TS by modifying the existing bus and installing a new breaker. Construct approximately 1.7 km underground line from the station to Albion Vaughan Rd and transfer loads from Kleinburg TS M8 to the new feeder. Also extend Kleinburg TS M7 approximately 5.5 km from Albion Vaughan Rd to Nobleton area to provide backup supply in Nobleton area. Minor switching work will be required to transfer loads between M5, M7 & M8.

RECOMMENDED ALTERNATIVE AND RATIONALE

Alternative One

Alternative one is recommended as it has lower cost and meets the need for the feeder load relief and reliability improvements in Bolton and Nobleton areas.

Investment Driver: N.D.C.2.02 Date: December 30,2014

AR Number: 22380 Title: Nobleton DS T1-new 27.6 kV transformer and feeder

Alternatives Compared

	Project Level Risk			
Business Value	**Current Risk**	**Alt1**	**Alt2**	**Comparison**
Reliability	HIGH	LOW	LOW	Both alternative 1 and alternative 2 include installation of backup supply line in Nobleton area.
Customer	HIGH	LOW	LOW	Both alternative 1 and alternative 2 reduce the risk of customer service outages by bringing all area feeders within the planned loading limit of 17 MVA.
Competitiveness	N/A	N/A	N/A	Not influential in the investment decision.
Safety and environment	N/A	N/A	N/A	Not influential in the investment decision.
Regulatory / Legal	MED	LOW	LOW	Alternative 1 and 2 removes the risk of Hydro One being found in breach of the Distribution System Code (s 4.4.1 of not maintaining its distribution system in accordance with good utility practice) and inviting increased scrutiny of its operational practices. Improved system reliability statistics also positively influence OEB decisions in other areas such as potential Hydro One acquisitions, service area amendments and rate approvals.
Reputation	HIGH	LOW	LOW	Hydro One will be seen to take proactive action to improve system supply reliability and load capacity.
Initial Cost ($M)		3.6	6.2	Alternative 2 has higher cost.
Financial: PV Cost / NPV ($M)		-3.0	-5.1	The NPVs are calculated by taking into consideration of the upfront capital expenditure and ongoing maintenance costs and assume the project in-service year of 2016 and the study length of 40 years.

Project Risk and Mitigation:

Cost:

The project cost is based on a Class C estimate from Stations and Lines, which is accurate in the range of +/-50% and includes a contingency for in-scope variances of $506k, which is 20% of the direct project cost.

Business Planning:

This investment is included in the 2015-2019 Business Plan as AIP005267 with sufficient funding.

Execution Risks:

Approvals Low
S.92 N/A
EA N/A
Outages Low
Resourcing Low
First Nations N/A
Real Estate N/A
Agreements N/A
Technology N/A

Investment Driver: N.D.C.2.02 | Date: December 30,2014

AR Number: 22380 | Title: Nobleton DS T1-new 27.6 kV transformer and feeder

Regulatory Considerations:

There are no significant regulatory issues anticipated other than standard need and prudence justification.

Capital expenditures for the Nobleton DS T1- 27.6 kV transformer and feeder project are included in the currently submitted Dx rate filing EB-2013-0416 (rate filing for years 2015 to 2019) under sub-category 'System Capability Reinforcement' in ISD# 'D2-System Upgrades Driven by Load Growth', totaling $3.0M in 2015, with a planned in-service date of 2015.

Funds Included in Business Plan: Y	**Director:** Paul Brown	**Planner:** Helen Guo
This Approval($M): 3.5	**Previous Approval($M):** 0.1	**Current Est. of Total Cost($M):** 3.6

Signature Block:

Submitted by: John Fuerth	**Title:** Manager	**Date:** FEB 18/15
Reviewed by: Glenn Scott	**Title:** Director	**Date:** Feb 18 2015
Recommended by: Paul Brown	**Title:** Director	**Date:** FEB 18/15
Approved by: Mike Penstone	**Title:** Vice President	**Date:** Feb19/15

Scientific Research & Experimental Development Tax Credits (SR&ED)

- Do you anticipate that the initiative to meet the set of business requirements in this document will result in a ***Technological Advancement***? N
- Do you anticipate that the initiative will resolve a ***Technological Uncertainty***? N

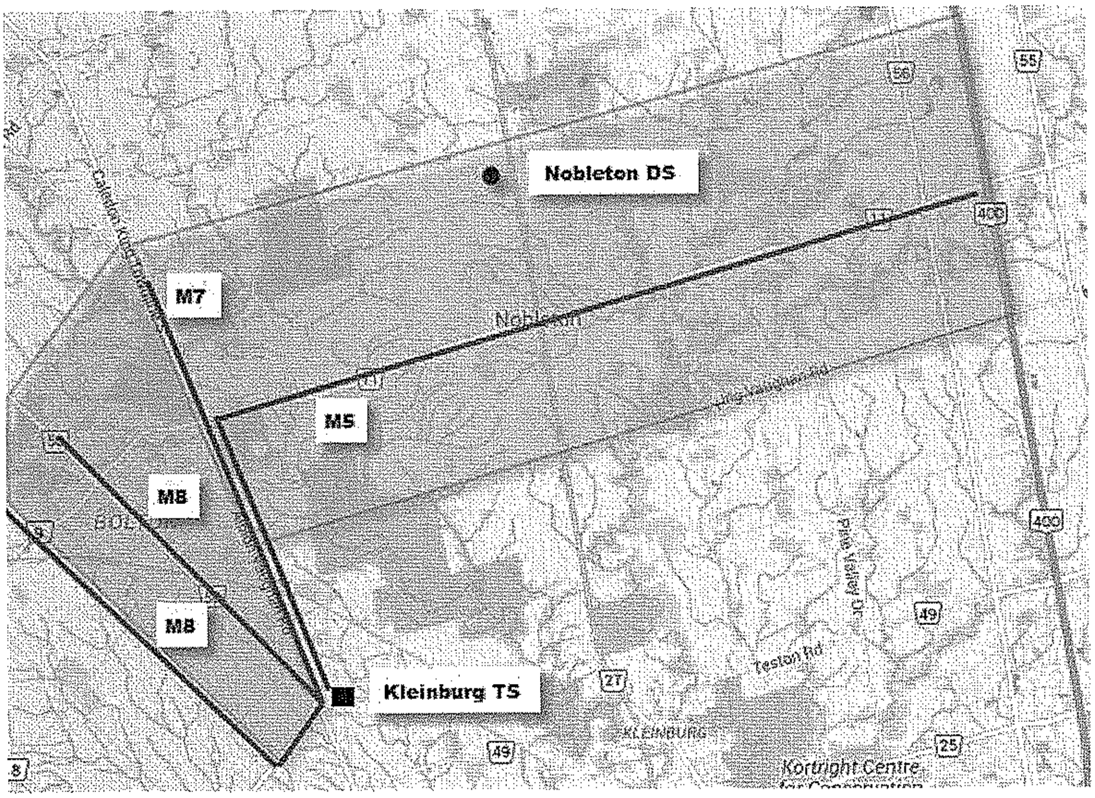

Figure 1 - Before configuration

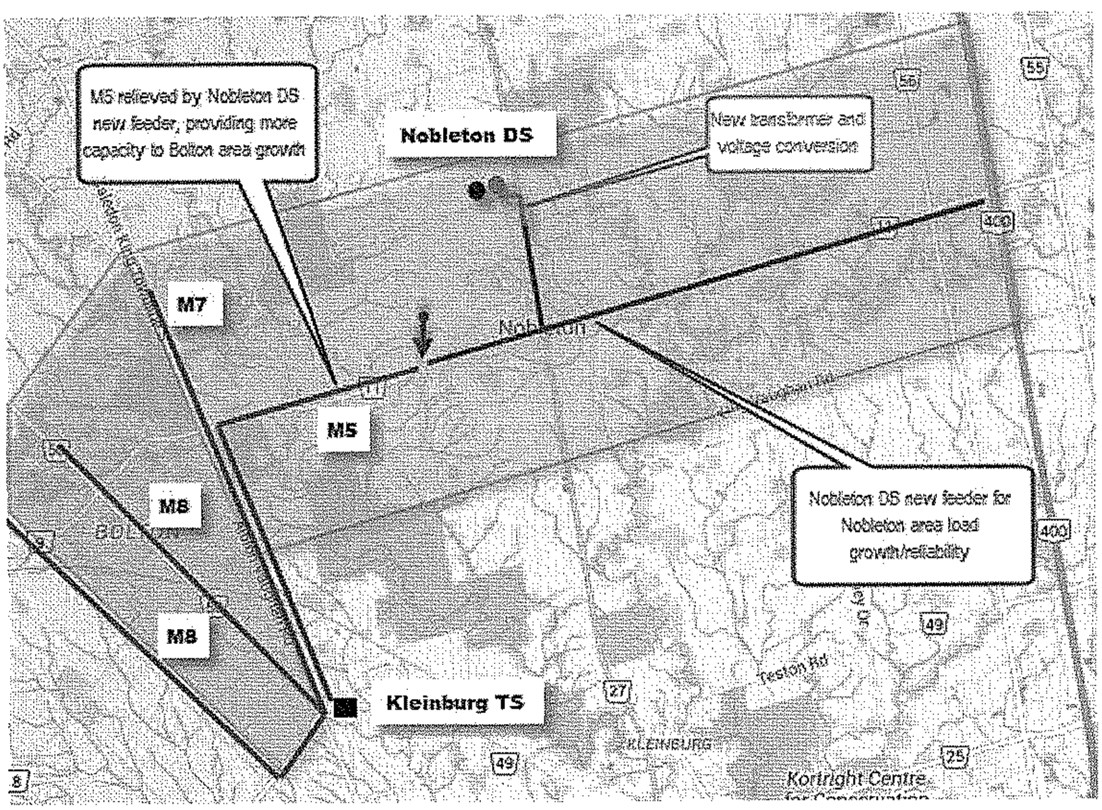

Figure 2 - After configuration

INTERIM REVIEW OF VARIANCE (IROV)

Check All Applicable Boxes to Show Variances Requiring OAR Approval

☑ Cost Increase ☑ Schedule (Business Impactive) ☑ Scope Change (Significant)

AR	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date
22380	DC202	Dx Asset Management	Stations	17-May-17

Investment Title			
Nobleton DS T1 - new 27.6kV transformer and feeder		Original Approved Cost *(as per BCS)*	$3,600 K
		Total Cost Approved plus Requested	$4,700 K
Original approved in-service date	Proposed new in-service date	Current Cost ratio	131%
November 30, 2016	June 30, 2017		

Background Situation:

This investment is to increase feeder capacity and reliability for 27.6kV feeders (Kleinburg TS M5, M7 and M8) servicing the Bolton and Nobleton areas. At present, the M5 is loaded well above planning limits, and is among the worst-performing feeders in the provice for both SAIDI and SAIFI indices (#15 and #30, respectively, on a 3-year rolling average). To address feeder loading and exposure, this investment is for the construction of a new 12MVA 44/27.6kV transformer, with one feeder, at Nobleton DS. Construction is presently well under way.

A business case to develop a Class A estimate was approved early in 2014, and a business case for project execution was subsequently approved at the beginning of 2015, based on the estimate received. However, the estimate that was developed was a Class C estimate, and the project was released based on this estimate.

Variance Explanation: *(Discussion of significant cost, schedule, and scope changes, and an explanation of root causes.)*

Project Cost Variance ($611k):
The requirement for MUS facilities to be offsite was not identified at the estimating stage, and is the primary cause of cost variance for this project. Due to wet conditions, more soil also needed to be removed / replaced at the station.

Scope Change ($400k):
The 44kV ingress was changed from overhead (as in the original design) to underground. Replacement of the old 8.32KV cables was identified as a necessary item to include at the same time the 27.6kV cables were being installed. Design changes were also made to the station egress poles, the station driveway, and installation of a future (spare) circuit in duct.

Schedule Variance ($89k):
Delays to the delivery of the station transformer resulted in additional storage fees. Delays were also caused by a design change which was a result of King Township providing a late notification that the road in front of the DS would eventually be widened.

Lessons Learned:

1) Releasing a project of this magnitude (i.e. >$300k) for construction based on a Class C estimate is not appropriate, as it does not adequately consider challenges which would be identified during a detailed design estimate.
2) The request for Class C estimate in SAP should have been coupled with an updated business case. The AM planner did not have the authority to diverge from the approved business case, which indicated a Class A estimate would be obtained.
3) The Scope for estimate should have been developed in consultation with field staff.

Planned Action:

1) Asset Management to ensure any project of significant scope is released based on a detailed design (Class A estimate), to minimize risk and to better understand project complexity.
2) A new redirection policy is being developed by Investment Management to manage In-Service-Additions (ISA) to help ensure that they remain within the OEB approved ISA budget.
3) Dx Asset Management is receiving regular forecast and LTD spend information from Transmission & Stations to identify the need for an IROV. Furthermore a regular IROV tracking report is now prepared by Decision Support, and reviewed by Dx Asset Management.

Accountable LOB	Distribution Asset Management	Proposed Completion Date	7/20/2016

Approvals

Approved by:	Signature	Date
Lyla Garzouzi, Director, Dx Asset Management	[signature]	May 18, 2017
Approved by:	**Signature**	**Date**
Chris Cooper, Director, Project Delivery	Chris Cooper	May 23, 2017
Approved by:	**Signature**	**Date**
Wade Frost, Manager, Decision Support	[signature]	May 23/17
Approved by:	**Signature**	**Date**
Darlene Bradley, Vice President, Planning	Darlene Bradley	May 24, 2017

IROV Author	Mark van Tol
Date Prepared	18-May-17

INTERIM REVIEW OF VARIANCE (IROV)

AR	IROV Claim #	Driver	BCS Originator *(LOB)*	Service Provider *(LOB)*	Date *(mm/dd/yy)*
22380	41000620	DC202	Dx Asset Management	Stations	May 17, 2017

Investment Title		
Nobleton DS T1 - new 27.6kV transformer and feeder	5. Original Approved Cost *(Line 1)*	$3,600 K
	6. Total Cost Approved Plus Requested *(line 4)*	$4,700 K

Project Manager	Planner	Current Cost ratio *(Box 6/Box 5)*	
Larry Karafilov	Mark van Tol		131%

1. Original approved cost *(per BCS)*	1.1 OM&A	$0 K	Original approved in-service date *(as per line 1)*	
	1.2 CAPITAL	$3,500 K	November 30, 2016	
	1.3 REMOVALS	$100 K		
	TOTAL	$3,600 K		
2. Total $ currently approved *(Original plus previous IROVs awards)*	2.1 OM&A	$0 K	Current approved in-service date *(as per line 2)*	
	2.2 CAPITAL	$3,500 K	November 30, 2016	
	2.3 REMOVALS	$100 K		
	TOTAL	$3,600 K		
3. Revision now requested		Total (A + B)	(A) Cost of Scope Increases	(B) Cost of "In-Scope" Project Variances
	3.1 OM&A	$0 K	$0 K	$0 K
	3.2 CAPITAL	$1,100 K	$1,100 K	$0 K
	3.3 REMOVALS	$0 K	$0 K	$0 K
	TOTAL	$1,100 K	$1,100 K	$0 K
4. Total Cost including OH & AFUDC *(Line 2 plus line 3)*	4.1 OM&A	$0 K	Proposed new in-service date *(as per line 3)*	
	4.2 CAPITAL	$4,600 K	June 30, 2017	
	4.3 REMOVALS	$100 K		
	TOTAL	$4,700 K		

Summary of Variance:

The project variance is primarily due to design changes that were not identified in the original estimate, since the estimate quality was Class C. It is unclear whether Asset Management was aware that the estimate delivered was Class C, since the business case approval was for a Class A estimate. The design changes identified during project execution are necessitating the requirement for a mobile substation to be installed off-site, which is costly.

#	Item / Description	Cost of Scope increase $K	In-Scope Variance $K
1	Installation of new cables for 8.32kV feeder egress (horizontal drilling with flex-ducts and new 28kV cables pulled through the ducts. One extra duct for each cct. Installed.)	$100 K	
2	Installation of second (future) 27.6kV feeder egress (same as above but new ducts and 28kV cables for two feeders.)(A third set of four empty ducts for a potential future feeder.)	$100 K	
3	Installation of 44kV cable ingress (same as above, but to replace overhead 44kV feed.)	$50 K	
4	Delays caused by delayed drilling and King Township informing us they are widening the road in the near future has caused a Lines design change and extra Mob and DE Mob charges for Construction.	$75 K	
5	Design change and re-issue for station to accommodate EMD requests, including wider driveways and some parking space in front of station.	$50 K	
6	Due to wet conditions, more soil removed and more replaced in and around station.	$100 K	
7	Delay to transformer delivery resulting in storage fees of $11K	$14 K	
8	Seven poles on south side of 15th Sideroad will replace three with framing and cable risers up four poles.	$100 K	
9	Mobile Substation (MUS) facilities - cost to have facilities off-site; site prep, grounding, fence, poles inside and outside (both sides of road) and driveway build-up for better access for MUS.	$500 K	
10	MUS facilities - cost of easements / land rental	$11 K	
	Total Variance Costs	**$1,100 K**	**$0 K**

Project Cashflow Detail by Year

Description		2014	2015	2016	2017	2018	TOTAL
Total Cost Approved plus Requested	OM&A	$0 K	$0 K	$0 K	$0 K	$0 K	$0 K
	CAPITAL	$100 K	$1,000 K	$2,400 K	$1,100 K	$0 K	$4,600 K
	REMOVALS	$0 K	$0 K	$100 K	$0 K	$0 K	$100 K
	TOTAL	$100 K	$1,000 K	$2,500 K	$1,100 K	$0 K	$4,700 K

UNDERTAKING – JT 3.1-10

Reference

I-24-AMPCO-22 (b)

Preamble: AMPCO requested the % of planned capital work undertaken for each of the years 2012 to 2017.

Undertaking

AMPCO's question should have been clearer. AMPCO seeks to understand how much of the total capital budget is spent on planned capital work compared to unplanned work for each of the years 2012 to 2017.

Capital Spend	2012	2013	2014	2015	2016	2017
% planned work						
% unplanned work						

Response

Capital Spend	2012 (Note1)	2013	2014	2015	2016	2017
% planned work	NA	56%	58%	59%	59%	58%
% unplanned work	NA	44%	42%	41%	41%	42%

Note 1: The breakdown between planned and unplanned work for 2012 is not readily available.

Witness: JESUS Bruno

UNDERTAKING – JT 3.1-11

Reference

I-24-AMPCO-23 (c)

Preamble: HONI indicates that most asset groups have data availability levels below 100%.

Undertaking

i. Please list the asset groups that have data availability levels equal to 100%.

ii. Please list the asset groups that have data availability levels of less than 50%.

iii. Please list the asset types that have data availability levels of greater than 50% but less than 75%

iv. Please list the asset types that have data availability levels of greater than 75% but less than 100%.

Response

Please see the table below for the station assets data availability:

Asset Type	Data Availability Level
i) The asset types that have data availability levels equal to 100%.	
Station Structures	100%
MUS structures	100%
ii) The asset types that have data availability levels of less than 50%.	
Circuit Breakers –All	38%
iii) The asset types that have data availability levels of greater than 50% but less than 75%.	
None	
iv) The asset types that have data availability levels of greater than 75% but less than 100%	
Station Transformers	89%
Mobile Unit Substation (Transformers)	87%
Station Reclosers - All	84%

All lines assets are inspected regularly as part of the distribution line patrol. During these inspections, condition is recorded on an exception basis – assets in good conditions do not have defect reports associated with them. For this reason, condition data is generally limited to assets in poor condition and therefore condition data availability is less than 100%.

Witness: GARZOUZI Lyla

UNDERTAKING – JT 3.1-12

Reference
I-24-AMPCO-23 (f)

Preamble: HONI indicates that not all asset types or sub-types have condition algorithms.

Undertaking
Please explain further what this means and the resulting impact on the condition assessment of the asset.

Response
Not all asset types or sub-types have condition algorithms that are used to determine if an asset is at the end of its useful life. When defects on assets with no condition algorithms are identified, they are addressed appropriately.

UNDERTAKING – JT 3.1-13

Reference

I-24-AMPCO-24 (c)

Undertaking

i. Please confirm the asset failure quantities in Attachment #1 includes failures that do not result in an outage.

ii. Please provide a version of the table with only asset failures that result in customer interruptions.

iii. HONI states "Note that in some cases, multiple assets can fail for a single outage." Please provide an example and explain how this impacts the asset failure quantities in the table.

Response

i. Confirmed.

ii. Please refer to interrogatory response I-29-AMPCO-028 (#Outage/Year) Table for pole failures that result in customer interruptions. For transformer failures that resulted in customer interruptions, please see table below.

Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Number of Transformer Failures	6	2	7	4	3	6	9

iii. For example, a single line outage on a feeder may be caused by a cascading pole failure where multiple poles fail. A cascading pole failure is an event where one pole fails mechanically falling to the ground and pulls down one or more adjacent poles. Thus the number of asset failures will be greater than or equal to the number of outages.

Witness: GARZOUZI Lyla

UNDERTAKING – JT 3.1-14

Reference

I-24-AMPCO-25

Preamble: HONI provided details on planned asset replacements.

Undertaking

i. Please clarify if the planned asset quantities provided include planned replacements under the System Renewal investment category only, or if planned asset replacements under System Access and System Service categories are also included.

ii. If the table reflects System Renewal planned investments only, please provide an updated excel table to show planned replacements under all three asset investment categories: System Renewal, System Access and System Service.

Response

i. These include planned replacements that are targeted at end of life asset categories under investments pertaining to System Renewal only; with the exception of station assets (which included planned replacements under System Service: SS-02 System Upgrades Driven by Load Growth) and AMI assets (which included planned meter replacements under System Access: SA-02 Metering Infrastructure Sustainment Program and SA-04 New Load Connections, Upgrades, Cancellations and Metering, as well as System Service: SS-01 Remote Disconnection / Reconnection Program).

ii. Hydro One does not track the quantity of planned asset replacements that are completed under all investment categories. System Access and System Service categories of investments are not primarily driven by end of life assets.

UNDERTAKING – JT 3.1-15

Reference

I-24-AMPCO-26

Preamble: HONI indicates a forecast of unplanned replacements is not available for the years 2018 to 2022.

Undertaking

Please explain how HONI determines the capital budget needed to address unplanned asset replacements?

Response

As documented in Exhibit C1, Tab 1, Schedule 2; Hydro One forecasts investment levels for unplanned capital based on average historical expenditures.

UNDERTAKING – JT 3.1-16

Reference

I-24-AMPCO-33 (d)

Preamble: HONI indicates that OEB approved figures are not available for 2012-2014 as these were IRM years.

Undertaking

Regardless of it being an IRM year, AMPCO assumes HONI had a planned System Service internal budget for each of the years 2012 to 2014. Please provide the System Service work deferred, cancelled or advanced compared to the budget for 2012 to 2014.

Response

	2012	**2013**	**2014**
Deferred	69.9	60.9	25.1
Cancelled	0	0	0
Advanced	0	0	0

UNDERTAKING – JT 3.1-17

Reference
I-24-AMPCO-34 (a) (b) (d)

Undertaking
AMPCO could not locate the MS excel files to be provided at (a), (b) and (d).
Please provide.

Response
Please see the attached MS Excel file.

UNDERTAKING – JT 3.1-18

Reference

I-29-AMPCO-27 (b)

Preamble: HONI indicates it could not provide the asset unit replacement levels by investment plan scenarios for total line component category as volumes are not available as they are dissimilar units replaced as part of both individual programs and as part of refurbishment projects.

Undertaking

i. Please explain this statement further.

ii. Please provide the asset groups included under Other Line Equipment.

iii. Please explain how HONI determined the spending for "Other Line Equipment" under each investment plan scenario.

Response

i. The "Other Line Components" category described in Section 2.4 of the DSP (Exhibit B1-1-1) refers to outages caused by the failure of any line component other than poles. As such, it includes outages due to the failure of a high number of different equipment types, most of which are not replaced as part of any specific program. For this reason, the total volume of component replacements is unavailable.

ii. Any and all lines components other than poles are included under "Other Line Components".

iii. As defined in Section 2.4 of the DSP (Exhibit B1-1-1), and for the reasons described in part (i) above, there is no defined spending level for "Other Line Components".

These components are replaced as part of a number of investments described in the DSP, including but not limited to, the "Distribution Lines Planned Component Replacement Program" described in Investment Summary Document SR-10, the "Distribution Lines Sustainment Initiatives" described in Investment Summary Document SR-12, and the "Life Cycle Optimization & Operational Efficiency Projects" described in Investment Summary Document SR-13.

Witness: JESUS Bruno

UNDERTAKING – JT 3.1-19

Reference

I-29-AMPCO-28

Undertaking

Please confirm the data in the three tables excludes Force Majeure and Loss of Supply events.

Response

Confirmed.

UNDERTAKING – JT 3.1-20

Reference

I-29-AMPCO-30

Undertaking

Please provide the km of low priority Rights of Way, medium priority Rights of Way and high priority Rights of Way.

Response

The new vegetation management program presented in Exhibit Q, Tab 1, Schedule 1 does not disaggregate the right-of-way inventory by priority and instead focuses on clearing high risk defects on all lines within the three year cycle.

UNDERTAKING – JT 3.1-21

Reference
I-18-SEC-31

Undertaking
For the following outcome measures, please confirm the historical actuals for 2014 to 2016 exclude Force Majeure and Loss of Supply events: Vegetation Caused Interruptions, Substation Caused Interruptions and Distribution Line Equipment Caused Interruptions.

Response
Confirmed.

UNDERTAKING – JT 3.1-22

Reference
I-38-AMPCO-38

Preamble: HONI provided a table in response to (a).

Undertaking
i. For the first row “Line Assets”, please indicate if the percentages shown reflect Inspected, Tested or Maintained.

ii. Please provide the forecast percentages for the years 2018 to 2022.

Response
i. For “Lines Assets”, the percentages primarily reflect asset inspections.

ii. Please see table below for the forecast percentages of stations and line assets to be inspected, tested and maintained in each of the years 2018 to 2022.

	2018	**2019**	**2020**	**2021**	**2022**
Lines Assets Inspected/ Tested/ Maintained	17%	17%	17%	17%	17%
Stations Assets Inspected/ Tested/ Maintained	100% / 100% / 4%	100% / 100% / 4%	100% / 100% / 4%	100% / 100% / 4%	100% / 100% / 4%

Witness: GARZOUZI Lyla

UNDERTAKING – JT 3.1-23

Reference

I-38-AMPCO-40 (a) & (c)

Undertaking

Please provide the forecast quantities for the years 2019 to 2022 for the tables provided in response to (a) and (c).

Response

Please see table below for the forecast quantity of inspections and testing under the Planned Preventative Station Maintenance program for each of the years 2019 to 2022, based on the forecast quantity provided for 2018.

	2019	**2020**	**2021**	**2022**
Quantity of Inspections	6209	6209	6209	6209
Quantity of Tests	2198	2198	2198	2198

Please see table below for the forecast quantity of assets to be maintained (based on condition) under the Planned Preventative Station Maintenance program for each of the years 2019 to 2022, based on the forecast quantity provided for 2018.

	2019	**2020**	**2021**	**2022**
Number of Assets Maintained *(Condition Based)*	596	596	596	596

UNDERTAKING – JT 3.1-24

Reference
I-38-AMPCO-41 (b) & (c)

Undertaking
Please provide the forecast quantities for the years 2019 to 2022 for the tables provided in response to (b) and (c).

Response
Please see table below for the forecast quantity of inspections and testing under the Line Maintenance program for each of the years 2019 to 2022.

	2019	**2020**	**2021**	**2022**
Inspection and Testing *(# of units)*	350,000	350,000	350,000	350,000

Please see table below for the forecast volume of assets maintained under the Line Maintenance program for each of the years 2019 to 2022.

	2019	**2020**	**2021**	**2022**
Preventive Maintenance *(# of units)*	6340	6365	6390	6415

Witness: GARZOUZI Lyla

UNDERTAKING – JT 3.1-25

Reference

I-38-AMPCO-45 (a)

Undertaking

Please provide the forecast number of FTEs working on vegetation management programs for the years 2019 to 2022.

Response

Hydro One forecasts there will be about 1000 FTEs working on vegetation management for each of the years 2019 to 2022 with an expected variation of ± 5%.

UNDERTAKING – JT 3.2

Undertaking

To review the six listed reports asked by School Energy Coalition, and provide the ones that relate to the hydro one distribution business.

Response

Please see the attached reports which have been redacted for non-Dx-related information and any items related to the security of Hydro One's operations.

1) Report 2014-29: Investment Planning
2) Report 2017-14: Investment Plan Governance Delivery Follow-up Report.
3) Report 2015-05: Asset Deployment
4) Report 2016-17: Asset Deployment Follow-up Review
5) Report 2015-32: Audit of Construction Project Management Process
6) Report 2015-34: Distribution Asset Management and Preventative Maintenance Optimization

INTERNAL AUDIT REPORT

INVESTMENT PLANNING

To:

Mike Penstone
Vice President, Planning

Distribution:

Carm Marcello	President and Chief Executive Officer
Sandy Struthers	Chief Operating Officer & EVP Strategic Planning
Ali Suleman	Acting Chief Financial Officer
Paul Brown	Director, Distribution Asset Management
Randy Church	Director, Network Connections & Development
Kathleen McCorriston	Manager, Investment Planning and Prioritization
Scott McLachlan	Director, Transmission Asset Management
Bing Young	Director, System Planning
Brad Bowness	Director, Project Management, E&CS
Mike Boland	Director, Station Services, Stations & Operating

Final Report Issued: January, 30, 2015
Draft Report Issued: December 31, 2014
Report Number: 2014-29

Auditor: Atul A. Solanki

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GLOSSARY:

AA	Asset Analytics – A support tool that focuses on asset risk prioritization to enable planners to make optimal asset decisions at any point in time (30+ year timeline)
AIP	Asset Investment Planning – A support tool that evaluates investment alternatives based on corporate risks and financial objectives to produce an optimized investment plan
BCS	Business Case Summary (used for Project approval)
BPC	Business Planning and Consolidation – A support tool that delivers an integrated financial model to support business planning, budgeting, and forecasting
BV	Business Values – These are the values that enable the achievement of the Company's strategic goals by forming the criteria against which investments are developed, risks are managed, and trade-offs are facilitated between investments.
IPP	Investment Plan Proposal – The output of the prioritization process that feeds into the Corporate Business Plan
OAR	Organizational Authority Register
PN	Potential Need notification (as documented in SAP against a specific asset)
SICA	Station Investment Capital Approval (used for "station centric" bundled program approval)
UPC	Unit Price Catalogue / Unit Price Cost

EXECUTIVE SUMMARY

Hydro One has adopted an Asset Management model since its inception to separate accountability for asset and system investment decision making from the execution of work. The Planning Organization is accountable to produce an annual Investment Plan Proposal (IPP) detailing investments (and resulting work) required to develop and sustain asset and system capabilities over the next five years. The IPP is a major input to the Hydro One's Corporate Business Plan that is approved annually by its Board of Directors. The IPP also forms a basis for the Transmission and Distribution rate filing with the Ontario Energy Board. The IPP is put together based on the results of customer, asset and system need evaluation using criticality, performance, and condition as key factors. The plan goes through a risk-based optimization to ensure the maximization of corporate business values[1] (such as safety, reliability, customer satisfaction, shareholder value, etc.). The plan is further adjusted by Management to ensure that it is executable, meets financial objectives, and reduces plan risks to an acceptable level.

We are pleased to observe that the Planning organization is able to deliver an annual IPP on schedule. The introduction of support tools such as Asset Analytics (AA) and Asset Investment Planning (AIP) has resulted in timely availability of asset information for analysis as well as optimization of investment selection based on specified constraints. The Planning organization has a good mix of experienced and new planners, as well as managers, who bring varied perspectives. A recent move towards "station centric" sustainment investment planning is expected to improve planning and execution efficiencies. However, several key challenges remain to consistently determine, develop, optimize and release investments required to meet customer, asset and system needs.

Based on the specific areas reviewed, we conclude that controls are often ineffective and significant improvements are needed to ensure that a consistent investment planning process is used to produce a risk-based Investment Plan Proposal to address customer, asset and system needs.

Our conclusion is based on the following key observations:
- Ineffective governance and controls over the investment planning end-to-end process.
- Inconsistent identification, assessment, prioritization and action on asset and system needs.
- Lack of risk-based alternatives with a thorough cost-benefit analysis for most plans.
- Inefficient investment plan prioritization process that is not well-understood by the planners and service providers.
- Lengthy approval process that delays release of major investments.

Action plans have been developed by management to address the areas noted above and are summarized in the Summary of Actions (Appendix H). We would like to thank the management and staff in Planning, Engineering & Construction, and Stations for their assistance and open discussions during this review.

Atul A. Solanki, Audit Associate

[1] "Corporate business values" is the term used in the Asset Investment Planning (AIP) optimization process. These are actually the Corporate Strategic Objectives.

OBSERVATIONS AND RECOMMENDATIONS

The Investment Planning audit focused on the following five areas:

1. Effective governance structure and control environment over the "end-to-end" Investment Planning process
2. Appropriate identification and assessment of customer, asset and system needs requiring investment
3. Development of risk-based investment alternatives to meet the identified needs
4. Optimization of investment plans selecting alternatives that maximize corporate business values.
5. Timely release of sufficiently detailed investment plans for execution by the Service Providers.

A sample of 16 investments from the 2015-2019 Investment Plan Proposal (IPP) were selected for review during this audit.

The following are our observations and recommendations related to the above five areas.

1. Ineffective governance and controls

Background:

An effective governance structure and adequate control activities are a must for an organization to achieve its stated objectives while managing the risks it faces to a level that it is willing to accept. The governance and controls set the tone at the top regarding management's expectation of how its business activities are to be performed and an expected standard of conduct for the employees performing those activities. Management sets the control environment by developing, reviewing, approving and communicating appropriate policies, standards, processes, procedures and guidelines in sufficient details. Management ensures that appropriately qualified and trained employees are equipped with adequate tools to perform the tasks assigned to them. An effective governance structure and control environment also requires that adequate supervision, monitoring and quality assurance are in place to meet the organization's key deliverables.

Observations:

We are pleased to observe the following:

1.1 The Planning organization has been developed and released an increasing work program in recent years with a largest work program release of $2.8 billion (gross) for 2015. The 2015-2019 IPP was approved as part of the Hydro One Business Plan at the November 2014 Board meeting.

1.2 A recent reorganization combining the asset management and system development divisions into a single business unit has resulted in a management team of varied experience and background.

1.3 Monthly management reports are being put together to communicate work progress in each department and division.

1.4 An Approvals, Customers, Estimates, and Releases (ACER) review process has been put in place where executive, director and manager level monthly reviews occur between planning and executing lines of businesses to discuss and resolve issues related to large and complex plans (>$1 Million and/or customer impact) prior to their full release.

1.5 The majority of planners are experienced and knowledgeable about the customer, asset and system needs. In most cases, junior planners are teamed with senior planners for mentoring and knowledge transfer. The planners have tools such as Asset Analytics (AA), Asset Investment Planning (AIP), SAP and other databases to perform their assigned tasks.

1.6 AIP training is provided prior to start of the annual investment planning cycle. Detailed PowerPoint training presentations and job aids are posted on the SharePoint site.

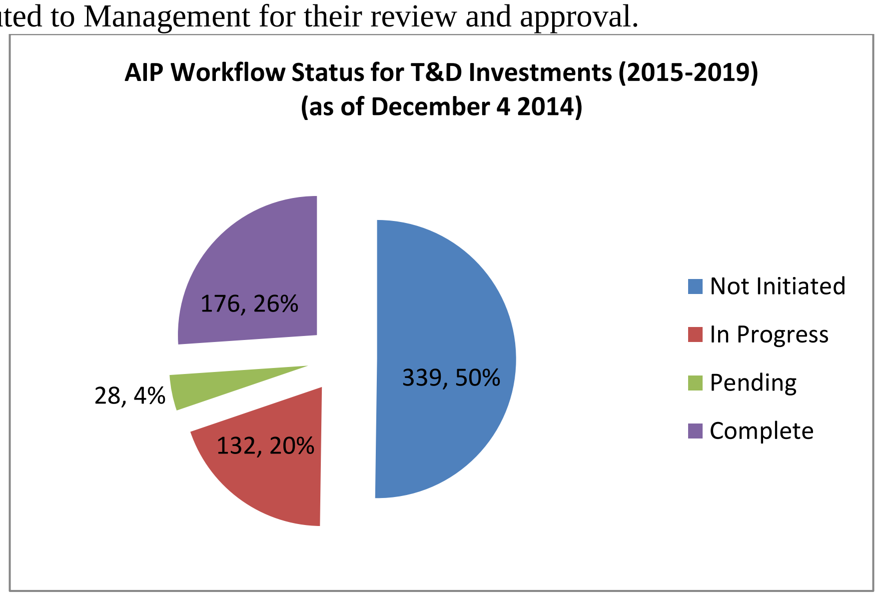
We also observed the following opportunities for improving controls:

1.7 There has been no recent and formal business risk assessment of the overall Planning business unit's objectives completed as per the Enterprise Risk Management Policy (SP0736).

1.8 Approximately 44 approved policies and directives are in place for planning and asset management. However, most of these documents are over 3 years old and do not have a review date. It is unclear if these policies are being followed by the planners as there were no references to any of these policies in the 16 investment planning documents that were reviewed during this audit. A key policy titled "*Asset Investment Planning Risk Assessment Corporate Operational Policy*" was developed in 2013 but was never approved by Management.

1.9 Approximately 363 business process models related to managing asset information and investments are documented in the ARIS Business Process modelling and management software, which is the official source of record for Hydro One business processes. The majority of these were developed during Cornerstone Phase 1 and 2 and have never been incorporated in the Hydro One Business Process Modelling Notation (H-BPMN). Only 42 process models have been mapped to process area "*01.02 Manage Asset Investments*" and "*01.03 Manage Asset Information*", which are the focus of this audit. Most of these process models are in "draft" form, have references to outdated process steps and work groups and have missing integration points with other business processes. Most planners are not aware of these process models and seldom follow them. Some departments have simplified versions of these processes in PowerPoint format for training and discussion purposes. Process clarification and guidelines are often communicated via e-mail or in training presentations.

1.10 There is no formally documented Quality Assurance process with related measures to assess the effectiveness of the "end-to-end" planning process. The "Investment Approval Process" within the training presentation indicated that all Investment plans (or ISR) prepared by an Investment Owner (Planner) were to be sent to the Driver Owner (Manager) for review and approval. All programs greater than $15M and all projects > $10M required additional review and approval by the Portfolio Owner (Director). These reviews and approvals were to occur through AIP workflows. The following is a summary of the AIP Workflow status for T&D investments where the Investment Summary Report (ISR) produced for each investment plan was to be routed to Management for their review and approval.



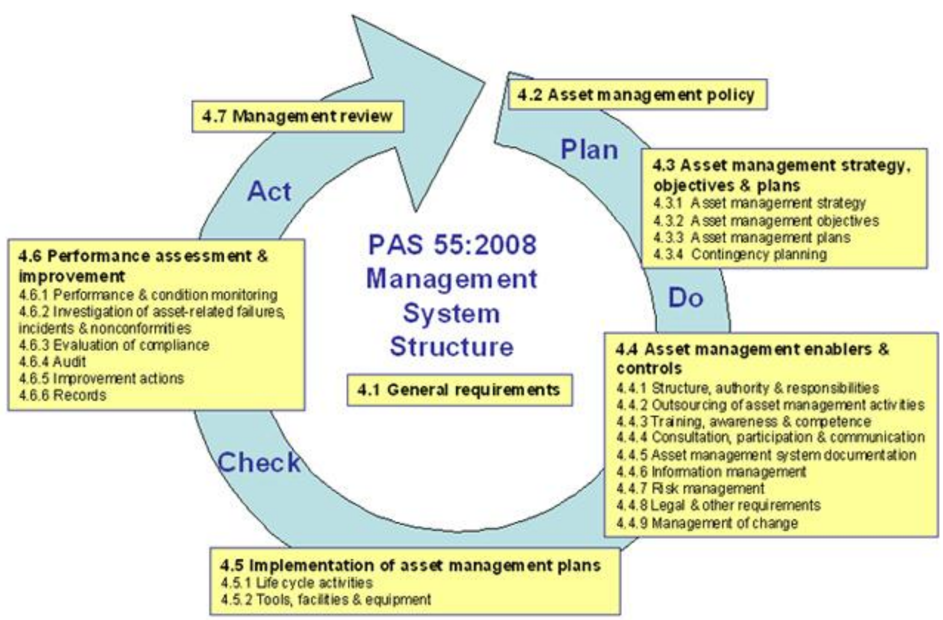
The above results show that half of the investments were never sent by planners to Management for review and approval. About 20% were sent for approval but were neither approved nor rejected by Management. Only the remaining 30% of the plans were either formally approved or rejected. Management has indicated that verbal reviews and approval did occur for all investments but the statuses were not updated in AIP due to time constraints. It was not possible to validate the quality of management reviews in the absence of appropriate documentation.

1.11 There is a lack of a clearly defined process and guidelines for the level of input to be sought by the planners and to be provided by the service providers during the investment plan development. For some plans, service provider input is only sought after an Investment Plan Proposal (IPP) has been put together. For other plans, service provider input is sought and incorporated during the early stages of plan development. Service providers have indicated a preference to be involved as early as possible during the plan development but this could lead to plans being influenced by the service providers' capability to execute rather than risk based customer, asset and system needs.

1.12 There is no formal training for the overall "end to end" planning process. However, there is informal training on use of tools. None of the training is tracked and refreshed as the process and tools evolve.

1.13 There is no formal lessons learned documentation for continuous process improvement. A Lessons Learned presentation was put together for discussion following completion of the 2013 planning cycle. However, it is unclear if any of these lessons were incorporated in the process that was followed during 2014 planning cycle.

1.14 At a high-level, the overall Investment planning process does seem to be aligned with the PAS55:2008 specification for the optimized management of physical assets with its "plan, do, check and act" phases as detailed below. However, significant opportunities exist to define an appropriate asset management strategy & objectives, implement appropriate enablers and controls, monitor performance and practice continuous improvement.



Source: Key Features of PAS55:2008, http://pas55.net/features.asp

Risks: R

- Lack of well-defined, communicated and understood policies, standards, processes, procedures and guidelines could lead to inconsistent decision making leading to poorly defined investment plans that are unable to adequately address the asset and system risks and needs.
- Inadequate specification of accountabilities, training and suitable tools would lead to staff performing their assigned duties on a best effort basis leading to poor quality output and resulting rework.
- Insufficient monitoring of process effectiveness and quality assurance of process outputs would lead to an increased risk of errors and degradation of output quality.
- Lack of continuous improvement through lessons learned would lead to inefficient processes that will have a lower chance of being adopted by the users.

Recommendations:
We recommend that Management:

1.1 Perform a formal risk assessment as per ERM Policy (SP0736) on an annual basis to ensure that business risks facing the planning organization are identified and mitigating actions are developed and tracked. (related to Observation 1.7)

1.2 Develop, review and approve sufficiently detailed policies, standards, procedures and guidelines to ensure a consistent risk-based approach to planning and decision making. This would require a review of the existing governance documents and ARIS process models for their accuracy and validity. Management has informed us that a Policy Review project is currently underway to consolidate policy and directive documents. (related to Observations 1.8 and 1.9)

1.3 Clarify the timing and level of input to be sought by the planners from the service providers as they develop their plans. (related to Observation 1.11)

1.4 Implement a formalized Quality Assurance process and related performance measures to assess the effectiveness of the end-to-end planning process. This would include quality expectations for plans being prepared by the planners and the quality of reviews and feedback being given by management prior to approving those plans. (related to Observation 1.10)

1.5 Formalize and track all process and tool related training being given to planners in their Learning Management System. Establish refresher training requirements whenever there are significant changes in process and tools. (related to Observation 1.12)

1.6 Document and communicate lessons learned after each planning cycle and use them for continuous improvement of the planning process. (related to Observation 1.13)

Management Response:
All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

1.1 Randy Church, Director, Network Connections and Development
1.2 Luis Marti, Director, Reliability Studies, Strategies and Compliance
1.3 Kathleen McCorriston, Manager, AM Processes & Tools
1.4 Scott McLachlan, Director, Transmission Asset Management
1.5 Mike Penstone, VP Planning
1.6 Kathleen McCorriston, Manager, AM Processes & Tools

Proposed Action Plan: *(Accountable Manager, above in Management Response)*

1.1 Planning will work with ERM Group to conduct a risk workshop to identify risks in achieving the planning business objectives.

1.2 Conduct a review of processes, procedures, standards and guidelines to determine the need, effectiveness, currency and to ensure they are aligned with and support the Corporate Operational Policies. Establish a review cycle for these documents.

1.3 At the annual LOB kick off, AM Processes and Tools will identify and seek input from the service providers to obtain their feedback on ideal timing and level of input required. Planning will also be in attendance to ensure agreement and consistency in approach.

1.4 Quality expectations and the required metrics for the end-to-end process will be established and communicated by the Planning Organization.

1.5 The Planning Organization will assess all training requirements including the frequency of refresher training and mechanism for tracking training completion. We will develop an implementation plan that defines the accountabilities for creation and delivery of training material.

1.6 AM Processes & Tools will document and communicate lessons learned after the 2016-2020 planning cycle.

Completion Dates:

1.1 Q4, 2015
1.2 Q4, 2015
1.3 Q1, 2015
1.4 Q3, 2015
1.5 Q4, 2015
1.6 Q3, 2015

2. Inconsistent Customer, Asset & System Need Assessment

Background:

Hydro One’s Transmission and Distribution (T&D) investment plans consist of four major categories of investments related to sustainment (maintain existing capability), development (add new capability to ensure secure and reliable supply), operation (operate and monitor assets and systems) and common corporate investments. For this audit, the focus was on T&D Station sustainment and development investments.

Key steps in investment planning process include:

i. the determination of investment needs from various stakeholders (including customers),
ii. collection and analysis of supporting data (e.g. asset data), and
iii. assessment of needs.

Sustainment investment needs are primarily identified using asset condition data collected during routine maintenance, inspections and testing, performance history, asset utilization, age, and criticality. Asset Analytics (AA) is a new tool available to planners to collect and analyze this data. An Overview of AA is provided in Appendix F. Development investment needs are primarily identified by system changes that include demand, performance, and configuration as well as changes to standards, codes and market rules. New customer connection requests as well as changes in Local Area Supplies and network transfer capabilities also result in development investment needs.

Both sustainment and development investment needs are assessed by focusing on mitigating risks associated with the likelihood and consequences of asset failures as well as maintaining T&D system performance and satisfying customer expectations.

Observations:
We are pleased to observe the following:

[redacted]

2.2 The Potential Need (PN) notifications in SAP are being used by field staff to alert the planners of future asset sustainment needs. This requirement and related process is formally documented in HODS as "Potential Need (PN) Notification Administration Guide (SP1546)".

2.3 For transmission station refurbishment, a detailed "desk-side station assessment" listing all asset conditions and needs is being documented by the planner and discussed with the field staff.

We also observed the following opportunities for improving controls:

2.4 There is inconsistent documentation and tracking of asset and system needs for later follow-up. Most planners have their own spreadsheets in which they capture needs discovered during field visits, e-mail discussions with field service specialists or recommendations from maintenance technical services. Customer needs and manufacturers' recommendations are also tracked in various e-mails and documents. For most investments, there is no tie back of earlier identified needs to the investments being made. There is no consistent documentation showing which customer, asset and system needs were received, reviewed, accepted/rejected and actioned.

2.5 The PN Notification process outlined in SP1546 is not being consistently followed. In 2014, 307 PN notifications for TS assets were created and 273 (89%) of these have not yet been reviewed by the planners, while only 10 PN notifications were created for DS assets and none of them have been reviewed by the planners. According to the SP1546, "*Asset Management is responsible for assigning a PN notification to every planned replacement and refurbishment candidate in the current business plan*". There is no evidence to support that this has consistently occurred in 2014.

2.6 There is inconsistent use of AA data to assess individual asset needs. There are no documented procedures or guidelines on how to validate AA Risk Index data and translate them into asset needs. Most planners use the AA data as a starting point for further discussion with the service providers to confirm asset needs.

2.7 The AA data quality remains a concern. The quality of underlying data (accuracy, completeness and timely availability of recent data) being used from SAP and other databases for risk index calculations is unknown. It was noted that:

- Only 44% of DS and 51% of TS Supporting Factor data used for risk index calculation is considered "Normal". The remaining data are statistical calculations or default values.
- Percentage of assets with missing Asset Risk Index data (ARI = 0) is as follows:

AA Data Quality – Missing ARI						
ARI	**Condition**	**Demographics**	**Criticality**	**Economics**	**Utilization**	**Composite**
Distribution Station	54%	54%	10%	54%	70%	10%
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

AA Data Quality – Missing ARI						
ARI	Condition	Demographics	Criticality	Economics	Utilization	Composite
[redacted]						

- [redacted]
- [redacted]

2.8 System development projects are based on area supply studies requiring power system historical data related to load flows, voltages, asset connectivity and statuses. These data are not available in AA.

2.9 There are no clearly documented asset strategies against which individual asset needs are assessed. However, work has recently started on developing Asset Strategy Documents for 30 key asset groups. These documents will detail key strategies in managing risks of a given asset group against which the individual asset needs will be assessed by the planners.

Risks: R Y

- Absence of a well-managed process to capture, review, assess, prioritize and action needs increases the risk of critical needs not being addressed in a timely fashion
- Absence of well-understood and quality asset information increases the risk of inadequate need assessment resulting in a less than optimal investment decision.
- Absence of clearly documented asset strategies increases the risk of inconsistent need assessment and investment decision.

