Court File No.: CV-15-535019-00CP

ONTARIO
SUPERIOR COURT OF JUSTICE

B E T W E E N :

BILL BENNETT

Plaintiff

- and -

HYDRO ONE INC., HYDRO ONE BRAMPTON NETWORKS INC., HYDRO ONE REMOTE COMMUNITIES INC., NORFOLK POWER DISTRIBUTION INC., and HYDRO ONE NETWORKS INC.

Defendants

Proceeding under the *Class Proceedings Act, 1992*

CERTIFICATION MOTION RECORD
(Returnable May 9-11, 2017)

VOLUME 4 OF 4

April 14, 2016

KOSKIE MINSKY LLP
20 Queen Street West
Suite 900, PO Box 52
Toronto ON M5H 3R3

Kirk M. Baert LS#: 30942O
Tel: (416) 595-2117 / Fax: (416) 204-2889
Garth Myers LS#: 63207G
Tel: (416) 595-2102 / Fax: (416) 204-4024

LAX O'SULLIVAN LISUS GOTTLIEB LLP
145 King St West
Suite 2750
Toronto ON M5H 1J8

Eric R. Hoaken LS#: 35502S
Tel: (416) 645-5075 / Fax: (416) 598-3730
Ian C. Matthews LS#: 55306N
Tel: (416) 598-5365 / Fax: (416) 598-3730
Lisa S. Lutwak LS#: 659851
Tel: (416) 645-5078 / Fax: (416) 598-3730
Lawyers for the Plaintiff

TO: **OSLER, HOSKIN & HARCOURT LLP**
100 King Street West
1 First Canadian Place
Suite 6200
P.O. Box 50
Toronto ON M5X 1B8

Laura K. Fric
Tel: (416) 862-5889 / Fax: (416) 862-6666
Lawrence Ritchie
Tel: (416) 862-6608 / Fax: (416) 862-6666
Robert Carson
Tel: (416) 862-4235 / Fax: (416) 862-6666
Lawyers for the Defendants

CERTIFICATION MOTION RECORD

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This is Exhibit "R" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Lisa Lutwak

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK

HYDRO ONE INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS
For the years ended December 31, 2014 and 2013

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 (the Consolidated Financial Statements) of Hydro One Inc. (Hydro One or the Company) for the year ended December 31, 2014. 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 are different from those of the US. This MD&A provides information for the year ended December 31, 2014, based on information available to management as of February 11, 2015.

EXECUTIVE SUMMARY

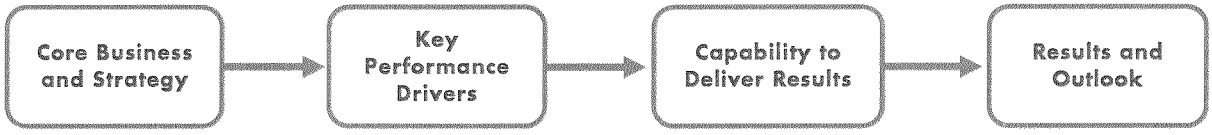
We are wholly owned by the Province of Ontario (Province or Shareholder), and our Transmission and Distribution Businesses are regulated by the Ontario Energy Board (OEB).

During 2014, we continued to focus tremendous effort on customer service and on forming a stronger relationship between our customers' satisfaction with our service and their perceptions of our company. The expectation is that in doing so, we will emerge from the challenges of this year with a renewed, transparent and consistent experience for all our customers by creating new customer tools, products, and processes and by establishing new standards for customer service. We have implemented a strong governance system that will ensure we are monitoring and measuring key performance indicators to support and advance our values with respect to being a customer caring company. We have achieved a number of targets with respect to call centre performance and billing issues to stabilize customer operations following the implementation of our new billing system, and we will continue to strive for stronger performance and an ever-improving experience for our customers.

To further improve our customer service performance culture, we have recently announced two new initiatives – a third party expert Customer Service Advisory Panel and our draft Customer Commitments. Our Customer Commitments will form the basis of our promises to our customers, and the Customer Service Advisory Panel will provide advice and hold us accountable to the promises we make to our customers. Once our Customer Commitments are finalized with input received from our customers, our employees and our Customer Service Advisory Panel, we will develop a public scorecard and will report on our performance as a transparent, accountable and customer focused organization.

Our mission and vision reflects the unique role we play in the economy of the Province and as a provider of critical infrastructure to all our customers. We strive to be an innovative and trusted company, delivering electricity safely, reliably and efficiently to create value for our customers. We operate as a commercial enterprise with an independent Board of Directors. Our strategic plan is driven by our values: health and safety; excellence; stewardship; and innovation. Safety is of utmost importance to us because we work in an environment that can be hazardous. We take our responsibility as stewards of critical provincial assets seriously. We demonstrate sound stewardship by managing our assets in a manner that is commercial, transparent and which values our customers. We strive for excellence by being trained, prepared and equipped to deliver high-quality service. We value innovation because it allows us to increase our productivity and develop enhanced methods to meet the needs of our customers.

We manage our business using the following framework:



Core Business and Strategy

Our corporate strategy is based on our mission and vision and our values. Our strategic objectives, which are discussed in the section "Overview – Our Strategy," encompass the core values that drive our business. Our strategy touches every part of our core business: health and safety; our customers; innovation; the reliability and efficiency of our systems; the environment; our workforce; Shareholder value; and productivity.

Key Performance Drivers

Performance drivers have been identified that relate to achieving our company's strategic objectives. We establish specific performance targets for each driver aimed at measuring the achievement of our strategic objectives over time. For example, we track the duration of unplanned customer interruptions per delivery point as an indication of our commitment to provide a reliable transmission system for our customers. We measure transmission and distribution unit costs as an indication of our commitment to increasing productivity. These and other key performance drivers are included in the discussion of our performance measures in the section "Overview – Performance Measures and Targets."

Capability to Deliver Results

We continue to use a balanced scorecard approach as we strive to manage our performance and deliver results each and every year. In 2014, we set 14 performance measure targets and we met or exceeded eight of them. We exceeded our targets for an injury-free workplace, timely and efficient connection of new customers, the ability to provide timely and accurate bills to customers, our Transmission Business cost-effectiveness, net income after tax, and our transmission and distribution in-service capital. Our targets, and our 2014 performance relating to these targets, are discussed in the section "Overview – Performance Measures and Targets." Our ability to deliver results in each of our strategic areas is limited by risks inherent in our regulatory environment, our business, our workforce, and in the economic environment. These risks, as well as our strategies to mitigate them, are discussed in the section "Risk Management and Risk Factors."

Results and Outlook

Consolidated Statements of Operations and Comprehensive Income

Year ended December 31 (millions of Canadian dollars, except per share amounts)	2014	2013	2012
Total revenue	6,548	6,074	5,728
Net income attributable to the Shareholder of Hydro One	749	803	745
Basic and fully diluted earnings per common share *(dollars)*	7,319	7,850	7,280
Cash dividends per common share *(dollars)*	2,696	2,000	3,523
Cash dividends per preferred share *(dollars)*	1.375	1.375	1.375

Consolidated Balance Sheets

December 31 (millions of Canadian dollars)	2014	2013	2012
Total assets	22,550	21,625	20,811
Total long-term debt	8,925	9,057	8,479
Preferred shares	323	323	323
Net assets	7,947	7,415	6,830

During 2014, we earned net income of $749 million and revenues of $6,548 million. We made capital investments totalling $1,530 million to improve our transmission and distribution systems' reliability and performance, address our aging power system infrastructure, facilitate new generation, and improve service to our customers. A full discussion of our results of operations, financing activities, and capital investments can be found in the sections "Annual Results of Operations" and "Liquidity and Capital Resources."

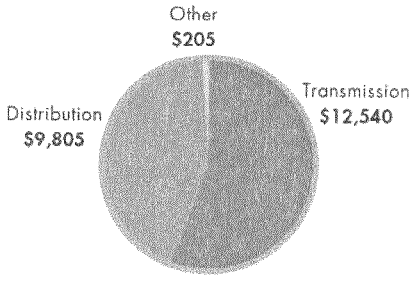
In August 2014, we completed the acquisition of Norfolk Power Inc. (Norfolk Power), an electricity distribution and telecom company located in southwestern Ontario. Hydro One has been a proud electricity distributor in Norfolk County for decades, serving approximately 14,000 Norfolk County customers. The acquisition of Norfolk Power enables our company to extend our service to the entire Norfolk County and a further 18,000 distribution customers. We are committed to delivering cost-effective service for Norfolk Power's customers and we remain focused on prudent management, efficient operations and

improving the customer experience for everyone we serve. In 2014, we also signed agreements to purchase two more local distribution companies (LDCs): Woodstock Hydro Holdings Inc. (Woodstock Hydro) and Haldimand County Utilities Inc. (Haldimand Hydro). A full discussion of the Norfolk Power, Woodstock Hydro and Haldimand Hydro acquisitions can be found in the section "New Developments in 2014 – Business Combinations."

In addition, we have completed a partnership transaction with the Saugeen Ojibway Nation (SON), where the SON has acquired a noncontrolling equity interest in our new limited partnership, B2M Limited Partnership (B2M LP). A full discussion of this transaction can be found in the section "New Developments in 2014 – Business Combinations."

OVERVIEW

We are the largest electricity transmission and distribution company in Ontario. We own and operate substantially all of Ontario's electricity transmission system, accounting for approximately 97% of Ontario's transmission capacity based on revenue approved by the OEB. Based on assets, our transmission system is one of the largest in North America. Our consolidated distribution system is the largest in Ontario and spans roughly 75% of the province.



Total Assets
December 31, 2014
(millions of dollars)

Our Businesses

Our company has three reportable segments:

- Our Transmission Business, which comprises the core business of providing electricity transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- Our Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- Other Business, which includes certain corporate activities and the operations of our telecommunications business.

Transmission Business

	2014	2013
Electricity transmitted *(TWh)*[1]	139.8	140.7
Ontario 20-minute system peak demand *(MW)*[1]	23,040	24,957
Ontario 60-minute system peak demand *(MW)*[1]	22,774	24,927
Total transmission lines spanning the province *(circuit-kilometres)*	29,344	29,344
Transmission stations *(#)*	290	285
Transmission transformers *(#)*	1,471	1,416
Transmission customers *(approximate #)*	5,000,000	5,000,000

[1] System-related statistics include preliminary figures for December.
TWh means terawatt-hours
MW means megawatts

Our transmission system totals approximately 29,000 circuit-kilometres of high-voltage lines whose major components consist of cables, conductors, wood or steel support structures, foundations, insulators, connecting hardware and grounding systems. We also own 290 transmission stations and over 1,400 transmission transformers. Our transmission system operates at 500 kV, 230 kV and 115 kV over relatively long distances and transmits electricity from hydroelectric, wind, solar, nuclear and coal-burning generators to customers consisting of 46 LDCs, our own distribution businesses, and 90 transmission-connected companies. It is also linked to five adjoining jurisdictions through 26 interconnections, through which we can accommodate electricity imports of up to 6,963 MW, and electricity exports of up to 6,295 MW. During 2014, our transmission system transported approximately 139.8 TWh of energy throughout Ontario.

Our Transmission Business includes the transmission businesses of our subsidiary Hydro One Networks Inc. (Hydro One Networks) as well as B2M LP. We own and operate substantially all of Ontario's electricity transmission system, and serve,

directly or indirectly, approximately five million customers. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from our Ontario Grid Control Centre.

In 2014, we earned total transmission revenues of $1,588 million, representing approximately 24% of our total 2014 revenues. At December 31, 2014, our Transmission Business assets were $12,540 million, representing approximately 56% of our total assets.

Distribution Business

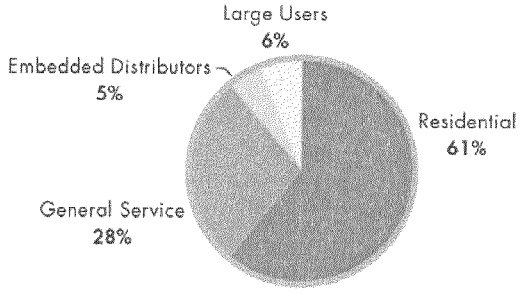
	2014	2013
Electricity distributed to Hydro One customers *(TWh)*[1]	29.8	29.8
Electricity distributed through Hydro One lines *(TWh)*[1,2]	42.4	42.5
Total distribution lines spanning the province *(circuit-kilometres)*	123,657	122,853
Distribution wood poles *(approximate #)*	1,551,000	1,550,000
Distribution and regulating stations *(#)*	1,026	1,017
Distribution customers *(#)*	1,439,321	1,420,379

[1] System-related statistics include preliminary figures for December.

[2] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

Our distribution system totals over 123,000 circuit-kilometres of distribution lines, and we own over 1,000 distribution and regulating stations and over 1.5 million distribution wood poles. Our distribution system distributes electricity from our transmission system and from more than 14,200 small generators to approximately 1.4 million of our rural and urban customers within Ontario. During 2014, approximately 42.4 TWh of electricity was distributed through our distribution system, including 29.8 TWh of electricity delivered to Hydro One customers.

Our consolidated Distribution Business includes the distribution businesses of our subsidiary Hydro One Networks and the newly acquired Norfolk Power, as well as our subsidiaries Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), and Hydro One Remote Communities Inc. (Hydro One Remote Communities).



2014 Distribution Revenues

- Hydro One Networks' distribution business operates a low-voltage electrical distribution network that distributes electricity to customers, including 23 LDCs not directly connected to our transmission system, 33 LDCs connected to our transmission system, 31 customers with loads exceeding 5 MW, and approximately 1.3 million rural and urban customers.
- Hydro One Brampton Networks operates the electricity distribution system and facilities within the City of Brampton, Ontario, serving approximately 150,000 urban retail customers.
- Hydro One Remote Communities operates 19 small, regulated generation and distribution systems in 21 remote communities across northern Ontario that are not connected to Ontario's electricity grid, serving approximately 3,500 customers.

In 2014, we earned total distribution revenues of $4,903 million, including cost of purchased power of $3,419 million, representing approximately 75% of our total 2014 revenues. At December 31, 2014, our Distribution Business assets were $9,805 million, representing approximately 43% of our total assets.

Other Business

Our Other Business segment includes the operations of our subsidiary, Hydro One Telecom Inc. (Hydro One Telecom), which operates a fibre optic communications network spanning over 6,000 kilometres. Hydro One Telecom provides dark

fibre and lit fibre optic capacity to telecommunications carriers and commercial customers with broadband network requirements, including a dedicated optical network providing secure, high-capacity connectivity across numerous health care locations in Ontario. Hydro One Telecom also provides telecommunication systems management and related functions which are required for our transmission and distribution businesses, including corporate data and voice networks and smart meter operations.

In 2014, our Other Business segment contributed revenues of $57 million, representing approximately 1% of our total 2014 revenues. At December 31, 2014, our Other Business segment assets were $205 million, representing approximately 1% of our total assets.

Our Strategy

Our corporate strategy builds on our strong commitment to the Province and is shaped by our values. It lays out a set of objectives to position our company to achieve our mission and vision, which is to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. Our values represent our core beliefs.

- ***Health and safety:*** Nothing is more important than the health and safety of our employees, those who work on our property, and the public.
- ***Excellence:*** We achieve excellence through continuous training, ensuring we are prepared and equipped to deliver high-quality and affordable service, with integrity.
- ***Stewardship:*** We invest in our assets and people to build a safe, environmentally sustainable electricity network in a commercial manner.
- ***Innovation:*** We innovate through new processes, people and technology to allow us to find better ways to meet the needs of our customers.

We have eight strategic objectives that are inextricably linked. They drive the fulfillment of our mission and vision and ensure we remain focused on achieving our corporate goal of providing safe, reliable and affordable service to our customers, today and tomorrow, while increasing enterprise value for our Shareholder.

- ***Creating an injury-free workplace and maintaining public safety.*** Health and safety must be integrated into all that we do as we continue to reinforce that nothing is more important than the health and safety of our employees. We will continue to create a passion for preventing injury, staying safe and keeping each other safe. We will invest in building a culture of accountability to continue our drive to zero injuries in the workplace. In addition, we will continue to strengthen our already strong safety culture through our Journey to Zero initiative and our successful certification to the Occupational Health and Safety Assessment Series (OHSAS) 18001 standard.
- ***Satisfying our customers.*** We exist to serve our customers, and serving our customers means reducing costs, improving customer service and meeting their expectations regarding reliable power supply. We will continue to focus our efforts to improve our relationship with customers and to improve our customers' satisfaction with us. We will meet our commitments, make customers our focus in all planning discussions, communicate effectively, coordinate across our company, and maximize opportunities to improve our corporate image and every customer interaction. We will develop and deliver targeted customer segment strategies, products and delivery channels that will respond to their unique needs.
- ***Continuous innovation.*** Innovation represents one of our values and is critical to achieving our mission and vision. We have been using innovation and technology to build the foundation of our company as the utility of the future. Over the next two decades, we will continue to build on that foundation to improve the reliability and efficiency of our transmission and distribution systems and provide our customers with more capability to manage their power costs. The development of the Advanced Distribution System (ADS) is a key element in our investment in innovation, as are the investments we have made, through our Cornerstone project, in next-generation business tools to enable us to implement leading industry practices and increase productivity.
- ***Building and maintaining reliable, affordable transmission and distribution systems.*** Our transmission strategy is to provide a robust and reliable provincial grid that accommodates Ontario's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance. Our distribution strategy is focused on continuing to meet the challenge of providing reliable, affordable service to our

customers in a wide range of geographical regions and climate zones; incorporating ADS technology to provide greater visibility; and increased control and improved customer service. We will meet customer expectations regarding reliability, in part through our investment planning process, which starts with the identification of asset and customer needs.

- ***Protecting and sustaining the environment for future generations.*** Consistent with our value of stewardship, we play a central role in reducing Ontario's carbon footprint through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use.
- ***Championing people and culture.*** We believe our primary strength is the capability of our people. In order to sustain this advantage, we will continue to address the issues of corporate culture, labour demographics, diversity, development of critical core competencies, and skill and knowledge retention. We will continue to develop a culture of accountability and trust as a key component to fostering employee engagement. Our labour strategy is to consolidate and clarify our collective agreements, increase flexibility and reduce costs, and maintain a progressive relationship with our unions.
- ***Maintaining a commercial culture that increases value for our Shareholder.*** For the delivery component of a customer bill, we are committed to maintaining total annual bill impacts for an average residential customer at or below the rate of inflation, and delivering income and dividends to our Shareholder. We will pursue growth opportunities through LDC consolidation to increase the enterprise value of our company by leveraging our existing assets, technologies, capabilities, unparalleled experience in LDC acquisitions, and our distribution and transmission footprint.
- ***Achieving productivity improvements and cost-effectiveness.*** To achieve our mission and vision, we must constantly strive for productivity through efficiency and effective management of costs. Productivity is key to meeting our other strategic objectives and, in particular, to achieving value for our customers and our Shareholder.

Performance Measures and Targets

We target and measure our performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that we maintain a focus on our strategic objectives and take mitigating actions as required. In 2014, we met or exceeded eight of 14 performance measure targets. Overall, we are making progress towards achieving many of our strategic goals.

Injury-free Workplace

The safety of our employees is paramount. For 2014, our company used the measure of all work-related injuries or illnesses as the performance measure for this strategic objective. A "recordable" injury/illness is one of the following: medical attention (treatment beyond first aid); modified work (restricted duties); lost time; or death. For 2014, our Board of Directors set the target at 1.9 recordable injuries per 200,000 hours worked for this measure. We exceeded this target.

Satisfying our Customers

In 2014, we approached the objective of customer satisfaction by addressing five measures related to improving customer relations. These measures relate to transmission and distribution customer satisfaction, and connection of new services, as well as estimated bills and no bill volume, as part of our customer service recovery project. Our customer service recovery project was a result of billing issues our company encountered due to the implementation in May 2013 of our new Customer Information System (CIS).

- ***Customer Satisfaction – Transmission***
  This measure is to determine the degree to which our transmission customers are satisfied with the service they receive from our company. It is based on survey results of customer surveys conducted on our company's behalf by independent third parties. The survey is given to three major groups of transmission customers. In 2014, we targeted a transmission customer satisfaction rate of 84%. We did not meet this target.
- ***Customer Satisfaction – Distribution***
  Similar to the transmission customers, we survey our distribution customers to assess the degree to which they are satisfied with the service they receive from our company. The results arise from surveys conducted on our

company's behalf by independent third parties. This measure reflects the overall satisfaction levels of three major distribution customer segments, based on transaction satisfaction levels, annual satisfaction surveys and the meeting of OEB milestones, respectively, for the three segments. For 2014, our company set a target for distribution customer satisfaction at 87%, and did well on the transactional elements, but did not meet this target on an overall basis.

- *Connection of New Customers*
  This measure relates to distribution low-voltage connections that is reported annually to the OEB. It addresses our customers' needs for a specific and timely connection date and assesses our efficiency in connecting new customers. It measures the percentage of connections for a requested new service (< 750 volts). The connection must be completed within five business days from the day on which all applicable service conditions are satisfied, or at a later date agreed upon by the customer and our company. We set a 2014 target of 90%, which we exceeded.

- *Unscheduled Estimated Bills*
  With respect to this measure, we seek to track our company's ability to provide accurate bills to our customers. We track the percentage of total customers that have received unscheduled estimates in any billing period. Our company established a target of 1.8% of all bills for this measure. We exceeded the target.

- *No Bill Volume*
  No bill volume is a customer service measure related to our company's ability to provide timely bills to our customers. This measure tracks the number of customers who have not received a bill in three consecutive billing periods. Our expectation was to reach a volume of 8,000 no-bill customers by September 2014, and sustain this level beyond that date. We exceeded this target.

Continuous Improvement and Cost-effectiveness

As part of our strategic objectives to increase productivity through efficiency improvements and effective management of costs, our company measures transmission unit cost and distribution unit cost and sets targets for those costs. Regarding the maintenance and reliability of the transmission and distribution systems, we continue to build and retain public confidence and trust in our company's operations, as stewards of Ontario's electricity grid. In 2014, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for customers in a safe, reliable and efficient fashion. Our company is conscious that commercial customers of all sizes require reliable service to allow them to deliver their products and services and that customers' expectations are for a reasonably limited duration when interruptions occur. Transmission and distribution reliability is measured through the duration of customer interruptions.

- *Transmission Unit Costs*
  For 2014, the transmission unit cost measure shows the Transmission Business cost-effectiveness by comparing the ratio of operation, maintenance and administration spending to gross fixed asset costs, using benchmarking initiatives. Our company set a target of 2.9% for 2014, and exceeded the target.

- *Distribution Unit Costs*
  Similar to transmission unit cost, the distribution unit cost measure demonstrates the distribution cost-effectiveness by comparing the ratio of operation, maintenance and administration spending to gross fixed asset costs, using benchmarking initiatives. For 2014, our company set a target of 5.7%, but did not meet this target.

- *Customer Interruption Duration – Transmission*
  This measure monitors the reliability of the transmission system by tracking the average length of unplanned interruptions (in minutes) to multiple-circuit supplied delivery points. Our company has set a target of 8.9 minutes per delivery point for 2014. During 2014, our company was aware that we would miss the target, which was not indicative of degrading reliability, but rather a result of refurbishing aging assets. In doing so, this resulted in occasions where load with a multiple-circuit supply was placed on single supply to accommodate the work program. This exposed the system to interruptions if there was a loss of the single supply. Our company determined that it was important to continue with the maintenance program even if this would result in missing the target. Our company, in fact, did not meet this target.

- *Customer Interruption Duration – Distribution*
  This measure is an indicator of the distribution system reliability that expresses the average length of outages in hours that a customer can expect to experience in the year. This measure excludes *force majeure* events and loss of

supply events (events caused by the transmission system or other distributors). Our company set a target of 6.7 hours per customer for this measure. In 2014, there were numerous storm events which were not considered *force majeure* events and comparatively more equipment outages that resulted in higher than normal customer interruptions. In the circumstances, we did not meet this target.

Maintaining a Commercial Culture

- *Net Income*
  Achievement of strong financial performance is measured by a performance measure of targeted level of net income after tax. Our target was $668 million net income after tax for 2014, and we exceeded our target.
- *Customer Service Recovery Cost*
  As a result of billing issues that arose from the implementation of our new CIS in 2013, the effects of which became acute in early 2014, our company established the customer service recovery project to dedicate staff to resolve outstanding and any new billing issues and stabilize the billing system. We anticipated, and fixed as a target, costs of $48 million (including revenue impacts) for this project. The project was completed in 2014 and the CIS is now in sustainment mode. As the costs of the customer service recovery project exceeded the target, our company did not meet this anticipated target.
- *In-Service Capital – Transmission*
  This new measure for 2014 evaluates how our company is meeting the OEB targets for in-service capital. For our Transmission Business, the 2014 target of 85% of in-service capital to our business plan is based on historical performance, our increasing capital work program, and the additional variability caused by external commitments and required approvals. Our 2014 result shows that our company exceeded the target.
- *In-Service Capital – Distribution*
  For our Distribution Business, our company set the 2014 target of 87% of in-service capital to our business plan based on historical performance, with adjustments to reflect that our Distribution Business has more storm-related capital spending than our Transmission Business, as well as the performance of our smart meter and distributed generation capital work programs. Our 2014 result was better than the target.

REGULATION

Our Transmission and Distribution Businesses are primarily regulated by the OEB and the National Energy Board (NEB).

Provincial Framework

The *Electricity Act, 1998,* and the *OEB Act* primarily establish the broad legislative framework for Ontario's electricity market. The *Electricity Act, 1998,* sets out the fundamental principles of Ontario's electricity industry, enabling open and nondiscriminatory access to transmission and distribution systems. The *OEB Act* provides the OEB with the jurisdiction and mandate to regulate Ontario's electricity market. The OEB provides a framework for the review of electrical utilities' distribution and transmission revenue requirements so that rates may be established based on historical average or forecasted needs.

The OEB approves both the revenue requirements of and the rates charged by our regulated businesses. The rates are designed to permit our businesses to recover the allowed costs and to earn a formula-based annual rate of return on our common equity 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 accounts over specified timeframes.

The OEB approved the use of US GAAP for rate setting and regulatory accounting and reporting by Hydro One Networks' Transmission and Distribution Businesses, as well as by Hydro One Remote Communities, beginning with the year 2012. Up to the year ended December 31, 2014, Hydro One Brampton Networks used Canadian GAAP (Part V) for its distribution rate-setting purposes, and has transitioned to International Financial Reporting Standards (IFRS) beginning on January 1, 2015.

Renewed Regulatory Framework

In December 2010, the OEB initiated a coordinated consultation process for the development of a Renewed Regulatory Framework for Electricity (RRFE). In October 2012, the OEB issued its report *A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.* The report identified three rate-setting models available to provide choices suitable for distributors having varying capital requirements: a fourth-generation Incentive Regulation Mechanism (IRM); a custom rate setting; and an Annual Incentive Rate-setting Index method. The report also provided information on performance measurement, continuous improvement and implementation of the new framework.

In late 2013, the OEB issued its *Report of the Board on Rate-Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*. This report sets out the OEB's policies and approaches to the rate adjustment parameters for incentive rate setting for electricity distributors and the benchmarking of electricity distributor total cost performance. It also includes the OEB's determination on rate adjustment parameter values for 2014 incentive rate setting, which were used to adjust Hydro One Networks' 2014 distribution rates.

Federal Framework

While most electricity power lines and facilities in Canada fall within provincial jurisdiction, the NEB has jurisdiction over the construction and operation of international power lines (IPLs). Hydro One Networks owns and operates IPLs with New York, Michigan and Minnesota, and is subject to several NEB-issued certificates and permits. According to the *NEB Act*, any modifications to an IPL require NEB approval.

In 2012, the NEB issued a general order and five amending orders for mandatory electricity reliability standards for certain IPLs in Canada. The orders (i) require Hydro One Networks, as the owner of such lines, to comply with specified North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council Inc. (NPCC) reliability standards, (ii) mandate certain reporting requirements, and (iii) contain provisions for IPL owners to seek exemptions. In March 2013, Hydro One Networks submitted to the NEB a declaration of compliance and a request for indefinite exemptions from a list of standards that do not apply to Hydro One Networks or to the IPLs it owns. On November 13, 2013, the NEB granted Hydro One Networks' exemption requests, with some minor exceptions. Hydro One Networks maintains compliance with all applicable NEB orders and seeks approval for all appropriate exemptions, as required.

NERC Critical Infrastructure Protection (Cyber Security) standards are designed to ensure that utilities and other users, owners, and operators of the bulk power system in North America have appropriate procedures in place to protect critical infrastructure from cyber attack. As a result, our physical, electronic and information security processes have been upgraded to meet more stringent security requirements in order to meet NERC's requirements. The NERC Cyber Security standards were updated and revised in 2013, resulting in additional work, effort and associated costs for our company. We anticipate these costs will be spread over a number of years, and expect that they will be recovered in future rates.

Regulatory Proceedings

The following table summarizes our company's recent major regulatory proceedings:

Application	Year(s)	Type	Date Filed	Current Status
Electricity Rates – Transmission Rate Applications				
Hydro One Networks	2013-2014	Cost-of-service	May 28, 2012	OEB decision received on January 9, 2014[1]
Hydro One Networks	2015-2016	Cost-of-service	September 16, 2014	OEB decision received on December 2, 2014
B2M LP	2015	Interim	October 24, 2014	OEB decision received on December 11, 2014
Electricity Rates – Distribution Rate Applications				
Hydro One Networks	2014	IRM	April 26, 2013	OEB decision received December 5, 2013
Hydro One Networks	2015-2019	Custom	December 19, 2013	OEB decision anticipated in 2015 Q1
Hydro One Brampton Networks	2014	IRM	August 14, 2013	OEB decision received December 5, 2013
Hydro One Brampton Networks	2015	Cost-of-service	April 23, 2014	OEB decision received on January 15, 2015
Hydro One Remote Communities	2014	IRM	October 25, 2013	OEB decision received March 13, 2014
Hydro One Remote Communities	2015	IRM	September 24, 2014	OEB decision anticipated in 2015 Q1
Mergers Acquisitions Amalgamations and Divestitures (MAAD) Applications				
Norfolk Power	n/a	Acquisition	April 26, 2013	OEB decision received July 3, 2014
Woodstock Hydro	n/a	Acquisition	July 9, 2014	OEB decision anticipated in 2015
Haldimand Hydro	n/a	Acquisition	July 31, 2014	OEB decision anticipated in 2015
Leave to Construct Application				
Supply to Essex County Transmission Reinforcement Project	n/a	Section 92	January 22, 2014	OEB decision anticipated in 2015

[1] OEB Oral Decision for 2013 transmission rates was received on November 8, 2012. On December 6, 2013, we submitted a draft Rate Order for our 2014 transmission rates. On January 9, 2014, the OEB approved the draft Rate Order for 2014 transmission rates as filed.

Electricity Rates

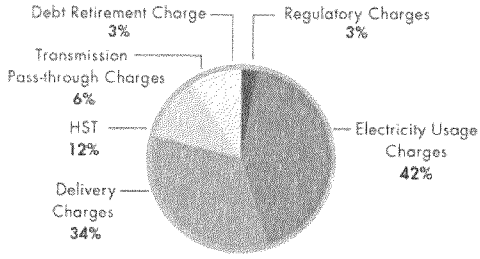
Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP). The RPP regulates the commodity price of electricity only and does not affect the rates charged for transmission and distribution of electricity. The OEB sets prices for RPP customers based on both a two-tiered electricity pricing structure with seasonal consumption thresholds, and a three-tiered electricity pricing structure with Time-of-Use (TOU) thresholds. New RPP prices are computed at six-month intervals and are the result of an integrated consideration of rebasing and true-ups. The following is a summary of the two-tiered RPP and the TOU RPP prices for the reporting and comparative periods:

RPP	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**Lower Tier 1**	**Upper Tier 2**
November 1, 2012	1,000	750	7.4	8.7
May 1, 2013	600	750	7.8	9.1
November 1, 2013	1,000	750	8.3	9.7
May 1, 2014	600	750	8.6	10.1
November 1, 2014	1,000	750	8.8	10.3

TOU RPP	Rates (cents/kWh)		
Effective Date	On Peak	Mid Peak	Off Peak
November 1, 2012	11.8	9.9	6.3
May 1, 2013	12.4	10.4	6.7
November 1, 2013	12.9	10.9	7.2
May 1, 2014	13.5	11.2	7.5
November 1, 2014	14.0	11.4	7.7

In 2010, the OEB issued its final determination to mandate TOU pricing for RPP customers. All eligible Hydro One distribution customers were migrated to TOU billing as of June 2011, except certain customers located in very rural and very sparsely populated areas. An exemption from the requirement to move these customers to TOU pricing was approved until December 31, 2014. On December 1, 2014, Hydro One filed a request with the OEB for a five-year exemption extension for 120,000 hard-to-reach customers and requested permission to migrate an additional 50,000 customers back to two-tiered RPP pricing, as it is not economically feasible to consistently provide actual readings from these meters. An OEB Hearing on this matter has commenced. The OEB issued an interim Decision granting an exemption extension until June 30, 2015 or until a final OEB Decision is issued.

Customers who are not eligible for the RPP and wholesale customers pay the market price for electricity, adjusted for the difference between market prices and prices paid to generators by the Independent Electricity System Operator (IESO) under the *Electricity Act, 1998*. The IESO is responsible for overseeing and operating the wholesale electricity market, as well as ensuring the reliability of the integrated power system.



Composition of Total Bill for Typical Residential Customer

A typical residential customer consumes 800 kWh of electricity per month. The total bill for a typical residential customer consists of the following: electricity usage charges based on RPP rates; electricity delivery charges based on OEB-approved distribution rates; transmission pass-through charges for the usage of the transmission system; regulatory charges, which include wholesale market costs and rural and remote rate protection amounts; the debt retirement charge; and the harmonized sales tax (HST).

Transmission Rates

Our transmission revenues primarily include our transmission tariff, which is based on the province-wide Uniform Transmission Rates (UTRs) approved by the OEB for all transmitters across Ontario. The OEB rate-setting process is a rigorous judicial process based on evidence, and usually legal cross-examination of witnesses who testify to the volumes of information submitted. The transmission tariff rates are set based on an approved revenue requirement that provides for cost recovery and a return on our common equity.

- **Hydro One Networks**

  In May 2012, we filed a cost-of-service rate application with the OEB for our 2013 and 2014 transmission rates. The application sought OEB approval for revenue requirement increases of approximately 0.6% in 2013 and 9.1% in 2014, or estimated increases of 0% in 2013 and 0.7% in 2014 on a typical residential customer's total bill. In November 2012, we submitted a draft Rate Order, which included revenue requirements of approximately $1,438 million and $1,528 million for 2013 and 2014, respectively. For a typical residential customer, this represents no change from the 2012 OEB-approved rate levels in 2013 and a 5.8% increase in 2014 for the transmission portion of the bill, or no change for 2013 and an increase of 0.5% for 2014 when considering total bill impact. In December 2012, the OEB approved the 2013 and 2014 transmission revenue requirements as requested. The 2013 Ontario UTRs remained unchanged at the 2012 levels.

  On December 6, 2013, we submitted a draft Rate Order for our 2014 transmission rates. The 2014 revenue requirement increased to $1,535 million from the originally-approved revenue requirement of $1,528 million, primarily due to changes in the cost of capital parameters for 2014 released by the OEB in November 2013. On January 9, 2014, the OEB approved the draft Rate Order for 2014 transmission rates as filed. For a typical

residential customer, this represents an increase of 6.3% in 2014 for the transmission portion of the bill, or 0.5% when considering total bill impact.

On September 16, 2014, Hydro One Networks filed its application, evidence and Settlement Agreement with the OEB in support of proposed transmission revenue requirements to be implemented on January 1, 2015 and January 1, 2016. This application is pursuant to a comprehensive Settlement Agreement between the stakeholders and Hydro One Networks. On January 8, 2015, the OEB approved the Hydro One transmission rates revenue requirement, excluding the B2M LP revenue requirement, for 2015 of $1,477 million and the 2016 revenue requirement of $1,516 million, subject to adjustments for the cost of capital parameters. For a typical residential customer, this represents increases of 0.4% in 2015 and 1.4% in 2016 for the transmission portion of the bill, or increases of 0.03% in 2015 and 0.1% in 2016 when considering total bill impact.

- **B2M LP**

  On October 24, 2014, B2M LP filed an application with the OEB for an interim transmission rate, effective January 1, 2015, seeking approval for a revenue requirement of $41 million in 2015. This rate is equal to the amount included in Hydro One Networks' transmission rates for the Bruce to Milton Line assets, resulting in no change to overall UTRs. The interim Rate Order was approved by the OEB on December 11, 2014. B2M LP was directed to file a full cost-of-service application for final 2015 transmission rates by April 1, 2015.

  A full discussion of the B2M LP transaction can be found in the section "New Developments in 2014 – Business Combinations."

Distribution Rates

Our distribution revenues primarily include our distribution tariff, which is based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. The distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and a return on our common equity.

- **Hydro One Networks**

  In June 2012, Hydro One Networks filed an IRM application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB issued a final Rate Order, which resulted in an increase in distribution rates of approximately 1.3% in 2013, or 0.4% when considering total bill impact, for a typical residential customer.

  On April 26, 2013, Hydro One Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. On September 26, 2013, the OEB issued a partial Decision, approving a rate rider to recover a 2014 revenue requirement of $29 million for operation, maintenance and administration expenses and in-service capital costs of the ADS Project, which will modernize our distribution system. On December 5, 2013, the OEB issued its final Decision, which resulted in an increase of distribution rates of approximately 2.4% in 2014, or 0.85% when considering total bill impact, for a typical residential customer.

  On December 19, 2013, Hydro One Networks filed a 2015-2019 distribution custom rate application with the OEB, for rates effective January 1 of each test year. This application is a five-year custom rate application submitted under the OEB's RRFE, and has been customized to fit Hydro One Networks' specific circumstances, which necessitate significant multi-year investments. We are seeking OEB approval for distribution revenue requirements of $1,415 million for 2015, $1,523 million for 2016, $1,578 million for 2017, $1,615 million for 2018, and $1,660 million for 2019. If the application is approved as filed, the resulting change to the distribution portion of the bill for a typical residential customer will be approximately a 1.4% decrease in 2015, 3.8% increase in 2016, 2.3% increase in 2017, 1.2% increase in 2018, and 2.6% increase in 2019. When considering total bill impact, the resulting change will be approximately a 1.5% decrease in 2015, 1.3% increase in 2016, 0.8% increase in 2017, 0.4% increase in 2018, and 0.9% increase in 2019 for a typical residential customer. A technical conference, a settlement conference and an Oral Hearing took place in the third quarter of 2014. On December 18, 2014, the OEB issued a Decision and interim Rate Order approving the 2014 distribution rates as interim 2015 rates effective January 1, 2015. The OEB also approved the discontinuation of the collection of revenues for the provincially funded portion of renewable generation connection investments of approximately $20 million per year from ratepayers effective December 31, 2014. A final Decision and Order from the OEB is anticipated in the first quarter of 2015.

- **Hydro One Brampton Networks**

  In August 2012, Hydro One Brampton Networks filed an IRM application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB released a Decision that resulted in an increase in distribution rates of approximately 0.3% for 2013, or less than 0.1% on the average total bill for a typical residential customer.

  In August 2013, Hydro One Brampton Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. On December 5, 2013, the OEB released a Decision that resulted in a reduction in distribution rates of approximately 2.3% for 2014, or a 0.5% reduction on the average total bill for a typical residential customer.

  On April 23, 2014, Hydro One Brampton Networks filed a cost-of-service application with the OEB for 2015 distribution rates, to be effective January 1, 2015, after being in an IRM application period for three years. The 2015 distribution rate application was seeking the approval of a revenue requirement of approximately $74 million for 2015. In its application, Hydro One Brampton Networks also requested OEB approval for retail transmission service rates and the approval of rate riders to dispose of certain deferral and variance accounts. A partial Settlement Proposal was filed with the OEB and the unsettled issues were heard by the OEB in an Oral Hearing in October 2014. On December 18, 2014, the OEB approved a revenue requirement of $72 million. The reduction of $2 million is mainly attributable to updates to the cost of capital parameters, operation, maintenance and administration, and depreciation expense. For a typical residential customer, this represents an increase of 4.5% in 2015 for the distribution portion of the bill, or 1.6% when considering total bill impact. The increase is reflective of increased rate base and higher operation, maintenance and administration costs since Hydro One Brampton Networks' last cost-of-service application in 2011. On January 15, 2015, the OEB issued its final Rate Order approving the application.

- **Hydro One Remote Communities**

  In September 2012, Hydro One Remote Communities filed a cost-of-service application with the OEB for 2013 distribution rates, seeking approval for a 2013 revenue requirement of $53 million. In August 2013, the OEB issued a final Decision approving a revenue requirement of $51 million and rate increase of approximately 3.45%, with an effective date of May 1, 2013.

  In October 2013, Hydro One Remote Communities filed an IRM application with the OEB for 2014 distribution rates, seeking approval for a rate increase of approximately 0.48%. On March 13, 2014, the OEB approved an increase of approximately 1.7% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2014. The final rate increase was adjusted by the OEB's updated rate adjustment parameters.

  On September 24, 2014, Hydro One Remote Communities filed an IRM application with the OEB for 2015 rates, seeking approval for increased base rates for the distribution and generation of electricity of 1.7% to be effective May 1, 2015. A final Decision from the OEB is anticipated in the first quarter of 2015.

Mergers Acquisitions Amalgamations and Divestitures (MAAD) Applications

Norfolk Power Acquisition

On April 26, 2013, Hydro One filed a MAAD application with the OEB for the approval of the acquisition of Norfolk Power. On July 3, 2014, the OEB issued its Decision and Order granting Hydro One leave to acquire all of the issued and outstanding common shares of Norfolk Power within 18 months from the date of this Decision and Order. In addition, among other items, the OEB's Decision and Order granted Norfolk Power Distribution Inc. (NPDI), a subsidiary of Norfolk Power, leave to transfer its distribution system to Hydro One Networks within 18 months from the date of this Decision and Order, and ordered that NPDI file with the OEB a draft Rate Order that includes a proposed Tariff of Rates and Changes reflecting the OEB's approval of a 1% reduction relative to NPDI's 2012 base electricity delivery rates. As part of the Norfolk Power acquisition agreement, Norfolk Power residential customers received a 1.4% reduction to their monthly distribution delivery rates, and general service customers received a reduction of between 1.4% and 1.6%, depending on their rate class, effective September 8, 2014. In addition, Norfolk Power customers' distribution rates will be frozen for the next five years. Once the NPDI distribution system transfer is completed, the OEB will transfer NPDI's electricity distribution licence and NPDI's Rate Order to Hydro One Networks. A full discussion of the Norfolk Power acquisition can be found in the section "New Developments in 2014 – Business Combinations."

Woodstock Hydro Acquisition

On July 9, 2014, Hydro One filed a MAAD application with the OEB for the approval of the acquisition of Woodstock Hydro, which is anticipated to be completed in 2015. A full discussion of the Woodstock Hydro acquisition can be found in the section "New Developments in 2014 – Business Combinations."

Haldimand Hydro Acquisition

On July 31, 2014, Hydro One filed a MAAD application with the OEB for the approval of the acquisition of Haldimand Hydro, which is anticipated to be completed in 2015. A full discussion of the Haldimand Hydro acquisition can be found in the section "New Developments in 2014 – Business Combinations."

Leave to Construct Application

Supply to Essex County Transmission Reinforcement Project

On January 22, 2014, Hydro One Networks submitted a Leave to Construct application to the OEB under Section 92 of the *OEB Act* to construct a new 13-kilometre 230 kV double-circuit transmission line in the Windsor-Essex region. The new transmission line will connect to a proposed transmission station in the Municipality of Leamington and an existing 230 kV transmission line between Chatham and Windsor. Further discussion of the Supply to Essex County Transmission Reinforcement Project can be found in the section "Liquidity and Capital Resources – Investing Activities – Major Transmission Projects."

Contractual Agreements, Codes and Licences

As a regulated company, we are subject to various contractual arrangements, codes and licences.

Operating Agreement with the IESO

The IESO is the system controller of Ontario's electricity system. The IESO manages the reliability of Ontario's power system, forecasts the demand and supply of electricity and co-ordinates emergency preparedness for Ontario's electricity system. The IESO also operates the wholesale electricity market, while ensuring fair competition through market surveillance.

Under the *Electricity Act, 1998*, the IESO is required to enter into agreements with transmitters, giving it the authority to direct the operations of the transmitters' systems. Our operating agreement with the IESO, which sets out the specific responsibilities of both parties relating to the provision of transmission service, extends until December 31, 2019. The distribution portion of Ontario's network is not directed by the IESO and remains subject to the operational control of LDCs in accordance with the regulatory framework.

Hydro One's Relationships with Other Market Participants

Generators, LDCs and customers directly connected to our transmission system must enter into agreements with us to ensure reliable connection service in conformity with the Transmission System Code (TSC) established by the OEB.

Some market participants, such as generators and large load customers embedded within distribution systems, are supplied from the wholesale market through lines and facilities that are defined or deemed by the OEB as "distribution" and owned by LDCs. At a minimum, under the *Electricity Act, 1998*, LDCs must provide nondiscriminatory access for eligible generators and customers to the wholesale markets administered by the IESO.

Electricity Industry Codes

The OEB has issued and revised several codes that govern the operation of OEB-licensed entities in Ontario. These codes include, but are not limited to, the Affiliate Relationships Code for Electricity Distributors and Transmitters, the Standard Supply Service Code, the TSC, the Distribution System Code (DSC), the Retail Settlement Code, the Electricity Retailer Code of Conduct, the Smart Sub-Metering Code, and the Conservation and Demand Management (CDM) Code. These codes

prescribe minimum standards of conduct and standards of service for transmitters, distributors, smart sub-metering providers and/or retailers in the electricity market.

Electricity Industry Licences

Our transmission and distribution licences were issued in 2003 and 2004, respectively. The licences for all of our regulated businesses have a 20-year term and incorporate reporting and record-keeping requirements in accordance with the OEB's Electricity Reporting and Record Keeping Requirements. Further discussion of the OEB's Electricity Reporting and Record Keeping Requirements can be found in the section "Regulation – Regulatory Developments – Performance Measurement and Continuous Improvement." Our licences promote the expansion and upgrading of the transmission and distribution systems to accommodate load due to forecasted demand growth over the long term, the connection of renewable energy generation facilities, and implementation of modern technologies to improve reliability, operations and network planning.

Regulatory Developments

Long-Term Energy Plan

On December 2, 2013, the Province released its updated Long-Term Energy Plan (2013 LTEP), *Achieving Balance*, replacing the 2010 LTEP. The 2013 LTEP sets out the Province's plan of action for the energy sector, including strategies for mitigating increases in electricity rates; continued renewable energy procurement; nuclear refurbishment; enhanced regional planning with respect to energy infrastructure; transmission enhancements; encouraging Aboriginal participation in energy development, transmission and conservation projects; and the expansion of natural gas infrastructure. The plans are guided by the goal of balancing five core principles: cost-effectiveness, reliability, clean energy, community engagement, and CDM. Pursuant to the 2013 LTEP, the Province "will encourage Ontario Power Generation Inc. (OPG) and Hydro One to explore new business lines and opportunities inside and outside Ontario. These opportunities will help leverage existing areas of expertise and grow revenues for the benefit of Ontarians." We will continue to work with the Province to develop business plans and efficiency targets that will reduce costs and result in significant ratepayer savings. The 2013 LTEP encourages conservation and reinforces the policy of considering conservation first in planning processes. Under the 2013 LTEP, conservation will be used to lessen the need for new supply-and-demand response initiatives to meet peak demand requirements.