Recommendations:

We recommend that Management:

2.1 Develop, implement and monitor an effective Need Identification Process. This may require review and enhancement of SP1546 to include both sustainment and development needs. This process should address a consistent mechanism for tracking details related to need identification, acceptance, review, prioritization, action as well as investment that has been made to meet the need. (related to Observations 2.4 and 2.5)

2.2 Develop detailed guidelines about how the planners should validate and use AA Risk Factors for the need assessment. (related to Observation 2.6)

2.3 Request an audit of Asset Analytics data sources and algorithms to confirm that quality data and appropriate calculation methods are used for calculating the six Asset Risk Indexes for individual assets as well as asset groups. (related to Observation 2.7)

2.4 Consider expanding the scope of the Asset Analytics tool to include up-to-date power system historical data such as load flows, connectivity, voltages, statuses, etc. (related to Observation 2.8)

2.5 Continue to develop sufficiently detailed Asset Strategy Documents for all asset groups and ensure that all future asset needs are assessed against these documented strategies. (related to Observation 2.9)

Management Response:
All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

2.1 Scott McLachlan, Director, Transmission Asset Management
2.2 Scott McLachlan, Director, Transmission Asset Management
2.3 Randy Church, Director, Network Connections and Development
2.4 Bing Young, Director, System Planning
2.5 Scott McLachlan, Director, Transmission Asset Management

Proposed Action Plans: *(Accountable Manager, Title above in Management Response)*

2.1 This recommendation will be addressed as part of the overall Quality Assurance Process and metrics as outlined in Proposed Action Plan 1.4.
2.2 This recommendation will be addressed as part of the overall Quality Assurance Process and metrics as outlined in Proposed Action Plan 1.4.
2.3 SAP Data Audit on Asset and Maintenance data is already underway. The results of these audits will be used to address the underlying data issues in AA. Workshops with respective LOBs will be held regarding usability of existing algorithms.
2.4 AM Process and Tools will request ISD to add audit recommendation to corporate application roadmap. Key requirement is to have access to NMS information.
2.5 We will continue to develop Asset Strategy Documents.

Completion Dates:

2.1 Q3, 2015
2.2 Q3, 2015
2.3 Q4, 2015
2.4 Q1, 2015
2.5 Q4, 2015

3. Lack of Investment Alternatives

Background:
Developing investment alternatives is the next step required in the Investment Planning process and it is guided by the results from the need assessment. Work bundling opportunities among several programs are also explored while developing alternatives. Some programs are demand driven (such as service upgrades, trouble calls, studies, storm damage, etc.) and have only one alternative that is included in the plan based on historical averages of funding. Projects that are already under execution also have only one alternative. Most other projects and programs should have more than one alternative with varying risks and benefits to allow selection of the best alternative during optimization process. Project alternatives can shift in time, while program alternatives can have varying levels of accomplishments.

For program work, four levels of alternatives are considered as follows:

1. Vulnerable – Minimal short-term funding to meet regulatory and safety risks
2. Intermediate (1..n) – Varying levels of risk exposures with increased funding above vulnerable level
3. Asset Optimal – Balancing point where asset lifecycle costs are minimized. This would be an ideal level of funding.

4. Accelerated – Exceeds asset optimal funding in order to mitigate an oncoming "bow wave" of asset needs.

Further detail on these alternatives is included in Appendix F.

Program work cost is unit priced while project work cost is based on the planner's estimate based on similar projects, budgetary estimate or detailed estimate from the service provider (where available).

The need, objectives, accomplishments, costs and risk assessment for each alternative is documented in the AIP tool by the planners and an Investment Summary Report (ISR) is produced for each investment. Management performs a quality assurance review of the ISR to ensure that a clear and compelling justification is made for each alternative along with uniform use of the risk assessment model.

Observation:

We are pleased to observe the following:

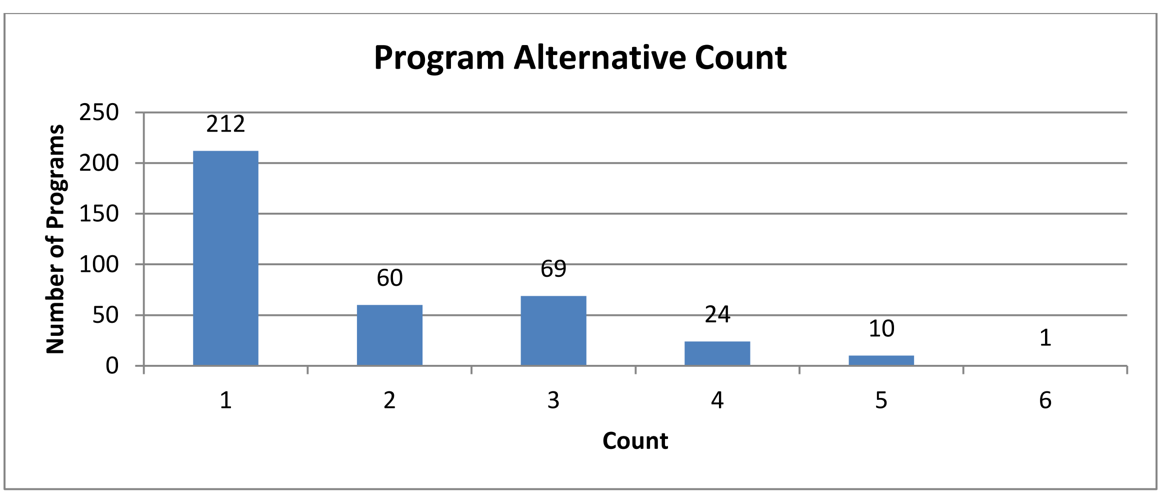
3.1 Investment values were calculated based on a weighted average of 8 corporate business values as follows: Safety (17%), Reliability (17%), Customer Satisfaction (13%), Productivity (13%), Financial Benefit (13%), Employees (9%), Environment (9%) and Shareholder value (9%).

3.2 Baseline and alternative risks for each investment are being evaluated using a sufficiently detailed and a standardized risk matrix based on 6 levels of probability and 9 levels of consequence.

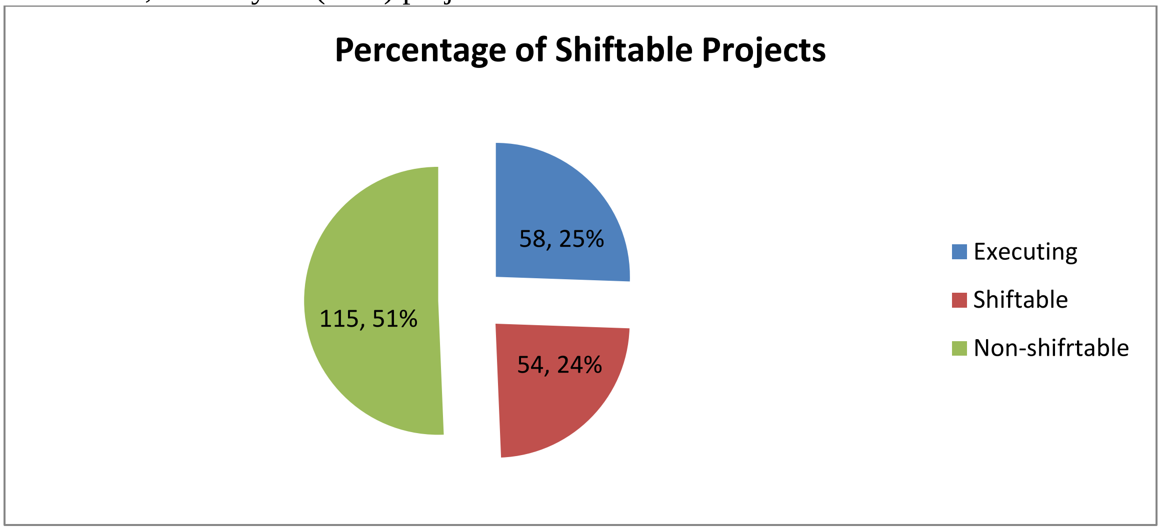
3.3 A risk consequence table was provided to the planners to guide their selection of the appropriate consequence for each corporate business value. A spreadsheet based tool was also developed to guide the planners in determining consequence ratings through a series of questions. Job aids related to risk assessment for each corporate value were also provided and posted on the SharePoint site for planners' use.

We also observed the following opportunities for improving controls:

3.4 For the AIP optimization to be effective, projects should be shiftable in time and programs should have more than one alternative. There are 675 plans for Transmission and Distribution drivers in the 2015-2019 IPP with 448 Programs and 227 Projects. Of the 448 programs, 50 programs are demand driven and 22 programs are already under execution so these are required to have only a single alternative. The remaining 376 are under short term planning and should have had more than one alternative specified. However, 212 (56%) have only one alternative specified. The following is the alternative count for these programs.



Of the 227 projects, 58 are under execution and are not shiftable. The remaining 169 should all be shiftable, but only 54 (24%) projects were identified as shiftable in time.



From the above analysis, it can be concluded that projects and programs do not have sufficient alternatives defined to allow optimal selection of best available alternative.

3.5 Baseline and alternative risks assessed for most investments are mostly subjective with no (or very little) quantitative data to support the assigned probability and consequence for the risks. Although informal guidelines were provided on how to translate AA risk factors into corporate risks, this was not done for most investments. Most planners have indicated that the current risk matrix is confusing and that the provided guidelines are subjective. The provided training and job aid explained the risk matrix but it did not specify how the planners should rank risks (i.e. pick a specific box in the risk matrix). It was left up to the management reviews of risk assessment to ensure that risk ranking is consistent across all investments.

3.6 There was no risk assessment done for transmission system development plans as all of these plans are non-discretionary.

3.7 Sample investments having single alternatives lack appropriate justification documented in the Investment Summary Report.

3.8 There is very little documentation of management quality assurance review of investment plans (including risk assessments). Management has indicated that these type of reviews have occurred with verbal feedback being provided to planners in most cases. Please refer to related observation 1.10.

3.9 Some of the unit prices being used for program work are outdated or incorrect. As an example, unit prices for TS maintenance work do not include material cost while the unit prices for DS maintenance work do include material cost. The 2015 PCB Retro fill program is considered “underfunded” by the service provider because the outdated 2013 unit prices were used in determining the funding level.

3.10 There is inconsistent engagement with internal service providers during the development of alternatives. Some investment plans have significant engagement with service providers to confirm start date, in-service date, accomplishment levels, resources or cash flow based on sufficiently detailed estimates provided by the service provider. Most other plans are based on planner’s estimates and desired schedule. The service providers have indicated a preference to be involved much earlier during the investment plan development. Please refer to related observation 1.11.

3.11 There are insufficient documented details on coordination of plans among sustainment and development groups as well as identification of any bundling opportunities between transmission and distribution work.

3.12 There are insufficient details on how the individual plans align with the regulatory filing.

3.13 There is a lack of details for placeholder investments having significant value. The placeholder investments are used for projects that are expected but have very little scope defined. The value of these placeholder investments is based on historical trends and future forecasts. There are 37 placeholder investments in the IPP totalling $914M (Gross) over the 2015-2019 planning period. Service providers are concerned about providing accurate forecasts for these placeholder investments that have no or very little defined scope.

Risks: R Y

- Lack of available alternatives increases the risk of less than optimal investment plans.
- Inadequate assessment of baseline and alternative risk could result in incorrect risk values being assigned to the alternative.
- Incorrect assumptions related to the timing and costs of investment could result in less than optimal cash flow requirements.
- Undue influence by the service provider during the planning process increases the risk of plans being made based on the service provider's ability to execute rather than on asset needs.

Recommendations:

We recommend that Management:

3.1 Require the planners to define more than one alternative for non-demand driven programs and time shift-able projects. Management should also ensure that appropriate justification is documented and reviewed for plans having only a single alternative. (related to Observation 3.4)

3.2 Simplify the risk assessment matrix and provide suitable training and guideline to planners to perform an effective risk assessment. Specific focus should be on using quantative data from AA and other systems to determine/support appropriate probability and consequence on the established risk matrix. (related to Observations 3.5, 3.6 and 3.7)

3.3 Increase quality assurance reviews and feedback to planners on the quality of their alternatives and risk assessment to ensure uniformity of plans and related risk assessment. (related to Observation 3.8)

3.4 Review and confirm the Unit Price Catalog with the service providers prior to the start of each planning cycle to ensure that the most current unit prices are being used to determine the funding level for the program work. (related to Observation 3.9)

3.5 Define and communicate the required level of engagement with the service provider when investment plans are being developed to ensure that plans are based on asset needs rather than executability by the service providers. Please refer to related Recommendation 1.3. (related to Observation 3.10)

3.6 Require the planners to electronically attach/link supporting data (such as those from AA) and related documentation for each alternative risks assessment to their ISR in AIP. (related to Observations 3.11, 3,12 and 3.13)

Management Response:
All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

3.1 Scott McLachlan, Director, Transmission Asset Management
3.2 Scott McLachlan, Director, Transmission Asset Management
3.3 Scott McLachlan, Director, Transmission Asset Management
3.4 Chong Ng, Project Development
3.5 Kathleen McCorriston, AM Processes & Tools
3.6 Scott McLachlan, Director, Transmission Asset Management

Proposed Action Plans: *(Accountable Manager, Title above in Management Response)*

3.1 We will define the framework for investments including the expectations outlining the definition and governance of programs and projects and requirements for program alternatives and time shift-able projects. Document and communicate these requirements.
3.2 We will improve the guidance on the use of the risk assessment matrix through the provision of practical examples.
3.3 This recommendation will be addressed as part of the overall Quality Assurance Process and metrics as outlined in Proposed Action Plan 1.4.
3.4 We will establish a process to ensure costs included in the investment plans are agreed upon between Planning and Operations (executing LOBs).
3.5 This recommendation will be addressed as part of the Proposed Action Plan 1.3 related to the timing and level of input to be sought from LOBs.
3.6 This recommendation will be addressed as part of the overall Quality Assurance Process and metrics as outlined in Proposed Action Plan 1.4.

Completion Dates:
3.1 Q3, 2015
3.2 Q4, 2016
3.3 Q3, 2015
3.4 Q4, 2015
3.5 Q1, 2015
3.6 Q3, 2015

4. Inefficient Investment Plan Optimization

Background:
Hydro One uses an Asset Investment Planning (AIP) tool for risk-based optimization to ensure that selected investments will result in the maximization of corporate business values. During each planning cycle, the AIP tool is set up with appropriate investment master data from SAP (such as driver, LOB, Appropriation Request Number, etc.), historical and forecast finance data, corporate value function and other constraints. The risk assessment, costs, schedule and accomplishments for each investment alternative is then input by the planners in to the AIP tool. Once all input is completed, the optimization process starts during which the AIP tool selects the best of the several alternatives of each investment based on the timing of investments that will maximize risk mitigation and financial benefits while satisfying pre-determined constraints and dependencies. The aggregation of work programs and projects selected from available alternatives during the optimization process yields the preliminary Investment Plan Proposal (IPP).

An enterprise engagement takes place whereby each line of business (planning, executing and finance) is represented at review meetings to discuss the preliminary IPP. Management discretion is used to adjust the IPP to ensure that appropriate resources are available to execute the plan, financial and regulatory objectives are met, and the level of risk imposed by the plan is acceptable.

Observations:

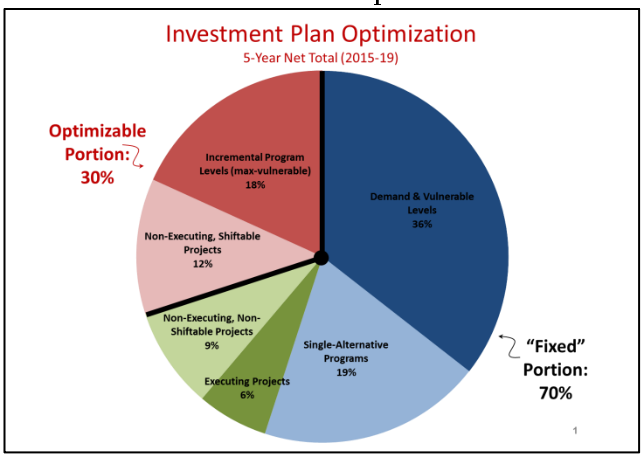
We are pleased to observe the following:

4.1 For the 2015-2019 Investment planning, a detailed schedule was developed and communicated to ensure that the optimization process and IPP review was completed by end of June 2014. The planned tasks on this schedule were completed on time and a weekly workflow status report was issued to management to indicate progress.

4.2 A detailed procedure exists for set up of the AIP tool at the start of the prioritization process.

We also observed the following opportunities for improving controls:

4.3 Only 30% of the plans in 2015-2019 IPP were optimizable within AIP.



Source: Director Review June 2 v2.pptx from Kathleen Kerr

4.4 The AIP tool was only available for a limited time resulting in planners having insufficient time for thorough documentation of their plans and management having insufficient time to review those plans in detail. The planned and actual schedule dates for the 2015-2019 planning cycle were as follows:

Event	Planned	Actual
LOB approval of Unit Price Catalog	April 11	No official signoff was received
Setup of AIP Tool Complete	April 11	April 11
AIP open for Planner Input	April 14	April 14
Investment Approval Workflow Submission deadline	May 9	May 9 – Workflow status reports were issued weekly to Management
Investment approval deadline	May 16	May 20 – Extra weekend was given for management review and approval
Start of Optimization	May 20	May 20
Optimization results review (Prelim. IPP)	June 2	June 2
LOB and Stakeholder review and input	June 13	June 13
IPP adjustments complete	June 30	July 4

Planners were given 4 weeks to complete their input into AIP and management was given 1 week to review it. As of May 15, one day before the plan approval deadline, only 49% of the plans had workflow initiated for review and approval by management. Please refer to related observation 1.10.

4.5 Manual workarounds are in place to update AIP data from SAP and other systems. Spreadsheet based tools are being used for data uploads. These uploads are based on a snapshot of available data from the originating system (such as SAP) and they became stale as soon as the snapshot is taken since the originating system is continually updated. As an example, forecast costs and in-service date changes are continually being updated in SAP by the service providers, but these changes are not reflected in AIP once the snapshot of data is taken from SAP and uploaded to AIP.

4.6 Enterprise engagement is occurring at the director level and above with a focus on comparison with previous year's plan to identify what has changed and discuss why. A line by line review is only occurring for major / complex plans. The LOB engagement for 2015-2019 IPP occurred over a four day period from June 9 to 13, but the service providers have indicated that they need more time to review each investment line item in IPP in sufficient detail with their project and program managers to ensure that the IPP can be executed as planned.

4.7 Adjustments and changes to the optimized IPP are logged in a spreadsheet based change log. This change log does not seem to capture all changes. As an example, total gross funding has significantly changed for DS preventive and corrective maintenance, TS preventive maintenance, P&C Maintenance and P&C NOEA support, but these changes are not logged in the change log. Service providers have also indicated that some of their project and program specific input was incorporated while others was not. They have also indicated that there was a lack of communication about why some input related to in-service date and cash flow changes was not accepted.

4.8 It is unclear what changes to the optimized plan would require the plan to be run through the optimization process again. The IPP, once optimized, is simply adjusted based on changes recommended during the enterprise engagement reviews. The resulting adjusted IPP may not be a fully optimized plan. It was noted that the preliminary IPP was adjusted and re-issued to LOBs approximately 10 times before being finalized.

4.9 It is unclear how multi-year in-service additions are being treated in the IPP. In all cases, the "station centric" multi-year programs are being shown as in-serviced in the final year of the program. The reality is that these programs are in-serviced each year as the work progresses.

Risks: R Y

- An insufficient number of optimizable plans defeat the benefits of overall plan optimization.
- Insufficient time to provide quality input to the optimization process and to review the results of the optimization process increases the risk of having less than optimal plan.
- Inadequate communication around changes to the optimized plan increases the risk of diminishing the plan's credibility and less acceptance of the plan by its users.

Recommendations:

We recommend that Management:

4.1 Increase the number of investments that are optimizable. (related to Observation 4.3) Please refer to related Recommendation 3.1.

4.2 Make the AIP tool available year around to allow the planners to input and update their plans and risk assessments throughout the year. Management has indicated that plans are already underway to upgrade the AIP tool to allow this to occur in 2015. (related to Observation 4.4)

4.3 Consider AIP tool integration with other systems and tools such as AA (for asset risk factors), SAP (for AR and driver related data), BPC (Business Process Consolidation, for LOB forecast and accomplishment data) and UPC (Unit price catalog, for unit price data) to ensure that information in AIP is kept up-to-date with other systems. (related to Observation 4.5)

4.4 Increase the enterprise engagement period to allow a detailed line by line review of unreleased work in the IPP by the project and program managers who will be executing the plan. This will allow better feedback on cash flows and in-service dates from the service providers based on the established scope. (related to Observation 4.6)

4.5 Implement a formal change log to document all recommended changes. This should also include appropriate review, approval and incorporation of changes with appropriate communication back to the requestor of the change. (related to Observation 4.7)

4.6 Determine and document which types of changes to the individual plans require the IPP to be run through the optimization process again to ensure that the resulting plan remains optimal. (related to Observation 4.8)

Management Response:

All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

4.1 Scott McLachlan, Director, Asset Management)
4.2 Kathleen McCorriston, Manager, AM Processes and Tools
4.3 Kathleen McCorriston, Manager, AM Processes and Tools
4.4 Kathleen McCorriston, Manager, AM Processes and Tools
4.5 Kathleen McCorriston, Manager, AM Processes and Tools
4.6 Kathleen McCorriston, Manager, AM Processes and Tools

Proposed Action Plans: *(Accountable Manager, Title above in Management Response)*

4.1 This recommendation will be addressed as part of the action plan for recommendation 3.1.
4.2 This recommendation will be addressed upon implementation of AIP tool upgrade.
4.3 AM Process and Tools will request ISD to add audit recommendation to corporate application roadmap.
4.4 Enterprise Engagement period will be revised and incorporated into the revised schedule for the 2016-2020 planning cycle.
4.5 All changes will be recorded in the accomplishment file change log and/or documented in the meeting minutes.
4.6 AM Process & Tools will document conditions and requirement for the IPP to be run through the optimization process again into the Investment Optimization Management Procedure.

Completion Dates:

4.1 Q3, 2015
4.2 Q3, 2015
4.3 Q3, 2015
4.4 Q3, 2015
4.5 Q1, 2015 – COMPLETED
4.6 Q2, 2015

5. Lengthy Investment Plan Approval and Release Process

Background:
After the completion of IPP prioritization and review/adjustment by Senior Management, the adjusted IPP is included in the Corporate Business Plan for approval by the Hydro One Board of Directors. Subsequently, individual investments are then released to the service provider for execution. Programs work is approved at Board level and released annually while project work is released after a review and approval of Business Case Summary (BCS) by the appropriate Organization Authority Register (OAR) authorities.

The planners ensure that BCS showing cash flow based on detailed estimates, start date and in-service date as agreed with the service providers and customers (if required) is prepared and approved by appropriate OAR authorities prior to releasing funds to the service provider through SAP.

In May 2013, changes to the project/program definition and approval limits were implemented as per recommendations by Finance and approval of the Executive Committee (EC). A key change was to apply the interpretation of “program” to include component replacement/refurbishment, including bundling of such work. This resulted in a number of “station centric” bundled programs (often referred to as “projam” because they have a scope and schedule similar to project work but are funded through approved programs using unit pricing) of significant value being approved at a director level using Station Investment Capital Approval (SICA) even though the value of the “projam” exceeded the director level OAR authority.

Observation:
We are pleased to observe the following:

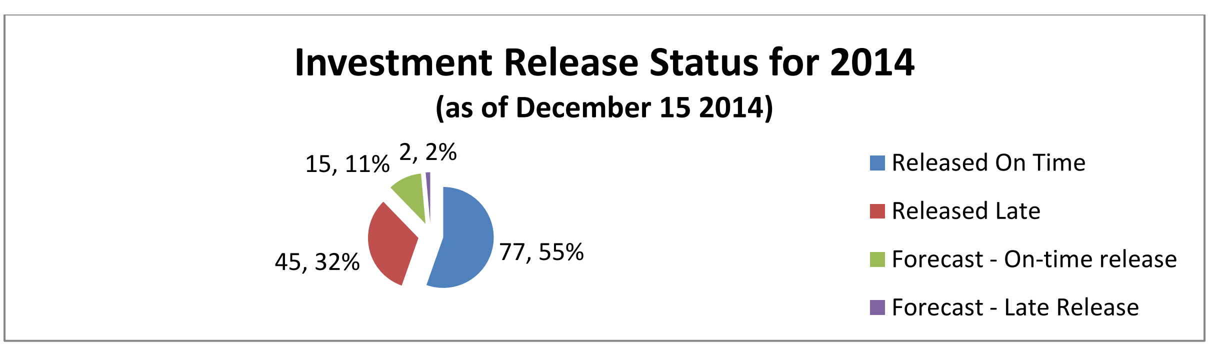
5.1 The approval and release process has not changed over the last several years. Appropriate training presentations, templates and job aids are available to planners for development of the BCS and directing it to the appropriate OAR authority.

5.2 [redacted]

We also observed the following opportunities for improving controls:

5.3 A requirement has been put in place recently to treat all “projam” greater than $20M as projects requiring an approved BCS by the appropriate OAR authority prior to release. However, it is unclear how the remaining “projam” investments will be approved and progress will be monitored.

5.4 [redacted]



From the above analysis, we conclude that release dates are often optimistic.

5.5 Of the 45 projects that were released late in 2014, only one had its in-service date pushed back due to late release. The service providers are concerned about the timing of work release as they can't execute the work without a release. They have requested that changes in the release date need to be tied to changes in the in-service date to ensure that it will be met.

5.6 The primary cause for a delayed release is a delay in availability of detailed estimates.

5.7 A BCS requiring board approval goes through a series of reviews at director, VP, SVP/COO/CFO, President/EC and BT Committee of the Board. All these reviews require timely submission of information and if there are any questions or concerns raised during the review, the process is delayed. A detailed "Investment Review Schedule" showing earliest and latest submission dates for approval at specific committee or board meeting date is available to planners. It shows that, in most cases, the review and approval process needs to start a minimum of 6 to 8 weeks ahead of the Board meeting date.

Risks: R Y

- Delayed release of investments increases the risk of not meeting the approved in-service date.
- Lengthy review and approval process of BCS requiring Board Approval increases the risk of delayed release.

Recommendations:

We recommend that Management:

5.1 Clarify the approval requirement and progress monitoring for "projam" investments. Review the project and program approval process with specific focus on shortening the approval timeline. This may include appropriate escalation triggers as well as clarification of requirement for timely review / approval. (related to Observation 5.7)

5.2 Ensure that realistic release dates are considered by the planners as they develop their plans. (related to Observation 5.4, 5.5 and 5.6)

Management Response:

All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

5.1 Mike Penstone, VP Planning

5.2 Scott McLachlan, Director, Transmission Asset Management

Proposed Action Plans: *(Accountable Manager, Title above in Management Response)*

5.1 This will be incorporated into annual review of OAR.

5.2 This recommendation will be addressed as part of the action plan for recommendation 1.4.

Completion Dates:

5.1 Q3, 2015

5.2 Q3, 2015

BACKGROUND

Hydro One has adopted an Asset Management model, since its inception, to plan, approve and implement work related to customers, assets and system needs. The Asset Management function is responsible for defining and planning work, while the Work Execution function is responsible for delivering asset and customer based services in accordance with work defined and planned by Asset Management. The primary responsibility for identifying needs, decision making, planning and defining work related to transmission and distribution assets lies with Asset Management, while the primary responsibility for design & engineering, construction, operation & maintenance and customer care services lies with the Work Execution function.

The Planning Organization, reporting to the Chief Operating Officer, has accountability for all planning activities related to programs and projects, including: Asset Management, Project Development, Network Development, Regional Planning, as well as accountability for reliability strategies, initiatives and compliance with electricity regulatrions. A key part of the Asset Management is the Investment Planning process, which is the focus of this audit. This process has never been audited before and the objective and scope of this audit is included in Appendix B.

The output of the investment planning process is the Investment Plan Proposal (IPP) which details the work plan, funding levels and accomplishments for a five year period. This plan is determined based on the assessment of identified needs using an iterative risk-based prioritization and optimization process that takes into account corporate business values (such as safety, reliability, customer satisfaction, shareholder value, etc.), investment strategies, financial constraints and resource/outage availability. The IPP is a major input to the Hydro One's Corporate Business Plan that is approved annually by its Board of Directors. The IPP also forms a basis for the Transmission and Distribution rate filings with the Ontario Energy Board. Although the IPP includes all investments related to the development and sustainment of transmission and distribution assets, operating assets and common corporate assets (such as IT, fleet, facilities, etc.), this audit specifically focuses on the development and sustaining investments being made at the transmission and distribution stations only.

A high-level Investment Planning process is summarized in Appendix D. Key steps of the process are as follows:

1. Identification of customer, asset and system needs
2. Data collection and assessment of needs
3. Development of risk-based Investment alternatives
4. Selection of Investments using an optimization process to maximize corporate business values within identified constraints
5. Approval and release of investments to Work Execution function

The above process steps result in an IPP showing the best portfolio of investments that achieve the optimal balance of cost effectiveness, customer expectations, asset and system needs within the financial, material, resource, outage availability as well as customer rate impact constraints. A thorough management review and appropriate adjustment of the optimized IPP ensures that the IPP is executable, financial objectives are met and the risks that the plan imposes are acceptable.

AUDIT OBJECTIVES & SCOPE

Audit Objective:
The primary objective of this audit was to provide management with assurances that processes and controls for investment planning within Hydro One Networks are effective. This was a high-level "end to end" process audit with future audits being recommended in specific areas of concern.

Scope of the Audit:
The scope of this audit was limited to the following areas related to development of the Investment Plan Proposal (IPP) with focus on the Transmission and Distribution stations assets only:

- Determine asset needs
- Develop Investment Plans
- Prioritize Investment Plans
- Approval and release of Investment Plans

Redirection and Change Control processes were out of scope as these processes are applied after IPP is approved and implemented. This review included work related to the development of the 2015-2019 Investment Plan Proposal and related documentation produced as of November 30, 2014.

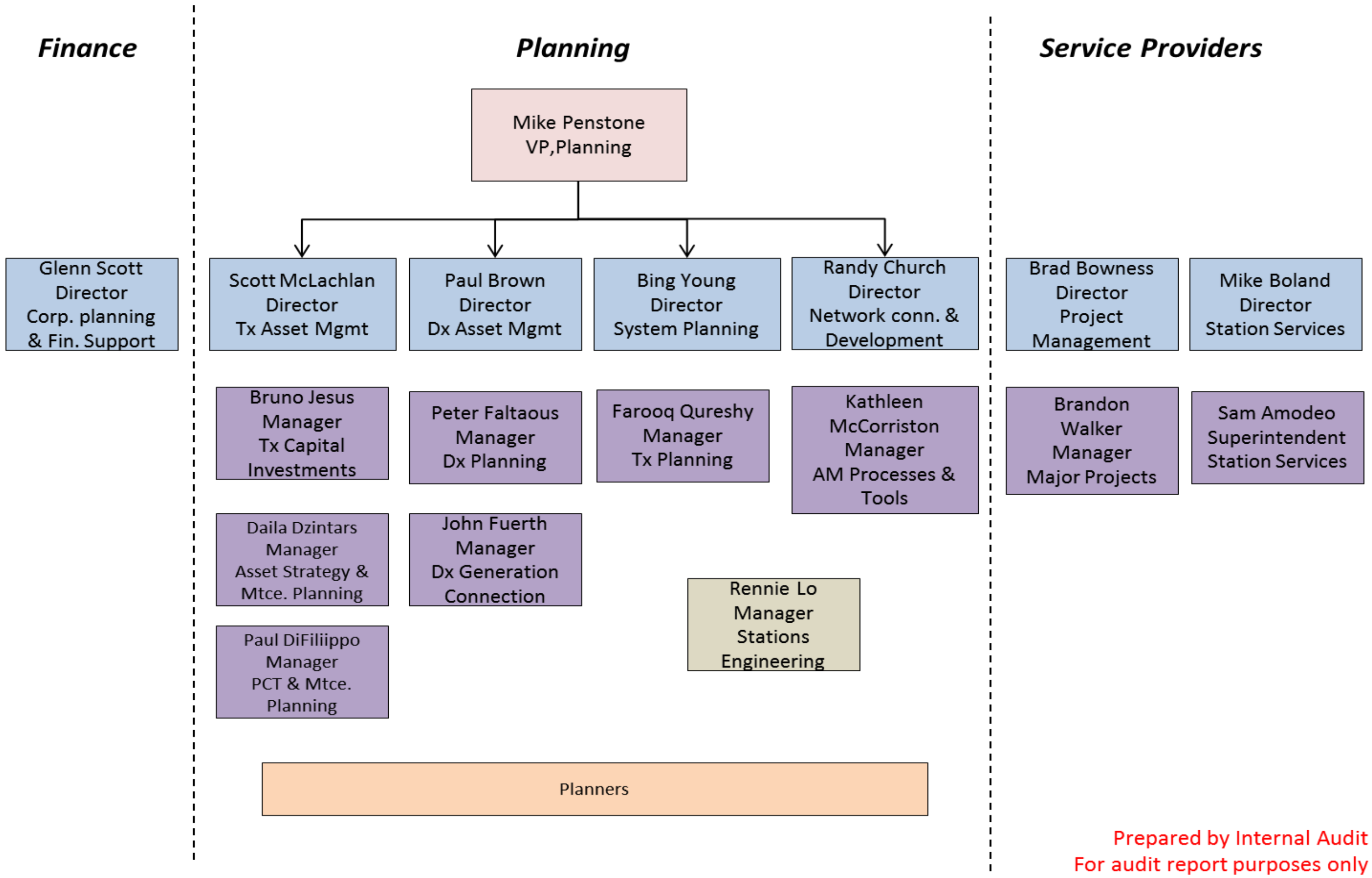
Approach:
This audit involved the following activities:

1. Review the existing investment planning process documents and examples of current investment plans.
2. Confirm and update our understanding of the investment planning processes and tools by having discussions with management and staff.
3. Document the process for audit purposes.
4. Update our understanding of the key controls that provide assurance relative to the audit objectives.
5. Interview and discuss with the accountable management, staff and stakeholders regarding control effectiveness.
6. Test a sample of investments and records related to the scope for control effectiveness.
7. Brief management on any control issues throughout the review.
8. Recommend improvements, where appropriate.

Disclaimer
In this report, we provide suggestions for improving controls to mitigate the risks identified. These recommendations may not be the only solution, nor are they intended to be prescriptive as to management's action. It is management's responsibility to ensure that they develop and implement action plans that are both cost-effective and address the risks identified in the report.

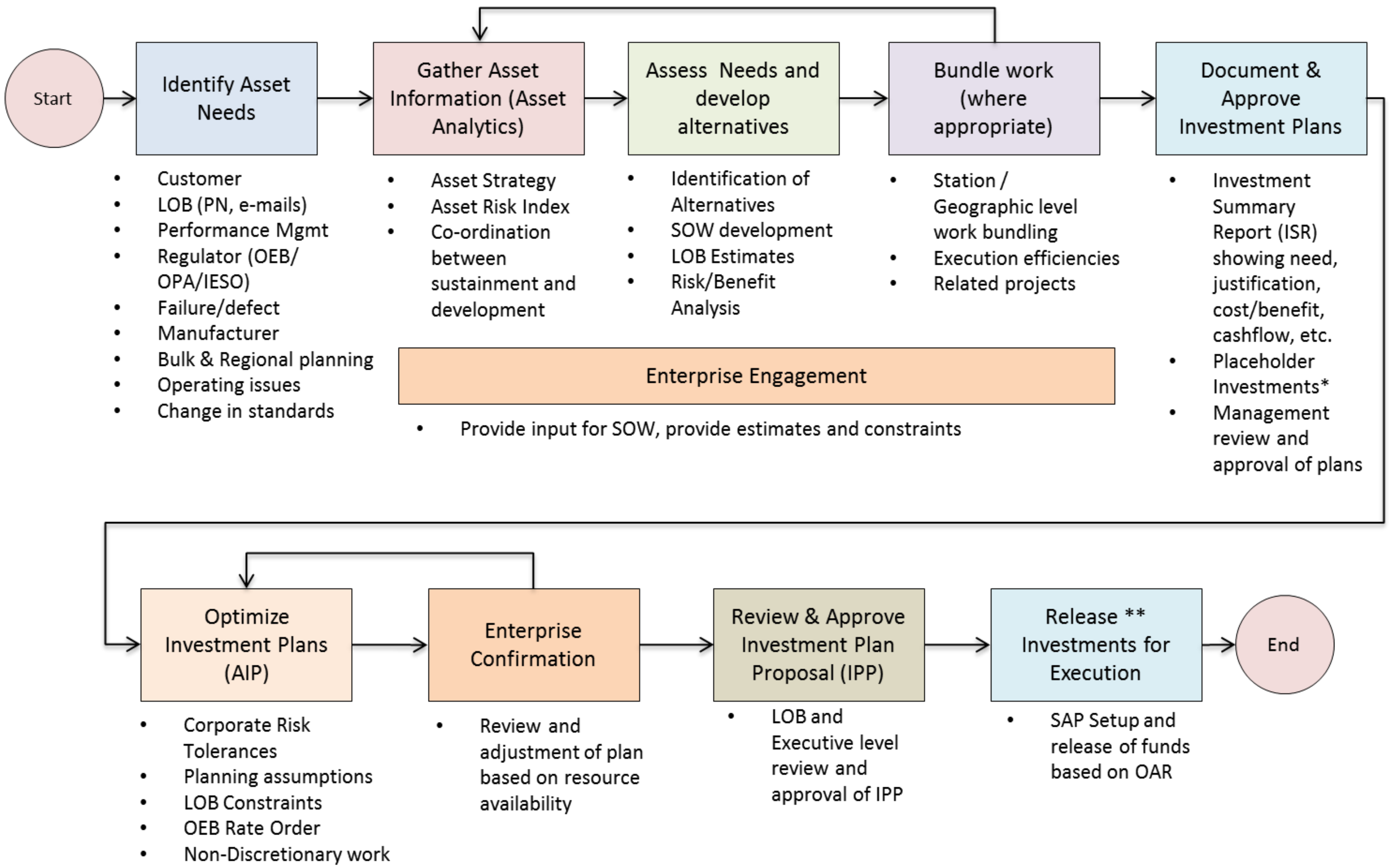
AUDIT CONTACTS

INVESTMENT PLANNING PROCESS AUDIT CONTACTS (for Tx and Dx Station only)



INVESTMENT PLANNING PROCESS (HIGH LEVEL)

HIGH-LEVEL INVESTMENT PLANNING PROCESS (for Tx and Dx Station only)

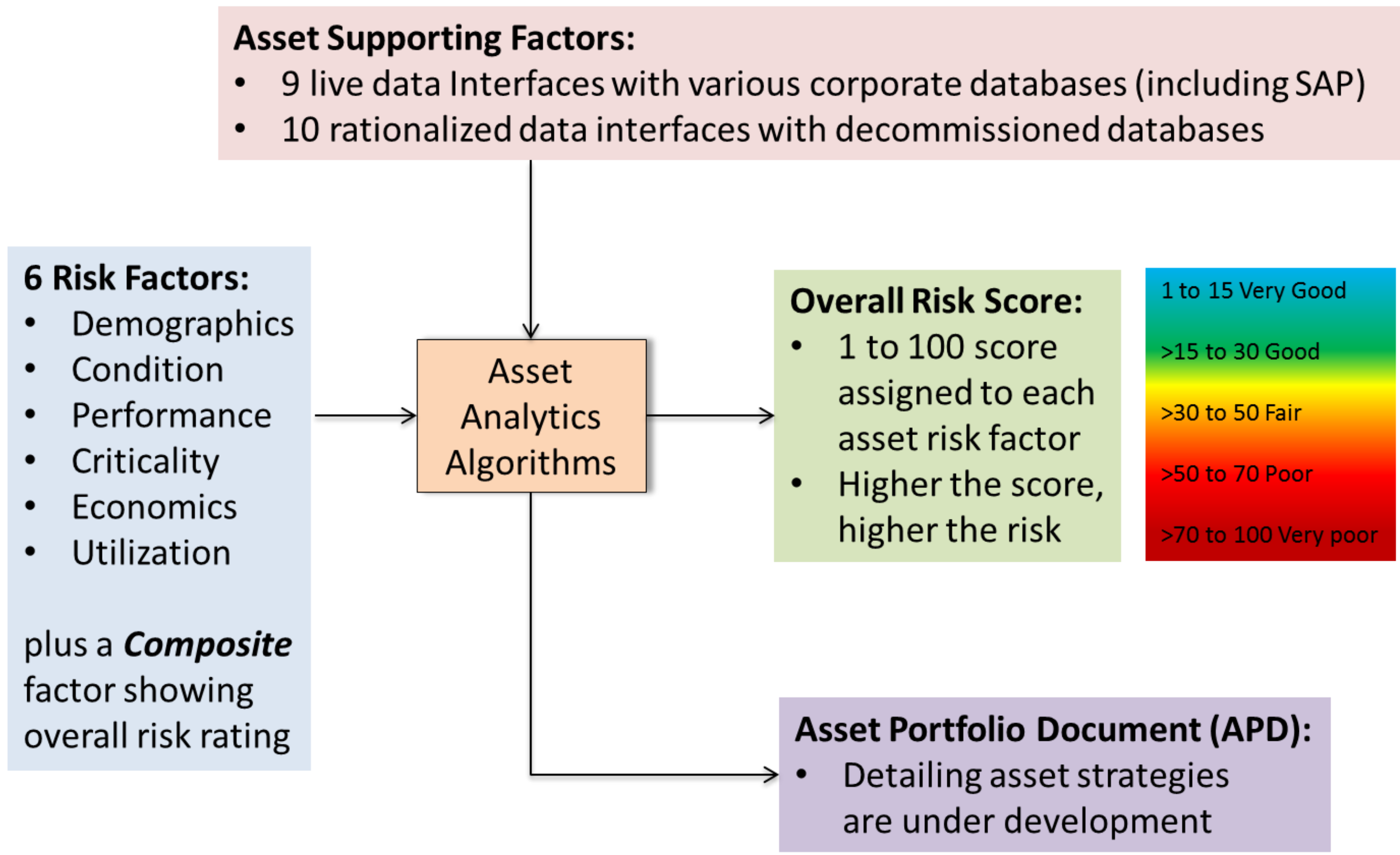


* Large investment with limited scope definition at the time of business planning
** High priority projects are released ahead of time or while the process is going on

Prepared by Internal Audit
For audit report purposes only

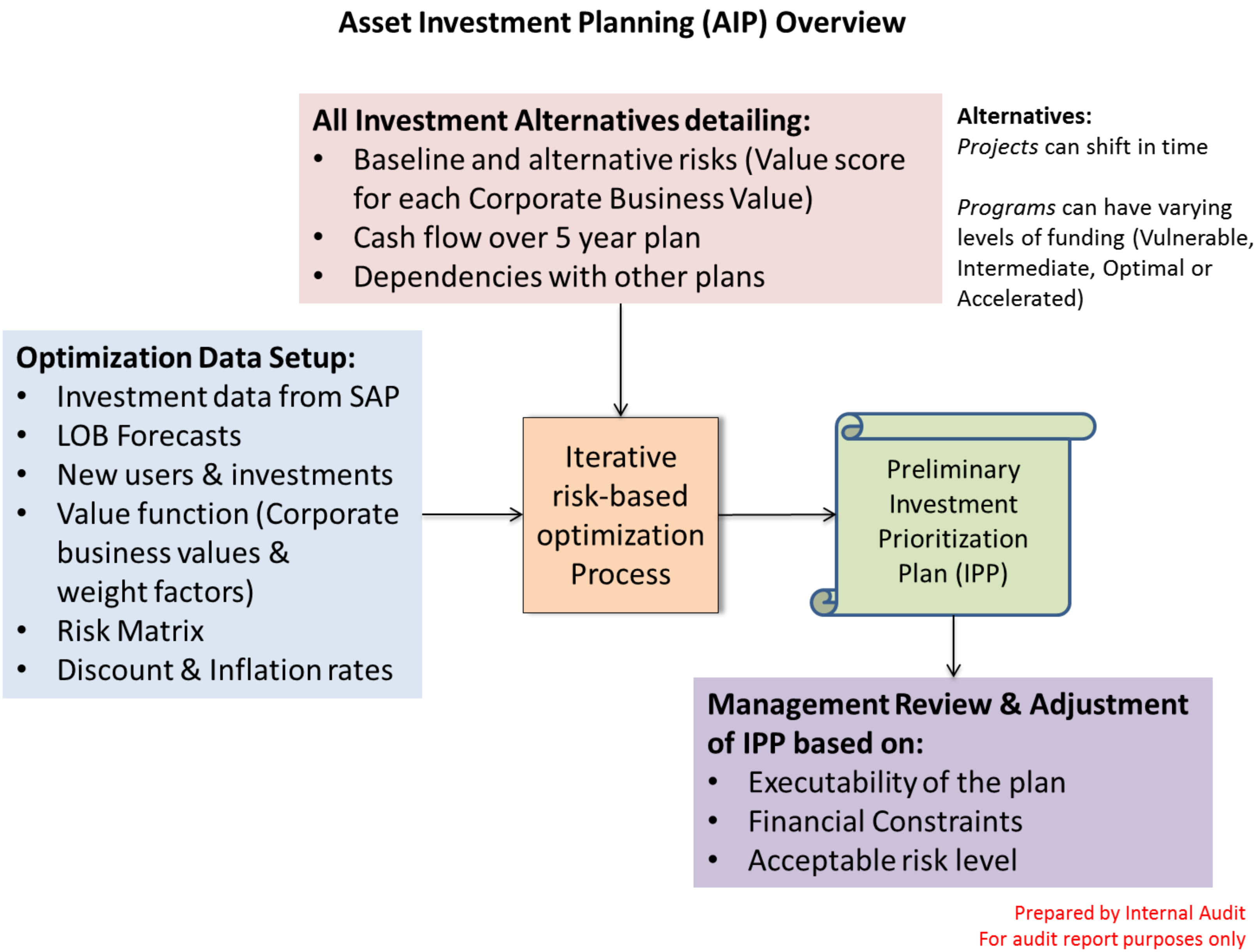
ASSET ANALYTICS (AA) OVERVIEW

Asset Analytics (AA) Overview



Prepared by Internal Audit
For audit report purposes only

ASSET INVESTMENT PLANNING (AIP) OVERVIEW



INVESTMENT ALTERNATIVES OVERVIEW

Concepts and Definitions

hydro one

Investment Alternative Names (for Programs)

Alternative	Definition
Accelerated	▪ This investment alternative exceeds "Asset Optimal" in order to mitigate a coming "bow wave" of asset needs. ▪ It is normally only applied where in a future year there will be a jump in required investment beyond what can be resourced or reasonably executed, so a 'head start' is necessary to ensure that the "Asset Optimal" investment level is achievable in future years
Asset Optimal	• This investment alternative represents the ideal balance point, where total lifecycle costs (not unit cost) of the asset are minimized and risk is low • Asset needs are fully met and there is a high degree of confidence that the assets will perform as aligned with the Asset Strategy which in turn aligns with the Corporate Strategy
Intermediate (1..n)	• These investment alternatives represent materially less risk exposure and materially more cost than "Vulnerable" but remain below "Asset Optimal" and therefore are less than ideal • All intermediate levels lie between "Vulnerable" and "Asset Optimal" in terms of cost and risk
Vulnerable	▪ This investment alternative is tolerable for only brief periods and exposes the company to significant risk of the asset not performing. ▪ Asset maintenance and/or replacement needs are not fully met. Future performance of the asset is uncertain, and is almost certain to drop below acceptable levels beyond 5 years if the level of investment is not increased. ▪ Short-term, strict regulatory compliance and safety is reasonably assured, but little else; the level of residual risk at the end of the 5 year planning period is just outside the "red zone" which is tolerable only in the near term and is not sustainable

Note: Projects will only have one alternative (which can be named the same as the project name)

Source: Business Concepts
2015-19 Investment Planning, April 2014, PPT Presentation

SUMMARY OF ACTIONS

(R) #	Observations	Risk	Recommendations (R)	Action Plan	Accountability	Completion Date
1. Governance and Controls						
1.1	There has been no recent and formal business risk assessment of the overall Planning business unit's objectives completed as per the Enterprise Risk Management Policy (SP0736).	M	Perform a formal risk assessment as per ERM Policy (SP0736) on an annual basis to ensure that business risks facing the planning organization are identified and mitigating actions are developed and tracked.	Planning will work with ERM Group to conduct a risk workshop to identify risks in achieving the planning business objectives.	Randy Church, Director, Network Connections and Development	Q4, 2015
1.2	Policies, processes, procedures, standards and guidelines are missing, incomplete, outdated or not being used consistently	H	Develop, review and approve sufficiently detailed policies, standards, procedures and guidelines to ensure a consistent risk-based approach to planning and decision making. This would require a review of the existing governance documents and ARIS process models for their accuracy and validity. Management has informed us that a Policy Review project is currently underway to consolidate policy and directive documents.	Conduct a review of processes, procedures, standards and guidelines to determine the need, effectiveness, currency and to ensure they are aligned with and support the Corporate Operational Policies. Establish a review cycle for these documents.	Luis Marti, Director, Reliability Studies, Strategies and Compliance	Q4, 2015
1.3 3.5	There is a lack of a clearly defined process and guidelines for the level of input to be sought by the planners and to be provided by the service providers during the	M	Clarify the timing and level of input to be sought by the planners from the service providers as they develop their plans.	At the annual LOB kick off, AM Processes and Tools will identify and seek input from the service providers to obtain their feedback on ideal timing and level of input required.	Kathleen McCorriston, Manager, AM Process & Tools	Q1, 2015

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
	investment plan development. There is inconsistent engagement with internal service providers during the development of alternatives.		Define and communicate the required level of engagement with the service provider when investment plans are being developed to ensure that plans are based on asset needs rather than executability by the service providers.	Planning will also be in attendance to ensure agreement and consistency in approach.		
1.4 2.1 2.2 3.3 3.6 5.2	There is no formally documented Quality Assurance process with related measures to assess the effectiveness of the "end-to-end" planning process.	H	Implement a formalized Quality Assurance process and related performance measures to assess the effectiveness of the "end-to-end" planning process. This would include: • a Need identification and tracking process • guidelines on use and validation of AA data to assess needs and risks • QA reviews of Investment Summary Reports and feedback to planners • Supporting document availability and review, and • realistic investment release dates	Quality expectations and the required metrics for the end-to-end process will be established and communicated by the Planning Organization.	Scott McLachlan, Director, Transmission Asset Management	Q3, 2015
1.5	There is no formal training for the overall "end to end" planning process. However, there is informal training on use of tools. None of the training is tracked and refreshed as the process and tools evolve.	M	Formalize and track all process and tool related training being given to planners in their Learning Management System. Establish refresher training requirements whenever there are significant changes in process and tools.	The Planning Organization will assess all training requirements including the frequency of refresher training and mechanism for tracking training completion. We will develop an implementation plan that defines the accountabilities	Mike Penstone, VP Planning	Q4, 2015

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
				for creation and delivery of training material.		
1.6	There is no formal lessons learned documentation for continuous process improvement.	M	Document and communicate lessons learned after each planning cycle and use them for continuous improvement of the planning process.	AM Processes & Tools will document and communicate lessons learned after the 2016-2020 planning cycle.	Kathleen McCorriston, Manager, AM Process & Tools	Q3, 2015
2. Customer, Asset and System Need Assessment						
2.3	The AA data quality remains a concern. The quality of underlying data (accuracy, completeness and timely availability of recent data) being used from SAP and other databases for risk index calculations is unknown.	H	Request an audit of Asset Analytics data sources and algorithms to confirm that quality data and appropriate calculation methods are used for calculating the six Asset Risk Indexes for individual assets as well as asset groups.	SAP Data Audit on Asset and Maintenance data is already underway. The results of these audits will be used to address the underlying data issues in AA. Workshops with respective LOBs will be held regarding usability of existing algorithms.	Randy Church, Director, Network Connections and Development	Q4, 2015
2.4	System development projects are based on area supply studies requiring power system historical data related to load flows, voltages, asset connectivity and statuses. These data are not available in AA.	M	Consider expanding the scope of the Asset Analytics tool to include up-to-date power system historical data such as load flows, connectivity, voltages, statuses, etc.	AM Process and Tools will request ISD to add audit recommendation to corporate application roadmap. Key requirement is to have access to NMS information.	Bing Young, Director, System Planning	Q1, 2015

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
2.5	There are no clearly documented asset strategies against which individual asset needs are assessed. However, work has recently started on developing Asset Strategy Documents for 30 key asset groups.	M	Continue to develop sufficiently detailed Asset Strategy Documents for all asset groups and ensure that all future asset needs are assessed against these documented strategies.	We will continue to develop Asset Strategy Documents.	Scott McLachlan, Director, Transmission Asset Management	Q4, 2016
3. Investment Alternatives						
3.1 4.1	For the AIP optimization to be effective, projects should be shiftable in time and programs should have more than one alternative. Only 30% of the plans in 2015-2019 IPP were optimizable within AIP.	H	Increase the numbers of investments that are optimizable by requiring the planners to define more than one alternative for non-demand driven programs and time shift-able projects. Management should also ensure that appropriate justification is documented and reviewed for plans having only a single alternative.	We will define the framework for investments including the expectations outlining the definition and governance of programs and projects and requirements for program alternatives and time shift-able projects. Document and communicate these requirements.	Scott McLachlan, Director, Transmission Asset Management	Q3, 2015
3.2	The current risk matrix is confusing and that the provided guidelines are subjective.	M	Simplify the risk assessment matrix and provide suitable training and guideline to planners to perform an effective risk assessment. Specific focus should be on using quantative data from AA and other systems to determine/support appropriate probability and consequence on the established risk matrix.	We will improve the guidance on the use of the risk assessment matrix through the provision of practical examples.	Scott McLachlan, Director, Transmission Asset Management	Q4, 2016

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
3.4	Some of the unit prices being used for program work are outdated or incorrect.	M	Review and confirm the Unit Price Catalog with the service providers prior to the start of each planning cycle to ensure that the most current unit prices are being used to determine the funding level for the program work.	We will establish a process to ensure costs included in the investment plans are agreed upon between Planning and Operations (executing LOBs).	Chong Ng, Director, Project Development	Q4, 2015
4. Investment Plan Optimization						
4.2	The AIP tool was only available for a limited time resulting in planners having insufficient time for thorough documentation of their plans and management having insufficient time to review those plans in detail.	M	Make the AIP tool available year around to allow the planners to input and update their plans and risk assessments throughout the year. Management has indicated that plans are already underway to upgrade the AIP tool to allow this to occur in 2015.	This recommendation will be addressed upon implementation of AIP tool upgrade.	Kathleen McCorriston, Manager, AM Process & Tools	Q3, 2015
4.3	Manual workarounds are in place to update AIP data from SAP and other systems.	L	Consider AIP tool integration with other systems and tools such as AA (for asset risk factors), SAP (for AR and driver related data), BPC (Business Process Consolidation, for LOB forecast and accomplishment data) and UPC (Unit price catalog, for unit price data) to ensure that information in AIP is kept up-to-date with other systems.	AM Process and Tools will request ISD to add audit recommendation to corporate application roadmap.	Kathleen McCorriston, Manager, AM Process & Tools	Q3, 2015

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
4.4	Enterprise engagement is occurring at the director level and above with a focus on comparison with previous year's plan to identify what has changed and discuss why. A line by line review is only occurring for major / complex plans. The LOB engagement for 2015-2019 IPP occurred over a four day period from June 9 to 13, but the service providers have indicated that	H	Increase the enterprise engagement period to allow a detailed line by line review of unreleased work in the IPP by the project and program managers who will be executing the plan. This will allow better feedback on cash flows and in-service dates from the service providers based on the established scope.	Enterprise Engagement period will be revised and incorporated into the revised schedule for the 2016-2020 planning cycle.	Kathleen McCorriston, Manager, AM Process & Tools	Q3, 2015
	they need more time to review each investment line item in IPP in sufficient detail with their project and program managers to ensure that the IPP can be executed as planned.					
4.5	Adjustments and changes to the optimized IPP are logged in a spreadsheet based change log. This change log does not seem to capture all changes.	M	Implement a formal change log to document all recommended changes. This should also include appropriate review, approval and incorporation of changes with appropriate communication back to the requestor of the change.	All changes will be recorded in the accomplishment file change log and/or documented in the meeting minutes.	Kathleen McCorriston, Manager, AM Process & Tools	Q1, 2015 Complete

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
4.6	It is unclear what changes to the optimized plan would require the plan to be run through the optimization process again. The IPP, once optimized, is simply adjusted based on changes recommended during the enterprise engagement reviews. The resulting adjusted IPP may not be a fully optimized plan. It was noted that the preliminary IPP was adjusted and re-issued to LOBs approximately 10 times before being finalized.	M	Determine and document which types of changes to the individual plans require the IPP to be run through the optimization process again to ensure that the resulting plan remains optimal.	AM Process & Tools will document conditions and requirement for the IPP to be run through the optimization process again into the Investment Optimization Management Procedure.	Kathleen McCorriston, Manager, AM Process & Tools	Q2, 2015
5. Investment Plan Approval and Release						
5.1	A requirement has been put in place recently to treat all "projam" greater than $20M as projects requiring an approved BCS by the appropriate OAR authority prior to release. However, it is unclear how the remaining "projam" investments will be approved and progress will be monitored.	H	Clarify the approval requirement and progress monitoring for "projam" investments. Review the project and program approval process with specific focus on shortening the approval timeline. This may include appropriate escalation triggers as well as clarification of requirement for timely review / approval.	This will be incorporated into annual review of OAR.	Mike Penstone, VP Planning	Q3, 2015

INTERNAL AUDIT REPORT

Investment Planning Follow-up (IPF)

To:

Darlene Bradley
Vice President, Planning

Distribution:

Mayo Schmidt	President & Chief Executive Officer
Greg Kiraly	Chief Operating Officer
Chris Lopez	Senior Vice President, Finance
Bruno Jesus	Director, Strategy & Integrated Planning
Kevin Mancherjee	Manager, Investment Planning and Process
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Final Report Issued: September 6, 2017
Draft Report Issued: June 30, 2017
Report Number: 2017-14

Lead Auditor: Atul A. Solanki
Audit Manager: Jeff Schaller

EXECUTIVE SUMMARY

Background:

In January 2015, we completed an audit of the Investment Planning process covering the identification of asset needs to the approval and release of investment plans to address those needs. That audit included our assessment of the controls in place to effectively identify, develop, prioritize and select investment plans in support of the Hydro One five-year business plan and the work program. Our final report concluded that the key controls concerning the Investment Planning process needed significant improvement. The final report contained 18 recommendations that resulted in actions being identified by management under 5 subject areas. At that time, management committed to action plans to address our recommendations and mitigate the risks identified within the report. Management has reported all actions as complete through the quarterly tracking of actions.

Objective and Scope:

The primary objective of this follow-up audit was to provide assurance that Hydro One has completed the committed actions and addressed all the audit recommendations and mitigated the associated risks.

Our work included a review of:
- Governance framework (roles, accountabilities and oversight for addressing audit recommendations)
- Completion of committed action items to effectively address the recommendations and risks
- Assessment of design effectiveness and implementation of any new/revised controls
- Communication of progress and completion of committed action plans (to senior management and process stakeholders)

The following table summarizes our assessment of audit action plan status and control design effectiveness.

Assessment Item	Risk (2015)	Action Item Status Assessment[1]	Control Design Assessment	Risk (2017)
1.1 Business Risk Assessment	M	Substantially Complete	Partially Effective	M
1.2 Governance Documents	H	Substantially Complete	Substantially Effective	M
1.3 Operations Group Input	M	Substantially Complete	Substantially Effective	L
1.4 Quality Assurance Program	H	Substantially Complete	Substantially Effective	M
1.5 Training and tracking	M	Complete	Effective	L
1.6 Lessons Learned	M	Substantially Complete	Substantially Effective	L
2.3 Asset Analytics Data	H	Partially Complete	Not Applicable	H
2.4 Power System Data	M	Partially Complete	Not Applicable	M
2.5 Asset Strategies	M	Substantially Complete	Substantially Effective	L[2]
3.1 Optimizable Alternatives	H	Complete	Substantially Effective	L
3.2 Risk Assessment Matrix	M	Substantially Complete	Partially Effective	M[3]
3.4 Unit Price Catalogue	M	Substantially Complete	Substantially Effective	L

[1] The Action Item Status and Control Design Assessment ratings are described in the legend at the end of this Executive Summary.

[2] Although the development of the required asset strategies are still in progress, management has introduced controls to track and monitor their development by May 31, 2018 with assigned accountabilities and periodic review cycles.

[3] Management has recently introduced a new Risk Assessment Matrix for Transmission and Common assets so the residual risk for these assets may be lower but a similar matrix for Distribution assets is planned to be introduced in 2018 so the residual risk for these assets remains at Medium.

4.2 AIP Tool Availability	M	Complete	Effective	L
4.3 AIP Manual Workarounds	L	Partially Complete	Not Applicable	L
4.4 Enterprise Engagement period	H	Complete	Effective	L
4.5 IP Change Log	M	Substantially Complete	Substantially Effective	L
4.6 Re-optimization requirement	M	Complete	Effective	L
5.1 "Projam" Investments	H	Complete	Effective	L

Success Factors:

We noted that the following success factors were in place:

- Management is now providing instructor-led training to planners for the Investment Planning Process and Risk Assessment with support from the Investment Management team providing drop-in sessions and one-on-one assistance to Planners during the Investment Planning cycle.
- Management has significantly increased access to the Asset Investment Planning (AIP) tool for planners to provide their input on the investment plans from a 4 week window to a 6-month window.
- Management has increased the Enterprise Engagement Review period to a 7-8 week timeframe to enable a line-by-line review of the investment plan by the Operations group.
- Management has developed and documented guidelines for optimization of the investment plans and conditions which must be met in order to re-optimize the plan.
- Management has established more robust oversight controls for "Station Centric" asset sustainment investments by managing them as specific projects (with specific scope, time and cost constraints) rather than on-going multi-year programs.

Summary of Key Recommendations:

We have discussed our observations with management throughout this follow-up audit. The key recommendations we made, which management has reviewed and developed action plans, are included in the following list of high and medium residual risk impact items:

High Risk:

- Continue to identify and correct issues with Asset Analytics input data and risk factor algorithms that will affect the degree to which the output results can be used to influence investment decisions.

Medium Risk:

- Develop and implement a process with accountabilities to identify emerging risks and periodically review existing business risks and related mitigating actions. Incorporate results of other targeted risk workshops into the overall business risk register.
- Review and formalize existing management direction, presently being delivered as part of Investment Planning training presentations, into governance documents (policies, processes, procedures, standards, guidelines, etc.) and decommission existing out-dated governance documents (including draft policies and process documentation).
- Establish and implement appropriate measures and targets for the Investment Planning Scorecard. Track "go to green" action plans for management to achieve the targets either for the current or future Investment Planning cycles. Document the results of quality assurance reviews performed by management and feedback given to planners.
- Review and establish appropriate funding and actual implementation plans for the enhancements identified in the Asset Management Tool Integration Roadmap.

- Assess the effectiveness of the recently implemented, simplified risk assessment approach for the transmission assets and develop a plan to implement a similar approach suitable for distribution assets.

Audit Opinion:

Management has made significant progress in addressing the control deficiencies that we identified and documented within the 2015 audit report, however further progress is needed. Based on the specific areas reviewed, **we concluded that control improvements are needed** to effectively identify, develop, prioritize and select investment plans in support of the Hydro One six-year business plan and the work program.

Management has developed action plans to mitigate the identified risks and address our recommendations, as summarized in Attachment "A" of this report. In a separate memorandum we have shared with management additional opportunities for improvement that we believe will further strengthen this function. Additional details are available upon request.

Management Response:

Bruno Jesus, Director, Strategy and Integrated Planning

Management agrees with Internal Audit's observations and recommendations and we are committed to complete our associated actions by the completion dates.

Assessment of Action Item Status and Control Design Effectiveness by Internal Audit[1]		
Assessment Type	**Assessment Level**	**Description**
Action Item Status	Complete	All committed management actions are complete and fully implemented.
	Substantially Complete	All committed management actions are complete but not yet communicated, approved or implemented.
	Partially Complete	Work is progressing on committed management actions with a clear plan to achieve implementation.
	Incomplete	No or little work progress on committed management actions with no clear plan to achieve implementation.
Control Design Effectiveness	Effective	New or revised controls introduced through management actions have mitigated all identified risks to an acceptable level.
	Substantially Effective	New or revised controls through management actions have mitigated most but not all risks to an acceptable level. Minor control enhancement is required to achieve full risk mitigation
	Partially Effective	New or revised controls through management actions have not mitigated the risk to an acceptable level. Substantial control design improvement are needed to achieve full risk mitigation
	Ineffective	No new or revised controls have been introduced through management action. Identified risks remain unmitigated.

OBSERVATIONS, RECOMMENDATIONS AND MANAGEMENT ACTIONS

Observations	Recommendations	Action Plan
1.1 Business Risk Assessment	**Risk**[4] M	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
During our audit on this subject in 2015, we noted that a recent and formal business risk assessment for the Planning business unit had not taken place. Subsequent to that audit, a business risk workshop was completed later in 2015 identifying five Investment Plan risks. Four of these risks were discussed in detail with only one risk (related to productivity underachievement) requiring mitigating actions. The fifth risk, related to erosion of customer goodwill, was not fully discussed due to time limitations of the workshop. Management informed us that the mitigating action related to developing accountabilities and plans for productivity underachievement risk was assigned to Finance which has been completed, but has not yet been fully implemented. Management further informed us that a targeted risk workshop specific to the Distribution System Plan was conducted in 2016. The risk workshop reports did not identify risk owners and no documented accountabilities or processes are currently in place to identify, monitor, control or communicate emerging or revised business risks on a periodic basis as per the Enterprise Risk Management (ERM) framework. ***Risk:*** *Lack of identified business risks and mitigating actions could result in an inability to meet the business objectives and goals.*	Develop and implement a process with accountabilities to identify emerging risks and periodically review existing business risks and related mitigating actions originally identified in the 2015 Investment Plan Risk Workshop Report. Incorporate results of other risk workshops into an overall Planning business risk register for appropriate tracking by specifying business objectives, risks, risk owners, mitigating actions, and target completion dates.	The requirement to conduct risk assessments on the annual Investment Plan will be added to the overall Investment Planning deliverables each year. Any recommendations/action items resulting from the risk assessment will be added to the Planning Division's tracker for action items (Internal Audit, AEI, etc.) **Completion:** March 31, 2018

[4] Residual Risk levels applied are described in the legend that follows this table.

Observations	Recommendations	Action Plan
1.2 Governance Documents	**Risk**[2] M	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
During our audit on this subject in 2015, we found that approved policies and directives were out-dated or not being followed while business process models documented in ARIS[5] were incomplete. Since then, a Corporate Operational Policy Development Review process has been documented and used to develop 13 new policies. The older policies are being reviewed, updated or rescinded as part of the Corporate Policy Review project. Management further informed us that a key policy document titled "Asset Investment Planning Risk Assessment Corporate Operational Policy" continues to remain in draft form since 2013 as the Investment Planning Process is currently under review. The process models documented in ARIS on this subject are now recognized as out-dated by management but they have neither been formally decommissioned nor replaced. Management's current approach is to provide required direction through investment planning process training, however this will likely not be effective as only the individuals receiving the training will become aware of management direction while other stakeholders will not be aware of the investment planning process and related requirements. ***Risk:*** *Lack of well-defined, communicated and understood governance documents could lead to inconsistent decision making and poorly defined investment plan.*	Review and formalize existing management direction, presently being delivered as part of Investment Planning training, into governance documents (policies, processes, procedures, standards, guidelines, etc.) and decommission out-dated governance documents (including draft policies and process documentation within ARIS).	Appropriate governance documents (policy, process, procedure, standard or guideline) will be established taking the existing Investment Planning training material into account. All other existing draft documentation that no longer applies will be removed (e.g. ARIS). **Completion:** June 30, 2018.

[5] **AR**chitecture of **In**tegrated information **S**ystem (ARIS) is business process modeling tool used for enterprise wide business process modeling.

Observations	Recommendations	Action Plan
1.3 Quality Assurance Program	**Risk**[2] M	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
Management had agreed to establish and communicate quality expectations and required metrics for the end-to-end investment planning process based on our recommendation from the audit on this subject in 2015. Subsequent to that audit, Management implemented an Investment Planning Scorecard, Manager Quality Assurance checklist, and Investment Health Report to assist in identifying potential errors and quality issues as they develop and review the investment plans. Although the Investment Planning Process Scorecard and Investment Health Report provide statistical information regarding potential quality issues, there are no realistic targets or expectations of actions required to achieve those targets. Management informed us that quality assurance review feedback is not documented but verbally provided to the planners based on issues observed during the quality reviews. Without comparing the current measures to established targets and related "go to green" plans to ensure that the targets will be met, the effectiveness of the current quality assurance program cannot be fully assessed. ***Risk:*** *Insufficient monitoring of process effectiveness and quality assurance of process outputs would lead to an increased risk of errors and degradation of output quality.*	Establish and implement appropriate measures and targets for the Investment Planning Scorecard (specifically for non-accomplishment related measures such as estimate quality, Potential Need (PN) [6] notifications that are actioned/accepted, etc.). Track "go to green" action plans for management to achieve the targets either for the current or future Investment Planning cycles. Document the results of quality assurance reviews performed by management and feedback given to planners.	Key performance indicators (KPI) for the investment planning process will be developed and incorporated into 2018 scorecards for impacted directors as per the recommendation. **Completion:** December 31, 2017

[6] Potential Need (PN) is an SAP notification that provides visibility to assets in need of replacement or refurbishment. PNs can be entered into SAP by head office or field Operations staff and are reviewed as part of the investment planning process.

Observations	Recommendations	Action Plan
1.4 Asset Analytics (AA)	**Risk**[2] H	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
Asset Analytics (AA) is a tool available to planners to assess asset needs based on asset condition data collected during routine maintenance, performance history, utilization, age and criticality. Management informed us that Asset Risk Indexes (ARI) from the AA tool are one of many inputs that feed into the development of candidate investments, and that these ARIs are not intended to be used as a replacement for the sound engineering judgment and decisions of the qualified Planning engineers, and is only one step of the broader process which is used in conjunction with physical inspections. In 2016, management held workshops with key stakeholders involved in the Investment Planning Process to review and discuss changes to ARI algorithms, input data and new risk factors. To date, management has not implemented any of the requirements identified in the AA workshops, however plans are underway to address 78 requirements related to two new risk factors and 159 requirements related to enhancements to risk factors by end of 2020. We remain concerned about the data quality from supporting systems (such as SAP) that are used as inputs to Asset Analytics. ***Risk:*** *The absence of well-understood and quality asset information increases the risk of inadequate asset need assessment which can result in diminished confidence in the process involving the AA tool and the potential for less than optimal investment decisions.*	Continue to identify and correct issues with Asset Analytics input data and risk factor algorithms that will affect the degree to which the output results can be used to influence investment decisions.	Plans related to data required for Asset Analytics will be developed and key steps and milestones to address the recommendation will be tracked in the Divisional Scorecard. **Completion:** December 31, 2017

Observations	Recommendations	Action Plan
1.5 Asset Management Tool Enhancements	**Risk**[2] M	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
Asset Analytics (AA) and Asset Investment Planning (AIP) are two key support tools used by planners for which a number of deficiencies were identified during the last audit. We had noted that the load flows, voltages, asset connectivity and statuses related power system historical data required for area supply studies in support of System development projects were unavailable in AA. We had also noted that there were manual workarounds in place to update AIP input data from SAP and other systems (such as Unit Price Catalogue, Project Forecasts, etc.). Since then, Management has developed an Asset Management Tool Integration Roadmap in 2015, identifying 24 enhancement requests and 16 integration requests with other systems. The roadmap shows that the requirement to integrate power system data from NMS & PSDB[7] systems is ranked 22nd out of 24 in priority. A firm implementation schedule for the enhancement and integration requests identified in the roadmap is unavailable. Management informed us that in the absence of further progress, same manual workarounds as those observed in 2015 remain in place. ***Risk:*** *Unavailability of required data in AA & AIP tools may result in incorrect/inconsistent decision making. Manual workarounds as a result of lack of data integration could result in delays and/or poor quality investment plans.*	Review and establish appropriate funding and actual implementation plans for the enhancements identified in the Asset Management Tool Integration Roadmap.	Management will review the tool enhancement roadmap, to determine necessary enhancements taking into account cost/benefit with decisions to keep, defer or discard items. **Completion:** June 30, 2018

[7] Network Management System (NMS) and Power System Database (PSDB) are two systems that contain power system historical data.

Observations	Recommendations	Action Plan
1.6 Risk Assessment Matrix	**Risk[2]** M [8]	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
During our audit on this subject in 2015, we found that the risk assessment matrix being used to assess baseline and alternative risks for a given investment was being used inconsistently. Subsequent to that audit, management has conducted annual Risk Assessment training to provide specific guidance to planners with examples on how to perform risk assessment using the available risk matrix. A risk calibration session held in 2016 indicated a moderate success in aligning risks across all investments. As a result, management sought the services of an external consultant (McKinsey) in 2017 to review and recommend a simplified approach to consistent risk assessment for the 2017 investment planning cycle. A new simplified risk assessment is now planned for transmission investments in 2017 with plans to use a similar approach for distribution investments starting in 2018 because the Distribution investment plans are presently with the regulator and "frozen" for the current planning cycle. We note that an informal survey of 17 planners indicated that challenges remain related to risk assessments for distribution investments. ***Risk:*** *Inadequate assessment of baseline and alternative-specific risk could result in incorrect risk values being assigned.*	Assess the effectiveness of the recently implemented, simplified risk assessment approach for transmission assets and develop a plan to implement a similar approach suitable for distribution assets.	Management will assess the effectiveness of the current transmission process and develop a plan (relating to risk assessment approach) to improve the distribution process accordingly. **Completion:** June 30, 2018.

[8] A new Risk Assessment Matrix for Transmission and Common assets has been recently introduced so the residual risk for these assets may be lower but a similar matrix for Distribution assets is planned to be introduced in 2018 so the residual risk for these assets remains at Medium

LEGEND: ACTION ITEM STATUS AND CONTROL DESIGN EFFECTIVENESS RATINGS:

Assessment of Action Item Status and Control Design Effectiveness by Internal Audit[1]		
Assessment Type	**Assessment Level**	**Description**
Action Item Status	Complete	All committed management actions are complete and fully implemented.
	Substantially Complete	All committed management actions are complete but not yet communicated, approved or implemented.
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Control Design Effectiveness	Effective	New or revised controls introduced through management actions have mitigated all identified risks to an acceptable level.
	Substantially Effective	New or revised controls through management actions have mitigated most but not all risks to an acceptable level. Minor control enhancement is required to achieve full risk mitigation
	Partially Effective	New or revised controls through management actions have not mitigated the risk to an acceptable level. Substantial control design improvement are needed to achieve full risk mitigation
	Ineffective	No new or revised controls have been introduced through management action. Identified risks remain unmitigated.

LEGEND: RESIDUAL RISK CLASSIFICATION:

RESIDUAL RISK CLASSIFICATION[2]	Assessment Indication
MEDIUM: The risk will cause some elements of the objective to be delayed or not be achieved, causing potential negative impacts to the organization's strategic objectives.	M
HIGH: The risk will cause the objective to not be achieved, causing negative impacts to the organization's strategic objectives.	H

INTERNAL AUDIT REPORT

HYDRO ONE NETWORKS INC.
ASSET DEPLOYMENT

To:

Sandy Struthers,
Chief Operating Officer and EVP Strategic Planning

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Auditors: Jeff Schaller
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EXECUTIVE SUMMARY

An Internal Audit of the Asset Deployment[1] process within Hydro One Networks Inc. (Networks) was conducted from October to December 2014, as a follow up to the 2012 Control Self-Assessment (CSA). The objective of this Audit was to assess the controls in place to effectively deploy power system assets and focused on transmission station projects and programs associated with the deployment of large equipment from the point where the requirements of a new asset are identified, up to the point where the asset is placed in-service and operating. This Audit also included a follow up status of the findings from the 2012 Control Self-Assessment workshop report[2] included in Appendix A (Figure A3).

Of the eight 'possible improvement ideas' identified in the 2012 Control Self-Assessment report, two have been identified as complete, two are partially complete and three items are incomplete. The eighth improvement idea was not reviewed due to an Internal Audit being planned in that area in 2015.

This audit revealed that a lack of end-to-end oversight of the Asset Deployment process is resulting in assets being placed in service with technical issues that create the need for a combination of emergency response, operating contingencies/action and corrective action. [redacted]

Since there is no single end-to-end accountability for the Asset Deployment process, there is no comprehensive consideration or understanding of the collective risks posed by the current state of Asset Deployment. Risk considerations are fragmented, left to individual LoBs looking at risks associated only within their own accountabilities.

Based on our review, **we have concluded that the key controls concerning the Asset Deployment process needs improvement** in the following areas with a grading of exposed residual risk[3]:

Key Control	Oversight	Risk Mgmt	Perf. Measures	Estimating Controls	Comm-unication	Project Planning	Procure -ment	QA	Staged Release	Project Close-Out	Records
Assessment of Control	I	I	I	NI	NI	NI	NI	I	NI	I	NI
Residual Risk	H	M	M	M	M	M	H	M	M	M	M

Assessment of Control: G = Good NI = Needs Improvement I = Ineffective

We were pleased with the following positive observations during the audit: COMSE (Constructability, Operability, Maintainability, Safety & Environment) meetings have continued, which provide the opportunity for input from LoB stakeholders early in the project/asset deployment process and management has put in place a station-centric approach to project/program work planning and execution.

Management has prepared action plans[4] to improve controls in the above areas. We would like to take this opportunity to thank all management and staff involved; Project Management, Engineering, Planning, Station Services & Operating, Construction Services and Supply Chain for their cooperation throughout the audit.

Jeff Schaller	Ginette Karjanmaa
Director, Technical Audits	Audit Associate
Internal Audit	Internal Audit

[1] Asset Deployment involves the implementation of equipment and infrastructure on the Hydro One network and involves a multi-stage process from needs requirement through to commissioning and in-servicing. For more detail, refer to the Background section in Appendix A.
[2] Control Self-Assessment Workshop, Asset Deployment Effectiveness, May 3, 2012, IAD Report #2012-03
[3] Audit Assessment Summary provided in ***Appendix C: Controls Assessment Summary***
[4] Audit Observations and Management Action Plans are provided in ***Appendix G: Summary of Actions.***

OBSERVATIONS AND RECOMMENDATIONS

1. There is no high level oversight of the Asset Deployment process.

Background:
The Asset Deployment process involves six Lines of Business (LoBs) i.e. Project Management, Engineering, Planning, Station Services & Operating, Construction Services and Supply Chain. As a result there are many hand-offs between groups, multiple meetings, processes with a local department/division focus (silo perspective) and procedures that are not always known and understood among LoBs stakeholders. LoBs are often focused on achieving their own targets sometimes inadvertently to the detriment of other LoBs (e.g. the asset management role is to provide work releases by year end and this creates a backlog for other groups who receive much of the work at once). LoB's are constantly challenged to complete Hydro One's annual work program that requires a cohesive work planning and execution process where success is dependent on the cooperative efforts of multiple LoBs. Furthermore, there is a lack of effective project close-out reporting and a lessons learned process which would have the potential to provide valuable feedback to the various contributing LoB groups. A One Company approach requires process oversight including monitoring and communication between contributing groups.

Observations:
Presently, there is no single authority or governance structure with high level oversight of the Asset Deployment process[5] (from Plan/Release through to In-servicing). Each LoB is limited to its own accountabilities to address concerns. This creates issues that occur between LoB handoff points and the issues are not being highlighted or addressed in a systematic manner. Despite some improvements driven by reorganization efforts, most issues raised during the Control Self-Assessment in 2012[6] still exist. Internal Audit's follow-up status of the findings from the 2012 Control Self-Assessment workshop report is included in Appendix A, Figure A3. Of the eight 'possible improvement ideas' identified in the 2012 Control Self-Assessment report, two have been identified as complete, two are partially complete and three items are incomplete. The eighth improvement idea was not reviewed due to an Internal Audit being planned in that area in 2015 (i.e. Maintenance Strategy).

For example:

- The current lessons learned database tracking tool process is considered onerous, time consuming to many and it is being underutilized. Recorded lessons are focused on specific experiences rather than identifying specific actions that can be assigned, tracked to drive better decision making and process improvements. The learnings are not consistently shared with LoBs. This was previously identified and articulated several times in the 2012 Control Self-Assessment.
- Project Managers (PM) are expected to accept approved projects that include in-service dates that have become unrealistic due to approval delays.

Accountabilities of the LoBs involved in the end-to-end process are not well understood. For example, there are "expectations" (assumed accountabilities) by some LoBs of other LoBs that certain activities are performed:

- Supply Chain expects that Engineering is exercising due diligence, e.g. that Safety by Design is being taken into account within the design.

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[5] Refer to Background section of this report for a description of the Asset Deployment process

[6] Examples of improvements were identified in the Control Self-Assessment workshop in 2012 from page 20 to 22- Summary of Possible Improvement Ideas.

- Engineering, Construction Services expects Supply Chain to exercise due diligence in vendor selection and Factory Acceptance Tests and delivery of quality products according to specifications.
- Supply Chain expects that Construction Services performs Quality Assurance inspection of delivered equipment and materials.

Yet, in each of these cases, there are no effective processes, measures and reporting to provide documented indication that these activities are occurring.

There are inefficiencies and cost and time overruns due to repeat mistakes from one project to another contributing to lack of continuous improvement. A review of IROV documents from major projects in years 2012-2014 revealed a pattern in the variance explanations reported by management, namely, insufficient scope definition prior to release and incorrect estimates, based on past project actuals.

It is not practical and in many cases not possible to measure and track all of the cost and time impacts resulting from the inefficiencies mentioned previously. However, some of these tangible effects are available from tracking of work in SAP pertaining to emergency response, operating contingencies/action and corrective action on recently deployed assets, as provided by Asset Management:

- [redacted]
- [redacted]

[redacted]

Risks:
The status quo exposes Hydro One Networks to the following risks:

- The lack of oversight of the end-to-end asset deployment process can result in:
  - Assets not deployed as originally planned
  - Escalated cost and inefficiencies through re-work
  - Impact to committed in-service dates
  - Burden of O&M corrective costs to address asset deficiencies following in-service
  - Delays in major equipment delivery
  - Multiple extensions of supply chain contracts (appears as single source)
- Loss of opportunities to leverage equipment and material pricing Unclear and/or gaps in accountabilities may result in some steps being missed and affect the efficient constructability of the asset.
- Delays in up front stages of Asset Deployment can create compression at the construction and commissioning stages, thereby putting the functionality and maintainability of the assets at risk.
- Inefficiencies and cost and time overruns due to repeating mistakes from one project to another.
- Limitations to continuous improvement opportunities of the Asset Deployment process.

Recommendation:
We recommend that Management establish a single point of accountability (Process Owner) for the overall end-to-end asset deployment process. Ideally, the Process Owner would establish oversight controls (e.g. conduct periodic meetings including LoB/Asset Deployment stakeholders and report on process status and identify opportunities for further improvement). The Process Owner would establish and monitor key processes (e.g. Lessons Learned) to identify process improvements and facilitate cross-LoB process improvements.

Management Response: *(Sandy Struthers – COO & EVP Strategic Planning)*

Disagree. The recommendation is not clear and does not address the concern being raised which of the accountable VP's. I believe there is an opportunity to better define accountabilities to address many of the LoB's to allow for a better process. Establishing a single point of accountability is not the answer.

Proposed Action Plan:

The COO will request Internal Audit to attend a meeting with the appropriate line of business VP's and the Director of Engineering to lead the group through and to review the issues identified through this audit. The Director of Work Program Management will attend and a mitigation plan will be established that will be tracked by the Director of Work Program Management for the COO.

Completion Date:

Q3, 2015

2. **Risks relating to deployment of assets are contemplated but not formally documented or managed at a high level.**

Background:
SP 0736 (Enterprise Risk Management Policy) provides a uniform process to identify, measure, and consciously accept or mitigate risk within approved risk tolerances. It supports the Board's corporate governance needs and the due diligence responsibilities of senior management. It also helps to strengthen our management practices in a manner demonstrable to external stakeholders.

Since there is no single end-to-end accountability for Asset Deployment within the company, there is no comprehensive consideration or understanding of the collective (end-to-end) risks posed by the current state of Asset Deployment.

Observations:
Risk considerations are fragmented, left to individual LoBs looking at risks associated with their own accountabilities. There is a lack of a consistent risk assessment approach from an overall end-to-end Asset Deployment process and a uniform process to identify, measure, treat and report on key risks as per SP 0736 (Enterprise Risk Management Policy).

Risks:
The lack of identifying risks early in the Asset Deployment process exposes HONI to risks in achieving its corporate strategic objectives. Risk exposures include:

- Threat to timely completion of capital and operation work programs.
- Financial risk – increased project costs due to process inefficiencies.

Recommendation:
Establish a high level (cross-LoB) risk assessment approach to address risks of the overall Asset Deployment process.

Management Response: *(Sandy Struthers – COO & EVP Strategic Planning)*
Disagree.

Proposed Action Plan:
The COO will request Internal Audit attend a meeting with the LoB VP's and Directors' as noted above to talk about how a One Company approach can be used to address issues related to work initiation, project risk identification, etc. If appropriate and if the business agrees a risk register will be established but at a minimum it will be agreed that the interlinked business process, issues and inefficiencies will be discussed for action to be taken annually.

Completion Date:
Q3, 2015

3. Existing performance measures do not provide incentives for quality and continuous improvement.

Background:
The current high level performance measures applicable in Asset Deployment are the existing Corporate Scorecard Performance Measures: *In-Service Capital–Transmission* and *In-Service Capital–Distribution*. High level performance measures within the corporate scorecard are based on pre-defined budget targets and in-service dates. These measures were designed for reporting to the Board. They do not provide the detail needed to effectively measure the performance of the end-to-end Asset Deployment process. With only these measures in place, they can become the exclusive focus of management. The lack of Key Performance Measures for the end-to-end Asset Deployment process puts Hydro One at risk of increased costs due to inefficient processes, rework and churn due to the just-in-time approach to its internal processes, and poses risk to post in-service support (e.g. close-out reporting process, post in-service emergency and corrective demand work).

Observations:
There is no coordinated set of KPIs that establish performance of the end-to-end Asset Deployment process.
Existing Corporate Scorecard Performance Measures include:
Corporate Scorecard:
-In-Service Capital – Transmission (% of Plan)
-In-Service Capital – Distribution (% of Plan)
Accomplishments are based on spend vs. budget.
These high profile performance measures are lagging (retroactive) and therefore do not provide an effective means or incentive to identify timely adjustments to processes, performance and continuous improvements.

Risk:
The lack of measures that track performance throughout the asset deployment process exposes Hydro One to risks to its corporate strategic objectives and inability to identify and correct process and control issues.

Recommendation:
Establish Key Performance Indicators (KPIs) within each business function affecting the Asset Deployment process with the ability to aggregate up at the COO level to provide an indication of Asset Deployment effectiveness. The KPIs should provide incentives for management to drive quality and continuous improvements (i.e. drive efficiencies and productivity through improved process, controls, tracking, monitoring and reporting). Include leading measures to provide indications for areas that require more management focus and attention.

Management Response: *(Sandy Struthers – COO & EVP Strategic Planning)*
Agree

Proposed Action Plan:
A plan will be created to establish KPIs from contributing LoB business leads to provide monitoring of the end-to-end Asset Deployment process. As noted above, working with Internal Audit who will act as the facilitator as noted in recommendation 1 establish reasonable LoB metrics which can be easily tracked that will meet the issues identified, consistent with the objective of affecting improved Asset Deployment Effectiveness.

Completion Date:
Q3, 2015

4. There is a lack of controls (e.g. QA/KPIs) in place to ensure effective project estimating.

Background:
The present estimating process originates from a comprehensive and well-documented set of procedures [7]. The procedures include goals and objectives, role descriptions, quality objectives, flow diagrams, instructions to ensure proper documentation within SAP (e.g. using Work Breakdown Structures). A Centralized Estimating Site (CES) process has been established (in place since the beginning of 2014) to improve management of Appropriation Requests (ARs) to drive efficiencies and embed needed controls. The site uses SharePoint as a central platform for managing estimates for new projects and includes additional features such as revision control, status tracking, digital signatures for streamlined approvals and workflow features to help drive the estimating process along. This site facilitates the transparency of the process status and is a very positive step forward for process improvement with built in process controls. The solution has been up and running for about a year and is considered by management to be stable. While individual project tracking is available from this site, there is no systematic reporting or roll-up of all projects in the system. Management agrees that there are opportunities to leverage this system that are not yet in place.

The CES provides an interface between the estimating group (Project Definition) and other LoBs (including Asset Management, Project Management, etc.) There have been other changes underway driven by the recent changes in management and organizational structure to accommodate the recent ramp up of project work volume.

Observations:

a) The project estimating process is inconsistently applied, i.e. not always applied as it was designed to function. This was identified as a gap in the 2012 CSA and is continuing to occur. There are inconsistencies between LoB approaches (e.g. Project Management uses costing and Stations Scheduling uses labour hours for estimating). Bypass of the process is done occasionally to fast track

[7] E&CS Front End Planning Procedures Manual, 2009

efforts to accelerate large volumes of capital work through the existing estimating process. This situation is further complicated by a lack of thorough understanding of the estimating and project definition processes. The new CES provides improved documenting, approval, status and tracking controls over the past processes. However, not all LoBs that need to be engaged with this new approach are up to speed; e.g. Construction Services still uses the Knowledge Management System (KMS) and Meridian software. Along with the changes associated with CES and other changes, certain terms such as Categories and Tiers have become unclear.

b) The CES has shed light on a number of ARs that are backlogged (e.g. the Engineering Coordinator for the associated project needs to assign an Engineering Forecast Date before it enters the CES for tracking.) This is a bottle neck in the end-to-end Asset Deployment process and a potential blind spot that should be measured and managed. 54% of ARs in the CES are backlogged; i.e. no engineering coordinator assigned.

c) CES is not yet optimized. There are additional beneficial opportunities for tracking, roll-up reports and reporting along with the integration with related data in SAP, to improve performance of this function. The project definition phase involves use of SAP, Meridian and SharePoint (CES). There may be an opportunity to integrate estimating processes and systems. Re-institution of the Project Closure and Lessons Learned reports (as separate recommendations within this report) will help to resolve this issue. Also, high estimates are believed to be the result of compounding margins and contingencies. However, this topic was not explored in detail since it was beyond the scope of this audit. This area will be audited in more detail as there is a pending Audit on the 2015 Internal Audit work program.

Risks:

- An inefficient estimating and project definition stage can cause delays and additional costs to the asset deployment process (e.g. additional work claims submitted due to inaccurate estimates, unplanned scope changes).
- High variance, unnecessary rework/churn, multiple approvals (e.g. IROVs),
- Working against efficiency/productivity improvements (e.g. consistent overestimating may appear as under achieving from an OEB perspective).

Recommendations:

We recommended to Management that:

a) Project Definition to ensure that there is a clear and unified understanding of the project definition process, including associated terminology, among the LoBs involved in this process.

b) Controls should be established to identify, report and manage the backlog of ARs that have not yet entered the CES and to minimize in the future.

c) Project Definition should explore and identify an integrated solution for overall project definition processes, including project estimation, that optimizes data recorded within SAP.

Management Response: *(CK Ng – Director, Project Definition)*

Agree

Proposed Action Plans:

a) Project Definition to lead the estimating process and associated changes so that involved Lines of Businesses are aligned. Reinforce the estimating process with controls, monitoring of KPIs and feedback to drive efficiencies and effectiveness through continuous improvement of the process. Provide instruction to LoBs to ensure a unified understanding of the project definition process, accountabilities and roles from involved LoBs. (e.g. clarify use of terms such as "categories" and "tiers")

b) *Project Definition will establish controls to identify and manage the backlog of ARs that have not yet entered the CES. Establish measures to track the estimating process (i.e. from CES) and ensure that it is effective and report the process measurement results to management of affected LoBs.*
c) *Project Definition will explore solutions that provide a more integrated approach to the project definition function including the estimating process. (e.g. a solution to better leverage data within SAP)*

Completion Dates:
a) *Q4, 2015*
b) *Q3, 2015*
c) *Q4, 2015*

5. There is a lack of consistent communication to LoB stakeholders throughout the project, involving the deployment of assets.

Background:
LoB stakeholders are not consistently identified early in the planning process and communication is lacking about changes that occur throughout the project life-cycle. Project scope and timing evolves throughout the pre-release stages of planning. While certain LoB stakeholders (typically Construction Services and Station Services) are involved in pre-release planning, at times they find out much later in the project that changes to the scope of the project have occurred and they are not given adequate notice or lead time to adjust to these changes. [redacted]

The largest changes in scope to projects typically occur during the Planning and Project Definition stages. Whereas, once a project has been released, the scope and timeframe for construction and commissioning does not generally change significantly. When these scenarios were discussed with Engineering and Project Management, there was a genuine understanding and quick response for the need for improved communication with LoB stakeholders and how this would be best accomplished by leveraging existing project meetings. This was also identified by management in the 2012 Control Self-Assessment. Follow-up of this item as part of this audit, identified as: *"Wider involvement is needed from all LoBs affected by the project"* has been found to be partially complete. Refer to Figure A3 – Status of Control Self-Assessment 2012 within this report.[8]

[8] Control Self-Assessment Workshop Report - Internal Audit Report #2012-13

Observations:

a) Changes to the project scope at the pre-release stages are not being effectively communicated to all affected LoBs. There have been many extra work claims submitted due to a breakdown in communication of scope changes. From February 2013 to October 2014, 27 IROVs have been submitted. The IROVs indicate a pattern of scope modification.

b) Changes to project scope and/or schedule at the post-release stages are not being effectively communicated to all affected Lines of Business.

The above are pre-existing issues identified in Control Self-Assessment and not fully resolved. Pages 20 to 22 - Summary of Possible Improvement Ideas.[6]

Risk:

Lack of effective communication with contributing Lines of Business can affect the execution and committed in-service dates and project costs, and unnecessarily create resource constraints.

Recommendation:

Establish a protocol and a procedure that ensures more visibility and opportunity to all affected LoB stakeholder including, Station Services for input to pending projects at both the (a) pre-release and (b) post-release stages.

Management Response:

a) (CK Ng – Director, Project Definition)
Agree

Proposed Action Plan:

Project Definition will ensure that Station Services are included in the pre-release planning stages of pending projects.

Completion Date:

Q2, 2015

b) (Brad Bowness – Director, Project Management)
Agree

Proposed Action Plans:

Significant changes to projects (i.e. scope of work, cost, schedule) are reported through our established month-end process. This includes status updates via the standard PP-190 BI report. Variances to major projects are also tabled for discussion to SVP and or EC reviews by the Director of Project Management.

Project Management has a plan to improve downstream communication with the Station Services on changes to project timing and or scope changes using the existing SAP Work Acceptance Process and Integrated Business Unit (IBU) process. An ongoing dashboard of Station Services required hours will be reviewed on a quarterly basis to identify gaps in the current work program. Further, the IBU process will be refined and communicated in Q2 with the review of the 2016 Work Program.

Completion Date:

Q2, 2015

6. Insufficient planning of projects creates unrealistic in-service dates and creates compression on the construction/in-service stages of the Asset Deployment process.

Background:
Lines of Business (LoBs) are often challenged to complete Hydro One's annual work program that requires a cohesive work planning and execution process where success is dependent on the cooperative efforts of multiple Lines of Business (LoB)s. Every work group has their own objectives and targets in the Asset Deployment process. When priorities change for one group and not are communicated well, it affects the targets of other groups, thereby creating compressed time lines at the construction and commissioning stages. This puts the constructability and maintainability of the assets at risk. These have been chronic issues, previously identified in the Control Self-Assessment workshop report (2012) in addition to specific examples noted during this audit.

Observations:

a) Changes in project priorities and timelines prior to release create inefficiencies in some cases, e.g. acceleration of work to accommodate other project work that was delayed. This creates compression to meet unrealistic in-service timelines of affected projects (e.g. scope change of released projects). Examples of this concern were raised in the 2012 Control Self-Assessment workshop as:
   - *"Time compression an issue to do (im)proper Engineering"*, Control Self-Assessment Report[9], page 13.
   - "*Construction only getting part of the story re: early engineering"* Control Self-Assessment Report, Page 13.
   - *"Timing always a challenge based on when drawings are ready" affecting Engineering and Procurement*, Control Self-Assessment, page 12 .

[redacted]

b) Changes in released project schedules create compression in latter stages of the project and have an impact on Stations Services' and Construction Services' ability to mobilize, retain and coordinate resources with appropriate skillsets for the work. Station Services provided several recent examples of this situation:
   - [redacted]
   - [redacted]
   - [redacted]

[9] Control Self-Assessment Workshop Report - Internal Audit Report #2012-13
[10] Deficiency Report Prepared by Station Services

[redacted]

These issues had been previously identified in the Control Self-Assessment and not fully resolved. Pages 20 to 22- Summary of Possible Improvement Ideas and in Item 2 Constructability[11].

Risks:
The status quo exposes Hydro One Networks to the following risks:
- Risk to In-Service date due to delays in approval and release stages.
- Risk to significant cost inefficiencies and resource planning.
- Compression at the construction and commissioning stages can put the Functionality and Maintainability of the asset at risk.

Recommendations:
a) Pre-release: A risk assessment of the project should take into account the impact of changes to cost/resources/operations, etc. on the project/asset deployment horizon so that execution of project work/asset deployment is realistically achievable.
b) Post-release: Establish controls to mitigate compression to Construction Services. Minimize changes to project priorities, particularly once field crews have been deployed. Put controls in place to ensure that once set in motion (i.e. drawings released, Construction Services and/other field crews have been deployed), any further changes to the project are discussed and coordinated with all affected LoBs.

Management Response:
a) Pre-Release (CK Ng – Director, Project Definition)
Agree

Proposed Action Plan:
Establish a process for risk assessments of projects/programs and associated documentation. This is expected to take into account risks to in-service dates, costs and resources.

Completion Date:
Q2, 2015

b) Post Release (Brad Bowness – Director, Project Management)
Agree

Proposed Action Plan:
Project Management will continue to coordinate schedule changes of released work with Stations Services and Construction.. To mitigate compression of executing timelines, Project Management, Engineering and Construction are working with Asset Management to provide "accelerated future year work for early engineering".

Completion Date:
Complete and Ongoing

[11] Control Self-Assessment Workshop Report - Internal Audit Report #2012-13

7. Equipment requiring long lead times for orders/shipments are not being identified with sufficient lead time.

Background:
Lead time is an issue with the order and delivery of large equipment. Under the existing process, Supply Chain is not made aware of potential orders until a requisition is issued. Often, this does not provide sufficient lead time for large equipment to be delivered on time. Generally, it takes about 4 months from work release to Purchase Requisition. Supply Chain is made aware of equipment requirements at later stages of asset planning/asset deployment cycle. It takes another 6-8 weeks to establish a successful proponent through the tendering process.