Procurement of New Generation

The Ontario Power Authority's (OPA) Feed-in Tariff (FIT) Program is designed to procure energy from a wide range of renewable energy sources, including wind, solar, photovoltaic, bio-energy, and water power up to 50 MW. The FIT program is currently divided into three streams: MicroFIT (projects up to 10 kW), Small FIT (projects between 10 kW and 500 kW), and regular FIT (projects greater than 500 kW), all of which may result in connections to our distribution system. Under the FIT program, the OPA has entered into contracts or conditional contracts with generation proponents pursuant to which the OPA will pay a fixed rate for power produced over a specified period of time. We continue to connect projects for which there are firm contracts.

On May 30, 2013, the Province announced that it would make 900 MW of new capacity available between 2013 and 2018 for the Small FIT and MicroFIT programs. The Province has set annual procurement targets, from 2014 onwards, of 150 MW for Small FIT generation and 50 MW for MicroFIT generation. The Province is working with the OPA to develop a competitive process for renewable energy generation projects above 500 kW. The new process will replace the existing large project stream of the FIT program. As at December 31, 2014, our company has connected more than 560 FIT and nearly 12,000 MicroFIT projects, enough energy to power approximately 274,000 homes. These connections represent over 1,000 MW of power.

Conservation and Demand Management

The OEB's CDM guidelines for electricity distributors provide guidance on certain provisions in the CDM Code and the type of evidence that should be filed by distributors in support of applications for OEB-approved CDM programs. The guidelines also provide details on the Lost Revenue Adjustment Mechanism (LRAM) related to CDM programs implemented under the CDM Code. LRAM is the mechanism by which LDCs are compensated for lost revenues associated with their respective load reductions resulting from CDM programs. In addition, the guidelines state that savings associated with TOU pricing are

eligible to be counted towards the 2011-2014 CDM targets. The funding for the OPA-contracted Ontario-wide CDM programs is in place until December 31, 2015. This will provide an opportunity for the OPA and LDCs to work collaboratively to strengthen the current framework, and to keep customer programs in place for 2015.

On September 30, 2014, in accordance with the CDM Code, Hydro One Networks and Hydro One Brampton Networks each filed a 2013 Annual CDM Report with the OEB outlining CDM activities, energy and peak demand savings results achieved in 2013, and expectations regarding CDM targets for 2014. Hydro One Networks reported that it expected to reach 95% to 100% of its demand target and 80% of its cumulative energy target by the end of 2014. Hydro One Brampton Networks reported that it expected to reach 60% of its demand target and 100% of its cumulative energy target by the end of 2014.

In March 2014, the Minister of Energy issued parallel directives to the OEB and the OPA, respectively, regarding the new "2015-2020 Conservation Framework." The directives call for the OPA to establish a provincial target of 7 TWh of persistent energy savings to be achieved by 2020 and for all LDCs to enter into an Electricity Conservation Agreement with the OPA by December 31, 2014. Both Hydro One Networks and Hydro One Brampton Networks submitted their signed Electricity Conservation Agreements to the OPA in December 2014. Conservation opportunities will be provided to customers and available to distributors to ensure both end-user usage and utility systems are as efficient as possible.

The OPA allocated targets and budgets to LDCs on October 31, 2014. Hydro One Networks' 2015-2020 CDM savings target is 1,159 GWh, to be achieved with a budget of approximately $322 million. Hydro One Brampton Networks' 2015-2020 CDM savings target is 255.2 GWh, to be achieved with a budget of approximately $67 million. All LDCs must submit CDM Plans indicating how they will achieve their allocated targets by May 1, 2015 using either "Full Cost Recovery" or "Pay-for-Performance" funding models. All CDM programs must be cost-effective to ensure full cost recovery. LDCs may, at any point, resubmit changes to their CDM Plan for approval by the OPA.

On December 19, 2014, the OEB issued its new CDM Guidelines (2015 Guidelines). The 2015 Guidelines are consistent with the Directive the OEB received in March 2014 from the Minister of Energy requiring the OEB to take steps to promote CDM, including amendments to the licences of electricity distributors and the establishment of CDM Requirement guidelines.

Revenue Decoupling for Distributors

In November 2012, the OEB initiated a project to coordinate revenue decoupling with the new rate-setting policies proposed in the RRFE. On April 3, 2014, the OEB released a Draft Report of the Board on Rate Design for Electricity Distributors (Rate Design Report) to solicit stakeholder comments. The Rate Design Report presents three proposals to achieve revenue decoupling: (1) a single monthly charge which is the same for all consumers within the rate class; (2) a fixed monthly charge, with the size of the charge to be based on the size of the electrical connection; and (3) a fixed monthly charge where the size of the charge is based on use during peak hours. The OEB expects to issue a report in early 2015 regarding the phase-in implementation of fixed rates.

Performance Measurement and Continuous Improvement

On March 5, 2014, the OEB issued its *Report of the Board on Performance Measurement for Electricity Distributors: A Scorecard Approach* (Performance Report) under its RRFE. The Performance Report sets out the OEB's policies on the measures that will be used by the OEB to assess a distributor's effectiveness and improvement in achieving customer focus, operational effectiveness, public policy responsiveness, and financial performance to the benefit of existing and future customers, as well as the form and implementation of a performance monitoring tool – a Scorecard.

On July 15, 2014, the OEB issued a Staff Discussion Paper "Electricity Distribution System Reliability Measures and Targets" to establish specific performance targets for the existing system reliability measures, to develop customer-specific reliability measures and to address the monitoring of momentary outages.

Regional Plans

In August 2013, the OEB amended the TSC and DSC to implement a more formal and structured approach to regional planning in Ontario. The new regional planning approach consists of two main processes: Regional Infrastructure Planning (RIP) to be led by transmitters, and Integrated Regional Resource Planning (IRRP) to be led by the OPA. The RIP process

focuses mainly on wires planning, both transmission and distribution, and the IRRP process focuses on resources planning (e.g. generation, CDM) and the integration of resources with wires planning. The development of regional plans will involve close coordination of the two processes and active participation by the OPA, transmitters, distributors and other applicable agencies such as the IESO.

The regional plans are intended to support investments brought forward in transmitter and distributor rate submissions and transmitter Leave to Construct applications. Regional plans are to be reviewed or developed at least every five years. The OEB expects the first cycle of regional plans for all regions in Ontario to be completed in the next three to four years. For regional planning purposes, the province has been subdivided into 21 regions. Hydro One is the lead transmitter responsible for the RIP process for 19 of the 21 regions. Planning activities are underway and the regional plans are expected to be completed between 2015 and 2017.

NEW DEVELOPMENTS IN 2014

Premier's Advisory Council on Government Assets

On April 11, 2014, the Province announced the appointment of the Premier's Advisory Council on Government Assets (Council) to provide the Province with recommendations designed to maximize the value of certain provincially owned assets, one of which being our company. The objective of the review is to advise the Province on how to best maximize value from its assets. The Council's Terms of Reference provided guidance indicating that it would give preference to continued ownership of government assets, but would consider mergers, acquisitions, divestments if there is a strong business case, and would enhance value to taxpayers of the Province.

The interim report released on November 19, 2014, noted our company's Transmission Business is a well-run entity with some opportunities to deliver savings on the operating side and on capital expenditures, and recommended that the Province maintain its ownership of our company's Transmission Business. The interim report noted that Ontario's local electricity distribution system is an unnecessarily cluttered and fragmented system with too many entities, some of which are highly inefficient, unable to adapt to the changing environment and lack capital to modernize or consolidate.

Consequently, the Council recommended that our company's Transmission and Distribution Businesses be separated, and that Hydro One Networks' distribution business and Hydro One Brampton Networks be used to spur industry consolidation. The Council also recommended that the Province reduce its equity interest in our company's Distribution Business by bringing in private sector investment.

The Province has now asked the Council to build on its work by entering phase two, which includes the Council receiving and discussing written ideas related to encouraging consolidation and to Hydro One Brampton Networks and Hydro One Networks' distribution business, and finalizing its recommendations to the Province. We understand that the Province is specifically considering the sale of Hydro One Brampton Networks, as well as the distribution business of Hydro One Networks.

Business Combinations

B2M LP

In 2012, we entered into an agreement with the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively referred to as the SON, where a noncontrolling equity interest in B2M LP would be made available for purchase at fair value by the SON. B2M LP was formed by Hydro One in 2013 to hold most of the transmission lines and a licence to use the related land. These assets are associated with our Bruce to Milton Transmission Reinforcement Project, an electricity transmission line (Bruce to Milton Line) in southwestern Ontario, from the Bruce Power facility in Kincardine to our Milton Switching Station in the Town of Milton. Hydro One Networks will maintain and operate the Bruce to Milton Line in accordance with an operation and management services agreement. In November 2013, the OEB issued a Decision and Order granting B2M LP a transmission licence and granting Hydro One Networks leave to sell the relevant Bruce to Milton Line transmission assets to B2M LP.

On December 16, 2014, the relevant Bruce to Milton Line 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 SON acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired. B2M LP is now operational.

Details of B2M LP's transmission rate application can be found in the section "Regulation – Regulatory Proceedings – Transmission Rates."

Norfolk Power Acquisition

On August 29, 2014, our company completed the acquisition of the outstanding shares of Norfolk Power from The Corporation of Norfolk County. Norfolk Power is a holding company that owns NPDI, a local electricity distribution company, and Norfolk Energy Inc., a non-rate regulated energy services company, located in southwestern Ontario. The selection of our company as successful bidder followed a comprehensive, competitive sales process initiated by Norfolk Power.

The total purchase price for Norfolk Power, net of the long-term debt assumed and adjusted for preliminary working capital and other closing adjustments, is approximately $68 million. The determination of the fair values of assets acquired and liabilities assumed has been based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. We have also determined the preliminary purchase price adjustments based on agreed working capital and other balances at the acquisition date. The resulting preliminary goodwill of approximately $40 million arising from the Norfolk Power acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Norfolk Power. We intend to complete the determination of the final purchase price adjustments during the first half of 2015.

Norfolk Power contributed revenues of $18 million and net income of less than $1 million to our company's consolidated financial results for the year ended December 31, 2014.

Details of the Norfolk Power MAAD application can be found in the section "Regulation – Regulatory Proceedings – MAAD Applications."

Woodstock Hydro Purchase Agreement

On May 21, 2014, we reached an agreement with the City of Woodstock to acquire 100% of the common shares of Woodstock Hydro for approximately $29 million, subject to final closing adjustments. Woodstock Hydro is an urban electricity distribution company located in southwestern Ontario. The transaction is the result of extensive discussions between Hydro One and the City of Woodstock which involved consideration of economic development opportunities and other benefits resulting from the sale of Woodstock Hydro. The acquisition is pending a regulatory decision from the OEB and is anticipated to be completed in 2015.

Details of the Woodstock Hydro MAAD application can be found in the section "Regulation – Regulatory Proceedings – MAAD Applications."

Haldimand Hydro Purchase Agreement

On June 10, 2014, we reached an agreement with Haldimand County to acquire 100% of the common shares of Haldimand Hydro for approximately $65 million, subject to final closing adjustments. Haldimand Hydro is an electricity distribution and telecom company located in southwestern Ontario. The transaction is the result of extensive discussions between Hydro One and Haldimand County. The acquisition is pending a regulatory decision from the OEB and is anticipated to be completed in 2015.

Details of the Haldimand Hydro MAAD application can be found in the section "Regulation – Regulatory Proceedings – MAAD Applications."

Other

Environment Canada Regulations

In April 2014, Environment Canada issued Canada Gazette II, which included amendments to the existing polychlorinated biphenyl (PCB) regulations, including the extension of the end-of-use deadline beyond 2014 for equipment containing certain concentrations of PCBs, with an effective date of January 1, 2015. The amendments extend the end-of-use deadline for our company's PCBs in concentrations of 500 parts per million or more from December 31, 2014 to December 31, 2025. As a result of an annual review of environmental liabilities, our company recorded a revaluation adjustment in 2014 to reduce our environmental liabilities by $20 million. This adjustment included the impact of the PCB regulations amendments.

Electricity Sector Pension Plans

On August 1, 2014, a Report on the Sustainability of Electricity Sector Pension Plans (Sustainability Report) was released by Jim Leech, Special Advisor to the Minister of Finance for Ontario. As part of its fiscal 2013 budget, the Province announced its intention to establish a government-led industry Working Group (Working Group) to address pension issues associated with the single-employer pension plans at Hydro One, OPG, IESO and the Electrical Safety Authority (ESA). This Sustainability Report is intended to inform and help frame the efforts of the Working Group. The Sustainability Report noted that it is critically important for any pension plan for public-sector workers to be sustainable so that the retirement income of retirees and active members is secure. Management will continue to monitor the initiatives of this Working Group and potential impacts of any recommendations for Hydro One accordingly. To ensure the sustainability of the Hydro One Pension Plan, our company has implemented a gradual increase in the amount of employee contributions to the plan.

Outsourcing Agreements

The current agreement with Inergi LP (Inergi), an affiliate of Capgemini Canada Inc., expires on February 28, 2015. On November 28, 2014, we entered into an agreement with Inergi (Inergi Agreement), the service provider selected through a competitive procurement process which began in 2013, for second-generation back office and IT outsourcing services for a term of 58 months, commencing March 1, 2015 to December 31, 2019. Under the agreement, Inergi will provide us with settlements, source to pay services, pay operations services, information technology and finance and accounting services.

Coincident with the conclusion of negotiations on the Inergi Agreement, we reached agreement with Inergi to provide us with second-generation customer service operations outsourcing services for a fixed period of three years beginning March 1, 2015 to February 28, 2018.

In its re-tendering initiative, Hydro One set out four objectives for its new outsourcing agreements: continually improved value for money; providing operational flexibility; delivery of services to reflect global best practices; and robust, effective performance management and governance. This agreement achieves those objectives and supports our company's key strategic objectives, while allowing the Company to focus on its core activities of maintaining, planning and operating our Transmission and Distribution Businesses and delivering excellent service to our customers. The agreement will see cost savings on annual base fees while at the same time providing service delivery improvements, as we continue our ongoing efforts to reduce costs and drive more efficiency in our business.

In September 2014, we entered into an agreement with Brookfield Johnson Controls Canada LP (Brookfield), a service provider selected through a competitive procurement process, for facilities management services for a term of ten years, effective January 1, 2015 to December 31, 2024, with the option to renew for an additional term of three years. Over the term of the contract we will transition the facilities management of all of our facilities. Under the agreement, Brookfield will provide us with facilities management and execution of certain capital projects as deemed required by our company. The Brookfield Agreement has a value of up to approximately $658 million over the ten-year term of the agreement, including the facilities management portion of the contract, plus a variable amount of capital work depending on the needs that may arise as determined by our company, with no minimum capital work guarantee.

Details of our contractual obligations under our outsourcing agreements can be found in the section "Liquidity and Capital Resources – Summary of Contractual Obligations and Other Commercial Commitments."

ANNUAL RESULTS OF OPERATIONS

Year ended December 31 (millions of Canadian dollars)	2014	2013	$ Change	% Change
Revenues	6,548	6,074	474	8
Purchased power	3,419	3,020	399	13
Operation, maintenance and administration	1,192	1,106	86	8
Depreciation and amortization	722	676	46	7
	5,333	4,802	531	11
Income before financing charges and provision for payments in lieu of corporate income taxes	**1,215**	**1,272**	**(57)**	**(4)**
Financing charges	379	360	19	5
Income before provision for payments in lieu of corporate income taxes	836	**912**	**(76)**	**(8)**
Provision for payments in lieu of corporate income taxes	89	109	(20)	(18)
Net income	**747**	**803**	**(56)**	**(7)**
Net income (loss) attributable to noncontrolling interest	(2)	–	(2)	(100)
Net income attributable to Shareholder of Hydro One	**749**	**803**	**(54)**	**(7)**

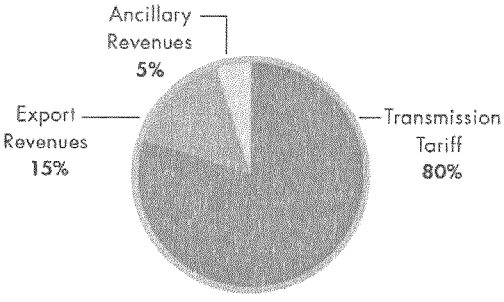
Revenues

Year ended December 31 (millions of Canadian dollars)	2014	2013	$ Change	% Change
Transmission	1,588	1,529	59	4
Distribution	4,903	4,484	419	9
Other	57	61	(4)	(7)
	6,548	6,074	474	8
Average annual Ontario 60-minute peak demand (MW)[1]	20,596	21,493	(897)	(4)
Distribution – units distributed to our customers (TWh)[1]	29.8	29.8	–	–

[1] System-related statistics are preliminary.

Transmission

Transmission revenues primarily consist of our transmission tariff, which is based on the monthly peak electricity demand across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting excess generation to surrounding markets, ancillary revenues primarily attributable to maintenance services provided to generators, and secondary use of our land rights.



Composition of 2014 Transmission Revenues

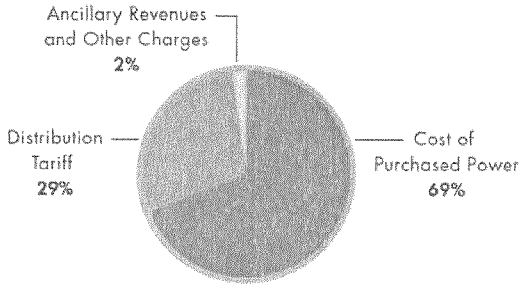
Our 2014 transmission revenues increased by $59 million, or 4%, compared to 2013. The components of the increase include the following:

- $90 million increase due to new transmission rates effective January 1, 2014 approved by the OEB in January 2014;

- $42 million increase due to the OEB's approval of increased export service revenues in recognition of higher electricity exports to other jurisdictions and the disposition of certain OEB-approved transmission regulatory accounts;
- $45 million decrease due to lower average Ontario 60-minute peak demand in 2014. The lower electricity demand in 2014 was mainly due to milder weather in the summer and fall of 2014, compared to 2013; and
- $28 million decrease due to ancillary transmission revenues, primarily associated with OEB-approved regulatory accounts.

Distribution

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by the customers of our Distribution Business. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. Distribution revenues also include minor ancillary distribution service revenues, such as fees related to the joint use of our distribution poles by the telecommunications and cable television industries, as well as miscellaneous charges such as charges for late payments.



Composition of 2014 Distribution Revenues

Our 2014 distribution revenues increased by $419 million, or 9%, compared to 2013. The components of the increase include the following:

- $399 million increase due to the recovery of higher purchased power costs, as described below under "Purchased Power;"
- $12 million increase due to new distribution rates effective January 1, 2014 approved by the OEB in December 2013; and
- $8 million increase due to ancillary distribution revenues, primarily associated with OEB-approved regulatory accounts.

Purchased Power

Purchased power costs are incurred by our Distribution Business and represent the cost of purchased electricity delivered to customers within our distribution service territory. These costs comprise the wholesale commodity cost of energy, the IESO wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy is based on the OEB's RPP or the market price for electricity. A discussion of the electricity rates can be found in the section "Regulation – Regulatory Proceedings – Electricity Rates."

Our purchased power costs increased by $399 million, or 13%, in 2014, compared to 2013. The components of the increase include the following:

- $291 million increase resulting from higher purchased power costs for customers who are not eligible for the RPP;
- $78 million increase resulting from the impact of changes in the OEB's RPP rates for residential and other eligible customers;
- $26 million increase resulting from the OEB transmission rate decision effective January 1, 2014;
- $10 million increase due to wholesale market service charges levied by the IESO;
- $4 million increase resulting from the IESO's Smart Metering Entity charge effective May 1, 2013; and
- $10 million decrease due to lower energy consumption in 2014, mainly resulting from a milder summer and a warmer fall in 2014.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, which is substantially established under collective bargaining agreements, and materials, equipment and purchased services, which are subject to public tenders. Key enablers of the successful implementation of our work programs are our human and material resourcing strategies. Our human resources strategy is focused on hiring through our apprenticeship program and our association with universities, colleges and our unions, as well as skills development and retention, including earlier identification and more rapid development of staff who demonstrate management potential. Our skilled labour pool primarily consists of line, forestry, construction and stations staff who live and work across the province.

Our operation, maintenance and administration expenditures include work program costs and costs to support the operation and maintenance of the transmission and distribution systems. Also included in these costs are payments in lieu of property taxes related to our transmission and distribution lines, stations and buildings. Our transmission operation, maintenance and administration costs are incurred to sustain our high-voltage transmission stations, lines and rights-of-way, and include preventive and corrective maintenance costs related to our power equipment, overhead transmission lines, transmission station sites, and brush control. Our distribution operation, maintenance and administration costs are required to maintain our low-voltage distribution system, and include costs related to distribution line clearing and brush control, line maintenance and repair, as well as land assessment and remediation (LAR). Our company continues to focus on managing its costs, while continuing to complete our planned work programs for both our Transmission and Distribution Businesses.

Year ended December 31 (millions of Canadian dollars)	2014	2013	$ Change	% Change
Transmission	394	375	19	5
Distribution	742	672	70	10
Other	56	59	(3)	(5)
	1,192	1,106	86	8

Transmission

Our 2014 transmission operation, maintenance and administration costs increased by $19 million, or 5%, compared to 2013.

Our 2014 transmission work program costs were $240 million, compared to $237 million in 2013, an increase of $3 million. The increase is mainly due to the following:

- increased forestry expenditures related to brush control and line clearing on our transmission rights-of-way;
- a higher volume of corrective and preventive maintenance on power equipment and overhead lines; and
- higher transmission site facilities maintenance requirements.

Our 2014 transmission support costs were $154 million, compared to $138 million in 2013, an increase of $16 million. The increase is mainly due to the following:

- a one-time reduction to our provision for payments in lieu of property taxes in 2013 related to transmission stations for the years 1999 to 2012, inclusive, following the finalization of the related regulations and receipt of a final assessment of our property tax returns;
- partially offset by lower expenditures due to the recovery of insurance proceeds for the 2013 floods at our Richview and Manby transmission stations; and
- increased attribution of overheads to capital project expenditures in 2014.

Distribution

Our 2014 distribution operation, maintenance and administration costs increased by $70 million, or 10%, compared to 2013.

Our 2014 distribution work program costs were $599 million, compared to $515 million in 2013, an increase of $84 million. The increase is mainly due to the following:

- our customer service recovery initiatives and the increase in our bad debt expense, resulting from higher electricity consumption due to a substantially colder than normal winter, combined with higher electricity prices and the suspension of certain collection tools and efforts during several months in 2014. We resumed some of our collection tools and efforts in September 2014.

Our 2014 distribution support costs were $143 million, compared to $157 million in 2013, a decrease of $14 million. The decrease is mainly due to the following:

- decreased expenditures in 2014 related to CIS, as it was placed in-service in May 2013.

Depreciation and Amortization

Our 2014 depreciation and amortization costs increased by $46 million, or 7%, compared to 2013. This increase was primarily attributable to higher property, plant and equipment depreciation expense in 2014, mainly related to the growth in capital assets as we continue to place new assets in-service, consistent with our ongoing capital work program.

Financing Charges

Our 2014 financing charges increased by $19 million, or 5%, compared to 2013. The increase is primarily due to the following:

- an increase in interest expense on our long-term debt due to a higher average level of debt;
- partially offset by a lower average interest rate.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes (PILs) decreased by $20 million, or 18%, to $89 million in 2014, compared to 2013. The decrease is primarily due to lower levels of pre-tax income in 2014 compared to 2013.

Net Income

Our 2014 net income attributable to the Shareholder of Hydro One decreased by $54 million, or 7%, to $749 million, compared to 2013. The decrease is primarily due to the following:

- $70 million increase in our 2014 distribution operation, maintenance and administration costs, mainly due to our customer service recovery initiatives and the increase in our bad debt expense, resulting from higher electricity consumption due to a substantially colder than normal winter, combined with higher electricity prices and the suspension of certain collection tools and efforts during several months in 2014;
- $46 million increase in our 2014 depreciation and amortization costs, mainly due to higher property, plant and equipment depreciation expense in 2014, related to the growth in capital assets as we continue to place new assets in-service, consistent with our ongoing capital work program; and
- partially offset by a $59 million increase in our 2014 transmission revenues, mainly due to new OEB-approved 2014 transmission rates.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters, from the quarter ended March 31, 2013 through to December 31, 2014. This information has been derived from our unaudited interim Consolidated Financial Statements and our audited annual Consolidated Financial Statements, which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(millions of Canadian dollars)	2014				2013			
Quarter ended	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**
Total revenue	1,662	1,556	1,566	1,764	1,557	1,542	1,403	1,572
Net income attributable to Shareholder of Hydro One	221	173	115	240	160	218	168	257
Net income to common Shareholder of Hydro One	216	169	110	236	155	214	163	253

Electricity demand generally follows normal weather-related variations, and consequently, our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

2014 Fourth Quarter Results of Operations

Three months ended December 31 (millions of Canadian dollars)	**2014**	**2013**	**$ Change**	**% Change**
Revenues	1,662	1,557	105	7
Purchased power	893	794	99	12
Operation, maintenance and administration	247	286	(39)	(14)
Depreciation and amortization	190	184	6	3
	1,330	1,264	66	5
Income before financing charges and provision for payments in lieu of corporate income taxes	**332**	**293**	**39**	**13**
Financing charges	98	93	5	5
Income before provision for payments in lieu of corporate income taxes	**234**	**200**	**34**	**17**
Provision for payments in lieu of corporate income taxes	15	40	(25)	(63)
Net income	**219**	**160**	**59**	**37**
Net income (loss) attributable to noncontrolling interest	(2)	–	(2)	(100)
Net income attributable to Shareholder of Hydro One	**221**	**160**	**61**	**38**

Our total revenues for the three months ended December 31, 2014 were $1,662 million, compared to $1,557 million during the same period in 2013, an increase of $105 million or 7%. The increase is mainly due to the following:

- the recovery of higher purchased power costs;
- new transmission and distribution rates effective January 1, 2014;
- the OEB's approval of increased export service revenues in recognition of higher electricity exports to other jurisdictions and the disposition of certain OEB-approved transmission regulatory accounts;
- partially offset by lower average Ontario 60-minute peak demand and energy consumption in the fourth quarter of 2014, mainly due to milder weather in the fall of 2014; and
- lower ancillary revenues, primarily associated with OEB-approved regulatory accounts.

Our purchased power costs for the three months ended December 31, 2014 were $893 million, compared to $794 million during the same period in 2013, an increase of $99 million or 12%. The increase is mainly due to the following:

- higher purchased power costs for customers who are not eligible for the RPP;
- partially offset by lower energy consumption in the fourth quarter of 2014, mainly due to milder weather in the fall of 2014;
- wholesale market service charges levied by the IESO; and
- OEB transmission rate decision effective January 1, 2014.

Our operation, maintenance and administration costs for the three months ended December 31, 2014 were $247 million, compared to $286 million during the same period in 2013, a decrease of $39 million or 14%. The decrease is mainly due to the following:

- decreased distribution operation, maintenance and administration costs, primarily due to lower storm response expenditures as a result of lower storm activity in 2014, compared to 2013; and
- decreased expenditures related to brush control and distribution line maintenance work.

Our depreciation and amortization costs for the three months ended December 31, 2014 were $190 million, compared to $184 million during the same period in 2013, an increase of $6 million or 3%. The increase is mainly due to higher property, plant and equipment depreciation expense in 2014, mainly related to the growth in capital assets as we continue to place new assets in-service, consistent with our ongoing capital work program.

Our financing charges for the three months ended December 31, 2014 were $98 million, compared to $93 million during the same period in 2013, an increase of $5 million or 5%. The increase is mainly due to the following:

- an increase in interest expense on our long-term debt due to a higher average level of debt; and
- partially offset by a lower average interest rate.

Our provision for PILs for the three months ended December 31, 2014 was $15 million, compared to $40 million during the same period in 2013, a decrease of $25 million or 63%. The decrease is due to the following:

- changes in net temporary differences, such as capital cost allowance in excess of depreciation, deductions for pension payments made in excess of amounts expensed for accounting purposes, and interest deducted for tax purposes in excess of interest expensed for accounting purposes; and
- partially offset by higher pre-tax income for the three months ended December 31, 2014 compared to the same period in 2013.

Net income attributable to the Shareholder of Hydro One for the three months ended December 31, 2014 was $221 million, compared to $160 million during the same period in 2013, an increase of $61 million or 38%. The increase is mainly due to the following:

- decreased distribution operation, maintenance and administration costs, primarily due to lower storm response expenditures as a result of lower storm activity in 2014, compared to 2013, and decreased expenditures related to brush control and distribution line maintenance work;
- a decrease in our provision for PILs, primarily due to changes in net temporary differences; and
- an increase in our 2014 transmission revenues, mainly due to new OEB-approved 2014 transmission rates.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from our operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include our capital expenditures, servicing and repayment of our debt, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (millions of Canadian dollars)	2014	2013
Operating activities	1,256	1,404
Financing activities		
Long-term debt issued	628	1,185
Long-term debt retired	(776)	(600)
Amount contributed by noncontrolling interest	72	–
Dividends paid	(287)	(218)
Investing activities		
Capital expenditures	(1,504)	(1,387)
Acquisition of Norfolk Power	(66)	–
Proceeds from investment	250	–
Other financing and investing activities	(38)	(14)
Net change in cash and cash equivalents	(465)	370

Operating Activities

Net cash from operating activities decreased by $148 million to $1,256 million in 2014, compared to 2013. The decrease was primarily due to the following:

- lower 2014 net income, compared to 2013;
- changes in accrual balances, mainly related to timing of capital projects;
- changes in regulatory accounts, including the retail settlement and external revenue variance accounts; and
- partially offset by higher property, plant and equipment depreciation expense in 2014, mainly related to the growth in capital assets as we continue to place new assets in-service, consistent with our ongoing capital work program.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program, under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, and our revolving credit facility.

Our Commercial Paper Program is supported by our $1,500 million committed revolving credit facility with a syndicate of banks, which matures in June 2019. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

At December 31, 2014, we had $8,923 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2015 and 2064. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million. At December 31, 2014, $1,187 million remained available until October 2015.

We rely on debt financing through our MTN Program and our Commercial Paper Program to repay our existing indebtedness and fund a portion of our capital expenditures. The credit ratings assigned to our debt securities by external rating agencies are important to our ability to raise capital and funding to support our business operations. Maintaining strong credit ratings allows us to access capital markets on competitive terms. A material downgrade of our credit ratings would likely increase our cost of funding significantly, and our ability to access funding and capital through the capital markets could be reduced. Our corporate credit ratings from approved rating organizations are as follows:

	Rating	
Rating Agency	Short-term Debt	Long-term Debt
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	A1
Standard & Poor's Rating Services Inc. (S&P)	A-1	A+

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets, and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that third party debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We were in compliance with all of these covenants and limitations as at December 31, 2014.

In 2014, we issued $628 million of long-term debt under our MTN Program, compared to $1,185 million of long-term debt issued in 2013. In 2014, we also repaid $750 million in maturing long-term debt, compared to $600 million of long-term debt repaid in 2013. In addition, long-term debt totalling $26 million assumed on the Norfolk Power acquisition was repaid in September 2014. We had no short-term notes outstanding at December 31, 2014 or December 31, 2013.

Common share dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements, and other relevant factors, such as industry practice and Shareholder expectations. Common share dividends pertaining to our quarterly financial results are generally declared and paid in the following quarter.

During 2014, we paid dividends to the Province in the amount of $287 million, consisting of $269 million in common share dividends and $18 million in preferred share dividends, compared to dividends of $218 million, consisting of $200 million of common share dividends and $18 million of preferred share dividends, paid to the Province in 2013.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates and to deliver appropriate financial returns to our Shareholder.

Investing Activities

During 2014, we continued to focus on making important investments in our transmission and distribution systems to address our aging power system infrastructure, improve our systems' reliability and performance, and improve service to our customers. We made capital investments totalling $1,530 million in 2014, compared to $1,394 million of capital investments in 2013, and have placed $1,574 million of new assets in-service in 2014, compared to $1,491 million of new assets placed in-service in 2013.

Capital investments consist of cash capital expenditures and related accruals. Capital investments primarily relate to sustaining, enhancing and reinforcing our transmission and distribution infrastructure.

Year ended December 31 (millions of Canadian dollars)	2014	2013	$ Change	% Change
Transmission	845	714	131	18
Distribution	680	673	7	1
Other	5	7	(2)	(29)
Total capital investments	1,530	1,394	136	10

Transmission Capital Investments

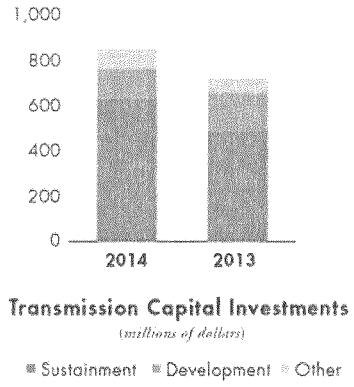
Our 2014 transmission capital investments were $845 million, compared to $714 million in 2013, an increase of $131 million or 18%, primarily due to sustainment programs to address our aging infrastructure. Given the aging of our infrastructure, we have ongoing investment plans which are designed to reliably power our economy and to support the innovation that can be expected over the next decade.

The following table presents the main components of our transmission capital investments during 2014 and 2013.

Year ended December 31 (millions of Canadian dollars)	2014	2013	$ Change	% Change
Sustainment	625	481	144	30
Development	132	170	(38)	(22)
Other	88	63	25	40
Total transmission capital investments	845	714	131	18

Sustainment Transmission Capital Investments

Our current transmission sustainment programs include protection and control systems, wood poles, breakers and high-voltage instrument transformer replacements. Our 2014 transmission sustainment capital investments were $625 million, compared to $481 million in 2013, an increase of $144 million or 30%. The increase was mainly due to the following:



- several system re-investments, including the Gerrard and Timmins transmission stations and new type of breakers at our Bruce Transmission Station, which progressed in 2014, as well as completed projects, such as the Pinard Transmission Station Breakers and the Wallaceburg Transmission Station;
- several replacements of end-of-life power transformers at our Pembroke Transmission Station in eastern Ontario, and our Hanover, Allanburg, and Elmira transmission stations in southwestern Ontario, as well as the emergency replacement of a unit at the Trafalgar Transmission Station;
- increased work within our station and lines equipment replacement and refurbishment projects and programs, including our investment to address the condition of the conductors on the 170 kilometre 230 kV circuit from the Chats Falls Switching Station to the Havelock Transmission Station in southeastern Ontario, and increased work on overhead lines wood pole structure replacements; and
- increased volume of replacements related to addressing aging protection and control equipment.

Development Transmission Capital Investments

Our current transmission development projects include transmission system upgrades, local area supply projects, and inter-area network projects. These investments will expand and reinforce power reliability for electricity customers throughout the province, including our residential and industrial customers. Our 2014 development capital investments to expand and reinforce our transmission system were $132 million, compared to $170 million in 2013, a decrease of $38 million or 22%. The decrease was mainly due to the following:

- the successful completion of our Sundusk and Summerhaven Switching Stations upgrades in 2013 to incorporate renewable energy into our transmission system; and
- reduced expenditures related to some of our major projects which were completed in 2014, such as the Lambton to Longwood Transmission Upgrade Project, the Barwick Transmission Station, and the Allanburg Transmission Station to ensure mandatory transmission system standards are met.

Other Transmission Capital Investments

Our 2014 other transmission capital investments were $88 million, compared to $63 million in 2013, an increase of $25 million or 40%. The increase was mainly due to the following:

- the development phase investment in our Network Management System Project, a critical operating tool used for monitoring and control of our transmission system;
- the investment in our Payroll Transformation Project to realize various process efficiencies; and

- partially offset by a decrease from the higher investments in 2013 as a result of emergency flood restoration work at our Richview Transmission Station resulting from a major rainstorm in July 2013.

Major Transmission Projects

Our company successfully advanced or completed a number of transmission capital investments projects during 2014. The following table summarizes the status of our major projects at December 31, 2014:

Project Name	Location	Type	Planned In-Service Date	Approved Budget	Capital Cost To-Date	Current Status
Lambton to Longwood Transmission Upgrade	Sarnia area to west of London area Southwestern Ontario	Transmission line upgrade	2014	$41 million	$24 million	Placed in-service in September 2014
Barwick Transmission Station	Rainy River/Fort Frances Northwestern Ontario	New transmission station	2014	$25 million	$21 million	Placed in-service in September 2014
Allanburg Transmission Station	Niagara area Southwestern Ontario	Transmission station upgrade	2014	$33 million	$29 million	Placed in-service in December 2014
Toronto Midtown Transmission Reinforcement	Toronto Southwestern Ontario	New transmission line	2015	$115 million	$83 million	Project is in progress
Guelph Area Transmission Refurbishment	Guelph area Southwestern Ontario	Transmission line upgrade	2016	$103 million	$24 million	Project is in progress
Manby Transmission Station	Toronto Southwestern Ontario	Transmission station upgrade	2016	$24 million	$14 million	Project is in progress
Clarington Transmission Station	Oshawa area Eastern GTA	New transmission station	2017	$297 million	$42 million	Project is in progress
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	To be determined	–	Section 92 application filed with OEB in January 2014
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	As early as 2020	To be determined	–	OPA recommendation letter received in October 2014

Lambton to Longwood Transmission Upgrade

Our Lambton to Longwood Transmission Upgrade project involved the upgrade of approximately 70 kilometres of 230 kV double-circuit transmission line between our Lambton and Longwood transmission stations in southwestern Ontario. The investment refurbished 36 tower foundations, replaced the conductor with a higher capacity wire and replaced insulators along the line. This project involved an innovative new technology that allowed the vast majority of the towers to remain in place, and will enable approximately 500 MW of additional clean energy to be connected to the grid. The additional capacity on the grid will also contribute to meeting provincial energy supply targets for installed non-hydroelectric renewable generation by 2021.

Barwick Transmission Station

Our Barwick Transmission Station provides more capacity for communities between Rainy River and Fort Frances in northwestern Ontario, thereby strengthening the reliability of the power supply for both residential and commercial customers in the area. The Barwick Transmission Station consists of two 115 kV/44 kV transformers and allows for shorter spans of 44

kV power lines to connect customers to our system, ultimately improving the reliability of their power supply. The project involved in-house construction crews, local vendors and labour from the Rainy River First Nation community.

Allanburg Transmission Station

As a result of new generation connections and various transmission project upgrades in the Niagara area of southwestern Ontario, the Allanburg Transmission Station 115 kV switchyard short circuit level has increased and exceeded breaker capability limits. Consequently, upgrade work was required to replace 15 end-of-life breakers with upgraded short circuit capability in accordance with the TSC standards.

Toronto Midtown Transmission Reinforcement

Supply to the midtown Toronto area is currently provided by three 115 kV circuits between the Leaside Transmission Station and the Wiltshire Transmission Station. These circuits also supply the Bridgman and Dufferin Transmission Stations and provide load transfer capability between the Leaside and Manby transmission stations. The Toronto Midtown Transmission Reinforcement project includes the replacement of an aging underground cable which is nearing its end of life; the installation of an additional 115 kV circuit between the Leaside and Bridgman transmission stations to relieve loading on the existing circuits which are currently operating above their capacity; and the installation of new equipment at the Leaside Transmission Station, and Bayview, Birch and Bridgman Junctions. These transmission infrastructure reinforcements are intended to reduce the risk of power outages, improve reliability for electricity customers, and provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west.

Guelph Area Transmission Refurbishment

The Guelph Area Transmission Refurbishment Project, an upgrade of a transmission line and transmission stations in Guelph and the surrounding area, includes the installation of two new autotransformers at the existing Cedar Transmission Station, an upgrade of approximately five kilometres of an existing transmission line from 115 kV to 230 kV in south-central Guelph, and an upgrade of the existing Guelph North Junction to a switching station by installing new facilities and fencing. These refurbishments will reinforce the electricity supply and will minimize the impact of any major transmission outages on area customers.

Manby Transmission Station

The Manby Transmission Station project will upgrade the station short circuit capability and install higher rated breakers, which will permit incorporation of new renewable generation in the central Toronto area. Upgrade work requires the replacement of 16 end-of-life breakers and other components in the 115 kV Manby switchyard.

Clarington Transmission Station

To accommodate the eventual closure of the Pickering Nuclear Generating Station, the Clarington Transmission Station will provide additional autotransformer capacity to reliably supply load in the eastern GTA. Upon completion, the Clarington Transmission Station will consist of two 500/230 kV autotransformers and a 230 kV switchyard, and will connect to the existing 230 kV and 500 kV transmission lines. The project will enable future electricity demand growth in the local area and provide the area with the necessary facilities to ensure a safe, reliable supply of electricity to existing and future customers.

Supply to Essex County Transmission Reinforcement Project

On January 22, 2014, Hydro One Networks submitted a Leave to Construct application to the OEB under Section 92 of the *OEB Act* to construct a new 13-kilometre 230 kV double-circuit transmission line in the Windsor-Essex region. The new transmission line will connect to a proposed transmission station in the Municipality of Leamington and an existing 230 kV transmission line between Chatham and Windsor. The new transmission line and transmission station will address future growth in electricity demand and anticipated expansion in the local agricultural sector and improve the reliability of electricity supply in the broader Windsor-Essex region.

Northwest Bulk Transmission Line

In November 2013, the Minister of Energy issued a Directive to the OEB, which in turn issued a Decision and Order on January 9, 2014, to amend the transmission licence of Hydro One Networks to develop and seek approval for the Northwest Bulk Transmission Line Project, an expansion and reinforcement of the transmission system in the area west of Thunder Bay in northwestern Ontario. The project consists of a new transmission line that would increase transmission capacity and maintain the reliability of electricity supply to meet forecasted electricity demand growth and accommodate new generation capacity. Over the long term, it would also enhance the potential for development and connection of renewable energy facilities. Because of its importance to the region, this new line has been identified as a priority project in Ontario's LTEP. The Northwest Bulk Transmission Line Project will be developed by our company in cooperation with Infrastructure Ontario. The scope and timing of the project shall be in accordance with the recommendations of the OPA.

On October 1, 2014, Hydro One received a letter from the OPA outlining the scope and timing of the Northwest Bulk Transmission Line Project. The scope of the development work will include preliminary design and engineering, cost estimation, public engagement and consultation, routing and siting, and the preparation of an environmental assessment in support of this project. Hydro One is currently initiating the development work for the project and discussions are ongoing with Infrastructure Ontario on the project plan and related accountabilities.

Other Transmission Capital Investments

Pan American (Pan Am) Games

The Pan Am Games project tracking initiative is underway to ensure that we provide a high level of electricity supply reliability to the Pan Am and Parapan Am Games during the summer of 2015, and that operating, maintenance and capital work plans are coordinated across lines of business to minimize outage risks to the venues hosting the 2015 Pan Am and Parapan Am Games. Key major capital projects and site-specific maintenance work in the GTA are being monitored on a monthly basis to ensure our customer commitments are met. This work will ultimately benefit all of our customers in the GTA.

Niagara Reinforcement Project

This project comprises the construction of 76 kilometres of 230 kV line from our Allanburg Transmission Station in the Niagara area to our Middleport Transmission Station in the Hamilton area. The Niagara Reinforcement Project status is considered substantially on time, with the exception that some project work has been delayed due to access issues related to Aboriginal land claims on a section of the line.

Distribution Capital Investments

Our 2014 distribution capital investments were $680 million, compared to $673 million in 2013, an increase of $7 million or 1%, primarily due to our distribution sustainment programs to address our aging infrastructure.

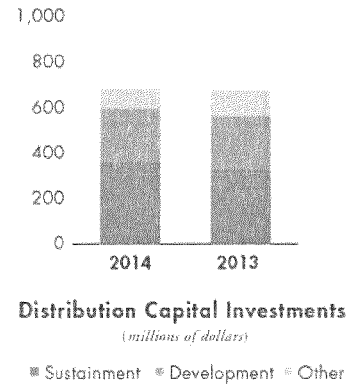
The following table presents the main components of our distribution capital investments during 2014 and 2013.

Year ended December 31 (millions of Canadian dollars)	2014	2013	$ Change	% Change
Sustainment	356	324	32	10
Development	236	235	1	–
Other	88	114	(26)	(23)
Total distribution capital investments	680	673	7	1

Sustainment Distribution Capital Investments

Our current distribution sustainment programs include wood pole and meter replacements, emergency work for storm restoration, distribution station refurbishments and upgrades, and work related to joint-use and relocation of our distribution lines. Our 2014 distribution sustainment capital investments were $356 million, compared to $324 million in 2013, an increase of $32 million or 10%. The increase is mainly due to the following:

- increased investments in meter replacements, including Itron Sentinel 16S meter replacements and Field Metering Services installations;
- higher volume of end-of-life wood pole replacements;
- increased focus on capital lines work, mainly due to the lines large sustainment initiatives program;
- increased work within our station refurbishment programs due to more refurbishments accomplished in 2014; and
- partially offset by less storm restoration work in 2014 due to lower storm activity compared to 2013.



Development Distribution Capital Investments

Our current development projects to expand and reinforce our distribution network include new customer connections and upgrades, system capability reinforcement projects, line transfers requested by our customers, and connections to new generation facilities. Our 2014 distribution development capital expenditures were $236 million, compared to $235 million in 2013, an increase of $1 million. The increase is mainly due to the following:

- increased work for subdivision connections, new customer connections, and upgrades;
- the purchase of retail revenue meters for all new connections and service upgrades; and
- partially offset by less lines and stations work related to upgrading and adding capacity to our distribution system.

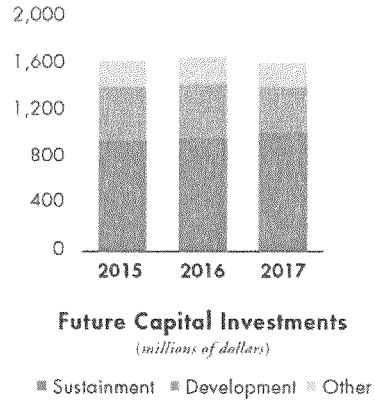
Other Distribution Capital Investments

Our 2014 other distribution capital expenditures were $88 million, compared to $114 million in 2013, a decrease of $26 million or 23%. The decrease is mainly due to the following:

- decreased expenditures in 2014 related to CIS, as it was placed in-service in May 2013;
- decrease due to higher investments in 2013 as a result of emergency flood restoration work at our Richview Transmission Station resulting from a major rainstorm in July 2013; and
- partially offset by the investment in our Payroll Transformation Project to realize various process efficiencies.

Future Capital Investments

Our capital investments for 2015 are budgeted at approximately $1,600 million. Our 2015 capital budgets for our Transmission and Distribution Businesses are approximately $900 million and $700 million, respectively. Consolidated capital investments are expected to be approximately $1,625 million in 2016 and $1,575 million in 2017. These investment levels reflect our continued sustainment focus on our aging infrastructure. Our sustainment program capital investments are expected to be approximately $925 million in 2015, $950 million in 2016 and $1,000 million in 2017. Our development capital investments are expected to be approximately $450 million in 2015, $450 million in 2016, and $375 million in 2017. Our development projects include the inter-area network upgrades that reflect supply mix policies, local area supply improvements, the ADS Project, new load and generation connections and requirements to enable DG, and customer demand work. Other capital investments are expected to be $225 million in 2015, $225 million in 2016, and $200 million in 2017. This includes investments in operating infrastructure integration, information technology (IT), fleet services and facilities, and real estate. Our future capital investments amounts do not include future LDC acquisitions.



Hydro One's plans to maintain, refurbish or replace existing facilities are developed on the basis of maintenance standards, asset condition assessments and end-of-life criteria specific to each type of equipment. Priorities are assigned to each type of investment based on the risks that it mitigates. In addition, investments that are cross-functional and/or require IT involvement are governed by a productivity framework with substantive benefits. These capital investment plans are also included in our rate filings submitted to the OEB for approval.