Observations:
There is a backlog of material and equipment specifications needed to support the tendering process. Tendered contracts are being extended because of this backlog. Supply Chain tracks over 1,100 active contracts. The current 18 month outlook involves tracking 37 commodities (multiple contracts for commodities) affecting over 8,600 Material Masters that cannot proceed to tender since associated technical specifications to support the tendering process have not been received. These are technical specifications required by other LoBs (Engineering, Conceptual Engineering, Asset Management, Lines, etc.). Extensions of the contracts are necessary to accomplish the work program. Although Supply Chain is tracking this status, the lack of a formal process with controls is allowing this backlog to continue.

Management acknowledged that the best supply strategy is to order long lead time equipment as soon as the project is committed and approved. This was also identified and agreed to in the CSA 2012.

Also, there is a backlog of equipment contracts that requires a retendering process. This puts Hydro One at risk of not operating an open, fair and transparent manner[12].

Risks:
- The current backlog of equipment contracts that require a retendering process puts Hydro One at risk of not operating an open, fair and transparent manner[13]
- Insufficient lead time to receive asset places the asset deployment projects at risk - cost escalations and impact to resourcing and in-service plans.
- Delays can be incurred if the assets or materials are not delivered on time and the project is delayed. Resources may not be available to complete the work on schedule.
- Restricted ability for Supply Chain to proceed with contract tenders can result in:
    - Delays in major equipment delivery
    - Multiple extensions of contracts (appears as single source)
    - Loss of opportunities to leverage pricing

Recommendation:
a) Supply Chain, with involvement from Planning, Engineering, should establish and document a process to identify and periodically review long lead time equipment expected for upcoming asset deployment projects. This process should focus on managing equipment posing supply risk to future projects, including backlog of equipment contracts that are past or approaching expiration, and communicate these on a periodic basis to internal stakeholders.

[12] Ontario Government Broader Public Sector Procurement Directive, July 1, 2011.
[13] Ontario Government Broader Public Sector Procurement Directive, July 1, 2011.

b) Supply Chain should actively monitor and report on the status of contracts to senior management. (e.g. track and report contracts that are in place, and which have been extended, single or multiple times) and establish targets for contract status and extensions (i.e. reinforce CoM "Service Getting").

Management Response: *(Sebastian Palazzo– Manager, Strategic Sourcing, Supply Chain Services)*
Agree

Proposed Action Plan:

a) *Supply Chain will take lead action to work with LoB stakeholders Asset Management, Corporate Standards, Engineering and Planning & Project Definition to create a formal set of processes complete with sign offs against key milestones that would allow Supply Chain to properly monitor and measure the process from beginning to end. Supply Chain has already developed a draft responsibility matrix, with Corporate Standards, based on the RACI principles which will be stakeholdered with affected Lines of Business.*
b) *Supply Chain will escalate reporting on status of contracts to COO/Process Owner of end-to-end Asset Deployment process to reinforce action from LoBs required to support the sourcing program.*

Completion Date:

a) *Q4, 2015*
b) *Q2, 2015*

8. There is no quality assurance process for material and equipment for the deployment of assets.

Background:

Construction Services has described situations where equipment and material are directly shipped to the site and in some cases the expected quality is lacking. Construction Services had raised quality of equipment and material during the Control Self-Assessment workshop in 2012[14]. They mentioned *"Quality & condition of material affects constructability"*, *"Construction uses many 'workarounds' when material comes sub-standard – e.g. size of holes in steel"*, *"Pre-fabricated equipment received – may not be adequate"*. Construction Services verified that these issues raised in the workshop two years ago are still continuing. Management also noted that vendors will sometimes substitute material parts without notifying Hydro One. Supply Chain establishes supply contracts for equipment and materials based on specification and performs inspections for large equipment at the manufacturer's facilities to ensure that Hydro One will receive the specified equipment within the expected timeframes. Supply Chain relies on Vendors to ship correct material based on Material Masters/Specifications but there is no mechanism for verification. Once the equipment is delivered to a site for installation and commissioning, Supply Chain has no visibility unless a serious problem arises and they are notified by other LoBs (e.g. Construction, Station Services, Project Management, Engineering) when intervention with the Supplier becomes necessary.

For contracted work, the contractor performs quality control. Project Management assigns a site inspector to ensure that contractors are on site and meets all aspects of the contract including following their own safety plans.

Observations:

[14] Control Self-Assessment Workshop Report - Internal Audit Report #2012-13

There is no quality assurance process that enables Hydro One to record, track, report and take action on equipment and material deficiencies. The lack of a quality assurance process results in no formal feedback mechanism for corrective action back to Supply Chain. Quality problems with materials are presently dealt with in an ad hoc manner.

Management expects that Construction Services will identify any material or equipment quality issues. While Construction Services was able to describe situations where they experienced equipment and material quality deficiencies, they were not able to provide documented examples, i.e. forms/communications pertaining to material/equipment quality issues.

Quality of equipment delivered to site is a continuing issue as described above in the background section e.g. switches built cheaply, material and parts not appropriate for the task that requires customization. Commissioning takes longer and the equipment don't operate properly. This affects build time and cost and increased equipment outages are required to address the issue.

Risk:
Lack of Quality Assurance can result in longer commissioning timeframes and equipment that may later require corrective repairs. This affects build time, cost and increased outages to the power system and large customers.

Recommendation:
Establish a quality control process with monitoring and reporting to internal stakeholders to address deficiencies with material and equipment delivered to site.

Management Response: *(Andrew Spencer – Director, Engineering)*
Agree

Proposed Action Plan:
Create a QA process to ensure material and equipment meet required standards, process and shall be bi-directional between technical authorities and end users (Construction, Station Services, Maintenance &Technical Services) for power system equipment and materials that can impact the major equipment.

Completion Date:
Q4, 2015

9. Staged release of build work to Construction and Station Services creates inefficiencies.

Background:
The most efficient workflow exists when drawings, materials and equipment are delivered to a site in advance of Construction Services and Station Services staff commencing the work. Complete sets of drawings provide the full set of information required for the work to be completed. Timely delivery of material and equipment reduces delays and workarounds that add time and cost to the project. Traditionally, design drawings have been delivered as they become available from Engineering. This was previously identified in the Field Marked Print Internal Audit report[15]and in the 2012 Control Self-Assessment workshop. Engineering has an action plan to establish a process for coordinated issuance of drawing package releases across engineering disciplines. The Project Definition group considers staging[16]

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[15] 2014-09 Internal Audit Report – Field Marked Prints, Recommendation 3.4(a)
[16] The internal staging process can be viewed in ***Figure D1, Appendix D- Project Services-EPC Process***

asset deployment projects internally as an advantage, using a just-in-time design and engineering to keep the work flowing. However, this creates other problems of rework, redesign and resource redeployment, when the flow of the just-in-time approach wanes. Outside contractors are provided more detailed scope of work specification since this level of detail is a necessary as part of the tendering process. With the internal workforce, Planning and Engineering provide less defined scope documents.

Observation:
For internally engineered projects, Construction Services and Station Services typically receive drawings, equipment and materials in a just-in-time approach. This creates problems and inefficiencies for these LoBs when they are late. Their experience is that work packages prepared for outsourcing are a better approach because the entire work package is delivered at one time. The complete package provides a better perspective on the work required and more efficient work planning and execution. There are benefits to Hydro One providing work packages in stages by discipline, however this needs be performed with a more managed approach. Management has acknowledged this issue and has begun to take steps to improve related processes. E.g. Engineering has started focusing on the design of future work, to move away from a just-in-time approach but requires communication and culture change to take effect. This is a joint initiative with Project Management, early upfront discussion and commitment with PM to what the Engineering milestones and deliverables are in timeframe and degree of completeness.

Risk:
The status quo exposes Hydro One Networks to a risk of delays In-Service dates due to delays in approval and release stages.

Recommendation:
Establish protocols and agreed to timeframes for input from stakeholder LoBs involved in the asset deployment process for build stage release approaches that work best. Achieve complete release of drawings and materials by discipline e.g. civil, mechanical, electrical. Ongoing communication between Project Management, Engineering, Construction Services and Station Services is key.

Management Response:
Actions were received from both Engineering and Project Management to address the recommendation.

a) (Andrew Spencer– Director, Engineering)
Agree

Proposed Action Plan:
Establish a Performance Measure to increase the proportion of engineering work completion in advance of construction start.

Completion Date:
Q2, 2015

b) (Brad Bowness – Director, Project Management)
Agree

Proposed Action Plan:
Project Management is accountable to conduct a "project kick-off" meeting with applicable project partners at the start of project execution. This meeting will address key milestone dates and timelines of engineering deliverables and environmental approvals to support Construction

and Stations, project risks, and outage staging requirements. This process already exists. Emphasis and clarification of this process will be given to the Project Management division.

Completion Date:
Q2, 2015

10. Lack of consistent project close-out process.

Background:
Interviews with stakeholder LoBs clearly revealed a lack of consistent project close-out execution and communication. In addition, a recent presentation from management[17] highlighted the fact that E&C Project Management is not consistently following its close-out process as documented in SP 0738[18]. The Close-out process is documented in the Front End Planning Procedures Manual – Section 1.6, Sheet 8a and Project Management Services Presentation (Q4, 2014). Lessons Learned is a sub-process to the Close-out process.

Observation:
The existing Project Close-out process is not being tracked or consistently applied. Project Management has surveyed stakeholder LoBs for input to what should be included in the Project Close-out process and is in the process of implementing changes that will provide an improved project close-out and monitoring to ensure the new process is consistently executed.

Risks:
The status quo exposes Hydro One Networks to the following risks:
- Inefficiencies and cost and time overruns due to repeating mistakes from one project to another.
- Lack of continuous improvement.

Recommendation:
Continue efforts to implement the improved Project Close-out process and implement monitoring to ensure that the Project Close-out process is completed that includes close-out documentation (e.g. reports, minutes of meetings, follow up action tracking).

Management Response: *(Brad Bowness – Director, Project Management)*
Agree
Proposed Action Plans:
Project Management re-introduced the Project Close-Out Process in 2014. Further efforts are underway to ensure projects greater than $5M have a close-out document completed and that stakeholder feedback and reviews are completed in the interest of continuous improvement.

An executive summary of these project close-outs and reviews is being created and is expected to be functional for communicating by the end of second quarter.

Completion Date:
Q2, 2015

[17] Project Close Out Process, Q4-2014 (Project Management Services SharePoint)
[18] SP 0738 Project Management Policy, June 2011

11. Official documentation records are in silos. Network Management Instruction (NMI), HODS, Network Operating Document System (NODS) and Engineering Standards (on SharePoint) do not enable transparency across LoBs.

Background:
Hydro One's multiple document systems perpetuates a silo perspective and is counterproductive for asset deployment, a process that involves numerous LoBs. The recent redesign of HODS made the system more intuitive, easy to use with greater search capability and a faster stakeholdering process. HODS documents are used by all employees and must not be copied or duplicated in any other system[19]. NMIs are primarily used by NOD and exist because NOD needs the ability to revise and reissue an update immediately. NMIs contain other LoBs accountabilities in their documents and there is no standardized process for stakeholding and not consistent with related HODS documents. Cross referencing of documents sometimes create confusion when one document is updated in one system and not in another or documents do not refer back to each other. Similar issues were noticed with information in Engineering Standards in SharePoint duplicating information in HODs.

Observations:
A detailed audit of documentation systems is beyond the scope of the Audit. However, this audit uncovered examples of documents within the NMI and HODS systems that are not aligned or coordinated. There are several separate official documentation repositories with no cross-reference between document systems.
For example:

- NMI 0525 NOD Change Control Accountabilities for Installing, Changing or Removing Assets, indicates alignment with HODS but does not refer to a specific HODS.
- NMI 7037 Operation of the Circuit Breaker Control Selector Switch refers to HODS SP 1118 for direction but the HODS does not refer back to NMI 7037.
- NMI 7051 Stations Insulator Contamination Monitoring provides work direction to other LOB's with no means of confirmation that the work direction was accepted or a documented process exist in HODS.
- There are no clear guidelines about the type of documents (and subject matter) contained within these systems, which contributes to the siloes (e.g. Procedural document in Engineering Standards.)
- HODS drives best practice, such as a stakeholdering process. This is not always the case, e.g. unlike HODS documents, Engineering Standards (i.e. when the subject matter affects other LoBs) are not adequately stakeholdered – NB: This area is in the 2015 audit plan.

Risks:
The status quo exposes Hydro One Networks to the following risks:

- Lack of awareness of processes and procedures.
- Lack of coordination amongst LoBs using the various documentation systems.
- Threat to timely and correct completion of capital and sustainment work programs.
- Financial risk – escalating project costs due to work inefficiencies.

Recommendation:
We recommend that management conduct a review to ensure that staff can effectively and efficiently retrieve all the necessary documents relevant to their work relating to the Asset Deployment process[20].

[19] HO 1806 HODS Governance, 2014/07/15
[20] In reference to the documented named in the examples of the Observation section above.

Management Response: *(Sandy Struthers – COO & EVP Strategic Planning)*

Disagree. The recommendation is nebulous and does not address the fundamental issue which is not clearly articulated.

Proposed Action Plan:

Senior Management will discuss with the input and guidance of internal audit the desire and need to replace and modernize the HODS system. From that discussion, a decision will be made to direct IT to investigate technical options available to the Company to modernize its document record system in accordance with good practices demonstrated in other jurisdictions. The COO will raise this item for discussion at the EC.

On an ongoing basis where documents are identified in systems as being inconsistent and hence presenting an issue as to Asset Deployment the inconsistency in documents will be highlighted, brought to the attention of the Director, Work Program Management recorded, provided to Asset Management to resolve and to report back on their resolution. On a quarterly basis the number of documents identified and in progress will be reported at the EC month end review.

Completion Dates:

Q4, 2015

BACKGROUND

Asset Deployment in 2012

The Internal Audit Department's (IAD) 2012 work program included an operational audit of "Commissioning". During the preliminary scoping phase of this audit, it became clear that there were known challenges in the processes, from concept through to in-servicing, that needed to be identified and addressed in order to effectively place equipment into service (i.e., Asset Deployment).

The Asset Deployment success is defined by the achievement of the following four objectives:

a) Functionality – The functional requirements of the asset are met in a compliant manner.
b) Constructability - The asset can be constructed in a safe, efficient and compliant manner.
c) Operability - The asset can be operated in a safe, reliable and compliant manner.
d) Maintainability - The asset can be maintained in a safe, efficient and compliant manner.

When the 2012 Audit was being planned, management acknowledged that there were serious problems with the end to end Asset Deployment process. It was decided by management and IA that the best way to proceed was to conduct a Control Self-Assessment (CSA) workshop to review the process for Asset Deployment – from the point where the requirements of a new asset are identified, up to the point where the asset is in-service and operating, in lieu of the planned Audit.

The five key steps to the deployment of an asset are as follows.

1. Needs Requirements - Needs, Functional Requirements and Single Line Diagram
2. Engineering - Facility Design, Equipment Specifications and Project Plan
3. Procurement - Tender, Evaluation, Recommendations and Award
4. Construction - Construct and Quality Assurance
5. Commissioning / In-Servicing - Functional Checks, Test Results and Documentation

Note: These key processes are not organization-based. Figure A2 provides more detail and a process flow view of these keys steps.

The details of the workshop discussions were captured in a report and presented to the workshop sponsors' representatives. An action plan was developed to address and implement the gaps in the effectiveness of Asset Deployment over the next year. An updated summary of the Status of Improvement ideas are listed in figure A3 and the suggested improvement ideas were used as the basis for the 2014 Asset Deployment Audit.

Asset Deployment in 2015

The completion of Hydro One's annual work program requires an integrated work planning and execution process where success is dependent on the cooperative efforts of multiple Lines of Business (LoB)s. Internal Audit met with the six LoB representatives (Figure A1) involved in supporting the Asset Deployment process; Planning, Project Management, Engineering, Supply Chain, Construction Services and Station Services.

Each group's accountabilities within the Asset Deployment process are described below;

Planning:

- **Asset Management (Sustainment Planning):** This group develops programs and plans to manage both new and existing assets, integrating and prioritizing all work plans, both capital and OM&A.
- **System Planning:** System Planning is responsible for the delivery of the transmission development work program to meet reliability, performance and connection needs of Hydro One

transmission customers. The group manages customer connections to the transmission Network - both load and generation.

- **Project Definition:** Prepares Advanced Engineering Packages (AEP) for scope development and Conceptual Design Package (CDP) for Estimate. Coordinates estimates compilations and builds-out the lower level WBS/Work Orders as per estimate.

Engineering: Engineering's role is to perform the detailed engineering, designs and drawings for released projects.

Supply Chain: The Supply Chain role is to source materials and services required for the effective deployment assets.

Project Management: Their role is to assess scope sufficiency, work acceptance, contract management, coordinate work, provide best advice and the management of all execution functions.

Construction Services: Construct as per specification and design.

Station Services: Commission, in-service and perform ongoing maintenance of equipment.

The Asset Deployment Process

The Asset Deployment process is divided into six functional segments (Figure A2). It begins with the identification by System Planning to install or replace an asset.

A Planning Spec. is developed and a preliminary project plan is created by Planning (AM) which identifies the asset need. Outsourcing considerations are evaluated at this stage and a PM is assigned to the project. Request for estimates are submitted along with the high level Work Breakdown Structure (WBS) items in SAP. This stage often involves consultation among the LoBs involved.

A PPP (Preliminary Project Plan) and/or AEP (Advanced Engineering Plan) is created by Project Definition. The estimate and plan is created and sent to Planning for review. Requests for Estimate are sent to Engineering based on the identified scope. Once the detailed estimate is complete, it is sent back to Planning for review, approvals and release.

The next step is the Work Acceptance process - by Investment Administrators/Managers – At this stage, there is an opportunity to collaborate with Planning, Project Management and Engineering to refine the work and work estimate. Once the work has been accepted by the PM, the project is released for execution and a project kick off meeting is held. The approved business case, funding and in-service date are all entered into SAP and a detailed project schedule is created.

Drawings are prepared and major materials/equipment ordered in SAP. Once the drawings are issued the RFP process begins for material/equipment and materials/equipment are shipped to the site. The outage plan is created and the construction phase begins. Outages are requested and issued and the equipment is built followed by function testing and commissioning. Once the work is completed, the equipment is placed in service and the project is closed followed by a lessons learned report (for large projects).

The goal at the end of the process is to have a fully functional, operable and maintainable asset.

FIGURE A1 - ORGANIZATION CHART – ASSET DEPLOYMENT

October 2014 to January 2015

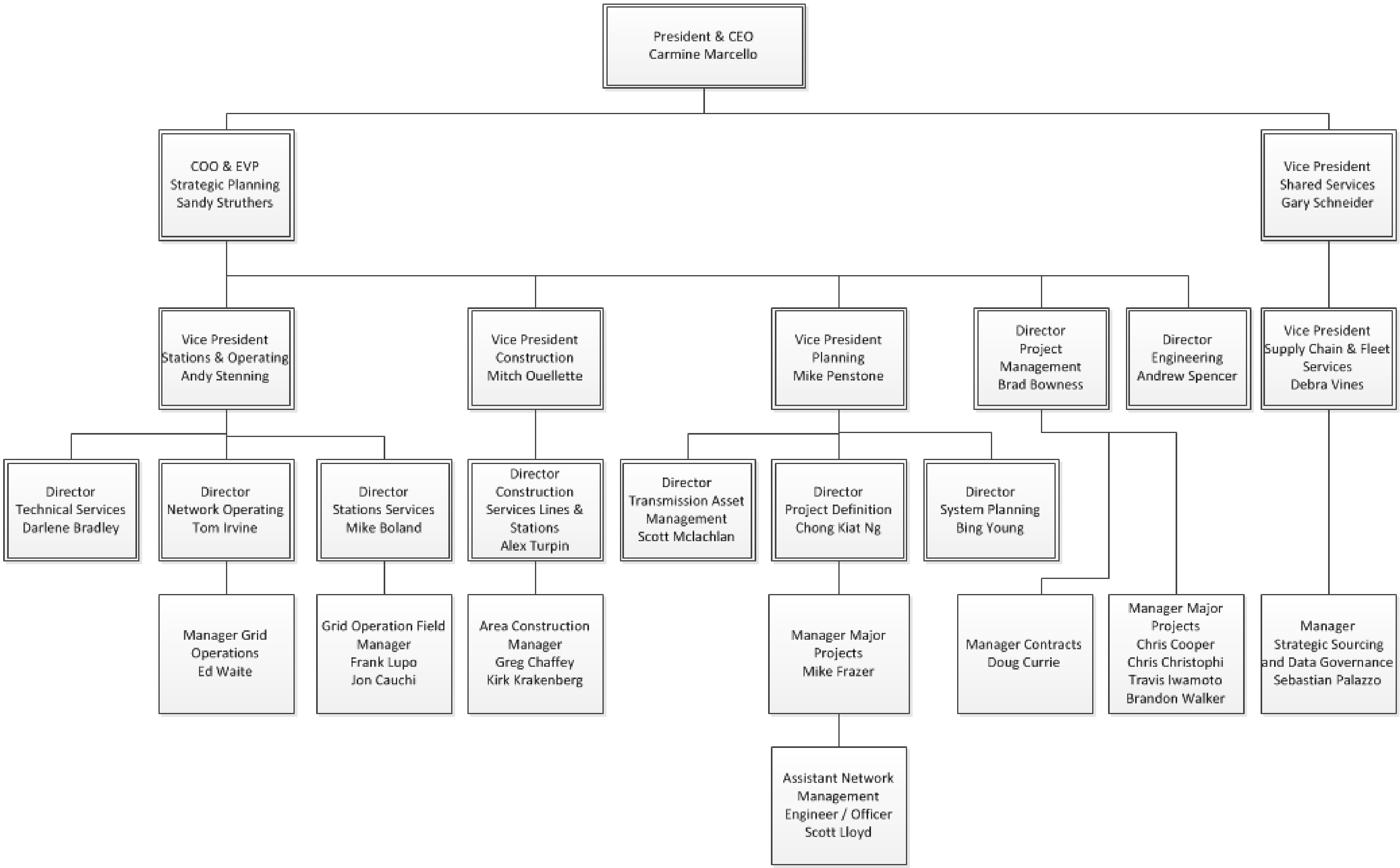


FIGURE A2 ASSET DEPLOYMENT PROCESS
As documented in the 2012 Control Self-Assessment

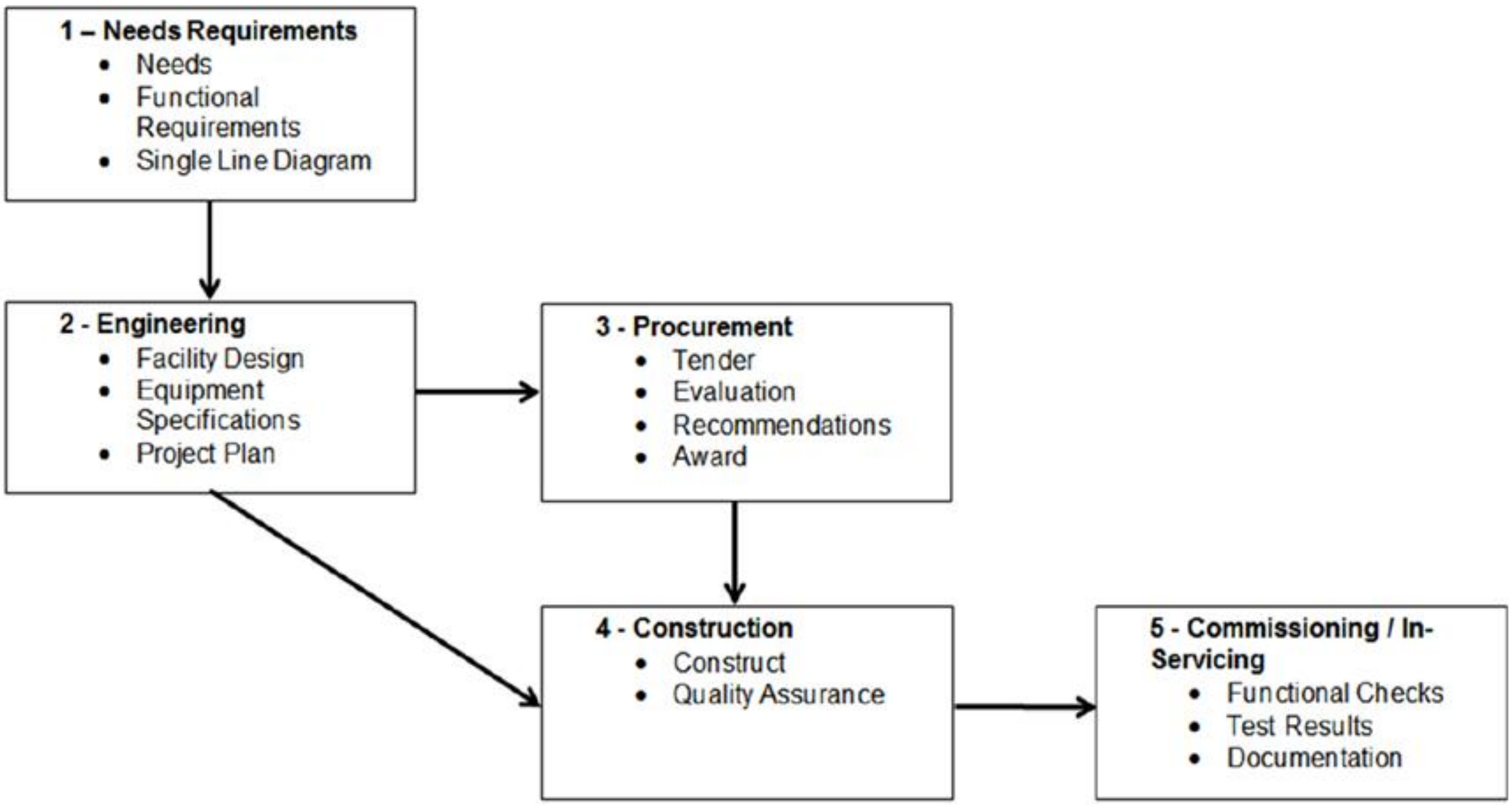
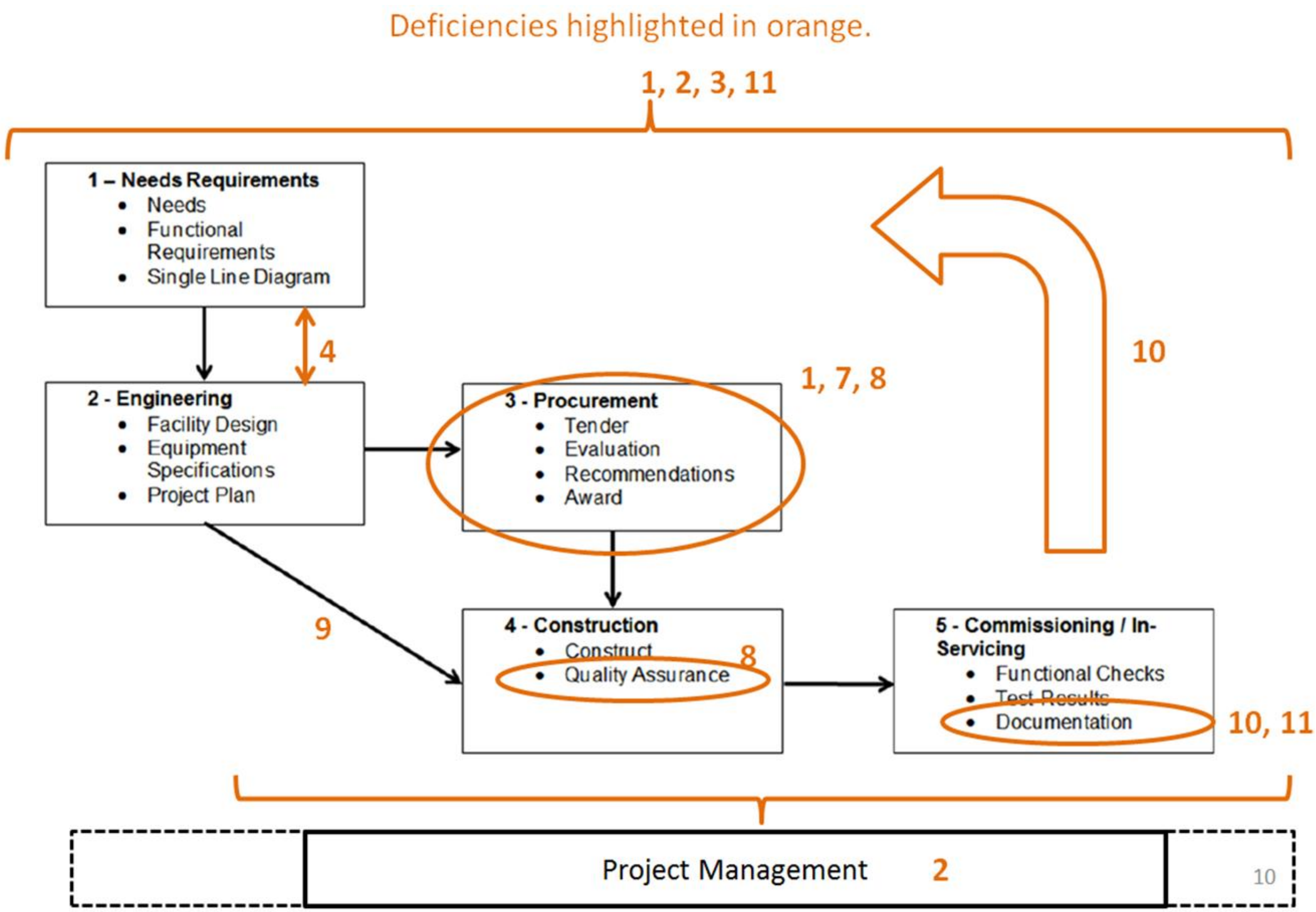


FIGURE A3 – STATUS OF CONTROL SELF-ASSESSMENT 2012

STATUS OF "IMPROVEMENT IDEAS" from CONTROL SELF-ASSESSMENT

2010 Control Self-Assessment - Possible Improvement Ideas (Rpt#2012-04):	**Internal Audit Observations - November 2014**	**Rating**	**IA Finding Reference**
1. **More holistic view of work needed at entire station, e.g. Burlington TS.**	<u>COMPLETE</u> Management has put in place a station-centric approach to project and programs work.		**n/a**
2. Corporate Wide Lessons Learned process.	<u>PARTIALLY COMPLETE</u> Management has established a Lessons Learned database however; this tool has not been widely rolled out or formally supported.		**1**
3. More prescriptive details required in Functional Spec. and Project Definition.	<u>INCOMPLETE</u> A lack of clarity as to appropriate level of details in the Functional Spec. and Project Definition still exists.		**4, 5, 6, 9**
4. The plan to implement equipment with long lead times required for purchase must be provided to Procurement earlier in the planning process.	<u>INCOMPLETE</u> Supply Chain function is still calling for upfront business plans to ensure that equipment with long lead times can be effectively managed. There is a backlog of incomplete technical specs to support overdue tendering process.		**7**
5. Wider involvement is needed from all LoBs affected by a project.	<u>PARTIALLY COMPLETE</u> Several meetings with multiple stakeholders still proving to be insufficient to identify and communicate needs and changes to ensure asset functionality, constructability, operability and maintainability.		**5**
6. There is a need for information pertaining to future assets, sooner in the planning/project timeline. • Need asset real-time data strategy – for a piece of equipment – for operating, maintenance, and Asset Manager.	<u>INCOMPLETE</u> Information needs of involved LoBs still need to be identified and addressed.		**6, 7**
7. FREIS report – accountability needs to be clear.	<u>COMPLETE</u> The process and design of forms have been recently updated to be more streamlined and improve clarity of accountability.		**1, 9, 11**
8. Need Maintenance Strategy – including SAP and operating and maintenance training.	**Will be reviewed in a separate Internal Audit**		**N/A**

FIGURE A4 ASSET DEPLOYMENT PROCESS



AUDIT OBJECTIVE AND SCOPE

Objective:
The objective of this audit was to assess the controls in place to effectively deploy power system assets.

Scope:
The scope of this audit included power system station assets with a focus on transmission station projects and programs. This audit included a follow up status of the findings, 'possible improvements' and the Asset Deployment process identified within the Control Self-Assessment workshop report[21] and the Engineering and Construction Services Work Program – Key Improvements presented in May 2014 to the Executive Committee.

Approach:
This audit included the following activities:

- Review the existing process documents and associated policies and procedures.
- Interview 26 key management and staff in 6 LoBs with accountabilities and/or roles relating to this subject. See table (Appendix E) and reference evidence table (Appendix F)
- Document the process flow for audit purposes.
- Identify key internal controls that provide assurance relative to the audit objective.
- Evaluate the adequacy of internal controls.
- Test samples of information and documentation relating to the audit scope.
- Recommend improvements, where appropriate.

Disclaimer:
In this report, we provide suggestions for improving controls to mitigate the risks identified. These recommendations may not be the only solution, nor are they intended to be prescriptive as to management's action. It is management's responsibility to ensure that they develop and implement action plans that are both cost-effective and address the risks identified in this report.

[21] Control Self-Assessment Workshop, Asset Deployment Effectiveness, May 3, 2012, IAD Report #2012-03

CONTROL ASSESSMENT SUMMARY

Key Findings Related to the Control Objectives Reviewed	Assessment of Controls	Residual Risk[22]
1. Oversight - There is no high level oversight of the Asset Deployment process.	Ineffective	H
2. Risk Management - Risks relating to deployment of assets are contemplated but not formally documented or managed at a high level.	Ineffective	M
3. Performance Measures - Existing performance measures do not provide incentives for quality and continuous improvement.	Ineffective	M
4. Estimating Controls - There is a lack of controls (e.g. QA/KPIs) in place to ensure effective project estimating.	Needs Improvement	M
5. Communication - There is a lack of consistent communication to LoB stakeholders throughout the project, involving the deployment of assets.	Needs Improvement	M
6. Project Management - Insufficient planning of projects creates unrealistic in-service dates and creates compression on the construction/in-service stages of asset deployment process.	Needs Improvement	M
7. Procurement -Equipment requiring long lead times for orders/shipments are not being identified with sufficient lead time.	Needs Improvement	H
8. QA - There is no quality assurance process for material and equipment for the deployment of assets.	Ineffective	M
9. Staged Release - Staged release of build work to Construction Services and Station Services creates inefficiencies.	Needs Improvement	M
10. Project Close-Out - Lack of consistent project close-out process.	Ineffective	M
11. Records - Official documentation records are in silos. NMI, HODS, NODS, and Engineering Standards do not enable transparency across lines of business.	Needs Improvement	M

CONTROL AND RESIDUAL RISK ASSESSMENT LEGEND:

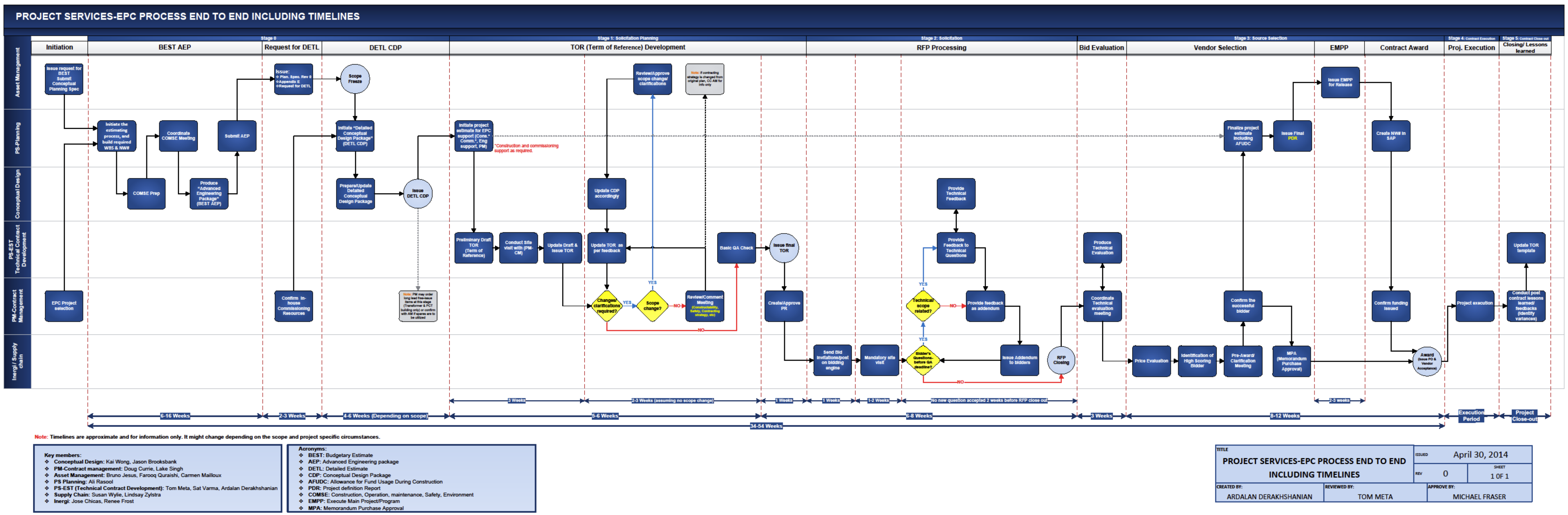
Auditor's Assessment of Control	
Assessment	**Assessment Indication**
• Best Practice Identified or • Small number of Minor Weaknesses	Good
• Numerous Low risk issues and / or systemic weaknesses	Needs Improvement
• Major weaknesses found	Ineffective

Auditor's Assessment of Residual Risk[23]	
Assessment	**Assessment Indication**
Low The risk will not substantively impede the achievement of the objective, causing minimal impact over the achievement of the organization's objectives.	L
Medium The risk will cause some elements of the objective to be delayed or not be achieved, causing potential negative impacts to the organization's strategic objectives.	M
High The risk will cause the objective to not be achieved, causing negative impacts to the organization's strategic objectives.	H

[22] Refer to ***Appendix G*** for the resulting Summary of Actions by management.
[23] Residual risk level is defined as the possibility that an event will occur which will impact an organization's achievement of objectives based on the effectiveness of controls in place observed during this audit. Residual Risk of individual control objective components is provided in ***Appendix G***: *Summary of Actions.*

PROJECT SERVICES-EPC PROCESS

FIGURE D1 EPC (Engineering, Procurement, Construction) PROCESS – Illustrates project staging in Observation #9
(This process aligns with Steps 2, 3 and 4 within the Asset Deployment End-to-End Process Illustrated in Figure A4)



EPC Process End to End

For a larger view of this document, open attachment or print separately.

INTERVIEW LIST

Name	Title	LOB	Date
Mitch Ouelette	Vice President, Construction Services	Construction Services	Pre audit meeting
Alex Turpin	Director Construction Services Lines & Stations	Construction Services	Wednesday Nov.12
Greg Chaffey	Area Construction Manager	Construction Services	Wednesday Nov.12
Kirk Krakenberg	Area Construction Manager	Construction Services	Wednesday Nov.12
Andrew Spencer	Director, Engineering	Engineering	Thurs. Nov.6 PM
Mike Penstone	Vice President, Planning	Planning	Pre audit meeting
Scott McLachlan	Director, Transmission Asset Management	Planning	Monday Dec 08
Bing Young	Director, System Planning	Planning	Monday Nov. 17
CK NG	Director, Project Definition	Planning	Monday Nov. 24
Mike Frazer	Manager, Major Project	Planning	Wednesday Feb 4th
Scott Lloyd	Assistant Network Management Eng/Off	Planning	Wednesday Feb 4th
Brad Bowness	Director, Project Management	Project Management	Pre audit meeting
Chris Cooper	Manager, Major Project	Project Management	Thursday Nov 6 AM
Chris Christophi	Manager, Major Project	Project Management	Thurs. Nov.11 PM
Travis Iwamoto	Manager, Major Project	Project Management	Thurs. Nov.11 PM
Doug Currie	Manager, Contracts	Project Management	Tuesday Nov. 18
Brandon Walker	Manager, Major Project	Project Management	Thursday Jan 8
Debbie Vines	Vice President, Supply Chain & Fleet Services	Shared Service	Pre audit meeting
Sebastian Palazzo	Manager, Strategic sourcing & Data Governance	Shared Service	Thursday Nov. 13
Andy Stenning	Vice President, Stations and Operations	Stations & Operating	Pre audit meeting
Mike Boland	Director, Station Services	Stations & Operating	conf call 30 min. Mon. Nov.3
Darlene Bradley	Director, Technical Services	Stations & Operating	Monday Dec 15 PM
Tom Irvine	Director, Network Operating	Stations & Operating	Pre audit meeting conf call
Ed Waite	Manager, Grid Operations	Stations & Operating	Monday Nov. 10 PM
Jon Cauchi	Grid Operations Field Manger	Stations & Operating	Wednesday Nov 26 AM
Frank Lupo	Grid Operations Field Manger	Stations & Operating	Wednesday Nov 19 AM

EVIDENCE LIST

Evidence List

1. Oversight

Lessons Learned information retrieved from the SharePoint site: Project Management Services-Project Management Processes-Process Areas. Category: Lessons Learned
https://teams.hydroone.com/sites/ecs/pm/PITQA/Processes%20%20Templates/Forms/Continuous%20Improvement.aspx

- Lessons Learned Process Directive June 2012
- Lessons Learned Refresher February 2015
- Lessons Learned Data Base
- Work acceptance by E&C (Appropriation Request Review)

Assessment of IROVs and Lessons Learned-Briefing Note dated April 2013 (Received from Darlene Bradley)
Details of the top 15 IROVs from 2009-2012 supporting the briefing note above.
OM&A cost associated with Breakers & Transformers. (Supporting documentation received from Barry Mirzaei)
HODS 1304 Value Realization Corporate Operational Policy
IROVs from 2012-2013 refer to section 5
Control Self-Assessment (IAD Report #2012-03), Page 20-22

2. Risk Management

SP0736 Enterprise Risk Management Policy

3. Performance Measures

Performance Measures Descriptions

- [redacted]
- Distribution (Dx) In-Service Capital

Interview notes with VP, Planning; Director, Engineering; Director, Asset Management; Manager, Major Projects

4. Estimating Controls

Email from Manager, Major Projects; Project through FEP process- clarification question
Advanced IM Concepts for Conceptual Design presentation
CES SharePoint Site https: //teams.hydroone.com/sites/777/SitePages/Home.aspx
CES Job Aid for Team Lead and Managers
Project Services Estimating Road Map
CES Workflow Diagram
Memorandum: Review Of Organizational Structure and Internal Processes – EC&S Feb 4, 2004
Email from Manager, Major Projects; Project Management software
Control Self-Assessment (IAD Report #2012-03), Pages 20-22

5. Communication

IROVs Examples:

- [redacted]
- [redacted]
- [redacted]
- [redacted]

- [redacted]
- [redacted]
- [redacted]

Control Self-Assessment (IAD Report #2012-03), Pages 20-22

6. Project Planning
Compression Examples from Stations and Project Management
List of AR (Appropriation Request) Approved and Under Review for Contents of Scope, Cost and Schedule
Control Self-Assessment Page 20-22, Item 2 Constructability

7. Ordering Lead Time
List of Outstanding Technical Specification (Material Masters)
Control Self-Assessment (IAD Report #2012-03), Page 20-22

8. Quality Assurance
Interview notes – Director, Engineering; Manager, Supply Chain; Construction Services (3 contacts)
Control Self-Assessment (IAD Report #2012-03), Page 13

9. Stage Release
Director, Engineering, Meeting notes
Compression Examples from Stations and Project Management
Project Services-EPC Process end to end including timelines
Control Self-Assessment (IAD Report #2012-03), Page 20-22

10. Project Close-Out
SP 0738 Project Management Policy
Project Close-Out process – Front End Planning Procedures Manual – Section 1.6, Sheet 8a
Project Close-Out Process Q4 2014 information from retrieved the SharePoint site: Project Management Services-Project Management Processes-Process Areas. Category: Project Closure
https://teams.hydroone.com/sites/ecs/pm/PITQA/Processes%20%20Templates/Forms/Continuous%20Improvement.aspx

11. Records
Evidence from Director, Environment email
Interview Notes from Manager, Operating
NMI #0525 Example
NMI #7051
NMI #7037
SP 1118
NMI 7037

SUMMARY OF ACTIONS

Observation	Risk	Recommendation	Action Plan	Accountability	Completion Date
1. There is no high level oversight of the Asset Deployment process.					
There is no single authority or governance structure with high level oversight of the Asset Deployment process (from Plan/Release through to In-servicing). Each LoB is limited to its own accountabilities to address concerns. Despite reorganization efforts, most issues raised during the Control Self-Assessment in 2012 still exist.	H	Establish a single point of accountability (Process Owner) for the overall end-to-end asset deployment process. Ideally, the Process Owner would establish oversight controls (e.g. conduct periodic meetings including LoB/Asset Deployment stakeholders and report on process status and identify opportunities for further improvement). The Process Owner would establish and monitor key processes to identify process improvements and facilitate cross-LoB process improvements.	The COO will request Internal Audit to attend a meeting with the appropriate line of business VP's and the Director of Engineering to lead the group through and to review the issues identified through this audit. The Director of Work Program Management will attend and a mitigation plan will be established that will be tracked by the Director of Work Program Management for the COO.	COO	Q3, 2015
2. Risks relating to deployment of assets are contemplated but not formally documented or managed at a high level.					
Risk considerations are fragmented, left to individual LoBs looking at risks associated with their own accountabilities. There is a lack of a consistent risk assessment approach from an overall end-to-end Asset Deployment process and a uniform process to identify, measure, treat and report on key risks as per SP 0736 (Enterprise Risk Management Policy).	M	Establish a high level (cross-LoB) risk assessment approach to address risks of the overall Asset Deployment process.	The COO will request Internal Audit attend a meeting with the LoB VP's and Directors' as noted above to talk about how a One Company approach can be used to address issues related to work initiation, project risk identification, etc. If appropriate and if the business agrees a risk register will be established but at a minimum it will be agreed that the interlinked business process, issues and inefficiencies will be discussed for action to be taken annually.	COO	Q3, 2015

Observation	Risk	Recommendation	Action Plan	Accountability	Completion Date
3. Existing performance measures do not provide incentives for quality and continuous improvement.					
There is no coordinated set of metrics that establish performance of the end-to-end Asset Deployment process.	M	Establish metrics within each business function affecting the Asset Deployment process with the ability to aggregate up at the COO level to provide an indication of Asset Deployment effectiveness. The metrics should provide incentives for management to drive quality and continuous improvements (i.e. drive efficiencies and productivity through improved process, controls, tracking, monitoring and reporting). Include leading measures to provide indications for areas that require more management focus and attention.	A plan will be created to establish metrics from contributing LoB business leads to provide monitoring of the end-to-end Asset Deployment process. As noted above, working with Internal Audit who will act as the facilitator as noted in recommendation 1 establish reasonable LoB metrics which can be easily tracked that will meet the issues identified, consistent with the objective of affecting improved Asset Deployment Effectiveness.	COO	Q3, 2015
4. There is a lack of controls (e.g. QA/KPIs) in place to ensure effective project estimating.					
The project estimating process is inconsistently applied and there are inconsistencies between LoB approaches.	M	a) Project Definition to ensure that LoBs have an understanding of the estimating process and establish alignment of LoBs to the process. Ensure that there is a clear and unified understanding of the project definition process including associated terminology among the LoBs involved in this process.	a) Project Definition to lead the estimating process and associated changes so that involved Lines of Businesses are aligned. Reinforce the estimating process with controls, monitoring of KPIs and feedback to drive efficiencies and effectiveness through continuous improvement of the process. Provide instruction to LoBs to ensure a unified understanding of the project definition process, accountabilities and roles from involved	Planning – Project Definition	Q4, 2015

Observation	Risk	Recommendation	Action Plan	Accountability	Completion Date
			LoBs. (e.g. clarify use of terms such as "categories" and "tiers")		
		b) Controls should be established to identify, report and manage the backlog of ARs that have not yet entered the CES.	b) Project Definition will establish controls to identify and manage the backlog of ARs that have not yet entered the CES. Establish measures to track the estimating process (i.e. from CES) and ensure that it is effective and report the process measurement results to management of affected LoBs.	Planning – Project Definition	Q3, 2015
		c) Project Definition to explore an integrated solution for project estimation and overall project definition processes and optimize data collected within SAP.	c) Project Definition will explore solutions that provide a more integrated approach to the project definition function including the estimating process. (e.g. a solution to better leverage data within SAP).	Planning – Project Definition	Q4, 2015
5. There is a lack of consistent communication to LoB stakeholders throughout the project, involving the deployment of assets.					
Changes to the project scope at the pre-release and post-release stages are not being effectively communicated to all affected LoBs. There have been many extra work claims submitted due to a breakdown in communication indicating a pattern of scope modification.	M	Establish a protocol and a procedure that ensures more visibility and opportunity to all affected LoB stakeholder including, Station Services for input to pending projects at both the (a) pre-release and (b) post-release stages.	a) Project Definition will ensure that Station Services are included in the pre-release planning stages of pending projects.	Planning – Project Definition	Q2, 2015

Observation	Risk	Recommendation	Action Plan	Accountability	Completion Date
			b) Significant changes to projects (i.e. scope of work, cost, schedule) are reported through our established month-end process. This includes status updates via the standard PP-190 BI report. Variances to major projects are also tabled for discussion to SVP and or EC reviews by the Director of Project Management. Project Management has a plan to improve downstream communication with the Station Services on changes to project timing and or scope changes using the existing SAP Work Acceptance Process and Integrated Business Unit (IBU) process. An ongoing dashboard of Station Services required hours will be reviewed on a quarterly basis to identify gaps in the current work program. Further, the IBU process will be refined and communicated in Q2 with the review of the 2016 Work Program.	Project Management	Q2, 2015

Observation	Risk	Recommendation	Action Plan	Accountability	Completion Date
6. Insufficient planning of projects creates unrealistic in-service dates and creates compression on the construction/in-service stages of the Asset Deployment process.					
a) Changes in project priorities and timelines prior to release create inefficiencies and work delays. b) Changes in released project schedules create compression in latter stages of the project and have an impact on Stations Services and Construction Services's ability to mobilize, retain and coordinate resources with appropriate skillset for the work.	M	a) Pre-release: A risk assessment of the project should take into account the impact of changes to cost/resources/operations, etc. on the project/asset deployment horizon so that execution of project work/asset deployment is realistically achievable.	a) Establish a process for risk assessments of projects/programs and associated documentation. This is expected to take into account risks to in-service dates, costs and resources.	Planning – Project Definition	Q2, 2015
		b) Post-release: Establish controls to mitigate compression to Construction Services. Minimize changes to project priorities, particularly once field crews have been deployed. Put controls in place to ensure that once set in motion (i.e. drawings released, Construction Services and/other field crews have been deployed), any further changes to the project are discussed and coordinated with all affected LoBs.	b) Project Management will continue to coordinate schedule changes of released work with Stations Services and Construction. To mitigate compression of executing timelines, Project Management, Engineering and Construction are working with Asset Management to provide "accelerated future year work for early engineering".	Project Management	Complete and Ongoing
7. Equipment requiring long lead times for orders/shipments are not being identified with sufficient lead time.					
ere is a backlog of material and equipment specifications needed to support the tendering process and contracts are being extended because of this backlog. The Control Self-Assessment in 2012 identified that the best supply strategy is to order long lead time equipment is as soon as the project is committed and	H	a) Supply Chain with involvement from Planning, Engineering, should establish and document a process to identify and periodically review long lead time equipment expected for upcoming asset deployment projects. This process should focus on managing equipment posing supply risk to future projects,	a) Supply Chain will take lead action to work with LoB stakeholders Asset Management, Corporate Standards, Engineering and Planning & Project Definition to create a formal set of processes complete with sign offs against key milestones	Supply Chain Services	Q4, 2015

Observation	Risk	Recommendation	Action Plan	Accountability	Completion Date
approved.		including backlog of equipment contracts that are past or approaching expiration, and communicate these on a periodic basis to internal stakeholders.	that would allow Supply Chain to properly monitor and measure the process from beginning to end. Supply Chain has already developed a draft responsibility matrix, with Corporate Standards, based on the RACI principles which will be stakeholdered with affected Lines of Business.		
		b) Supply Chain should actively monitor and report on the status of contracts to senior management. (e.g. track and report contracts that are in place, and which have been extended, single or multiple times) and establish targets for contract status and extensions.	b) Supply Chain will escalate reporting on status of contracts to COO/Process Owner of end-to-end Asset Deployment process to reinforce action from LoBs required to support the sourcing program.	Supply Chain Services	Q2, 2015
8. There is no quality assurance process for material and equipment for the deployment of assets.					
There is no quality assurance process that enables Hydro One to record, track, report and take action on equipment and material deficiencies.	M	Establish a quality control process with monitoring and reporting to internal stakeholders to address deficiencies with material and equipment delivered to site.	Create a QA process to ensure material and equipment meet required standards, process and shall be bi-directional between technical authorities and end users (Construction, Station Services, Maintenance &Technical Services) for power system equipment and materials that can impact the major equipment.	Engineering	Q4, 2015

Observation	Risk	Recommendation	Action Plan	Accountability	Completion Date
9. Staged release of build work to Construction Services and Station Services creates inefficiencies.					
For internally engineered projects, Construction Services and Station Services typically receive drawings, equipment and materials in a just-in-time approach. This creates problems and inefficiencies for these LoBs.	M	Establish protocols and agreed to timeframes for input from stakeholder LoBs involved in the asset deployment process for build stage release approaches that work best. Achieve complete release of drawings and materials by discipline e.g. civil, mechanical, electrical. Ongoing communication between Project Management, Engineering, Construction Services and Station Services is key.	a) Establish a Performance Measure to increase the proportion of engineering work completion in advance of construction start.	Engineering	Q2, 2015
			b) Project Management is accountable to conduct a "project kick-off" meeting with applicable project partners at the start of project execution. This meeting will address key milestone dates and timelines of engineering deliverables and environmental approvals to support Construction and Stations, project risks, and outage staging requirements. This process already exists. Emphasis and clarification of this process will be given to the Project Management division.	Project Management	Q2, 2015

Observation	Risk	Recommendation	Action Plan	Accountability	Completion Date
10. Lack of consistent project close-out process.					
The existing Project Close-out process has not been consistently applied. Project Management has surveyed stakeholder LoBs for input to what should be included in the Project Close-out process and is in the process of implementing changes that will provide an improved project close-out and monitoring to ensure the new process is consistently executed.	M	Continue efforts to implement the improved Project Close-out process and implement monitoring to ensure that the Project Close-out process is completed that includes close-out documentation (e.g. reports, minutes of meetings, follow up action tracking).	Project Management re-introduced the Project Close-Out Process in 2014. Further efforts are underway to ensure projects greater than $5M have a close-out document completed and that stakeholder feedback and reviews are completed in the interest of continuous improvement. An executive summary of these project close-outs and reviews is being created and is expected to be functional for communicating by the end of second quarter.	Project Management	Q2, 2015
11. Official documentation records are in silos. NMI, HODS, NODS and Engineering Standards (on SharePoint) do not enable transparency across LoBs.					
This audit uncovered examples of documents within the NMI and HODS systems that are not aligned or coordinated. There are several separate official documentation repositories with no cross-reference between document systems.	M	We recommend that management conduct a review to ensure that staff can effectively and efficiently retrieve all the necessary documents relevant to their work relating to the Asset Deployment process.	Senior Management will discuss with the input and guidance of internal audit the desire and need to replace and modernize the HODS system. From that discussion, a decision will be made to direct IT to investigate technical options available to the Company to modernize its document record system in accordance with good practices demonstrated in other jurisdictions. The COO will raise this item for discussion at the EC.	COO	Q4, 2015

Observation	Risk	Recommendation	Action Plan	Accountability	Completion Date
			On an ongoing basis where documents are identified in systems as being inconsistent and hence presenting an issue as to Asset Deployment the inconsistency in documents will be highlighted, brought to the attention of the Director, Work Program Management recorded, provided to Asset Management to resolve and to report back on their resolution. On a quarterly basis the number of documents identified and in progress will be reported at the EC month end review.		