Transmission

Transmission capital investments are incurred to manage the replacement and refurbishment of our aging transmission infrastructure in order to ensure a continued reliable supply of energy to customers throughout the province. Our sustainment program future capital investments include the replacement and/or refurbishment of end-of-life air blast circuit breakers and switchgear, high-voltage underground cables, high-voltage circuits and power transformers. Also, given the current age of our assets and infrastructure and to achieve significant cost efficiencies, we have moved to a more integrated station and circuit centric refurbishments approach than has been undertaken historically in order to address and bundle component and refurbishment replacements that would have occurred over time into one project. These investments are necessary to ensure that we maintain our current levels of supply to our customers and continue to meet all regulatory, compliance, safety and environmental objectives.

Our future development capital investments include the Clarington Transmission Station Project to install additional autotransformer capacity in the eastern GTA; the Guelph Area Transmission Refurbishment Project, an upgrade of a transmission line and transmission stations in south-central Guelph; investments in ADS; requirements to enable DG; the Supply to Essex County Transmission Reinforcement Project, a new transmission line in the Windsor-Essex region; and the Toronto Midtown Transmission Reinforcement Project, a new circuit in midtown Toronto and the refurbishment of an underground cable. Development capital investments also include the connection of new generation projects to the transmission system; however, these investments are largely funded by the connecting generation customers.

Based on the OEB's framework for competitive designation for the development of eligible transmission projects, we did not include in our budgeted future capital investments any projects that could meet the definition of expansions. We do not plan to undertake large capital investments without a reasonable expectation of recovering them through our rates.

The actual timing and investments of many development projects are uncertain as they are dependent upon various regulatory approvals, negotiations with customers, neighbouring utilities and other stakeholders, and consultations with First Nations and Métis communities. Projects are also dependent upon the timing and level of generator contributions for enabling facilities.

Distribution

Distribution capital investments include the sustainment of our infrastructure. Our core work will continue to focus on maintaining the performance of our aging distribution asset base through renewal and refurbishment activities. Planned capital investments include the continued replacements of equipment and components that are beyond their expected service life, as well as increased wood pole replacements and distribution station refurbishments. Sustainment capital investments related to the smart metering project will decrease through 2016.

Distribution development capital investments are expected to be relatively stable through 2016, with the exception of capital contributions for capacity improvements at the Orleans Transmission Station in the Ottawa area in 2015 and the Hanmer Transmission Station in the Sudbury area in 2016. We will continue to make investments required to connect new load and DG customers, as well as investments to ensure the system is capable of supplying customer needs. During 2015 and 2016, a number of our projects will address local load growth issues. Generation connection investments, consisting of OPA-contracted FIT and MicroFIT Program generators, will decrease as the volume of connections is expected to decrease.

The ADS Project continues to pilot various technologies and related capital investments and will begin to decrease in 2015 and 2016. Pilot technologies include improvements to outage response management through more effective resource dispatch, automation to isolate faults where needed, and the dynamic regulation of voltage to reduce power losses.

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 our 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 our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2014 (millions of Canadian 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[1]	8,923	550	1,100	978	6,295
Long-term debt – interest payments[1]	7,765	419	774	677	5,895
Pension[2]	361	174	187	–	–
Environmental and asset retirement obligations[3]	284	19	73	68	124
Outsourcing agreements[4]	701	179	291	218	13
Operating lease commitments	45	7	19	10	9
Total contractual obligations	18,079	1,348	2,444	1,951	12,336
Other commercial commitments *(by year of expiry)*					
Bank line[5]	1,500	–	–	1,500	–
Letters of credit[6]	134	134	–	–	–
Guarantees[6]	331	331	–	–	–
Total other commercial commitments	1,965	465	–	1,500	–

[1] The "long-term debt – principal repayments" amounts are not charged to our results of operations, but are reflected on our Consolidated Balance Sheets and Consolidated Statements of Cash Flows. Interest associated with the long-term debt is recorded in financing charges on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

[2] Contributions to the Hydro One Pension Fund were generally made one month in arrears. However, due to the interest rate environment, the annual contributions have been prepaid in each of the last two years. No contribution prepayments are anticipated in 2015. The 2015 and 2016 minimum pension contributions are based on an actuarial valuation as at December 31, 2013. Pension contributions totalling $174 million were made during the year ended December 31, 2014. Minimum pension contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016, and will depend on future investment returns, changes in benefits, or actuarial assumptions. Pension contributions beyond 2016 are not estimable at this time.

[3] We record 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. We also record a liability for asset retirement obligations associated with the removal and disposal of asbestos-containing materials installed in some of our facilities, as well as the future decommissioning and removal of two of our switching stations. The forecasted expenditure pattern reflects our planned work programs for the periods.

[4] In 2014, we have finalized a new outsourcing agreement with Inergi for the provision of certain services, as well as a facilities outsourcing agreement with Brookfield. Details of the new outsourcing agreements can be found in the section "New Developments in 2014 – Other – Outsourcing Agreements." Based on the September 2013 Shareholder Resolution, the Province requires us to contract only with parties who are employed and physically located in Ontario when providing services to our company. The contractual amounts disclosed include an estimated contractual annual inflation adjustment in the range of 1.9% to 2.1%. Payments in respect of our outsourcing agreements are recorded in operation, maintenance and administration costs on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

[5] In support of our liquidity requirements, we have a $1,500 million revolving standby credit facility with a syndicate of banks maturing in June 2019.

[6] We currently have outstanding bank letters of credit of $126 million relating to retirement compensation arrangements. We provide prudential support to the IESO in the form of letters of credit, the amount of which is calculated based on forecasted monthly power consumption. At December 31, 2014, we have provided a letter of credit to the IESO in the amount of $8 million to meet our current prudential requirement. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of $330 million, and on behalf of two distributors using total guarantees of $1 million.

RELATED PARTY TRANSACTIONS

We are owned by the Province. The Ontario Electricity Financial Corporation (OEFC), IESO, OPA, OPG, and the OEB are related parties to our company because they are controlled or significantly influenced by the Province. The following is a summary of our related party transactions during the year ended December 31, 2014:

The Province

- During 2014, we paid dividends to the Province totalling $287 million, compared to $218 million paid in 2013.
- In November 2014, we redeemed the $250 million Province of Ontario Floating-Rate Notes held as a long-term investment. These notes were originally purchased in January 2010 with a maturity date of November 19, 2014.

IESO

- During 2014, we purchased power in the amount of $2,601 million from the IESO-administered electricity market, compared to $2,477 million purchased in 2013.
- We receive revenues for transmission services from the IESO, based on OEB-approved UTRs. Our 2014 transmission revenues include $1,556 million related to these services, compared to $1,509 million in 2013.
- We receive amounts for rural rate protection from the IESO. Our 2014 distribution revenues include $127 million related to this program, compared to $127 million in 2013.
- We receive revenues related to the supply of electricity to remote northern communities from the IESO. Our 2014 distribution revenues include $32 million related to these services, compared to $33 million in 2013.

OPA

- The OPA funds substantially all of our CDM programs. The funding includes program costs, incentives, and management fees. During 2014, we received $33 million from the OPA related to these programs, compared to $34 million received in 2013.

OPG

- During 2014, we purchased power in the amount of $23 million from OPG, compared to $15 million in 2013.
- Our company has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. Our 2014 other revenues include $12 million related to these service level agreements, compared to $9 million in 2013. Our 2014 operation, maintenance and administration costs related to the purchase of services with respect to these service level contracts were $1 million, compared to $1 million in 2013.

OEFC

- During 2014, we made payments in lieu of corporate income taxes to the OEFC totalling $86 million, compared to payments of $138 million made in 2013.
- During 2014, we purchased power in the amount of $9 million from power contracts administered by the OEFC, compared to $8 million purchased in 2013.
- During 2014, our company paid a $5 million annual fee to the OEFC, compared to $5 million paid in 2013, for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999.

OEB

- Under the *OEB Act*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and transmitters. During 2014, we incurred $12 million in OEB fees, compared to $12 million incurred in 2013.

At December 31, 2014, the amounts due from and due to related parties as a result of the transactions described above were $224 million and $227 million, respectively, compared to $197 million and $230 million at December 31, 2013, respectively. At December 31, 2014, included in amounts due to related parties were amounts owing to the IESO in respect of power purchases of $214 million, compared to $217 million at December 31, 2013.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Effect of Load on Revenue

Our load, based on normal weather patterns, is expected to increase in 2015 due to economic growth in all sectors of the Ontario economy, partially offset by the load impact of CDM and embedded generation. Overall load growth due to the economy alone is forecasted to be approximately 1.9%, with the commercial and industrial sectors slightly outperforming the residential sector. The load impacts of CDM and embedded generation are expected to have a negative impact on load growth of approximately 0.6% and 0.4%, respectively. On the whole, our load is expected to increase by approximately 0.9% in 2015. Our approved revenue requirement for 2015 has taken the negative load impact of CDM and embedded generation into account. A load growth below our load forecast, included in our approved revenue requirement, would negatively impact our financial results.

Effect of Interest Rates

Changes in interest rates will impact the calculation of the revenue requirements upon which our rates are based. The first component impacted by interest rates is our return on equity (ROE). The OEB-approved adjustment formula for calculating ROE will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. All other things being equal, we estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our ROE would reduce Hydro One Networks' transmission and distribution businesses' 2015 results of operations by approximately $20 million and $13 million, respectively. As interest rates decline, there is more risk of a decline in our net income. The second component of revenue requirement that would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the OEB would impact our results of operations.

Input Costs

In support of our ongoing work programs, we are required to procure materials, supplies and services. To manage our total costs, we regularly establish security of supply, strategic material and services contracts, general outline agreements, and vendor alliances and we also manage a stock of commonly used items. Such arrangements are for a defined period of time and are monitored. Where advantageous, we develop long-term contractual relationships with suppliers to optimize the cost of goods and services and to ensure the availability and timely supply of critical items. As a result of our strategic sourcing practices, we do not foresee any adverse impacts on our business from current economic conditions in respect of adequacy and timing of supply and credit risk of our counterparties. Further, we have been able to realize significant savings through our strategic sourcing initiatives.

During 2014, we finalized a new outsourcing agreement with Inergi for the provision of certain services, as well as a facilities outsourcing agreement. Details of the new outsourcing agreements can be found in the section "New Developments in 2014 – Other – Outsourcing Agreements."

Pension Plan

In 2014, we contributed approximately $174 million to our pension plan, compared to contributions of approximately $160 million made in 2013, and incurred $158 million in net periodic pension benefit costs, compared to $287 million incurred in 2013. We currently estimate our total annual pension contributions to be approximately $174 million for 2015 and $175 million for 2016, based on an actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Actuarial valuations are required to be filed at least every three years. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. In 2014, our pension plan experienced positive returns of approximately 12.3%, compared to approximately 17.9% in 2013.

Our 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."

RISK MANAGEMENT AND RISK FACTORS

We have an Enterprise Risk Management (ERM) Program that aims at balancing business risks and returns. A company-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic goals. Our ERM program helps us to better understand uncertainty and its potential impact on our strategic goals. It sets out the uniform principles, processes and criteria for identifying, assessing, evaluating, treating, monitoring and communicating risks across all lines of business. It supports our Board of Directors' corporate governance needs and the due diligence responsibilities of senior management.

While our philosophy is that risk management is the responsibility of all employees, the Board of Directors annually reviews our company's risk tolerances, risk management policies, processes and accountabilities. Twice per year, the Board of Directors reviews our risk profile, which is the list of key risks prepared by senior management, and represents the greatest threats to meeting our strategic objectives. The Board of Directors' committees review risks relevant to their mandate at every meeting. The Audit, Finance and Pension Investment Committee of our Board of Directors annually reviews the status of our internal control framework.

Our President and Chief Executive Officer (CEO) has ultimate accountability for risk management. Our Leadership Team provides senior management oversight of our risk portfolio and our risk management processes. The leadership team provides direction on the evolution of these processes and identifies priority areas of focus for risk assessment and mitigation planning.

Our Chief Financial Officer (CFO) is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. The CFO has specific accountability for ensuring that ERM processes are established, properly documented and maintained by our company.

Our senior managers, line and functional managers are responsible for managing risks within the scope of their authority and accountability. Risk acceptance or mitigation decisions are made within the risk tolerances specified by the head of the subsidiary or function.

The CFO provides support to the committees of our Board of Directors, the President and CEO, the senior management team and key managers within our company. This support includes developing risk management frameworks, policies and processes, introducing and promoting new techniques, establishing risk tolerances, preparing annual corporate risk profiles, maintaining a registry of key business risks and facilitating risk assessments across our company. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems. Starting in 2013, our Board of Directors has taken on an enhanced role in our governance structure. Each committee of the Board of Directors will take accountability for reviewing specific risks of our company.

Key elements of our ERM Program enable us to identify, assess and monitor our risks effectively. These include having an ERM policy and framework which communicates our philosophy and process for risk management across our company. A discussion of risks is an integral part of each line of business' planning documents on an annual basis. Risk identification is also considered as part of each business case for investments. Finally, discrete risk assessments and workshops are performed for specific lines of business, key projects and various profiles, such as customer relationships and regulatory compliance. In order to drive consistency throughout our risk identification and risk management processes, we use a standard list of risk sources known as our risk universe. These sources are maintained in a single database that provides a consistent basis for risk identification and classification and serves as a repository for our risk assessments. All risk assessments in our company start with this risk universe. We also use standard risk criteria, which establish the metrics and terminology used for assessing and communicating on risks, and help ensure a consistent basis for our risk assessments and risk evaluations across all lines of business. Risk criteria include formally established risk tolerances and standard scales for assessing the probability of a risk materializing and the strength of controls in place to mitigate them.

Our key risks are as follows:

Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors, appoint the Chair, and influence our major business and corporate decisions. We and the Province

have entered into a memorandum of agreement relating to certain aspects of the governance of our company. Pursuant to such agreement, in September 2008, the Province made a declaration removing certain powers from our company's directors pertaining to the off-shoring of jobs under the 2001 Inergi Agreement. In 2011, the Province made a declaration preventing our company from seeking cost recovery through the regulatory process for the cost of upgrades required for either MicroFIT or Small FIT generators for costs related to investment and expenditures made. Effective September 30, 2013, the Province made a declaration regarding the outsourcing of services covered by the Inergi Agreement.

Effective December 17, 2014, the Province made a further declaration pursuant to the memorandum of agreement and section 108 of the *Business Corporations Act* (Ontario) regarding the provision of information, personnel and resources to the Premier's Advisory Council on Government Assets. By way of the declaration and concurrent Shareholder resolution, the Province restricted the rights, powers and duties of our Board of Directors, and at the same time assumed such rights, powers and duties, with respect to providing the Premier's Advisory Council on Government Assets, the Government or the Ministries and their advisors and consultants all information, assistance, personnel, resources and reports as and when requested and co-operating with those Government advisors tasked with providing recommendations on labour relations matters and pension-related matters. The directors are charged with carrying out the intention of the declaration and resolution, including taking such necessary steps to issue similar declarations and resolutions with respect to Hydro One Networks and Hydro One Brampton Networks. The Province could mandate the selling of all or part of our distribution business and this could have a material adverse effect on our company.

In 2009, the Province required our company, among other entities, to adhere to certain accountability measures regarding consulting contracts and employee travel, meal and hospitality expenses. The Province may require us to adhere to further accountability measures or may make similar declarations in the future, some of which may have a material adverse effect on our business. Our company's credit ratings may change with the credit ratings of the Province, to the extent the credit rating agencies link the two ratings by virtue of our company's ownership by the Province.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, including any potential outcomes arising out of the recommendations of the Ontario Distribution Sector Review Panel's report, the Province's ownership of OPG, and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us, which could have a material adverse effect on our business.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our Transmission and Distribution Businesses that permit a reasonable opportunity to recover the estimated costs of providing safe and reliable service on a timely basis and earn the approved rates of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption materially falls below projected levels, our net income for either, or both, of these businesses could be materially adversely affected. Also, our current revenue requirements for these businesses are based on cost 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 our costs.

The OEB's new RRFE requires that the term of a custom rate application (distribution business) be a five-year period. There are risks associated with forecasting over a longer period. Changes in the industry may alter the investment needs or require changes to rate setting that could result in a significant impact on our company's capability to execute its plan.

Our load could also be negatively affected by successful CDM programs. We are also subject to risk of revenue loss from other factors, such as economic trends and weather.

We expect to make investments in the coming years to connect new renewable generating stations. There is the possibility that we could incur unexpected capital expenditures to maintain or improve our assets, particularly given that new technology is required to support renewable generation, and unforeseen technical issues may be identified through implementation of projects. The risk exists that the OEB may not allow full recovery of such investments in the future. To the extent possible,

we aim 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.

While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential asset impairment and charges to our results of operations, which could have a material adverse effect on our company.

In Ontario, the Market Rules mandate that we comply with the reliability standards established by NERC and NPCC. As a result, we will be required to comply with the United States Federal Energy Regulatory Commission's definition of Bulk Electric System unless we are granted an exception which will allow the application of the new definition in a cost-effective manner. Our company plans to submit exception applications and will look for recovery of costs incurred in meeting the definition in our rates; however, an adverse decision on an exception of recovery of costs could have an adverse effect on our company.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including cyber and physical terrorist type attacks and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations resulting from these events. Losses from lost revenues and repair costs could be substantial, especially for many of our facilities that are located in remote areas. We could also be subject to claims for damages caused by our failure to transmit or distribute electricity. Our risk is partly mitigated because our transmission system is designed and operated to withstand the loss of any major element and possesses inherent redundancy that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss we would apply to the OEB for recovery of such loss; however, there can be no assurance that the OEB would approve any such applications, in whole or in part, which could have a material adverse effect on our net income.

First Nations and Métis Claims Risk

Some of our current and proposed transmission and distribution lines may traverse lands over which First Nations and Métis have Aboriginal, treaty or other legal claims. Although we have a recent history of successful negotiations, engagement and consultation with First Nations and Métis communities in Ontario, some communities and/or their citizens have expressed an increasing willingness to assert their claims through the courts, tribunals, or by direct action, which in turn can affect business activities. As a result, there exists uncertainty relating to business operations and project planning which could have an adverse effect on our company.

Risk from Transfer of Assets Located on Reserves

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999, did not transfer title to some assets located on Reserves. Currently, OEFC holds legal title to these assets and we manage them until we have obtained necessary authorizations to complete the title transfer. To occupy Reserves, our company must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, we must negotiate an agreement (in the form of a Memorandum of Understanding) with the First Nation, OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the federal Department of Aboriginal Affairs and Northern Development issuing a permit. Where the agreement and permit are for transmission assets, our company must negotiate terms of payment. It is difficult to predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required agreements from First Nations. In 2014, we paid approximately $1 million to First Nations in respect of these agreements. OEFC will continue to hold these assets until we are able to negotiate agreements with First Nations and occupants. If we cannot reach satisfactory agreements and obtain federal permits, we may have to relocate these assets to other locations 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 our net income if we are not able to recover them in future rate orders.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems which are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems. Our increasing reliance on information systems and expanding data networks increases our exposure to information security threats. We mitigate this risk through various methods including the use of security event management tools on our power and business systems, by separating our power system network from our business system network, by performing scans of our systems for known cyber threats, and by providing company-wide awareness training to our personnel. We also engage the services of external experts to evaluate the security of our IT infrastructure and controls. We perform vulnerability assessments on our critical cyber assets and we ensure security and privacy controls are incorporated into new IT capabilities. Although these security and system disaster recovery controls are in place, there can be no guarantee that there will not be system failures or security breaches. Upon occurrence, 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 our company.

Workforce Demographic Risk

By the end of 2014, approximately 17% of our employees were eligible for retirement and by the end of 2015 up to 21% could be eligible. These percentages are not evenly spread across our workforce, but tend naturally to be most significant in the most senior levels of our staff and especially among management and executive staff. Accordingly our continued success will be tied to our ability to attract and retain sufficient qualified staff to replace the capability lost through retirements and meet the demands of our work programs. This will be more challenging than in the past for a number of reasons.

Firstly, we expect the skilled labour market for our industry to be highly competitive in the future: many of our current employees and many of the employees we are going to be looking for possess skills and experience that will also be highly sought after by other organizations inside and outside the electricity sector; secondly, a variety of restraints on compensation and benefits for management and executive staff (including Bill 8) together with possible pension plan changes, and the uncertainty attaching to Hydro One's future size and scope as a result of the work of the Council, may adversely impact our ability to attract and retain the number and calibre of people we need in these roles.

In order to mitigate the potential effects of these factors, we are focused on earlier identification and more rapid development of staff who demonstrate the potential to progress quickly, especially those who demonstrate leadership potential, and on maintaining robust but flexible succession plans for the organization. In addition we continue to advance our apprenticeship and technical training programs to ensure that our future operational staffing needs will be met.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers' Union (PWU) or the Society of Energy Professionals (Society). Over the past several years, significant effort has been expended to increase our flexibility to conduct operations in a more cost-efficient manner. Although we have achieved improved flexibility in our collective agreements, including a reduction in pension benefits for Society staff hired after November 2005 similar to a previous reduction affecting management staff and increased pension contributions for PWU and Society staff, we may not be able to achieve further improvement. The existing collective agreement with the PWU will expire on March 31, 2015, and the existing Society collective agreement will expire on March 31, 2016. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In addition, in the event of a labour dispute, we could face operational risk related to continued compliance with our licence requirements of providing service to customers. Any of these could have a material adverse effect on our company.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and fund a portion of capital expenditures. We have substantial amounts of existing debt, including $550 million maturing in 2015 and $500 million maturing in 2016. We plan to incur capital expenditures of approximately $1,600 million in 2015 and $1,625 million in 2016. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market

conditions, the ratings assigned to our debt securities by credit rating agencies, and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our 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 our company.

Asset Condition

We continually monitor the condition of our assets to determine need and timing of preventative or remedial actions to maintain the desired level of service. Condition assessment is one of the key drivers for asset maintenance, refurbishment or replacement strategies to maintain equipment performance and provide reliable service quality. Our capital programs have been increasing to maintain the performance of our aging asset base. Execution of these plans is partially dependent on external factors, such as outage planning with the IESO and transmission-connected customers, funding approval by the OEB, and supply chain availability for equipment suppliers and consulting services. In addition, opportunities to remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to customer and generator priorities.

Adjustments to accommodate these external dependencies have been made in our planning process, and we are focused on overcoming these challenges to execute our work programs. However, if we are unable to carry out these plans in a timely and optimal manner, equipment performance will degrade which may compromise the reliability of the provincial grid, our ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets. This could have a material adverse effect on our company.

Environmental Risk

Our health, safety and environmental management system is designed to ensure hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. This system includes a standing committee of our Board of Directors that has governance over environmental matters. However, given the territory that our system encompasses and the amount of equipment that we own, we cannot guarantee that all such risks will be identified and mitigated without significant cost and expense to our company. The following are some of the areas that may have a significant impact on our operations.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary LAR program covering most of our stations and service centres. This program involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for our company and adjacent private properties. Any contamination of our properties could limit our ability to sell these assets in the future.

We record a liability for our best estimate of the present value of the future expenditures required to comply with Environment Canada's PCB regulations and for the present value of the future expenditures to complete our LAR program. The future expenditures required to discharge our PCB obligation are expected to be incurred over the period ending 2025, while our LAR expenditures are expected to be incurred over the period ending 2022. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures.

Under applicable regulations, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. We record an asset retirement obligation for the present value of the estimated future expenditures. The estimates are based on an external, expert study of the current expenditures associated with removing such materials from our facilities. Actual future expenditures may vary materially from the estimates used for the amount of the asset retirement obligation.

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.

We anticipate that all of our future environmental expenditures will continue to be recoverable in future electricity rates. However, any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on our company.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, or governments decide to implement exposure limits, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities. Any of these could have a material adverse effect on our company.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are minimally 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, 2013, and was filed in June 2014. Our company contributed approximately $160 million in respect of 2013 and approximately $174 million in respect of 2014 to its pension plan to satisfy minimum funding requirements. Contributions beyond 2014 will depend on investment returns, changes in benefits and actuarial assumptions and may include additional voluntary contributions from time to time. Nevertheless, future contributions are expected to be significant. A determination by the OEB that some of our pension expenditures are not recoverable from customers could have a material adverse effect on our company, and this risk may be exacerbated as the quantum of required pension contributions increase.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we entered into outsourcing arrangements with Inergi and Brookfield. Details of the new outsourcing agreements can be found in the section "New Developments in 2014 – Other – Outsourcing Agreements." If either of these outsourcing agreements are terminated for any reason or expire before a new supplier is selected, we could be required to incur significant expenses to transfer to another service provider or insource, which could have a material adverse effect on our business, operating results, financial condition or prospects.

Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity price risk. We do have foreign exchange risk as we enter into agreements to purchase materials and equipment associated with our capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material. We could in the future decide to issue foreign currency-denominated debt which we would anticipate hedging back to Canadian dollars, consistent with our company's risk management policy. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formulaic approach.

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 40% common equity and 60% debt will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. We estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our rate of return would reduce our Transmission Business' 2015 net income by approximately $20 million and our Hydro One Networks' distribution business' 2015 net income by approximately $13 million. Our net income is adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize 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. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counterparties, limiting total exposure levels with individual counterparties, and by entering into master agreements which enable net settlement and by monitoring the financial condition of counterparties. We do not trade in any energy derivatives. We do, however, have interest rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs 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 our 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 our company.

Risk Associated with Transmission Projects

Transmission projects involve either modifying existing or building new transmission lines and/or stations or both. Such projects are required primarily to address limitations on the transmission network to transfer power from generation sources to load centres, improve regional load supply capacity and reliability, connect new generators and load customers, and to meet new, or changes to, codes and standards.

In many cases, transmission investments are contingent upon one or more of the following approvals and/or processes: *Environmental Assessment Act* (Ontario) approval(s); receipt of OEB approvals which can include expropriation; and appropriate consultation processes with First Nations and Métis communities. Obtaining OEB and/or *Environmental Assessment Act* (Ontario) approvals and carrying out these processes may also be impacted by opposition to the proposed site of transmission investments which could adversely affect transmission reliability and/or our service quality, both of which could have a material adverse effect on our company.

With the introduction on August 26, 2010, of the OEB's competitive transmission project development planning process, in the absence of a government directive, all interested transmitters will be required to submit a bid to the OEB for possibly some identified enabler facilities and network enhancement projects. The facilitation of competitive transmission could impact our future work program and our ability to expand our current transmission footprint. In addition, as bid costs are recoverable only by the successful proponent, additional costs for unsuccessful bids would be absorbed. This could have a material adverse effect on our company.

Risk from Provincial Ownership of Transmission Corridors

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002*, the Province acquired ownership of our transmission corridor lands underlying our transmission system. Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks, which could have an adverse effect on our company.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our Consolidated Financial Statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our 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 our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments. We have identified the following critical accounting estimates used in the preparation of our Consolidated Financial Statements:

Revenues

Our monthly distribution revenue is estimated based on wholesale electricity purchases. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The newly implemented CIS phase of our entity-wide system improvement project will allow us to use historical trends at a customer level to better estimate our unbilled revenue each period. This change in methodology for estimating revenue is anticipated to be implemented in 2015. Any changes in estimate will be accounted for prospectively.

Allowance for Doubtful Accounts

The allowance for doubtful accounts reflects management's best estimate of losses on billed accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The

allowance for doubtful accounts on customer receivables is estimated by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment.

Regulatory Assets and Liabilities

Our 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. Our regulatory assets mainly include costs related to the pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, and environmental liabilities. Our 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

We record 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.

In April 2014, Environment Canada enacted amendments to the existing PCB regulations, which included the extension of the end-of-use deadline from 2014 to 2025 for equipment containing certain concentrations of PCBs. Further discussion of the PCB amendments and related impact on our company can be found in the section "New Developments in 2014 – Other – Environment Canada Regulations."

Employee Future Benefits

Our 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 our current and retired employees. Employee future benefits costs are included in our 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 our 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, 2014 decreased to 4.00% from 4.75% used at December 31, 2013, in conjunction with decreases in bond yields over this period. The decrease in the discount rate has resulted in a corresponding increase in employee future benefits liabilities 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 our long-term expectations. We believe 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 2.00% per annum as at December 31, 2013 to approximately 1.70% per annum as at December 31, 2014. 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, 2014.

Mortality Assumptions

Our 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 at December 31, 2014 was updated to the final tables issued by the Canadian Institute of Actuaries (for public sector, with projection scale CPM-B and no adjustment due to pension size). As at December 31, 2013, the draft tables published by the Canadian Institute of Actuaries were used.

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. A 1% increase in the health care cost trends would result in a $23 million increase in 2014 interest cost plus service cost, and a $248 million increase in the year-end 2014 benefit liability.

Asset Impairment

Within our regulated businesses, the carrying costs of most of our 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. We regularly monitor the assets of our unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2014, no asset impairment had been recorded for assets within our regulated or unregulated businesses.

Goodwill represents the cost of acquired LDCs that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. We have concluded that goodwill was not impaired at December 31, 2014.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal controls have been documented and tested for adequacy and effectiveness, and continue to be refined over all business processes.

In compliance with the requirements of National Instrument 52-109, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2014, together with other financial information included in our securities filings. Our Certifying Officers have also certified that disclosure controls and procedures (DC&P) have been designed to provide reasonable assurance that material information relating to our company is made known within our company. Further, our Certifying Officers have certified that internal controls over financial reporting (ICFR) have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Consolidated Financial Statements. Based on the evaluation of the design and operating effectiveness of our company's DC&P and ICFR, our Certifying Officers concluded that our company's DC&P and ICFR were effective as at December 31, 2014.

NEW ACCOUNTING PRONOUNCEMENTS

In May 2014, the Financial Accounting Standards Board (FASB) issued an accounting standards update that provides guidance on revenue recognition which depicts 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. This update is applicable to our company for the years and interim periods beginning on January 1, 2017. We are currently assessing the impact of adoption of this accounting standards update on our consolidated financial statements.

In August 2014, the FASB issued an accounting standards update that provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and related disclosures. This update is applicable to our company for the year ending December 31, 2016, and for annual and interim periods thereafter. We do not anticipate that the adoption of this accounting standards update will have a significant impact on our consolidated financial statements.

In November 2014, the FASB issued an accounting standards update that provides guidance on accounting for hybrid financial instruments issued in the form of a share. This update is applicable to our company for the years and interim periods beginning on January 1, 2016. We are currently assessing the impact of adoption of this accounting standards update on our consolidated financial statements.

OUTLOOK

We will achieve our mission and vision and remain focused on achieving our corporate goal of providing safe, reliable and affordable service to our customers, today and tomorrow, while increasing enterprise value for our Shareholder. We will do this by continuing to concentrate on our strategic objectives of safety, customer satisfaction, continuous innovation, reliability, protection of the environment, championing people and culture, Shareholder value and productivity and cost-effectiveness. We continue to seek to strike the right balance between making prudent risk-based reliability investments and keeping customers' rates low. Effectively and efficiently managing costs is an important part of achieving this balance.

Given the nature of the work undertaken by our employees and contractors, safety remains our top priority. We will continue to focus on creating an injury-free workplace and maintaining public safety through several health and safety initiatives, including maintaining our OHSAS 18001 standing.

We are focused on becoming a customer centric company and achieving our vision of improving customer satisfaction, maintaining affordable rates for the portion of the customers' bill within our control and building a trusted partner relationship with our customers. Our plan has taken into account discussions with our customers and reflects the planned development and delivery of targeted customer segment strategies, products and services which respond to our customers' unique needs. This includes realizing value from our new CIS, simplifying and shortening timeframes for the delivery of services, enhancing accessibility in person, by phone or through our web portal and/or our mobile application to ensure effective self-service for simple transactions, and delivering programs which help customers better manage their energy

consumption. In addition, to further improve our customer service performance culture as a transparent, accountable and customer-focused organization, we have recently announced two new initiatives – a third party expert Customer Service Advisory Panel and our draft Customer Commitments.

We will continue to focus on driving our transformation to a culture that is accountability-based. All of our management staff received training under our Craft of Management program. In addition, a new Talent Management program was piloted in 2014 and will be rolled out company-wide in 2015. These programs will serve as the foundation for establishing that culture of accountability. Investments in these programs, coupled with existing programs which enhance employee skills and ability, will help us deliver best-in-class service to our customers, continue the drive to zero workplace injuries and create a great workplace that will lead to improved employee engagement. We remain focused on managing the resourcing requirements of an increasing work program through appropriate compensation policies, labour negotiations, use of outsourced multi-skilled staff and support of internal and external college and university training programs. Aging workforce demographics provide opportunities, through retirements, to restructure and transform the workforce.

Our assets are in the midst of a demographic change with an increasing proportion of assets reaching the end of their expected service life and an increasing average asset age. To ensure the electricity system's reliability in the public interest, we have planned for significant investments in transmission and distribution infrastructure. Our plan includes targeted, risk-based investments to maintain, refurbish and replace existing assets that are in poor condition and beyond their expected service life, within the policy set by the OEB. Investments in technology, such as the successful implementation of Asset Analytics, have provided us with real-time asset condition and performance data, giving us the ability to make asset optimization life-cycle decisions, and opportunities through planning and scheduling data to improve materials procurement and to deploy work crews to better manage work programs to meet customer needs.

The actual timing and expenditures in our business plan are predicated on obtaining various approvals including: OEB approvals and environmental assessment approvals; successful negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities.

Over the last five years, we have replaced all of our core IT systems with a company-wide IT system. Further development of the existing IT platform will enable various tools to consistently provide a comprehensive and cascading information view of asset risks based on demographics, condition, performance, criticality, economics and utilization. In addition, we have introduced talent management, employee pay and time reporting enhancements to reduce costs, and to further develop and retain critical core competencies, skills and knowledge of our people. These new initiatives will allow us to effectively plan and reprioritize work and integrate customers' needs into multi-year investment plans. This outcome is consistent with the OEB's direction in its new Outcomes-Based Approach to regulation.

Our plan is focused on delivering integrated asset-to-work planning, optimized scheduling, and execution, as well as field mobility. Through our investment in our Workflow of the Future initiative (currently a pilot program), we will bring together data, analytics and mobility to allow our employees, especially those in the field, to do more at the job site with their mobile devices.

Significant opportunity resides with smart meters and the proliferation of ADS including energy efficiency, demand response and distributed-resource technologies over the long term. Our investments in this area will focus on reliability, customer needs and affordability. We will continue to invest on a prudent basis in the development of ADS and related grid modernization standards, customer demand work (connections and upgrades), smart meters, DG connections, including station upgrades, protection and control, new lines and some contestable work, for which we will receive customer capital contributions. There is little flexibility to reduce this work as most of it is customer demand driven.

Consistent with our corporate strategy, we will pursue an LDC consolidation approach that is robust but prudent, to facilitate the consolidation of Ontario's distribution sector. This is consistent with the Ontario Distribution Sector Review Panel's assessment that there are substantial efficiencies to be found through consolidation of Ontario LDCs and we are key to the solution. We will also work with our Shareholder to address the recommendations of the Council once they are finalized in the Council's final report which is anticipated in the spring of 2015. Our plan does not include funding for LDC acquisitions or assume any disposition of our service territory. These opportunities will be managed as they arise. Our plan also does not incorporate any projects related to competitive transmission. However, as leaders in the sector, we plan to bid on key projects. The OEB notes in its *Framework for Transmission Project Development Plans* that where projects are otherwise equivalent or close in other factors, information such as socio-economic benefits, including First Nations involvement, could

prove decisive in a competitive bid. As such, First Nations involvement in competitive bids is likely to become more prevalent.

CHANGES TO OUR BOARD OF DIRECTORS

On March 7, 2014, our Shareholder, the Minister of Energy, on behalf of the Government of Ontario, announced that Sandra Pupatello would be appointed Chair of our Board of Directors, effective April 1, 2014, and on April 1, 2014, the Shareholder formally elected Ms. Pupatello as our new Chair. Ms. Pupatello is the Director of Business Development and Global Markets at PricewaterhouseCoopers Canada. She is also the Chief Executive Officer of the WindsorEssex Economic Development Corporation. Ms. Pupatello has been a member of our Board of Directors since November 2013.

On April 11, 2014, the following new members were added to our Board of Directors: William Limbrick, Tom Moss, and John Wiersma. William Limbrick was the Vice President of Information and Technology Services, Chief Information Officer of the IESO, and a Principal Consultant within the utilities practice of PricewaterhouseCoopers and Sun Life Assurance in the United Kingdom. Tom Moss is the former President and Chief Operating Officer of Telecom Ottawa, and has held strategic policy positions in the federal government at Treasury Board and Industry Canada. John Wiersma, P.Eng., is a former director of the ESA (Ontario) and IESO Board of Directors, and a former member of the Board of the Electrical and Utilities Safety Association and the Canadian Energy Efficiency Alliance.

On April 25, 2014, the following new members were added to our Board of Directors: Sally Daub, Maureen Sabia, and Carole Workman. Sally Daub is a director and former President and Chief Executive Officer of ViXS Systems, a former chair of the Small Business Agency of Ontario, and a former board member of the Information Technology Association of Canada and the Global Semiconductor Association. Maureen Sabia is the Chair of the Board of Canadian Tire Corporation Limited, and has an extensive background with organizations at the provincial and federal levels. She has been named one of Canada's Most Powerful Women and is also an officer of the Order of Canada. Carole Workman is a member of the Board of Allstate Insurance of Canada (Toronto). She also served on the Board of the Ottawa Hospital and its affiliates since 2007, and is a former member of the Board of Hydro Ottawa Holding Inc.

On April 1, 2014, James Arnett resigned from our Board of Directors. Mr. Arnett has been a member and Chair of our Board of Directors since March 2008. The Board of Directors terms for Michael Mueller, Walter Murray, Robert Pace, and Douglas Speers expired on April 11, 2014.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate, and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: expectations regarding energy-related revenues and profit and their trend; statements regarding our transmission and distribution rates and customer bills resulting from our rate applications; statements related to the FIT program; statements about CDM; statements about our strategy, including our strategic objectives; statements regarding considerations of current economic conditions; statements regarding the new regional planning process; statements related to employee future benefits; expectations regarding First Nation involvement in competitive bids; statements regarding our liquidity and capital resources and operational requirements; statements about our standby credit facility; expectations regarding our financing activities; statements regarding our maturing debt; statements regarding our ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives (including productivity savings, process improvements, and customer satisfaction) and their completion dates; expectations regarding the recoverability of large capital investments; expectations regarding generation connection investments; statements regarding expected future capital and development investments, the timing of these expenditures and our investment plans; expectations regarding OPA recommendations; statements regarding contractual obligations and other commercial commitments; statements related to the OEB; statements regarding future pension contributions, our pension plan and actuarial valuation; statements about our outsourcing arrangements with Inergi and Brookfield and such future outsourcing arrangements; statements regarding customer service performance culture, including statements about the Customer Service Advisory Panel and Customer Commitments; expectations regarding work and costs of compliance with environmental and health and safety regulations; statements related to the 2013 LTEP; statements regarding recent accounting-related guidance; statements related to the Council; statements related to the Working

Group on electricity sector pension plans; statements related to B2M LP; and statements related to LDC consolidation including our acquisition of Norfolk Power, Woodstock Hydro, and Haldimand Hydro. 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. We do not intend, and we disclaim any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining the required approvals; no unforeseen changes in rate orders or rate structures for our 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 us, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our 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:

- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, the Province could mandate the selling of all or part of our distribution business, as well as potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction, including regulatory decisions regarding our revenue requirements, cost recovery, rates, acquisitions and divestitures;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risk that we 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, with maintaining a complex information technology system infrastructure, and with transitioning most of our financial and business processes to an integrated business and financial reporting system;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- the ability to negotiate appropriate collective agreements;
- the risk that we are not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital investments and other obligations;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the risk that future environmental expenditures are not recoverable in future electricity rates;
- the risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders;
- the risk that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions;

- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if either of our agreements with Inergi or Brookfield are terminated or expire before a new service provider is selected;
- the risks associated with changes in the forecasted long-term Government of Canada bond yield;
- the risks of counterparty default on our outstanding derivative contracts;
- the risks associated with current economic uncertainty and financial market volatility;
- the risk that our long-term credit rating would deteriorate;
- the inability to prepare financial statements using US GAAP, or IFRS, as applicable;
- the impact of the 2013 LTEP on our company and the costs and expenses arising therefrom;
- unanticipated changes in electricity demand or in our costs;
- the risk that unexpected capital investments may be needed to support renewable generation or resolve unforeseen technical issues; and
- the impact of the ownership by the Province of lands underlying our transmission system.

We caution 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. You should review this section in detail.

In addition, we caution the reader that information provided in this MD&A regarding our outlook on certain matters, including potential future expenditures, is provided in order to give context to the nature of some of our future plans and may not be appropriate for other purposes.

Additional information about the Company, including the Company's Annual Information Form, can be found on SEDAR at www.sedar.com and on the US Securities and Exchange Commission's website at www.sec.gov.

This is Exhibit "S" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Lisa Lutwak

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK

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Hydro One Customer Service and Billing Issues – Lessons Learned

December 2014

pwc

Disclaimer

This report is prepared by PwC and reflects PwC's assessment in light of the information available at the time of its preparation. The observations are based on the review of documents and artefacts provided, and interviews with selected members of the Customer Information System (CIS) project team. The definition of Lessons Learned, in the context of this report, refers to good management and project practices put in place and potential opportunities for future learning.

PwC is providing no opinion, attestation or other form of assurance with respect to our work and we did not verify or audit any information provided. Our work does not constitute an audit conducted in accordance with generally accepted auditing standards, an examination of internal controls or other attestation or review services in accordance with standards established by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, we do not express an opinion or any other form of assurance on the project information provided, or operating and internal controls of Hydro One. Should further information come to our attention after the analysis was completed, the results expressed herein could change.

Our work was based primarily on the information supplied by those interviewed and was carried out on the basis that such information is accurate and complete. Information was not subject to checking or verification procedures, except to the extent expressly stated to form part of the scope of work.

This report is intended solely for the internal use of Hydro One management. Any third-party use of this report or reliance thereon, or any decision made based on it, is the responsibility of such third party. PwC accepts no responsibility for damages, if any, suffered by any third party as a result of decisions made or actions based on this report.

This report furthermore incorporates responses received from Hydro One management. These comments are appended at the end of the Executive Summary presented in Section A of this report as well as at the end of each of the eight Lessons Learned listed in Section E of this report. PwC has incorporated these management responses into the report without further validation of any information presented therein. As a result, PwC is providing no opinion, attestation or other form of assurance with respect to the management responses incorporated into this report.

Contents

A. Executive Summary

PwC Engagement

The Business Transformation Committee (BTC) of Hydro One's Board of Directors engaged PwC to perform an independent review, in the form of a ***Lessons Learned exercise***, to gain perspective on the reasons for the unexpected outcomes of the Customer Information System (CIS) implementation, with an emphasis on project recovery and organizational responsiveness during the post go-live period, and to determine how these lessons learned may be applied to future projects.

The review period in scope is effective ***from April 5, 2013***, which is the date when the User Acceptance Testing (UAT) results were initially made available, ***to February 4, 2014***, which is the date of the public announcement made by the Provincial Ombudsman. However, the factors affecting the outcome and the corresponding lessons learned for future projects spanned across the entire duration of the project.

CIS Project Background

In 2006, Hydro One developed a 4-phase business transformation strategy, known as Cornerstone, to replace its customized legacy applications and transform its business through the implementation of new business processes and software applications. The focus of this report is on the 4th phase of Cornerstone, which commenced in 2011 to replace Hydro One's main customer-facing systems with SAP CIS.

SAP CIS is a leading commercial off-the-shelf (COTS) software available in the market today, for deployment of utility customer information and billing systems. This solution is highly configurable and, if implemented properly, significantly reduces the expense associated with extensive and time consuming code changes associated with older systems. This ultimately benefits the company as it considerably reduces costs once the system is stabilized.

In general, utility CIS implementations are complex and difficult projects with a mixed track record of success across North America. The Hydro One implementation was anticipated to be challenging to deliver given the desired timeline and the many system, data and process dependencies that existed. The unique aspects of the Ontario regulatory context and electricity market, challenges with end-to-end smart meter data acquisition and related processes, complex billing processes for commercial customers, and a complex vendor ecosystem added further complexity.

The vendors involved in the CIS project were HCL Axon (HCL), SAP, Inergi LP and their contact centre and billing services subcontractor, Vertex. Hydro One acted as the business lead, HCL as the integrator and overall project manager, SAP as the application provider, and Inergi LP and Vertex as both resource providers on the project as well as the operational sustainment teams via Hydro One's outsourcing strategy.

It became apparent in the early stages of the project that the original 17 month implementation timeline was overly ambitious. In May 2012, based on project experience to date, Hydro One rebaselined the project, replaced the HCL project executive team, extended the timeline 7 months and released the $25M contingency that had been planned for in the original $180M budget. The revised 24 month implementation timeline was in keeping with the 24-36 month industry benchmark that we see for similar sized utility industry CIS installations.

By the fall of 2012, the project was falling behind schedule and budget. At this point, Hydro One changed their project sponsor, adjusted the project scope, added senior executive resources to the Steering Committee and Project Management Office (PMO) and enhanced the quality of the project reporting by establishing Key Performance Indicators (KPIs) that were tracked and shared with all project governance levels throughout

the remainder of the project. The CIS project went live on the planned, revised date of May 21, 2013 and was delivered within the originally agreed budget envelope of $180 million (including $25M contingency).

Upon implementation, the CIS billing system and its associated processes functioned largely as planned, with the vast majority of bills (81%) being produced with actual meter data. Within the first 30 days post go-live it became apparent that there were legacy system/data issues as well as issues associated with the new billing processes and timelines that were causing a higher than expected number of 'estimated' bills, billing exceptions and 'no-bills'. Several corrective actions were taken over the ensuing months to address the root causes of these billing issues however, by January 2014, 5% of customers were still experiencing persistent 'estimated' bills or 'no-bills'. These billing challenges eventually resulted in an investigation into the billing and customer service practices at Hydro One by the Provincial Ombudsman in February of 2014.

Post implementation challenges

The main contributing factor for the above noted billing delays and issues appears to be the fact that the Meter-To-Cash process was generating an excessive number of 'estimated' or 'no-bill' exceptions. Those exceptions that could not be cleared prior to the next billing cycle compounded month to month until such time as they were resolved which further aggravated the situation and impacted customer service responsiveness.

As billing exceptions were remediated, it often resulted in a large catch-up bill which generated further inquiries, excessive bank account withdrawals, cancel/rebills and refund cheque issues. Additionally, when those affected customers called for answers, they were not given a definitive response or adequate assurance that their problem would be addressed and resolved in a timely fashion. By January 2014, the number of backlogged escalated customer complaints had increased to 670 as compared to their historic monthly backlog levels of 100-150.

The growing billing backlogs, combined with an inadequate response to the increasing volumes of customer inquiries and complaints, drove customer dissatisfaction. In an attempt to get their issues resolved many customers escalated their complaints to their local MPP's, the Ontario Ombudsman and to the Ontario Energy Board (OEB).

Reasons for unexpected outcomes

The negative impact on customer experience and satisfaction that resulted from the CIS project came from a number of contributing factors with varying degrees of impact across three key phases of the project lifecycle.

1. **Blueprint** ... where project scope, approach, governance and staffing decisions were made;
2. **Go-Live readiness** ... where data quality was reviewed, system and processes were tested, and training was conducted; and
3. **Hyper-care period** ... where issues stemming from system go-live were understood, analysed and remedied.

Significant contributing factors for the customer care and billing challenges are listed below and further elaborated in Section D of this report.

	Blueprint	Go-Live readiness	Hyper-care period
1. Ambitious scope and timeline	✓	✓	-
2. Inconsistent governance execution	✓	✓	✓
3. Variable quality of project reporting	✓	-	✓
4. Ineffective team complement	✓	✓	✓
5. Ineffective vendor management	✓	✓	✓
6. Gaps in testing disciplines	-	✓	✓
7. Reactive customer response	✓	✓	✓
8. Lack of operational nimbleness	-	-	✓

Lessons Learned

Using our PwC Framework for Project Delivery Excellence, which defines leading practices that can improve project outcomes, we have taken the findings from our analysis of the Hydro One CIS project and organized them into "lessons learned" that may be applied to future projects:

1. Clear scope definition ...
   Establish a Discovery Phase for large-scale projects before confirming project scope and concluding contracts.
2. Decision enabling governance ...
   Engage a broad cross-section of executives, functions and stakeholders in decision making.
3. Active quality management ...
   Ensure the testing phases and testing windows of projects are protected.
4. Managed risks and opportunities ...
   Continue the practice of formal project risk assessments and internal audits at key stages of projects.
5. Integrated suppliers ...
   Improve vendor oversight and management and hold project vendors to account.
6. High performing teams ...
   Ensure project leaders and team members possess the right skills and experience.
7. Agile change control ...
   Maintain project tracking and documentation rigour always.
8. Operational sustainment ...
   Ensure the right number of people with the right expertise and experience are put in place until the system is fully stable.

Current State of Affairs

While not a focus of our report, in the course of our review we identified that between February 2014 and July 2014, Hydro One has achieved significant progress in addressing their remaining technical/operational issues associated with delayed bills and smart meter data processing. They have also improved their frontline customer servicing practices. Outlined below are some of the highlights of progress achieved:

- A new Customer Charter of Rights has been introduced and new customer focused servicing policies have been put in place such as:
    - Interest-free payment plans for customers who receive bills covering long billing periods;
    - Cheque refunds for credit balances on customer statements; and
    - Waived service charges for customers with billing issues.
- Additional numbers of staff have been added to the contact centre, billing and Hydro One's Customer Relations Centers (CRC) teams to improve customer service quality and responsiveness.
- Members of Hydro One Customer Service Operations (CSO) management team are now embedded in the Vertex contact centre and billing operations to provide improved oversight of the Vertex management team.
- Enhanced change management processes have been put in place to ensure staff are appropriately trained and knowledge ware systems are updated prior to implementation of changes.
- Numerous technical/operational fixes have been put in place to address delayed bills and smart meter data processing.
- New project orders have been raised to address identified issues and gaps e.g. updating of technical documentation.

All of the above have contributed significantly to improve the following key metrics for Hydro One:

- Volume of 'no-bills' have dropped from a high of 53K bills down to pre-CIS levels of 20k.
- Volume of 'estimated bills' have dropped from a high of 30k to 10k.
- Call volumes have returned to January 2013 levels.
- CRC backlogs are at their lowest levels in the past 2 $^1/_2$ years.
- Improved service levels and customer satisfaction scores.

Comments Received from Management

Hydro One management confirms it has reviewed the Report and its specific responses to report recommendations are embedded in Section E of the Report. Management also confirms that it has taken decisive action to implement certain report recommendations and will incorporate key recommendations into future large-scale projects, particularly as they relate to decision governance, quality management, risk, project controls, working with suppliers, and operational sustainment.

We note that the review period for the Lessons Learned Report was identified as April 5, 2013 to February 4, 2014. However, management would like to take this opportunity to outline the progress made to date with respect to our Customer Service Recovery initiative of the last nine months.

Hydro One's move to a new Customer Information System (CIS) in 2013 represented the final phase of the Company's Cornerstone Project; a ten-year, four-phase IT strategy to replace several of Hydro One's key enterprise information systems. Cornerstone represented a major business process transformation initiative to improve Hydro One's efficiency and productivity and ultimately, its customer service offerings.

Regardless of the best efforts to ensure a seamless transition to the new CIS, implementation of this complex, large-scale project resulted in a number of customer billing issues for approximately 5 per cent of our customers. Hydro One acknowledges and regrets that we let some of our customers down and we have focused considerable resources and energy to correct issues resulting from the transition to a new system.

In February of 2014, Hydro One initiated the Customer Service Recovery project, an intensive project to not only resolve technical problems that resulted from introducing a new billing system, but to also improve service through new customer friendly policies and by changing our customer service culture by:

- Clearing the backlog of customers that have gone a prolonged period of time without receiving a bill.
- Decreasing the number of customers that have had prolonged periods of estimated bills.
- Introducing a 10-day commitment for resolving customer issues, with a resolution within 10 days or by a promised date.
- Changing call-centre training, adding customer service centre agents and introducing flexible customer-centric policies for those affected by billing issues (providing interest-free payment plans, waiving service charges and issuing refunds versus credits).
- Improving billing and consumption information on the Hydro One website.
- Hosting Virtual Town Halls with customers to talk about issues that matter to them. Almost 60K customers have participated in these Town Halls.
- Establishing and implementing new/revised customer service policies, approaches and products.

Our efforts are paying dividends. To date, we can report that:

- No Bill Volumes have been reduced by 90% from when compared to volumes experienced following the cutover to the new system.
- The number of backlogged exceptions generated by the new system has been reduced by 90% from peak. *
- Frequency of Unscheduled Estimated Bills has been cut in half.
- Call Center Performance improved throughout 2014 as it relates to accessibility and quality: weekly Call Centre customer satisfaction has hovered in the 85% range and twice has exceeded 90%.

At the end of September, in light of the progress made in getting these key measures back to "pre-CIS" levels, Hydro One made the decision to close down the project and hand over customer care to a new sustainment Customer Service organization, which reports directly to the President and CEO. The new sustainment organization has established a new customer service governance model, and continuously monitors new service metrics so that we have a clear and ongoing line of sight to the performance of the new system and to the levels of service we are providing to our customers.

Hydro One has established a Service Champion Advisory Panel and has invited a number of external experts in the area of customer service to provide advice to the CEO about how we are doing and how we can better serve our customers. They will review our performance and we will make our report card results public. We will also make public our specific customer commitments which define the customer service standards to which we will be held to account. We know these are the right things to do, but we will do more.

Looking to the future, we know we must redouble our efforts to restore our customers' trust in Hydro One. Our focus must turn to transforming our customer service offerings and our service culture. This starts with developing strategies to further improve performance, employee engagement, customer communication, our follow-through on commitments, and leverage technology to improve customer experience.

Management appreciates the opportunity to respond to the PwC Lessons Learned Report. We would also like to acknowledge the work of the CIS project and sustainment teams who, as noted in the PwC report, "demonstrated incredible effort and commitment" to deliver this project; many who continue to work tirelessly to make further improvements to service our customers.

Most importantly, Hydro One wishes to thank its customers who were impacted by the implementation of the new customer system for their patience and understanding while we worked to resolve their issues.

** Exceptions are a normal occurrence of any billing process and are explicitly designed to trigger manual review/intervention. Put another way, an exception is a safety net that safeguards against a billing error. We rely on our billing system to generate exceptions to avoid billing errors.*

B. PwC Engagement

The Business Transformation Committee (BTC) of Hydro One's Board of Directors engaged PwC to perform an independent review, in the form of a ***Lessons Learned exercise***, to gain perspective on the reasons for the unexpected outcomes of the Customer Information System (CIS) implementation, with an emphasis on project recovery and organizational responsiveness during the post go-live period, and to determine how these lessons learned may be applied to future projects.

Mandate

The primary mandate of our engagement was to perform an independent 'lessons learned' exercise to provide Management and the Board of Directors with a better understanding of the factors that contributed to the negative outcomes and challenges which resulted in the public announcement by the Provincial Ombudsman on February 4, 2014. Specifically, the goal was to understand:

- The reasons why the Hydro One CIS implementation experienced unexpected outcomes despite extensive preparations.
- What lessons can be learned from this project that may be applied across the organization to future capital projects.

Scope

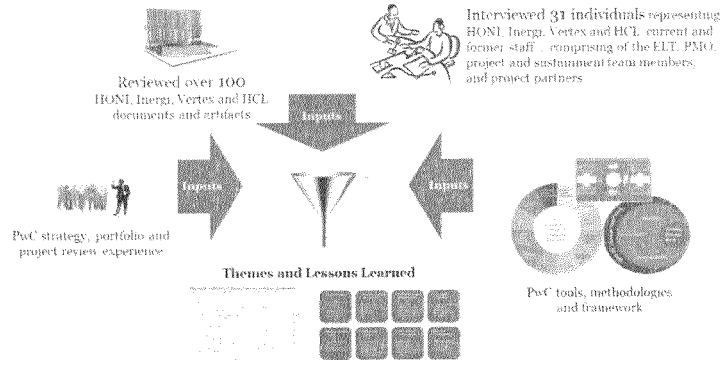
The review period in scope started ***from April 5, 2013***, which is the date when the test results were initially made available as a result of the User Acceptance Testing (UAT), ***until February 4, 2014***, which is the date when the public announcement was made by the Provincial Ombudsman. However, the factors affecting the outcome and the corresponding lessons learned for future projects spanned across the entire duration of the project.

Approach

PwC's independent analysis was conducted over an eight week period and incorporated input from:

- Interviews with key Hydro One, Inergi LP, Vertex and HCL project, sustainment and governance team members;
- Review of key documents and artifacts provided by Hydro One; and
- PwC experience and methodologies from similar projects.

The PwC framework for project delivery excellence was used to guide our analysis of the Hydro One CIS implementation.



C. Context

Background

Hydro One is the largest electricity transmission and distribution company in Ontario, accounting for approximately 97% of the province's transmission capacity and 1.152 million customers (at the time of the implementation) across about 75% of the province. Hydro One has a long standing history of serving Ontario dating back to 1906.

Consistent with other mature organizations, Hydro One recognized a need to modernize their technology systems to remain responsive to the continuously changing regulatory and business needs of the utilities industry. In order to meet this challenge, Hydro One developed a business transformation strategy known as *Cornerstone*, to replace its customized legacy applications and transform its business through the implementation of applications requiring minimal customization.

This was a staged plan consisting of four phases to replace end of life information systems with SAP as follows:

- 2008: Phase 1 – Replacement of legacy Enterprise Asset Management (EAM) and Supply Chain system.
- 2009: Phase 2 – Replacement of legacy PeopleSoft accounting and payment systems along with certain Asset Management functions and information management/reporting capabilities.
- 2011: Phase 3 – Enhancements to the first two phases relating to EAM Analytics.
- 2013: Phase 4 – Replacement of customized, legacy customer systems built on discontinued platforms with SAP Customer Information System (CIS).

This report relates specifically to Phase 4 of the Cornerstone Strategy, the Hydro One CIS Project.

Objective

The legacy Hydro One customer system, Customer One (CSS), was a fully depreciated asset built on an Accenture platform that is no longer supported. Over a period of 12 years, Hydro One had modified the CSS numerous times to meet changing Ontario regulatory requirements. By 2013, the CSS had become a highly customized stand-alone system operating on a discontinued platform. As such, this system was in dire need of replacement with a new application that could be supported by the vendor and other service providers and could provide Hydro One with a more flexible platform to better support their desired customer service processes and outcomes.

Overall, the CIS replacement project was designed to meet the following three objectives:

1. **Address current needs:**
   Eliminate operational risk by replacing an aging, customized, legacy system with similar functionality.

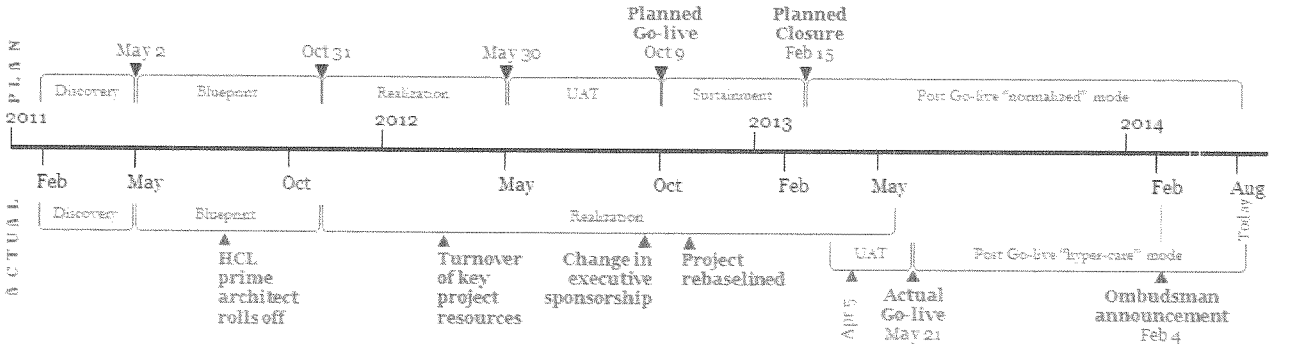
2. **Improve customer value:**
   Adopt best practice processes to produce better customer service results, be able to quickly accommodate regulatory changes and lower IT operating costs.

3. **Enable a customer service delivery vision:**
   Eliminate duplication and streamline delivery by consolidating back office functions and fully leveraging technology investments (Smart Meter, Smart Grid, and CIS).

Project Details

From the initial planning stage, the project was widely known to be complex with extensive configuration needed to meet the requirements of the Ontario electricity market. The Hydro One CIS project had an ambitious timeline with many system, data, process and vendor dependencies. This was further complicated by the unique aspects of the Ontario electricity market, challenges with smart meters and associated business processes, as well as a complex vendor ecosystem. Beyond the complexity drivers noted above, a number of enhancements were also included in the scope of the project such as changes to customer billing processes (removal of the 13 day billing delay) and remote meter disconnect capability.

The initial scope of the project included approximately 2900 requirements, 90 interfaces, 170 enhancements and 141 data conversions with a planned budget of $180 million (including $25M contingency) and a planned duration of 17 months.



The project involved four key parties, namely Hydro One, HCL Axon (HCL), SAP (a leading large-scale utility software application provider), Inergi LP and their Contact Centre and Billing Services subcontractor, Vertex. Hydro One acted as the business lead, HCL as the system integrator and overall project manager, SAP as the application provider, and Inergi LP and Vertex as both resource providers on the project as well as the operational sustainment teams via Hydro One's outsourcing strategy.

While the composition of the various CIS governance committees differed from previous Cornerstone phases, the same successful project governance and delivery model was employed. The governance model consisted of the Business Transformation Committee (BTC), the Executive Committee (EC) and a Steering Committee/ Senior Project Leadership Team. The project team structure consisted of a Project Management Office (PMO), Team Leads, Architects, Stream Leads and Project Teams.

The project was planned to follow an approach consisting of six phases as follows:

1. **Project Prep** ... RFP & vendor selection of a software application,system integrator and project manager.
2. **Discovery** ... set scope, finalize fixed price with integrator and define benefits.
3. **Blueprint** ... finalize scope and design of the solution including processes, roles, organizational and business change and the technology components.
4. **Realization** ... implement and test the solution design including business process re-engineering, data cleansing, hardware and software configurations, go-live acceptance criteria and transformation plans.
5. **Final Prep** ... prepare the system, users and organization for go-live including user acceptance testing, Go/No-Go decision, migration to production and end user training.
6. **Go-Live & Stabilize** ... support the system by monitoring and resolving any issues identified post go-live prior to transitioning the system to steady state operations.

Based on the high level requirements identified during the Discovery Phase, the project budget was established and the timeline set for a 17 month implementation. During the Blueprint phase, a further 68 business requirements were added to the scope of the project without any change to the timeline or budget. As the project progressed through the Realization phase in the spring of 2012, it became apparent to the project team that the billing and smart meter data processing was much more complicated than originally anticipated. In May 2012, based on project experience to date, Hydro One rebaselined the project, replaced the HCL project executive team, extended the timeline 7 months and released the $25M contingency that had been planned for in the original $180M budget. The revised 24 month implementation timeline was in keeping with the 24-36 month industry benchmark that we see for similar sized utility industry CIS installations.

By the fall of 2012, the project was falling behind schedule and budget. At this point, Hydro One changed the project sponsor structure, adjusted the project scope added senior executive resources to the Steering Committee and PMO and enhanced the quality of the project reporting by establishing Key Performance Indicators (KPIs) that were tracked and shared with project governance levels throughout the remainder of the project. The CIS project went live on the planned, revised date of May 21, 2013 and was delivered within the originally agreed budget envelope of $180 million (including $25M contingency)

Project Delay Highlights	**Planned**	**Actual**
Blueprint *to* Go-Live	17 months	24 months
Realization	7 months	19 months
UAT/ORT	4 months	2 months
Testing (SIT/UAT/ORT) & Development	Sequential	Overlapped
Go-Live *to* Sustainment	4 months	On-going
Sustainment (normal operations)	February 15, 2013	TBD

Post Go-Live

Upon implementation, the CIS billing system and its associated processes functioned as planned, with the vast majority of bills (81% of 1.152 million) being produced with actual meter data. Within the first 30 days post go-live it became apparent that there were legacy system/data issues as well as issues associated with the new billing processes and timelines that were causing a higher than expected number of 'estimated' bills (8% or 89k), billing exceptions and 'no-bills' (11.5% or 122k). Examples of the types of specific customer billing challenges that occurred were: missing meter readings, bill blocks due to defects, billing/invoice outsorts, cancel/rebill etc.

As billing issues were resolved, an amended bill for the month in question would be produced. If the correction occurred after a subsequent billing period(s) all bills from the billing period in question to the month in which the billing issue was resolved were reproduced and sent to the customer to ensure accurate record keeping. These issuance of multiple bills often caused further customer confusion when received.

Several corrective actions were taken over the ensuing months to address the root causes of these billing issues however, by January 2014, 5% of customers were still experiencing persistent 'estimated' bills or 'no-bills'. Between go-live and November 2013 the escalated customer complaint backlog had doubled from approximately 325 complaints to 670. Historically, escalated complaint backlogs prior to December 2012 appeared to run in the 100-150 range.

D. Challenges faced

Utility billing projects are inherently risky to implement and have a history of challenges across the North American utility industry. The Hydro One Customer Information System (CIS) project was an ambitious project from the outset with challenging timelines, complex vendor relationships, legacy customizations, many system dependencies and planned new functionalities.

The negative impact on customer experience and satisfaction that resulted from the CIS project came from a number of contributing factors with varying degrees of impact across three key phases of the project lifecycle:

1. Blueprint ... where project scope, approach, governance and staffing decisions were made,
2. Go-Live readiness ... where data quality was reviewed, system and processes were tested, and training was conducted, and,
3. Hyper-care period ... where issues stemming from system go-live were understood, analysed and remedied.

As noted previously, there were several billing and service related challenges which eventually drove Hydro One's customers to take their complaints to their local MPP's, the Ontario Ombudsman and to the Ontario Energy Board (OEB). A summary of the root causes of implementation issues is provided below, and further elaborated on with comparable industry information, where applicable, in the following sections.

	Blueprint	Go-Live readiness	Hyper-care period
1. Ambitious scope and timeline	✓	✓	-
2. Inconsistent governance execution	✓	✓	✓
3. Variable quality of project reporting	✓	-	✓
4. Ineffective team complement	✓	✓	✓
5. Ineffective vendor management	✓	✓	✓
6. Gaps in testing disciplines	-	✓	✓
7. Reactive customer response	✓	✓	✓
8. Lack of operational nimbleness	-	-	✓

1. Ambitious scope and timeline

CIS implementations are complex and difficult projects. Hydro One's CIS implementation was even more so due to the ambitious timeline, "big bang" implementation approach and the many system, data and process dependencies that were in scope. The complexity of this project was further compounded by the unique aspects of the Ontario electricity market, challenges with end-to-end smart meter data acquisition and related processes, the complex billing processes for commercial customers, and a complex vendor ecosystem.

Given the approximately 2900 requirements, 170 enhancements, 90 interfaces and extensive amount of data conversion in the scope of the CIS project, Hydro One leadership recognized that a systems integrator would be required to successfully deliver the project. As such, Hydro One went through an RFP process and selected HCL as their integrator and project manager.

The initial planned timeline of 17 months was an aggressive timeline when compared to other similar implementations. Our experience indicates that a typical duration for a CIS implementation is between 24 and 36 months. It appears that HCL agreed to this compressed timeline at the time of vendor selection for the following two reasons. First, it appeared that the CIS implementation was expected to be primarily an 'out-of-the-box' solution (i.e. that it would require little customization). Secondly,the nuances of Smart Metering and the Ontario Market were not well understood by the vendor. Delivering the project in a shorter timeframe benefited Hydro One as it meant a lower cost of implementation as well as earlier benefits realization from the new CIS system and earlier mitigation of the operating risks associated with the aging CSS system.

The CIS system interfaces with many other external systems such as financial institutions, credit agencies, the Independent Electric System Operator (IESO), among others, to obtain metering information, customer credit information, and payment validations. In the legacy CSS, these interfaces, especially those with the IESO Meter Data Management and Repository (MDM/R) application, had become highly customized over time to meet regulatory changes and other needs, and some of these customizations were not clearly understood or identified by the project team during the Discovery phase of the CIS project. The CIS project also had hard dependencies on the Smart Metering project which was still evolving. The level of understanding of the nuances of the Smart Metering system was limited and made it difficult to accurately document the related requirements. In total, approximately 30 different disparate systems/customizations were retired and replaced by the new CIS. Without having a clear understanding of how the end to end solution had evolved over time, there were challenges in defining the detailed requirements of the new CIS system. By the end of the Blueprint phase the number of enhancements in scope had increased from 102 to 170. These incremental 68 enhancements had not been taken into consideration when determining the initial timeline and budget.

Additionally, the CIS implementation was not an "as is" implementation, whereby the legacy system is replaced with a new system with the same core functionality. In this case often desired enhancements are implemented in a later phase post core system conversion. The CIS implementation planned for significant enhancements to the legacy processes and system such as the reduction of the 13 day billing delay and remote meter connect/ disconnect, many of which served to create a compelling financial business case via improved operating efficiency and enhanced customer experience. Given the inherent high risk associated with replacing the CSS system as well as the volume and complexity of some of the enhancements included in the scope of this project, choosing to adopt a 'big bang' implementation approach, versus a phased implementation approach, may have added to the complexity of the system requirements, implementation and testing.

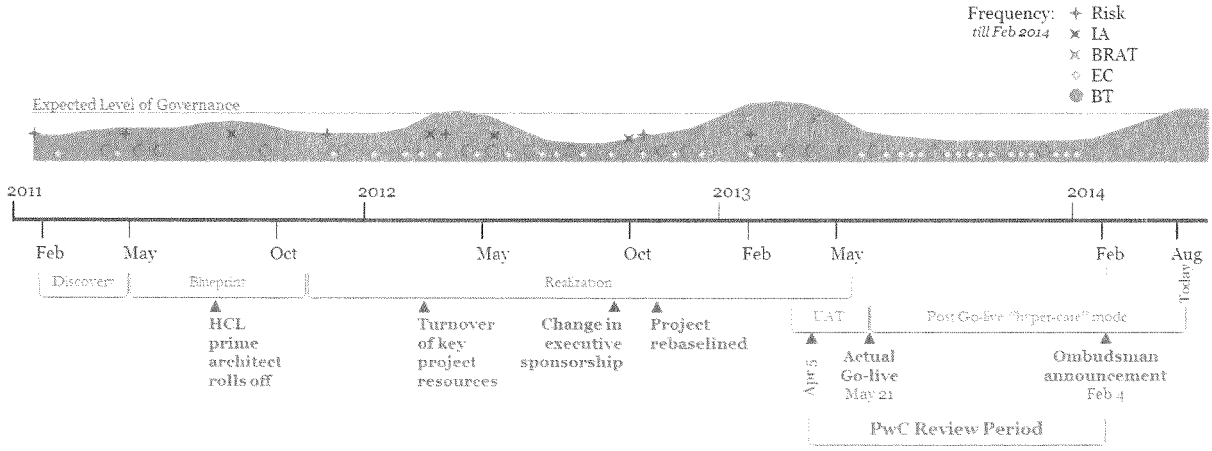
Industry opinion is split on whether the 'big bang' approach is better than a 'phased' approach, either by geography, customer segment (i.e. residential, commercial), interfaces or enhancements. Some experts believe that a 'phased' approach can serve to reduce implementation risks while still achieving the requisite business case benefits while others believe that it introduces additional cost and complexity, such as: maintaining two systems in parallel; reduced operational efficiencies caused by having customer service teams split across the two systems until the final phase is implemented; and, having to execute a phased customer communication strategy.

2. Inconsistent governance execution

The CIS Project adopted a governance framework similar to the ones successfully used in the previous 3 phases of the Cornerstone strategy. While the governance evolved and adapted to the needs of the project throughout its lifecycle, overall governance could have been improved in the areas of organizational structure and composition, transparency of reporting, communication and consistent inclusion of key stakeholders.

The CIS project governance structure was defined with: (a) two layers of 'oversight': the Executive Committee (EC), and the Business Transformation Committee (BTC); and, (b) two layers of 'decision makers': the Project Steering Committee and the PMO.

The oversight layers consisted of Senior Executives who were not embedded within the project, thus bringing an arms-length, objective perspective to the project and seasoned executive input, advice and guidance to support the project sponsors. The decision making layers were responsible for providing day-to-day project oversight and managing project direction, risks, budget, schedule and approach. These multiple layers of project governance provided the benefit of senior levels of advice and support while still providing project efficiency.



While a mature governance structure was put in place, the team composition of the various governance committees and cadence of meetings varied throughout the lifecycle of the project. As depicted above, the governance composition was strongest through the period from October 2012 to May 2013 when senior Hydro One executives joined the Steering Committee and became engaged on a day-to-day basis in the PMO. This provided an additional seasoned source of advice from a multi-disciplinary perspective and helped stabilize the project.

However, post go-live, the level of senior executive involvement in the project on a day-to day basis declined and this impacted Hydro One's ability to quickly deal with the various scenarios, plan for contingencies and right-size the remediation efforts to resolve defects post go-live.

Hydro One's Risk and Internal Audit (IA) teams also played key support roles providing internal arm's length project oversight; however, they were not part of the PMO and their involvement was inconsistent over the course of the project and fell off significantly post go-live. In the case of IA, a full time auditor was assigned to the project however demands posed by the external auditor relating to the data conversion phase of the project stretched their capacity. The project may have benefitted from additional audit support. The advice and counsel that both Risk and Internal Audit provided to the project and governance teams was sound and their active involvement post go-live may have provided a valuable voice when making key operational decisions post go-live.

Key project partners, such as HCL and Inergi LP, were represented at the PMO and Steering Committee levels; however, Inergi LP did not become part of the Steering Committee structure until late in the project (around September 2012). As a key partner on the project from the earliest phases of the project, it would have been beneficial to have them engaged at the Steering Committee level from the point of their engagement on the project. Given Hydro One's contractual outsourcing arrangement with Inergi LP and Vertex, Vertex was represented by Inergi LP at both the Steering Committee level and at the PMO level for the majority of the project but did not have a direct representation at the key project governance levels until October 2013 when they joined the PMO. As Hydro One's face to the customer, having Vertex involved in the senior governance process would have provided a stronger voice of the customer to the decision making process.

At the PMO level, team composition and turnover, especially in the early stages of the project, impacted the project. Some of the PMO challenges included:

- The HCL Project Manager (PM) changed three times during the course of the project, twice at the request of Hydro One due to performance issues.
- Vertex did not join the PMO until post go-live.

The project lost the benefit of resource continuity across all phases of the project as well as the diversity of various points of view at the PMO level that parties such as Vertex, Risk and Internal Audit may have brought had they been engaged on the PMO throughout the lifecycle of the project. Balanced representation on the PMO and active day-to-day PMO involvement from key support partners such as Risk and IA may have enhanced the decision making process throughout all phases of the project including post go-live.

It has also been noted in our review that the oversight committees relied heavily upon updates, project insights and recommendations from the project stakeholder groups to inform their decision making. These included the PMO, vendors, IA, Risk and an internal review team called BRAT (Business Readiness Assessment Team) that provided a final arm's length assessment of the operational readiness of the organization to support the system post Go-Live. Compared to industry practice Hydro One's external auditor had minimal involvement in the project. The focus was primarily on the financial reporting impacts of the implementation.

It is good practice to have insights of those closest to the project and from within the organization; however, commissioning an independent third party to provide project oversight and risk assessments over the course of the project would have provided an arm's length, objective view of the project's progress, risks and mitigation strategies at each project gate, thereby enhancing the Board's and EC's decision making ability. Based on our industry knowledge, most utilities who are implementing projects of this size and complexity with a similar risk profile bring in external independent third parties to evaluate progress and risk assessments at the various gates of the project. This is done to provide a direct, independent line of communication to the Board.

In hindsight, Hydro One would have benefited from:

- Retention of heavy governance support during the sustainment phase for a minimum of two to three billing cycles post go-live and longer if required; and,
- Engagement of an external third party to perform an independent review to support project governance decision making at all key milestones of the project.

3. Variable quality of project reporting

High quality and consistent project reporting is critically important on large, complex project from two perspectives. First, it permits the project manager to track and evaluate the progress of a project and compare it to the original plan. As projects tend to evolve over time, high quality reporting allows the Project Manager (PM) to track changes, risks and mitigations and provides a historical record of key decisions made throughout the course of the project thereby providing traceability of outcomes. Secondly, it serves to inform stakeholders of the project's progress and keep them actively involved in the project. The information provided should contain the details necessary to allow stakeholders, given their role and level of management, to make informed decisions and maintain oversight of the project.

A variety of tools such as Axon's Project Support Environment (APSE) and HP Quality Centre (HPQC) were in place to allow for both the tracking and monitoring of risks, impacts and mitigations and the tracking of defects, severity and resolution. These tools were utilized throughout the project and all levels of the project team were provided access and direction to log risks using these tools. Having tools such as these and ensuring proper documentation and tracking is in place is a leading practice.

Similar to what was observed with respect to governance, the level and quality of reporting also varied over the course of the project. In the Discovery phase, a detailed project plan, budget estimate and project charter was defined and communicated. In the Blueprint phase, however, the quality of reporting declined with: (a) only high level updates, (b) minimal forward view of the work to be completed within next review period, (c) limited use of Key Performance Indicators (KPIs) to track progress; and (d) robust risks or mitigation strategies began to be reported once project reported in yellow status in April 2012 as per BTC meeting presentation materials.

Under new executive sponsorship between October, 2012 and May, 2013 the reporting quality significantly improved. During this phase, a project baseline was created and progress reporting against the new baseline was established. Also, a regular cadence of governance meetings occurred and issues, risks and mitigation strategies were routinely shared. New quantified, task-level, leading and lagging KPIs for both technical and business related aspects of the project were established, tracked and reported.

The go-live reporting did an effective job of quantifiably supporting each technical KPI status. To further enhance the reporting going forward, we also commonly see added metrics/details such as:

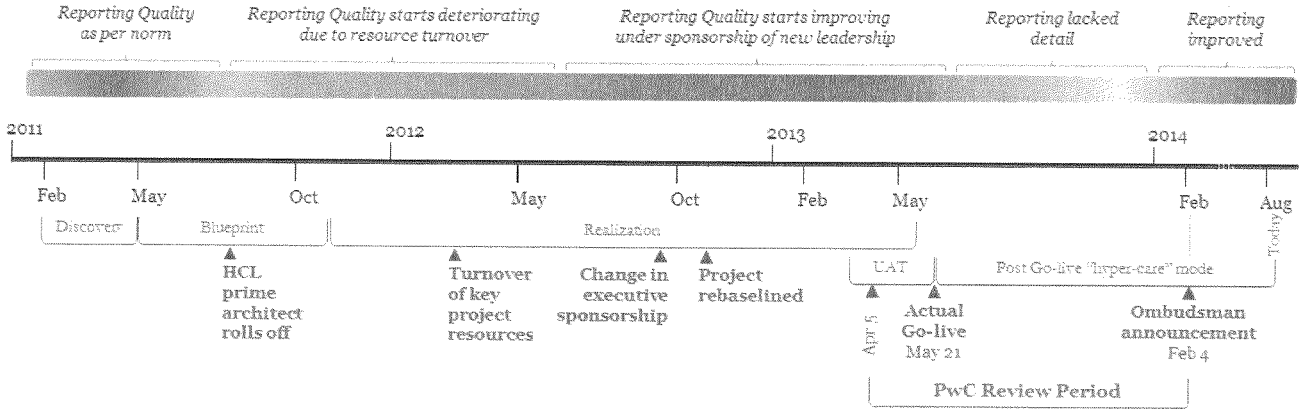
- defect severity breakdown of the reported defect backlog numbers; and
- actual dress rehearsal results i.e. load time results versus the targeted load time.

The same level of quantification was not evident with the CSO Go/No-Go operational metrics. These details may have been provided verbally in the go-live meetings; however they were not evident in the Go/No-Go documentation provided for this review.

Post go-live, the quality of reporting noticeably decreased as key project team members rolled off the project. Post go-live there appeared to be good reporting in place on the various volumetric measures, however key operational KPIs, such as aging of exception backlogs, no-bills, defects and customer complaints were not tracked for several weeks post go-live. In July, the CSO created an ad hoc aging report which Vertex subsequently pulled on a periodic basis however the aging of the backlogs does not appear to have been shared with the EC or BTC. The absence of reported measures such as aging of the various backlogs, receivable impacts etc., as well as the lack of clear documented action plans and glide paths to remedy post go-live issues failed to convey the severity of the operational issues and the associated impacts to the customers to the EC and BTC.

By February 2014, all operational reporting had been put in place and a more robust set of customer and business centric KPIs were established, tracked and reported on as part of the CIS stabilization project. Detailed action plans and glide paths were also pulled together to clear backlogs and return to targeted service levels.

Due to the varying quality of reporting, the EC and BTC ability to provide the full value of their expertise in a timely fashion was impacted during critical phases of the project as shown in the heat map below (i.e. Blueprint to October 2012 and from post go-live to February 2014).



In the course of our review, there are examples where both vendors and functional leads brought forward project risks, concerns and recommendations that do not appear to have been brought to the attention of the EC or BTC, for example: Vertex's training No-Go concerns and recommendation (March 1, 2013) and Inergi LP's Go/No-Go concerns and recommendations (April 10 and 29, 2013); as well as the Vertex May 9, 2013 incremental staffing recommendation. Updating the EC and BTC with the noted concerns and risks along with the planned mitigations and resolutions may have given the EC and BTC a better sense of the risks involved with this project, particularly with respect to the risks and concerns that were brought forward close to the go-live decision date. In turn the project team may have benefitted from the EC and Board's advice and counsel as to whether proposed mitigations and decisions were appropriate based on their collective experience.

4. Ineffective team complement

Successful project teams are inclusive of all key stakeholders and have an appropriate number of resources with the requisite skills and experience to perform their assigned duties; clearly defined roles and responsibilities; and, are empowered with the appropriate level of decision making authority.

Unlike the previous 3 phases of Cornerstone, the CIS project was led by a new set of Hydro One executives that had limited experience leading large, complex, transformational projects. Having a consistent leadership team with the relevant transformational project experience in charge for the entire duration of the project may have positively benefited the eventual outcome of the project.

The consolidated teams demonstrated tremendous commitment and effort to complete their designated tasks both pre and post go-live (e.g. level of overtime worked, completion of data entry backlogs created by the 21 day data conversion window within 48 hours post go-live etc.). The effort and dedication demonstrated by the members of the project team was critical to this project being delivered by the revised target date of May 21, 2013.

Hydro One experienced a number of resourcing challenges over the course of this project which greatly impacted its ability to deliver the expected scope and quality and to effectively deal with the operational and technical challenges experienced post go-live. Some of the resourcing challenges and root cause issues included:

- Meter-To-Cash knowledge gaps in the Discovery phase caused downstream project delays and budget overruns. By not including key Hydro One smart meter resources in the Discovery phase, requirements relating to meter-to-cash process were not robust, which drove an under-estimation of the project complexity, scope and timelines.

- Insufficient resourcing at times in the project lifecycle. More than 70+ incremental resources were added to the project during the Blueprint and Realization phases in order to address skill gaps and deliver the project with the desired scope within the revised 24 month timeframe. The project would have benefitted greatly from better up-front planning and having the right number of resources, with the right skills and knowledge on the project at the right time.

- Gaps existed in the area of SAP reporting. In order to deliver the full scope of planned operational reporting, incremental SAP Business Intelligence resources were added post go-live and ad hoc management reports were develped and pulled to provide key operational insights on a periodic basis. By December 2013, 102 of 106 planned operational reports had been delivered.

- The turnover of the HCL system architects, Project Managers and HCL leadership team adversely impacted the project as each new resource joining the project had to be brought up to speed and the project lost the benefit of resource continuity and familiarity with the project across the various phases.

- The defect volumes experienced post go-live were significantly higher than anticipated, which exceeded the capacity of the technical team to resolve the defects in a timely manner. As a result, key operational support staff were seconded back to the project to help resolve defects. This adversely impacted the stabilization of the Vertex operational teams. Inergi LP identified that they required specific technical skill augmentation in the areas of SAP device management, billing, FI-CA, SAP CRM, and complex billing (EDM/RTP) to deal with the volumes of these defect types.

- The functional organization of the project team structure built deep but siloed expertise and very few people had end-to-end knowledge of the new system and business processes. This impaired the ability of the team to quickly identify the root causes of issues and understand implications of proposed fixes and changes in the post go-live period. End-to-end expertise is now being built.

5. Ineffective vendor management

A key aspect of governance in the Hydro One outsourced operating model is to ensure that key project vendors are appropriately engaged and managed as part of both projects and operations. Services, accountabilities and quality standards must be clearly defined, appropriately contracted for and reviewed in order to be operating effectively.

While different contracting methodologies were utilized (e.g. fixed price, time and materials, etc.) when contracting services from HCL, Inergi LP and Vertex, all approaches had merit. There are, however, instances where Hydro One failed to clarify accountabilities (e.g. call scripting, hold vendors accountable to contractual obligations or leverage key contractual clauses) which would have been of benefit to the project. The most prominent examples are listed below.

In previous projects, Hydro One had used time and material (T&M) contracts with Inergi LP and Vertex with success. With the CIS project it became clear that initially Hydro One did not contract for a suffcient number of Vertex and Inergi LP resources with the required skills, knowledge and experience to support the system fully following system acceptance. This is evidenced by the increase in the growth of the defect backlogs post system sign-off from 473 as of October 2nd to 635 as of December 19th, 2013; the 20+ HCL resources that Inergi LP subcontracted post system sign-off to augment the Inergi LP sustainment team; and, Inergi LP's self-identified need for additional SAP training post go-live. Including enhanced terms and conditions regarding service and quality expectations related to skills and knowledge attributes associated with the new platform, such as stipulating that the SAP competency level required by each sustainment team role be demonstrated pre go-live, and clearly defining the standard to prove Inergi LP's ability to sustain the system post system acceptance signoff, may have been beneficial to this project and is not evident in the project orders or change requests made available for review.

- With respect to the fixed price HCL contract, Hydro One established system acceptance criteria with HCL. Evaluation of system acceptance was completed in September 2013 and indicated that HCL had not fully met the exit criteria. However, Hydro One signed-off on the acceptance of the system and released HCL, but did hold back final payment until the outstanding deficiencies were deemed to have been met. While financial holdbacks can be an effective mechanism to ensure accountability for agreed-upon deliverables, it would have been helpful had Hydro One had clear criteria with both the system integrator and the sustaining organizations to empirically determine whether the operation of the system has been smoothly transitioned.

- As part of the Business Transformation contract with Vertex, Hydro One had relaxed servicing standards and suspended some operational services such as all call-listening, thereby losing valuable operational insight into the issues that customers were reporting and the appropriateness of agent responses. This, coupled with the fact that not all of the operational reporting was in place immediately post go-live and that the Hydro One vendor management team did not have an onsite presence in the call centre, limited their insights into the extent of the customers issues and the aging of the backlogs.

Hydro One has since taken steps to remedy this situation and the vendor management team is now co-located within the Vertex operations area and has adopted a much more visible day-to-day oversight with the vendor management team. This is a management practice that has been adopted by many customer focused organizations that have outsourced their customer servicing operations in order to give them a more immediate line of sight into the servicing operations.

6. Gaps in testing disciplines

Due to delays in development during the Realization phase and yet still meet the May 21 go-live date, the testing phases between Systems Integration Testing (SIT), User Acceptance Testing (UAT) and Operational Readiness Testing (ORT) were allowed to overlap, which is a high-risk practice. While it is not unusual to see some level of SIT and UAT overlap in large scale projects with time constraints as experienced in this project, at least one clean round of SIT should be performed prior to proceeding to UAT and there should be no overlap between UAT and ORT from a leading practice perspective.

During the Blueprint phase, the Hydro One CIS project had approximately 2900 documented requirements, of which 519 related to out-of-the-box functionality. A joint decision was made by Hydro One and the HCL project team, to exclude the 519 out-of-the-box requirements from testing. While this may have been an appropriate decision for Hydro One at the time, industry leading practices recommend that all requirements should at least go through one full cycle of SIT to ensure these capabilities are performing, as required.

The original test plan included two full cycles of SIT testing followed by three cycles of UAT. It is our understanding that due to delays in development, the testing plan was modified and, as a result, four cycles of SIT were executed followed by one cycle of UAT testing. However, all of these cycles overlapped as identified defects were being remediated with code changes while the subsequent test phases were being executed. As previously noted this is a high risk practice and at least one clean round of SIT should have been completed prior to proceeding to UAT.

For UAT, there were a total of 271 planned test scenarios, covering 68 business processes, which were to be executed throughout the realization phase of the project. Due to delays in the development phase, and in order to meet the go-live date of May 2013, UAT scope was reduced to test only 29 critical test scenarios, covering 32 business processes. This accounted for approximately 10% of the planned scenarios and 50% of the business processes, which is a considerable reduction in the scope of testing while recognising that this management decision reflected a view that the original test plans needed to be "right sized". During ORT, it was planned that 101 exception types would be triggered; however, only 50 were received. Of the 50 that were received only 47 were attempted and of the 47 attempted, only 29 or 60% could be completed. Additionally, new exception types occurred that had not yet been identified in UAT. Due to time constraints and competing priorities, the project team was unable to assess and remediate the newly identified exceptions appropriately; therefore, further workarounds were created to deal with these exceptions. Based on this, new work instructions had to be created for the sustainment teams to help them understand and execute the new workarounds. With these activities occurring up to the night before go-live, there was not sufficient time to familiarize or train the sustainment team on the various exceptions, which negatively impacted productivity post go-live.

The volume of exceptions experienced in ORT was significantly higher than anticipated. To address this issue, a revised staffing strategy should have been mobilized immediately to bring in additional staff. Due to typical lag times associated with recruiting and training, this may not have prevented the exception backlogs from growing to 300% of baseline post go-live; however, it would have allowed the backlogs to be addressed faster and thereby prevented further issues from arising and customer issues from escalating.

During pre and post go-live, significant time pressures were experienced by the project team; resulting in relaxed disciplines and lack of appropriate documentation of changes. It was noted by HCL in the system acceptance sign-off summary that documentation was not complete and Inergi LP also noted documentation gaps in their Transition Readiness assessment completed in June/July 2013. Incomplete documentation of functional and

technical changes hindered Hydro One's ability to affect proper change control downstream, and negatively impacted knowledge transfer and the ability to troubleshoot and resolve defects on a timely basis. In October 2013, Hydro One contracted Inergi LP to update the documentation gaps and incurred additional costs that could have been avoided had documentation rigor been maintained throughout the project and post go-live.

7. Reactive customer response

Pre-existing customer service policies, such as the no-refund policy, impacted Hydro One's ability to appropriately deal with the post go-live billing issues and further served to exacerbate an already difficult situation. By late summer, new customer scripting and customer treatments to address some of the billing issues had been put in place to help the staff manage the various billing inquiries and customer complaints which helped to improve customer interactions.

Post go-live the top priority was to resolve customer billing issues and get bills sent out to customers in a timely manner. In the rush to put fixes in place, the customer impacts of those fixes were not always fully appreciated and lacked the required supporting customer treatments and communication strategies (e.g. the large bill shock for customers who had not been billed for several months). This lack of end-to-end customer-focused thinking helped exacerbate an already difficult situation.

In due course a new Customer Charter of Rights was established, customer servicing policies were modified, and enhanced customer communications were created.

Had Hydro One been more proactive and timely with these customer-focused changes it may not have experienced the level of customer frustration and negative media attention. A more customer focused cultural transformation will require ongoing support and investment to become fully institutionalized across the organization and within its outsourced service providers.

8. Lack of operational nimbleness

There are many definitions of nimble in the business world. For the context of this review, we define operational nimbleness as Hydro One's ability to quickly and effectively respond to changing demands while maintaining peak performance. Several factors impaired Hydro One's operational nimbleness, particularly in the hyper-care phase such as resourcing challenges, operational reporting gaps, ancillary operational system failures (e.g. Numero and MTCCA) and non-customer-centric customer servicing policies.

The fixed price nature of the HCL contract, incented HCL to roll-off staff post go-live as soon as possible. Had defect volumes remained stable post go-live, the plan for Inergi LP to pick up HCL duties over the four month hyper-care period should have been manageable. However, given that the defect backlog grew from 373 at go-live to 793 by July 16, 2013, losing 65% of the highly skilled HCL resources impacted the technical teams' ability to resolve defects quickly. Ultimately, Inergi LP ended up subcontracting 20+ HCL resources to augment the sustainment teams to help deal with the defect volumes and backlogs. Industry experience suggests that the project team, including HCL, should have been kept intact until such time as the billing system and associated processes were performing to the expected standard.

Hydro One proactively contracted Vertex to hire incremental staff to cover the anticipated training impacts and post go-live operational impacts of implementing the new CIS. This is an industry leading change management practice. The required lead time to execute this contract required Hydro One and Vertex to make volume and productivity assumptions prior to empirical project data being available in order to estimate the incremental staffing requirements. During operational readiness testing (ORT) which was conducted from April 16th, 2013 to May 9th, 2013 it became apparent that the volume of exceptions and handling times would far exceed the 20-25% assumptions in the BT plan and that the capacity levers available to them such as overtime and postponement of

vacations, would not be enough to cover staffing shortfalls. Had an incremental hiring plan been put into effect immediately following ORT as recommended by Vertex on May 9th, 2013, it would have helped Vertex and Hydro One deal with their exception volumes in a more timely manner.

Due to the ongoing discovery of issues and defects in UAT and ORT and the associated workarounds that were being implemented right up to the go-live date, the billing staff were not fully trained prior to go-live. This impacted their productivity and increased the number of user-driven errors which, in turn, adversely impacted the technical sustainment team's capacity to deliver.

Due to the time constraints experienced in the earlier phases of the project, reporting was de-scoped and only 44 of the 106 planned reports were available at go-live. Based on the reports made available for this report, there appears to have been sufficient volumetric data available; however key operational KPIs, such as aging of exception backlogs, no-bills, defects and customer complaints, do not appear to have been tracked and if available, were not reported. Not tracking key metrics such as aging of work volumes impaired the organization's ability to optimally manage the business from a customer centric perspective.

The loss of key workflow management tools post go-live, such as Vertex's proprietary workflow engine (Numero) and the new Meter-To-Cash Composite Application (MTCCA) CIS, which provide the ability to efficiently route work to the most appropriately skilled resources as well as provided "time to critical" service level reporting, impaired the operations team's ability to disseminate work in a timely manner and easily track service levels. Ad hoc SAP reports were eventually created several weeks following go-live to help provide these key operational insights but by then backlogs had grown substantially. This impacted the organizations overall productivity and responsiveness. The contingency plan for workflow tracking required manual tracking of work volumes via Excel spreadsheets. However, trying to manage a large number of exceptions over an extended period of months was not sustainable.