INTERNAL AUDIT REPORT

Asset Deployment Follow-up (ADF)

To:

Greg Kiraly, Chief Operating Officer

Distribution:

Mayo Schmidt	President & Chief Executive Officer
Greg Kiraly	Chief Operating Officer
Michael Vels	Chief Financial Officer
Brad Bowness	Vice President, Construction Services
Mike Penstone	Vice President, Planning
Gary Schneider	Vice President, Shared Services
Andy Stenning	Vice President, Stations & Operating
Andrew Spencer	Director, Engineering Services
Additional Recipients	Email Distribution List

Final Report Issued: March 2, 2017
Draft Report Issued: November 18, 2016
Report Number: 2016-17

Lead Auditor: Atul A. Solanki
Audit Manager: Jeff Schaller

EXECUTIVE SUMMARY

An internal audit of Asset Deployment was completed in May 2015 to assess the controls in place to effectively deploy power system assets that involves multiple Lines of Business (from planning to in-servicing of assets). The audit concluded that the key controls concerning the asset deployment process needed improvement. The final report contained 15 recommendations under 11 subject areas that resulted in 17 actions being identified by management. These management actions were intended to address the recommendations and mitigate the risks identified in the report. Management has reported all actions as complete through the quarterly tracking of actions.

The primary objective of this audit was to perform a follow-up of the audit recommendations and provide assurance that Hydro One has addressed all the audit recommendations and mitigated the associated risks.

Our work included a review of:

- Governance (roles, accountabilities and oversight for addressing audit recommendations)
- Clear understanding and commitment to agreed recommendations and action plans
- Appropriate prioritization and plan to address any incomplete management actions
- Completed management actions effectively address the recommendations and risks
- Progress monitoring and communication (reporting to Senior Management and Stakeholders) of management actions

Since the issuance of the Asset Deployment audit report in May 2015, management has made significant progress with the control environment improvements as shown in the summary table below across the audit areas.

We noted that the following success factors were in place:

- [redacted]
    - [redacted]
- Throughout this follow-up review, we have observed an increased team work approach among stakeholder LOBs and willingness to address cross-organizational challenges. Frequent face-to-face conversations are occurring at every level to discuss expectations and resolve asset deployment issues.
- An increased emphasis has been placed on adequate project planning and definition with input from all stakeholder LOBs to ensure resources and outages will be available to execute the defined scope within agreed cost and schedule.

The following table summarizes our assessment of audit action plan status, control effectiveness and resulting risk mitigation of the areas which had been reported by management as complete in each of the 11 subject areas of Asset Deployment.

Audit Subject Area Reported as Complete	Risk (2015)	Actual Action Plan Completion Status *	Control Design Effectiveness *	Risk * (2016)
1. End-to-End Process and Oversight	High	Partially Complete	Partially Effective	Medium
2. Asset Deployment Risk Management	Medium	Partially Complete	Partially Effective	Medium
3. Asset Deployment Performance Measures	Medium	Substantially Complete	Partially Effective	Low
4. Project Estimates	Medium	Substantially Complete	Substantially Effective	Low
5. Project Communication	Medium	Substantially Complete	Substantially Effective	Low
6. In-service date compression	Medium	Substantially Complete	Partially Effective	Medium
7. Equipment lead-time	High	Complete	Effective	Low
8. Material & Equipment Quality Assurance	Medium	Substantially Complete	Substantially Effective	Low
9. Timely Release of build work	Medium	Substantially Complete	Partially Effective	Medium
10. Project Closeout	Medium	Substantially Complete	Partially Effective	Low
11. Asset Deployment Document Mgmt.	Medium	Incomplete	Not Applicable	Medium

* Note: The legend that describes the assessment levels is included at the end of this executive summary.

We have discussed our observations with management throughout this follow-up audit. The key recommendations we made, which management has reviewed and for which action plans have been developed, are included in the following list of high and medium residual risk impact items:

- Confirm asset deployment end-to-end process ownership with the new COO. Confirm accountabilities and oversight controls as part of the on-going efficiency improvement initiatives in each stakeholder LOBs.
- Continue to track and periodically review asset deployment risks and mitigating action effectiveness.
- Establish periodic review of Asset Deployment performance measures and follow-up actions.
- Improve controls over project milestone date changes, related stakeholdering and communication.
- Reinforce existing controls related to communication and monitoring of actions resulting from lessons learned.
- Revisit plans to identify inconsistencies and cross-referencing among asset deployment related documents in use by stakeholder LOBs from multiple document management systems.

Based on the specific areas reviewed, **we concluded that control improvements are needed** to effectively deploy power system assets with oversight and alignment across multiple Lines of Business (from planning to in-servicing of assets). It is noted that the primary focus of this follow-up review was for transmission asset deployment with an expectation that a similar approach will be used for distribution asset deployment in the near future. Management has developed action plans to mitigate the identified risks and address our recommendations, as summarized in Attachment "A" of this report. Additional details are available upon request.

We would like to thank the management and staff in the Planning, Engineering, Construction Services, Supply Chain and Stations & Operating organizations for their assistance and open discussions during this review.

Summary Management Response:
Brad Bowness, VP Construction as designated Operations Lead of Asset Deployment for Greg Kiraly, COO:

As designated Operations Lead of the Asset Deployment process, I acknowledge and am in general agreement with Internal Audit's observations and recommendations included within this report. The table within the executive summary of this report represents a point-in-time status illustrating the progress that management has made which is in line with the expected results of Transmission Capital Efficiency Initiatives approved by The Board of Directors under the Let's Get Great transformation.

Management is committed to continuing progress in this area as part of the Transmission Capital Efficiency Initiatives and commits to follow through on the actions that address the recommendations proposed by Internal Audit in this report, with specific emphasis on Stage Gate Rigour, Estimating and Project Controls.

Legend for Assessment Levels pertaining to the table above:

Assessment of Action Item Status and Control Design Effectiveness by Internal Audit		
Assessment Type	**Assessment Level**	**Description**
Action Item Status	Complete	All committed management actions are complete and fully implemented.
	Substantially Complete	All committed management actions are complete but not yet communicated, approved or implemented.
	Partially Complete	Work is progressing on committed management actions with a clear plan to achieve implementation.
	Incomplete	No or little work progress on committed management actions with no clear plan to achieve implementation.
Control Design Effectiveness	Effective	New or revised controls introduced through management actions have mitigated all identified risks to an acceptable level.
	Substantially Effective	New or revised controls through management actions have mitigated most but not all risks to an acceptable level. Minor control enhancement is required to achieve full risk mitigation
	Partially Effective	New or revised controls through management actions have not mitigated the risk to an acceptable level. Substantial control design improvement are needed to achieve full risk mitigation
	Ineffective	No new or revised controls have been introduced through management action. Identified risks remain unmitigated.

OBSERVATIONS, RECOMMENDATIONS AND MANAGEMENT ACTIONS

(R) #	Results of Assessment	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
Audit Recommendation 1 - Improve Asset Deployment End-to-End Process Oversight.						
1.0	A high-level, chevron based, 10 stage, end-to-end overview process has been developed with high-level LOB VP and Director level accountabilities for each stage. The current documented process is linear with no feedback mechanism or parallel activities. The overall process owner and key management controls related to review and approval of specific deliverables are not yet identified. Management has informed that discussion under COO leadership are planned to further enhance this process with additional controls and lower-level details as part of LOB efficiency improvement initiatives currently underway. ***IA Assessment of Current Status:***[2] Partially Complete ***IA Assessment of Control Design:*** Partially Effective ***Risk:*** *Lack of details and oversight for end-to-end asset deployment process can result in inefficient execution of work (cost overrun,*	M	a) Confirm that the new COO is the owner of the End-to-End Asset Deployment process. b) Restart progress on earlier identified actions related to improving oversight controls, accountabilities and further process improvement (similar to what has been developed within Project Definition and Project Closure processes) as part of on-going initiatives in each Operating LOB.	We will: a) Achieve COO direction on end-to-end process ownership and communicate to COO Direct Reports. b) Refine and rollout a consistent reporting framework and meeting cadence to track and manage Asset Deployment goals and objectives.	Brad Bowness as designated Operations Lead of Asset Deployment for Greg Kiraly, COO	June 30, 2017

[1] Residual Risk levels applied are described in the Legend that follows this table (Page 16).
[2] Definition of scales used for IA Assessment of Current Status and Control Design are described in the table on page 16

(R) #	Results of Assessment	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	schedule delays, functional requirement not being met).					
Audit Recommendation 2 - Document and Manage Asset Deployment Risks.						
2.0	Two risk workshops have been held where 15 risks related to asset deployments process were identified through brainstorming and 3 of those risks have been prioritized and further discussed for risk impact and mitigating actions. A risk register has been developed and published based on these two risk workshops. Management has informed us that no further follow-up was required on remaining risks in the risk register. Management has informed that asset deployment risks and mitigating actions will be discussed as part of the larger efficiency improvement initiatives such as Stage Gate Rigor & Advanced Readiness, Project Controls, Enhanced Delivery and Benchmarking. ***<u>IA Assessment of Current Status:</u>*** Partially Complete ***<u>IA Assessment of Control Design:</u>*** Partially Effective ***<u>Risk</u>:*** *Insufficient monitoring of overall asset deployment risks and mitigating actions may result in inability to align LOB goals and objective to complete planned work on-time*	M	a) Develop plans to periodically review Asset Deployment process risks and related action items identified in the risks register. b) Communicate changes to Asset Deployment process risk profiles and progress on mitigating actions to stakeholders.	a) Actions to address the risks identified and discussed in the most recent risk workshop have been documented and are being tracked. A risk workshop will be planned this year to review and address the top risks. This will be an annual process. This will address continuous improvement over time, and is being carried out according to our Enterprise Risk Management Framework. b) The resulting Risk Register and report will be communicated to	Brad Bowness as designated Operations Lead of Asset Deployment for Greg Kiraly, COO	June 30, 2017

(R) #	Results of Assessment	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	and on-budget.			the Asset Deployment stakeholder LoB Leads.		
Audit Recommendation 3 - Develop performance measures to provide incentives for quality and continuous improvements						
3.0	A set of LOB specific Asset Deployment KPIs have been identified and organized to create an Asset Deployment Dashboard with 51 KPIs. Process and accountability to provide/collect underlying data on a monthly basis has been developed and communicated with the Dashboard being published monthly for information purposes only. The ownership of the dashboard and effective use of the KPIs to drive management actions for quality and continuous improvement remain unclear. A review of the dashboard published on September 30, 2016 indicated that many of the KPIs are not being updated on a monthly basis, have questionable targets and measures, or are yet to be determined (e.g. KPI listed as "% of request for estimate released on or before target date (ACER)" under Asset Needs is listed as 0% YTD with target listed as N/A) ***IA Assessment of Current Status:*** Substantially Complete ***IA Assessment of Control Design:*** Partially Effective	L	Re-establish review of Asset Deployment Dashboard as part of the "Getting Work Done" - type meetings with the COO.	The dashboard will be reviewed and refined and will be reviewed on a quarterly basis with LoB Leads. We will establish a process to develop continuous improvement plans based on metric status.	Brad Bowness as designated Operations Lead of Asset Deployment for Greg Kiraly, COO	September 30, 2017

(R) #	Results of Assessment	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	Risk: *The lack of effective performance measures monitoring may result in inability to identify and correct process and control issues.*					
Audit Recommendation 4 - Ensure effective project estimating						
4.0	The project estimating process has been substantially enhanced and further enhancements are currently underway. The backlog of estimate request has been cleared and appropriate controls are now in place to monitor progress of estimating requests. Estimating templates have been developed based on past project costs. A new estimating tool (Timberline EOS) to be used by all stakeholder LOBs is being envisioned but there are no firm plans for its deployment. Stations & Operating Management has informed us that preparation of detailed estimate (+/-10%) without substantial completion of engineering design on agreed scope and staging plans is challenging. Planning Management has informed us that current estimating timeframe for detailed estimate is too long and quality of estimate is a concern because project forecasts are typically less than approved totals. ***IA Assessment of Current Status:*** Substantially Complete ***IA Assessment of Control Design:*** Substantially Effective	L	Review and confirm stakeholder LOB expectations for project estimating timelines as well as quality of estimate requests and estimate details.	a) Estimating timelines will be tracked according to the Dashboard metrics. (driven by process improvement by one of the key sub-processes put in place). b) Quality of estimates will be addressed as part of the Estimating and Benchmarking initiative.	Kathleen McCorriston, Director, Work Program Management, Construction Services	March 31, 2017 (complete as of January 2017) December 31, 2017 (aiming for Sept)

(R) #	Results of Assessment	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	Risk: *Inaccurate cost and schedule estimate increases the risk of high variances and inefficient resource utilization (e.g. unplanned overtime).*					
Audit Recommendation 5 - Ensure consistent communication among LOB stakeholders throughout the project delivery						
5.0	A series of 10 key project meetings have been identified to facilitate LOB communication throughout project delivery; 9 meetings are for project planning and the 10th meeting is for project closeout. It is further expected that the Project Manager will keep all LOB stakeholders informed using periodic meetings throughout project execution. Detailed Terms of Reference have been developed for these key project meeting identifying Purpose, Scope, Chairperson, Required Attendees, Required Inputs and Expected Outcomes/output. LOB Management informed us that LOB communication has substantially improved, however further improvement are needed related to timely scheduling of key meetings to ensure LOB participation as well as appropriate documentation and timely follow-through on discussed issues and action items. ***IA Assessment of Current Status:*** Substantially Complete ***IA Assessment of Control Design:*** Substantially Effective	L	Monitor and improve rigor to document and follow-through on issues and action items discussed at project meetings.	We will reinforce the requirement to ensure that all key project meetings have minutes documented, all action items identified during these meetings get tracked to resolution and that any changes to the decisions made during these meetings get communicated to the affected stakeholders in a timely fashion.	Kathleen McCorriston, Director, Work Program Management, Construction Services	May 31, 2017

(R) #	Results of Assessment	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	Risk: *Lack of effective communication among LOB stakeholders could result in missed expectation, delayed responses and unnecessary escalations.*					
Audit Recommendation 6 - Coordinate schedule changes to minimize compression of execution timelines						
6.0	A project specific risk register detailing risk to in-service date, costs and resources is now being developed and managed for all projects greater than $20M. An enhanced Variance Change Notice (VCN) process is in place to review and approve any planned in-service date change. A process to review, stakeholder, approve and communicate changes to project milestones agreed at project kick-off meeting remains unclear. Stations & Operating Management have informed us that upstream delays continue to cause In-service date pressure where Project Managers are requesting overtime work to meet the planned in-service dates. Schedule Enhancement using Primavera P6 tool has been underway in Construction Services but a clear strategy is needed to align different schedules across Operating LOBs so that full impact of schedule changes can be analyzed and managed. ***IA Assessment of Current Status:*** Substantially Complete	M	Monitor and approve changes in milestone dates only with consultation and concurrence of LOBs accountable for downstream work to ensure resource availability and timely completion.	We will reinforce a requirement for downstream LoB consultation for milestone date changes. Note: In the long term, Primavera P6 tool will be used to track and communicate milestone date changes.	Kathleen McCorriston, Director, Work Program Management, Construction Services	March 31, 2017

(R) #	Results of Assessment	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	IA Assessment of Control Design: Partially Effective ***Risk:*** *Unplanned schedule delays increase the risk of cost overrun and/or scope decrease.*					
Audit Recommendation 7 - Identify and manage timely delivery of long-lead equipment						
7.0	The current Estimating and Pre-Engineering Process requires that Long-lead material and funding required be identified in the Preliminary Project Plan (PPP) deliverable. Supply Chain is engaged prior to submitting the PPP to Asset Management to discuss Long Lead Material requirements and any changes to current Outline Agreements or future requirements that may be needed for that project. An integrated Sourcing Plan is in place to identify new sourcing requirements and upcoming changes to existing contracts. Bi-weekly meetings are in place to discuss the plan and identify sourcing issues/concerns that require LOB input. A BI Burn Report is in place to monitor usage and remaining funding on current contracts. This will identify opportunities for early renewal to ensure contract continuity as well as escalation of issues requiring LOB support for contract renewal. ***IA Assessment of Current Status:*** Complete	L	None.	Not applicable.	Not Applicable	

(R) #	Results of Assessment	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	IA Assessment of Control Design: Effective ***Risk:*** *Insufficient lead time to order and receive material and equipment will put timely completion of projects at risk.*					
Audit Recommendation 8 – Establish a Quality Assurance process for material and equipment for the deployment of assets						
8.0	Although a Material Complaints and Failures Resolution process exists as per SP0365 and Construction Management informed us that they are following this process, Engineering Management informed us that they are not involved in this process. A review of the Complaints database indicated that majority of material quality issues being documented are for commodity type material for distribution lines. Engineering Management further informed us that material and equipment quality issues are generally handled by Project Manager directly with the vendor with limited involvement by Engineering on a case-by-case basis. Engineering Management further informed us that there are issues are with timely inspection of material and equipment arriving at site for defects/missing parts as well as improper storage of equipment at site leading to deterioration/damage of equipment.	L	a) Reinforce the need to follow the Material Complains and Failure Resolution process outlined in SP0365 with participation by Engineering. b) Review the effectiveness of existing process for inspecting material and equipment as they arrive at site and their proper storage to ensure quality.	a) Working with other accountable stakeholders, we will: • Conduct an effectiveness review of the existing Material Complaints and Failure Resolution process outlined in SP0365. • Reflect any agreed to process improvements in SP0365. • Reinforce to affected management the need to follow the Material Complaints and Failures	Andrew Spencer, Director, Engineering Services	a) June 30, 2017 b) May 31, 2017

(R) #	Results of Assessment	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	IA Assessment of Current Status: Substantially Complete ***IA Assessment of Control Design:*** Substantially Effective ***Risk:*** *Lack of material and equipment quality assurance could result in commissioning delays and corrective repairs.*			Resolution process as outlined in SP0365 b) We will review the effectiveness of existing process for inspection of material and equipment as they arrive at site and their proper storage to ensure quality. As applicable, make improvement recommendations to accountable management.		
Audit Recommendation 9 – Ensure timely release of build work to Construction and Station Services						
9.0	Engineering is required to release drawings and material on a timely basis to Construction and Stations Services to enable field work. "On-Time Completion of Production Engineering Milestones (Internal & External)" has been developed and implemented in the Asset Deployment Dashboard to monitor this timely release. The schedule milestones and outage plans are discussed and confirmed with stakeholder LOBs at the Project Kick-off meeting.	M	Reinforce the need to respect the agreed milestones for delivering complete Engineering packages as well as starting construction or commissioning work. Any changes to these milestones should be appropriately stakeholdered prior to approval.	We will reinforce to the Project Managers the requirement to communicate agreed Engineering milestone date changes to downstream impacted LoBs. Note: In the long	Kathleen McCorriston, Director, Work Program Management, Construction Services	May 31, 2017

(R) #	Results of Assessment	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	Construction and Stations Services Management have indicated that timely availability of engineering drawings and material continues to be a challenge for project under execution with frequent changes to Engineering Completion Dates (ECD) without appropriate stakeholdering for downstream impacts. ***IA Assessment of Current Status:*** Substantially Complete ***IA Assessment of Control Design:*** Partially Effective ***Risk:*** *Delays in engineering deliverables compresses the schedule for construction and commissioning with risk of delays in-service date.*			term, Primavera P6 tool will be used to track and communicate milestone date changes.		
Audit Recommendation 10 – Implement a consistent project closeout process						
10.0	A Project Closeout process has been developed and rolled out within Construction Services requiring the Project Manager to hold a Project Closeout meeting and complete a Project Closeout Report within 90 days of project completion for projects over $5M. Lessons Learned discussions are taking place as part of the project closeout with appropriate documentation of issues and lessons learned. Stations Services and Supply Chain Management has informed us	L	a) Reinforce or enhance existing controls to communicate and monitor progress of action items coming out of lessons learned as part of the project closeout. b) Ensure stakeholder LOB participation in project closeout discussions.	a) LoB Single Point of Contacts are already engaged in the Lessons Learned process. This existing process will be reinforced with the need to communicate Lessons and	Kathleen McCorriston, Director, Work Program Management, Construction Services	April 30, 2017

(R) #	Results of Assessment	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	that they are unaware of any lessons learned being implemented or any actions assigned to their LOBs. Planning Management have indicated that Project Closeout Report does not go far enough to confirm original functional requirements and they are unaware of any actions being taken by planning to address lessons learned. ***IA Assessment of Current Status:*** Substantially Complete ***IA Assessment of Control Design:*** Partially Effective ***Risk:*** *Lack of project closeout and lessons learned would result in inability to learn from past successes and failures for continuous improvement.*			progress/resolution on related actions to all stakeholders. b) Attendance at Closeout meetings (already being tracked) will be communicated to LoBs.		
Audit Recommendation 11 – Ensure efficient retrieval of documents required for asset deployment						
11.0	Staff are required to retrieve Asset Deployment documents effectively and efficiently from multiple document management systems. No new controls have been implemented to facilitate this retrieval. The previous COO had raised the need to replace and modernize these Document Management systems at the Executive Committee meeting. It was agreed that this was not a valuable investment needed at that time. The CIO had recommended that	M	Revisit the earlier plans to identify and cross-reference asset deployment related documents used by all Operating LOBs with the goal of identifying and correcting any inconsistencies or missing details in support of asset deployment process.	Planners will be directed to identify inconsistencies in Asset Deployment documents, track and resolve identified issues. Note: Upon Issue of the Draft Audit Report, VP Planning	Mike Penstone, VP Planning	Mar. 31, 2017

(R) #	Results of Assessment	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	"Google" like search capability of the Intranet be used to search and retrieve documents related to specific projects or asset deployment process. Based on this recommendation, the previous COO had agreed with VP, Planning that all Planners will access available documents related to their work and identify inconsistent documents that require updating, however this has not yet occurred. ***IA Assessment of Current Status:*** Incomplete ***IA Assessment of Control Design:*** Not Applicable ***Risk:*** *Inability to easily retrieve required information could lead to lack of awareness of processes and controls as well as timely coordination among LOBs.*			directed his Planners to identify inconsistencies in Asset Deployment documents. These inconsistencies will be tracked and resolved in a timely manner.		

LEGENDS: ASSESSMENT LEVELS AND RESIDUAL RISK CLASSIFICATION:

Assessment of Action Item Status and Control Design Effectiveness by Internal Audit		
Assessment Type	**Assessment Level**	**Description**
Action Item Status	Complete	All committed management actions are complete and fully implemented.
	Substantially Complete	All committed management actions are complete but not yet communicated, approved or implemented.
	Partially Complete	Work is progressing on committed management actions with a clear plan to achieve implementation.
	Incomplete	No or little work progress on committed management actions with no clear plan to achieve implementation.
Control Design Effectiveness	Effective	New or revised controls introduced through management actions have mitigated all identified risks to an acceptable level.
	Substantially Effective	New or revised controls through management actions have mitigated most but not all risks to an acceptable level. Minor control enhancement is required to achieve full risk mitigation
	Partially Effective	New or revised controls through management actions have not mitigated the risk to an acceptable level. Substantial control design improvement are needed to achieve full risk mitigation
	Ineffective	No new or revised controls have been introduced through management action. Identified risks remain unmitigated.

RESIDUAL RISK CLASSIFICATION[1]	**Assessment Indication**
LOW: The risk will not substantively impede the achievement of the objective, causing minimal impact over the achievement of the organization's objectives.	L
MEDIUM: The risk will cause some elements of the objective to be delayed or not be achieved, causing potential negative impacts to the organization's strategic objectives.	M
HIGH: The risk will cause the objective to not be achieved, causing negative impacts to the organization's strategic objectives.	H

INTERNAL AUDIT REPORT

AUDIT OF CONSTRUCTION PROJECT MANAGEMENT PROCESSES

To:
Brad Bowness, Vice President, Construction Services

Distribution:

Mayo Schmidt	President and Chief Executive Officer
Michael Vels	Chief Financial Officer
Chris Cooper	Director, Project Delivery
Kathleen McCorriston	Director, Work Program Management

Final Report Issued: March 8, 2016 Auditor: Faraj Hossni
Draft Report Issued: December 10, 2015
Report Number: 2015- 32

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EXECUTIVE SUMMARY

The Project Services Organization within the Construction Services at Hydro One is accountable for estimating, coordinating, monitoring, controlling and reporting on work related to safe and cost-effective delivery of capital projects and programs within the established budget and schedule as per approved plans. It obtains project and program scope from Planning Organization, relies on Engineering Services for detailed project engineering, and coordinates work execution with Construction Services and the Operation & Maintenance Organization (Stations, Provincial Lines & Forestry). Construction Project Management Services managed 289 fully released projects with the following overall performance results for 2015:

Description	Budget	Actuals	%
$ Value of the Projects - Gross[1]	$1.029B	$1.026B	100%
$ Value of the Projects - Net[2]	$845.8M	$905.7M	107%
Budget Performance Based on In-Service Date in 2015	$630M	$687M	109%

- Number of Top[3] Programs & Projects — 57 with a $ value of $608M
- Number of Top Programs & Projects completed — 19 with a $ value of $307M
- Number of Top Programs & Projects which were on
- Time within 30 days of original Business Case Summary in-service date — 17

We conducted an audit of Construction Project Management Processes at Hydro One. The objectives of this review were to assess that construction project management process and controls are adequately:

- Designed
- Documented and implemented
- Effective for delivering projects within scope, with acceptable quality, on time, within budget, and in compliance with Hydro One's policies.

Our work included:

- Review of the following randomly selected projects:
  - [redacted]
  - [redacted]
  - [redacted]
  - [redacted]
  - Port Severn DS-New Station
  - [redacted]
- Discussion with management and staff at Hydro One to confirm our understanding of roles/accountabilities, and processes currently in place.
- Review of supporting documentation – policies and procedures.

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1 **Gross Cost** is defined by the Construction Project Management Services as Direct Costs + Interest + Overhead.

2 **Net Cost** is defined by the Construction Project Management Services as Gross Costs less Capital Contributions and Removals.

3 Top Programs & Projects is defined by the Construction Project Management Services as:

a. Board Projects - Total Release ≥ $20M
b. Major Customer Connections
c. Projects with significant system reliability impacts

- Evaluation of key internal controls.
- Sample review of project documentation used to manage and monitor the projects.
- Sample review of project documentation for appropriateness and compliance with the existing policies.

During this audit, we noted that the following success factors were in place:

- Business Cases are prepared for projects, and they are being approved appropriately.
- A process for reporting such as Project Definition Report (PDR), Month End Report (MER), and Project Closure Report are in place.
- The Work Program Management team is drafting a plan to set up a Quality Assurance process.
- Action Log which is part of MER is used to track identified project issues, their severity, accountability and resolution.
- A Project Schedule being prepared for each project and milestones are identified.
- Projects are set up in SAP as a centralized system providing access to all authorized individuals.
- Construction related procurements are handled through Supply Chain processes.

We made the following recommendations, which management accepted and provided their action plans and expected completion dates:

- Provide a documented Project Management Methodology, which will be used by the project management group consistently.
- Provide a documented Project Execution Plan (PEP), which will be used by the project management group consistently.
- Establish a process of more effective accountability amongst various groups involved in the projects.
- Put a standard quality assurance process in place for project teams to follow.
- Implement a standard and detailed Risk Methodology recommended by the Enterprise Risk Management group to be utilized in all projects..
- Put in place a comprehensive project cost estimating method which will lead to a more realistic project cost estimating.
- Put a process in place which will enhance quality of reports, such as Earned Value reporting, Month-End-Report, and Asset Registry.
- Put a requirement in place that contingency funds only be used for specifically those situations which have been forecasted and documented in the project approval process.
- Put a process in place to ensure remaining contingency is:
  - Reported accurately, and
  - Monitor to ensure contingency balance does not exceed 25% (threshold as a flag to force Project Managers make more realistic forecast) of remaining Gross Spending for a month over month.
- Introduce a comprehensive standard forecasting methodology, which can provide more accurate forecast for costs and schedule.
- Introduce a process, which provides monitoring of project performances when Earned Value is not applicable to certain projects.

Based on our review, we concluded that the construction management processes requires improvement. With continuing focus and collaboration among supporting teams coupled with management actions to the recommendations in Attachment A of

this report will provide a good foundation for future integration projects.

We would like to take this opportunity to thank management and staff of the Construction Project Management for their assistance and open discussion on areas for control improvements.

ATTACHMENT A

RECOMMENDATIONS AND MANAGEMENT ACTIONS

	Observation	Audit Recommendations	Risk	Management Action Plan	Accountability	Completion Date
1.	**Strategy/Organization**					
	Project Management Methodology / Process Project Management Methodology, as defined by PMBOK[4], is "*A system of practices, techniques, procedures, and rules used by those who work in a discipline*." There is no documented and consistent process required to be followed for all projects against which the project performance, e.g., scope, budget, and schedule can be evaluated based on identified controls. In the absence of a codified enterprise wide methodology there is a potential for inconsistent practices. ***Risk:*** *Inconsistent use of project management processes may lead to ineffective monitoring process in achieving the project objectives.*	We recommend that management identify a project management methodology and establish a consistent process that Project Management will follow, so that performance can be evaluated based on identified controls.	M	Project Delivery will ensure a consistent framework is documented and adhered to for all projects. This framework will follow project management best practices for Scope & Quality Management; Schedule and Cost Management; Risk & Issue Management; and Stakeholder Management. Initial framework to be refined in Q1/Q2 with full rollout to all staff and all projects by Q3, 2016	Chris Cooper Director, Project Delivery	Q3, 2016
	Project Execution Plan The Project Execution Plan (PEP) is a governing document that is recommended by PMBOK as an industry best practice which establishes the means to execute, monitor, and control projects. The plan serves as the main communication vehicle	We recommend management to mandate preparation and use of the Project Execution Plan.	M	Project Management will develop a threshold matrix where PEPs are a mandatory requirement; i.e., Board level, $ amount, Complexity. As a part of the Project Management methodology implementation, Project	Chris Cooper Director, Project Delivery	Q3, 2016

[4] Project Management Body Of Knowledge

	Observation	Audit Recommendations	Risk	Management Action Plan	Accountability	Completion Date
	to ensure that everyone is aware and knowledgeable of project objectives and how they will be accomplished. Project manager creates the **Project Management Plan** following input from the project team and key stakeholders. The plan should be agreed and approved by at least the project team and its key stakeholders. There is no documented project execution plan in place. ***Risk:*** *Unclear project objectives and the way to achieve those objectives on a timely basis.*			management will ensure PEPs are a mandatory requirement for all projects greater than $10M or items that have significant project complexity.		
	Alignment Between Various LoBs In various meetings we held with the project team members we were advised by Project Managers that there is a need for a better communication/alignment between Asset Management (for Planning Specs), Project Services (for PDR), Project Management (for Execution), and other stakeholders. Based on our interviews, Project Managers' understanding of accountabilities of other LoBs is not clear, e.g., Project Managers assume that certain activities are being performed by other LoBs such as safety designs, Quality Assurance, proper selection of vendors which may or may not be the case. Project Managers cannot execute their plan effectively if the information received is inadequate. Some project managers were concerned that they are being blindsided by: ➢ Procurement being handled by Supply	Recommendations made for the observations 1, 5, 6, and 7 in the Asset Deployment Audit Review will apply to this observation. However, in summary we recommend that management should re-evaluate the existing organizational relationship to provide more effective accountability between the team members involved in the projects.	M	As a follow up to the Asset Deployment Audit, Work Program Management is leading the initiative to develop cross LoB business processes and KPIs to ensure the successful delivery of the capital work program. The ongoing management reviews will look at process, organization and toolset improvements to drive continuous improvement. Actions will be tracked under the Asset Deployment Audit.	Kathleen McCorriston, Director, Work Program Management	To be tracked under asset deployment audit

	Observation	Audit Recommendations	Risk	Management Action Plan	Accountability	Completion Date
	Chain with no involvement from Project Management. ➢ Resources who are functionally accountable to someone else, such as engineering staff who work on the project but report to their own managers. ***Risks:*** *1. Potentially unable to meet budgeted in-service date.* *2. Functional inefficiency due to unclear understanding of the requirements.*					
2.	**Quality Assurance**					
	Quality Assurance Quality Assurance processes and guidelines ensure that appropriate quality standards and operational definitions are used uniformly across the organization. The Quality Assurance process should specify: • How quality is measured • How quality is reported • Timing and frequency of review There are no documented process/guidelines in place for Quality Assurance to ensure consistency among project documents (e.g., Scheduling, Estimating, and Reporting). We were advised that the Work Program Management team is drafting a plan to set up a Quality Assurance process. ***Risks:*** *1. Inability to ensure that the project requirements are met and validated.*	Management should put a standard Quality Assurance process in place and project teams are required to adhere to.	M	We will establish a high level Quality Assurance framework for project management.	Kathleen McCorriston, Director, Work Program Management	Q1, 2016

	Observation	Audit Recommendations	Risk	Management Action Plan	Accountability	Completion Date
	2. *Potential for increased operational and maintenance cost.*					
3.	**Scope**					
	Asset Registry One of Hydro One's requirements for construction projects is completion of an Asset Registry in SAP upon completion of the project. Engineering is accountable to complete the Asset Registry; however, the Project Manager is accountable to ensure completion of Asset Registry. The purpose of Asset Registry is to ensure SAP contains accurate and the most current asset data. We noted that the Asset Registries are not always complete / adequate; out of 6 projects we reviewed, four projects were completed but had incomplete Asset Registry. Two of the sampled projects we reviewed were still in progress and had not yet reached the stage to update the Asset Registry. ***Risk:*** *Carrying incorrect/incomplete asset data in SAP impacting accurate accounting for capital assets.*	Management should ensure that the Asset Registry in SAP is updated as soon as the project reaches its closure status.	M	Project Management ensure major system components and directly associated auxiliary supplies are registered. If they were not, the IESO would not allow us to place the asset in-service. In addition, as a part of the project closure process, it is now a requirement to ensure all SAP Asset Registry information has been updated before the project is closed. Management will take the action to review to ensure these activities are being completed and documented appropriately in project closure reports.	Chris Cooper Director, Project Delivery	Q1, 2016
	Lesson learned. There is no evidence that all lessons to be learned are being logged or are complete / adequate in the Close out Report. We did not see a demonstration of lesson learned being actioned. [redacted]	We recommend that management ensure to: 1. Modify criteria for lessons learned to include projects where costs are below approved budget. 2. Update the existing processes and ensure actions resulting from lessons learned are	L	There is a robust lessons learned process that is able to capture lessons through the asset deployment life cycle, after reviews of variance and at project closure. At the end of a project there is a joint lessons learned and project closure meeting at which all stakeholders	Kathleen McCorriston Director, Work Program Management	a) Q1 2016 b) Complete

	Observation	Audit Recommendations	Risk	Management Action Plan	Accountability	Completion Date
	[redacted] ***Risk:*** *Inability to leverage on the past experience to perform more efficiently/effectively.*	documented and tracked to reflect on the lessons learned going forward.		throughout the process are expected to attend. The terms of reference for this meeting are in draft and being stakeholdered. The final version is expected by the end of January 2016. a) We will modify the criteria for lessons learned to include projects where costs are below approved budget. b) We have a process whereby each LoB has identified a SPOC who is accountable for following up on actions and communicating changes as a result of actions to their LoB. We also have a quarterly director review of all high risk lessons learned, where actions for these are assigned to managers with a Director level sponsor these actions are tracked followed up on a quarterly basis.		
4.	**Risk Management**					
	Risk Methodology There is no documented risk Methodology in place. Each Project uses few sentences in Project Definition Report (PDR) to identify possible point of failures. There should be a risk matrix developed to be used uniformly to assess various types of risks and their impacts on the different components of the project. ***Risk:*** *Potential for project failure.*	Management should implement a standard and detailed Risk Methodology recommended by the Enterprise Risk Management group to be utilized in all projects.	**M**	Project Management will continue to participate in the corporate initiative to improve risk management practices for Projects. Work Program Management has completed a pilot for an overall project risk management framework and tool set for identifying project risks during the project definition phase and tracking these items through the delivery phase. This framework will be rolled out to all projects >$20M in 2016.	Kathleen McCorriston Director, Work Program Management	Q1, 2016

	Observation	Audit Recommendations	Risk	Management Action Plan	Accountability	Completion Date
5. Scheduling						
	Description of Variances We noted that the schedule variances such as the differences between the approved in-service dates and the forecasted in-service dates are not being explained or processed appropriately. We were advised that variances are discussed in the project meetings, however it is important to clearly document and explain: ➢ The reasons for variance. ➢ Whether it is business impactive. ➢ Who reviewed and reached such a conclusion. ➢ Need for IROV and VCN when changes are evident. ***Risk:*** *Without adequate information to provide the reason for variance, there is a risk of not detecting the root cause in order to avoid a repeat in the future.*	We recommend that management should require: 1. Full and detailed explanation for schedule variances. 2. Immediate preparation of VCN when changes are evident.	**M**	Project Delivery will ensure : a) Expectations are clearly articulated when reporting variances b) Training to be conducted as required c) Input from Decision Support and Regulatory Affairs is garnered during development for those projects where PD is reporting the variance	Chris Cooper Director, Project Delivery	Q1, 2016
6. Costs						
	Setting up WBS for Projects There is no standard format for setting-up Work Breakdown Structure (WBS) at the planning stage of the projects. Project Managers or schedulers set-up WBS based on their own preferences. This may lead to setting up fewer WBSs than required from Finance department's point of view for the purpose of aggregating cost and reporting. This practice may potentially lead to ineffective: ➢ Capitalization of the components of the	We recommend management put in place: 1. A standard WBS format for setting up projects. 2. A process for better coordination amongst Project Managers, Schedulers, and Financial Management Group.	**L**	We will provide additional guidance to Project Managers/Schedulers on good practices when setting up WBSs. We will ensure Finance has reviewed and agreed to the practices. We will provide the same instructions to the Estimating Team to ensure alignment.	Kathleen McCorriston Director, Work Program Management	Q1, 2016

Internal Audit: Audit review of Construction Project Management Processes

	Observation	Audit Recommendations	Risk	Management Action Plan	Accountability	Completion Date
	project, ➢ Management of the costing side of the project. ***Risk:*** *Ineffective cost aggregation and reporting.*					
	Project Cost Estimates Project cost is continuously estimated higher than actual cost. This practice impacts accuracy of project performance reviews as they consistently represent the project completed costs being below approved budget. We noted that 3 out of 4 completed projects under review were completed with variances higher than the required variance threshold[5] according to the estimate classes considered for projects as following: ➢ [redacted] ➢ [redacted] ➢ Port Sevren DS – New Station 42.4% ➢ [redacted] [redacted] Three of the completed projects were class "A" estimate and one completed project was Class "B" estimate ***Risks:*** 1. *Inability to evaluate project*	We recommend management put in place: 1. A comprehensive process which will enable more realistic method of project cost estimating 2. A temporary process as a workaround until the comprehensive project cost estimating method is implemented.	M	1. We will review and revise the estimating process identifying best practices and benchmarks. 2. We will, where practical/possible, obtain an RFP response for outsourced projects prior to seeking approval for the full release. This will be much easier once we have pre-qualified vendors.	Kathleen McCorriston Director, Work Program Management	Q2, 2016

[5] Hydro One's cost variance requirement for:
Class "A" estimate is the actual cost to be within +/-10% of the estimated cost
Class "B" estimate is the actual cost to be within +/-20% of the estimated costs.

	Observation	Audit Recommendations	Risk	Management Action Plan	Accountability	Completion Date
	performance results accurately. 2. *Poor upfront planning may lead to inability to identify the required resources based on proper number of assumptions.*					
	Reports The project team prepares Earned Value report (for those projects approved by the Board or the non-routing projects) as well as the Month End Report (MER). We noted the following irregularities in the reports: 1. There were occasions where exact figures were used to report the values for Budget, Forecast, and Actual costs in Earned Value reporting. 2. The VCN values reported in the MER we sampled (January and May 2015) were stated incorrectly, e.g., 3,558% was the incorrect value stated in these reports rather than the correct 3.6%. 3. Number of VCNs reported in the MER did not correspond to actual number of VCNs generated or changes included in the MER: ➢ One project issued five VCN while MER listed only three VCN ➢ No VCN was prepared for one project while MER listed four changes. 4. Variances were not explained beyond simple “N/A”. 5. Close out report was not produced for one out of six projects we reviewed. ***Risks:*** 1. *Incorrect data being reported.* 2. *Ineffective monitoring of variances may*	We recommend that management put a process in place to enhance the quality of reporting. Poor upfront planning results in not identifying required resources in a timely manner	M	Work Program Management will conduct a detailed review as a part of the project management methodology to ensure that all processes and tools are optimized for project and program reporting. After the review is complete, a work plan will be developed and implemented to improve the reporting framework.	Kathleen McCorriston Director, Work Program Management	Q3 2016 (for update)

	Observation	Audit Recommendations	Risk	Management Action Plan	Accountability	Completion Date
	reduce the benefit of variance identification as a detective control. 3. *Without Close out report there may not be assurance that all project deliverables are completely received.*					
	Contingency As part of the cost estimate process, a contingency provision of 10% - 15% of the project direct costs is included. Currently, there is no formal guidance to restrict utilization of contingencies to specific and pre-determined occurrences. Project teams are provided with a flexibility to utilize contingency against any variance. We also noted the following inconsistencies in managing the contingencies: 1. Contingencies are being forecasted and reported in the Month-End-Report inaccurately – Higher than total remaining spend for the month. 2. Remaining contingencies exceeded 25%[6] of remaining Gross Spending for a month over month. 3. Reported remaining contingency is unreasonably higher than remaining spend, e.g., 126% ***Risk:*** *Potential for ineffective use of contingency funds.*	We recommend that a requirement be put in place to: 1. Require use of contingency funds for specifically those occasions which have been forecasted and documented in the project approval process. 2. Monitor remaining contingency balance to ensure it does not exceed the required 25% (threshold) of remaining Gross Spending a month over month. 3. Report remaining monthly contingencies accurately.	M	Project management utilizes the VCN process to review contingency use and approve the release of contingency. Project management will continue to refine/improve the VCN process to ensure quality submissions. A quality review will be completed quarterly to ensure consistent and quality submissions. Project Management will develop a set of reports to review overall contingency usage, remaining balances and ensure contingency is released when risks are mitigated and report on overall contingency within the portfolio.	Chris Cooper Director, Project Delivery	Q4, 2016

[6] 25% threshold has been defined by Hydro One as an internal flag to force Project Managers to prepare more accurate/realistic forecasts.

Internal Audit: Audit review of Construction Project Management Processes

	Observation	Audit Recommendations	Risk	Management Action Plan	Accountability	Completion Date
	Forecasting process and Cost Monitoring We noted that project teams monitor the approved Budget against the Forecast. There is no clear methodology to provide a consistent process to forecast the cost and schedule for the incomplete tasks; instead Project Managers use their past experience to forecast which leads to inconsistency, and even in some cases, inappropriate results. In the absence of a standard project forecasting methodology, variances may not be presented accurately. ***Risk:*** *Inaccurate presentation of actual variances.*	We recommend that management introduce a comprehensive standard forecasting methodology to be utilized by the project management team for more accurate forecasting for both cost and schedule.	M	Management will develop and rollout a more robust and consistent forecasting methodology, process and toolset.	Chris Cooper Director, Project Delivery	Q3, 2016
	Earned Value Earned value reports are generated for board approved as well as non-routine projects. Projects that do not fall into either of these categories such as Distributed Generation Connection (DG) are not subject to Earned Value reporting. In the absence of Earned Value reporting for non-board approved and non-routine projects, it will be difficult to evaluate/monitor projects' success factors. ***Risk:*** *Inability to monitor projects success factors.*	Project Office should introduce a process which provides monitoring of project performances when Earned Value is not applicable to certain projects.	M	Project management will ensure that EV reporting is utilized for all projects >$10M by the end of 2016. For smaller projects, month end status reporting on project progress, issue management, financial forecasting and overall project health for cost and schedule will remain as the tracking framework.	Chris Cooper Director, Project Delivery	Q4, 2016

Legend	Residual Risk Levels
L	Low risk to the project achieving the scheduled completion date, acceptable quality and the budgeted cost.
M	Medium risk to the projects achieving the scheduled completion date, acceptable quality and the budgeted cost.
H	High risk to the project due to lack of governance achieving the scheduled completion date, acceptable quality and the budgeted cost.