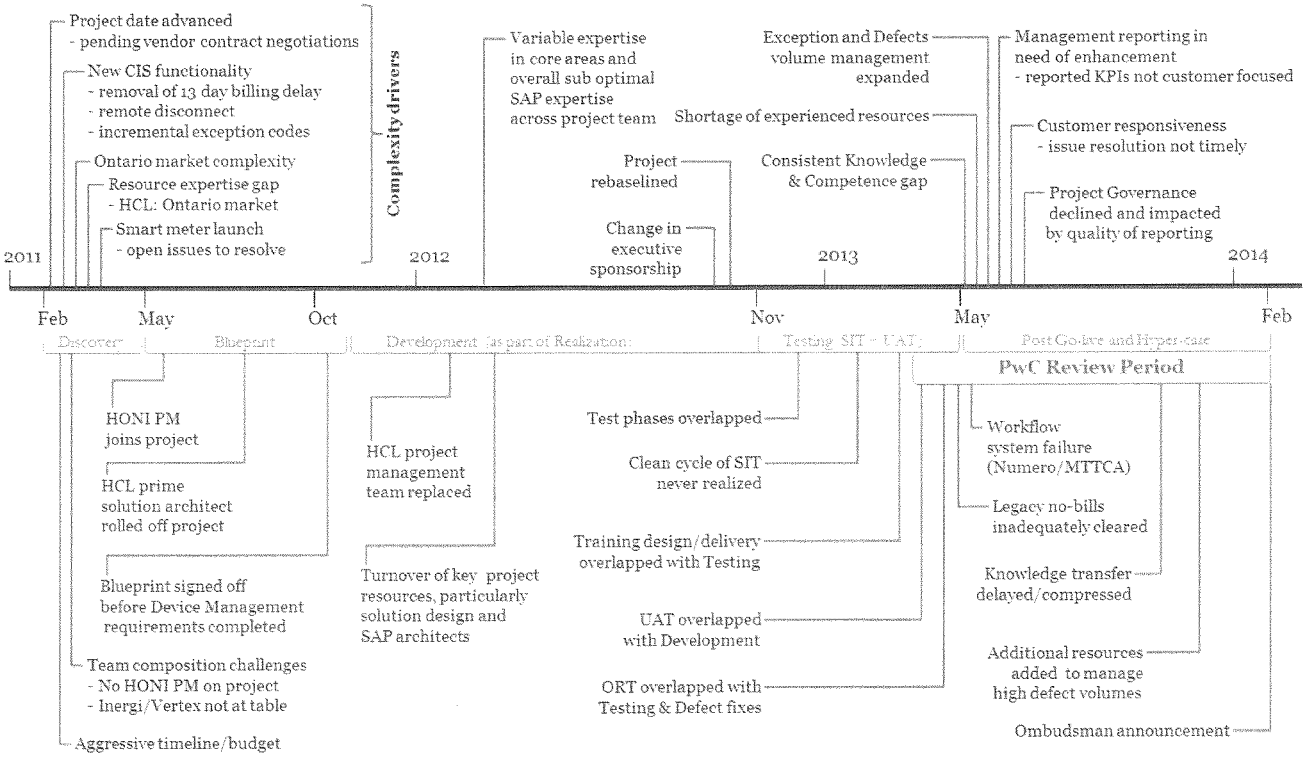
Hydro One adopted the industry leading practice of implementing a robust Post Go-Live Support (PGLS) plan that included functions such as forward command posts, triage teams, power users and operational floor walkers and a Change Control Board (CCB). The purpose of PGLS was to provide the project with executional nimbleness while maintaining sound operational and technical controls. Many aspects of this plan worked well in the early days following go-live; however, under the overwhelming volume of exceptions and defects the operational support processes broke down, as floor walkers and power users were seconded back to the project teams to help resolve defects, thereby eliminating a key frontline support system.

Project Go-Live Decision and Recoverability

Based on information available to the project and management teams prior to go-live, they had reasonable justification to believe that the CIS could be launched successfully. Additionally, they had:

- A plan in place to resolve the known outstanding go-live issues.
- Business and technical team contingency plans in place to deal with anticipated surplus volumes and productivity hits, although ultimately underestimated based on the actual impacts experienced.
- A robust post go-live support plan to help address and manage emerging issues and stabilize the system.

As pictorially represented below, the Hydro One CIS project faced many hurdles from its earliest phases, each of which contributed to the either the challenges experienced post go-live and/or impaired the organization's ability to remedy the issues and stabilize the operation. In the end, the level of exceptions generated post go-live due to production meter data issues and the system and user defects were much higher than anticipated, and the sheer growth of the exception and defect volumes overwhelmed both the operational and technical teams.



The following actions may have allowed Hydro One to more successfully deal with the challenges faced post go-live:

- Keep the entire project team, including HCL, in place to provide more manpower to deal with defects for a minimum of 3 billing cycles post go-live or until the system and billing processes were deemed stable.
- Leave the operational floor support staff in place to address training gaps and reduce user-driven errors.
- Align staffing levels in the contact centre and billing teams based on actual exception volumes and baseline service levels as soon as possible to help ensure that exceptions were resolved prior to the next billing cycle thereby averting the "snowball effect".
- Augment technical team resources, if required, faster to reduce defect volumes faster.
- Design and implement customer-focused treatments prior to go-live to deal with anticipated issues.
- Bring in SAP BI resources immediately to address operational reporting gaps in a timely manner.

Maintaining the October 2012 - May 2013 project governance structure and transparency of reporting post go-live until such time as the majority of defects and customer issues had been resolved; and, operating with an enhanced focus on end-to-end customer impacts and responsiveness would have significantly helped mitigate the issues that Hydro One experienced post go-live.

E. Lessons Learned

Using our PwC Framework for Project Delivery Excellence, which defines leading practices that can improve project outcomes, we have taken the findings from our analysis of the Hydro One Customer Information System (CIS) project and organized them into "lessons learned" that may be applied to future projects:

1. Clear scope definition

PwC Experience:

A comprehensive and robust understanding of existing systems, business processes and hard dependencies must be applied to appropriately assess project scope, requirements, approach, budget and timelines.

Summary Observation:

Hydro One's CIS project experienced issues with respect to scope definition, dependency mapping, project structure, team composition, and the implementation strategy and timelines. Prior to the implementation of Hydro One's new CIS, the Company's customer system was comprised of many complex legacy applications. Many of these applications had interdependencies which were not always documented or understood. This contributed to project risks and adverse outcomes in both the late stages of the project and in the post go-live phase of the CIS project.

Recommendation:

Establish a Discovery Phase for large-scale projects before confirming project scope and concluding contracts.

Maintain the current leading practice of undertaking a Project Discovery Phase prior to confirming project scope and concluding contracts. Ensure all vendor and Hydro One resources included in this phase have the requisite functional expertise and understanding of hard system dependencies in order to clearly define the full scope of project requirements.

Where appropriate, look for opportunities to phase-in changes to mitigate the risks associated with the implementation of large-scale projects.

Management's Response:

Agreed. Management acknowledges that the complexities associated with smart meter interfaces and commercial customer billing were under-estimated during the Discovery Phase of the project. This in turn, contributed to the decision to push the October 2012 "go-live date" to May 2013 and led to a compression and overlap of the testing phase of the project.

With respect to the recommendation to "phase-in changes", management notes that during the Discovery Phase of the project, it made the decision to go-live with the entire solution rather than stagger the solution given the risks and complexities associated with running two billing systems concurrently.

2. Decision enabling governance

PwC Experience:

Project governance should be defined, operationalized, monitored and adjusted in accordance with the project complexity, and executed diligently and rigorously.

Summary Observation:

The CIS Project had a sound project governance framework in place. This framework evolved and adapted over the course of the project. This review found that governance could have been improved, particularly in the areas of organizational structure and composition, transparency of reporting, communication and through consistent inclusion of key stakeholders.

Recommendation:

Engage a broad cross-section of executives, functions and stakeholders in decision making.

Establish a disciplined governance structure, consider independent project sponsors to support the Board and introduce a robust measurement and reporting process to:

- Enhance decision-making processes, ensure an appropriate cross-section of executives is included at both the Steering Committee and the Project Management Office levels throughout all phases of the project. This would involve including key support functions such as Risk and Internal Audit and representation from key functional stakeholder groups such as vendors.

- Establish robust project and post implementation Key Performance Indicators (KPIs) for operations that include sufficient secondary detail. This will in turn provide a full and accurate view and operational status of the project during every phase. Measurement should include leading and lagging indicators, volumetric and key customer satisfaction measures, as well as detailed explanations with respect to variance from targets.

- Maintain a project reporting format, during the post go-live phase, which incorporates technical and operational KPIs and tracks progress against the previous reporting period. Reporting should also capture planned activities and timelines, and operational risks and associated mitigations. This would ensure the Executive Committee and the Business Transformation Committee of the Board are appropriately informed and would allow the project to gain full benefit of their specific experience, advice and counsel.

- Maintain a robust level of governance oversight and transparency throughout all phases of the project, including the post go-live phase, until the project deliverable is deemed to be operating as required. Reconstitute the governance structure in a timely manner, should latent project issues emerge.

- Consider a qualified and experienced independent project advisor to supplement the project governance structure and to provide a direct line of communication to both the project sponsor and the Board.

Management's Response:

Agreed. As noted by PwC, a sound governance structure was established for the project and management accepts there is an opportunity to incorporate further improvements in its approach to project governance. Hydro One has already reviewed and modified aspects of its governance structure to enhance decision-making, improve transparency and ensure an appropriate cross-section of executives are engaged in decision-making. Further, Hydro One has modified its approach to establishing, monitoring, and reporting Key Performance Indicators (KPIs) that best measure customer service health.

3. Active quality management

PwC Experience:

Allow sufficient time to design and execute a robust testing plan. Ensure that there is empirical and quantitative evidence of end-to-end operational readiness in terms of technical, process and user readiness, incorporate independent quality assurance oversight, and ensure there is a sound quality acceptance strategy.

Summary Observation:

In order to meet the go-live date of May 21, 2013, testing timelines were compressed, critical testing phases overlapped and key exit criteria were relaxed. This was due in part, to delays experienced earlier in the project and as a result of the need to manage data from legacy systems. These issues cumulatively created risk for the post go-live phase of the project. It was observed that a significant number of issues were identified, fixed or mitigated prior to go-live. However, it was also noted that a number of operational impacts relative to plan assumptions were not sufficiently remediated nor were the cumulative impacts of system defect workarounds sufficiently tested. This ultimately caused front line staffing shortages when resourcing the mitigation effort.

Recommendation:

Ensure the testing phases and testing windows of projects are protected.

Testing is a critical function in a large scale IT project and one that is often compressed due to delays incurred earlier in the life-cycle of a project. In future, care should be taken to protect proposed testing windows.

If time constraints require the compression of testing phases, the following leading practices should be adhered to as a bare minimum:

- Complete at least one clean round of System Integration Testing (SIT).
- Do not overlap UAT (User Acceptance Testing) with SIT.
- Test all planned scenarios in ORT (Operational Readiness Testing).
- Establish empirical evidence to reflect that the frontline operations teams are able to execute all required processes and that all key staffing assumptions are validated.
- Consider developing a testing centre of excellence to enhance the maturity level of Hydro One existing capability.

Management's Response:

Agreed. Management recognizes that when implementing large-scale projects, it needs to strike the optimal balance between scope, quality, effort/cost, risk and adherence to project deadlines. Management accepts that late system development completion caused a compression and overlap of the test phases of the project and that operational readiness testing proved to be inadequate. Further, receiving organizations were not adequately prepared to manage day-to-day customer service and billing operations.

For this reason, since "go-live" of the new system, Hydro One has:

- increased resources to reduce the backlog of issues impacting customers;
- conducted additional training for people managing billing issues;
- made adaptive changes to the billing system to improve workflow and timely completion of billing exceptions; and
- improved customer commitment follow-through processes.

4. Managed risks and opportunities

PwC Experience:

Effective Risk Management is a critical discipline on large-scale projects. Ownership for the operational risks and mitigations should be established, considered cumulatively and form part of the project gating process.

Summary Observation:

Hydro One undertook several Risk Assessments and Internal Audits over the course of the project including two Business Readiness Assessment Tests (BRATs). These assessments and audits identified the majority of issues that ultimately arose over the course of the project. As a result, the opportunity existed to better quantify the impact of cumulative operational and customer risks and appropriateness of mitigation procedures, pre and post go-live.

More rigorous assessment of billing issue remedies and the involvement of Risk and Internal Audit functions during the hyper-care phase may have benefited the project. Further, Hydro One senior executives and the Business Transformation Committee of the Board relied primarily on the project groups and the Risk and Internal Audit functions to inform their decision making. The use of an independent third party risk assessor, accountable to the Board, would have provided additional objective insight into the project risks and appropriateness of planned risk mitigations across all key project gates.

Recommendation:

Continue the practice of formal project risk assessments and internal audits at key stages of projects.

Further improvements could be made as follows:

- Ensure Risk and Internal Audit play a more active role in the post go-live phase. This will ensure the appropriate assessment of risks associated with day-to-day decision-making. It will also mitigate reactive decision-making during this challenging period.
- Establish and maintain a disciplined approach to assessing and tracking operational impacts throughout the project. This will help ensure the resource (staffing) implications of decisions are more clearly understood and will support efforts to maintain adequate service levels post go-live.
- Improve BRAT (Business Readiness Assessment Test) by:
    - completing one BRAT following Operational Readiness Testing (ORT) to allow the BRAT team to validate and evaluate the quality of the ORT recommendations;
    - having the BRAT team conduct a detailed level of testing and auditing to validate the appropriateness of readiness and mitigations identified; and
    - ensuring that the BRAT team members are fully independent of the project.
- Use an independent third party risk assessor that is accountable to the Board to provide objective insight into the project risks and appropriateness of planned risk mitigations across all key project gates.

Management's Response:

Agreed. Management agrees that formal risk and audit assessments during key stages of large-scale projects are critical. In fact, the decision to replace customer systems in the final phase of the Cornerstone project was intended to reduce risk to customers and customer service as it would allow Hydro One to build experience with SAP in internal projects first.

As noted in the report, Hydro One undertook several internal audits and risk assessments during the project and acknowledges that Risk and Internal Audit can play a more active role in the post go-live phase of the project. To this end, the Customer Service Recovery effort has been assessed by Hydro One's Internal Audit organization and associated recommendations are being actioned. Further, the Hydro One's Internal Audit group has increased its staff complement with individuals who have the skills and knowledge necessary to support the Internal Audit's increased focus on operational audits. With respect to risk, future risk assessments are planned to assess the performance of the CIS sustainment organization.

With respect to the use of third party experts to assess ongoing quality and proficiency of operations, management will review with the Board, when a large-scale project is planned to determine if additional expertise is required.

5. Integrated suppliers

PwC Experience:

On large scale projects, appropriate vendor management is of critical importance. Services and accountabilities must be clearly defined, service and product quality standards specified and appropriately contracted for, and review and oversight needs to be in place.

Summary Observation:

While different contracting methodologies were utilized in contracting services from HCL, Inergi LP and Vertex, all approaches had merit. There are, however, instances where Hydro One failed to clarify vendor accountabilities (e.g. call centre agent scripting). Hydro One should hold vendors accountable to their contractual obligations and/or leverage key contractual clauses which would have been of benefit to the project.

Recommendation:

Improve vendor oversight and management and hold project vendors to account.

In any project where vendors are engaged:

- Continue to clearly define vendor accountabilities and improve vendor oversight to ensure their specific accountabilities are properly executed.
- Ensure vendor's project and day-to-day operational accountabilities are effectively transitioned and executed.
- Clearly specify service/product quality standards for vendors. For example, if a vendor is providing resource augmentation or assuming responsibility for operating new technology platforms, it is important to establish an agreed-upon level of system competency/ certification and determine method of compliance.
- Use appropriate contract mechanisms to support enforcement of delineated services, standards, and accountabilities. Ensure the Project Management Office and Executive sponsors are aware of these contractual clauses and that they excute clauses as needed.
- For critical clauses including system acceptance, ensure that criteria are fully met and that vendor(s) are held accountable until such time as the project is deemed to be stable and in "sustainment" mode.
- Ensure that comprehensive vendor quality and reference checks are conducted during the preparation phase of the project.

Management's Response:

Agreed. Management agrees that while project vendors had requisite skills, knowledge and experience and worked to well-established statements of work, there was an issue ensuring that key personnel were in place for the duration of the project. For this reason, measuring vendor proficiency at all stages of a project and beyond becomes a critical learning from the project. These learnings will influence Hydro One's approach to vendor oversight and management for future projects and the management will consistently hold vendors to account for the aspects of the project for which they have been engaged.

It should be noted that Hydro One's outsourced service provider has proven themselves to be proficient at managing other aspects of our enterprise information technology. They have also evolved their organization's ability to work in an increasingly complex technology environment. The outsource provider has enhanced its SAP CIS application management skills since go-live and they have played a key role in stabilizing the overall operation.

The original system integrator continues to work on warranty fixes and has also remained engaged in the recovery effort.

As outlined in this report, Hydro One has embedded its customer service managers within the call centre and continues to conduct daily formal checkpoints to assess vendor's customer interactions, escalations and call centre operational metrics. There is also ongoing quality monitoring of calls and coaching as required.

6. High performing teams

PwC Experience:

Successful project team structures are inclusive of all key stakeholders, have clearly defined roles and responsibilities, are empowered with the appropriate level of decision making authority, and have the appropriate number of resources with the requisite skills and experience to perform their assigned duties.

Summary Observation:

Incredible effort and commitment was demonstrated by the project and sustainment teams, pre and post go-live. However during the review period, several issues relating to team structure and turnover, resource capability, empowerment and role clarity existed on the CIS project. These issues became more evident as the project transitioned from project mode to the hyper-care phase.

Recommendation:

Ensure project leaders and team members possess the right skills and experience.

The dedication and commitment of the entire project team to deliver the CIS project on May 21, 2013 suggests the Hydro One has created a strong platform on which new projects can be built. In future, it will be important that projects are adequately resourced from Discovery to Sustainment and with people holding the requisite skills and knowledge.

Further improvements could be made as follows:

- Properly assess project leaders and staff to ensure they hold the requisite technical and domain experience to lead or to play key roles on large-scale projects.
- Ensure people are managed by individuals with the requisite experience to provide the level of support and guidance required to accelerate their learning curve.
- Align project governance accordingly.

Management's Response:

Agreed. Management appreciates and echoes report findings that commend both the project and sustainment teams for their "incredible effort and commitment." Management also notes that the appropriate skills, knowledge and experience existed within Hydro One and its project vendors and acknowledges that in some instances, these capabilities could have been better leveraged and integrated. Further, it is important that, to the extent possible, project leadership is consistent at all stages of a major project.

Better team integration could have prevented some of decisions that resulted in less than positive customer service in the post go-live period. This is a key learning for future large-scale projects and Hydro One has since taken steps to put the right people in strategic roles to leverage the capability of the new CIS and to continually drive service quality improvements.

7. Agile change control

PwC Experience:

Long term, complex projects will go through many changes over the life of the project. Discipline must be taken to appropriately track, manage and communicate changes to ensure traceability.

Summary Observation:

During the course of the project, robust and comprehensive tracking tools, controls and documentation were in place. However leading up to go-live and throughout the hyper-care phase, project pressures saw these disciplines relaxed and subsequently created downstream project risks.

Recommendation:

Maintain project tracking and documentation rigour always.

Throughout much of the project, good tracking tools, controls and documentation were in place. It is critical to maintain tracking and documentation rigour throughout the entire project, particularly during high pressure phases such as pre go-live and hyper-care phases. It is during these phases that there is a tendency to relax tracking, controls and documentation, thereby increasing the potential for downstream project risks.

With SAP projects that involve complex security configuration and design, appropriate segregation of duties should be maintained. Further, an individual's level of systems access should be granted based on the individual's role and responsibilities. This would serve to enhance and maintain system security and limit the operational risk associated with open access.

Management's Response:

Agreed. Management had implemented rigorous change control which we believe had mitigated the control weaknesses identified by PwC. Management does not believe this to be a root cause issue but we do agree that the adequate controls or compensating controls are an essential component of the design, development and build associated with any large-scale project. As noted, we believe that adequate mitigating controls existed during the project, and continue to exist, for granting and monitoring SAP user access.

8. Operational sustainment

PwC Experience:

The success of any project is determined by how well the various user groups, including frontline staff, technology and support staff are trained; how effectively key stakeholders, including customers, are kept informed of changes that will impact them; and, how effectively key performance measures are monitored and managed.

Summary Observation:

Training and knowledge transfer plans, Vertex Business Transformation (BT) plan and the Post Go-Live Support (PGLS) plans were developed in detail. However, compressed timelines leading up to go-live, exception and defect volumes and insufficient reporting, and monitoring of Key Performance Indicators (KPIs) post go-live, adversely impacted the execution of those plans.

Customer impacts associated with changes to billing practices were given due consideration and the associated communications activities were well thought out and executed in the pre go-live phase. However the timeliness of on-going communications and the lack of appropriate customer focus and responsiveness in the post go-live phases had a negative impact on customer satisfaction.

Recommendation:

Ensure the right number of people with the right expertise and experience are put in place until the system is fully stable.

Continue with the Project Go Live Support plans to address emerging project issues. Continue the practice of hiring incremental operational staff to reverse dips in performance resulting from project changes and in order to maintain service levels and standards.

Opportunities to improve operational nimbleness post go-live include:

- Reconciling staffing plans based on the results of Operational Readiness Testing findings (ORT). This will ensure appropriate numbers of staff are in place to manage anticipated volumes plus the volumes associated with new business processes and workarounds.
- Maintaining service standards throughout the change period in order to maximize operational flex in the event that impact assumptions were understated.
- Establishing robust staffing contingencies for both operational and technology teams in the event workloads exceed plan.
- Gathering empirical evidence prior to cut-over that both operational and technical sustainment teams are appropriately trained and can execute all of the duties expected of them post go-live.
- Ensuring that key customer and business-focused operational KPI reporting and secondary diagnostic reports are available post go live and shared with all levels of the governance structure. Reporting should include variance to baseline, longitudinal trending and plans, status reporting and risk and mitigation to provide management a clear line of sight to the health of the operation post go-live.
- Having reporting resources available post go-live to address ad-hoc management reporting needs.
- Maintaining project team in place for a minimum of 2-3 billing cycles to allow rapid stabilization of the system.

- Ensuring contract mechanisms are in place between Hydro One and key vendors so that project teams can be augmented if the move to sustainment is delayed.
- Continuing to build the Customer Service Operations and the outsource provider customer culture.
- Establishing/Retooling policies to allow more nimble and appropriate response to emerging customer issues.

Management's Response:

Agreed. Management acknowledges that operational readiness could have been improved, particularly in the post go-live phase of the project. Support organizations were overwhelmed with system outputs and the time expended to resolve billing exceptions was inadequate. This led to compounding billing problems and bills not being released for multiple billing cycles. The gravity of the issues were not fully understood by the project post go-live or properly communicated in making their way to the Senior Executive team and thus not to the Board of Directors.

In response to these issues, there have been a number of personnel changes and day-to-day management has been improved as outlined above and as a result, customer issues have been reduced, as per the following:

- No Bill Volumes have been reduced by 90% from when compared to volumes experienced following the cutover to the new system.
- The number of backlogged exceptions generated by the new system has been reduced by 90% from peak.
- Frequency of Unscheduled Estimated Bills has been cut in half.
- Call Center Performance improved throughout 2014 as it relates to accessibility and quality: weekly Call Centre customer satisfaction has hovered in the 85% range and twice has exceeded 90%.

In addition, Hydro One is establishing a new customer service governance model and continuously monitoring new service metrics so that we have a clear and ongoing line of sight to the performance of the new system and to the levels of service we are providing to our customers.

This is Exhibit "T" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Lisa Lutwak

Commissioner for Taking Affidavits (or as may be)

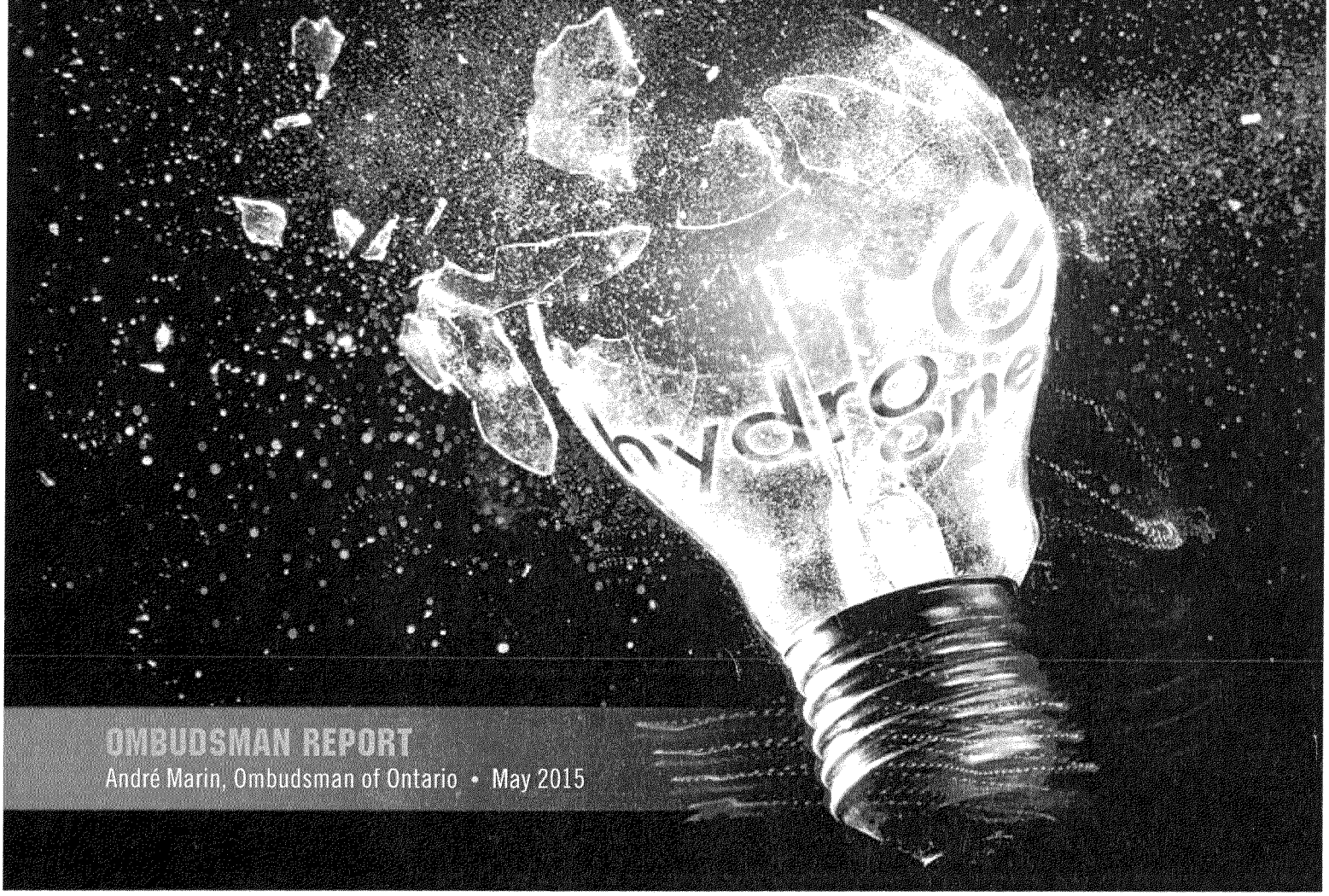
LISA S. LUTWAK

Ombudsman
ONTARIO

ONTARIO'S WATCHDOG

IN THE DARK

Investigation into the transparency of Hydro One's billing practices and the timeliness and effectiveness of its process for responding to customer concerns

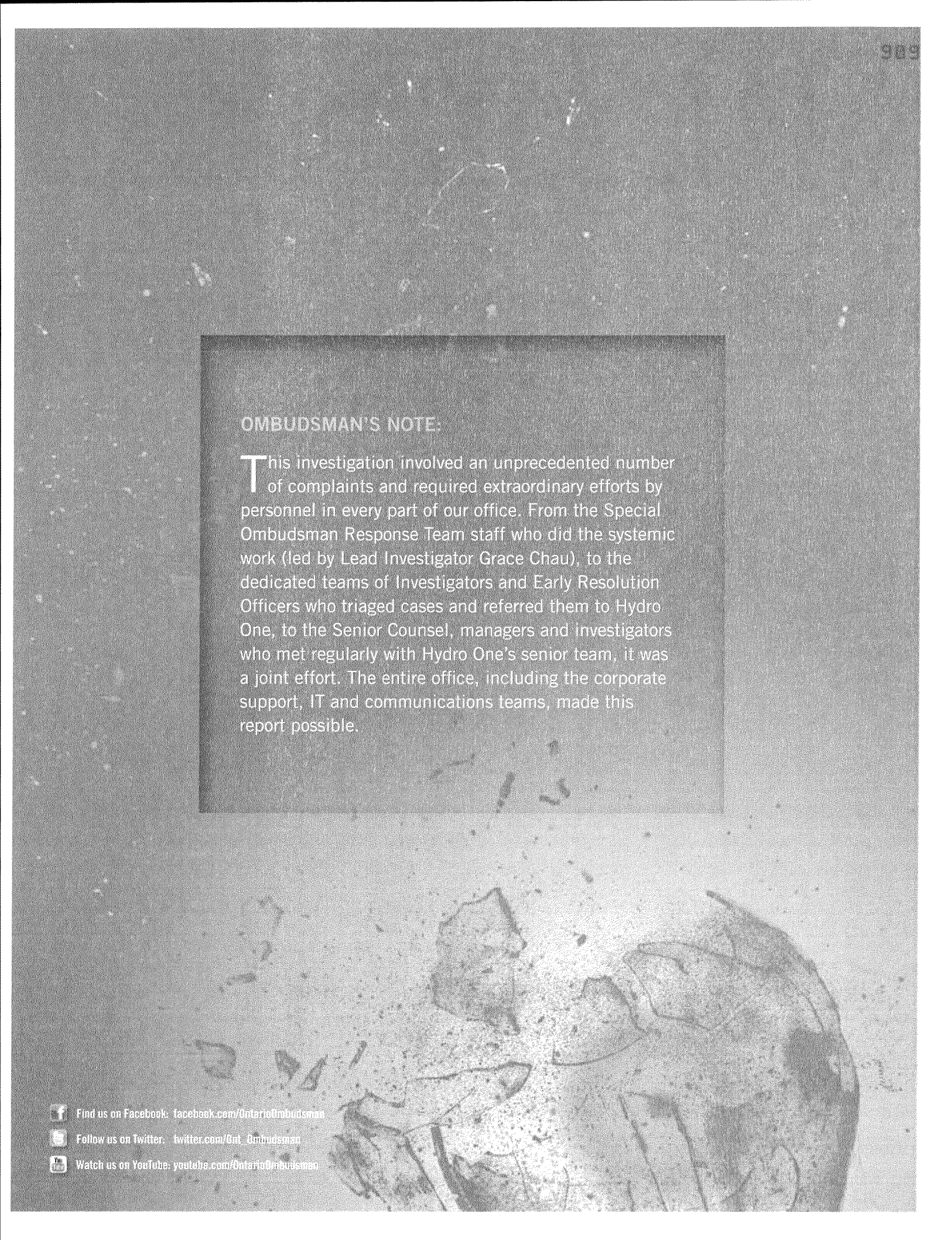


OMBUDSMAN REPORT

André Marin, Ombudsman of Ontario • May 2015

OMBUDSMAN'S NOTE:

This investigation involved an unprecedented number of complaints and required extraordinary efforts by personnel in every part of our office. From the Special Ombudsman Response Team staff who did the systemic work (led by Lead Investigator Grace Chau), to the dedicated teams of Investigators and Early Resolution Officers who triaged cases and referred them to Hydro One, to the Senior Counsel, managers and investigators who met regularly with Hydro One's senior team, it was a joint effort. The entire office, including the corporate support, IT and communications teams, made this report possible.



Ombudsman

Ombudsman Report

Investigation into the transparency of Hydro One's billing practices and the timeliness and effectiveness of its process for responding to customer concerns

"In the Dark"

May 2015

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Executive Summary

1 Large public sector corporations carrying on monopolistic commercial enterprises can sometimes forget the citizens they were created to serve. Hydro One, which distributes electricity to 1.3 million Ontario consumers, made a critical mistake when installing a new billing and account management system in May 2013. In planning for and implementing its "customer information system" to meet its business goals, Hydro One lost sight of its public interest purpose and failed to adequately consider the impact on its customers. Its overconfidence in its technical superiority fostered complacency. When glitches arose with the new system, Hydro One's first response was to scramble for technical fixes. It forgot to consider the consequences to its customers.

2 Soon after the system changeover, more than 89,000 customers stopped receiving bills. Some were not billed under the new system for months, while others only received bills based on estimates for prolonged periods. Then, as technical glitches were being addressed, the system issued a flurry of multiple invoices and huge "catch-up" bills, leaving customers frustrated and confused. Many had large sums withdrawn automatically from their bank accounts without notice or explanation. Tens of thousands of accounts were affected by bizarre errors, as Hydro One worked frantically to clear unexpected system problems. Hydro One's outsourced call centre and its in-house customer relations centre were left to cope with the ensuing flood of calls and complaints without proper training or adequate tools and resources. Workload pressures contributed to rude, insensitive, and substandard customer service.

3 Hydro One's board of directors and executive managers claimed they were caught off guard and oblivious to the developing crisis. They blamed lower-level managers for presenting them with overly optimistic reports. Some Hydro One representatives deliberately kept the situation under wraps, deflecting media inquiries and even deceiving the electricity regulator, my Office and other stakeholders about the extent and nature of the company's billing and customer service disaster.

4 Hydro One tried to contain reputational damage by dealing quietly and reactively with issues as they arose. Whenever bad publicity surfaced in the press, Hydro One adopted a dismissive and minimizing approach, claiming that only a small percentage of its customers were affected by the billing problems. Its statistics and descriptions of the issues were nebulous and shifted over time, however, it ultimately confirmed that in February 2014, **84,394** customers were

either receiving multiple estimated bills or had not received a bill for more than 90 days. When one adds the thousands who experienced hardship as a result of other system errors and billing inaccuracies since May 2013, the tally of those affected by Hydro One's bungling is likely well over 100,000.

5 Until February 2014, when I launched my investigation and Hydro One's cover was effectively blown, the company feverishly tried to spin positive news stories. Since then, it has faced a crisis of confidence that has rocked it to its public sector core and damaged its financial bottom line. Hydro One has paid a hefty price trying to make things right, spending more than $88 million to dig its way out of controversy and restore public trust.

6 My Office received an unprecedented number of complaints in connection with this investigation – **10,565** as of the writing of this report, and counting. While the volume has dropped markedly over the last year, we continue to hear from about a dozen people a day who remain concerned about Hydro One's billing and customer service.

7 The source of Hydro One's mind-boggling maladministration does not lie in defective data and software programming. Rather, its fatal fault is a technocratic and inward-facing organizational culture that is completely out of step with public sector values. Even after Hydro One pledged to become more customer-centric, to do better, and to learn from its mistakes, it continued to display insensitivity and disregard for its customers. As late as February 2015, during the coldest month in Ontario's recorded history, the company lied to and bullied customers with the threat of disconnection.

8 Hydro One's ordeal has underscored an expensive lesson in public administration: Its customers must be considered in every aspect of its operations. Although the Chief Executive Officer and President has offered a public *mea culpa* and several changes have been made to improve customer service, much remains to be done to bring the company up to the standard Ontario's citizens deserve.

9 The Ontario government has recently announced plans to significantly restructure Hydro One, including disposing of 60% of the utility, while retaining a 40% ownership interest. It has also proposed to appoint an in-house ombudsman to address customer complaints about the new privatized utility. My investigation demonstrates that Hydro One has historically not lived up to the principles of good public administration expected of Ontario's public bodies. During the recent billing and customer service fiasco, its customer service was abysmal by any standard. A corporate ombudsman's loyalty is ultimately to the employer it serves and is no substitute for independent investigative oversight.

In introducing structural changes to Hydro One's operations, the government of Ontario should ensure that the public interest in fair, timely and effective customer service is preserved, including the right of recourse to my Office.

10 I make **66** recommendations in this report, 65 addressed at reorienting Hydro One's corporate persona and improving its operational practices to better serve the public interest, reflecting the public sector values of openness, transparency and accountability. Hydro One has accepted all of these recommendations. Recommendation 66 is aimed at ensuring that implementation of my recommendations continues as the Government of Ontario moves forward with the proposed restructuring of Hydro One. Regrettably, in responding to this recommendation, the Ministry of Energy has confirmed that the government's privatization plans include abandoning independent and external oversight through my Office.

11 I will monitor Hydro One's progress in fulfilling its commitments. I will also continue to encourage the government to retain existing accountability mechanisms, including Ombudsman oversight of Hydro One and any successor corporation. My report clearly documents Hydro One's failure to communicate openly, honestly and proactively with its customers, its regulator, Ministry officials and my Office. I am concerned that unless accountability is assured through independent and impartial scrutiny, stakeholders may once again find themselves in the dark.

Investigative Process

12 My Office first noticed a rising trend in Hydro One complaints in 2012-2013, when we received 328, up from 232 the previous year.[1] In 2013-2014, that number more than doubled, reaching **647** by early February 2014. Most complaints focused on bills that were wrong, excessive, duplicated, unreasonably delayed or estimated based on unclear criteria. Our attempts to resolve customer concerns were also increasingly met by stonewalling by Hydro One officials, a frustrating experience I likened to "wrestling with a slippery pig."[2] We were particularly concerned about people who found themselves in vulnerable situations and facing significant financial hardship and stress because of their dealings with Hydro One.

[1] Ombudsman Ontario, Annual Report 2012-2013, p. 29. Online: https://ombudsman.on.ca/Resources/Reports/2012-2013-Annual-Report.aspx#Ministry_of_Energy
[2] http://news.nationalpost.com/news/canada/like-wrestling-with-a-slippery-pig-ontario-ombudsman-to-investigate-hydro-one-after-increasing-complaints

13 Common complaints involved large "catch-up" bills issued to customers who had received estimated bills or no bills for long periods, and who were given little time to pay or explanation for the amounts billed. Many also cited long waits, for what turned out to be inadequate information from Hydro One's customer service operations.

14 Given the rising complaint volume and our own experience with Hydro One's delayed and reticent response to our inquiries, on February 4, 2014, I announced a systemic investigation into complaints about serious problems with billing and customer service at Hydro One. I stated that the investigation would focus on the transparency of the utility's billing practices and the timeliness and effectiveness of its process for responding to customer concerns.

15 The investigation was assigned to the Special Ombudsman Response Team (SORT). A team of seven investigators carried out the investigation under the direction of SORT's director and with the assistance of senior counsel.

16 My Office received more complaints about Hydro One than we have about any single organization in our 40-year history. In addition to the original **647** complaints, nearly 10,000 poured in after the investigation was announced. To deal with this unprecedented volume, my Office took a two-pronged approach: While SORT pursued the broad systemic issues, a team of 12 early resolution officers and investigators triaged Hydro One complaints, and referred complainants elsewhere if their issues were outside the scope of our authority. Another 12-member dedicated team resolved individual cases with a 10-member team that Hydro One created in February 2014 as a special "SWAT" team to deal with cases from my Office. Not all complaints to our Office required referral to or follow-up by Hydro One. However, since April 2013, **4,142** complaints have been resolved through our intervention and Hydro One's efforts. My Office's director of investigations and senior counsel also met regularly with senior Hydro One officials throughout the investigation.

17 I met with the Chief Executive Officer and President of Hydro One several times and addressed systemic themes that we identified. I also took a turn on the phone lines alongside my staff to hear complainants' concerns firsthand.

18 SORT conducted **190** interviews, including with current and past Hydro One executives, outsourced agencies that perform work on behalf of Hydro One, complainants and stakeholders.

19 Our attempts to identify and interview relevant Hydro One staff were complicated by a significant degree of transition within the company's management. During the first month of the investigation, two customer service

executives left the company; one retired, the other was terminated. The same month another key official departed to join another company. At least six other executives shifted positions as the investigation proceeded, and leadership at the outsourced call centre changed.

20 SORT investigators requested briefing sessions with Hydro One at the beginning of the investigation to get an overview of its billing system and some of the technical issues relating to billing. Investigators also met with representatives from other agencies, including the Ontario Energy Board and the Independent Electricity System Operator.

21 As well, some 25 industry insiders and whistleblowers, including current and former Hydro One staff and staff from its outsourced service providers, contacted us to express concerns about billing and customer service issues. They provided us with helpful insights into the culture of the company.

22 Site visits and interviews with staff were conducted at Hydro One's two outsourced call centres, in Markham and London, Ont. At both locations, our investigators had an opportunity to monitor call centre agents as they handled customer calls.

23 SORT made two formal requests and several additional requests for documents when it became clear some relevant information was omitted. The bulk of the documentation reviewed was in electronic format – on 10 USB keys, equivalent to more than **23,000** pages of printed material. In addition, in response to our request for the electronic communications of 12 Hydro One staff, we received a hard drive containing **151,471** emails.

24 In addition to complaints about Hydro One billing and customer service, we received many complaints about subjects that were not the focus of this investigation – chiefly, electricity pricing and smart meters. The Ontario Energy Board approves the rates that utilities can charge customers for electricity. As for the smart metering initiative, at the time my investigation was launched, it was already under scrutiny by the Auditor General of Ontario. Her findings were reported on December 9, 2014, in her annual report, in which she also identified concerns with billing problems at Hydro One. Included among her recommendations were calls for improved tracking of inquiries and complaints, better education of ratepayers and fixing problems with the billing system.[3]

[3] This section of the Auditor General's report can be found here: http://www.auditor.on.ca/en/reports_en/en14/311en14.pdf

25 SORT also reached out to other utilities to learn about best practices in Canadian and international jurisdictions. Ontario is the only province that mandates time-of-use pricing for electricity and one of a few Canadian jurisdictions to use smart meters to collect time-of-use information.

26 Given the unprecedented volume of complaints, and strong interest from complainants, Hydro One customers and public officials, I issued a brief public update on my investigation on March 11, 2015.[4]

Hydro One: The Power that Be

27 Hydro One Inc., the largest electricity transmission and distribution company in Ontario, is wholly owned by the provincial government, which appoints its board of directors. It operates in association with five subsidiaries[5] and has $22.6 billion in total assets. Hydro One generates significant public profits. In 2013, Hydro One's net income was **$803 million**, which resulted in a **$218-million** dividend payment to the province.

28 The company provides direct service to 21 remote communities and some 1.3 million rural and urban distribution customers. It issues about 1 million bills a month. Since 2002, Hydro One has outsourced customer call handling, billing, credit and collections to a private operator. Initially, Hydro One retained Inergi LP to run its call centres. That company in turn subcontracted this responsibility to Vertex Customer Management (Canada) Ltd. As of March 1, 2015, Inergi LP is directly responsible for these outsourced services under a new three-year agreement.

System Refresh

29 In 2011, as part of a four-phase, multi-year project to refresh its information technology systems, Hydro One allocated $180 million to replace its customer information system. The existing system was operating on an old platform installed in 1998, which was no longer supported by the vendor. Hydro One predicted that the new system would improve customer service and yield up to $172 million in financial benefits over a seven-year period. The initial target

[4] The update can be found online here: https://ombudsman.on.ca/Newsroom/Press-Release/2015/Ombudsman-receives-10,000--complaints-about-Hydro-.aspx

[5] The five subsidiaries are: Hydro One Networks Inc. (which had primary accountability for the issues I investigated), Hydro One Remote Communities Inc., Hydro One Telecom Inc., Hydro One Brampton Networks Inc., and Norfolk Power Distribution Inc.

date for the new system to be implemented – or "go live," in the company's parlance – was over the October 2012 Thanksgiving long weekend.

30 The company had successfully replaced other internal information systems as part of the project, but the last phase was the first to have, in Hydro One's phrase, "a direct customer-facing impact." The customer information system is used for many customer service functions, including billing and account management. It is also an important resource for call centre staff, who handle about 1.5 million customer calls and 280,000 items of correspondence each year.

31 Hydro One estimated that the new system would increase the number of calls resolved on the first contact with the call centre by 5%, while decreasing the average call handling time by 20 seconds, and the average correspondence handling time by 16 seconds.

32 It was understood that with any system change, customer complaints would likely increase in the short term. Hydro One predicted that for routine matters, call volume and average handling time would increase by about 20% in the first month, but would normalize by the five-month mark. It also projected a 25% increase in the average handling time and volume for more complicated calls in the first month, but expected these to normalize within 10 months.

33 Our investigation revealed that Hydro One's forecasts fell glaringly short of the mark. For starters, the implementation date was delayed by seven months. The new customer information system did not "go live" until the May 21, 2013 Victoria Day long weekend.

34 Still, the company cautiously celebrated the success of the new system. In an internal newsletter on the day of the launch, it declared "We did it!" and said: "There was much to celebrate this Victoria Day weekend

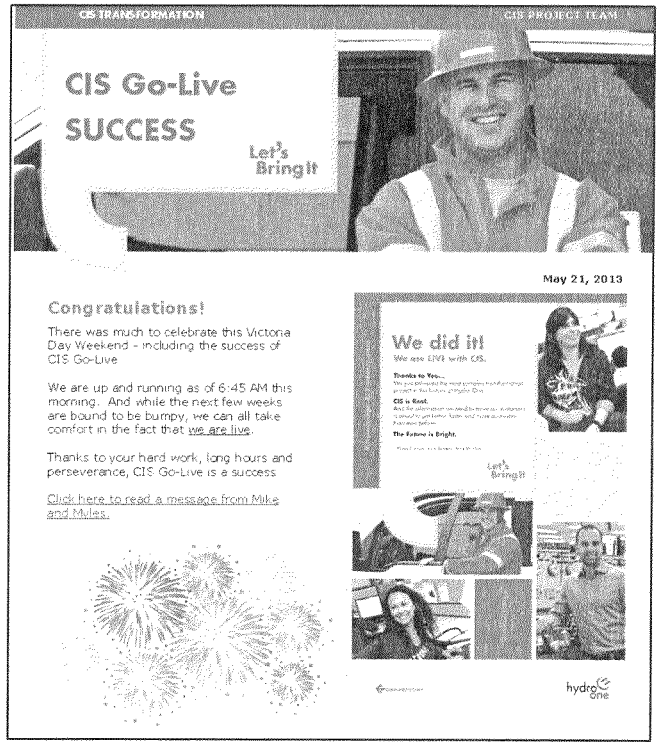


Figure 1: Hydro One internal newsletter, May 21, 2013.

– including the success of [customer information system] Go-Live!" The newsletter noted that "while the next few weeks are bound to be bumpy, we can all take comfort in the fact that we are live."

35 According to internal emails we reviewed, technical glitches began to surface soon after the system went live, but officials were confident they could be resolved. Seasoned Hydro One staff also considered the situation mild in comparison to the installation of the previous system in 1998, which had triggered 200,000 delayed bills. As one put it in an internal audit report, "there was a collective relief that the problems were seemingly less than might have been expected. This might have led to a sense of complacency."

36 Internal emails circa June 2013 refer to daily crises, but also improvements. There was a sense that the worst was over – one even noted there were no "major news stories" and "no *Toronto Star*-worthy issues so far." By September 2013, Hydro One's organizational spirits were buoyed when it won, for the second time, an award from the company that designed its information system. It was praised for helping to ensure "customer care operations remain top in the industry, including reliable call center interactions and increased accuracy and timeliness in their billing process."[6]

37 Unfortunately, these good omens proved to be the calm before the storm. Within a matter of months, it became clear that Hydro One's predictions about the impact of the system change on the call centre were drastically wrong. Problems associated with the changeover soon led to an unprecedented outpouring of customer confusion, frustration, and outrage, resulting in a dramatic increase in complaint volumes and average handling times. As one call centre manager told us, the original projected targets "were blown out of the water."

38 By February 2014, when I launched my investigation, Hydro One could no longer ignore the fact that it was facing major systemic problems and widespread public distrust.