INTERNAL AUDIT REPORT

Distribution Asset Management & Preventive Maintenance Optimization

To:

Mike Penstone
Vice President, Planning

Distribution:

Mayo Schmidt	President & Chief Executive Officer
Michael Vels	Chief Financial Officer
Paul Brown	Director, Distribution Asset Management
Sinisa Grkovic	Manager, Distribution Investment Planning
Additional Recipients	Email Distribution List

Final Report Issued: June 2, 2016
Draft Report Issued: January 18, 2016
Report Number: 2015-34

Lead Auditor: Shabbir Shakir
Audit Manager: Jeff Schaller

The contents of this report are classified for Internal Use only, not to be copied or distributed externally. Internal distribution is to be limited on a need to know basis.

EXECUTIVE SUMMARY

Preventive Maintenance programs are in place for Hydro One Networks' transmission and distribution system assets to ensure safe and reliable operation of these systems while meeting regulatory maintenance requirements for these assets. The Planning Organization is accountable for developing and funding Preventive Maintenance Optimization (PMO) programs for transmission and distribution assets with the objective of ensuring cost-effective preventive maintenance is performed on the right equipment at the right time to maintain continuity of system operation. The PMO programs include periodic visual inspections, diagnostic testing as well as intrusive inspections and maintenance (such as cleaning, lubrication and worn out parts replacements) based on observed test results, asset conditions and planned useful service life.

The primary objective of this audit was to provide assurance that the governance and controls within the Planning Organization are effective for the development and management of PMO programs. Separate audit reports were produced for Transmission and Distribution business areas. *This* report focuses on PMO in the distribution business.

Our work included:

- Interviews with the management and planners with respect to the controls and processes for developing and managing preventive maintenance programs.
- Review of governance documents related to maintenance planning (strategies, policies, processes, procedures, training etc.).
- Review of the annual maintenance plans, as well as cost and accomplishment variance reports from 2012-2015 and maintenance plans set up in SAP.
- Analysis of work order data from SAP to determine the completeness of the recorded work accomplishments.

We noted that the following success factors are in place:

- PMO program mandate and accountabilities are well-understood within the Planning organization.
- A high level PMO strategy exists to perform preventive maintenance on distribution assets in compliance with the Distribution System Code and Market Rules and Manual.
- A five year plan and an annual preventive maintenance plan for each of: Stations, Lines and Vegetation Management are developed and released to the service providers on a timely basis, according to the schedule, and agreed upon with the affected Lines of Business.
- Inputs from the service providers are obtained to develop the annual preventive maintenance plan.
- Monitoring of cost and work accomplishments at the program level is performed on a monthly basis with the service providers. Formal reports are available from the work management system (SAP) for PMO program variance monitoring (PP-177 Operations Status Report – Programs – Schedule A&C Gross).
- Prioritization criteria for vegetation management have been modified to reflect a greater influence from reliability measures, as per the Auditor General's 2015 report recommendation #10.

Management has accepted and established action plans to address the following recommendations that we made:

- Update and ensure consistency of details among various PMO investment planning documents for Lines, Stations and Vegetation Management.
- Conduct a formal risk assessment in line with the company's ERM Framework that includes identifying, assessing, prioritizing risks for achieving the business objectives and developing appropriate mitigating strategies.
- Establish a periodic review cycle and update all Work Standard Documents for Stations, Lines and Vegetation Management.
- Ensure that documentation is in place to reflect the committed changes to the 2016 Vegetation Management budget and work accomplishment targets.
- Develop a clearer plan to achieve the OEB vegetation management targets in future years, to address the increasing line clearing work backlog that is currently at approximately 29,000 km (28% of 102,000 km, total estimated Right-of-Way inventory). This plan is expected to establish how the 34% increase in unit cost per km of line clearing experienced over the 2010-2015 period will be turned around to achieve the projected 16% reduction in unit cost per km of line clearing by 2020 (compared to 2015 effective unit cost level).
- Develop a process and clarify accountabilities for defining new assets and maintenance plans along with creation of maintenance work orders in SAP that are consistent with the agreed annual maintenance plan.
- Establish a mechanism to consistently identify maintenance work backlogs.
- Ensure documentation, appropriate tracking and timely communication of management redirection actions for program costs and accomplishment variances.
- Extend the approach of identifying and incorporating industry best practices in the Vegetation Management planning process to Lines and Stations programs.

We identified the following opportunities for improvement to strengthen existing controls:

- Establish work process training to support the planners to ensure the effective and efficient execution of the planning process.
- Establish SAP as a 'source of truth' for feeder data and periodically review to ensure that data in SAP synchronizes with FMS.

Additional details on the audit issues and recommendations, and status of the management action plans are contained in Attachment A.

Based on our review, we concluded that controls over Preventive Maintenance Optimization for Distribution Assets require significant improvements.

We would like to take this opportunity to thank management and staff of Distribution Asset Planning Management for their assistance and open discussions on areas for improvements.

ATTACHMENT A

OBSERVATIONS, RECOMMENDATIONS AND MANAGEMENT ACTIONS

	Observation	Risk[1]	Recommendation	Action Plan	Accountability	Completion Date
1. Governance Controls						
1.1	**Governance Documents** Governance documents are developed, reviewed, approved and communicated by Management to set the expectations around how Distribution Asset Management Preventive Maintenance Optimization (Dx AM PMO) planning work is to be performed. We observed the following deficiencies in the existing governance documents for Stations, Lines and Vegetation Management maintenance planning: • Asset-specific strategy documents were not in place at the time of the audit; however we were advised that Management is currently developing a comprehensive distribution strategy that will include asset-specific strategy elements. • Policies, process and procedures documents are not developed in a consistent manner and implemented for various preventive maintenance programs. • Scope of Work documents have inconsistent details of work accomplishment and reporting requirements. • Work Standard Documents are in place for Stations and Vegetation Management, however the contents between these documents have inconsistent details and their formatted layout differs. Work Standard Documents for Overhead Lines are not in place at all.	M	Ensure consistency of details within various PMO investment planning documents across all asset types such as asset strategies, planning documents, scope of work and work standard documents. Embed the periodic review cycle as part of the planning documents.	a) Management agrees that there should be consistency in documentation among various work programs. It also appears there is a need to review the documentation hierarchy and we agree to undertake this review in Q2. b) In terms of updating all documentation, there is a need to validate the effort level and prioritize. c) Schedule for updating the planning documents to be determined by end of Q2, 2016. d) Planning documents will be updated as per the established schedule.	Paul Brown, Director, Distribution Asset Management	Q2, 2016

[1] Residual Risk levels applied are described in the Legend that follows this table (Page 11).

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	Observation	Risk[1]	Recommendation	Action Plan	Accountability	Completion Date
	Risk: *Poorly defined, inconsistent or missing governance documents increase the risk of confusion around strategy, policy, risk-analysis as well as work plan, execution and reporting requirements.*					
1.2	**Process Risk Assessment** A formal risk assessment in line with Hydro One's Enterprise Risk Management (ERM) Framework has not been performed for the overall preventive maintenance planning function by the Distribution Asset Management (DxAM) planning group. ***Risk:*** *Untimely or non-identification of risk exposures may impact on the achievement of the program cost and work accomplishment targets.*	M	The Dx Asset Management (DxAM) Planning group should conduct a formal risk assessment in line with the company's ERM Framework that includes identifying, assessing, prioritizing risks for achieving the business objectives and developing appropriate mitigating strategies. Requesting the ERM group's assistance could help in its expeditious completion.	Dx Asset Management will perform a risk assessment as recommended.	Paul Brown, Director, Distribution Asset Management	Q3, 2016
1.3	**Work Standard Documents (WSDs)** • WSDs for Dx Stations are not reviewed or updated as per the review cycle prescribed by the procedure document SP1564. • There is no review cycle established for the review of WSDs in Lines and Vegetation Management similar to the one established	M	• Review and update WSDs for Dx Stations. • Establish a review cycle for Lines and Vegetation Management	Agreed. The review and update of plans for WSDs will be established as part of the Management Action plan in 1.1 above.	Paul Brown, Director, Distribution Asset Management	Q2, 2016

ATTACHMENT A

	Observation	Risk[1]	Recommendation	Action Plan	Accountability	Completion Date
	in the procedure document SP1564 for Transmission and Distribution Stations WSDs. ***Risk:*** *Absence or outdated guidance to the service providers will impact the effectiveness of executing the work.*		WSDs.			
2. Preventive Maintenance Strategy						
2.1	**Vegetation Management Preventive Maintenance Program Strategy** The line clearing program budget is approximately $100M per annum. This constitutes approximately 70% of the total budget for Vegetation Management. We observed that: • The current planning documents and 2016 work release are not in line with the OEB directed cost and units accomplishment targets[2]. For example, budget and targeted units in the Investment Planning Approval Documents (IPAD) are not consistent with those in the Accomplishments file. • The changes in the Vegetation Management program as per the Budget redirection that occurred in 2015 are not reflected in the planning documents (e.g. IPAD) at this time, therefore the plan to achieve OEB targets in future years remain unclear. • Management has defined an 8 year maintenance cycle target for vegetation management line clearing work in their investment plan (dated May 14, 2015) for	H	• Ensure that documentation is in place to reflect the committed changes in 2016 to the Vegetation Management budget and work accomplishment targets and, • Develop a plan to achieve the OEB vegetation management targets in future years.	The plan to bring the Vegetation Management program back on track with OEB targets will be done as part of the 2017 planning cycle. Note that budgets associated with PMO programs are subject to adjustments within the Operations organization to balance with requirements in other areas of the Hydro One Networks business in response to external influences (e.g. new or changed regulations, customer demand volumes for services, extreme weather events and factors such as corporate revenues).	Paul Brown, Director, Distribution Asset Management	Q4, 2016

[2] OEB targets as per decision EB-2013-0416/EB-2014-0247,March 12, 2015

ATTACHMENT A

	Observation	Risk[1]	Recommendation	Action Plan	Accountability	Completion Date
	the 2016-2020 period. To achieve this target requires that 12,750 km of line clearing work be completed each year. Management informed us that the exact Right-of-Way inventory for line clearing work is unknown, partly due to the impact of recent acquisitions, and is estimated at 102,000 km, as filed with the OEB. At the end of 2015, approximately 28% (29,000 km) of line clearing maintenance is behind the planned 8 year cycle schedule. Furthermore, there has been a shortfall of line clearing accomplishment between 10% and 26% in each of the years during the 2010-2015 period. Management tracking indicates that actual line clearing is presently being achieved at a 9.5 year cycle. • The effective cost per km for line clearing work has consistently increased during the 2010 to 2015 period from $6,861 per km to $9,193 per km (a 34% increase), yet management has budgeted lower unit costs, $8,909 per km in 2016, with progressive reduction in unit cost to $7,764 by 2020 (a 16% reduction from the 2015 level), without clearly documented plans on how these lower unit cost per km for line clearing work will be achieved. While we recognize that management is approaching this from a number of directions, including: a) Variable vegetation management cycles (4-8 years), b) Better communication between Forestry and Planning on budgetary matters/developments and, c) Innovative approaches to vegetation					

ATTACHMENT A

	Observation	Risk[1]	Recommendation	Action Plan	Accountability	Completion Date
	management such as the Muskoka – Parry Sound initiative, all of these approaches are at an early development stage. For further details, refer to "Attachment B". ***Risks:*** *1. Inability to meet the Regulator's targeted planned maintenance accomplishment.* *2. Based on Distribution Asset Management's own studies, reducing line clearing frequency (planned maintenance) can result in reduced reliability, increased unit costs and increased safety risks.*					
3. Annual Maintenance Program						
3.1	**New Assets with missing maintenance plans** The process and accountabilities for ensuring that appropriate maintenance work orders are created in SAP for new assets are unclear. There is no periodic review process in place to ensure that the items flagged in SAP for maintenance plans are in fact identified by the planners and appropriate maintenance plans are attached to them. When we reviewed and analyzed Distribution Asset data provided we noted the following instances : • Under preventive maintenance programs for Lines, no maintenance plans were associated with the 93 feeders added during the year. • Out of 485 pieces of Stations equipment	H	Develop a process and clarify accountabilities to ensure that: • Maintenance plans are defined in SAP for the new assets in a timely manner and that appropriate work orders are created in SAP to monitor the annual work accomplishments. • Maintenance plans are removed/ suspended for the decommissioned assets in SAP in a	Management agrees that a review of the processes for new and decommissioned assets needs to be reviewed and updated or to be developed if necessary. A documentation review will be undertaken to close this gap.	Paul Brown, Director, Distribution Asset Management	Q3 2016

ATTACHMENT A

	Observation	Risk[1]	Recommendation	Action Plan	Accountability	Completion Date
	added during 2015, 182 (38%) were assets which required to be maintained but do not have maintenance plans attached to them. We were further informed by the planners that currently there is no report available to inform them about assets which have been decommissioned, so that planners can suspend corresponding maintenance plans on a timely basis. ***Risks**:* 1. *Missing assets and work orders in SAP could lead to planned maintenance not being performed on specific assets.* 2. *Distribution assets may not be maintained on timely basis resulting in increased performance failures and higher corrective maintenance.*		timely manner.			
4. Monitoring of PMO programs accomplishments						
4.1	**Monitoring of Maintenance Backlog** We noted that "PP-177 Operations Status Report–Programs - Schedules A&C Gross" from SAP is used to monitor maintenance costs and work accomplishment at the program level. There is no detailed reporting available to the planners to determine which specific work orders were backlogged. We analyzed SAP work order data and noted that Distribution Lines Patrols had the following work orders from previous years which had not been closed in SAP: 2012: 105 (13%) 2013: 280 (47%) 2014: 275 (58%)	H	Establish a mechanism to consistently and accurately identify maintenance backlog which will include timely closeout of work orders.	Agreed. Management supports this recommendation and will establish a mechanism for consistently and accurately identifying tracking and closing maintenance backlog.	Paul Brown, Director, Distribution Asset Management	Q4, 2016

ATTACHMENT A

	Observation	Risk[1]	Recommendation	Action Plan	Accountability	Completion Date
	2015: 275 (45%) As a result, it is impossible to confirm the magnitude or nature of the backlog using SAP work order data. ***Risk:*** *Ineffective monitoring for maintenance backlog would increase the risk of missed or delayed maintenance.*					
4.2	**Program Redirection Decisions** Currently redirection of previous budget allocation decisions among the various preventive maintenance programs are made at the Operations Committee level. There is no documentation and timely communication of these decisions within the Dx Asset Planning Function for subsequent implementation and monitoring. ***Risk:*** *Missing or poor documentation of redirection decisions would lead to confusion around which maintenance should be delayed or deferred.*	M	Ensure that program redirection decisions affecting preventive maintenance planning are documented and communicated within Dx Asset Planning Organization on a timely basis, so that affected documentation can be updated and Dx Asset Management monitoring can continue in an effective manner.	Agreed. Management will ensure that all redirection decisions impacting the preventive maintenance programs are documented and communicated with the Dx Asset Planning Organization on a timely basis.	Paul Brown, Director, Distribution Asset Management	Q1, 2016
5.	**Continuous Improvement**					
5.1	**Issues Log and Lessons Learned** We noted that there is no planning issue log in place to capture and resolve on a timely basis those process and data issues that arise during planning and execution meetings / discussions. We also noted that there is no process to: • Identify and extract lessons learned from various issues resolved during planning and execution of maintenance work which may have impacts on the planning process.	L	• Develop and maintain a planning issues log to identify and track various planning issues. • Review the issues for lessons learned with the stakeholders at the	Management agrees that lessons learned and issues log should be undertaken for the planning/execution meetings. To be done at the start of the present 2016-2022 investment planning cycle.	Paul Brown, Director, Distribution Asset Management	Q1, 2016

ATTACHMENT A

	Observation	Risk[1]	Recommendation	Action Plan	Accountability	Completion Date
	• Ensure timely communication of these lessons learned and other stakeholder feedback among the planners for on-going process improvements. ***Risks:*** *1. Issues affecting the planning process may not be identified, tracked and resolved on a timely basis.* *2. Absence of a lessons learned process may result in perpetuation of flawed process.*		start of the annual planning cycle.			
5.2	**Alignment with Best Practices for Program Optimization** In order to determine the optimum preventive maintenance strategies for the Distribution Assets, the existing strategies should be aligned with best industry practices for PMO programs. We noted that as per the OEB directives in 2015, Dx Asset Management undertook to survey other distribution utilities for the purpose of identifying and incorporating best practices in the preventive maintenance strategy for Vegetation Management, however we were advised that no similar alignment with industry best practices is performed for Lines and Stations (non-vegetation related) preventive maintenance strategies. ***Risk:*** *Lack of identification of industry best practice and incorporating them in the process may result in less than optimal maintenance plan.*	L	Extend the approach of identifying and incorporating industry best practices in the planning process for Vegetation Management to Lines and Stations programs.	Dx Asset Management will align Lines and Stations PMO with industry best practices.	Paul Brown, Director, Distribution Asset Management	Q4, 2016

ATTACHMENT A

LEGEND: RESIDUAL RISK CLASSIFICATION:

RESIDUAL RISK[1] CLASSIFICATION	Assessment Indication
LOW: Unable to make year over year planning process and efficiency improvements.	L
MEDIUM: Unable to meet planned cost and accomplishment targets or address asset performance and condition issues through maintenance.	M
HIGH: Unable to identify assets and maintenance requirements, comply with regulatory requirements or increasing maintenance backlog.	H

OPPORTUNITIES FOR IMPROVEMENT

The following Opportunities For Improvement, identified as part of completing this Audit, are provided for Management's consideration (the anticipated LoB accountability is identified in parenthesis):

PMO Process Training: Currently, planners are following their own program-specific planning process based on their understanding and experience about what needs to be done. All three planners for Overhead Lines, Stations and Vegetation Management are relatively new (less than five years in their role) and have had little or no knowledge transfer or process training.
We suggest that Dx Asset Management establish work process training to support the planners to ensure the effective and efficient execution of the planning process.
(*Paul Brown, Director, Distribution Asset Management*).

Asset Data for Planning: Availability of complete and accurate feeder data is important for the effective planning of preventive maintenance (PM) work under vegetation management. We noted the following inaccuracies in the planning data for vegetation management:

- Number of feeders is inconsistent between SAP and Forestry Management System database (FMS). Number of feeders in SAP was 3,239 vs. 2,980 in FMS.
- Length of the feeder data are inaccurate or missing in SAP e.g. 6% (201) feeders in SAP were recorded with "0" km length.
- In some cases, feeder ID references between SAP and FMS are not consistent (i.e. they do not align).
- According to the Dx Management documentation, an accurate inventory of Right-of-Way is not known. As per Asset Portfolio Document for 2016-2020 dated May 2015, the "*...exact Right-of-Way km inventory is unknown*" and "*…it is expected that Right-of-Way inventory has increased from our filed inventory of 102,000 km to approximately 112,000 km*".
- We were informed that time is spent to manually reconcile the feeder data between SAP and FMS annually.

We suggest that Dx Asset Management establish SAP as a 'source of truth' for feeder data and periodically review to ensure that data in SAP synchronizes with FMS. Alternatively, consider the integration of SAP with FMS or automation of the reconciliation process to increase efficiency in the planning process. (*Paul Brown, Director, Distribution Asset Management*).

ATTACHMENT B

Vegetation Management PMO Strategy *(Details pertaining to Audit Finding # 2.1)*

Background

Hydro One owns and operates approximately 120,000 kilometers of distribution line. These lines are built on approximately 102,000 kilometers of rights-of-way (ROW) and 112,000 hectares of land. A majority of these ROWs support diverse and complex plant communities that if left unmanaged, present a risk of growing into energized equipment and impeding access to line assets. The Vegetation Management program is required to manage the natural plant communities found in rural areas, as well as the landscaped plant communities common in urban areas. The program is designed to provide cost effective control of vegetation growth, meet reliability expectations, provide a safe environment for our employees and the public, and minimize environmental, ecological and social impacts.

The strategy for the vegetation management investment is to regain control of our backlogged rights-of-way and place our assets on an 8-year clearing cycle.

Audit Observations:

The table below provides the historic and proposed funding for preventive maintenance work in Vegetation Management. The line clearing program constitutes approximately 70% of the total budget for Vegetation Management.

Table B1- Preventive Maintenance Historical Actual and Future Budget for Dx Vegetation Management [3]

N.D.M.1.03	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Preventative Maintenance ($M)	120.7	120.8	129.4	126.6	131.1	119.9	*160.6* *130.8*[4]	*161.1*	*149.8*	*149.8*	*143.4*
Line Clearing ($M)	78.4	80.5	87.1	8.0	92.2	95.3	*117.5* *98.0*[5]	*120.2*	*106.9*	*99.8*	*99.01*
Target Line Clearing Units (km)	12,750	12,750	12,750	12,750	12,750	12,750	*14,250* *11,000*[6]	*14,250*	*12,750*	*12,750*	*12,750*
Line Clearing Units (km) Completed	11,432	11,097	11,195	10,378	9,474	10,366	-	-	-	-	-
Units for Line Clearing (km) Incomplete	1,318	1,653	1,555	2,372	3,276	2,384	-	-	-	-	-
Line Clearing Units ($/km)	6,861	7,258	7,777	7,994	9,732	9,193	*8,249* *8,909*[7]	*8,436*	*8,383*	*7,829*	*7,764*

- The analysis above shows that funding has consistently increased through the 2010-2014 year range. In 2015, the OEB approved a budget of $129M for vegetation management. We were informed that this budget was further reduced by $9.5M based on corporate direction (Operations Committee meeting).
- Vegetation Management has not been able to accomplish the targeted work of 12,750 km of Right of Way (ROW) line clearing under the preventive maintenance program despite increased funding levels from 2010 to 2014.

[3] Actual values for 2010-2015 and Budgeted values for 2016-2020
[4] The Program Optimization process within Hydro One resulted in the reduction of the budget for preventive maintenance work.
[5] Budget for the line clearing program was reduced from $117.5M to $98M.
[6] Due to the reduced budget, the work accomplishment target was also reduced from 14,250 km to 11,000 km.
[7] The revised unit cost calculated based on the revised budget and work accomplishment target.

ATTACHMENT B

Vegetation Management PMO Strategy *(Details pertaining to Audit Finding # 2.1)*

- Based on the work accomplishments, actual average maintenance cycle length is approximately 9.5years. The targeted maintenance cycle is 8years as defined in the Investment Planning Document for 2016-2020 dated May 14, 2015 as the high level Dx Asset Management strategy.
- Vegetation Management analysis shows that provincially approximately 28% of Hydro One Right-of-Way inventory is greater than 8 years since last clearing date.
- Backlogged maintenance increases operational unit costs, increases risk to public safety and reliability and negatively impacts shareholder/regulator value risk.
- In its filings for the Distribution Rate Application EB-2013-0416/EB-2014-0247 for the period 2015-2019, Hydro One proposed an annual cost of $180M for 2016, for preventive and corrective (demand) maintenance work including work required to clear the preventive maintenance backlog.
- The Ontario Energy Board approved $167M ($160M preventive + $7M for corrective) with a yearly cut of $13M for each of the years during this period from the proposed budget for the same volume of work. The direction was to increase the work efficiency and reduce the unit cost per km of work.
- As a result of the Program Optimization process within Hydro One, this budget was further reduced from $167M to $145M. The accomplishment target for the Line Clearing program for 2016 was also reduced to 11,000 km from 14,250 km (12,750 km to sustain an 8 year maintenance cycle plus 1,500 km backlog).

Business Risks:
With the $13M annual reduction in budget directed by the OEB, achieving the units for the budget will be a challenge. Further cuts to this budget has made achieving the OEB objectives even less likely, resulting in a regulatory risk along with the reliability, cost and safety risks associated with underachieving the vegetation management cycle targets.

Management Strategies for Managing Risk:
Accomplishments at the proposed level remain below the asset optimal and the biggest risk categories affected are productivity/cost efficiency and public safety in populated areas. Public safety risks will be managed through demand maintenance and continued backlog reduction. Productivity/cost efficiency risks will be managed through improved operational planning and a purchased services agreement that will put downward pressure on costs.

UNDERTAKING – JT 3.3

Undertaking

To determine (a) if there are buildings that you are forecasting to deem surplus; (b), the value of those or forecast value; (c) and if you have included or not included those in the application.

Response

Hydro One Networks has one facility that may be deemed surplus, being Beachville Operations Centre. The approximate market value for this location is estimated at $150K, and was not considered in the rate application.

UNDERTAKING – JT 3.4

Undertaking

To provide the amount of the in-service additions that you are expecting in 2018.

Response

Table 1 below reflects forecast in-service addition assumptions related to distribution program investments.

Column 1 reflects the assumption for 2018 capital expenditures that are in-serviced in 2018. Column 2 reflects the total planned in-service for 2018 relative to the 2018 capital expenditure. The difference being that Column 2 includes the in-servicing of capital expenditures from previous periods (i.e. the work in progress).

Where the Column 1 figure is less than 100%, the residual capital expenditure is assumed to be in-serviced the following year.

Table 1: In-Service Addition Assumptions for Distribution Program Investments

		Column 1	**Column 2**
Ref #	**Investment Name**	**Percentage of 2018 Capital estimated to be ISA in 2018**	**Total 2018 ISA* / 2018 Capital**
SA-01	Joint Use and Line Relocations Program	49%	+100%
SA-02	Meter Infrastructure Sustainment	100%	100%
SA-03	AMI Network Expansion	100%	100%
SA-04	New Load Connections, Service Upgrades, Cancellations and Metering	90%	89%
SA-05	Generation Connections	40%	+100%
SR-01	Distribution Station Demand Program	35%	84%
SR-02	Mobile Unit Substations Program	35%	59%
SR-03	Station Spare Transformer Purchases	35%	41%
SR-04	Distribution Station Component Planned Replacement Program	35%	+100%
SR-05	Distribution Station Feeder Upgrade	35%	56%

SR-06	Distribution Station Refurbishments	35%	+100%
SR-07	Distribution Lines Trouble Call and Storm Damage Response Program	95%	96%
SR-08	Distribution Lines PCB Equipment Replacement Program	99%	99%
SR-09	Pole Replacement Program	99%	99%
SR-10	Distribution Lines Planned Component Replacement	84%	94%
SR-11	Component Replacement Submarine Cable	93%	88%
SR-12	Distribution Lines Sustainment Initiatives	40%	93%
SR-13	Life Cycle Optimization and Operational Efficiency	40%	+100%
SR-14	AMI Hardware Refresh	100%	-
SS-01	Remote Disconnection Reconnection Program	100%	100%
SS-02	System Upgrades Driven by Load Growth	40%	+100%
SS-03	Reliability Improvements	40%	+100%
SS-04	Demand Investments	40%	+100%
SS-05	Distribution System Modifications	40%	+100%
SS-06	Worst Performing Feeders Program	40%	40%
GP-02	Real Estate Facilities Capital	88%	+100%
GP-03	MFA Servers and Storage	100%	100%
GP-04	MFA PC and Printer Hardware	100%	100%
GP-05	Hardware/Software Refresh and Maintenance	85%	+100%
GP-06	MFA Telecom Infrastructure	100%	100%
GP-28	Call Centre Technology	100%	100%

*Includes amounts spent in prior year, but not ISA until 2018

UNDERTAKING – JT 3.5

Undertaking

With reference to the Navigant Study, to break stations down into full station rebuilt, and substation-centric, with respect to the plan for 2018 and 2022.

Response

Of the seventy-three stations identified for refurbishment listed in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.7, ISD SR-06 Distribution Station Refurbishments, Hydro One Distribution estimates that eleven will be full station rebuilds and sixty-two will be substation-centric refurbishments. The breakdown of full station rebuilds versus substation-centric refurbishments is subject to change following the completion of individual scope documentation for each station.

UNDERTAKING – JT 3.6

Undertaking

To provide the 2017 data in the table at I24-Energy Probe-34.

Response

Table 1 - Historical Urban SAIDI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Excluding LOS and Excluding FM	2.9	2.0	2.3	2.6	2.2	1.9
Excluding LOS and Including FM	3.4	10.3	2.6	3.4	2.8	2.6
Including LOS and Excluding FM	3.2	2.2	2.8	2.8	2.4	2.4
Including LOS and Including FM	3.8	11.1	3.1	3.5	3.0	3.3

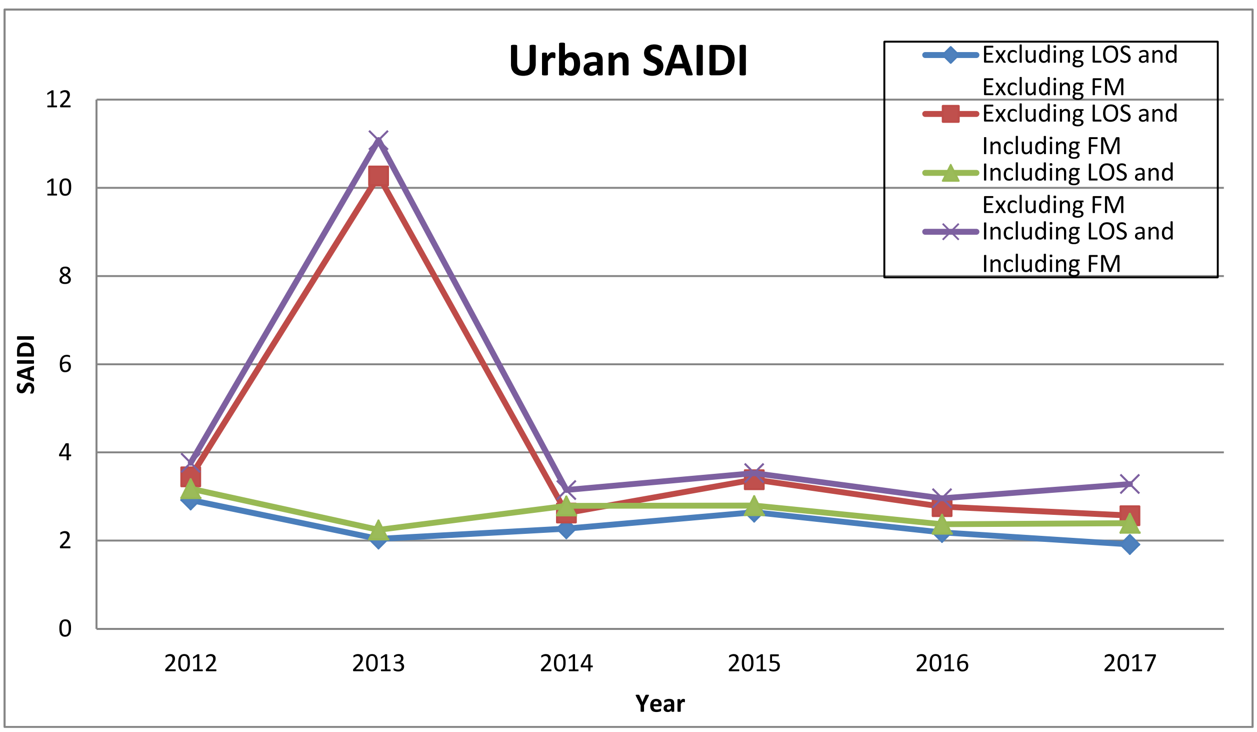

Figure 1 – Chart of Historical Urban SAIDI

Witness: JESUS Bruno

Table 2 - Historical Urban SAIFI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Excluding LOS and Excluding FM	1.3	1.1	1.4	1.1	1.1	1.0
Excluding LOS and Including FM	1.5	2.1	1.4	1.2	1.2	1.1
Including LOS and Excluding FM	1.7	1.6	2.3	1.4	1.6	1.4
Including LOS and Including FM	1.9	2.8	2.3	1.6	1.7	1.6

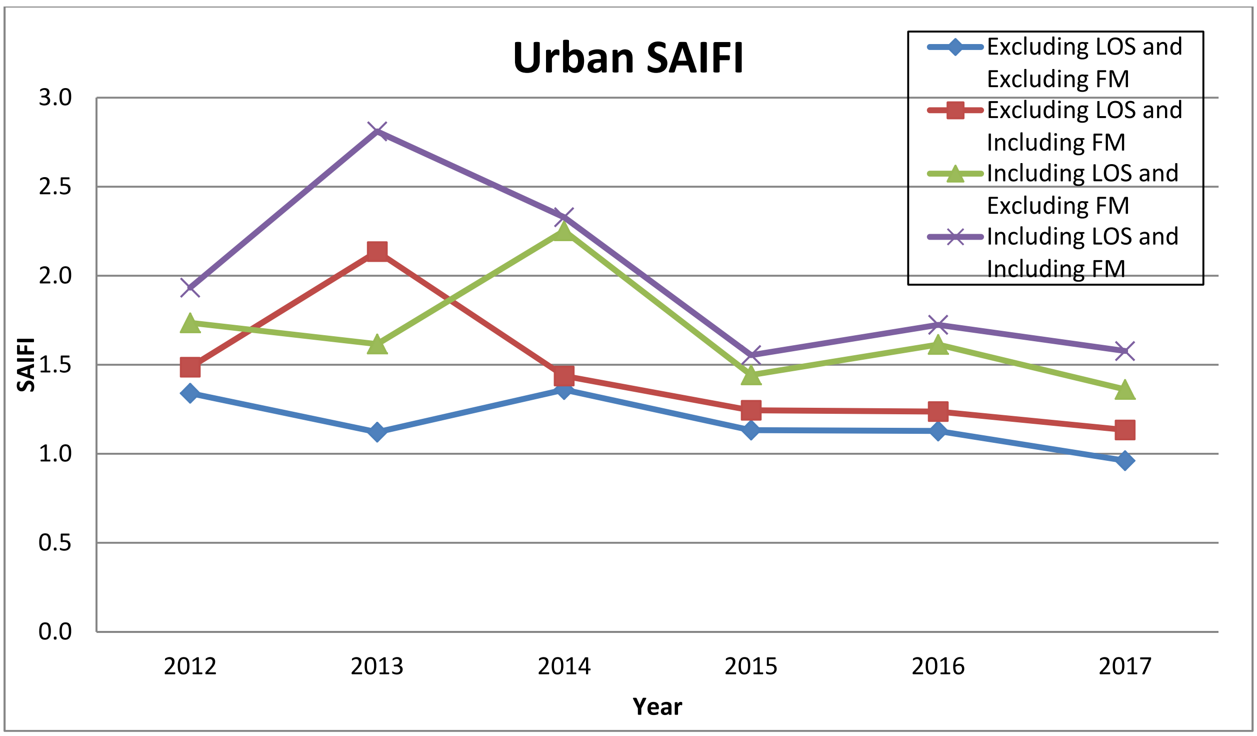

Figure 2 – Chart of Historical Urban SAIFI

Table 3 - Historical Urban CAIDI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Excluding LOS and Excluding FM	2.2	1.8	1.7	2.3	1.9	2.0
Excluding LOS and Including FM	2.3	4.8	1.8	2.7	2.2	2.3
Including LOS and Excluding FM	1.8	1.4	1.2	1.9	1.5	1.8
Including LOS and Including FM	1.9	3.9	1.4	2.3	1.7	2.1

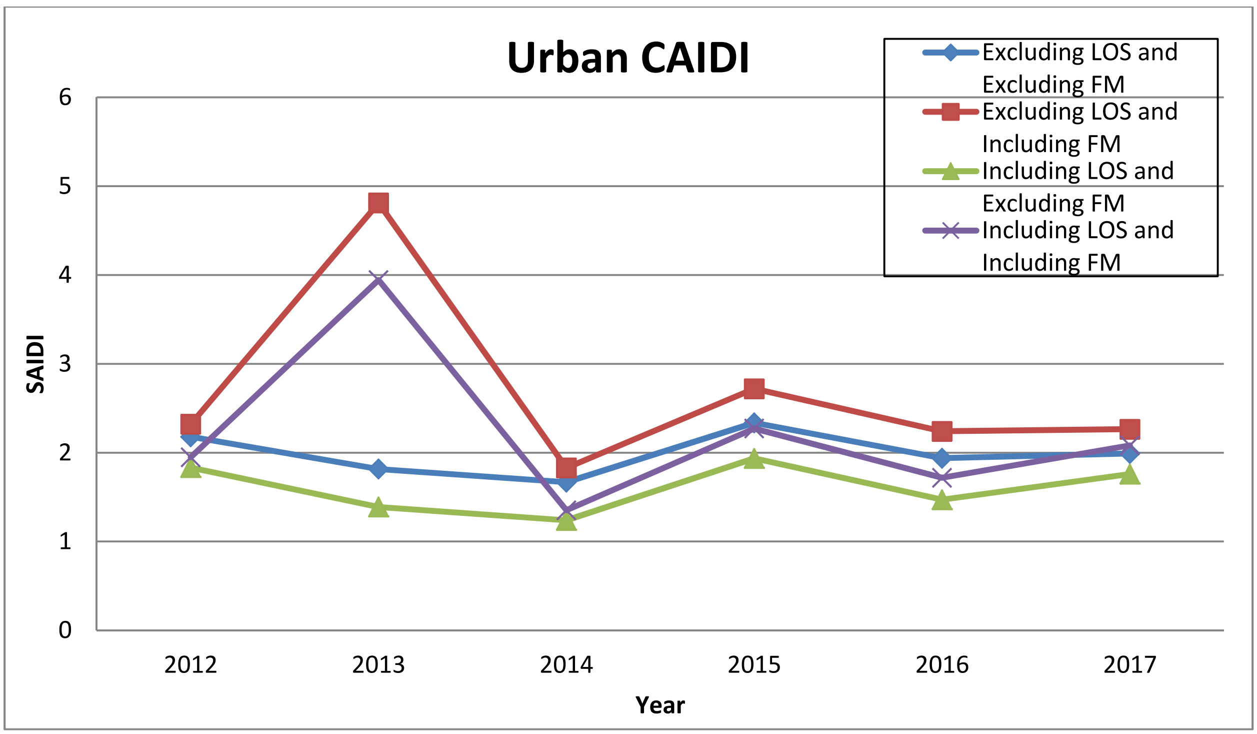

Figure 3 – Chart of Historical Urban CAIDI

Table 4 - Historical Rural SAIDI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Excluding LOS and Excluding FM	7.7	7.5	8.2	8.4	8.6	8.8
Excluding LOS and Including FM	11.8	29.0	10.3	13.5	14.0	13.5
Including LOS and Excluding FM	8.2	8.1	8.6	9.1	9.1	9.4
Including LOS and Including FM	12.6	30.0	10.9	14.3	14.6	14.4

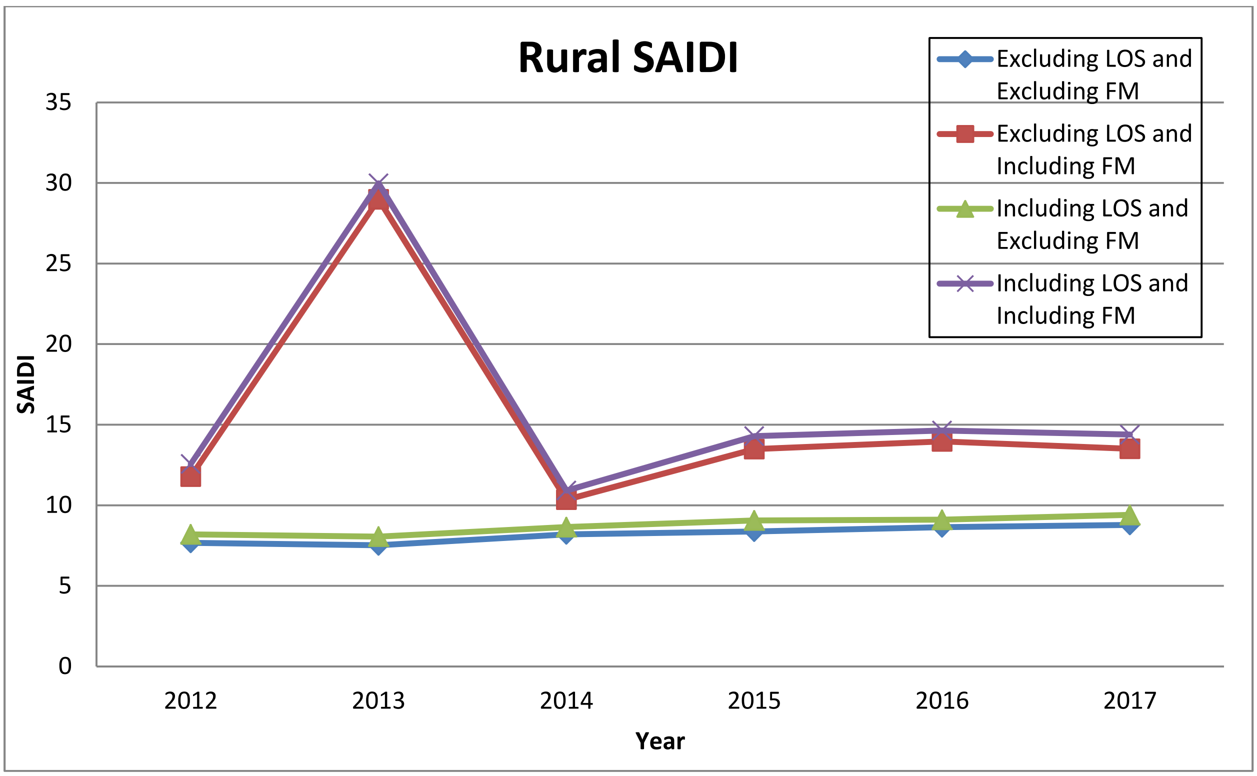

Figure 4 – Chart of Historical Rural SAIDI

Table 5 - Historical Rural SAIFI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Excluding LOS and Excluding FM	2.8	2.7	2.9	2.8	2.7	2.5
Excluding LOS and Including FM	3.4	4.6	3.1	3.3	3.2	3.2
Including LOS and Excluding FM	3.3	3.0	3.4	3.4	3.1	3.0
Including LOS and Including FM	4.0	4.9	3.7	3.9	3.7	3.7

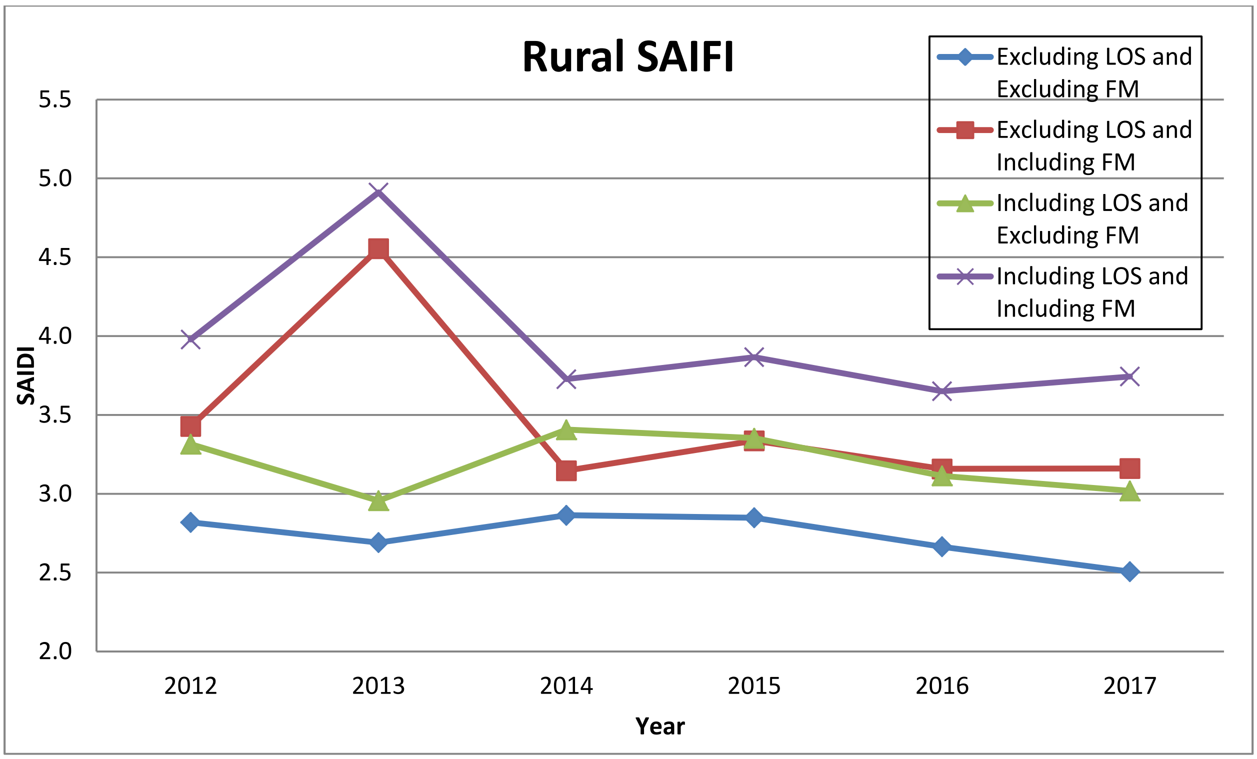

Figure 5 – Chart of Historical Rural SAIFI

Table 6 - Historical Rural CAIDI Summary

Outage Cause	2012	2013	2014	2015	2016	2017
Excluding LOS and Excluding FM	2.7	2.8	2.9	2.9	3.2	3.5
Excluding LOS and Including FM	3.4	6.4	3.3	4.0	4.4	4.3
Including LOS and Excluding FM	2.5	2.7	2.5	2.7	2.9	3.1
Including LOS and Including FM	3.2	6.1	2.9	3.7	4.0	3.8

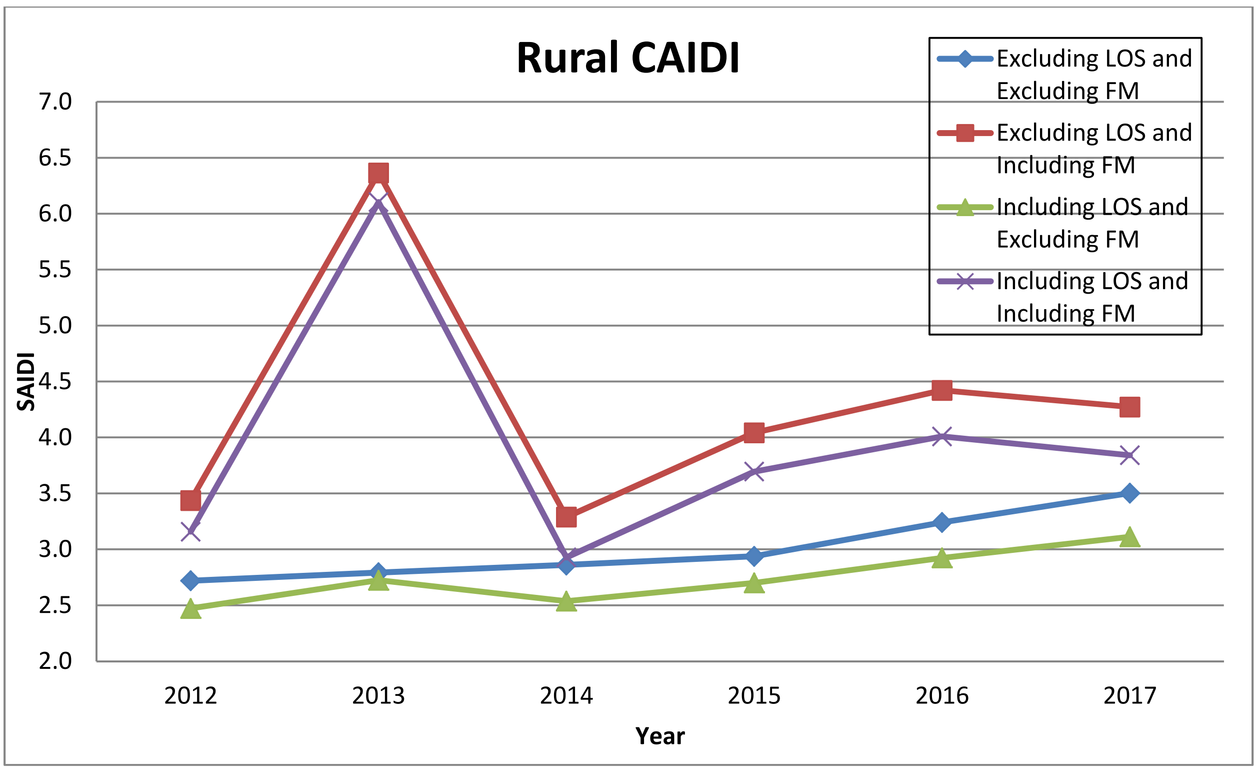

Figure 6 – Chart of Historical Rural CAIDI

UNDERTAKING – JT 3.7

Undertaking

To break down each of the three steps into the four spending categories. So system access, system renewal, general plant, so we understand not just what the changes were overall but in which categories.

Response

The tables below reflect a summary of 2018-22 planned costs for distribution investments at the various investment planning stages, broken down into the OEB categories of System Access, System Renewal, System Service, General Plant and System O&M.