Egregious Errors and Baffling Bills

39 Hydro One installed the new customer information system to address historical issues relating to its billing and account management programs. However, the

[6] In 2012, Hydro One received a "Top Innovator in Technology" award for demonstrating "commitment to meeting customer needs while working toward building the grid of the future by completing projects that span the complete value chain of its business."

vast majority of complaints to my Office involve billing issues – customers who received incorrect bills, multiple bills, prolonged estimated bills, large "catch-up bills," or no bills at all. We also received complaints about a host of other issues such as improper automated bank withdrawals, disconnection notices and poor customer service.

40 Some customers eventually resolved their concerns and even received some goodwill credits equal to monthly service charges, but usually this took sustained effort on their part. Many told us they made multiple calls to Hydro One's call centre and repeatedly had their complaints escalated to managers – only to receive confusing, conflicted, delayed and inadequate responses.

41 What follows are some examples from among the thousands of stories we heard during our investigation. Where possible, we have included customers' names with their consent, but many of those who complained to us preferred to remain anonymous for a variety of reasons, including fear of repercussions.

42 A senior from **Timmins** first realized there was something wrong when Hydro One stopped withdrawing automatic payments from his bank account in May 2013. Then in September 2013, his bank called to say Hydro One was trying to grab more than **$10,000** from his account. He managed to stop the payment, which Hydro One acknowledged was excessive, but was told it could take a year to resolve. Then without warning, Hydro One withdrew even more money from his bank account – including a charge for late payment. Hydro One eventually returned the money, but not before this beleaguered customer ended up on the hook for overdraft charges. The situation wasn't resolved until January 2014, when his bill was reduced to **$778**. He was relieved the matter was settled, but upset that he was offered no apology or clear explanation about what had happened.

43 An **Inglewood** man sold his property in April 2013, but spent months waiting for his final bill, which he figured was under $100. He was gobsmacked when he received a letter from a collections company in October 2013, saying he owed **$18,000**. He contacted Hydro One's call centre and even managed to get through to a senior executive. In November 2013, Hydro One assured him that it was all a big mistake. Then in August 2014, a different collections company began to hound him for the money. When we intervened, we learned there was a problem during the migration of data to the new customer information system, accounting for the high usage charges. In fact, he only owed **$56.35**. He was bewildered by the customer service nightmare he experienced, and the cavalier attitude he encountered when he tried to correct it. He described Hydro One's customer service as "trained deflection and not really taking on the issue at hand with any genuine effort." As he put it:

> It's all rehearsed, it's all scripted… It's not the right way to do business for anyone, let alone a provincial utility.

44 Despite multiple calls to Hydro One, a **Huntsville** woman was getting nowhere in her efforts to find out why she received no hydro bills for nine months after April 2013 – only to receive a bill containing an excessive estimate of **$1,800**. She complained and received another estimated bill for **$700** less, but with no explanation. She continued to demand answers and finally learned in 2014 that because of workload backlogs, Hydro One's system had not been updated to reflect that her meter was changed in February 2013. What followed was a series of implausible meter readings that caused the system to block her bills until they could be reviewed and readjusted. Once the situation was straightened out, Hydro One credited her with nine months of service charges and put her on an interest-free repayment plan for the balance owing.

45 A **Kilworthy** man contacted Hydro One's call centre after not receiving a bill for a year. He was told he owed **$3,600**. When he disputed the amount, the call centre agent blamed him for providing the wrong address, told him he owed late fees, and placed his account on the list for disconnection. He later learned his address had not been properly transferred to the new system. Eventually, Hydro One issued an apology, gave him 12 months' worth of service credits, and cancelled the disconnection notice.

46 In the fall of 2013, an 84-year-old **King Township** woman stopped receiving electricity bills, which had averaged $200 a month. Then, inexplicably, she received three bills in the same month, covering the same time period, for **$9,000** each. Distraught, she contacted Hydro One's call centre, which assured her the situation would be resolved. In February 2014, Hydro One sent her a more reasonable bill for **$640** and offered an apology, but she was never told why she had been charged so much in one month. Hydro One told my Office the mixup was due to human error, and it provided her with five months' worth of service charge credits.

47 A **Sudbury** man received a bill for **$19,152** in April 2014 after a long period of estimated bills. We learned that his meter was replaced in November 2013, but it took four months to update the system. When the actual readings from his meter arrived, the system then mistakenly charged him many multiples of what he owed. Once the error was corrected, his bill was reduced to **$74**.

48 After a prolonged period of estimated bills, a **Bolton** man received no bills from June to September 2013. Then, starting in October, he received a series of confusing ones, some based on estimates and some based on actual meter

readings, with cancelled and corrected bills thrown in for good measure. After he complained to Hydro One, it sent him a new set of bills for a three-year period, with a balance owing of **$73,385**. Horrified, he disputed this and Hydro One reduced the amount by $8,489, but still could not explain why he still owed so much. After we intervened, Hydro One recalculated the charges, found that the final balance was actually **$34,476.29**, and offered him a three-year payment plan to pay it off.

49 In July 2013, **Madeleine Fex-Tinkis**, a senior from **Lively**, received a call from Hydro One, warning her to expect a large bill. However, she did not receive any bills until October 2013, when multiple bills totaling **$2,208** arrived, along with a warning that the money would be withdrawn from her bank in two weeks' time. She desperately tried calling Hydro One to set up a repayment plan. When she didn't hear back, she was forced to go into her line of credit to prepare for the withdrawal. Then in January 2014, she received a set of 15 bills, based on actual meter readings, covering the same billing period and indicating that she owed an additional $540. It was only when we contacted Hydro One that it provided an explanation for its calculations. In the end, Hydro One issued her a service charge refund of $310.05 and set up a repayment plan for the balance. Not surprisingly, the unhappy customer removed herself from Hydro One's pre-authorized payment plan.

50 A **Matheson** man who received no bills over the summer of 2013 was hit with six estimated bills in October that year. He called Hydro One and was assured the company would look into it, but no one did. In February 2014, without notice, it withdrew **$1,959** from his bank account. When we asked Hydro One what happened, it reviewed its records and discovered he had overpaid on his billing plan. It refunded the money it had withdrawn, and gave him a service charge credit of **$144.**

51 **William and Lise Burley** of **Porcupine** contacted us in shock after receiving a bill for **$11,638** in February 2014. They had been paying for electricity based on estimated usage for four years and were baffled by this huge bill. After we intervened, Hydro One eventually reduced their charges to **$2,238**.

52 **Shannon Lebrun** changed residences in July 2013, not long after the new customer information system was implemented. She received no bills for over a year, and then came home in November 2014 to find her electricity cut off. She had to rent a generator and, to add insult to injury, Hydro One charged her $155 in interest and $147 for disconnection and reconnection fees. She discovered that Hydro One had been mailing bills and disconnection notices to her old address and calling her old phone number. The call centre blamed her for not inquiring about the missing bills sooner. When my Office intervened, Hydro

One acknowledged the call centre's failure to update the system with Ms. Lebrun's new contact information. She received an apology and a 14-month service credit of **$233** on her account. The fees associated with the disconnection were also reversed.

53 A **Schumacher** man was dumbstruck in June 2014 when he received a package of bills totalling **$45,000**, covering a three-year period – some of which he had already paid for. He contacted Hydro One in a panic and was referred to a manager, whom he found arrogant and uninformed. In desperation, he wrote to anyone he could think of who could help, including my Office. He described how he was "left feeling anxious, without a voice, frustrated and bullied." Eventually, Hydro One contacted him. He was astounded to learn that because of a mixed meter issue, he was being billed for electricity used by a nearby gold mine. By August 2014, his charges were reduced to **$9,723.04**, he was given a 34-month service credit and enrolled in a repayment plan. Then, just as things had settled, he received two more bills within days of each other, for **$15,000** and **$12,000**. Hydro One assured him he could disregard them, but he told us he found "the whole experience was nothing short of abuse."

54 After receiving no bills between July 2013 and March 2014, a **Waterloo** man coping with terminal cancer was stunned to find that he owed Hydro One more than **$10,000**. The company agreed to provide him with a discount, but began threatening him with disconnection at the same time. After we intervened, the disconnection notices were cancelled. At the time this report was written, Hydro One was still reviewing his account.

Who Are You Going to Call? Customer Complaints

55 When customers write or call Hydro One's 1-888 number about billing and service inquiries they are connected to the outsourced customer communications centre for response. This centre – referred to throughout this report as the "call centre" receives about 6,000 calls a day and operates out of two locations, in Markham and London, Ont. The London location deals primarily with collections and overflow calls from the Markham location.

56 Customers who remain dissatisfied after talking to an agent can ask to speak to a supervisor, who is expected to attempt to resolve their concerns. Unresolved complaints can be referred to Hydro One's in-house customer relations centre. This centre also deals with communications from Members of Provincial Parliament, the Ontario Energy Board, my Office, or from customers involved with any of them.

57 Hydro One's new customer information system had an impact on the call centre locations and the customer relations centre that verged on the catastrophic.

Post-Launch Calls and Complaints

58 In May 2013, the number of billing-related calls to the call centre was **55,147**. The first month after the new system was introduced the call volume relating to billing issues jumped to **84,966** – a **54%** increase, well above the estimate of **20%** used during the planning stages for the project. By September 2013, the volume of calls about billing was still exceptionally high – around **73,000**. It took the better part of a year before call levels returned to normal.

59 The volume of complaints escalated to managers within the call centre also increased significantly. In April 2013, there were **1,370** escalated complaints. Once the new system was installed in May, the volume steadily increased. In September 2013, managers were trying to address **3,428** escalated complaints. By February 2014, they were coping with an influx of **3,970** unresolved complaints, almost triple the regular load.

60 When my investigators toured the Markham call centre location in February 2014, they were told there were 220 staff in Markham and 80 in London. This was after a 40% staffing increase, put into place before the new system was implemented, in anticipation of higher call volumes. Mandatory overtime was also instituted intermittently from April through October 2013, and again in March and April 2014. We were told that management originally planned to lay off the extra workers in November 2013, but because of the deluge of customer calls, those layoffs never materialized.

61 In December 2013, a senior call centre official said in an email to Hydro One management:

> (W)e're struggling with the sheer volume of complaints. Under normal circumstances, we have approximately 8-9 staff assigned to escalations. We currently have in the range of 20 and we're still struggling to answer a high % of the calls. [...]
>
> We're doing our best to balance all of these resource demands with a resource pool that is currently maxed out. At the heart of the issue is our ongoing billing and exceptions issues. We need to find a way to quickly address the issues that are continuing to drive calls and complaints.

62 In February 2014, after my investigation was launched, approval was given to increase call centre staff to **435,** and to **569** by May 2014. Mandatory overtime was reintroduced in March 2014.

63 However, call centre staff continued to be overwhelmed by the volume and complexity of customer inquiries. According to internal emails we reviewed, one Hydro One manager learned at a March meeting with Ontario Energy Board officials that some call centre staff were suggesting to customers that "the only way their billing problem will be resolved in a timely fashion" was to contact the Board. Another official described the situation at the call centre as "a cry for help."

64 In April 2014, Hydro One established a special handling desk, operated by trained call centre agents to deal with customer calls about high bills. This desk answered 885 calls in the first two days of its operation.

Customer Relations Centre Backlog

65 The month before the new system was installed, Hydro One's in-house customer relations centre had a backlog of about **300** complaints. By December 2013, it had soared to **691**. One Hydro One official told us that by the end of 2013, "we were not able to dip into that volume, we were just barely treading water." Most complaints came from customers who received no bills or unusually high bills. Resolution of many complaints was delayed four months or more.

66 The customer relations centre had historically been staffed by eight people. In planning for the new system, it was projected that three additional employees would temporarily be needed to handle complaints. However, in late fall 2013 and into 2014, staff at the centre was more than doubled to deal with the complaint influx. It was only in March 2014 that the centre was able to make any inroads in reducing the backlog.

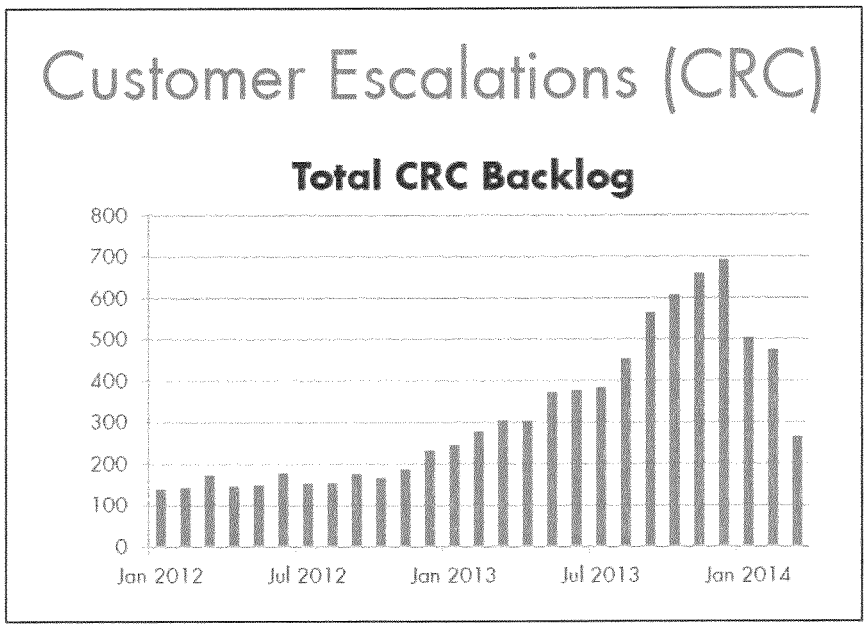


Figure 2: Chart showing the backlog of complaints escalated to Hydro One's in-house customer relations centre, between January 2012 and January 2014. Source: Internal Hydro One document.

Technical Glitches

67 Many of the complaints generated by the switch to the new system arose from technical glitches affecting billing. These problems, identified as "defects" and "exceptions," resulted in the all-too-common customer experiences of receiving estimated bills for prolonged periods, sudden large and/or multiple bills, or no bills at all. Our review of Hydro One emails revealed a series of mishaps.

Defects Detected

68 In the installation and operation of data systems, it is common for "defects" to crop up, such as coding or data errors that require technical fixes and workarounds. Hydro One told us that at the time the customer information system was launched, there were no "severity 1 defects" – that is, problems that would critically compromise its operation or the data generated. However, there were **232** defects at the outset, varying in severity. According to an internal email, between May 21, 2013 and September 20, 2013, **6,509** defects were logged. By February 2014, there was a backlog of **618** requiring resolution. The

number of new defects since my investigation began is more than **1,000**. In several cases, the same issues had to be fixed more than once.

69 According to Hydro One records, system defects affected the ability of call centre agents and customer relations centre staff to resolve customer concerns. Agents had difficulty viewing customer history on their computer screens, frustrating their efforts to resolve or explain the billing and meter issues that came up. Customer relations centre staff also could not access some data without assistance from the call centres. Most cases involving no bills being issued or bad estimated bills could also not be readily resolved due to systems defects, contributing to extensive backlogs.

70 Hydro One told us it could not confirm how many customer accounts were affected by each defect. However, in May 2014, we learned through our review of Hydro One's records that there were **101,244** in all, **49,894** of which required billing corrections.

71 Problems with the system appeared soon after it was implemented. Within days, an account was flagged that had been billed $11,000 although the customer's normal electricity usage was $300. Hydro One internal emails on May 24, 2013 refer to a defect resulting in excessive electronic fund withdrawals from **140** customers' bank accounts. The defect related to previous bill cancellations that were transferred over from the old system. One account was debited **$58,000** by mistake. A retail customer had **$50,000** withdrawn in error. On May 31, 2013, the company discovered that the system was generating duplicate and confusing installment plan letters, as well as some letters with incomplete addresses, and others with no meter information.

72 In June 2013, thousands of customers were affected by a variety of defects. On June 5, there were more than **3,000** bills showing zero charges. On June 11, Hydro One identified more than **40,000** retail accounts with overly high estimates. One retailer received six grossly overestimated bills due to one defect – including one for more than **$3 million**. On June 18, the system mistakenly estimated **27,575** accounts for which actual usage data was available.

73 In July 2013, an issue arose with customers on installment plans being unaccountably charged for late payments. One retailer had **$163,000** automatically withdrawn from the bank even though the bill in question had been paid. These charges were later reversed and corrected, and agents were instructed to tell callers complaining about this issue: "We are extremely sorry for this error."

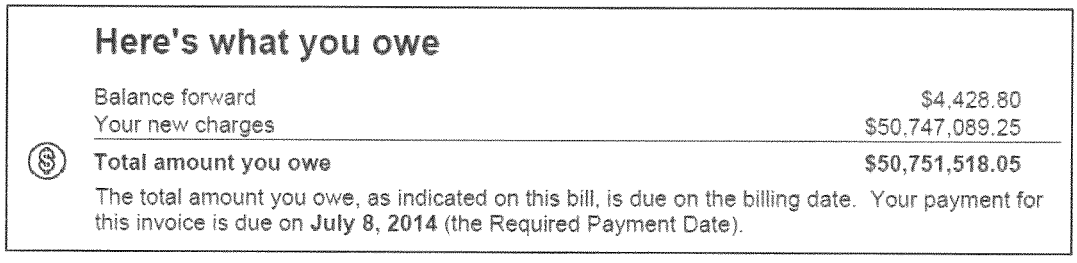
74 In August 2013, **8,200** accounts were affected by a defect that improperly added previous electricity consumption onto new bills. A Hydro One staff member also alerted management to a defect that resulted in an attempt to automatically withdraw $10,000 from the bank account of his father-in-law's church. "I think we need to ask ourselves how an invoice 200 times larger than normal got through all the checks and balances," he wrote in an email.

75 Some **48,000** customers were also affected by a defect that resulted in their bills showing a total kilowatt usage for the billing period that did not correspond with their time-of-use information. This resulted in **21,014** customers being under-billed and **20,912** being overbilled.

76 Defects resulting in erroneous automatic withdrawals and inaccurate estimated bills persisted though the fall of 2013. Hydro One also reported in September that there were 12 privacy breaches relating to customers being billed under the wrong names.

77 System errors continued well into 2014. In February, a defect involving incorrect time-of-use information inflated bills. Another defect resulted in incorrect first bills for some **30,000** new customers. One customer was billed more than **$35,000** for a vacant farm, when the real amount owing was only **$122**. In April, a combination of factors led to a corporate customer receiving a bill for more than **$15 million** rather than the **$4,034.47** owed. In May, Hydro One withdrew **$9,000** from a customer's account without first checking why the system was showing exceptionally high electrical usage for two months.

78 In June 2014, a customer was mistakenly billed **$20,087.64** instead of **$1,309.71**, and the Canadian Army's Garrison Petawawa was wrongly billed more than **$50 million**. A month later, a company was issued a bill for **$11 million** in error.



Here's what you owe

Balance forward	$4,428.80
Your new charges	$50,747,089.25
Total amount you owe	**$50,751,518.05**

The total amount you owe, as indicated on this bill, is due on the billing date. Your payment for this invoice is due on **July 8, 2014** (the Required Payment Date).

Figure 3: Excerpt from Garrison Petawawa's erroneous bill for $50.7 million.

79 In November 2014, Hydro One told us that **32,766** accounts were inaccurately billed: **13,650** were underbilled an average of $46.84 ($639,460 in total), and 19,160 were overbilled an average of $26.32 ($504,410 in total). The company eventually decided to write off the charges for the underbilled accounts.

Exceptions Prove the Rule

80 Most Hydro One customers are billed on a monthly basis. Bills are generated by the customer information system, mainly based on electrical consumption data that is gathered and transmitted electronically to the company by the so-called "smart" meter on the property. If usage information is not received – for instance, because a meter is not communicating data for some reason – the bill will be based on an estimate. When an error is identified in the calculation of a bill, the system cancels and reissues the bill.

81 If there are problems or errors, such as incomplete or questionable meter readings, the system creates an "exception." Exceptions can be triggered at various points within the system. The system is designed to automatically detect large numbers of exceptions and prevent accounts from being processed until they are resolved. Hydro One told us it is normal for the system to generate exceptions, and they are not problematic unless they are not cleared within the billing cycle.

82 One of the intended benefits of the new customer information system was that it would reduce billing-related exceptions to 400,000 a year. Instead, there were even more than before. As the accompanying chart shows, the number of exceptions relating to "customer care" peaked at **114,754** during the week of August 12, 2013. On February 13, 2014, Hydro One's Chief Executive Officer reported to the board of directors that **700,000** billing exceptions had been cleared. However, he did not refer to the number of outstanding exceptions, which stood at **93,200** as of February 21. In April 2014, there was a backlog of **84,300** exceptions awaiting resolution.

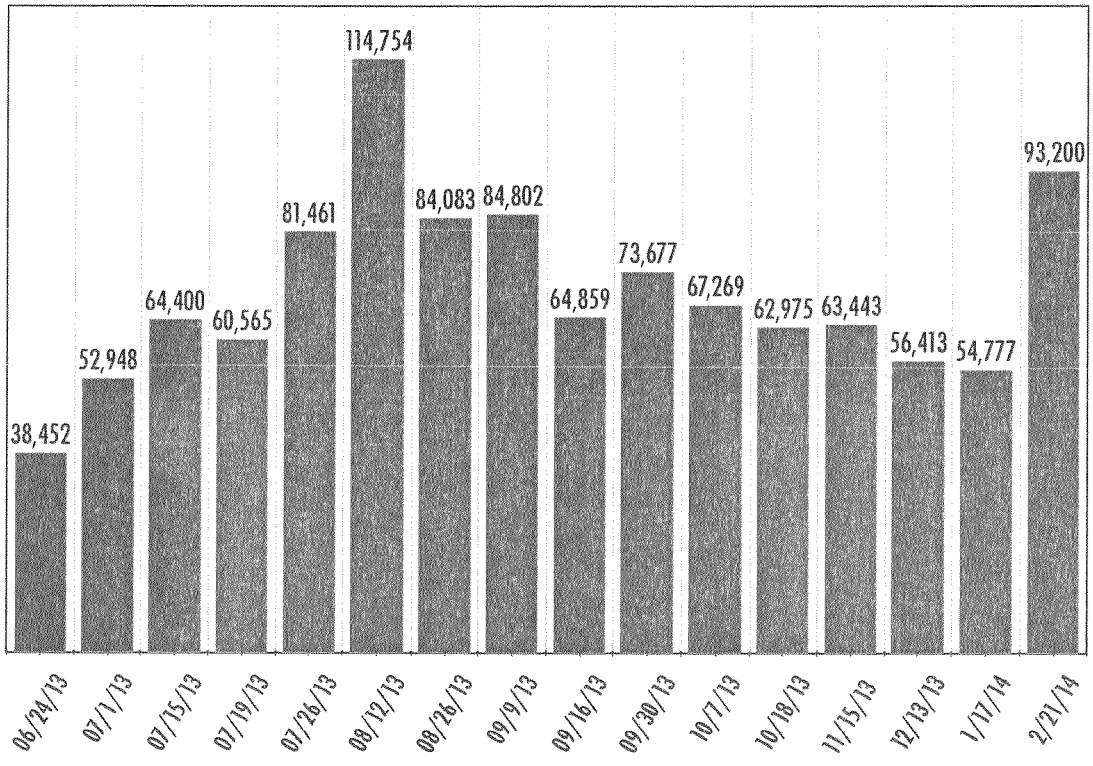


Figure 4: Chart compiled from figures in internal Hydro One documents, showing the backlog of exceptions relating to "customer care" between June 2013 and February 2014.

83 Hydro One officials and call centre staff told us that the rising volume of system exceptions contributed to instances of human error, resulting in inaccurate bills being released instead of being held back for correction.

84 The number of technical support staff to deal with systems issues was initially increased from 40 to 132, and increased to 152 in May 2014. By December 2014, the exceptions backlog had been reduced to a more manageable **12,717**.

No Bills

85 According to Hydro One documents, it was common in the past for a relatively small number of customers not to receive regular bills – some 6,000-8000 per month. Just prior to the new system launch, there were 12,000 accounts not receiving bills. When the new system was implemented, there was a surge in "no bills" cases. In June 2013, the number of accounts coming within this category was **89,107**. The volume of these cases fluctuated over time, as the

accompanying chart shows, but it was consistently and significantly higher than under the former system.

86 Initially, Hydro One management was not overly concerned about this issue, as the number of "no bills" accounts gradually dropped. The company focused on deploying technical staff to work through the exceptions and resolve the underlying problems that were preventing bills from being sent out. These efforts proved successful in releasing thousands of bills after many months. Unfortunately, in concentrating on clearing technical glitches, Hydro One failed to factor in the impact on customers, who suddenly received a flurry of large "catch-up" bills, and in some cases had large sums automatically withdrawn from their bank accounts without advance warning or explanation.

87 As complaints flooded the call centres in the summer of 2013, Hydro One was slow to connect the dots. One official told us that she first started to hear about "no bills" in September 2013, when there were more escalated complaints and more calls from MPPs. She said, "these were some of the warning bells, in my mind, that things weren't working right."

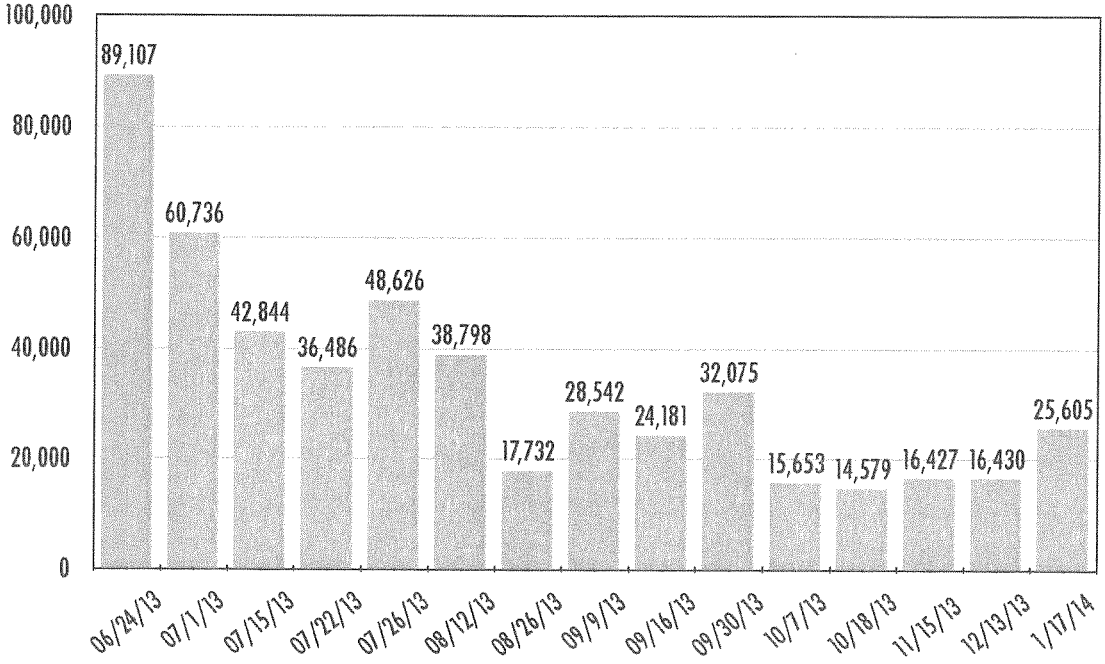


Figure 5: Chart compiled from figures in Hydro One executive committee briefing materials, showing the volume of "no bills" cases between June 2013 and January 2014.

88 When I announced my investigation, Hydro One was still wrestling with the "no bills" problem. In March 2014, the volume of "no bill accounts" was 53,000. On April 11, 2014, Hydro One told us this was down to 47,100 and the company was taking several steps to reduce the backlog further, including adding technical staff and creating a dedicated "SWAT" team to address root causes. By December 2014, the volume of "no bill" accounts had decreased to **2,636**.

Wrongly Addressed Bills

89 After the system changeover, there were some **68,000** customers whose bills were issued with incorrect addresses because of a data migration problem when the old system was replaced. A technical fix was implemented in October 2013, but address errors continued to cause problems for close to 2,000 customers. Hydro One staff assured us in January 2015 that the company immediately corrects any wrong addresses after receiving returned mail. However, when bills are not returned, the company simply relies on customers to call if they don't receive bills and correct any wrong address information.

Never Billed

90 In addition to the thousands of accounts whose bills were generated but delayed by the new system, there were also many whose bills stopped altogether after it was implemented. Those customers never received a bill after May 2013. On August 13, 2013, Hydro One reported internally that there were some **23,550** customers in this category. In November 2013, the company was contacted by a municipality that estimated it owed more than $1 million, but had never received a bill. The matter still had not been resolved months later.

91 Hydro One officials told us that considerable effort was invested in getting this situation resolved, and by December 2013, all accounts had been billed under the new system. However, we later learned that the "never billed" accounts were simply lumped in with the "no bills" accounts. Hydro One records indicate that as of February 2014, there were still **2,000** accounts where customers had not received a bill under the new system, but where the system had issued and then cancelled the bill.

Estimated Bills

92 Hydro One officials told us some customers receive estimated bills until actual hydro usage can be confirmed and the bill is "trued up." Estimated bills are typically used to address situations where meters are not receiving and

transmitting usage data – for instance, in rural areas where heavy leaf cover in the summer may interfere with meter transmissions. Once the accurate meter data is available, the bills are corrected, sometimes resulting in large "trued-up" bills. Under the old information system, approximately 3% of Hydro One's time-of-use customers were issued estimated bills.

93 On February 10, 2014, the Ontario Energy Board notified Hydro One that it was receiving a significant number of billing-related complaints about trued-up bills. It called on Hydro One to limit estimated billing to a period of 90 days. In response, a Hydro One executive, after noting that "estimated reads are a reality in the utility industry," set out the remedial steps the company would take, emphasizing that the highest priority for the company was to resolve the customer information system issues that were contributing to persistent bill estimation.

94 During our investigation, Hydro One told us that 3% of its customers, approximately **39,000**, were still receiving estimated bills for longer than 90 days.

Electric Personality – Inward-Facing Culture

95 Corporate culture is a fascinating subject. I have had the opportunity to study a variety of organizational personalities in the course of my work. I have found that public corporations in the business of selling a commodity or exercising monopolistic technical expertise often reflect a private sector mentality. They have a tendency to emphasize business goals, profit motives, and technological excellence over the public interest and concern for individual customers.

96 Hydro One is the only game in town when it comes to billing for electricity in many rural and remote communities. It has expertise in delivering electric power and takes pride in its technological achievements and status as an award-winning utility. Hydro One is also closely aligned with private-sector business models, delivering a large portion of its customer service through a third-party private provider. Although outsourcing customer service operations may make financial sense, it has left Hydro One detached and distanced from those it serves. As one individual previously involved with project implementation at Hydro One put it to us:

> If the lifeblood of the company is taking care of the customers – and I don't know whose company isn't like that – I don't know why on earth you'd give it to somebody else to do for you.

97 Several current and former Hydro One officials noted to us that Hydro One is also physically out of touch with its customer base, with its head office and about 1,000 staff located in downtown Toronto. Given its history and present circumstances, it is perhaps unsurprising that Hydro One has found itself disconnected from its customers.

98 Several former and current Hydro One representatives, as well as others who have worked closely with the company, shared their insights with us about its corporate character. They recognized that Hydro One's distinct workplace culture had a direct influence on how officials approached problem solving and customer relations. A member of a stakeholder group representing energy consumers, described Hydro One as having "a very inward culture" reminiscent of the private sector, and great "pride" in its technical ability, which he said sometimes results in "hubris." He added: "They're not good at listening on the outside."

99 A former Hydro One official candidly told us that some of Hydro One's problems with the new customer information system stemmed from an overly technical focus. He suggested that the company sought system solutions instead of working on customer relationships, and failed to treat customers fairly, understand what they were experiencing and manage their expectations. He noted:

> I still contend that some of our biggest root causes are customer attitude root causes. That we created many of our own upset customers by our own stupidity. Sure, there were going to be system root causes, but unless you understood what the root cause effect on a customer was, you had the wrong mindset.

100 A Hydro One executive also acknowledged that the company stressed the technical aspects of its operations and the importance of complying with technical and regulator standards, observing:

> We've always been very inward focused and we've always been very compliance-focused… Compliance-driven cultures also tend to not deal with their problems very well. You're complying with something, but you're not changing something or fixing something or making something better.

Poor Customer Service: A Symptom, Not the Disease

101 The technical problems accompanying the transition to the new customer information system were not the cause of Hydro One's organizational culture. The system change, accompanied as it was by a spectacular increase in complaints, simply brought Hydro One's cultural failings into sharper focus.

102 Well before the system change, my Office encountered cases of abysmal customer service at Hydro One. In 2010, it removed more than **$11,000** from **Alan Skeoch**'s bank account without notice or clear explanation. He had received estimated bills for two years for his **Wellington County** property, then was hit with a huge bill once his actual electricity usage was confirmed. He went through six different call centre agents and got nowhere, until he went to the local media about his plight. A senior Hydro One official finally agreed to meet with him and work out a payment plan. He told us the Hydro One executive "promised me that this would never happen again… that this is really an anomalous situation." He added:

> And then suddenly, this is 2014, and here it is in the paper again. People in the same situation I was in, treated in a very cavalier manner by a huge corporation.

103 In 2012, Hydro One threatened **Rebecca Carter** of **Demorestville** with disconnection for unpaid hydro charges, although the amount wrongly included a period when her home was destroyed by fire. That same year, an **Ottawa** man was charged **$11,000** by mistake when his meter was changed and the company rebilled him for five years of electricity he had already paid for. It took him over a year, some 40 calls to the call centre, five escalated complaints to managers, and ultimately the intervention of our Office to get the mess sorted out. Customers also regularly complained to us about the insensitive and rude attitude of Hydro One officials and the "bafflegab" they were subjected to when they tried to get absurd bills straightened out.

104 Hydro One readily admits that it had billing problems under the old information system. Indeed, that is the key reason it was replaced. However, the issues we encountered before the system change had more to do with attitudinal barriers to good public service than outdated technology.

105 Here are just a few of the comments customers shared with us about their demoralizing and dehumanizing experiences in dealing with Hydro One:

They're telling me, "oh, just pay whatever you think." What kind of an answer is that? That's customer service – they need to give you a better answer than that.

All I make of it is that their apologies are completely hollow... it's actions, not words. It's nice to say "oh, we're sorry" and send you off a form letter, and say, "we're sorry about that and will try and do better," but they don't. All they do is send us a higher bill next time.... It's extremely frustrating.

I am left feeling anxious, without a voice, frustrated, and bullied... It was just so wrong, so spurious, that I knew that there had to be an explanation that somebody would figure out.

[A service charge credit] certainly doesn't pay for all the anxiety and sleepless nights that I went through. I don't have a big pension and mainly I live a lot on my old age security and my CPP.

The onus was placed on me to keep following up, keep following up because they were busy, that was the message. They were busy, they were backlogged, they were busy and they couldn't deal with me right now.

I think it was the most stressful time I think I've had in many years. Nobody would listen and nobody cared. And I had a different person every time. And every time that I called, I documented their name and their PIN number... I think I did get a supervisor one time and he was just rude... so I left it.

I actually was treated very rudely a couple of times – that they would contact me, that I did not need to contact them so much. I don't think they realized my level of frustration, and I'm normally a very calm person. I really just want it to be resolved. I didn't want a conflict. I just want to pay my bill and get on with my life. And I didn't want this [hanging] over my head.

106 Ultimately, it was Hydro One's corporate culture that led it to overlook the human face of its customers when implementing its new customer information system, and generated the toxic atmosphere of customer distrust.

From A+ to Failing Grade – Systems versus People

107 The technical mindset prevalent in Hydro One's culture had a strong influence in the planning and implementation stages of the customer information system project. Hydro One executives repeatedly told us they were unaware of customer service issues until late fall 2013, and that the full extent of the problem was not apparent until after my investigation was launched. Some attributed this to having the wrong people in charge of the project. According to one official, the project leaders were "more about technical solutions rather than dealing with people. We've lost sight of the people and that was a big mistake." Those most intimately involved with the new system did not seem to recognize or appreciate the potential impact on customers. Their focus remained on technical fixes and operational issues. As one executive told us:

> You get very, very focused on how the project is doing and how you're dealing with issues and problems. Where I believe our failure is, and you'll hear us say this time and again, it was how we resolved the problems. That we were not making customer-centric decisions.

108 Another Hydro One official told us that at the end of January 2014, while staff were busy congratulating themselves on reducing various billing backlogs, no one was considering the customer:

> What they were celebrating was fixing a technical solution that allowed us to get bills out the door, but what they didn't focus on was that there were people who haven't had bills in eight, 10 months, who were part of that backlog that all of a sudden got big bills with no explanation. Catch-up bills. No call to them … saying what the bill was for, why you'd get it; no offer of waiver of service charges, none of that kind of stuff… What we did was create a massive customer service problem by not thinking about the people at the other end.

109 A senior official also told us that in trying to address technical problems such as the "no bills" situation, the company failed to recognize the potential "downstream" effects on customers, such as multiple bills and huge catch-up bills suddenly arriving in the mail.

110 After I launched my investigation, some Hydro One staff suggested that the problems with billing and customer service were overblown in the media and inflamed by my announcement. It was as if they believed that if I had not called attention to the issues, they would have been resolved through technical fixes and quietly vanished from public view. They thought we were making a mountain out of a molehill.

111 Until recently, Hydro One officials collectively emphasized that, for the "majority" of the company's customers, the transition to the new customer information system was a resounding success. From an empirical technical perspective, Hydro One thought it was doing great. It was completely unaware that it was failing miserably from a human perspective. In internal discussions, board of director briefings and in media interviews, Hydro One management typically downplayed billing and service problems, referring dismissively to the "small" number of customers involved. They also used varying percentages instead of referring to the actual number of customers affected. For instance, an internal email on December 20, 2013 noted that the Chief Executive Officer stated in a media interview that technical issues affected "less than 1% of our customers." On January 9, 2014, a Hydro One representative told the media that only "0.8% of [the company's] 1.3 million customers," had never received bills under the new system, and that it had "since resolved that issue."[7] Even when the figures later climbed to 5% and then to 6% of Hydro One's customers, the company still selectively used figures to distract from the suffering of individual Ontarians. In terms of percentages, the figures touted by Hydro One appeared small, but in terms of people, they were significant – 6% of 1.3 million customers equates to **78,000** people.

112 Since February 2014, Hydro One's management has publicly acknowledged that it was wrong to disregard the tens of thousands of individuals inconvenienced and frustrated by billing and customer service issues. The company has also committed to considering customer impacts from a human rather than a statistical perspective. In October 2014, the Chief Executive Officer said in a presentation[8] that in installing the new customer information system:

> (T)he goal was to beat customers' expectations using the latest technology. We wanted to be the best utility in terms of customer service in Canada. We were replacing an unsupported and dying system with a modern one, and by any technical standard it was a successful implementation. We won awards.

[7] "Hydro One billing mismanaged: MPP," Peterborough Examiner, January 9, 2014: http://www.thepeterboroughexaminer.com/2014/01/10/hydro-one-billing-mismanaged-mpp

[8] The October 22 presentation, to the Ontario Energy Network, can be viewed on YouTube here: https://www.youtube.com/watch?v=SyWW8i4rTa8

113 In hindsight, he admitted that the company should not have been satisfied with its statistical success rate:

> Sure, 95% had no issue. If that was a math test, that'd be an A+. [But] 5% of your customer base having a problem is not even a passing grade. It's awful.[9]

114 When undertaking similar projects in future, Hydro One should ensure that the impact on customers is considered and factored into all phases of planning and implementation.

Recommendation 1
Hydro One Inc. should ensure that it considers the impact on customers as its first priority throughout all project planning phases and develops appropriate mitigation strategies and contingency plans.

115 In both its internal and external communications, Hydro One also described billing problems in vague and shifting terms. For instance, it insisted that as of December 2013, the problem of never-billed accounts was eliminated – when in fact it simply moved 2,000 such bills to the "no bill" delayed billing category because the system had invoiced the accounts but quickly cancelled them. In February 2014, one Hydro One official suggested in an internal email that there should be greater transparency with respect to this distinction and that it should be disclosed "from the customer's point of view." Another senior manager responded, in connection with a memo being prepared for the board of directors:

> I doubt they are going to ask about Never Bills. …. The 2,000 Never Bill numbers are counted in [the] No Bill number anyways, so no need to distinguish anymore.

116 In addition, in citing the number of customers affected by various issues, Hydro One typically referred only to how many customers were affected at distinct points in time, not the total since the system change. For example, in June 2013, the company's records indicate **89,107** customers had not received bills; in February 2014, **83,000** customers were affected by delayed or prolonged estimated bills. However, we did not find any cumulative total showing the aggregate number of customers affected by billing problems. The figures for the number of customers affected by various billing issues did not always add up, which made it challenging for our investigators to verify them. By providing

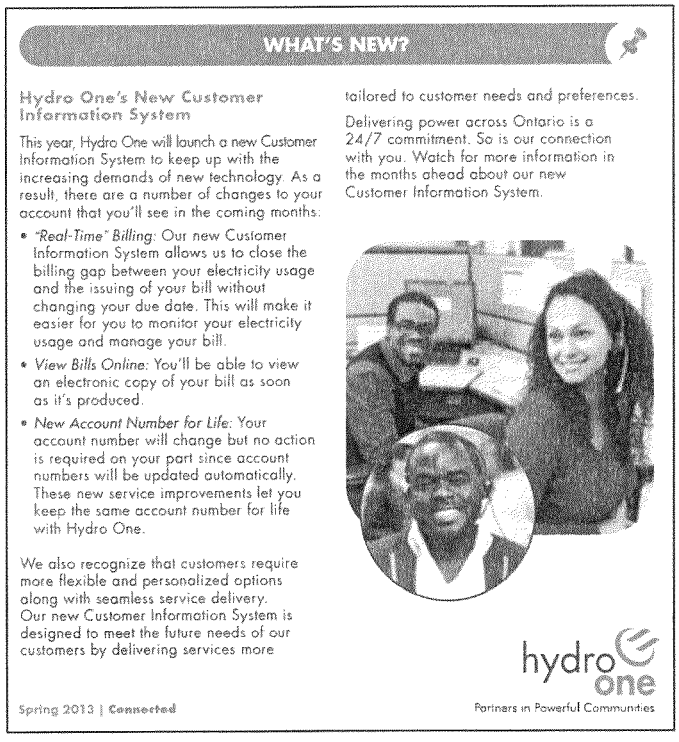
[9] Ontario Energy Network presentation, *ibid.*

statistics in isolation, Hydro One obscured the full extent of the service problems experienced by its customers. In future, it should ensure that it tracks and discloses the running total of individuals affected by various systems problems, and that descriptions of problem categories are clear, accurate and constant.

Recommendation 2
Hydro One Inc. should ensure that it keeps track of the cumulative total of customers affected by various systems issues and provides clear, accurate and constant descriptions of the various problem categories.

Communications Gap

117 Hydro One's organizational persona has played a pivotal role in its relationships with its customers and other stakeholders, particularly in corporate communications. The communications strategy relating to the new customer information system was planned well in advance. Hydro One's records reflect that it was determined to avoid the negative media coverage and complaints that marked Toronto Hydro's migration to a new system and its own experience with the technology system change in 1998. From March to May 2013, Hydro One proactively notified its customers that it was transitioning to a new system through its newsletter. It was a good-news piece, full of smiling faces, promising that the system was "designed to meet the future needs of our customers by delivering services more tailored to customer needs and preferences."



WHAT'S NEW?

Hydro One's New Customer Information System

This year, Hydro One will launch a new Customer Information System to keep up with the increasing demands of new technology. As a result, there are a number of changes to your account that you'll see in the coming months:

- *"Real-Time" Billing:* Our new Customer Information System allows us to close the billing gap between your electricity usage and the issuing of your bill without changing your due date. This will make it easier for you to monitor your electricity usage and manage your bill.
- *View Bills Online:* You'll be able to view an electronic copy of your bill as soon as it's produced.
- *New Account Number for Life:* Your account number will change but no action is required on your part since account numbers will be updated automatically. These new service improvements let you keep the same account number for life with Hydro One.

We also recognize that customers require more flexible and personalized options along with seamless service delivery. Our new Customer Information System is designed to meet the future needs of our customers by delivering services more tailored to customer needs and preferences.

Delivering power across Ontario is a 24/7 commitment. So is our connection with you. Watch for more information in the months ahead about our new Customer Information System.

Spring 2013 | Connected

Partners in Powerful Communities

Figure 6: Hydro One newsletter, Spring 2013.

118 From April to May 2013, Hydro One also sent a letter to 837,200 customers about the system changes. The only issue of potential customer concern it had identified prior to the new system launch was the elimination of a 13-day billing delay.[10] This change was addressed in some of its communications with customers.

119 Hydro One did develop communications responses based on worst-case scenarios, but it sought to shield the public from negative messages. According to internal communications materials, insiders could talk amongst themselves about "major billing issues" and "system failure," but external audiences could only be told that "some customers" had been affected by "some issues" with the system.

120 When problems arose soon after the system change, Hydro One concentrated on addressing individual issues discreetly as they came up, making private apology calls and sending letters to customers. For example, on June 4, 2013, Hydro One notified **500** retail customers by letter that the transition to the new system had caused an error that omitted consumption charges from their bills. On June 5, it sent some customers notice that the new system caused a pre-authorized payment error on their accounts. On August 29, **2,000** customers whose meters had been changed at the time the data migrated to the new system were notified that they were not billed for consumption before or after the meter change. Another **12,000** letters went out in August and September 2013 to customers who had never received a bill under the new system, offering a six-month, interest-free, fee-free billing payment plan. Additional letters were sent out to **5,000** customers in this category from October through December 2013, offering a one-month service charge credit as a goodwill gesture.

121 Hydro One's piecemeal and reactive communications approach reflected an attempt to institute damage control and insulate the company from any criticism about its award-winning customer information system. The language used to convey the message was closely vetted. For instance, when crafting the letter to 12,000 never-billed customers, officials decided to remove any reference to the system. One official noted:

> I am concerned about the … references to CIS [the customer information system] below creating some spin and undue nervousness.

[10] The 13-day delay was designed to allow for the final spot price to be received from the Independent Electricity System Operator. The delay was obsolete for most customers once a fixed price was introduced in December 2002.

In the end, the letter simply said the company was "currently experiencing some issues which have prevented us from issuing your bill."

122 When the new customer information system was first rolled out, call centre agents were instructed not to attribute billing issues to the transition to the new system, and to stay away from negative words like "defects." Call centre staff were instructed in training materials that the word was "an internal term that should not be discussed with the customer." As one senior call centre manager explained to us:

> (T)here were a lot of debates around messaging that should go to customers, and there was a reluctance for a long period of time for anybody to indicate that there were system problems or [time of use] issues… I think everybody was worried about it hitting the media and it would be a firestorm.

123 Unfortunately, Hydro One's communications planning appears to have been influenced by a sense of organizational positivism that was not borne out by reality. The company was left scrambling to contain the damage when problems began to surface publicly. When faced with negative publicity, Hydro One's overriding priority became managing its public relations image. With all its frenetic spinning, it neglected the real impact it was having on tens of thousands of Ontario's citizens.

Keeping Outsiders in the Dark

124 Senior Hydro One officials told us that it took several months for them to realize the full extent of the billing and customer service issues, but corporate records suggest that at least some were sensitive to the problems much earlier. Internal email communications from July 2013 discussed accounts that had not been billed under the new system, noting the need for "ensuring we do not go to the media." News was also slowly filtering into the public domain. A newspaper article listing a slew of billing and customer service issues[11] set off a chain of internal email communications at Hydro One, including this comment:

> I know Corporate Communications does not recommend responding to these types of articles, but this one may need us to do something to repair damage to our reputation.

[11] "Hydro One Customers fume over long-standing billing mess," Hugh Adami, *Ottawa Citizen*, July 31, 2013.

125 Another official responded that he had talked to a communications executive and got "the sense they want to wait it out." Senior executives undertook to raise the issue with the board of directors' regulatory and public policy committee. However, the information we obtained from this committee made no reference to this issue.