	Investment Development ($M)				
	2018	**2019**	**2020**	**2021**	**2022**
System Access	163.5	166.2	170.0	173.1	177.5
System Renewal	385.1	392.9	392.1	412.9	501.1
System Service	90.2	103.0	86.1	70.4	82.0
General Plant	171.1	205.0	125.0	122.4	120.9
Total Capital	**809.9**	**867.1**	**773.1**	**778.7**	**881.4**
System O&M	602.3	612.6	616.9	624.4	633.1
Total	**1,412.2**	**1,479.7**	**1,390.0**	**1,403.1**	**1,514.5**

	Investment Optimization ($M)				
	2018	**2019**	**2020**	**2021**	**2022**
System Access	163.5	166.2	170.0	173.1	177.5
System Renewal	264.9	273.8	275.6	288.2	375.2
System Service	84.3	93.2	93.8	86.2	77.0
General Plant	170.1	203.7	121.7	116.0	117.4
Total Capital	**682.9**	**736.7**	**661.1**	**663.4**	**747.1**
System O&M	583.0	592.1	596.9	605.2	614.1
Total	**1,265.9**	**1,328.8**	**1,258.0**	**1,268.6**	**1,361.2**

	Investment Approval and Implementation ($M)				
	2018	**2019**	**2020**	**2021**	**2022**
System Access	154.6	157.6	160.9	163.8	167.8
System Renewal	248.6	318.7	336.7	356.5	445.1
System Service	81.8	93.4	85.6	77.6	68.2
General Plant	149.0	187.1	135.8	133.4	136.6
Total Capital	**633.9**	**756.8**	**719.0**	**731.3**	**817.7**
System O&M	564.6	568.1	577.4	584.2	590.4
Total	**1,198.6**	**1,324.9**	**1,296.4**	**1,315.5**	**1,408.1**

Table above excludes integration of Acquired Utilities in 2021/22.

UNDERTAKING – JT 3.8

Undertaking

To advise which levels have been selected for which programs.

Response

The table below identifies the alternative funding level (Asset Optimal, Intermediate, Vulnerable, Demand) presented in this Application for each program.

Ref #	Investment Name	Alternative Funding Level
SA-01	Joint Use and Line Relocations Program	Demand
SA-02	Meter Infrastructure Sustainment	Demand
SA-03	AMI Network Expansion	Asset Optimal
SA-04	New Load Connections, Service Upgrades, Cancellations and Metering	Demand
SA-05	Generation Connections	Asset Optimal
SR-01	Distribution Station Demand Program	Demand
SR-02	Mobile Unit Substations Program	Vulnerable
SR-03	Station Spare Transformer Purchases	Vulnerable
SR-04	Distribution Station Component Planned Replacement Program	Vulnerable
SR-05	Distribution Station Reclosers Upgrade	Intermediate
SR-06	Distribution Station Refurbishments	Vulnerable
SR-07	Distribution Lines Trouble Call and Storm Damage Response Program	Demand
SR-08	Distribution Lines PCB Equipment Replacement Program	Demand
SR-09	Pole Replacement Program	Intermediate
SR-10	Distribution Lines Planned Component Replacement	Vulnerable
SR-11	Component Replacement Submarine Cable	Asset Optimal
SR-12	Distribution Lines Sustainment Initiatives	Intermediate
SR-13	Life Cycle Optimization and Operational Efficiency	Asset Optimal
SR-14	AMI Hardware Refresh	Vulnerable
SS-01	Remote Disconnection Reconnection Program	Asset Optimal
SS-02	System Upgrades Driven by Load Growth	Asset Optimal

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Ref #	Investment Name	Alternative Funding Level
SS-03	Reliability Improvements	Asset Optimal
SS-04	Demand Investments	Demand
SS-05	Distribution System Modifications	Intermediate
SS-06	Worst Performing Feeders Program	Vulnerable
GP-02	Real Estate Facilities Capital	Vulnerable
GP-03	MFA Servers and Storage	Intermediate
GP-04	MFA PC and Printer Hardware	Intermediate
GP-05	Hardware/Software Refresh and Maintenance	Vulnerable
GP-06	MFA Telecom Infrastructure	Intermediate
GP-28	Call Centre Technology	Asset Optimal

UNDERTAKING – JT 3.9

Undertaking

To provide the output of an optimization showing dollars per risk mitigated, showing the composite scores.

Response

Table 1 provides the total value and total planned cost over the 2018-22 period for System Renewal investments. Table 2 provides the risk assessments for their subcomponents, consistent with Exhibit I-24-Staff-100.

Table 2 shows the total value (risk mitigated, financial benefit) and baseline value (baseline risk exposure) for each of the System Renewal investments included in Exhibit I-24-Staff-100. As noted in Exhibit JT2.10, through optimization, projects may shift in time which may defer value and decrease the investment's total value. Given the scheduling variability, an efficiency calculation (value/$) has not been provided for each investment.

Table 1: System Renewal Investments and Total Value

	2018-22 Planned Expenditures ($M)	Total Value: Units of Risk Mitigated/Financial Benefits)
ISD-SR-01 - Distribution Stations Demand Capital Program	12.3	324,440
ISD-SR-02 - Mobile Unit Substation Program	26.9	946,252
ISD-SR-03 - Station Spare Transformer Purchases Program	18.6	439,028
ISD-SR-04 - Distribution Station Planned Component Replacement Program	11.0	664,438
ISD-SR-05 - Distribution Station Feeder Protection Upgrade	12.1	2,718,114
ISD-SR-06 - Distribution Station Refurbishment	148.1	1,698,097
ISD-SR-07 - Distribution Lines Trouble Call and Storm Damage Response Program	431.0	6,326,725
ISD-SR-08 - Distribution Lines PCB Equipment Replacement Program	72.8	312,205
ISD-SR-09 - Pole Replacement Program	579.0	3,076,901

ISD-SR-10 - Distribution Lines Planned Component Replacement Program	35.3	1,433,155
ISD-SR-11 - Submarine Cable Replacement Program	39.1	1,177,446
ISD-SR-12 - Distribution Lines Sustainment Initiatives	151.7	1,369,800
ISD-SR-13 - Life Cycle Optimization & Operational Efficiency Projects	134.0	2,047,887
ISD-SR-14 - Advanced Meter Infrastructure Hardware Refresh	79.9	83,981

Table 2:	**Outcomes (Total Value: Units of Risk Mitigated/Financial Benefits)**									**Baseline (Risk unit exposure in absence of investment)**							
Sub Description	**Value**	**Shareholder Value Risk**	**Reliability Risk**	**Employees Risk**	**Customer Risk**	**Environment Risk**	**Safety Risk**	**Productivity Risk**	**Financial (Currency)**	**Baseline**	**Shareholder Value Risk**	**Reliability Risk**	**Employees Risk**	**Customer Risk**	**Environment Risk**	**Safety Risk**	**Productivity Risk**
ISD-SR-01 - Distribution Stations Demand Capital Program																	
DS Demand/Emergency Capital Program	324,440	77,271	17,862	-	153,388	-	75,919	-	-	329,873	78,051	19,416	-	154,937	-	77,469	-
ISD-SR-02 - Mobile Unit Substation Program																	
DS MUS Purchase Program	946,252	107,515	40,924	-	432,419	164,515	200,879	-	-	1,095,201	108,499	58,247	-	464,812	234,153	229,489	-
ISD-SR-03 - Station Spare Transformer Purchases Program																	
DS Transformer Purchase Program	439,028	-	25,240	-	275,169	138,619	-	-	-	504,808	-	38,831	-	309,875	156,102	-	-
ISD-SR-04 - Distribution Station Planned Component Replacement Program																	
DS Component Replacement Program	664,438	-	15,340	-	432,740	216,358	-	-	-	725,955	-	26,990	-	464,812	234,153	-	-
ISD-SR-05 - Distribution Station Feeder Protection Upgrade																	
DS Recloser Upgrade Program	2,718,114	186,417	20,052	-	549,162	-	1,962,483	-	-	3,084,451	355,958	27,712	-	712,741	-	1,988,040	-
ISD-SR-06 - Distribution Station Refurbishment																	
DS Station Refurbishment Program	1,698,097	-	63,729	-	1,082,702	551,665	-	-	-	2,252,951	-	156,055	-	1,394,436	702,460	-	-
ISD-SR-07 - Distribution Lines Trouble Call and Storm Damage Response Program																	
Dx Capital Trouble Call Damage Claims	127,950	15,610	3,883	-	77,469	-	30,987	-	-	127,950	15,610	3,883	-	77,469	-	30,987	-
Dx Capital Trouble Call Poles & Equipme	781,599	104,068	388,314	-	206,583	-	82,633	-	-	781,599	104,068	388,314	-	206,583	-	82,633	-
Dx Capital Post Trouble Call & Power Qu	277,761	39,026	1,165	-	206,583	-	30,987	-	-	277,761	39,026	1,165	-	206,583	-	30,987	-
Dx Capital Storm Damage	4,296,308	520,341	2,329,885	-	1,032,916	-	413,166	-	-	4,296,308	520,341	2,329,885	-	1,032,916	-	413,166	-
Dx Capital Trouble Sub and UG Cable	843,108	41,627	388,314	-	206,583	-	206,583	-	-	843,108	41,627	388,314	-	206,583	-	206,583	-
ISD-SR-08 - Distribution Lines PCB Equipment Replacement Program																	

PCB Overhead Equipment Replacement	312,205	312,205	-	-	-	-	-	-	-	312,205	312,205	-	-	-	-	-	-
ISD-SR-09 - Pole Replacement Program																	
End of Life Replacement of Wood Poles	3,076,901	1,496,454	404,157	-	1,111,324	-	64,965	-	-	3,767,261	1,821,193	434,912	-	1,446,082	-	65,074	-
ISD-SR-10 - Distribution Lines Planned Component Replacement Program																	
Component Replacement - Regulators/Recl	86,858	-	37,278	-	49,580	-	-	-	-	108,573	-	46,598	-	61,975	-	-	-
Component Replacement - Sentinel Lights	154,937	-	-	-	154,937	-	-	-	-	154,937	-	-	-	154,937	-	-	-
Conductor Replacement - Overhead	767,464	-	209,690	-	278,887	-	278,887	-	-	852,738	-	232,988	-	309,875	-	309,875	-
Component Replacement - Nest Platforms	49,227	6,504	3,697	-	-	39,026	-	-	-	49,413	6,504	3,883	-	-	39,026	-	-
Component Replacement - Crossarms	83,744	-	31,065	-	-	-	52,679	-	-	100,806	-	38,831	-	-	-	61,975	-
Component Replacement - Switches	73,780	-	73,780	-	-	-	-	-	-	93,195	-	93,195	-	-	-	-	-
Component Replacement - Transformers	217,145	-	93,195	-	-	-	123,950	-	-	271,432	-	116,494	-	-	-	154,937	-
ISD-SR-11 - Submarine Cable Replacement Program																	
Conductor Replacement - Submarine	1,177,446	44,957	-	-	-	-	1,132,489	-	-	1,596,204	46,831	-	-	-	-	1,549,373	-
ISD-SR-12 - Distribution Lines Sustainment Initiatives																	
Large Sustainment Initiatives	870,674	155,915	93,195	-	311,751	-	309,813	-	-	871,295	156,102	93,195	-	312,122	-	309,875	-
Small Sustainment Initiatives	499,127	62,254	4,660	-	123,578	-	308,635	-	-	500,925	62,441	4,660	-	123,950	-	309,875	-
ISD-SR-13 - Life Cycle Optimization & Operational Efficiency Projects																	
Other Lifecycle Optimization Projects	139,101	90,327	3,359	13,549	26,896	4,389	581	-	-	139,112	90,327	3,370	13,549	26,896	4,389	581	-
Clearwater Bay voltage conversion Phase	16,265	15,298	328	-	639	-	-	-	-	16,967	15,610	582	-	775	-	-	-
Carleton Place DS Reconstruction	18,872	6,244	233	-	12,395	-	-	-	-	18,872	6,244	233	-	12,395	-	-	-
Manitou Lake DS & Line Work	16,921	15,563	582	-	775	-	-	-	-	16,967	15,610	582	-	775	-	-	-

Clearwater Bay voltage conversion Phas	14,141	13,042	501	-	598	-	-	-	-	16,380	15,022	582	-	775	-	-	-
Margach F3 voltage conversion	17,404	15,586	1,092	-	726	-	-	-	-	17,550	15,610	1,165	-	775	-	-	-
St Thomas DS Voltage Conversion	31,344	-	546	-	29,043	1,756	-	-	-	32,254	-	561	-	29,821	1,873	-	-
ISD-SR-13 - Life Cycle Optimization & Operational Efficiency Projects (cont'd)																	
Ridgetown Palmer DS Voltage Conversion	32,254	-	561	-	29,821	1,873	-	-	-	32,254	-	561	-	29,821	1,873	-	-
Beaver Valley RS	109,329	38,944	2,893	146	28,402	38,944	-	-	-	112,576	39,799	3,009	149	29,821	39,799	-	-
Dx Coniston Voltage Conversion	122,220	40,740	608	-	80,872	-	-	-	-	124,882	41,627	621	-	82,633	-	-	-
Hanmer TS Feeder Development	117,918	39,015	1,456	-	77,447	-	-	-	-	125,755	41,627	1,495	-	82,633	-	-	-
Burford DS Removal	30,220	-	525	-	27,939	1,756	-	-	-	31,130	-	540	-	28,717	1,873	-	-
Thorold Defoe DS Voltage Conversion	6,174	1,873	582	-	3,718	-	-	-	-	6,174	1,873	582	-	3,718	-	-	-
Princeton DS Voltage Conversion	63,757	-	1,061	-	56,452	6,244	-	-	-	63,757	-	1,061	-	56,452	6,244	-	-
Barry's Bay Voltage Conversion	36,990	-	582	-	30,164	6,244	-	-	-	37,814	-	582	-	30,987	6,244	-	-
Warkworth DS Removal	37,756	-	3,639	-	28,264	5,852	-	-	-	41,115	-	3,883	-	30,987	6,244	-	-
Alexandria Area Study	44,585	34,208	191	-	10,186	-	-	-	-	54,255	41,627	233	-	12,395	-	-	-
Newport DS removal via voltage conversi	88,599	-	1,094	-	58,191	29,314	-	-	-	88,599	-	1,094	-	58,191	29,314	-	-
Thorold Front DS Voltage Convers	125,523	-	40,942	-	56,246	28,335	-	-	-	128,484	-	40,979	-	58,191	29,314	-	-
Dundas Sydenham DS Voltage Conve	85,638	-	1,057	-	56,246	28,335	-	-	-	88,599	-	1,094	-	58,191	29,314	-	-
Thorold Turner DS Voltage Conver	80,190	-	990	-	52,668	26,532	-	-	-	84,175	-	1,039	-	55,285	27,850	-	-
Thorold Ormond Voltage Conversion	82,838	-	1,023	-	54,407	27,408	-	-	-	88,599	-	1,094	-	58,191	29,314	-	-
Thorold Cleveland DS Voltage Con	122,949	-	40,983	-	54,507	27,459	-	-	-	124,133	-	40,998	-	55,285	27,850	-	-
Thorold Allanport DS Voltage Con	126,871	-	42,290	-	56,246	28,335	-	-	-	131,258	-	43,753	-	58,191	29,314	-	-
Forest Jefferson and Mcnab DS Co	29,359	-	511	-	27,204	1,644	-	-	-	31,130	-	540	-	28,717	1,873	-	-
Lucan Market DS Conversion	30,220	-	525	-	27,939	1,756	-	-	-	31,130	-	540	-	28,717	1,873	-	-
Wallaceburg DS Conversion	29,712	-	517	-	27,505	1,690	-	-	-	31,130	-	540	-	28,717	1,873	-	-
Embrun Area Study	15,509	5,131	191	-	10,186	-	-	-	-	18,872	6,244	233	-	12,395	-	-	-
Brockville Town Area Study	15,509	5,131	191	-	10,186	-	-	-	-	18,872	6,244	233	-	12,395	-	-	-
Smiths Falls Area Study	15,859	5,482	191	-	10,186	-	-	-	-	18,872	6,244	233	-	12,395	-	-	-
Chesterville Area Study	15,509	5,131	191	-	10,186	-	-	-	-	18,872	6,244	233	-	12,395	-	-	-

Ivy Lea Area Study	15,509	5,131	191	-	10,186	-	-	-	-	18,872	6,244	233	-	12,395		-	-	-
Actons Corners Area Study	15,509	5,131	191	-	10,186	-	-	-	-	18,872	6,244	233	-	12,395		-	-	-
Russell Area Study	15,509	5,131	191	-	10,186	-	-	-	-	18,872	6,244	233	-	12,395		-	-	-
Maxville Area Study	15,509	5,131	191	-	10,186	-	-	-	-	18,872	6,244	233	-	12,395		-	-	-
Kemptville Area Study	15,509	5,131	191	-	10,186	-	-	-	-	18,872	6,244	233	-	12,395		-	-	-
ISD-SR-13 - Life Cycle Optimization & Operational Efficiency Projects (cont'd)																		
Prescott Area Study	15,509	5,131	191	-	10,186	-	-	-	-	18,872	6,244	233	-	12,395		-	-	-
Berwick - Finch Area Study	15,509	5,131	191	-	10,186	-	-	-	-	18,872	6,244	233	-	12,395		-	-	-
Dresden DS Conversion	30,593	-	531	-	28,258	1,804	-	-	-	31,130	-	540	-	28,717	1,873		-	-
Drumbo DS Conversion	29,359	-	511	-	27,204	1,644	-	-	-	31,130	-	540	-	28,717	1,873		-	-
Anderdon DS Conversion	27,483	-	479	-	25,465	1,539	-	-	-	30,067	-	520	-	27,674	1,873		-	-
Wardsville DS Conversion	27,483	-	479	-	25,465	1,539	-	-	-	30,067	-	520	-	27,674	1,873		-	-
Ridgetown DS Conversion	29,359	-	511	-	27,204	1,644	-	-	-	31,130	-	540	-	28,717	1,873		-	-
Brookside DS removal	37,756	-	3,639	-	28,264	5,852	-	-	-	41,115	-	3,883	-	30,987	6,244		-	-
Lily Lake DS Removal	37,756	-	3,639	-	28,264	5,852	-	-	-	41,115	-	3,883	-	30,987	6,244		-	-
ISD-SR-14 - Advanced Meter Infrastructure Hardware Refresh																		
AMI Hardware Refresh (EOL)	83,981	83,981	-	-	-	-	-	-	-	85,520	85,520	-	-	-		-	-	-

UNDERTAKING – JT 3.10

Undertaking

To provide the same table as provided for staff and for each category show the calculations.

Response

Here are the underlying calculations for stations, other station components and vegetation management impacts as reflected in Exhibit DSP Section 2.4.

Stations

Table 52 of DSP Section 2.4, Exhibit B1-1-1 assumes that eliminating all stations in poor condition stations will lead to a 14% improvement in station reliability. The updated assumption is that, by addressing all stations in poor condition, a 9% improvement in station-related reliability will be achieved based on the percentage of station outages that occurred at stations that are in poor condition. Station SAIDI and SAIFI impacts are assumed to be directly proportional to the number of stations that remain in poor condition as shown below.

	Stations in Poor Condition	Calculation	Change in Fleet Condition	Reliability Impact
Current	70	-	-	-
Plan A	0	1 – (0/70)	100%	9%
Plan B	40	1 – (40/70)	43%	4%
Plan C	90	1 – (90/70)	-29%	-3%
Plan B-Modified	70	1 – (70/70)	0%	0%

Other Components

The capital funding available to address other line components is covered under the Planned Component Replacement investment (see Investment Summary Document SR-10). This funding is required to address the replacement of other distribution lines components. The incremental funding available under each scenario relative to Plan B is assumed to address, proportionately, the number of outstanding line equipment defects of approximately 300,000 as shown in the table below.

	Incremental Line Defects Addressed Relative to Plan B (k)	**Calculation**	**Change in # of Defects (Reliability Impact**	**Reliability Impact Shown (Tables 52-53)**
Plan A	25	1 – (275/300)	8.3%	10%
Plan B	0	1 – (300/300)	0%	0%
Plan C	-34	1 – (334/300)	-11.3%	-10%
Plan B-Modified	-5	1 – (305/300)	-1.7%	-5%

Vegetation Management

Plans A, B and B-Modified, reduce the rights of way maintenance on medium or low-priority rights of way by 1,000 kilometers per year. This results in increasing the vegetation backlog by 8% and degrades SAIFI and SAIDI by 1%. These increases are offset by the 9% improvement expected in the high priority rights of way resulting in a total reliability improvement of 8% (i.e. 9% - 1%).

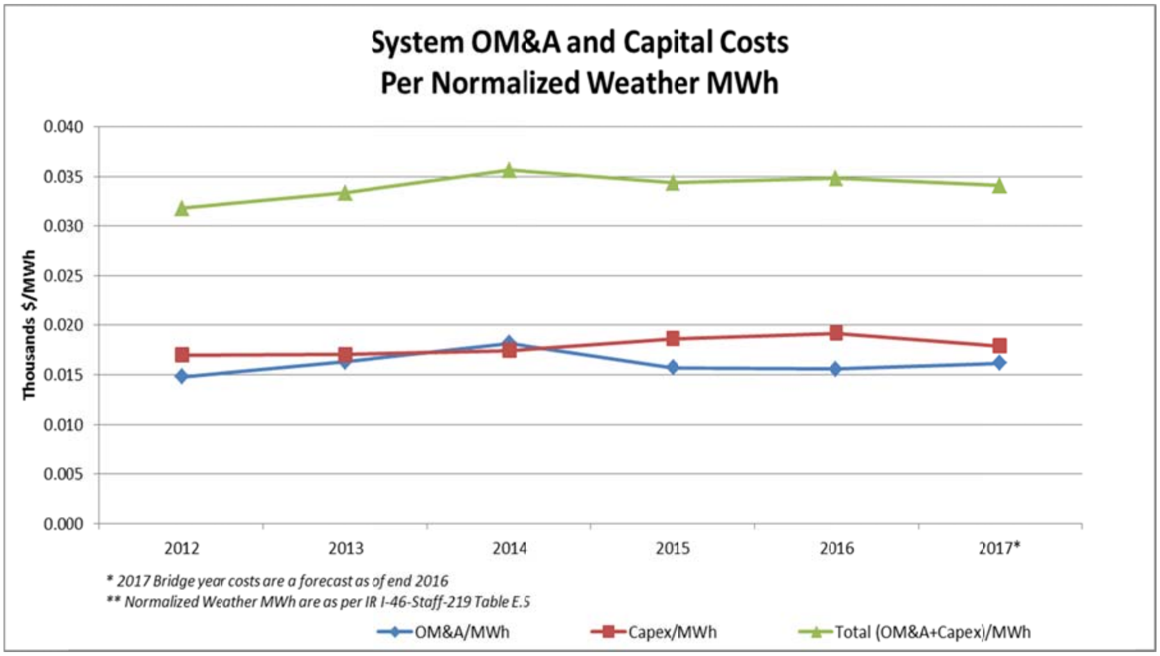
Plan C would reduce maintenance by an additional 1000 kilometers per year on the medium to low-priority rights of way. This is expected to further increase the backlog maintenance and degrade SAIFI and SAIDI by 5%. This is offset by the 9% improvement expected in the high priority rights of way resulting in a total reliability improvement of 4% (i.e. 9%-5%).

UNDERTAKING – JT 3.11

Undertaking

With reference to IR Energy Probe No. 16, to break down the chart into operating and capital, separate them, if possible; to define what OM&A and capital is being included.

Response



Attached is the revised graph showing total system OM&A and Capital costs as per Table 4 shown in Exhibit Q1, Tab 1, Schedule 1 and the Normalized Weather GWh shown in interrogatory I-46-Staff-219 Table E.5.

Witness: JESUS Bruno

UNDERTAKING – JT 3.12

Undertaking

To update the table at Energy Probe IR 17 with 2017 actuals.

Response

Table 4 has been updated with historical data for 2013-2017 as shown below.

SAIDI

SAIDI[1]:	Avg. 2013-17: 7.5 hours/year	Average Number of Hours a Customer is Interrupted					
	Assumptions			Forecasted Impact on SAIDI by 2022[2]			
	Failure Rate/Impact	Contribution to SAIDI	SAIDI Contribution (based on 2013-17)	Plan A	Plan B	Plan C	Plan B-M[3]
Poles	• 0.3k outages/year • 0.4k customers/outage • 4 hours/outage	6%	0.4	12%	10%	(18)%	7%
Stations	• 0.1k outages/year • 0.9k customers/outage • 3 hours/outage	2%	0.2	9%	4%	(3)%	0%
Other Line Components	• 8k outages/year • 0.1k customers/outage • 3 hours/outage	22%	1.6	10%	0%	(10)%	(5)%
Vegetation	• 7k outages/year	34%	2.5	8%	8%	4%	8%
Estimated Impact to SAIDI				6%	3%	(2)%	2%
Forecasted SAIDI (hours)				7.1	7.2	7.6	7.3

1-Excludes force majure and loss of supply event
2-These columns reflect the forecasted impact on SAIDI by the end of 2022. Estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value
3-Impacts for "Plan B-M" refer to Plan "B-Modified" described earlier in this Section

UNDERTAKING – JT 3.13

Undertaking

To provide the compound rate of growth of the rate base over the five years.

Response

Using 2017 OEB approved Distribution rate base as the starting point, the compound average growth (CAGR) of rate base from 2017 to 2022 is 5.3%. The formula for CAGR leverages the first and last year of the range in the calculation. In this specific calculation, the acquired LDCs are included in 2022 rate base, but are not embedded within 2017 OEB approved rate base. To normalize, the CAGR of rate base from 2017 to 2022 excluding the acquired LDCs is 4.9%.

UNDERTAKING – JT 3.14

Undertaking

To review and confirm standards especially regarding DERS.

Response

Hydro One has been involved in developing or updating the technical standards/requirements listed below to effectively enable DER connections to the grid:

- Hydro One's Distributed Generation Technical Interconnection Requirements Interconnections at Voltages 50kV and Below Rev 3. The document contains references to all the standards used during the creation of the Interconnection Requirements.
  See section 3, page 137.
  https://www.hydroone.com/businessservices_/generators_/Documents/Distributed%20Generation%20Technical%20Interconnection%20Requirements.pdf

- Technical Interconnections Requirements for Distributed Generation Micro Generation & Small Generation, 3-phase, less than 30 kW. The standards used for Micro Generation are much the same as those used for larger DGs. https://www.hydroone.com/businessservices_/generators_/Documents/microFIT_TIR_for_Distributed_Generation.pdf

- Hydro One has participated in the development of CSA C22.3 and IEEE 1547.7.

Witness: GARZOUZI Lyla

UNDERTAKING – JT 3.15

Undertaking

To review the white paper referred to in Anwaatin 2 and provide a summary of its content.

Response

See Attachment 1.

EPRI-Hydro One Energy Storage Project

Introduction

With advances in energy storage and the drop in related costs, energy storage shows promise in supporting the energy needs of electricity customers. The following provides a brief description of the EPRI-Hydro One Energy Storage Project.

Project Description

This project aims to advance distribution planning methods when considering energy storage as one element within a Distributed Energy Resources (DER) portfolio.

- Key elements of this project include:
    - Developing a Distribution needs assessment to identify, define, and quantify the value of services that energy storage systems can provide across a utility service.
    - Developing methods to identify energy storage system requirements to adequately address distribution needs within any identified operational constraints.
    - Developing energy storage deployment scenarios:
        - Where to apply energy storage systems along the Distribution feeders;
        - Determining how much storage can be installed when the distribution feeder is already constrained due to reliability/power quality levels.

  Figure 1 below provides the project framework.

- The creation of a formal process will facilitate a better understanding of the potential grid impacts of various deployment scenarios and the opportunities of energy storage (utility-connected as well as customer sited) along the distribution system.

- A methodology will be developed for conducting the technical and cost/benefit analysis of potential solutions involving energy storage.

- Software will be produced so that Hydro One can conduct these siting and sizing analyses. EPRI will also provide training in how to use these tools.

- Traditional distribution planning techniques rely heavily on static power flow data for a selected loading condition – usually the peak power demand forecasted for a selected planning period. This does not give an accurate representation of variable resources such as wind and photovoltaic (PV) generation and limited duration distributed energy resources like energy storage. This project will determine how to use time dependent load flows.

Who is involved:

- Electric Power Research Institute (Principal Investigator)

- Hydro One Networks Inc. (Distribution Planning, Distribution Automation, Operations, RD&D/Strategy & Integrated Planning)

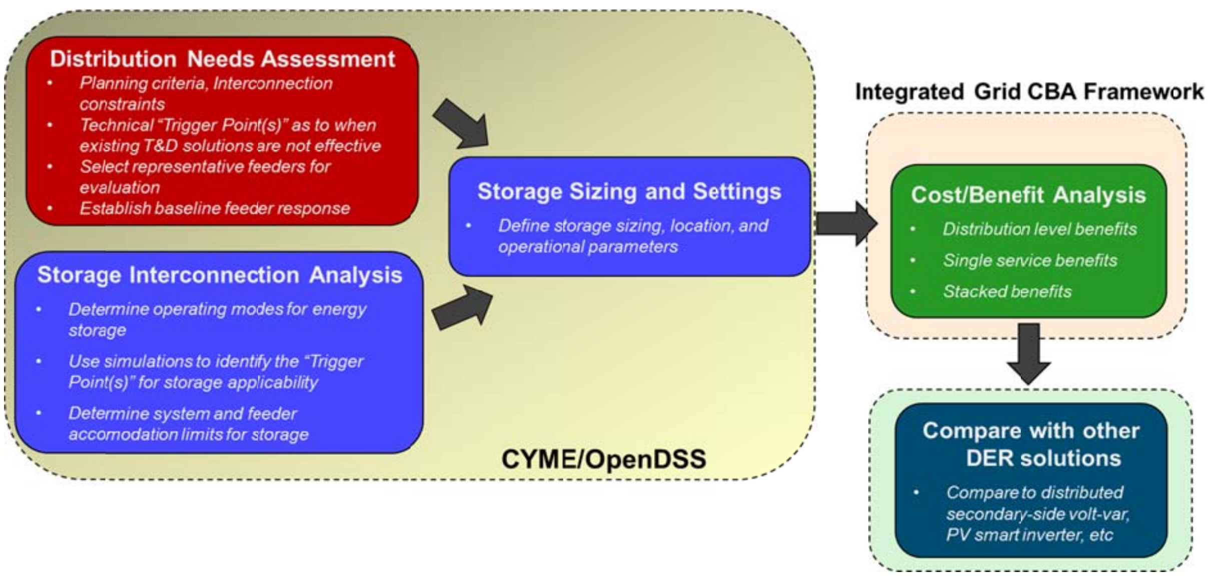
When it will be completed and ready for use:

- September 2018.

Benefits:

- Energy storage (ES) technology has potential benefits for utilities, system operators, and end users to increase reliability and reduce the cost of electricity.
- Hydro One believes storage may be used in Ontario in a number of applications, including frequency regulation, energy security/outage management, power quality, voltage VAR management, and peak shaving.
- It may be especially important as a flexibility asset to address the integration of variable generation resources such as wind and solar.
- Hydro One is also interested in better understanding the potential for energy storage to be a solution for providing service to remote communities.
- Storage may also be a tool to improve asset utilization at the distribution level, and if costs are low enough, it can be used for diurnal energy arbitrage.

Figure 1: EPRI Energy Storage Locational Analysis Framework on Distribution



UNDERTAKING – JT 3.16

Undertaking

To provide averages for urban and rural SAIDI and SAIFI respectively for C1 and C2.

Response

Figures C.1 and C.2 compare the SAIDI and SAIFI values for feeders serving Anwaatin communities with Hydro One's Urban and Rural SAIDI and SAIFI on a year-by-year basis for the past five years. Overall, the Anwaatin feeders' average SAIDI is consistent with overall average. The performance was relatively worse in 2013 with some improvement in later years.

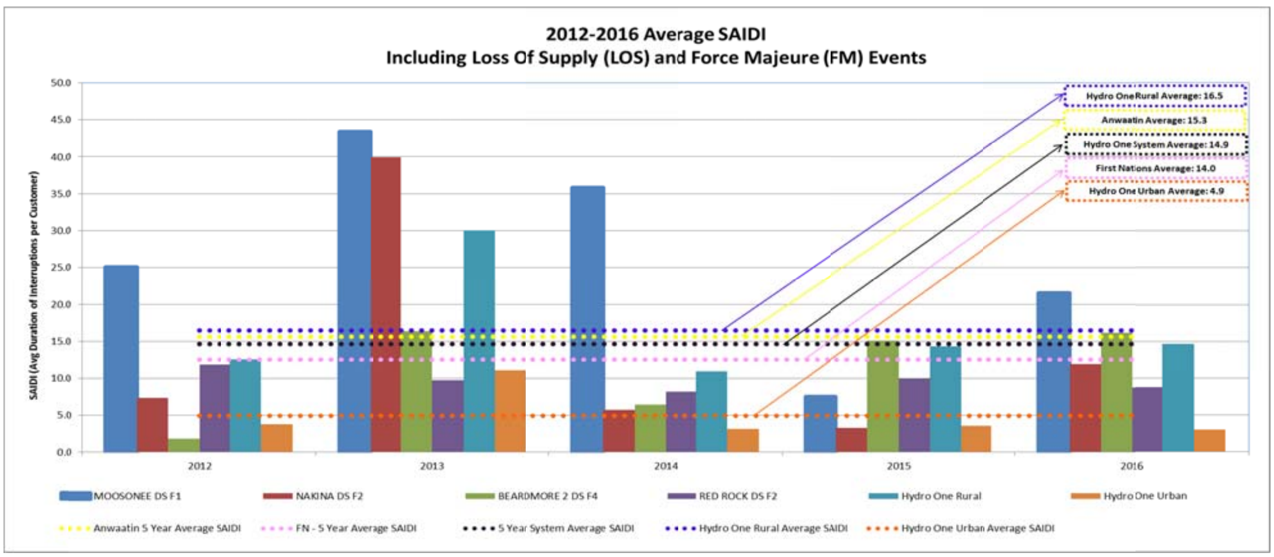


Figure C.1: Comparison of SAIDI from 2012-2016

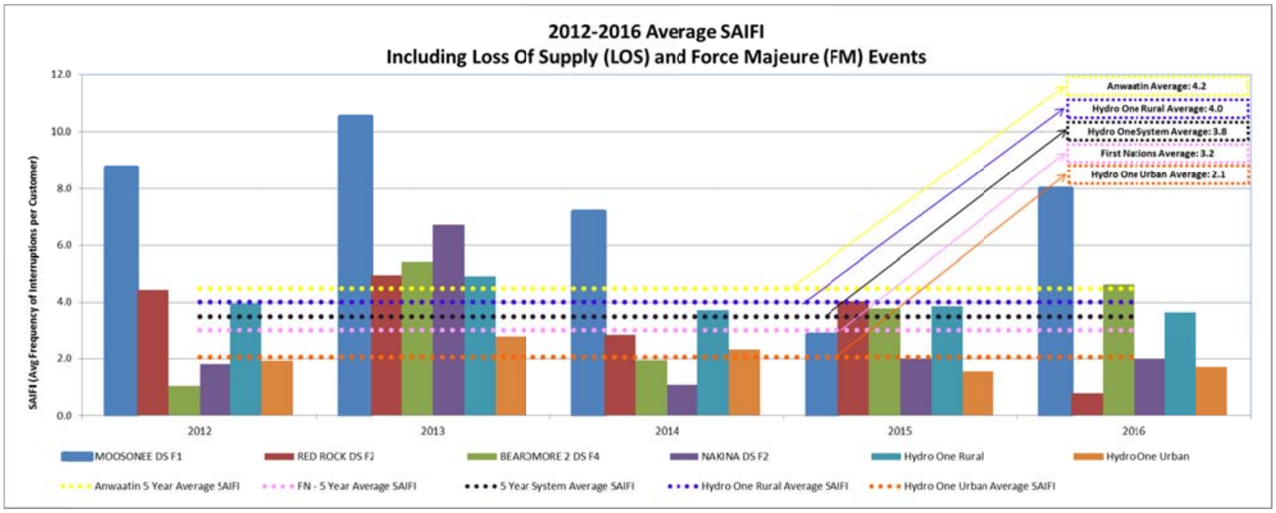


Figure C.2: Comparison of SAIFI from 2012-2016

Note: *The data is categorized as Urban (UR) and Rural (R1 and R2). Data from 2012-2016 is available.*

UNDERTAKING – JT 3.17

Undertaking

To provide the costs compared to the activity for each year from 2012 to 2017.

Response

Please see tables below for the costs for each year (2012 to 2016, and 2017 forecast) associated with the activities noted in Board Staff interrogatories (I-38-Staff-189 to I-38-Staff-192, and I-38-Staff-194).

I-38-Staff-189 *(Reference: C1-01-02 Page: 15)*

Description	2012	2013	2014	2015	2016	2017
Trouble Calls ($M)	65.5	87.7	77.1	72.9	68.8	76.5

I-38-Staff-190 *(Reference: C1-01-02 Page: 16)*

Description	2012	2013	2014	2015	2016	2017
Disconnects/Reconnects ($M)	9.3	10.2	11.9	12.5	13.5	12.2

I-38-Staff-191 *(Reference: C1-01-02 Page: 18)*

Description	2012	2013	2014	2015	2016	2017
Defect Corrections ($M)	5.0	6.1	3.3	4.9	9.2	3.7

I-38-Staff-192 *(Reference: C1-01-02 Page: 20)*

Description	2012	2013	2014	2015	2016	2017
PCB Inspection and Testing ($M)	-	-	0.3	2.3	5.6	7.3

I-38-Staff-194 *(Reference: C1-01-02 Page: 29)*

Description	2012	2013	2014	2015	2016
Brush Control ($M)	34.7	35.6	23.9	7.7	35.0
Line Clearing ($M)	87.4	83.2	97.9	93.7	87.4

As noted in interrogatory response I-38-Staff-194, the line clearing and brush control programs were synchronized and amalgamated in 2017. The cost of this amalgamated vegetation management between the tactical maintenance and cycle clearing programs was $128.8 million.

Witness: GARZOUZI Lyla

UNDERTAKING – JT 3.18-1

Topic: Historical CDM Included in Load Forecast Model

Reference

43-VECC-75
43-VECC-65
2016 Ontario Planning Outlook (OPO)
http://www.ieso.ca/sector-participants/planning-and-forecasting/ontario-planning-outlook

Preamble:

The load forecast models use actual load data up to and including 2016 (E1/T2/S1, page 7).

VECC 75, Attachment 1 indicates that the historical CDM savings attributable to Hydro One's service area were derived from CDM savings reported in the OPO.

VECC-65 confirms that the CDM savings shown in in Exhibit E1/Tab 2/Schedule 1, page 42 – Table E.9 are end-use values.

Undertaking

a) VECC 75 indicates that the historical CDM savings were taken from the 2016 Ontario Planning Outlook (OPO). However, the OPO only provides historical CDM savings up to 2015. Please indicate where the 2016 actual savings came from and provide a reference to/copy of the source.

b) Attachment 1 indicates that 16.56% of historical provincial CDM savings due Codes and Standards (C&S) was assumed to be attributable to Hydro One' service area. It also indicated that the 16.56% represents Hydro's One's share of the targeted CDM savings for 2015-2020. Please explain how the use of this percentage appropriately reflects Hydro One's share of historical C&S savings.

c) Also, Attachment 1 shows Hydro One total end use CDM savings for 2016 of 1,866.7 GWh whereas Exhibit E1/Tab 2/Schedule 1, page 42 – Table E.2 shows total end use savings for the same year of 2,765 GWh. Similar differences exist for all historical years. Please reconcile the differences and/or correct the data/forecast as required.

d) Please clarify whether historical savings set out in the OPO are: i) based on the annualized savings from EE programs assuming all savings from a year's programs come into play on January 1st or ii) based on actual savings for the year which would recognize that EE programs are implemented throughout the year?

Response

a) The 2016 CDM assumptions are not actual savings but rather a forecast based on the OPO 2016 information.

b) The verified historical C&S savings are not available from the IESO. Hydro One uses the same Hydro One share of targeted CDM savings for the C&S category to yield a consistent data set over time for modeling purposes.

c) 1866 GWH savings at the end use level is only for Hydro One retail customers, while 2765 GWH includes savings from the embedded LDCs. This same reason applies to data for other historical years

d) Hydro One assumes that the reported results from the IESO are annualized impacts and that savings are in effect on January 1st.

UNDERTAKING – JT 3.18-2

Reference

43-VECC-75
2016 Ontario Planning Outlook (OPO)

Preamble:

VECC 75 requested detailed data on historical savings by implementation year which, according to the responses to parts (a) – (c), Hydro One is unable to provide.

VECC 75 requested (parts (g) and (h)) copies of Hydro One's verified CDM results reports

Undertaking

a) Attachment 2 only provides the impact of 2011-2014 programs for the period 2011-2014. Please provide the IESO report that indicates the persisting impact of these programs though to 2020 as originally requested.

b) Please complete parts (a) and (b) of VECC 75 based on the verified results for Hydro One's historical EE programs.

c) With respect to the response to part (g), please explain the "definitional" difference between historic EE program savings as reported by Hydro One and the historic EE savings reported in the OPO (Data Tables, Figure 11) for the period 2006-2020.

Response

a) The requested information is provided in the MS Excel attachment to this response.

b) Verified results for Hydro One are not available for 2005-2010. The 2011-2016 EE program savings are provided below based on the available verified results from the IESO. The information is the combined savings for retail and ST-direct customers as the information is not broken out by the IESO for Retail and ST-Direct customers.

Hydro One Historical Verified EE Programs for 2011-2016 (GWh)

Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
2011	86	85	85	79	76	69	61	60	62	54	51	37
2012	1	61	59	59	55	52	41	38	38	37	30	28
2013	0	2	80	77	74	66	57	54	54	54	51	45
2014	1	2	11	212	200	194	186	182	180	177	176	171
2015	-	-	-	-	336	316	313	313	312	310	306	305
2016	-	-	-	-	-	212	210	210	209	208	206	206

c) The definition of the EE programs savings reported by Hydro One is same as the historical EE savings reported in the OPO.

For 2006-2010, the EE programs includes non-target CDM programs initiated by both LDCs and the OPA, as well as the CDM programs funded by other organizations, such as federal, provincial and/or municipal government, natural gas companies, and other non-government organizations.

For 2011-2014 period, the EE programs includes incremental LDCs 2011-2014 target programs and the persistence of 2006-2010 programs.

For 2015-2020 period, the EE programs include incremental LDCs 2015-2020 target programs and the persistence of 2006-2014 programs.

UNDERTAKING – JT 3.18-3

Topic – CDM Savings Included in Load Forecast

Reference

43-VECC-75 Attachment 5
2016 Ontario Planning Outlook (OPO)
17-OSEA-6

Preamble:

VECC 75 Attachment 5 indicates that the source of the forecast provincial CDM savings is the 2016 OPO.

OSEA -6 sets out Hydro One's 2015-2020 CDM Plan

Undertaking

a) Please clarify whether the forecast savings in the OPO are: i) based on the annualized savings from EE programs assuming all savings from a year's programs come into play on January 1st or ii) based on actual savings for the year which would recognize that EE programs are implemented throughout the year?

Response

a) The reported results from the IESO are annualized impacts and savings are in effect on January 1st.

UNDERTAKING – JT 3.18-4

Topic: LRAMVA Threshold

Reference

55-CCC-75

46-Staff-233

Preamble:

In response to 55-CCC-75 HON confirmed it was establishing an LRAM Variance Account.

Staff-233, Table 3 sets out Hydro One's proposed LRAMVA thresholds (i.e., CDM amounts assumed in the load forecast)

Undertaking

a) Please confirm that Hydro One will be seeking recovery of:
   i. Lost revenues in 2018 from programs implemented in 2015-2018.
   ii. Lost revenue in 2019 from programs implemented in 2015-2019, and
   iii. Lost revenues in 2020 from programs implemented in 2015-2020?

   If not, please clarify Hydro One's proposals for lost revenue recovery.

b) Are the CDM savings values set out in CCC-75, Table 3 annualized values (i.e., assuming all CDM programs are implemented January 1st) or do the values represent the expected forecast savings in each year?

c) Are the values set out in CCC-75, Table 3 the base CDM savings against which Hydro One plans to calculate the LRAMVA amounts?
   i. If yes and the values are not "annualized" please provide the annualized equivalents.
   ii. If no, please provide Hydro One's proposed "annualized" LRAMVA thresholds for each year for which it will be seeking a lost revenue recovery.

d) Since the load forecast model is based on actual data up to 2016 and actual CDM savings are reported by the IESO up to 2016, why aren't the 2015 and 2016 implementation year values in Table 3 based on the actual verified Hydro One savings for 2015 and 2016?

e) Since the load forecast model is based on actual data up to 2016 and actual CDM savings are reported by the IESO up to 2016, why is it necessary to seek recovery for lost revenue from programs implemented in 2015 and 2016?

f) For the program years 2017-2020, why use the values in CCC-75 as opposed to those set out in HON's approved CDM plan – provided in response to OSEA #6?

g) Since the LRAM calculations are class specific – please provide a breakdown of the proposed LRMVA kWh threshold for each year (2018-2020) by customer class and indicate how the values were derived.

h) Staff-233 makes reference (page 2, line 14) to an attached MS Excel file. However, there does not appear to be a corresponding attachment on the OEB web-site. Please provide.

Response

a) No. Hydro One will be seeking recovery of:
   i. lost revenues due to the incremental savings in 2018 from programs implemented in 2017-2018;
   ii. lost revenues due to the incremental savings in 2019 from programs implemented in 2017-2019; and
   iii. lost revenues due to the incremental savings in 2020 from programs implemented in 2017-2020.

b) The CDM saving values set out in Exhibit I-55-CCC-75 are the annualized forecast savings in each year.

c) Yes.
   i. The values are forecasted annualized savings due to EE programs.
   ii. Not applicable.

d) Hydro One incorporates cumulative CDM impacts (including EE and C&S) in the load forecast based on the OPO information. The 2015 and 2016 actual CDM savings from the EE target programs are implicitly included in the *total* CDM assumption. When the load forecast for this Application was prepared, Hydro One did not have the 2016 verified result report and 2011-2015 persistence report from the IESO. As such, Hydro One applied Hydro One's share of the OPO EE savings for the forecast years (2017-2022).

e) Hydro One will be only seeking recovery for lost revenue due to incremental savings from programs implemented in 2017 and beyond, as indicated in the response to part a).

f) Hydro One applied its share of Ontario energy savings based on the OPO information for 2017-2022. The proposed CDM programs in the CDM plan can be updated by LDCs as often as needed to reflect actual program performance. In addition, the expected energy savings are very close to the target of 1,159 GWh by the end of 2020. Therefore, Hydro One simply used the target CDM assumptions per the OPO in preparing its load forecast.

g) The proposed 2018-2020 LRAMVA threshold by rate class is as follows:

Implementation Year	Service - Demand Billed	General Service - Energy Billed	Residential - Medium Density	Residential - Low Density	Seasonal	transmission Direct customers	General Service - Demand	General Service - Energy Billed	Urban Residential
	kW	KWH	KWH	KWH	KWH	KW	KW	KWH	KWH
2018	6,497	87,066,805	56,144,302	53,234,536	7,115,397	47,520	1,002	23,296,048	22,291,454
2019	14,410	130,006,286	84,798,946	79,316,486	10,537,861	64,340	3,953	34,902,484	33,525,240
2020	17,850	172,532,973	113,839,336	105,044,163	13,870,876	77,381	5,449	46,478,919	44,817,001

The threshold is the incremental savings in 2018-2020 compared to the savings in 2016. For the energy billed customers, the share of CDM savings by rate class was applied to the incremental six year target program CDM savings in 2018-2020 vs 2016. For the demand billed customers, the share of six year target program savings of total EE savings was applied to peak savings.

h) Please see MS Excel attachment to this reponse, which is based on OEB's template. The threshold and CDM adjustment savings for 2018 calculated in the attached file are different from the number Hydro One used in its load forecast and represent a different methodology for incorporating CDM into the load forecast.

UNDERTAKING – JT 3.18-5

Topic: Forecast Customer Counts

Reference

43-VECC-70

46-Staff-219

Undertaking

a) VECC-70 b) requested the actual customer count values by class for 2017. The response referred to Staff-219, Table 4. Please confirm that the correct reference is Table E.4 of the Staff-219. If not, what is the correct reference?

b) For which months in Staff-219, Table E.4 are the customer counts based on actual (as opposed to forecast) values?

c) The response to Staff-219 includes a revised forecast for both customer count and load by class. Is Hydro One proposing to adopt these new forecasts and update its Application to reflect the revised values?

Response

a) Confirmed.

b) June.

c) Yes, Hydro One is proposing to adopt the updated load forecast provided in the response to Exhibit I-46-Staff-219 and will reflect the impact of the new load forecast as part of the draft rate order material prepared in response to the OEB's decision on this Application.

UNDERTAKING – JT 3.18-6

Reference

43-VECC-71, Attachment 1

Preamble:

The attachment to VECC 71 sets out the impact of reclassification on the customer counts for the various GS classes and there are two tables (starting at Rows 64 and 82 respectively) – one purportedly before reclassification and one after. However, they are both labelled "Before Reclassification".

Undertaking

a) Please indicate whether it is the table at Row 64 or 82 that is the After Reclassification counts?

b) The customer counts set out in the Application appear to use the Row 64 values. Please confirm whether these are the correct values.

Response

a) The headings and data under rows 64 and 82 were mixed up in Attachment 1 to Exhibit I-43-VECC-71. Please see the corrected lines 64-89 in the MS Excel file attached to this response.

b) Please see response to a). The correct values are in row 82 of the attached file.

Witness: ALAGHEBAND Bijan

UNDERTAKING – JT 3.18-7

Topic: Use of Multiple Models

Reference

43-VECC-76

46-CME-70

Preamble:

VECC 76 c) provides the load forecasts from the different models and resulting preliminary forecast. It notes in part c) that this forecast was adjusted upwards to arrive at the forecast used in the application.