Obstructing the Ombudsman

126 Hydro One's tactic of avoiding external communications about its problems with the new system appears to have extended to my Office. In July 2013, senior officials from my Office and Hydro One met to discuss the significant growth in the number of complaints we were seeing about meters and billing. My Office also raised concerns about the increasing delays we were experiencing in getting answers from the customer relations centre staff. In some cases, it was taking two to four months to obtain substantive responses.

127 At the meeting, Hydro One representatives provided an overview of some of the technical issues with meters and various aspects of the billing process, but they scrupulously avoided any reference to the customer information system. There was no mention of the struggles Hydro One was encountering with system defects and exceptions, the increased volume of calls from frustrated customers, or the complexity of the billing problems. Instead, they played up the positive features of the new system.

128 We later learned from internal emails that Hydro One deliberately sanitized the script it used at that meeting, to ensure it contained more "confidence-boosting content." The emails indicate a decision was made to avoid reference to the new system and its impact on billing and customer complaints. It was suggested that reference to the new system be omitted until it had "stabilized," or that it be mentioned "as little as possible, and only on a reactive basis." One official warned:

> (I)t can get dangerous if we offer up too much info, or if we state too many benefits... we don't want this to be the new topic for review and discussion. If we simply state that we are essentially in line with expected customer reaction… that's a healthy story.

129 A month later, after my staff called a customer relations centre staffer about a customer who had not received bills for some time, the Hydro One employee wrote in an email to a supervisor:

> ... [Ombudsman staff] started to ask if we were having a lot of accounts that are not billing, to which I stated that I wasn't aware that there was a problem except with a couple that I was working with. ... I basically told her that we hadn't heard that there was any issue and we moved onto another account.

130 In response, the manager praised the employee's discretion and circulated the comments to other Hydro One officials, saying:

> Thanks for the heads up... good warning in case they come knocking. Please keep holding the line with messages like you conveyed – I think this is appropriate given that we have the majority of our customers (over 96%) billing with no issues but there is work to be done. If you get the feeling that they're going to investigate more aggressively or escalate, let us know.

131 Rather than acknowledge that tens of thousands of its customers were experiencing billing issues, Hydro One continued to stress to outsiders that there was nothing to be concerned about, deflecting concern with evasive, misleading and upbeat messaging. We received similar vacant assurances when we asked about the impact of "exceptions" on billing in November 2013. A Hydro One official told us that exceptions are a normal product of billing and collections processes and that the exceptions relating to the new system were "not unexpected for a project of this nature." This was simply misleading and disingenuous.

132 Hydro One's failed attempts to hide the extent of the impact of its billing systems errors even from my Office is reflective of an organization that cares more about its corporate facade than its obligations to its customers or to its provincial overseers.

Obfuscating the Ontario Energy Board

133 On August 22, 2013, Ontario Energy Board officials toured the Markham call centre with Hydro One officials, who failed to enlighten them about the problems associated with the new customer information system. In September 2013, the board sent an email inquiry to Hydro One, asking about billing concerns it was hearing about from MPPs. A Hydro One official responded that about 10,000 customers had not received bills since the transition to the new customer information system, and mentioned that there were other "small groupings of issues related to budget billing, but other than that, nothing

systemic." Hydro One minimized the problem, assuring the board that bills would be out by the end of September, if not before.

134 When the problem of estimated bills persisted, the board wrote to Hydro One again on October 23, 2013, expressing concern. It acknowledged Hydro One's offer to affected customers of a six-month, interest-free billing plan, but noted that it was still receiving an increasing number of complaints about billing and metering. The Ontario Energy Board has continued to monitor Hydro One's progress in addressing areas it identified for corrective action.

Mollifying the Minister's Office

135 By fall 2013, the Minister of Energy was also concerned about the situation at Hydro One, including its delays in responding to inquiries from MPPs. Internal Hydro One documents indicate that in October 2013, the company accepted a recommendation from the Minister's office that it proactively offer a service charge credit to customers who had never received a bill under the new system, for every month after September that they were not billed.

136 On December 17, 2013, the Minister of Energy's chief of staff wrote in an email to Hydro One's Chief Executive Officer:

> Hate to have to bring this to your attention, but we have seen a really inexcusable uptick in customer service complaints these past several months that are really untenable…

137 Hydro One's Chief Executive Officer responded the next day, stressing the low number of customers – 22,000, or less than 2% – who had submitted complaints. He also explained that it was taking time to address the 180 MPP requests that had been received.

138 Although the Chief Executive Officer's response remained positive, an internal email from another senior official in December referred to the company entering "crisis mode with respect to the growing backlog of [customer relations centre] complaints."

Befuddling the Board of Directors

139 Hydro One's board of directors is responsible for hiring the Chief Executive Officer to manage Hydro One and general oversight of its operations. It relies on the company's executives to keep it informed of problematic issues. When we

interviewed the former chair of the board, who was at the helm when the new customer information system was introduced, he said my investigation came as an unpleasant surprise. In November 2013, the board's business transformation committee was briefed about the high volume of customer complaints, but management assured them the root causes were being investigated and mitigated, and that the complaints were just "a statistical issue" that was under control and getting better. "Management… in whom we had confidence at that point, presented a positive, 'we're in control of the situation, don't worry' point of view," he said.

140 Minutes from the November 13, 2013 meeting confirm that committee members were told the company had received about four times the normal number of complaints, most about billing issues. The committee was assured that mitigation measures were underway and that survey results showed the company had scored 80% for customer satisfaction.

141 The former chair said management regaled the board in December 2013 about "the fantastic year that had just finished," including "the great success" of the new customer information system. He said the board had no idea that the Ontario Energy Board had raised concerns in October, and it was news to him when the Minister's Office expressed dismay about delays in responding to requests from MPPs:

> (T)he board was not aware that there was something abnormal happening here. … We thought that we were [at] a statistically acceptable level and that people were dealing with it. What we didn't realize [was] that there were these bizarre bills …

142 As to why the board was not informed about the brewing controversy, he said:

> Basically, there are only two interpretations: Either that management didn't know or didn't understand what was going on, or that they were wilfully misleading all of us as to what was going on. And I don't think that was the case… I don't know how it could have evolved the way it did.

143 In hindsight, he reflected that management might have been "overly self-confident," insensitive to the information they were seeing, and failed to ask the right questions. He also suggested that the information gap might have arisen because of longstanding unresolved issues with operational silos within the company's management.

Inside Crisis – Outside Calm

144 Based on our interviews with Hydro One executives, it is clear that by December 2013, senior managers were fully aware of the significant billing and customer service issues plaguing the company. By then, Hydro One had started to implement internal mitigation measures, adding staff and devoting increasing attention to fixing technical problems. It stopped charging interest on all late payments because of the continuing problems, and, starting in December, it quietly suspended collection activity on select accounts where arrears were attributable to systems issues. Internal documents indicate that on December 22, 2013, Hydro One staff requested a full shutdown of the "dunning process" on an urgent basis to address the wave of customer complaints.[12] On January 24, 2014, Hydro One decided to create a "dunning lock" in the customer information system to "trap" accounts with three or more consecutive estimated bills and those with no bills for more than 90 days. Suspension of collection efforts cost the company $1.6 million a month and forgiveness of late payment charges another $900,000 a month.

145 As internal and external pressures increased and Hydro One horror stories hit the media, the company could no longer maintain radio silence about its system problems. However, it continued to emphasize the positive, minimizing the scope of the problem, and stressing that the transition to the new system was a success for most customers.

Light Bulb Moment: Too Late to Apologize?

146 When the story of **Mountain** cattle farmers **Nancy and Bob Zwarts'** ordeal with Hydro One hit the news on December 18, 2013, the company was forced to react publicly. The couple's saga of faulty smart meters, delayed billing, exorbitant charges, and poor call centre service attracted considerable attention.[13] On December 20, 2013, Hydro One's Chief Executive Officer issued the first of what would become a succession of public apologies for the company's substandard service. He promised, "we will learn from this and we will do better."

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[12] Dunning refers to the collections process from communicating gentle reminders to involving collections agencies to threatening disconnection to restricting or cutting off a customer's hydro for non-payment.
[13] "Cattle farmers Nancy and her husband Bob Zwarts are having a Hydro One nightmare," Wayne Cuddington, *Ottawa Citizen*, December 18, 2013. Online: http://www.ottawacitizen.com/technology/Cattle+farmers+Nancy+husband+Zwarts+having+Hydro+nightmare+because+their+smart+meter+transmitting+data+utility/9307585/story.html

147 After coping with the December 2013 ice storm, Hydro One faced 2014 with the hope that it could avoid further public airing of concerns with its services. However, on January 7, 2014, MPP Laurie Scott (Haliburton-Kawartha Lakes-Brock – PC) brought customer complaints back into the spotlight when she wrote an open letter to the Minister of Energy.[14] In it, she referred to Hydro One customers in her riding as "the victims of Hydro One's billing fiasco and pathetic customer service practices," and described constituents who had received huge bills, threats of disconnection, and inaccurate information from rude and condescending call centre staff.

148 Two days later, a Hydro One spokesperson issued an apology on behalf of the company for call centre service "below the company's standard" and assured the public that things were coming under control with the addition of extra resources. However, stories about abysmal customer service and absurd billing mixups continued to emerge.

An "Innocuous" $30-Million Error

149 On January 22, 2014, a newspaper article appeared about a ski club[15] that Hydro One billed **$37,000** in error. According to the article, after obtaining an apology and a promise to resolve the situation from Hydro One, the club received a revised bill for almost **$37 million** ($36,658,510.75, to be exact). Hydro One's vice-president for corporate relations then apologized publicly. Although the company appeared remorseful externally, internal communications suggest that some executives still could not comprehend why external stakeholders were making such a fuss. One official opined in an email that the article was a "good example of how something innocuous takes on a life of its own."

Ombudsman Intervention

150 Through the summer and fall of 2013, my Office received increasing complaints about Hydro One billing and customer service. Despite numerous phone calls during this period, Hydro One persistently delayed in responding to us on individual cases, and provided incomplete information. Meetings with executive and senior Hydro One staff failed to shed light on the situation, and I was left

[14] The letter is available online here: http://lauriescottmpp.com/feature

[15] "Hydro One's $36-million bill to ski club highlights utility's billing glitches," Adam Radwanski, *Globe and Mail*. Online: http://www.theglobeandmail.com/news/national/hydro-ones-billing-glitches-fuel-ontarians-energy-angst/article16443803/

with no practical option but to launch a systemic investigation to get to the root of the problems.

151 I provided notice of my investigation to Hydro One and the Ministry of Energy on February 3, 2014, and publicly announced it the next morning. By that afternoon, the Chief Executive Officer of Hydro One had issued yet another public apology.[16] It said:

> (W)e know that approximately 3% of our customers have received estimated bills for too long and about another 2% have gone for more than 90 days without receiving a bill. While the vast majority of our customers continue to receive normal bills, some of our customers have not had a positive experience. We know that this level of service isn't acceptable to our customers and it's not acceptable to Hydro One. We have taken aggressive steps to fix the issues. We are reaching out to our customers, we are fixing the exceptions and we have brought in additional staff to listen to customers and help work through their billing inquiries…

Reputation Rehabilitation Begins

152 The day Hydro One learned of my investigation, it launched a "customer service recovery plan," targeted at resolving technical and operational issues and repairing its flagging reputation. Hydro One was intent on getting beyond what one internal document called the "perfect storm" – the media stories, the December 2013 ice storm, and announcement of my investigation – that led to its "current crisis of confidence."

153 The Chief Executive Officer rallied the troops. He sent out an all-staff email on February 7, 2014, acknowledging that there was no doubt that the move to a new and complicated billing system had created "some customer challenges and issues." He also emphasized that "although these challenges are affecting a small number of customers, they jeopardize our corporate reputation and public trust." He relayed four key messages to Hydro One and call centre staff:

- I do not want our customers to worry.
- I want them to know implicitly that if we have sent them a bad bill, we will correct it.
- I don't want them to worry that they will have to pay charges or interest when we have not delivered a timely bill.

[16] Available on Hydro One's website here: http://www.hydroone.com/OurCommitment/Documents/Letter%20to%20Our%20Customers.pdf

- I want them to trust that they will ultimately only pay for the energy they consume.

154 The customer service recovery plan included retaining an external advisor to assist with crisis management, introducing policy changes, and developing customer commitments. External consultants were also employed to provide advice on the development of crisis communications plans and strategies.

155 Staffing levels were also increased to tackle the exceptions backlog and the persistently high call volumes. Call centre agents received additional training and new scripts. A project team was established to correct defects and enhance the customer information system, and work processes were reorganized to better identify early warnings relating to potential data or billing issues.

156 While Hydro One had previously addressed issues somewhat on an ad hoc basis, the customer recovery plan was a more organized response to billing and customer service problems. Beginning in February 2014, technical fixes were put into place to hold bills until they could be released with minimum negative impact on customers.

157 At the beginning of February, a technical "trap" was set on accounts that had not received bills for multiple months and were due to receive a large true-up bill covering three or more months. Letters of explanation were included with bills mailed to **35,025** customers. Some customers were called proactively and automatically enrolled on an interest-free installment plan. By the end of 2014, Hydro One had paid out **$7.3 million** worth of service credits – a credit for every month customers did not receive a bill.

158 On February 14, 2014 a message was added to all bills with credit balances, telling customers they could call if they would prefer to get money back, rather than credit. This was in direct response to concerns raised by my Office about customers who were told they could only obtain credit – not refunds – if they had overpaid or been overcharged by Hydro One. By June 2014, **5,112** refund cheques had been issued, valued at $5.1 million.

159 On February 21, 2014, another "trap" was set to stop large catch-up bills from being issued to customers who had received estimated bills for prolonged periods. Beginning March 4, proactive calls were made to **10,203** of these customers, and **10,794** letters were sent, explaining the situation and offering an interest-free payment plan.

160 At the same time, accounts due to receive multiple bills as a result of adjustments were held by the system until they could be sent to customers in a

single package to minimize confusion. Starting March 3, **26,821** multiple bill packages were sent out, along with a letter clearly explaining the amounts owing.

161 Another trap was set for **4,341** bills that were due to trigger large automatic bank withdrawals. The affected customers were called to confirm whether they consented to the withdrawal, or would prefer to enter into a payment plan. Explanatory letters were also sent out with the bills.

162 Hydro One suspended late payment charges incurred by customers as a result of billing errors as well. It continued the suspension of collections it had temporarily and selectively applied in December 2013, and clarified that it would not disconnect customers in cases where Hydro One was to blame for the billing issue.

163 February 2014 was also when the company created a SWAT team to work with my Office on cases we flagged, and established a liaison to resolve concerns brought forward by members of provincial parliament.

164 In April 2014, Hydro One introduced a commitment that it would resolve customer concerns or confirm a date for resolution within 10 days. It also announced that it was creating a customer service advisory panel composed of stakeholder representatives, reporting to the Chief Executive Officer in an independent advisory capacity.

Centering on Customers

165 Hydro One's customer service recovery plan included repositioning its communications to be more "customer-centric." The company moved quickly to exchange its reactive communications strategy for a more direct approach.

166 The day after I announced my investigation, senior officials began compiling a "top 10 irritants" list, based on media questions and coverage. Internal emails indicate that plan was to have the Chief Executive Officer announce decisions he had made to resolve at least five of the issues, referred to as "low-hanging fruit." The list was as follows:

> Top 10 Irritants:
> 1. Months on estimates without an actual [meter reading]
> 2. Large true-up bills with no payment plan communication attached
> 3. Large true-up bills being withdrawn through accounts – sometimes >$10K for residential customers

4. Several bills arriving in one month – all different amounts, no explanation
5. No bills arriving at all
6. No offer of a refund; just a credit
7. Long delays in getting answers from the call centre/CRC; sometimes several months
8. Inaccurate statements/bad advice – such as "don't pay until you see a bill."
9. Issues argued by agent rather than investigated – e.g., customer found neighbour's [smart meter] serial # on their own bill and vice-versa
10. MPPs calling in issues but not getting a response – follow-up only going to customer even when proper consent provided

167 Hydro One began in earnest to renovate its image and stanch the flow of negative publicity. It reached out to customers and other stakeholders through traditional and social media. On February 7, 2014, the Chief Executive Officer revealed several planned initiatives to support customers: Introduction of a customers' bill of rights (later referred to as "customer commitments"), provisions of refunds where necessary, and a pledge not to charge interest or cut off electricity on accounts affected by Hydro One's billing errors.

168 The company's "reputational recovery plan" was discussed on February 11, 2014 at a joint meeting of two board of directors committees. A communications strategy was tabled that outlined the company's recommended approach to reposition Hydro One as the "primary advocate for its customers and restore the level of trust customers have in Hydro One's ability to manage their issues." The first phase of the plan called for the company to acknowledge its customer service issues, apologize, and explain how issues could be resolved. The next phase involved communicating resolution of the issues through "customer-direct" communications and by equipping frontline staff with communications tools. According to Hydro One documents, the next phase would also implement a strategy "to get ahead of the Ombudsman report by proactively communicating initiatives."

169 Starting in mid-February 2014, the Chief Executive Officer issued a series of letters to customers, the media and MPPs, containing soothing phrases and positive commitments. These were also posted on Hydro One's website. In a February 12, 2014 letter to the editor, sent to multiple newspapers across the province, he acknowledged that call centre agents had struggled with the new system and stated:

> The last thing I want is for our customers to worry. They deserve bills that are clear, timely and accurate. So, I want your readers – our customers – to know that they will only pay for the electricity they use. If they receive a catch-up bill because they have been billed on estimates or have not received a bill, we will work with them to arrange a reasonable payment plan. If we have made a mistake on a bill, we will not charge interest and we will not apply service charges or fees. If we find that we have overbilled an account, we will notify our customers and offer them a refund cheque.
>
> We are improving training at our call centre to make sure our agents have the information they need to answer more of your questions on the first call. [17]

170 Hydro One began sending out more than 1 million apology letters to all residential, seasonal and general service customers on February 20. The Chief Executive Officer also personally called MPPs in Hydro One's service territory. In April 2014, he sent them an update on the progress made; I received a similar letter.

171 Hydro One also revised its website in March 2014, adding a section for correspondence and policy changes related to my investigation, as well as one entitled "Working to Get Better." It posted videos answering various billing and service-related questions. In addition, the company held three telephone "town hall" meetings – one in April and two in November 2014 – which allowed some 60,000 customers to call in to get their questions answered by the Chief Executive Officer and senior managers.

172 The public also heard from the then-chair of the board of directors, who vowed to hold management accountable. He noted in a February 2014 media interview that Hydro One "may not have been quite as customer-oriented as we would like it to be or as people frankly demand in today's world."[18] On March 7, 2014, the government announced that the chair would be replaced as of April 1 that year.

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[17] Available online here: http://www.hydroone.com/Ombudsman/Pages/LettertotheEditor.aspx

[18] "Hydro One chair vows to fix erratic billing system," Adrian Morrow, *Globe and Mail*, February 10, 2014. Online: http://www.theglobeandmail.com/news/national/hydro-one-chair-vows-to-fix-erratic-billing-system/article16793395/

Corrupted Communications Culture

173 In Ontario's public sector, transparency, openness and accountability are highly prized, particularly when it comes to its communications with stakeholders. Unfortunately, prior to my investigation, Hydro One's external communications approach was the antithesis of these democratic values. Its public messaging was opaque, disingenuous, and self-serving. It reflected a corporate mindset suffused with technocratic superiority and fondness for private-sector practices.

174 Instead of honestly and promptly explaining that it had systems problems that were affecting customer service, Hydro One officials engaged in a reactive campaign of deflection and deceit. Its representatives effectively lied through omission when dealing with my Office, the Ontario Energy Board, its customers and other stakeholders. It was only after the situation was finally exposed that it began desperately trying to regain customer trust and credibility.

175 The former chair of the board of directors, who oversaw the company during the customer information system transition, was of the view that senior management did not consciously mislead the board or others. It is certainly possible that Hydro One executives were so blinkered by their faith in the new computer technology and their overreliance on statistics that they simply missed the significance of the litany of technical glitches and the rising complaints. Even so, it is extremely disturbing and indicative of an insular and malignant organizational culture.

176 Our review of internal Hydro One documents also clearly shows that at least some management staff deliberately accentuated the positive aspects of the new computer system, while concealing information about billing problems and customer complaints that would cast the company in a bad light.

177 In future, Hydro One should commit to a communications strategy that is transparent, open, and accountable to the public. It should adopt a proactive approach to communicating with stakeholders, as well as oversight and regulatory bodies. It should tell the truth about issues affecting the delivery of its services, and it should do so in a timely way. It should also ensure that private-sector entities carrying out services on its behalf are held to the same communications standards.

Recommendation 3
Hydro One Inc. should adopt a proactive, transparent, open and accountable approach to communications with stakeholders and oversight and regulatory bodies.

Recommendation 4
Hydro One Inc. should ensure that any provider of outsourced services communicates with stakeholders and oversight and regulatory bodies in a transparent, open, and accountable manner.

Recommendation 5
Hydro One Inc. should monitor call centre communications to ensure that they reflect the transparency, openness and accountability expected of a provider of public services.

Operational Missteps

178 While Hydro One's culture and communications played a significant role in inciting customer distrust, mismanagement of several planning and operational issues also contributed to the company's billing and customer service problems.

Training Wreck

179 Hydro One recognized that one of the key elements required for successful implementation of the new customer information system was staff training. However, a delay in completing systems testing prior to the changeover affected the training schedule. Staff training was a moving target as the "go live" date shifted from October 2012 to March 2013, and finally to the May 2013 long weekend.

180 In January 2013, an internal risk assessment identified a problem with staff readiness. In February, emails referred to the training team "struggling to get their course materials finalized." Training of call centre staff had begun by March, but internal email communications identify concerns with the adequacy of the training and the training environment, which was overcrowded and uncomfortable. The electronic training system was apparently also unstable, often crashing and interfering with exercises. A March "go live" target date was abandoned in part because of the risk that poor training would lead to increased call handling time and customer frustration.

181 Some 1,293 staff were trained on the new system, including 330 from the call centre, between March 11 and May 17, 2013. Several call centre staff we interviewed told us the training materials were incomplete and disjointed, and the information changed daily as new defects and exceptions were discovered.

They also said the instruction was quite basic and left them unprepared to answer customer calls when the system went live. Several permanent call centre staff expressed concern that only temporary staff were trained on resolving system "exceptions." They said they would have been able to provide better service if they had been trained in more functions. We were also told that delays in training on the various "exceptions" arising with the new system contributed to backlogs in clearing them.

182 Hydro One's customer relations centre staff, who handle escalated inquiries, received compressed three-day training instead of the weeks of training provided to call centre agents. They did not receive training on exceptions, which meant they had to get call centre assistance to resolve complaints about them, causing further delays.

183 A December 2013 study conducted for Hydro One by a consultant identified various training problems, including that agents found work instructions too long and difficult to follow and lacked sufficient information about the system and various processes. More training was recommended.

184 An internal audit in April 2014 also found that the training did not adequately prepare agents, was rushed, and was not provided to everyone who needed it. In a post-training survey of 300 call centre staff, 43% said they felt unprepared to apply the new skills and tools successfully.

185 One of the common complaints we heard from both Hydro One customers and call centre staff was that agents had limited understanding of the technical aspects of billing and system issues. This led to overreliance on technical support staff and meant complaints often had to be escalated to managers.

186 In our interview with the Chief Executive Officer, he acknowledged:

> I think as a whole we were failing the agents … we didn't give them the tools they needed. I don't support that that's the way to do it, but that's a failing on our part in our system, and I think that was a wakeup call.

187 Internal emails show that after the billing and customer service controversy hit the news, additional "empathy training," focusing on understanding and acknowledging customer's situations, feelings and needs and quickly identifying resolution paths, was provided to call centre staff in January 2014. Refresher training for call centre agents also took place in March 2015.

188 In preparing for the new customer information system, Hydro One failed to ensure that staff responsible for dealing with customer concerns were adequately

trained. In future, before it introduces initiatives directly affecting customer service, Hydro One should provide comprehensive training for relevant staff and outsourced agents. It should also consult and obtain timely feedback from frontline staff to gauge training effectiveness, and provide supplementary training if necessary.

189 Hydro One should also consider providing more detailed training to call centre and customer relations centre staff so that they are better equipped to explore and respond to customer concerns about the billing process. Hydro One places much stock in "first call resolution" and evaluates call centre agents on their ability to satisfy customers in one call. However, unless those answering the phones have a clear understanding of the technical issues and trends affecting billing and other services, frequent escalations will continue to frustrate agents and customers.

Recommendation 6
Hydro One Inc. should ensure that it implements comprehensive staff training before introducing any initiatives with potential impact on customers.

Recommendation 7
Hydro One Inc. should consult with and obtain timely feedback from individuals responsible for contact with customers to ensure that training is effective and supplemented if necessary.

Recommendation 8
Hydro One Inc. should consider providing additional training to call centre and customer relations centre staff in technical and other operational issues to enable them to resolve customer service concerns more effectively.

190 Call centre staff also told us they were concerned about the adequacy of the scripts and work instructions they were given to address customer issues. Hydro One's records show that a technical staff member identified several inaccuracies in materials provided to call centre staff. An internal Hydro One audit in April 2014 confirmed that the scripts provided to staff were insufficient as they did not address the system problems that were encountered. By May 2014, 50 call centre agents had received refresher training on billing inquiries and scripts were reviewed and updated.

191 The quality of the information that call centre agents provide to customers is only as good as the information Hydro One gives to them. Accordingly, Hydro One should ensure call centre agents have accurate and up-to-date information,

so they can address billing and other customer service issues as they arise. In addition, Hydro One should consult with technical and frontline staff to ensure that the scripts provided to them are useful and allow them to respond effectively to customer queries.

Recommendation 9
Hydro One Inc. should ensure that it regularly provides clear, timely and accurate scripts for use by call centre staff to address billing and other customer service issues as they arise.

Recommendation 10
Hydro One Inc. should consult technical and front line call centre staff in the development of scripts to ensure that it provides the tools necessary to ensure effective customer communications.

It's Alive!!! – System Implementation

192 As Hydro One was preparing for the changeover of its customer information system, it relied on a "business readiness assurance team" to provide an independent opinion to the Chief Executive Officer about its state of readiness, to mitigate associated risks. However, the team was not responsible for assessing the fitness of the system itself.

193 A colour scale was used to describe the status of the project. In February 2013, the business readiness assurance team reported that the state of readiness for system implementation was "orange" – between red and yellow, meaning not ready. The team also observed that better communication was required amongst the project team and relevant directors. In an April 2013 report, it put the state of readiness at "yellow," but supported the May target for system implementation. However, the team never interviewed any of the call centre agents or the trainers to obtain their views on whether agents were sufficiently prepared to address customer service issues that might arise.

194 Hydro One's Chief Executive Officer made the call to continue with the plan to implement the new system in May 2013. A Hydro One internal audit document observed that while there were some unresolved problems with system applications, "it was considered a good business decision to [launch the new system] and manage the customer issues and fix the remaining software shortly afterwards." Business reasons supporting this move included continuing concerns with the degradation of the existing system, which was slow, had memory problems, and was at risk of crashing. With the benefit of hindsight, the

Chief Executive Officer told us he would still have pushed forward with the May 2013 launch, but he would have taken a different approach, including more rigorous attention to the billing problems and their effect on customers:

> I would have had a contingency plan around customer impacts… things like no bills and estimated bills and everything around that… I think that's the fundamental piece… I would've asked more questions around testing and the implications… I think I would have still gone live with a much more robust plan [to address problems].

195 In future, the company should include an evaluation of whether its staff and outsourced resources are fully prepared, as part of any business readiness assessments preceding major system changes.

Recommendation 11
Hydro One Inc. should ensure that evaluation of staff and call centre agents readiness is included in pre-implementation business readiness assessments preceding major system changes that impact customers.

Call Centre / Pressure Cooker

196 Although Hydro One's call centre is outsourced to a private-sector provider, it is the face and voice of the corporation for most of its customers. Increased stress on call centre staff inevitably filters down to Hydro One's customers. Unfortunately, Hydro One managers appeared oblivious to this fact after the new customer information system was installed and call centre staff were flooded with calls.

197 One of the criteria that Hydro One uses to assess call centre effectiveness is the "average handle time" for customer calls. This is a common metric employed to measure call centre efficiency. Hydro One's call centre provider is contractually bound to ensure 80% of calls are answered within **20-30 seconds**. The shorter the average call length, the more likely the provider will meet this service level. If service levels are not met, Hydro One can levy a financial penalty on the provider.

198 Hydro One officials monitor the average handle time closely. In planning for the system changeover, it was anticipated that call volumes and average handle time would initially increase but gradually normalize. Instead, call volumes were substantially greater than predicted, as was the average call length. Under the

old system, the average call lasted **305** seconds (**five minutes**); this jumped to upwards of **450** seconds (**7.5 minutes**) with the new system.

199 Despite rising call volumes and the complexity of billing inquiries, Hydro One's senior managers continued to exert pressure on the call centre to bring it in line with earlier projections and the contractual service level. Just three months after the new system launched, one Hydro One manager expressed concern to the call centre leadership in an email about the increasing length of time it was taking call centre staff to handle customer calls. Instead of addressing the reasons for the longer calls, he urged that efforts be made to shorten them, suggesting that a reduced target would "light fires." Emailing in response, a senior call centre official cautioned that what Hydro One was suggesting would only make the situation worse. He noted:

> (T)o be frank, we're not going to be able to drive through that sort of reduction simply by coaching our agents. In fact, you run the risk of increasing complaints if we push agents hard to push customers off the phone quickly. We have a lot of very irate customers. We need to work through this as a larger team so that we work through some of the underlying causes…
>
> All that I'm saying is that there are a host of problems that are driving the high [average handle time] and we need to address the underlying causes that are at the root of the problem.

200 Hydro One's push for reduced call handling times continued through the fall of 2013. A senior executive told us there was enormous pressure on the provider to bring the situation back to normal:

> (T)here was a lot of pressure to try and push [average handle time] down. From our perspective, it was the underlying billing issues that you really need to get fixed. Resolve that issue, because pushing customers off the phone is not going to be delivering a positive message.

201 Agents who fail to meet average handle time expectations can face disciplinary measures from the outsourced call centre management. Several employees filed grievances relating to this issue after the new system was introduced. During our interviews, call centre staff expressed frustration about the unrelenting emphasis on average handle time during this difficult period. They noted that calls about bills, particularly when they involve complicated issues, are typically lengthy, and many of the calls after the system changeover related to complex billing matters.

202 One agent candidly admitted that the unrealistic demand to keep the average handle time down spurred atrocious treatment of customers:

> There just is no way to meet [the average handle time]. So that agent that you will be presented with has crafted some way to fudge numbers to make it look like they have a good [average handle time], and/or they are hanging up on customers, being rude to customers, pretending that they don't see an issue in the account when they clearly do.

203 A former call centre team coach told us call quality was continually sacrificed for the sake of shorter handling times:

> For an agent on the floor, their average handle time is everything. It's their job. They're threatened. They're [held to] unrealistic expectations… Everybody's counting numbers and there's a financial penalty that [the provider] will incur if they don't meet those service levels, so numbers are everything. Quality? Quality was secondary…
>
> If it took 15 times for the customer to call to get something done, they don't care. It's as long as the call got answered promptly and they're off the phone again to take the next call. It's about making sure that the service level is always met. It doesn't matter if that customer has to call 15 times.

204 Some call centre agents told us they felt that their task wasn't to solve customer problems, but to get customers off the phone. As a Hydro One employee put it: "How do I get rid of a second? I don't say hello. How do you screw up a phone call for somebody who has been on hold for 17 minutes? Don't say hello."

205 As the workload stress increased on call centre staff, so did complaints about agent conduct. Once customer concerns hit the media, call centre management provided agents with additional "empathy training" and threatened a zero-tolerance policy for poor behaviour. Call centre staff told us these developments further contributed to plummeting morale.

206 After I launched my investigation, Hydro One management began to realize that shaving seconds off a customer call was not its prime concern. Less emphasis was placed on average handle time and more attention devoted to the quality of customer interaction.

207 By stressing average call handle time, Hydro One kept the focus on the technical process of answering and terminating calls, not on their content. Customer concerns and quality of service took a back seat to statistics. Consistent with its

renewed commitment to customer service, Hydro One should conduct research of call intake best practices and re-evaluate the measures that it uses to assess the customer service provided by its contracted call centre. In doing so, it should look beyond the private and utilities sectors and consider customer service benchmarks within the provincial public sector. It should also shift the spotlight from average handling time to the quality of contact and actual outcomes for its customers.

Recommendation 12
Hydro One Inc. should conduct research on call intake practices, and revise its performance measures to reflect public sector best practices and greater emphasis on the quality of calls and customer outcomes.

Call Quality Assurance, Please Hold

208 Under its contractual agreement, the call centre's private-sector operator is required to provide monthly reports to Hydro One. Representatives of the two companies also meet monthly to discuss these reports and whether the provider is meeting required service levels. The call centre has quality auditors, who monitor recorded calls and assess them against call evaluation and quality scoring standards. In turn, Hydro One has assigned an in-house customer service analyst to review a sample of the audited calls to ensure they meet the standards. If the call centre fails to meet specified service quality levels, a penalty will be assessed against the operator. In fall 2012, Hydro One suspended its quality monitoring to free up staff for other activities. Monitoring resumed in April 2014. The call centre also stopped monitoring calls after the new customer information system was launched, until October 2013.

209 Call monitoring is essential for identifying customer service concerns, systemic issues, and staff training needs. Hydro One's failure to ensure that call quality was monitored during the system launch period was significant. As an internal audit report later noted:

> The suspension of Hydro One call monitoring eliminated the one true source of truth with respect to customer satisfaction at this critical time.

210 Our investigation also revealed several flaws with the monitoring program. For instance, until the summer of 2014, only 10% of call centre calls were recorded. While all calls are now recorded, call centre auditors only review a fraction of these, about 250 each month. Audits are supposed to take place soon after the

calls occur. However, quality assurance auditors told us increased call volumes resulted in audits taking place up to a week later. Auditors are also expected to only spend a maximum of 20 minutes per call audit. This means more difficult, complex and lengthy calls are often skipped.

211 As well, we discovered that call centre audit results could be manipulated to paint an overly rosy picture. Some staff told us they "cherry pick" the calls they audit, selecting short calls that meet average handle time expectations. One candidly explained:

> If we get close to the end of the month and the quality is not where it should be, then we have to work to get the quality to where it should be. We choose the calls…

212 On Hydro One's side, only one customer service analyst performs call quality auditing. She does not independently monitor live calls, but listens to about 50 calls a month from those already audited by the call centre. As long as the scores given in both audits come within 5% of each other, an audited call is considered satisfactory. Any discrepancies are discussed at "calibration sessions" between the two organizations.

213 At present, Hydro One's call quality monitoring efforts are limited. It should be conducting more robust monitoring to satisfy itself that customers are receiving the respectful, courteous and professional service they deserve. It should not simply rely on auditing calls previously selected and reviewed by the call centre. Rather, it should engage in independent and random auditing of recorded calls and develop a process for live auditing of calls.

214 Internal documents indicate that some Hydro One officials and their family members relayed their own experiences with poor call centre service after the system change. In February 2014, there was also some discussion concerning making a few "secret shopper" calls to test call centre performance. Hydro One does not have a formal "secret shopper" program (i.e., people posing as customers to test the responsiveness and quality of the call centre), but should consider instituting such a program to gain more practical insight into call quality in real time.

Recommendation 13
Hydro One Inc. should engage in more robust monitoring of the quality of call centre calls through more extensive sampling of recorded calls, live call monitoring, random spot checks, and the introduction of "secret shopper" calls.

215 Although the call centre should be expected to monitor its own calls, it is not a disinterested party. To mitigate the risk that call centre audits may reflect overly positive outcomes, Hydro One should consider retaining an independent agency to conduct call audits.

Recommendation 14
Hydro One Inc. should engage an independent external third party to assist in conducting random audits of call quality.

216 Hydro One's call evaluation and call quality scoring standards have not been updated since April 2009. As part of its new emphasis on customer-centered service, the company should review and update these standards to ensure that they reflect this new focus.

Recommendation 15
Hydro One Inc. should review and update its call evaluation and call quality scoring standards to ensure that they reflect its goal of customer-centered service.

217 One glaring omission in Hydro One's call monitoring program is that it does not apply to its in-house customer relations centre, which handles escalated customer calls and those from stakeholders like MPPs, the Ontario Energy Board, and my Office. Hydro One is missing out on an opportunity to ensure that its own staff are appropriately responding to escalated complaints. It should develop quality standards for the customer relations centre that reflect the goal of customer-centered service. It should also record customer relations centre calls and introduce a call monitoring program with features such as live call monitoring, random spot checks, and secret shopper inquiries.

Recommendation 16
Hydro One Inc. should develop customer service quality standards for the customer relations centre.

Recommendation 17
Hydro One Inc. should record customer relations centre calls and develop a call monitoring program for the centre, including live call monitoring, random spot checks and secret shopper calls.

218 Hydro One owns most of the assets that are used to deliver outsourced services, and the two call centre locations are in Hydro One facilities. However, despite their close physical connection, Hydro One managers responsible for overseeing the call centre have tended to keep their distance from its day-to-day operation. It was only in late March 2014 that Hydro One managers set up a physical presence in the main Markham call centre, to provide more strategic oversight, operational direction, policy advice and guidance. This included listening in on calls to monitor quality and provide feedback. In addition, daily check-in calls were established amongst senior Hydro One managers to keep informed about call centre issues.

219 The company should ensure that managers continue to have a physical presence in the main call centre and engage in robust on-site monitoring of call centre activities.

Recommendation 18
Hydro One Inc. should continue to have managers located in the main call centre to ensure robust on-site monitoring.

Surveying the Situation

220 Another tool that Hydro One uses to evaluate customer satisfaction are surveys, which are carried out by private research companies. These surveys include residential and small business customers, large distribution customers and customers who connect their own generators to the distribution system.

221 One company surveys customers within a few days of their contact with the call centre, to determine their overall satisfaction with the transaction, and such issues as response time, information quality, skill and attitude of staff, and ease of access. The survey results for 2013 – the year of the customer information system fiasco – were reported in February 2014. They indicated an 82% overall satisfaction rating – a decline of just 2% from 2012. Until recently, the survey reviewed 100 customer transactions each month. That number recently increased to 600 a month. Shortly after our investigation began, Hydro One also started a short survey of call centre customers, which asks them to "rate your experience" by indicating whether the representative they spoke to was knowledgeable and understood their needs, and whether the call was resolved to their satisfaction.

222 Another company tracks residential and small business customer satisfaction and perceptions of the company. It surveys about 2,400 customers per year

about such things as overall satisfaction, customer service, hydro rates, billing and payments, service reliability, outage management and communication. This survey reported in October 2013 on overall satisfaction with Hydro One in 2012 and 2013 and found it actually increased during the year of the customer information system change – from 78% in 2012 to 80% in 2013.

223 After the introduction of the new customer information system, the perception surveys continued to produce positive results, and even the monthly transaction surveys did not signal any substantial customer service problems. While some measures saw occasional dips in the satisfaction ratings, these were not particularly unusual when compared to the results from previous years.

224 Key survey statistics are reported to senior Hydro One management. Regular reports and presentations are provided to the relevant managers. High-level survey results are also shared with the Ontario Energy Board, which uses this information to publish "scorecards" on its website.

225 Hydro One reported an overall 87% customer satisfaction rate for 2013. It told us that customer satisfaction "is an equally weighted composite index of the three distribution customer segments: residential and small business, large distribution customer accounts and distribution connected generators." The overall customer satisfaction rate is also posted on the company's scorecard on the Ontario Energy Board's website.

226 Given the escalating billing and customer service issues the system changeover in May 2013 spawned, it seems perverse that Hydro One scored so highly in customer satisfaction. It suggests that the surveys conducted that year were of no real value in identifying problem trends. The recent moves to increase the number of transaction surveys and survey call centre customers might help the company obtain better insight into emerging issues. However, Hydro One should conduct research and consult with customers and other stakeholders to determine if there are other, more effective and accurate means of measuring and reporting customer satisfaction.

Recommendation 19
Hydro One Inc. should conduct research and consult with customers and other stakeholders to evaluate whether there are other, more accurate means of measuring and reporting on customer satisfaction, and change its survey and reporting practices accordingly.

227 According to Hydro One records, the last customer satisfaction survey to gauge the quality of its customer relations centre was conducted 15 years ago. After the centre scored just 36%, the survey was abandoned. Hydro One should implement a survey program to evaluate satisfaction levels with this centre.

Recommendation 20
Hydro One Inc. should conduct customer satisfaction surveys of those using the customer relations centre and use the results to plan for operational improvements.

Knowing the Real Score: Performance-Based Compensation

228 Hydro One also publishes corporate scorecards every year that measure its success in meeting strategic objectives. Its non-bargaining unit employees, including the Chief Executive Officer and senior executives, enter into annual performance agreements that reflect their individual goals. Performance targets for senior officials are normally linked to the indicators on the corporate scorecard. Employees can qualify for a yearly short-term incentive payment depending on their performance and ability to achieve their targets.

229 For 2013, Hydro One's scorecard displays its customer satisfaction rate as 87%, based on survey results. This is clearly incongruous with the billing and customer service issues experienced by the company from May 2013 onward. In its Annual Information Form, published March 31, 2014, Hydro One acknowledged that in assessing the performance of three executives, it factored in "certain negative prolonged billing and related services issues concerning the Customer Information System."[19] In the case of the Chief Executive Officer, it observed: "The [board of directors] also gave significant weight to his overall responsibility for such negative issues related to the Customer Information System." Some incentive payments were awarded to reflect staff performance in 2013, but the board reduced those provided to the Chief Executive Officer and other key individuals in light of the problems that arose with the system implementation.

230 Hydro One's Chief Executive Officer has publicly shouldered personal responsibility for the billing and customer service fiasco, but others have shared

[19] The form is available online here: http://www.hydroone.com/InvestorRelations/Documents/Annual_Information_Forms/Hydro_One_Annual_Information_Form_2013_ENG.pdf

the blame. After my investigation was launched, one senior official precipitously retired and another's service was terminated.

231 The company's most recent scorecard is for 2014, published in its February 27, 2015 Annual Information Form. It shows customer satisfaction down slightly, from the previous year, to 85%. The scorecard also includes some new measurement categories for customer satisfaction, including "unscheduled estimated bills" and "no bill volume." Hydro One exceeded its targets in these two areas, with only 1.2% of its total bills fitting into the first and only **2,600** customers in the "no bill" category.

232 The 2014 scorecard also includes a new strategic objective: "Maintaining a commercial culture that increases shareholder value." This includes reference to the customer service recovery cost of **$88.3 million** – significantly more than the $47.8 million they had initially projected. It states that Hydro One accomplished a "concerted and successful response, through the customer service recovery project, to the billing issues that arose from the Customer Information System..." The company's net income was down $54 million from the year before, but it notes that it exceeded the net income goal it set for itself, bringing in **$749 million** in 2014.

233 Hydro One is in the business of generating hundreds of millions of dollars for provincial coffers, and its financial success is undoubtedly beneficial to Ontario's citizens. However, I am concerned that in relying primarily on surveys to gauge customer satisfaction, and in stressing its commercial culture, the company is perpetuating the organizational attitudes that led it to reputational ruin in early 2014. In future, Hydro One's objectives should relate to changing its organizational culture to clearly embrace public sector values. It should evaluate its ability to communicate with customers and other stakeholders proactively, and in accordance with the principles of openness, transparency and accountability. It should also assess its policies and practices to ensure customers are treated fairly, reasonably and with respect.

Recommendation 21
Hydro One Inc. should establish strategic objectives for its corporate scorecard, as well as for individual managers, related to changing its organizational culture to reflect public sector values.

Lessons Unlearned

234 Hydro One completed several risk workshops and internal audits as it was preparing to implement the new customer information system. However, the last risk assessment took place in January 2013. There was no evaluation of risks associated with billing and customer service after the system was introduced in May 2013. Unlike in earlier phases of the information systems transformation project, no formal "lessons learned" evaluation was done after the system was introduced. By failing to conduct audits and evaluate risks after the launch, Hydro One lost a valuable opportunity to identify and address problems affecting customers.

235 Interestingly, in November 2013, the Chief Executive Officer and another executive delivered their own version of "lessons learned" from the system refresh in a presentation they gave to a major construction company. According to notes from the presentation, it included such sage wisdom as:

> The post-go-live valley of despair can be deep and long. Get ready for it. Measure your way out of it. If you are planning for a three-month dip in performance, triple it; and
>
> Have a rock-solid post-go-live support structure. Expect process gaps, training gaps, system gaps, data gaps. Triage it and fix it. Keep everyone calm.

It is apparent that their focus was on technical challenges associated with the transition, not on its effect on customers.

236 After my investigation was announced in February 2014, Hydro One's then-chair directed that an internal audit of customer service scheduled for later in the year be commenced "expeditiously." An internal audit submission was made to the board's business transformation committee on March 25, 2014. It said "formal risk assessments would have helped identify and raise awareness that better actions and communication were essential." Committee members were also told:

> During the last few months of 2013, insufficient attention appears to have been paid by all concerned to the ongoing high number of problems in billing, higher than manageable number of … exceptions, higher than usual number of bills being produced with estimated usage rather than actual [time-of-use] usage measured from the smart meters, and to the resulting escalating trends in customer complaints.

237 In the wake of my investigation, Hydro One's board also spent $310,000 to have an external consultant (PricewaterhouseCoopers) conduct a "lessons learned" exercise. The consultant's final report was issued on December 2014.[20] Its conclusions were consistent with the information we obtained during our investigation.

238 The PricewaterhouseCoopers report identified eight root causes for the problems associated with the implementation of the new customer information system, starting with an overly ambitious implementation timeline. Other concerns identified included inconsistent use of internal audit and risk assessment teams over the course of the project (particularly once the system was launched), and significant turnover in the project teams and at the project management office, resulting in the loss of continuity.

239 The report also commented on the fact that the executive and board of directors' committees overseeing the project did not retain an independent third party to provide an objective view of the project's progress. It found that reliance on the project team resulted in information about risks and concerns never reaching the relevant oversight committees.

240 The consultants also observed that the quality of reporting on the system dropped off as key team members left the project, and after the system was implemented. It found that until February 2014, there was insufficient operational reporting to allow the executive and board of directors' committees to appreciate the "severity of the operational issues and the associated impacts to the customers..."

241 Hydro One's senior managers acknowledged to us that those leading the system implementation were not necessarily the best suited to this role. The "lessons learned" report also identified this as an issue and observed that the project was led by a new set of Hydro One executives with limited experience in leading large, complex, transformational projects. Other problems cited were resourcing challenges and ineffective vendor management.

242 We were told that the project planning called for a cascading series of tests. However, as time pressures increased, testing was overlapped. The report characterized this as a "high-risk" practice. It noted that testing occurred up to the night before the system launch, and there was insufficient time to familiarize or train those responsible for sustaining the system.

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[20] PricewaterhouseCoopers, *Hydro One Customer Service and Billing Issues – Lessons Learned*, December 2014. Online: http://www.hydroone.com/OurCompany/governance/Documents/Hydro_One_-_CIS_Lessons_Learned_Report.pdf

243 Although the report focused primarily on the planning, implementation and monitoring of to the new customer information system, it also briefly addressed the "reactive customer response." It noted that Hydro One failed to appreciate the "bill shock" experienced by customers who suddenly received large bills after prolonged periods of no bills.

244 The consultants also recognized that Hydro One's culture required a customer service reorientation. They wrote:

> Had Hydro One been more proactive and timely with these customer-focused changes it may not have experienced the level of customer frustration and negative media attention. A more customer focused cultural transformation will require ongoing support and investment to become fully institutionalized across the organization and within its outsourced service providers.