CME-70 also describes how the results from the three models were used to establish the load forecast.

Undertaking

a) How was the upward adjustment referred to in VECC 76 c) determined?

b) Table 2 of VECC-75 indicates that the results of the models were averaged and adjusted before adjusting the forecast for CDM? (Note the value for 2016 actual is equivalent to E1, Tab 2, Schedule 1, Table 7 – for the Retail Class before deducting CDM). However, CME 70 c) states the forecast was based on an average of the forecasts after adjusting for CDM. Please clarify whether the averaging was done before or after adjusting for CDM?

c) The response to VECC-75 indicates that it was the growth rates (over 2016 actuals) that were "averaged". However, CME-70 c) suggests it was the average of the forecast values that was averaged. Please clarify the approach used.

Response

a) At the time the forecast was being finalized, the economic outlook seemed to be improving over time. This was more in terms of improvement in expectations (e.g., rising consumer confidence and stock market prices) rather than rising economic forecast as Hydro One was already using the latest economic forecast available. Thus, it was not clear how much of that improvement was already factored into the economic forecast underlying the load forecast. Consequently, the upward adjustment to the forecast was based on expert judgment.

b) As noted in part c) of Exhibit I-46-CME-70, the averaging was done after deducting CDM. However, since the same CDM amount is deducted from different forecasts, averaging after deducting CDM yields nearly same result as averaging before deducting CDM and then deducting CDM from the result. In Exhibit I-43-VECC-75, Hydro One was asked to provide a comparison of gross forecasts (i.e., before deducting CDM) from different models and the gross forecast used in the Application. The response provided was the most direct way of performing such a comparison.

c) The approach used was averaging the growth rates of the three forecast methodologies.

UNDERTAKING – JT 3.18-8

Topic: Load Forecast Update

Reference

46-City of Hamiton-6

Preamble:

In City of Hamilton-6, HON indicates that it plans on updating the load forecast for 2021 and 2022.

Undertaking

a) Please indicate exactly what will the update entail. For example will Hydro One just be updating the inputs used in the various models, will the CDM values for the period 2017-2022 be updated, and will the models themselves also be updated?

Response

a) It will entail updating inputs used in various models and CDM values as well as the models themselves to reflect new information as of 2020 resulting in a forecast update for the years 2021 and 2022. Updated historical and bridge-year values at that time (including CDM values for the years 2017 to 2020) will also be provided.

UNDERTAKING – JT 3.18-9

Topic: Cost Allocation Inputs

Reference
46-VECC-87 a)

49-Staff-241

Preamble:
VECC-87 a) asked about the weighting factors for Billing & Collecting and Services and the response referenced Staff-241.

Undertaking

a) Staff-241 only discusses the basis for Billing & Collecting weighing factors. How were the Services weighting factors used in the Cost Allocation Model determined?

b) When was the last time the weights for Billing and Collecting were formally reviewed (i.e., a formal study was undertaken as opposed to being confirmed based on discussions with customer service staff)?

c) When was the last time the weights for Services were formally reviewed?

Response

a) The Services weighting factors are based on an estimated relative service connection length of 30, 20, 15, and 10 metres for the R2, Seasonal, R1 and UR customers, respectively, as described in Exhibit G1, Tab 3, Schedule 1 of Hydro One's last Distribution application EB-2013-0416.

b) Hydro One cannot find a record of a formal review of these weights. Hydro One notes that these weights apply to less than 7% of the total OM&A costs allocated by the model and any changes to the currently proposed weights would not be expected to materially impact the revenue-to-cost ratios for the rate classes.

c) The approach to determining the Services factors, as described in part a), was developed in 2013 and was reviewed and approved by the Board under proceeding EB-2013-0416.

Witness: ANDRE Henry

UNDERTAKING – JT 3.18-10

Reference

46-VECC-87 a)

49-Staff-241

Preamble:

VECC-87 b) asked about the allocation of Services costs to the acquired rate classes.

Undertaking

a) The response to VECC 87 b) confirms that the Services cost for the acquired utilities were included in the GFA adjustment factor and therefore these assets are included in the costs allocated to the acquired rate classes. However, as no Service costs are allocate to the acquired GS rate classes – where are the Services costs that the acquired utilities previously allocated to their GS rate classes now allocated in Hydro One's 2021 Cost Allocation Model? Are they all allocated to the acquired Residential rates classes?

Response

a) Hydro One's total forecast 2021 Services costs in USofA 1855 are allocated across all existing and new acquired residential classes. However, use of the proposed GFA adjustment factors ensures that the total amount of assets in USofA 1815 to 1860 (which includes 1855) appropriately reflects the combined total amount of those assets that should be allocated to each new acquired rate class. As such, for the acquired general service rate classes, slightly *more* of the assets associated with USofA accounts 1815, 1820, 1830, 1835, 1840, 1845, 1850 and 1860 are allocated to these classes to account for the fact that no assets in USofA 1855 are allocated to them. Consequently, slightly *less* of the assets associated with USofA accounts 1815, 1820, 1830, 1835, 1840, 1845, 1850 and 1860 are allocated to all other existing rate classes.

UNDERTAKING – JT 3.18-11

Reference

46-VECC-88 a) & b)

Preamble:

The response to VECC 88 a) & b) provides the average meter costs by customer class as used in the current 2018 & 2021 Cost Allocation models and also in the previous 2015 Cost Allocation Model (CAM).

Undertaking

a) Please explain why for the 2015 CAM – the UR and R1 classes had lower meter costs per customer than the R2 and Seasonal classes whereas in the current CAMs the average cost is the same for all four classes.

b) It is noted that for the Acquired Customer classes in the 2021 CAM the cost of a residential meter is less than that for Hydro One's existing R1 and R2 classes but the cost of an AcUGe and an AcGSe meter is substantially more for the Acquired classes than for Hydro One existing GS classes. Please explain why.

c) In contrast for the demand billed GS classes – the cost of the meter for the Acquired Utility classes is less than for Hydro One's existing GS classes. Please explain why.

Response

a) The meter costs per customer for UR, R1, R2 and seasonal customers in the 2015 CAM were estimated values determined in discussion with staff directly involved in meter installation activities. The different unit costs were intended to reflect the impact of travel time associated with meter installation for customers in different rate classes.

The meter costs per customer in the current CAMs are based on an average residential meter installation cost as recorded in Hydro One's SAP system. The cost data from SAP reflects the best information currently available for actual average meter installation costs and no further adjustment to the cost by rate class was readily available for use in the CAM.

b) The variance between meter costs reflects the different vendors/contracts, meter types and communication module costs that exist for the acquired utilities and Hydro One.

c) Same response as (b).

UNDERTAKING – JT 3.18-12

Reference

46-VECC-89 b)

Preamble:

The response to VECC 89 b) indicates that Hydro One has no information that would indicate the relative cost of serving the different density areas has changed.

Undertaking

a) In Hydro One's view what type of information should be looked at to make such a determination?

b) Has Hydro One made any such investigations? If not, why not?

Response

a) Density factors used in the cost allocation model are driven by the relative cost of assets and OM&A required to serve different density areas. As such, the information to be considered would be whether there have been any fundamanetal changes to the design of the distribution system and how operations and maintenance work is performed.

b) Pricing staff stay informed on changes to the distribution system and work programs that could materially impact the relative costs of doing work in rural vs higher density areas through ongoing discussions with asset management staff. The basic design of the distribution system has not changed (e.g. lower density areas still require longer lines, more poles and transformers to serve) and so relative asset costs and associated sustainment costs are not expected to have changed materially. The productivity improvements proposed in this application related to vegetation management are expected to reduce costs across all of Hydro One's service territory and are not anticipated to result in a disproportionate benefit to low versus high density areas.

Witness: ANDRE Henry

UNDERTAKING – JT 3.18-13

Reference

46-VECC-90 g)

Preamble:

In VECC 90 f) (g in the response) Hydro One was asked to calculate the GFA adjustment factors for specific USOA accounts and values were provided for accounts 1830 (Poles, Towers and Fixtures) and 1860 (Meters).

Undertaking

a) Please confirm that the costs for these two accounts are allocated to customers using two totally different allocation factors?

b) For certain acquired rate classes there is a significant difference between the GFA adjustment factors for these two accounts suggesting a more account specific determination of the adjustment factors would produce different cost allocation results and revenue to cost ratios. Is Hydro One willing to adopt "account-specific" GFA (and NFA) adjustment factors for purposes of its 2021 CAM? If not, why not?

c) Absent moving to the more detailed method – would Hydro One agree that the use of the simpler approach would suggest the application of a wide range for what would be considered an "acceptable" R/C ratio?

Response

a) Yes, USofA 1830 is allocated based on NCP and USofA 1860 is allocated based on CWMC (weighted meter capital). The assets allocated to the new acquired classes based on those two CAM allocators are subsequently adjusted by Hydro One's proposed GFA Adjustment Factors.

b) Hydro One submits that its approach of determining the adjustment factors using all local assets (i.e. USofA 1815 to 1860) as a group is most appropriate for the reasons given in Exhibit 1-46-VECC-90 (f). However, Hydro One is willing to adopt "account-specific" GFA adjustment factors for USoA accounts 1815-1860 if the OEB determines that to be appropriate.

c) Hydro One agrees that its proposed approach to calculating the GFA Adjustment Factors may suggest that the application of a wider range of R/C ratios for the new acquired rate classes could be appropriate.

UNDERTAKING – JT 3.18-14

Reference
49-Staff 242 d)

49-Staff-243 d)

Preamble:
The responses to Staff 242 d) and Staff 243 d) indicate that Hydro One does not plan on updating the GFA and NFA adjustment factors in future CAMs.

Undertaking
a) If one assumes that the CAM appropriately allocates any investments after 2021 to the acquired rate classes why wouldn't the adjustment factors change over time as the pre-2021 investments that drove the need for the adjustment become a smaller and smaller proportion of the total costs to allocated?

Response
a) Please refer to the response at Exhibit JT 3.26-3 part c.

UNDERTAKING – JT 3.18-15

Reference

48-VECC-96

13-CCC-15

Preamble:

VECC 96 asked about HON's plans to update its 2021 CAM and the response spoke to the CAM update arising from the December 2017 update. However, what the original question was referring to was Hydro Ones plans (if any) to update the 2021 CAM with the 2021 cost of capital parameters and the updated 2021 and 2022 load forecast as discussed in CCC-15

Undertaking

a) Please indicate what other aspects of the current 2021 CAM (apart from the cost of capital parameters and load forecast) will be updated (e.g., Other Aspects of the Revenue Requirement, Asset Values, Weighting Factors, Average Meter Costs, Meter Reading Weights, etc.)?

Response

a) The following 2021 CAM inputs will be updated to reflect changes to the cost of capital parameters and load forecast:
   - Return on debt
   - Return on equity
   - Income tax
   - Charge determinants by rate class (i.e. number of customers/connections, kWh and kW)
   - Demand information (1/4/12CPs and 1/4/12NCPs) by rate class

   Hydro One does not propose to update any other aspects of the 2021 CAM.

UNDERTAKING – JT 3.18-16

Topic: Transition to 100% Residential Fixed Rate

Reference

49-VECC-98

Preamble:

VECC 98 requested that Hydro One provide a table demonstrating whether its proposed transition to a fully fixed charge for its Residential and Seasonal classes met the Board's $4 impact criterion.

Undertaking

a) Please confirm that the table provided shows the total change in the monthly fixed charge for each affected class over the CIR period (i.e., the change shown is the result of both the move to a fully fixed charge plus the annual increase in rates for each class).

b) Please confirm that Appendix 12 of the Board's Revenue Requirement Work Form calculates the change in monthly fixed charge – excluding the impact of the overall rate increase.

c) Please re-do the response to VECC 98 using the same approach as the RRWF.

Response

a) Confirmed. The table provided in response to I-49-VECC-098 part a is the resulting monthly fixed charge of both the move to a fully fixed charge plus the annual increase in rates for each class.

b) Confirmed. The change in fixed rate that is calculated as a part of the Checks table in the Board's Revenue Requirement Work Form Tab 12 "New Rate Design Policy For Residential Customers" (cell B48) excludes the impact of the overall rate increase due to changes in revenue requirement.

c) The Excel attachment Hydro One provided in response to I-49-Staff-245 provides detailed calculations of the transition to all-fixed residential distribution rates for UR, R1, R2 and seasonal rate classes using the OEB's RRWF approach.

In I-49-Staff-245 Attachment 1, the year-over-year difference (cell B48) shows the impact of the move to a fully fixed charge only (excluding the impact of the overall rate increase due to changes in revenue requirement). The monthly fixed charges presented in that Attachment are the result of using the OEB's RRWF approach. Hydro One is not proposing the adoption of these fixed charges.

UNDERTAKING – JT 3.18-17

Reference
49-VECC-98

Preamble:
In the response Hydro One acknowledges that the annual changes are greater than $4 – but notes that the transition periods are in accordance with the Board's EB-2015-0079 Decision.

In that Decision (page 7) the Board also emphasized that the total annual bill impacts would be less than 10% for low volume customers.

Undertaking
a) Please indicate whether, in the current Application, this is still the case for each of the affected rate classes, over the entire transition period (excluding the impacts of Distribution Rate Protection)?

Response
a) The proposed total bill impacts for each year during the transition period (excluding the impacts of Distribution Rate Protection) for low volume residential customers are less than 10%, as shown in Table 1 of Exhibit H1, Tab 4, Schedule 1.

UNDERTAKING – JT 3.18-18

Topic: Reduction in vegetation management costs

Reference

I-42-VECC-64

Preamble:

During the third day of the Technical Conference (Transcript page 69, line 24 to page 70, line 7) the following question was deferred to Panel 3.

Undertaking

a) What costs did Hydro One incur in 2016 and were forecast for 2017 to provide vegetation management services to telecom companies?

Response

a) Costs related to telecom vegetation management services are included in Landowner Notification, Line Clearing and Brush Control costs found in C1-01-02, Table 5. Hydro One's estimated cost for telecom company vegetation management services is $6.52M per year.

UNDERTAKING – JT 3.18-19

Reference

56-SEC-96

Preamble:

Part (c) iii) of the response states: "The combined Hydro One and Acquired Utilities' revenue requirement is $9 M less than would have been in the absence of the transaction".

Undertaking

a) Please clarify whether the referenced quote was referring to the difference in revenue requirement, as stated in the response, or to the difference in OM&A costs.

b) If the reference was to the overall revenue requirement, please provide the 2021 forecast values for: i) Hydro One's distribution revenue requirement and ii) the Acquired Utilities' revenue requirement, in the absence of the transaction underpinning the response.

c) If the reference was actually to the difference in 2021 OM&A costs then, based on the forecasts of status quo OM&A and capital expenditures provided in the relevant acquisition proceedings, please provide a forecast of the 2021 revenue requirement for the Acquired Utilities, in the absence of the transaction.

Response

a) Hydro One confirms that the incremental OM&A cost to serve the three acquired utility's customers is $10.7M, as compared to the status quo OM&A of $19.7M.

The response also indicated that "The combined Hydro One and Acquired Utilities' revenue requirement is $9M less than it would have been in absence of the transaction." This was incorrect, the revenue requirement savings should have said $11.3 million.

b) Not Applicable

c) The equivalent calculation for total revenue requirement is $11.3 million, where $9.0 million represents OM&A.

Acquired Utilities 2021 Revenue Requirement			
$million	Status Quo	Post-Integration	Savings
OM&A	19.7	10.7	9.0
Depreciation	5.0	4.3	0.8
Return on Debt	4.9	4.3	0.6
Return on Equity	6.8	5.9	1.0
Income Tax	0.4	0.5	0.0
Revenue Requirement	36.9	25.6	11.3

UNDERTAKING – JT 3.19

Undertaking

To respond to Ms. Girvan's written questions for HONI panel 3.

Response

Consumers Council of Canada's March 14th, 2018 letter to the Board clarified that they had no further Technical Conference questions.

UNDERTAKING – JT 3.20

Undertaking

To provide details of the changes that caused savings to be lower than when HONI got approval.

Response

In Hydro One's MAAD applications to acquire Norfolk, Haldimand and Woodstock, filed in 2013 and 2014, "Projected LDC Acquisition OM&A and Capital Expenditures Savings" tables were provided. The tables illustrated a low-medium-and high case scenario, comparing the utilities "status quo" cost with a forecast after integration into Hydro One.

The total savings (OM&A and capital) forecast in each of these scenarios ranged from $80 million to $138 million over years 2015-2022. The savings in 2015 and 2016 were lower than expected due to delays in receipt of OEB approval and the subsequent impact on the timing of integrating each utility's distribution system into Hydro One.

The current forecast, provided in Exhibit I-56-SEC 90, is $91.3 million savings in OM&A and capital together and is within the range provided in the MAAD applications.

Hydro One has provided an OM&A 2017 and 2018 forecast to operate each of these utilities in EB-2017-0049. This forecast is based on Hydro One's current knowledge of operating each utility's distribution systems. The 2018 forecast was then adjusted by the price cap adjustment applied to all Hydro One distribution customers for 2019-2022. The capital forecast was based upon the findings in the Distribution System Plan, filed as Exhibit B1-1-1, Appendix A.

UNDERTAKING – JT 3.21

Undertaking

To provide an explanation that shows for 1815 and 1820, or for all of them, what was allocated in March and how and what was allocated in June and how.

Response

The table below summarizes the values for USofAs 1815 and 1820 that were initially allocated to the new acquired rate classes in the 2021 CAM, compared to the adjusted values allocated to the acquired classes using the cost allocation approach described in Exhibit G1, Tab 3, Schedule 1 (March 2017 and June 2017), and Exhibit Q, Tab 1, Schedule 1 Section 2.2 (December 2017).

		Application (March 2017)		Blue Page Update (June 2017) (Note 1)		Exhibit Q Update (December 2017) (Note 2)	
USofA	**USofA Description**	**Allocated by CAM**	**After Adjustment to CAM Allocation**	**Allocated by CAM**	**After Adjustment to CAM Allocation**	**Allocated by CAM**	**After Adjustment to CAM Allocation**
1815	Transformer station equip - above 50kV	$7,335,788	$7,335,788	$7,788,401	$ 7,788,401	$7,788,401	$9,212,494
1820	Distribution station equip - below 50kV	$41,646,316	$41,646,316	$40,639,443	$40,639,443	$40,639,443	$8,223,341

Witness: ANDRE Henry

UNDERTAKING – JT 3.22-1

Reference

Exhibit I-3-PWU-1

Preamble:

Interrogatory:

a) Which Hydro One rate classes benefit from bill protection pursuant to the terms of the Fair Hydro Plan (FHP)?

b) In 2016, how many customers were in each of these rate classes?

c) What percentage of Hydro One's total customers in 2016, do these customers represent?

d) In 2016, how much distribution revenue did Hydro One receive from these customers?

e) In 2016, what percentage of Hydro One's total distribution revenue was received from these customers?

Response:

a) Hydro One's R1 and R2 customers specifically benefit from the Distribution Rate Protection Program as set out in the Fair Hydro Plan.

Hydro One notes that there are certain aspects of the Fair Hydro Plan that benefit customers of all distributors in Ontario, including: i) reduced Global Adjustment charges and the Ontario Rebate for Electricity Consumers ("OREC") credits for residential and low volume general service customers, ii) reduced regulatory charges (OESP charge eliminated, RRRP charge reduced) and iii) lower eligibility threshold for the Industrial Conservation Initiative ("ICI") program so more large general service customers can participate.

b) In 2016, there were 441,836 R1 customers and 328,766 R2 customers.

c) In 2016, in terms of number of customers, R1 represented 34% of total and R2 represented 26% of total. Former Norfolk, Haldimand and Woodstock customers were not included in this analysis as these customers had not been integrated into Hydro One's rate structure.

d) In 2016, Hydro One received $295.7 million and $476.2 million (including the RRRP credit) in base distribution revenue from R1 and R2 classes, respectively.

e) In 2016, in terms of base distribution revenue, R1 represented 22% of total and R2 represented 35% of total. Former Norfolk, Haldimand and Woodstock customers were not included in this analysis as these customers had not been integrated into Hydro One's rate structure.

Undertaking

a) Please update the responses to the above questions for 2017 including the former Norfolk, Haldimand, and Woodstock customers

Response

a) No update. Hydro One notes that the former Norfolk, Haldimand and Woodstock customers are not eligible for Distribution rate Protection under the Fair Hydro Plan.

b) As indicated in the response to I-46-Staff-219 Table E.4, there were 447,647 R1 customers and 330,514 R2 customers in 2017.

c) In 2017, R1 represented about 33% and R2 represented about 25% of the total Hydro One customer count including the former Woodstock, Norfolk and Haldimand customers.

d) In 2017, Hydro One received $287 million and $485 million (including RRRP credit) in base distribution revenue from R1 and R2 classes, respectively.

e) In 2017, in terms of base distribution revenue, R1 represented about 21% of total and R2 represented 35% of the total including revenue from former Woodstock, Norfolk and Haldimand customers.

UNDERTAKING – JT 3.22-2

Reference

REFERENCE 1: Exhibit I-4-PWU-4 (Extracted from Hydro One response-Attachments 2-6)

2018

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2017 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
R1	Low	400		$84.03	($0.73)	-1.96%	$0.20	0.24%
	Typical	750		$122.38	($0.65)	-1.75%	$1.13	0.92%
	Average	920		$141.00	($0.61)	-1.66%	$1.58	1.12%
	High	1,800		$237.41	($0.42)	-1.14%	$3.91	1.65%
R2	Low	450		$91.24	($1.38)	-3.64%	($0.52)	-0.57%
	Typical	750		$124.88	($1.37)	-3.63%	$0.10	0.08%
	Average	1,152		$169.97	($1.37)	-3.62%	$0.93	0.55%
	High	2,300		$298.72	($1.36)	-3.59%	$3.30	1.10%

2019

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2018 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
R1	Low	400		$84.23	$0.00	0.00%	$0.00	0.00%
	Typical	750		$123.50	$0.00	0.00%	$0.00	0.00%
	Average	920		$142.58	$0.00	0.00%	$0.00	0.00%
	High	1,800		$241.32	$0.00	0.00%	$0.00	0.00%
R2	Low	450		$90.72	$0.00	0.00%	$0.00	0.00%
	Typical	750		$124.98	$0.00	0.00%	$0.00	0.00%
	Average	1,152		$170.90	$0.00	0.00%	$0.00	0.00%
	High	2,300		$302.01	$0.00	0.00%	$0.00	0.00%

2020

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2019 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
R1	Low	400		$84.23	$0.00	0.00%	$0.00	0.00%
	Typical	750		$123.50	$0.00	0.00%	$0.00	0.00%
	Average	920		$142.58	$0.00	0.00%	$0.00	0.00%
	High	1,800		$241.32	$0.00	0.00%	$0.00	0.00%
R2	Low	450		$90.72	$0.00	0.00%	$0.00	0.00%
	Typical	750		$124.98	$0.00	0.00%	$0.00	0.00%
	Average	1,152		$170.90	$0.00	0.00%	$0.00	0.00%
	High	2,300		$302.01	$0.00	0.00%	$0.00	0.00%

2021

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2020 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
R1	Low	400		$84.23	$0.00	0.00%	($0.06)	-0.07%
	Typical	750		$123.50	$0.00	0.00%	($0.12)	-0.10%
	Average	920		$142.58	$0.00	0.00%	($0.14)	-0.10%
	High	1,800		$241.32	$0.00	0.00%	($0.28)	-0.12%
R2	Low	450		$90.72	$0.00	0.00%	($0.04)	-0.04%
	Typical	750		$124.98	$0.00	0.00%	($0.06)	-0.05%
	Average	1,152		$170.90	$0.00	0.00%	($0.09)	-0.05%
	High	2,300		$302.01	$0.00	0.00%	($0.19)	-0.06%

2022

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2021 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
R1	Low	400		$84.17	$0.00	0.00%	$0.00	0.00%
	Typical	750		$123.39	$0.00	0.00%	$0.00	0.00%
	Average	920		$142.44	$0.00	0.00%	$0.00	0.00%
	High	1,800		$241.04	$0.00	0.00%	$0.00	0.00%
R2	Low	450		$90.68	$0.00	0.00%	$0.00	0.00%
	Typical	750		$124.92	$0.00	0.00%	$0.00	0.00%
	Average	1,152		$170.80	$0.00	0.00%	$0.00	0.00%
	High	2,300		$301.83	$0.00	0.00%	$0.00	0.00%

REFERENCE 2: Exhibit I-4-PWU-7 (Customer Engagement)

Power Workers' Union Interrogatory # 7

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:

B1-01-01 Section 1.3 Page: 4-15 (Customer engagement process)

Interrogatory:

a) Please confirm that this process was undertaken prior to the FHP coming into effect?

b) Did Hydro One undertake any additional customer engagement activities (in particular regarding the bill impact of the application) after the implementation of the FHP? If so:

i. describe the initiatives that were undertaken;
ii. describe the feedback received; and
iii. describe the manner in which any feedback was incorporated into the application in its current form.

Response:

a) The Customer Engagement process was undertaken prior to the Fair Hydro Plan coming into effect.

b) Hydro One did not undertake additional customer engagement activities after the implementation of the Fair Hydro Plan.

REFERENCE 3: Exhibit I-4-PWU-15 c & d

Interrogatory:

c) In view of the fact that a significant proportion of Hydro One's customers are being protected from bill impacts for the foreseeable future, why isn't the 2018-22 timeframe the ideal timeframe to ensure that Hydro One's asset condition and reliability are improved (or at least are no worse)?

d) Confirm that the effect of pursuing modified Plan B rather than Plan A or Plan B is to defer the incremental costs associated with those plans from a period of time where a significant proportion of customers have bill impact protections under the FHP, to a period of time when they will be lacking such protection.

Response:

c) Through Hydro One's customer engagement process, it was determined that keeping rates low was a top priority for customers. Plan B Modified was selected to balance customer needs with other business needs identified through the needs assessment process while allowing Hydro One to deliver on its business objectives. Please see section 1.3.4 (How the Plan Reflects Customer Needs and Preferences) of the DSP for details.

d) Plan B Modified defers some capital expenditures to later years in the planning period in order to mitigate rate impacts to customers while maintaining an acceptable overall risk profile. Hydro One makes no assumptions about the future of the Fair Hydro Plan.

Undertaking

a) Confirm that the R1 & R2 rate classes in Ref# 1 together represented 60% and 57%, respectively, of Hydro One's customers and distribution revenue in 2016 and these numbers would be higher if the newly acquired utilities are accounted for.

b) In Ref # 1, total bill impacts for 2018 (R1 &R2) range from a decrease of -0.57% to an increase of 1.65% depending on the level of consumption, despite the decrease in the distribution portion of the bill for all levels of consumption ranging from -1.14 to -3.64. What aspects of the bill are responsible for the slight increases in the total bill?

c) Ref #1 shows that for the rest of the test period (2019-2022), changes in both the distribution portion of the bill and total bill for customers in the R1 & R2 rate classes (of all levels of consumption) amount to 0% (freeze) with the exception of 2021 when in fact changes in total bill are negative. Please explain the drivers for the decrease in total bill in 2021.

d) Please confirm that the distribution rate for the acquired utilities - Norfolk, Haldimand and Woodstock is already frozen until 2021 as part of the MAAD application approvals and these utilities can expect further reduction due to the FHP.

e) Please confirm that the impact of the FHP on some customers is more than the average 25% decrease in total bill that was stipulated in the legislation behind the FHP.

f) Ref #2 shows that HO's customer engagement took place prior to the FHP came to effect whereas in Ref #3 HO states that Plan B Modified was selected taking into account the customers concern on bill impacts. Please confirm that the 0% increases (freezes) or decreases in the distribution portion of the bill as well as in the total bill cited under Question # c above were not disclosed to customers during HO's customer engagement.

Response

a) Yes, Hydro One confirms that the R1 & R2 rate classes together represented 60% and 57%, respectively, of Hydro One's customers and distribution revenue in 2016.

No, these numbers would not be higher if the newly acquired utilities are accounted for since the acquired utilities' customes are not classified as either R1 or R2. The acquired utilities' customers are not eglible to receive Distribution Rate Protection under the Fair Hydro Plan.

b) The impact of the proposed 2018 Retail Transmission Service Rates ("RTSRs"), from the current RTSRs, result in an increase to the R1 and R2 total bills. Details on RTSRs are provided in Exhibit H1, Tab 1, Schedule 1, Section 8.

c) RTSRs remain the same from 2018 to 2020, which is why there is no difference between the Distribution and Total bill impacts for those years. However, the proposed 2021 RTSRs are lower than the 2020 RTSRs, which result in a decrease to the R1 and R2 total bills in 2021. Details on RTSRs are provided in Exhibit H1, Tab 1, Schedule 1, Section 8.

d) Hydro One confirms that the OEB approved a 5-year base distribution rate freeze (with an additional 1% reduction) for these acquired utilities. As described in Exhibit I-3-PWU-1, while the acquired customers are receiving certain benefits from the FHP, they are not eglible to receive Distribution Rate Protection.

e) Confirmed.

f) The customer consultation Hydro One conducted in preparation of this application occurred during June and July 2016; the output of this consultation informed the development of Hydro One investment plans, approved by its Board of Directors in December 2016.

Ontario's Fair Hydro Plan was announced in March 2017, with an effective date of July 1, 2017.

The impacts of the Fair Hydro Plan were not known and not disclosed to customers when Hydro One conducted its customer consultation in 2016. The impacts of the Fair Hydro Plan were discussed as part of the OEB's community engagement process carried out in June and July of 2017.

UNDERTAKING – JT 3.23

Undertaking

With reference to Interrogatory Exhibit I, Tab 49, Schedule BLC 5, Part b, to examine whether a response is doable or if it is not doable; and if not why not.

Response

Hydro One has reviewed the information requested under part b) of I-49-BLC-5 and determined that it can largely provide the information requested prior to the oral hearing. Hydro One will use an assumed percentage split of seasonal customers that would migrate to the UR, R1 and R2 classes based on the same information as in the Seasonal report previously prepared for proceeding EB-2016-0315, as more current information is not readily available.

Hydro One also notes that sub-part iii of the question asks that the density factors, weightings, and other factors for the "new" Seasonal class consisting only of R2-Seasonal customers be maintained at the currently proposed values for the combined Seasonal class. This is not appropriate as the new R2-Seasonal class would consist of a substantially different subset of customers then the current Seasonal class that includes both medium and low density seasonal customers. As such, Hydro One will complete the requested cost allocation model run using the density factors, weightings, and other factors appropriate for a Seasonal class consisting solely of R2-Seasonal customers.

UNDERTAKING – JT 3.24

Undertaking

To advise how many customers in R2 are at the noted consumption level or below.

Response

With Hydro One's proposed 2018 rates, the "break point" (where the distribution charge would not be affected by any further increase in consumption) for R2 customers is 318 kWh per month.

About 15,000 R2 customers have average monthly consumption below 318 kWh.

UNDERTAKING – JT 3.25

Undertaking

To provide responses to Mr. Brett's questions for HONI panel 3.

Response

Hydro One did not receive written questions from BOMA as noted in Hydro One's March 14th, 2018 letter to the Board regarding the Status of Undertakings.

UNDERTAKING – JT 3.26-1

Reference

I-46-Staff-223

Undertaking

In the response to this interrogatory, Hydro One indicates that GDPONT[-4] means that the variable is lagged by four months. How did Hydro One determine that four months was the optimum lag period to be used in the model?

Response

As noted in Exhibit I-46-Staff-223, the lag would reflect the fact that it takes time to measure the actual GDP and to decimate GDP information to the public. For example, the current month value is not known to customers to respond to. After about three months, financial reports of all public companies would be available, which would reflect the performance of GDP in previous months. Also, after about 3 months, a great amount of analysis is performed by major banks and forecasting institutions regarding the performance of GDP in the previous months/quarter.

Another factor to be taken into account is reasonability of sign and magnitude of the related estimates in this regard. As presented in the table provided in this response, the sign is always positive as expected. The magnitude varies for different lags but there is no *a priori* information available of what it should be. The average of these estimates is 0.06, which is close to the one with four lags.

Purely statistical criteria to select the number of lags include t-ratio (not available for State-Space estimates), R-square, adjusted R-square, Akaike Information Criterion (AIC), and Schwarz (or: Bayesian) Information Criterion (BIC), which are also provided in the following table. In this relation, one would select the lag for which R-square or adjusted R-square are maximized or that AIC or BIC are minimized. These criteria point to nine lags as the optimal number of lags. However, this is considered to be too much lag in relation to the economic considerations noted above. Moreover, it turned out that such criteria are not much sensitive to number of lags so that observed differences are in the order of random discrepancies. Consequently, the other justifications noted above are more relevant in this regard.

Number of Lags	R Square	Adjusted R Square	AIC	BIC	Estimated GDP Coefficient
0	0.9873	0.9871	58.29	60.25	0.0307
1	0.9873	0.9872	58.13	60.08	0.0853
2	0.9873	0.9872	58.15	60.11	0.0856
3	0.9873	0.9871	58.27	60.22	0.0728
4	0.9873	0.9871	58.20	60.16	0.0613
5	0.9873	0.9872	58.15	60.10	0.0823
6	0.9873	0.9871	58.32	60.28	0.0294
7	0.9873	0.9871	58.26	60.22	0.0503
8	0.9873	0.9872	58.13	60.09	0.0540
9	0.9874	0.9872	57.96	59.90	0.0825
10	0.9873	0.9872	58.16	60.11	0.0317
11	0.9874	0.9872	58.09	60.04	0.0525
12	0.9874	0.9872	58.02	59.97	0.0544

UNDERTAKING – JT 3.26-2

Reference

I-46-Staff-227

Undertaking

As indicated in the interrogatory questions, C(4), the coefficient for LHDD and C(5), the coefficient for LCDD have low t-statistics and are statistically insignificant at a 90% confidence level. Did Hydro One undertake a load forecast omitting one or both of these variables? If so please provide the results. If not, please run the model without both of these variables and provide the results.

Response

Hydro One tried to delete one of the weather variables from the model in hope of improving the statistical significance of the other. This was motivated by the fact that a higher HDD would be associated with a lower CDD so that one may be sufficient as a proxy for both. However, deletion of HDD marginally reduced the t statistic for CDD (from 0.82 to 0.80). When CDD was deleted, the coefficient of HDD turned negative and remained statistically insignificant. Thus both weather variables were kept in the model, reflecting the fact that both cooling and heating load are used in embedded LDCs.

As requested, please see Table 1 below for the embedded LDC gross load forecast after deleting both HDD and CDD. The forecast is marginally (0.3%) higher compared to the forecast submitted for this Application in May 2017. It should be noted that, due to the presence of lagged dependent variable (embedded LDC gross load) on the right hand side of the equation, the resulting forecast is no longer weather-normal. Moreover, it is not clear how to correct the forecast for such weather effect as all the model estimated coefficients, which impact the forecast, are affected by the deletion of weather variables.

Table 1

Year	After Deleting CDD and HDD	Before Deleting CDD and HDD	% Difference
2017	12,184	12,151	0.27
2018	12,241	12,205	0.29
2019	12,322	12,284	0.31
2020	12,396	12,357	0.31
2021	12,455	12,415	0.32
2022	12,502	12,462	0.32

The impact of deleting both HDD and CDD on the updated forecast provided in Exhibit I-46-Staff-219, results in a difference ranging between -0.04% and 0.09% over the forecast years, as shown in Table 2.

Table 2

Year	After Deleting CDD and HDD	Before Deleting CDD and HDD	% Difference
2018	12,051	12,055	-0.04
2019	12,140	12,139	0.01
2020	12,223	12,218	0.04
2021	12,289	12,281	0.07
2022	12,343	12,332	0.09

UNDERTAKING – JT 3.26-3

Reference
I-49-Staff-242 and 243

Undertaking
With respect to the Gross Fixed Assets (GFA) and Net Fixed Assets (NFA) adjustments:

a) Why did Hydro One think it was necessary to adjust the starting balances for the capital assets of the acquired utilities?

b) Why does Hydro One believe that the allocation of the capital assets using the cost allocation methodology is too high? Is this an error in the cost allocation model or as a result of something else?

c) Please confirm that Hydro One will not be updating the adjustment factors even as more capital is invested into the acquired utilities' service territories.

d) How will any new capital spending in the acquired utilities' service territories be allocated if Hydro One will no longer separately track the costs associated with the acquired utilities?

Response
a) Hydro One believes that it is necessary to adjust the 2021 capital assets allocated to the six acquired rate classes in the Cost Allocation Model ("CAM") because in its Decisions in the MADD proceedings for the acquisition of Haldimand County Hydro, Norfolk Power Distribution and Woodstock Hydro Services the OEB stated that it expected Hydro One to propose rates at the time of rate rebasing that reflect the costs to serve these acquired utilities.

   As discussed in the evidence at Exhibit G1, Tab 3, Schedule 1, section 2, the allocation of costs are largely driven by the amount of capital assets allocated to the rate classes per the principles underlying the CAM. As illustrated in Tab 5 of the spreadsheet provided in Exhibit I, Tab 49, Schedule Staff-242 part (c), there is a material difference between the Gross Book Value ("GBV") that the 2021 CAM would normally assign to the six acquired rate classes and the forecast 2021 GBV for the acquired utilities (which is based on actual GBVs at the time of acquisition with forecast in-service additions up to 2021). As such, in order to set rates that appropriately reflect the costs to serve these acquired utilities, the amount of capital assets allocated to these acquired rate classes have to be adjusted.

b) Hydro One does not believe that there is an error in the OEB Cost Allocation model. However, simply allocating a share of Hydro One's total assets based on the relative peak loads of the acquired classes, consistent with the CAM principles, results in the allocation of costs to the acquired classes that are not consistent with the direction from the Board as discussed in part (a) above.

c) Hydro One does not anticipate needing to update the proposed adjustment factors in the near term. However, recognizing that the adjustment factors capture cost differences related to both the installed capital costs and the unique characteristics of the acquired utilities' distribution systems (e.g. customer density), in the long term, as more of the original assets are replaced at Hydro One's installed capital costs, Hydro One will assess the need to update the currently proposed adjustment factors.

d) Hydro One's <u>total</u> new capital spending, both within and outside the acquired utilities' service territories, will be shared by all Hydro One customer classes. This includes the acquired rate classes who will attract a share of all new capital spending as a result of the CAM's underlying allocation methodology and the use of the proposed GFA Adjustment Factors. Therefore there is no need to separately track the costs associated with the acquired utilities.

UNDERTAKING – JT 3.26-4

Reference
I-49-Staff-245 and I-49-VECC-98

In the response to the I-49-Staff-245, Hydro One stated that its approach "Results in a smoother transition to all-fixed rates for customers". The response to I-49-VECC-98 shows that the range of increases from 2018 to 2022 for R1 is $4.02 to $6.14.

Undertaking
a) Please confirm that using Hydro One's approach will still result in fully fixed rates over the same period of time.

b) Please confirm that the fixed charges using the OEB methodology (Excel spreadsheet attached to I-49-Staff-245) results in a range from $4.98 to $5.52, which is smoother than the Hydro One methodology.

c) Would Hydro One accept using the OEB methodology to transition to fully fixed rates?

Response
a) Confirmed.

b) Hydro One confirms that the R1 fixed charges using the OEB methodology (Excel spreadsheet attached to I-49-Staff-245) results in a range from $4.98 to $5.52, which is narrower than the resulting range of $4.02 to $6.14 when the Hydro One methodology is used. However, Hydro One submits that the annual percentage increase of the fixed charge from 2018 to 2022 is smoother throughout the five year period under Hydro One's approach. For example, for R1 customers, the percentage increase in the fixed charge ranges from 11% to 12% in the 2018 to 2022 period when the Hydro One approach is used, while under the OEB methodology the percentage increase ranges from 10% to 16%in the same period.

c) Yes. Hydro One would accept using the OEB methodology to transition to fully fixed rates.

UNDERTAKING – JT 3.26-5

Reference

I-52-Staff-250

Undertaking

Would Hydro One accept using the Alternative Scenario for changing the fixed charge for the DGen class?

Response

Yes. While Hydro One believes it is important to increase the DGen fixed charge, we agree that the alternative scenario fixed and volumetric rates will smoothen the 2018 and 2019 bill impacts among the low and high consumption DGen customers.

UNDERTAKING – JT 3.26-6

Reference
I-54-Staff-259

Undertaking
Please explain why different burden rates are shown on H1-02-03 Attachment 1, page 96 (59.3%) is different from that shown on H1-02-03 page 19 (53.6%-55.6%).

Response
The burden rates differ every year. The burden rate of 59.3% shown within H1-02-03, Attachment 1 is the 2016 burden rate. The burden rates shown within H1-02-03 are the burden rates for years 2018-2022.

Witness: BOLDT John

UNDERTAKING – JT 3.27

Undertaking

To provide corrected data for IR Response Exhibit I, Tab 51, Schedule ESC 2, table 16 and table 19.

Response

Refer to Attachment 1 for the updated Table 16 – Rate Code 45b - Connection Impact Assessments – Embedded LDC Generations

Refer to Attachment 2 for the updated Table 19 – Rate Code 45e – Connection Impact Assessments – Greater than Capacity Allocation Exempt Projects

Year	Rate Code	Specific Service Charge Description	Labour Description	Rate Amount	Hours/Units	Overtime Factor	Calculated Total	Payroll Burdens	Total Labour	Other Description	Rate Amount	Hours/Units	Calculated Total	Total Other	Total
2018	45b	Connection Impact Assessments - Embedded LDC Generators	Direct Labour - Clerical	$80.08	0.87		$69.67	$37.34	$107.01						
			Direct Labour - MP4	$117.84	1.25		$147.30	$78.95	$226.25						
			Direct Labour - Technician (GR64)	$89.20	1.58		$140.94	$75.54	$216.48						
			Direct Labour - MP2	$105.47	10.66		$1,124.31	$602.63	$1,726.94						
			Payroll Burden	53.60%					**$2,276.68**						**$2,276.68**
2019	45b	Connection Impact Assessments - Embedded LDC Generators	Direct Labour - Clerical	$81.00	0.87		$70.47	$38.27	$108.74						
			Direct Labour - MP4	$119.24	1.25		$149.05	$80.93	$229.98						
			Direct Labour - Technician (GR64)	$90.07	1.58		$142.31	$77.27	$219.59						
			Direct Labour - MP2	$106.92	10.66		$1,139.77	$618.89	$1,758.66						
			Payroll Burden	54.30%					**$2,316.97**						**$2,316.97**
2020	45b	Connection Impact Assessments - Embedded LDC Generators	Direct Labour - Clerical	$81.96	0.87		$71.31	$39.15	$110.45						
			Direct Labour - MP4	$120.69	1.25		$150.86	$82.82	$233.69						
			Direct Labour - Technician (GR64)	$91.00	1.58		$143.78	$78.94	$222.72						
			Direct Labour - MP2	$108.43	10.66		$1,155.86	$634.57	$1,790.43						
			Payroll Burden	54.90%					**$2,357.29**						**$2,357.29**
2021	45b	Connection Impact Assessments - Embedded LDC Generators	Direct Labour - Clerical	$82.92	0.87		$72.14	$40.11	$112.25						
			Direct Labour - MP4	$121.49	1.25		$151.86	$84.44	$236.30						
			Direct Labour - Technician (GR64)	$91.92	1.58		$145.23	$80.75	$225.98						
			Direct Labour - MP2	$109.27	10.66		$1,164.82	$647.64	$1,812.46						
			Payroll Burden	55.60%					**$2,386.99**						**$2,386.99**
2022	45b	Connection Impact Assessments - Embedded LDC Generators	Direct Labour - Clerical	$84.20	0.87		$73.25	$40.73	$113.98						
			Direct Labour - MP4	$122.77	1.25		$153.46	$85.33	$238.79						
			Direct Labour - Technician (GR64)	$93.20	1.58		$147.26	$81.87	$229.13						
			Direct Labour - MP2	$110.56	10.66		$1,178.57	$655.28	$1,833.85						
			Payroll Burden	55.60%					**$2,415.76**						**$2,415.76**

Year	Rate Code	Specific Service Charge Description	Labour Description	Rate Amount	Hours/Units	Overtime Factor	Calculated Total	Payroll Burdens	Total Labour	Other Description	Rate Amount	Hours/Units	Calculated Total	Total Other	Total
2018	45e	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - Capacity Allocation Required Projects	Direct Labour - Clerical	$80.08	0.62		$49.65	$26.61	$76.26	Small Vehicle Time	$10.00	1.81	$18.10		
			Direct Labour - MP2	$105.47	11.10		$1,170.72	$627.50	$1,798.22						
			Direct Labour - Intern	$67.06	28.71		$1,925.29	$1,031.96	$2,957.25						
			Direct Labour - MP4	$117.84	20.37		$2,400.40	$1,286.61	$3,687.02						
			Direct Labour - Field Staff (ADET)	$84.64	4.08		$345.33	$185.10	$530.43						
			Payroll Burden	53.60%					**$9,049.18**					**$18.10**	**$9,067.28**
2019	45e	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - Capacity Allocation Required Projects	Direct Labour - Clerical	$81.00	0.62		$50.22	$27.27	$77.49	Small Vehicle Time	$10.00	1.81	$18.10		
			Direct Labour - MP2	$106.92	11.10		$1,186.81	$644.44	$1,831.25						
			Direct Labour - Intern	$67.39	28.71		$1,934.77	$1,050.58	$2,985.35						
			Direct Labour - MP4	$119.24	20.37		$2,428.92	$1,318.90	$3,747.82						
			Direct Labour - Field Staff (ADET)	$85.54	4.08		$349.00	$189.51	$538.51						
			Payroll Burden	54.30%					**$9,180.42**					**$18.10**	**$9,198.52**
2020	45e	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - Capacity Allocation Required Projects	Direct Labour - Clerical	$81.96	0.62		$50.82	$27.90	$78.71	Small Vehicle Time	$10.00	1.81	$18.10		
			Direct Labour - MP2	$108.43	11.10		$1,203.57	$660.76	$1,864.33						
			Direct Labour - Intern	$67.77	28.71		$1,945.68	$1,068.18	$3,013.85						
			Direct Labour - MP4	$120.69	20.37		$2,458.46	$1,349.69	$3,808.15						
			Direct Labour - Field Staff (ADET)	$86.48	4.08		$352.84	$193.71	$546.55						
			Payroll Burden	54.90%					**$9,311.59**					**$18.10**	**$9,329.69**
2021	45e	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - Capacity Allocation Required Projects	Direct Labour - Clerical	$82.92	0.62		$51.41	$28.58	$79.99	Small Vehicle Time	$10.00	1.81	$18.10		
			Direct Labour - MP2	$109.27	11.10		$1,212.90	$674.37	$1,887.27						
			Direct Labour - Intern	$68.78	28.71		$1,974.67	$1,097.92	$3,072.59						
			Direct Labour - MP4	$121.49	20.37		$2,474.75	$1,375.96	$3,850.71						
			Direct Labour - Field Staff (ADET)	$87.42	4.08		$356.67	$198.31	$554.98						
			Payroll Burden	55.60%					**$9,445.55**					**$18.10**	**$9,463.65**
2022	45e	Connection Impact Assessments - Greater than Capacity Allocation Exempt Projects - Capacity Allocation Required Projects	Direct Labour - Clerical	$84.20	0.62		$52.20	$29.03	$81.23	Small Vehicle Time	$10.00	1.81	$18.10		
			Direct Labour - MP2	$110.56	11.10		$1,227.22	$682.33	$1,909.55						
			Direct Labour - Intern	$70.06	28.71		$2,011.42	$1,118.35	$3,129.77						
			Direct Labour - MP4	$122.77	20.37		$2,500.82	$1,390.46	$3,891.28						
			Direct Labour - Field Staff (ADET)	$88.70	4.08		$361.90	$201.21	$563.11						
			Payroll Burden	55.60%					**$9,574.94**					**$18.10**	**$9,593.04**

UNDERTAKING – JT 3.28

Undertaking

To update the response to part C of Exhibit I, Tab 51, Schedule ESC 2.

Response

The effort and time required to complete a CIA study for an energy storage facility is the same as any other generation facility. Therefore, the charges in Table 16, Table 17, Table 19, and Table 20 found in H1-02-03 Appendix B would apply to an energy storage facility greater than 10kW.

An energy storage facility equal to or less than 10kW would apply under the micro-embedded generation process for which there is no charge for the assessment/screening.

Written Statement – I-24-Anwaatin-008

Preamble

During the March 5, 2018 Technical Conference session, and in the context of I-24-Anwaatin-008, Hydro One committed to taking under advisement, but not as an undertaking, to review and determine if ten years of reliability data is available and what issues there may be with providing the data.

Response

Hydro One has raw data for the previous ten years, but in the responses to I-24-Anwaatin-008 provided information for the five-year period spanning 2012 to 2016.

Although, raw data spanning ten years exists, Hydro One maintains that there are two principal issues with providing this data in the context of an application where it may be relied upon to produce arguments or render decisions.

Of primary concern, is that the transmission system (i.e. the configuration of supply) has experienced significant changes in its configuration over ten years. The changes in the configuration of supply inherently impacted the reliability of the distribution system over time. Although changes in the configuration of supply are expected and the supply system is not static, examining reliability trends or contemplating distribution reliability performance over an extended period of time, such as ten years, introduces greater variability due to the configuration of supply, rendering a meaningful analysis impractical, and likely, inaccurate. While a five-year window is still subject to changes in the configuration of supply, it represents a much smaller and recent period in time which is more relevant for trending and for comparisons.

Additionally, the consistency for collecting and reporting data, i.e. the methodology used, over ten years cannot be verified.

For these reasons, Hydro One maintains that providing ten years of distribution system data is not appropriate and that such data cannot be used to infer any meaningful information or be used for correct trending and analysis. If compelled to provide this information, the Company cautions that the information should not be used to produce arguments for or against or to be used in rendering a decision in its current or future applications before the Ontario Energy Board.