245 The report concluded that several factors impaired Hydro One's operational nimbleness, such as the fact that new defects kept cropping up and workarounds were being implemented to deal with them right up to the "go-live" date, resulting in billing staff not being fully trained prior to the launch.

246 It made eight recommendations, which Hydro One management accepted:

1. Establish a discovery phase for large-scale projects before confirming project scope and concluding contracts;
2. Engage a broad cross-section of executives, functions and stakeholders in decision-making;
3. Ensure that testing phases and windows of projects are protected;
4. Continue the practice of formal project risk assessments and internal audits at key stages of projects;
5. Improve vendor oversight and management and hold project vendors to account;
6. Ensure project leaders and team members possess the right skills and experience;
7. Maintain project tracking and documentation rigour always;
8. Ensure the right number of people with the right expertise and experience are put in place until the system is fully stable.

247 Hydro One's board of directors can be credited with retaining an external resource to conduct this exercise. However, it was done well after the project was implemented and the problems associated with the new system had snowballed and drawn abundant negative public attention. In addition, Hydro One has never carried out an in-depth exercise to examine its failure to consider

customers during all stages of its project planning, implementation and stabilization. It has never engaged in any evaluation of the failed communications strategy employed after billing and customer service problems emerged. The "lessons learned" report identified what went wrong with the system planning, implementation and "post-go-live" response from the perspective of improving internal business practices. However, the impact on customers was only addressed summarily, and not for the purpose of making concrete recommendations to ensure a better customer experience overall.

248 Hydro One should ensure in future that whenever projects are undertaken, timely risk assessments and evaluations are carried out that specifically consider whether the impact on customers has been adequately reviewed and addressed.

Recommendation 22
Hydro One Inc. should ensure that timely risk assessments and "lessons learned" evaluations take place throughout all stages of project planning, implementation and stabilization. It should consider whether the impact on customers has been appropriately identified and addressed through mitigation and contingency planning, as well as communication strategies.

Sunny Days Are Here Again

249 During our investigation, we heard the term "sunny day reports" to describe the overly optimistic and positive project reporting that was used at Hydro One's executive and board of director levels to evaluate the progress of the new customer information system. Hydro One managers were well aware that the Ministry of Energy and the Ontario Energy Board were concerned about increased complaints and delayed responses from the company. Staff also knew they were struggling with an unprecedented volume of customer complaints and backlogged technical fixes. However, executive management and the board of directors apparently remained oblivious to these warning indicators until the situation was explosive.

250 In future, Hydro One should ensure there are clear early warning mechanisms in place to alert executive management and the board of directors to percolating problems. Its executive managers and the board of directors should be frequently briefed about resolved and unresolved customer service and billing issues. Sufficient background information about the nature of these issues should be provided to enable a true understanding of the impact on customers. Progress reports should also include cumulative statistical information to provide a comprehensive view of systemic concerns.

251 Hydro One must also minimize the opportunities for statistical information to be manipulated to present an overly bright picture of its operational health. While the executive committee and the board of directors were shown charts and graphs displaying a dramatic rise in the backlog of complaints at the customer relations centre, they failed to grasp their import because of how the information was presented. As Ontario's Auditor General recommended in her December 2014 report on the smart metering initiative, the company needs to improve its tracking of inquiries and complaints. It should compile information about all complaints and inquiries received and identify the source of complaints – customers, the media, my Office, the Ontario Energy Board, the Ministry of Energy and other stakeholders. This information should be carefully analyzed to identify problem trends and to highlight individual cases involving egregious customer treatment and errors. Executive management and the board should be fully and regularly briefed on these trends, along with individual cases demonstrating significant impacts on customers. Statistics only tell half the story. Hydro One and its board of directors need a more realistic picture of the true impact of its operations on individual customers and stakeholders.

252 Hydro One should continually reinforce for its staff, through training and direction, that the purpose of preparing billing and customer service statistics is to enable the company to have a clear, objective and accurate understanding of how well it is serving its customers. We found that Hydro One's statistics shifted over time and were difficult to reconcile. Its statistics should appear in a consistent, clear, and standardized format. They should also be accompanied by meaningful and honest analysis reflecting the actual state of affairs, not public relations spin.

Recommendation 23
Hydro One Inc. should ensure that executive management and the board of directors are immediately alerted to any signs of systemic customer service and billing problems, including rising complaint levels.

Recommendation 24
Hydro One Inc. should ensure that, in addition to regular briefings on complaint statistics, its executive management and board of directors routinely receive information about complaints and inquiries from all sources, as well as details of problem trends and individual cases reflecting egregious customer service and errors.

Recommendation 25
Hydro One Inc. should ensure that executive managers and the board of directors are regularly and fully briefed about the cumulative impact and nature of customer service and billing issues.

Recommendation 26
Hydro One Inc. should continually reinforce for its staff, through training and direction, that the purpose of preparing billing and customer service statistics is to enable the company to have a clear, objective and accurate understanding of how well it is serving its customers.

Recommendation 27
Hydro One Inc. should prepare statistics in a consistent, clear, and standardized format, accompanied by meaningful and honest analysis.

253 One senior Hydro One executive we interviewed told us that the board of directors was considering creating a customer service committee. Establishing such a committee would enable the board to concentrate more directly on customer service issues, and I encourage the company to proceed with this initiative. The committee should also look for opportunities to hear directly from customers and customer groups about issues that have impacted them.

254 In order to appreciate the relevance of various operational issues and statistics in the context of customer service, Hydro One's board of directors should also receive training on technical matters and the measures used to evaluate customer service performance. Such training would help board members ask the right questions and provide more active oversight.

Recommendation 28
Hydro One Inc. should create a customer service committee of the board of directors to highlight the significance of issues affecting its customers, meet with customers and customer groups to gain a better understanding of customer service issues, and effectively address systemic concerns.

Recommendation 29
Hydro One Inc. should ensure that its board of directors receives sufficient training to understand technical aspects of the company's operations, key performance indicators and other information relevant to customer service.

255 Hydro One must also learn to act with urgency when customer service issues arise. It should not focus on the percentage of customers affected, but on the individuals who have been poorly served, and ensure that adequate resources are allocated to meet operational demands. As an internal audit report noted in April 2014, the company was slow in addressing backlogged requests in the customer relations centre. A few staff members were added in May 2013, and a few more in January 2014, but it was not until February 2014 that the complement rose to 50 to help with the bulging backlog.

256 Hydro One officials acknowledged to us that they drastically underestimated the resources required to cope with the issues arising from the implementation of the new customer information system. However, the company also delayed authorizing additional staffing for several months, after it was aware that the scope of technical and customer service issues far outstripped the ability of human resources to cope with them. In future, Hydro One should ensure that it has sufficient resources to address problems as they arise.

Recommendation 30
Hydro One Inc. should ensure that it has adequate customer service and technical resources to address customer service issues.

Refund or Discredit

257 One of the issues I mentioned at my press conference announcing my investigation was that we had been hearing from customers that Hydro One was not refunding overpayments, but insisting that customers would only be credited for excess payments. Hydro One immediately took to Twitter to tell customers: "If you have a credit on your Hydro One account, you can request a refund…"

258 During our investigation, call centre staff routinely told us that refunds might be available in some cases, but only if a customer expressly asked for one. A Hydro One executive also confirmed that the company's practice was to offer credits, not refunds. The company placed greater emphasis on offering refunds for overpayments after my investigation began. However, we were told that the production of refund cheques was delayed for a time because of a technical malfunction.

259 In March 2014, **Elaine Crilly**, a senior from **Mildmay**, contacted us when a call centre agent told her she could not get a full refund for an overpayment. Hydro One later agreed to provide a refund, but told her it would take four to six weeks.

It eventually gave her a four-month credit, and assured us that as of late April 2014, refunds should only take three to five business days to process.

260 Despite this commitment, the problem persisted for months. In July 2014, the family of a widow from **Killaloe** incurred overdraft fees and other bank charges because Hydro One unexpectedly withdrew **$5,500** in payment of her account. After we intervened, the company arranged a refund and gave her a further credit of **$660.60**. I remain concerned that Hydro One still does not have a clear and consistent practice in place for ensuring that timely refunds are available to customers.

Recommendation 31
Hydro One Inc. should develop a system to ensure that timely refunds are available to customers who have overpaid their accounts, through inadvertence or system error.

Unclear Bills

261 Another issue that customers have repeatedly raised is that their bills are confusing and unclear. In summer 2014, Hydro One officials told us there was no plan to redesign the bills to make them more user-friendly. By November 2014, we were told that Hydro One was evaluating some "bill presentment alternatives for the future," but had no plan for changes. By December, we were told bills were being redesigned to make them clearer.

262 For most customers, the primary communication they receive from Hydro One is their bill. The fact that the company has only recently realized that it should revise its bills to make them more customer-friendly is concerning. Hydro One should pursue bill redesign with a view to ensuring that information is presented for maximum clarity. In the process, it should consult with customers and consider best practices from other utilities.

263 During the billing crisis, many customers were frustrated and confused when they received a flurry of multiple bills, sometimes as many as 20 at once. Even Hydro One staff were often flummoxed when asked to explain how this happened. When Hydro One must reissue bills because of mistakes, prolonged estimates or otherwise, it should prepare a single itemized bill, along with a letter clearly and simply explaining the account reconciliations and the reasons for them.

Recommendation 32
Hydro One Inc. should redesign its bills to ensure maximum clarity.

Recommendation 33
Hydro One Inc. should consider best billing practices and consult its customers and other stakeholders in redesigning its bills to ensure that any revisions actually meet customer needs.

Recommendation 34
Hydro One Inc. should prepare a single itemized bill, rather than multiple bills, to address rebilling because of mistakes, prolonged estimates or other circumstances, along with accompanying correspondence setting out a clear explanation as to why the account has been reconciled.

Confusing Complaints Process

264 Several Hydro One customers expressed confusion about its complaint escalation process. Many were unaware of the difference between Hydro One's customer relations centre and the outsourced call centre. Although there is a section on disputes embedded in Hydro One's conditions of service, it is not readily accessible and there is no clear explanation of the complaint process on the company's website. To assist its customers, Hydro One should post a plainly worded description of the various levels of its complaint process on its website.

265 Many customers also told us that despite their continuing dissatisfaction with the information Hydro One provided to them, they were never referred to the Ontario Energy Board or my Office. Hydro One should include reference to external avenues of complaint on its website and ensure that customer relations centre staff consistently make referrals to outside agencies when appropriate.

Recommendation 35
Hydro One Inc. should post a clear explanation of the complaint process, including information about call centre and customer relations centre escalations, and reference to external referrals.

Recommendation 36
Hydro One Inc. should ensure that the customer relations centre staff consistently provide external referrals to the Ontario Energy Board, the Ontario Ombudsman and other relevant bodies where appropriate.

The Power of Apology

266 Hydro One sent out form letters to apologize for individual problems encountered with the new customer information system, and when the media storm hit in February 2014, senior officials were quick to apologize publicly for poor service. However, the company does not follow a consistent practice in its oral or written apologies. We found some cases where customers received heartfelt apologies, while others who were equally inconvenienced heard nothing. One frustrated customer commented to us that this should be a matter of common courtesy:

> Be considerate. If people keep phoning back over and over and over, have somebody in authority call them back. Explain what is going on. Apologize.

267 Ontario's *Apology Act* encourages the use of apologies, insulating them from admission in civil, administrative and arbitral proceedings. Apologizing for errors, delays and misunderstandings is expected from public service agencies. Accordingly, Hydro One should develop a procedure to ensure that customers who experience substandard service receive sincere apologies as well as clear, detailed and accurate explanations for the problems they encountered.

Recommendation 37
Hydro One Inc. should develop a procedure to ensure that customers are consistently offered clear, detailed and accurate explanations as well as apologies for poor service.

Crossed Wires – Billing Resolution Duplication

268 Several teams at Hydro One worked independently to implement technical fixes to resolve customer billing concerns. Unfortunately, lack of communication and co-ordination amongst the groups sometimes put them at cross purposes. For instance, the customer relations centre might resolve a customer complaint by cancelling a customer's bill and revising it, only to have a SWAT team member repeat the process. Several Hydro One staff we interviewed confirmed that failure to communicate amongst the teams exacerbated customer service problems.

269 Hydro One's internal emails from June 2014 refer to six cases where one team's work cancelled out the work of another. One Hydro One manager attempted to

downplay the significance of the lack of co-ordination between these groups, assuring us that the number of bills affected was quite small. However, other staff expressed concern that overlapping responsibilities served to further frustrate customers. One SWAT case worker observed:

> We're trying to gain their trust back and the same sort of scenario just happened. They just got a duplicate set of bills again, so it makes them wonder what's going on… it's not a good situation.

270 Hydro One should ensure that different work areas co-ordinate and communicate to avoid duplication, inconsistency and poor customer service when trying to resolve billing issues.

Recommendation 38
Hydro One Inc. should ensure that its efforts to resolve billing issues are adequately monitored and co-ordinated to prevent duplication, inconsistency and negative impact on its customers.

Cultural Differences: Failing the Culture Change Test

271 Hydro One's Chief Executive Officer has been in his present role since January 2013, but he has worked for the company for decades. His senior managers agree that he has made concerted efforts to improve the company's culture and make it more transparent. One manager told us the Chief Executive Officer was trying to get the company "out of the compliance mindset." Others said he is trying to get more "outside vision."

272 After my investigation began, the Chief Executive Officer encouraged senior managers to make direct contact with customers, and he even took a turn at the call centre, answering calls. Since the summer of 2014, he has also asked Hydro One staff to carry a "core values" card that sets out five values, including "customer caring." The card states that Hydro One sees its work through the eyes of customers, and keeps its promises, sharing information and offering advice. The card also reminds staff: "Serving customers is why we are here."

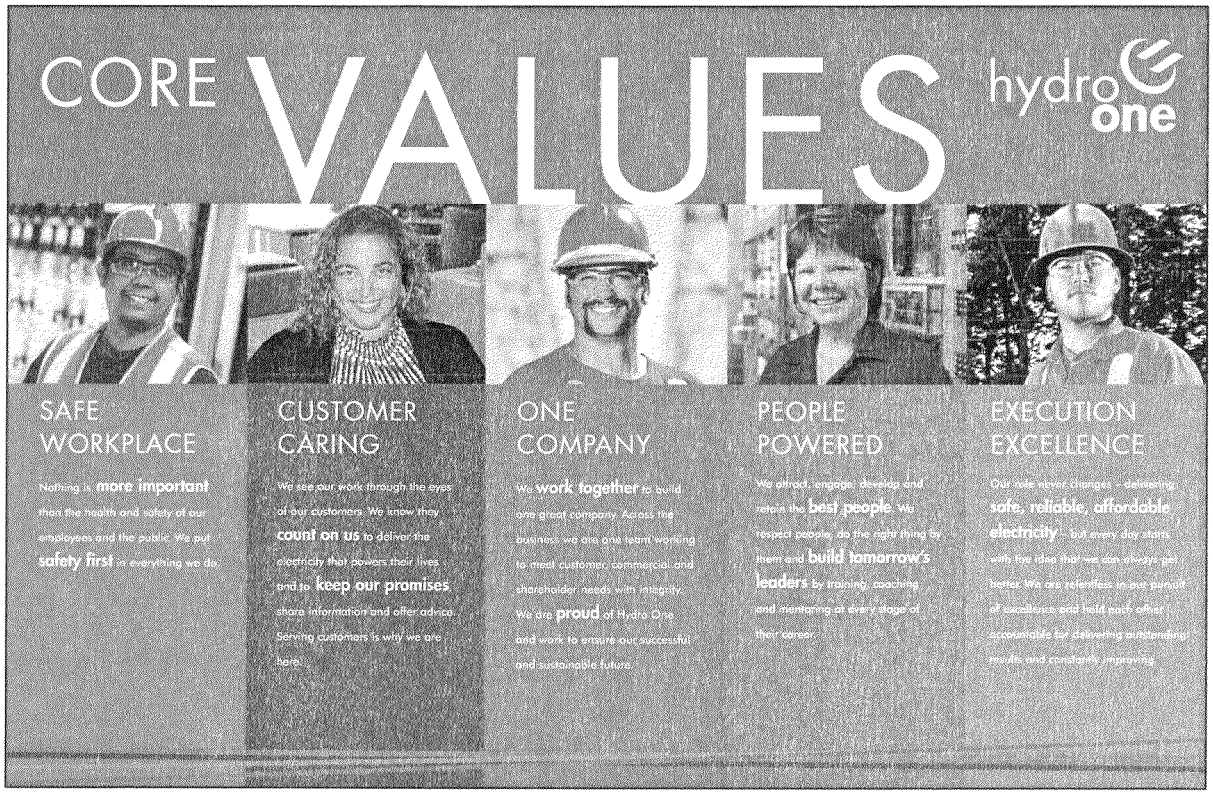

Figure 7: Hydro One's "Core Values" card.

273 Hydro One told us that its core values were recently incorporated into the call centre's quality training and related quality monitoring program. This includes greater attention to listening, empathy, education and assistance to customers.

274 Adopting corporate values and symbolic gestures to improve employees' appreciation of customer experiences are well-intentioned and positive measures. However, they are meaningless if they don't translate into real attitudinal change. Remnants of Hydro One's introspective culture remain – and one clear illustration of this is that the core values are nowhere to be found on the company's website.

275 After I announced my investigation, Hydro One pledged to change its culture to become more customer-focused. The Chief Executive Officer predicted in his October 2014 presentation to the Ontario Energy Network that "by the time the [Ombudsman's] report comes out, we will be a different company." The then-chair of the board of directors echoed that view, vowing that Hydro One would

become "customer-driven"[21] and later expressing the hope that by the time my investigation was finished, I would be "reporting on a historical point in time within Hydro One."[22]

276 Hydro One's executives maintain the company is providing very different customer service than it was in 2013 or early 2014. However, the litmus test for cultural change is whether the company has followed through on its promises. Regrettably, during my investigation, I saw few concrete signs that Hydro One had moved beyond its cultural comfort zone. I am not convinced that the company is significantly different than it was when we started.

Committing to Customer Commitments

277 On October 22, 2014, Hydro One's Chief Executive Officer wrote and told me that a draft "customer commitment document" would be posted to the company's website that very day. He indicated that Hydro One would seek input on its commitments from its customers, employees, stakeholders and the newly established customer service advisory panel. He further pledged that once the document was finalized, the company would establish metrics that would relate directly to the commitments, and form the basis of a public scorecard that would measure how Hydro One's performance "stacks up against our stated commitments." The letter to me was posted on the company's website.[23] However, in March 2015, when my investigators inquired about the whereabouts of the commitment document, it took seven business days to arrive – and what we were sent turned out to be a draft that is still a work in progress, under review by the customer service advisory panel. As of the writing of this report, there is still no customer commitment document on the company's website.

278 I am somewhat skeptical of customer charters, bills of rights and similar documents. It is my experience that sometimes the agencies with the most impressive value statements are the worst at living up to them. I was prepared to give Hydro One the benefit of the doubt when it announced that it would make formal commitments to its customers. However, the fact that the promised document is still missing in action six months after the Chief Executive Officer promoted this initiative is concerning.

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[21] "Sandra Pupatello named chairwoman of Hydro One," Dave Waddell, *Windsor Star*, March 7, 2014. Online: http://blogs.windsorstar.com/news/sandra-pupatello-named-chairwoman-of-hydro-one

[22] "At Hydro One helm, Pupatello vows to put customers first," Ashley Csanady, *Queen's Park Briefing*, March 14, 2014.

[23] The letter can be found here: http://www.hydroone.com/Ombudsman/Documents/Andre_Marin_File_No_276184_October_22_2014.pdf

279 The draft document that was finally sent to us in March 2015 consists of eight simple pledges:

1. We will **provide** you with a clear, timely and accurate bill.
2. We will **deliver** a reliable supply of electricity.
3. We will **treat** you with courtesy and respect.
4. We will **accommodate** your circumstances if you have special needs or if you are having a hard time financially.
5. We will **make it easy** to access your account information.
6. We will **respect** your property.
7. We will **help** you manage your electricity use and costs.
8. We will **keep** our promises.

Hydro One's website indicates that 60,000 customers were consulted about the commitments through online and telephone surveys. The company told us the customer service advisory panel is still determining how each commitment will be interpreted and measured.

280 To follow through on its commitment to customers, Hydro One should establish timelines and monitor progress of this initiative at the executive level. Its website states that it will publicly share detailed findings relating to the commitments in "early 2015," but it had not done so as of the writing of this report. To remedy this, it should post status updates on the commitments on its website. In creating service metrics and customer service scorecards to evaluate whether it has lived up to customer commitments, Hydro One should use simple, straightforward and clear measures and publish accurate statistics that plainly describe what they mean. To enhance organizational learning and public accountability and transparency, it should also publicize concrete examples of situations where it has both met and failed to achieve the standards it has set for itself. Hydro One must not return to "sunny day" reports and statistical sleight of hand. Ontarians deserve the plain truth, not a feel-good promotional exercise.

Recommendation 39
Hydro One Inc. should ensure that its customer commitment initiative has strong senior leadership and robust project planning, monitoring and reporting.

Recommendation 40
Hydro One Inc. should post regular status updates on the progress of its customer commitment initiative on a prominent place on its website for public consultation.

Recommendation 41
Hydro One Inc. should post the final customer commitment document in a prominent place on its website.

Recommendation 42
Hydro One Inc. should set timelines for the completion of the service metrics and public scorecard to accompany the customer commitment document, and ensure that these are prepared on an expedited basis.

Recommendation 43
Hydro One Inc. should post service metrics and the public scorecard related to the customer commitment document prominently on its website and ensure that these are regularly updated.

Recommendation 44
Hydro One Inc. should ensure that it provides clear and transparent explanations for the statistical information and other evaluations that it posts about its success in meeting its customer commitments.

Recommendation 45
Hydro One Inc. should post examples of cases where it has met and/or failed to meet its commitments to promote organizational learning, public accountability and transparency.

281 The delay in developing and posting the customer commitments also leads me to question how effectively Hydro One will make use of the customer service advisory panel it established in October 2014. This body is in addition to the customer advisory board, a stakeholder group that has been around since September 2002, and which also provides advice to management on how best to provide services to Hydro One customers. The customer advisory board meets about four times a year, and the board member we interviewed indicated the company has rarely given serious consideration to its advice. Hydro One should ensure that the customer service advisory panel is provided with sufficient information and opportunities to provide its insights. The public should also be informed about the panel's activities and any progress the company has made as a result of its contributions.

Recommendation 46
Hydro One Inc. should ensure that the customer service advisory panel is provided with sufficient information and opportunities to enable it to function effectively.

Recommendation 47
Hydro One Inc. should publish information about the customer service advisory panel's activities and the contribution it has made to customer service initiatives.

That's Cold - Winter of Our Disconnect

282 In my view, the most persuasive evidence that Hydro One still lacks any real understanding of what it means to reflect a public sector ethos lies in its winter disconnection notices. Hydro One supplies a service that customers are obligated to pay for. There is no question that Hydro One is entitled to collect on unpaid bills, and, in appropriate circumstances, disconnect electrical service to those who fail to pay for it. However, I found the way that Hydro One approached collection in winter abhorrent and shocking.

283 In December 2013, the company temporarily suspended its collections program. This continued as part of its February 2014 strategy to restore customer trust in response to my investigation. But by mid-September 2014, the collections program was back in force, which included sending disconnection warning notices to customers with overdue payments. In October 2014, there were **96,000** accounts in the collections program; of those, **33,000** were sent disconnection warning notices, **2,600** were the subject of disconnection orders issued, and **364** actual disconnections were completed.

284 As Ontarians are well aware, winter here can be long and cruel, with temperatures dipping well below freezing for extended periods. For those who rely on electricity to help heat their homes, going without can have devastating consequences. In recognition of this, Hydro One has a winter disconnection moratorium, the timing of which varies depending on local geography. It does not disconnect residential customers with unpaid bills during the winter months. Instead, it restricts their electricity usage through a "load limiter" device. Although the winter disconnection moratorium has been in place for many years, Hydro One deliberately kept this practice secret. It continued to send disconnection warnings and threats to cut off power throughout the winter – including over the December holiday season – to coerce customers to pay up.

285 During the winter of 2014-2015, my Office received about **75** complaints – including in February 2015, the coldest recorded month in Ontario's history – from desperate individuals who had been threatened with disconnection.

286 A senior couple living on a farm in **Mountain** received a notice in December 2014, warning that they would be disconnected if they didn't pay their bill in three days. Distraught, they pleaded with Hydro One for a reprieve until their

Canada Pension Plan cheques arrived at the end of the month. After my Office intervened, Hydro One allowed the couple time to obtain financial assistance and pay the remaining balance.

287 A woman from **Red Lake** had experienced multiple billing issues in the wake of the new system. She was sent a bill with the wrong address in July 2013, did not receive bills for months, and then received several contradictory bills. In December 2014, she found a disconnection notice in the mail. She called our Office, confused and fearful. After we raised the case with Hydro One, it agreed to stop the disconnection process, refund her 16 months of service charges, and allow her two years to repay the outstanding balance of **$1,226.29**.

288 A senior in **Portland** who was already having difficulty in making her hydro payments was hospitalized in December 2014 and diagnosed with cancer. When her partner discovered a disconnection notice in the mail in January 2015, he asked Hydro One for an extension, but was refused because his name wasn't listed on the account. Attempts by a community support worker to intercede on the customer's behalf were also rebuffed. We were able to facilitate a resolution, including a reasonable payment plan and an end to further collection activity.

289 An **Ilderton** man with a newborn baby and six-year-old son contacted us in February 2015 when Hydro One threatening to disconnect his electricity if he didn't pay the full balance of his **$3,278** bill. He was worried that disconnection would leave his family homeless. He eventually borrowed money and entered into a repayment plan.

290 Although it is not against the law to disconnect customers in winter, it is clearly against Hydro One's longstanding policy. Despite this, all of these people were sent form letters threatening that if their overdue payments were not received by a set date, their electricity service "may be disconnected." The form letter also warned:

> Hydro One Networks will assume no responsibility for any injury or damages that may occur to persons or property, including any equipment or appliances, as a result of any interruption of electricity service. We may disconnect your service even if you are not present at the time of disconnection or we may disconnect your service remotely without visiting your property or we may install a load-limiting device.

291 The standard form disconnection notice also referred recipients to financial assistance programs, including Hydro One's own Low-Income Energy Assistance Program (LEAP), administered through the United Way of Greater Simcoe County. As well, somewhat ominously, it included a fire safety notice

from the Ministry of Community Safety and Correctional Services about taking care when using alternative lighting, cooking and heating equipment.

292 For people who are already paying off arrears by installment and happen to miss a payment, the notice leaves no doubt about disconnection. It states:

> If payment of these outstanding amounts is not received by the effective date, the Arrears Instalment Plan will be cancelled and ***an order will be issued to disconnect electricity*** at your service address as noted above. If the electricity is disconnected, payment of the full past due balance will be required before we will reconnect your service. [*emphasis added*]

293 We confirmed with Hydro One that it would not cut the electricity to any of these people, despite what it had misled them to believe. We also helped where we could, facilitating repayment plans and bill adjustments. However, our attempts to convince Hydro One to reconsider its callous winter strategy of terrifying customers into settling their accounts were initially met with resistance.

294 In late January 2015, senior staff from my Office raised this matter with Hydro One executives and emphasized that its approach lacked the transparency expected of a public body. Hydro One officials defended the practice as consistent with that of other utility companies. They resisted the suggestion that they should publish information about the winter disconnection moratorium, saying it would be a disincentive to customers paying their bills on time. They also said the company's practice complied with the distribution service code approved by the Ontario Energy Board. In fact, the board has established minimum requirements for disconnection notices, but nowhere does it direct utilities to mislead customers about the spectre of disconnection.

295 I found the rationale Hydro One gave to justify lying about its intentions to support its collection efforts morally repugnant. On February 20, 2015, I met with the Chief Executive Officer to strongly voice my objection to a practice I considered both dishonest and disingenuous. I also pointed to several jurisdictions in the United States, such as Massachusetts, that specifically and publicly prohibit disconnections in winter. The Chief Executive Officer acknowledged that the tactic of sending disconnection notices was an empty threat, but would not commit to a change in practice on the spot. He indicated he would consider the matter further and provide me with a response as soon as possible. Six days later, a Hydro One executive assured my Office that a response was being drafted and should arrive the next day. It did not.

296 The first week of March, we were told that the response was in progress. As

time passed and I continued to hear from vulnerable people who were frightened by the prospect of losing their electricity in the continuing cold, I became increasingly concerned. Finally, tired of waiting, on the morning of Tuesday, March 10, 2015, I announced that I would issue a public update on my investigation at a press conference the next day. This move inspired Hydro One to respond at 4:55 p.m. on March 10. It advised us it had stopped sending out the residential disconnection notice the preceding Friday (March 6). It also enclosed a draft of a new letter, with the heading "URGENT NOTICE – SERVICE INTERRUPTION." Unfortunately, the revised notice still held out the possibility of disconnection – it simply left the timing uncertain and dependent on vagaries of the weather, noting, "depending on weather conditions, we may either install a load limiter to limit the flow of electricity to your property or disconnect the service altogether."

297 Just short of two hours before I was to hold my press conference on March 11, Hydro One sent another message, explaining that it had engaged a North American expert to look at credit and collections best practices across a range of industries so that it could develop strategies and tools, with a view to helping its customers stay current. It expected to have a new approach developed in the next couple of months and intended to engage various stakeholders, including my Office, in the process. Another revised disconnection notice was also attached. While somewhat simplified, it still stressed that the weather would determine if the customer would be disconnected or not.

298 After my press conference, Hydro One invited me through Twitter to rewrite the warning letter with them. It said: "We hear [the Ombudsman's] concerns. Hydro One would like to sit down with him and write the disconnection letter to his satisfaction."

299 The company also issued a press release,[24] plugging improvements it had made since my investigation began, and stressing that it was:

> (R)eviewing and revising its disconnection communications to ensure that they are a clear and accurate reflection of our policies and easy for our customers to understand.

The release noted, "We will work with the Ombudsman to resolve this issue." For the first time, Hydro One also admitted publicly: "We do not disconnect during the winter months."

[24] The press release is available online here: http://hydroone.mediaroom.com/2015-03-11-Hydro-One-provides-up-date-on-Customer-Recovery

300 The next day, the Chief Executive Officer wrote to me personally to let me know the language in the letter had been revisited and revised.[25] The latest version of the "Urgent Collections Notice" now explicitly states:

> **Out of concern for the safety of our customers, we do not disconnect residential customers during the winter months or periods of extreme cold.**

301 The Chief Executive Officer also noted that Hydro One's collections expert had advised them, based on his initial assessment, that the company's "collections practices are consistent with electrical utility industry, but Hydro One provides customers with more time and leeway to manage their accounts than is typical." He indicated that he had asked the expert to look beyond the utility sector for best practices.

302 I am pleased that Hydro One has finally moved to take action to stop collection efforts through intimidation and deceit, and that it has finally come clean about its winter disconnection moratorium. However, its protracted and reticent response to this issue suggests that it still clings to the vestiges of a private-sector mentality and lacks a public service vision.

303 Several North American jurisdictions let consumers know when there is no possibility of being disconnected.[26] For example, Massachusetts prohibits disconnections between November and March. Hydro One should publish moratorium dates every year, refer to them in customer collections communications during the winter months, and abide by them.

Recommendation 48
Hydro One Inc. should publish disconnection moratorium dates annually, refer to them in communications about collections during the winter months, and abide by them.

304 Many of those who contacted us about threatened disconnection were coping with extremely challenging personal situations. They included low-income seniors, families with small children, and individuals with disabilities and significant illness, who were callously dismissed and disregarded by call centre agents. At times, when our Office asked that Hydro One show compassion for

[25] The letter is available online here:
http://www.hydroone.com/WorkingtoGetBetter/Documents/Letter_to_Ombudsman_March12_2015.pdf
[26] A list of utility policies for various U.S. states can be found online here:
http://www.liheapch.acf.hhs.gov/Disconnect/disconnect.htm

people in difficult and tragic circumstances, we received insensitive responses, some suggesting that to give one person a break would ultimately cost other customers more. Hydro One should develop clear and consistent guidelines, policies and procedures for dealing with disconnection cases to ensure that individual circumstances are taken into account in negotiating payment plans and extensions, as befits a public sector organization. Referring people to financial resources in compliance with the Ontario Energy Board requirements is not enough. Hydro One should ensure that customers are treated with compassion and common sense, not left to face an insensitive bureaucratic wall.

Recommendation 49
Hydro One Inc. should develop a process that ensures individual circumstances are consistently and fairly taken into account when resolving collection matters.

Credit Collection – Owing an Apology

305 During the height of its billing and customer service crisis, Hydro One stopped collection of overdue accounts. When collections resumed in the fall of 2014, customers who had experienced billing system issues were supposed to be excluded from the collection process for 12 months. Several Hydro One insiders approached my Office on a confidential basis to raise concerns about the adequacy of testing and training that was done before collections resumed. Their comments proved prescient, as the call centre was soon deluged with calls from irate and confused customers. An internal Hydro One briefing note, dated October 20, 2014, confirmed that the reactivation of the collections process had "driven a much higher-than-expected volume of inbound calls to Hydro One's call centre," resulting in long wait times on the phone.

306 In November 2014, Hydro One had to suspend collection efforts for a few days when it discovered that **2,308** accounts were wrongly flagged for collection. Hydro One responded by calling some customers, reinforcing staff training, enhancing coding, and adding a second review of accounts before they enter the collection process.

307 Unfortunately, this error was evocative of the earlier problems encountered with the customer information system. It reflected a failure to ensure that customer interests were given priority and that sufficient safeguards were established to minimize impacts on them.

Recommendation 50
Hydro One Inc. should ensure that all changes in bill collection initiatives are thoroughly researched and planned, and include pre-implementation consideration of customer service impacts, risks and mitigation strategies.

Relying on Technicalities – Customer Beware

308 Hydro One's technical and introspective mindset also continues to be evidenced in its "buyer beware" approach to issues relating to billing classifications and rates. Some customers have suggested that the company has managed to profit from unsuspecting consumers who overpay for service because they are unfamiliar with technical terminology.

It's a Little Dense - Density Classifications

309 Customers pay different rates for electricity, depending on the type of service they receive. Residential properties are classified as urban high, medium or low density, according to the number of electricity consumers in an area, and those in different density areas may pay different rates. Generally, the higher the density of an area, the lower overall amount the customer pays – and vice-versa. Sometimes Hydro One inadvertently misclassifies a property's density. However, there are also circumstances that can lead to a change in density, such as growth of a subdivision, or renovation of a property to accommodate multiple users. We received more than 50 complaints from customers about their density classification.

310 A senior couple from **Moorefield** told us that they contacted Hydro One numerous times to get their density changed from low to medium, to match the classification for their neighborhood. They waited for a promised readjustment for months before contacting our Office.

311 A woman from **Brockville** compared her Hydro One bill with her mother's, and discovered that although they lived only 3.5 kilometers apart, she was paying considerably more for hydro, based on a low-density classification. After numerous fruitless calls to the call centre, she contacted our Office in October 2013. We determined she had been wrongly classified, but it still took Hydro One months to correct the error.

312 Historically, Hydro One has not engaged in proactive review of density classifications. Instead, it has relied on customers to come forward and complain. Even then, it has only adjusted classifications for those who request a review,

not for anyone else in the area. We received several complaints from members of a retirement community in **Stouffville** who discovered that they were paying significantly more for electricity than their neighbours. They found out that those who moved in during the early phases of the development were charged residential low-density rates, while later arrivals qualified for lower-priced medium-density rates. Some customers complained and Hydro One adjusted their classification. However, other residents who were unaware of this possibility continued to overpay their accounts for years.

313 Hydro One told us that in the past, it had no practical way to capture changes in density. However, as a result of refinements to its geographic information system tool, it can now more readily access this data. Recently, Hydro One applied to the Ontario Energy Board for approval to reclassify 11% (134,568) of its customers based on density. Beginning in April 2014, Hydro One quietly stopped reviewing requests for density reclassification, pending the results of the board application. We were told customers who raised concerns during this moratorium would have their classifications adjusted back to the date of the complaint, should the board find in their favour. The board issued its decision on the rate application on March 12, 2015, and set rates for the next three years. As a result, approximately 9% of Hydro One's customer base will be reclassified based on lower density, and the remainder will pay higher rates.

314 Since the Ontario Energy Board decision, Hydro One has been negotiating with customers who had previously raised concerns about retroactive rate readjustment. However, its treatment of this issue again demonstrates its failure to provide customers with sufficient information. Hydro One's website contains no information explaining to customers that they can challenge their rate classification based on density.

315 Hydro One's persistent failure to alert customers to the fact that they might be paying more for their electricity because of a wrong density classification reflects a lack of appreciation for the principles of transparency, openness and accountability. To remedy this, the company should publish clear and easily accessible information on its website, explaining the relationship between density classification and rates and setting out the process that customers can follow to have their density reviewed. Hydro One should also adopt a clear, consistent and fair retroactive adjustment policy. It should also abandon its practice of placing the onus on individual customers to come forward. In future, if a customer raises a substantiated concern about density, Hydro One should ensure that similarly situated neighbours receive the same adjustment.

Recommendation 51
Hydro One Inc. should post clear and easily accessible information on its website informing customers about the significance of different density classifications and their relationship to rates.

Recommendation 52
Hydro One Inc. should post information about the density classification review process on its website.

Recommendation 53
Hydro One Inc. should develop a clear, consistent and fair policy for retroactive adjustment of accounts that have been subject to an inaccurate density classification.

Recommendation 54
Hydro One Inc. should ensure that whenever a customer request results in a density reclassification, neighbouring properties are reviewed to assess whether the same adjustment should apply to them.

General Disservice – General Service Billing

316 Another example that Hydro One is operating on the "gotcha" principle when it comes to billing technicalities is apparent in its approach to the category of "general service" accounts. Several individuals complained to us about Hydro One's misclassification of their accounts this way. Most were unaware of the significance of this term until they became frustrated with paying consistently high bills.

317 The "general service" rate classification is intended to cover non-residential properties, such as commercial, industrial, educational, administrative, auxiliary and government-type services.

318 "General service" is a term of art in the utility industry. Its meaning is not readily apparent to the average consumer, but it generally results in customers paying higher rates than residential customers. Many customers told us that they simply assumed the phrase described normal residential hydro service.

319 A **Carleton Place** man contacted our Office in February 2014 to complain that he had not received a bill since September 2013. In the course of resolving his billing problems, we learned that his account was classified as general service. Although he had used the property as a residence for 20 years, the former owners had run an antique business from it. We were able to help him get the classification changed, but Hydro One refused to adjust his account retroactively.

320 **Rebecca Sharpe** had been paying the general service rate for years on her residential property in **Shedden**, but only learned of this when she called Hydro One to complain about high delivery charges on her bills. Her home's prior owners had used it for business purposes. Hydro One changed the classification, but initially refused to recalculate her charges. It eventually adjusted her account retroactively for two years and gave her a credit for five months of service charges.

321 A **Johnstown** woman realized that her rates were too high after five years in her home. She told us she spent more than 15 frustrating hours on the phone with the call centre to get the situation sorted out. She said she was repeatedly placed on hold, had to explain to seven different people what the problem was, and despite her efforts, no one was prepared to help. Our inquiries revealed that a prior owner had used the premises for a woodworking business. Hers was one of the few cases in which Hydro One agreed to recalculate her bills back to the date she moved in.

322 A widow from **Goderich** only realized that something was wrong with her rate classification when she compared bills with her neighbors. She had set up a new account in June 2013 in her name after her husband died, and Hydro One had mistakenly reclassified the property as general service. Despite numerous phone calls and three letters, it did not correct the account and issue her a credit until January 2014.

323 **Walter and Betty Klassen's** home in **Schreiber** was mistakenly classified as a recreational park – and therefore a general service account – for four years. They told us they first complained about high rates in December 2012, but Hydro One had no record of this and only responded with a classification change and a nominal goodwill credit after they complained again in August 2013.

324 Hydro One told us that when a property classified as general service changes hands, normally the classification continues. Staff are not instructed to ask the new owners/customers whether the general service account will be changing to residential. Call centre and customer relations centre staff acknowledged in our interviews that customers might not understand or necessarily question what the general service classification means, even if they notice the reference to "general service" on their bills. There is also no information on Hydro One's website to alert customers about what they can do if they believe their property is misclassified.

325 Hydro One does not provide customers with adequate information about classification differences or how to challenge wrong classifications, leaving

many to pay higher rates unwittingly, sometimes for years. When customers do manage to identify a classification error, its approach to retroactive adjustments is inconsistent. Typically, it is reluctant to credit customers for past overpayments based on misclassification.

326 Hydro One should provide clear information about the different rate classifications to customers, both in general terms and with respect to their individual accounts. It should also explain to customers how they can dispute rate classifications. In addition, Hydro One should take steps to mitigate the risk that accounts set up online or through the call centre will be misclassified. For example, it should instruct call centre agents to confirm the details of a property's usage whenever a new account is established or an account is transferred to another customer. It should also develop and consistently apply criteria for providing retroactive account adjustment in cases of misclassification.

Recommendation 55
Hydro One Inc. should inform individual customers, in clear language, of the significance of their rate classifications in terms of billing, and include information about how to request a change in classification if they believe their property is misclassified.

Recommendation 56
Hydro One Inc. should post clear information about the different rate classifications (such as general service) and their impact on billing on its website, and include information about how customers can request a change in classification if they believe their property is misclassified.

Recommendation 57
Hydro One Inc. should ensure that call centre agents are instructed to confirm the use being made of the property when setting up or transferring accounts that are classified as general service, to ensure proper classification.

Recommendation 58
Hydro One Inc. should ensure that when accounts are created online, the nature of the service is confirmed to ensure proper classification.

Recommendation 59
Hydro One Inc. should develop a transparent and consistent process for providing retroactive credits and refunds when it is discovered that an account has been misclassified, and post information about this process on its website.

Two Years Too Late – Retroactive Charges

327 Under the Ontario Energy Board's *Retail Settlement Code*[27] and Hydro One's conditions of service, if a billing error results in prolonged underbilling through no fault of a residential customer, Hydro One can only require the customer to make up the difference on up to two years' worth of charges. However, we found several cases where Hydro One had not applied this restriction until my staff pointed it out.

328 **Brenda Parkin** of **Holland Landing** told us that in September 2013, her elderly father suddenly received three bills for differing amounts. After she complained, the bills were cancelled and three more were issued, showing credits. In July 2014, a package containing 20 bills arrived, showing an outstanding balance of **$2,150**. Ms. Parkin believes the aggravation of trying to decipher these bills aggravated her father's heart condition and led to his being hospitalized the next day. Hydro One initially offered a discount of **$215.** We discovered that the bills wrongly included charges for periods dating back more than two years. Hydro One ultimately applied a further credit of more than **$1,200** to the account.

329 A **Flesherton** woman received a trued-up bill in May 2014 for **$21,771.31** after receiving estimated bills for more than three years (39 months). It was only after we intervened that Hydro One realized it had billed her for periods beyond two years and her account was adjusted, reducing her arrears by **$8,373.58**.

330 A **Woodlawn** family received a large catch-up bill and three packages of bills dating back three years. Hydro One only adjusted the account after we found that this violated the *Retail Settlement Code*.

331 A **Schumacher** man who was rebilled well beyond the two-year limit told us his attempt to address the retroactive charges with Hydro One agents was met with rudeness and refusal. He described it as follows:

> I said, not only have you retroactively billed me for three years, which is, like, ridiculous, but you've changed bills that I've already paid… The individual I spoke with at the customer service line advised me that it was basically my tough luck, and that I should just pay up, and that was that. Honestly, it was as abrupt and rude as that. I said, "You can't do that." She goes, "Yeah, we can."

[27] S.7.7.7 Retail Settlement Code. Online: http://www.ontarioenergyboard.ca/oeb/_Documents/Regulatory/Retail_Settlement_Code.pdf

332 Hydro rates are already a source of concern for many Ontarians. Receiving delayed and excessive retroactive bills can cause extreme hardship for customers. Hydro One should scrupulously ensure that it does not issue bills to customers in contravention of the *Retail Settlement Code,* and that it trains staff to ensure that they are aware of and consistently apply the two-year restriction.

333 Hydro One should also ensure that information about this restriction is more clearly and prominently posted on its website.

Recommendation 60
Hydro One Inc. should ensure that it does not issue retroactive bills in contravention of the *Retail Settlement Code,* and should train call centre and customer relations centre staff so that they understand and apply the two-year billing limit.

Recommendation 61
Hydro One Inc. should prominently post information on its website about the two-year restriction for collecting charges from residential customers for underbilling.

Giving Credit Where it is Due

334 Beginning in October 2013, at the Minister's suggestion, Hydro One offered customers who had never been billed under the new system a "fixed flat charge," or service charge credit for each month they went without bills. The service charge represents the flat distribution charge, which varies depending on the customer's classification. During our investigation, the monthly service charge for residential customers ranged from $16.64 to $29.11. According to Hydro One, this fee pays for the costs of billing, meter reading, customer service, and 24-hour power restoration services. Call centre agents also have the authority to offer "goodwill" credits, waiving the monthly service charge at their discretion to resolve customer disputes. However, we found that goodwill service credits were inconsistently applied. Four months after my investigation began – June 2014 – Hydro One issued a final goodwill credits policy, emphasizing that customers are to be treated in a fair, consistent, and sensitive manner.

335 Hydro One should change its vocabulary in these cases. It should appreciate that waiving service charges is not a "goodwill" gesture, but compensation for failing to provide acceptable service. It does not deserve a service charge when it has not delivered decent service. Some customers we interviewed felt it was offensive to be offered a goodwill credit after the frustration they had endured. As one put it, "that's very insulting – there's no goodwill." Hydro One should

revise its policy to eliminate the reference to "goodwill" and acknowledge that it should not charge for substandard service. It should also publish its credits policy and ensure it is consistently applied. In addition, failure to issue bills or providing customers with erroneous ones is unacceptable. With this in mind, Hydro One should take steps to amend its conditions of service to incorporate a right for customers to automatically receive service charge credits whenever they do not receive bills, or receive inaccurate bills.

Recommendation 62
Hydro One Inc. should revise its goodwill credits policy to eliminate reference to "goodwill," post the revised document on its website, and ensure that it is applied consistently.

Recommendation 63
Hydro One Inc. should take steps to revise its conditions of service to provide customers with a right to receive service charge credits if they do not receive bills, or receive erroneous bills.

Still Looking on the Bright Side

336 Hydro One has paid a steep financial price in its effort to recover from its crisis of confidence. Internal records reflect that by November 2014, it had paid out **$5.1 million** in service credits, written off **$23.8 million** in net bad debts, and forgone **$11.2 million** in revenue from late payment charges. Its customer service recovery costs total **$88.3 million**. The fallout from the customer service nightmare also contributed to a **$54-million** decrease in its net income for 2014.

337 Today, the company's goal of reaping a **$172-million** financial benefit within seven years of the installation of the new customer information system appears unrealistic. Hydro One has paid an astounding premium for its failure to adequately plan for the system and factor in its impact on customers. Still, it continues to look on the bright side.

338 In February 2015, Hydro One began to proclaim publicly that it had fixed the problems that plagued its billing since the launch of the new customer information system.[28] When we asked for clarification, it responded:

[28] One example can be found under the heading "Hydro Billing" in this "Sudbury Daystarter," article at CBC.ca: http://www.cbc.ca/news/canada/sudbury/sudbury-daystarter-news-weather-to-start-your-friday-1.2946912

> The majority of the underlying issues affecting the billing system have been resolved. This is most clearly demonstrated by the fact that no-bill volumes have declined and are now below pre-go-live levels. In addition, bills with unscheduled estimated usage reached a low of 1.2% in December. For any remaining billing system issues, additional resources, workarounds and safety nets are in place to minimize and/or eliminate any customer impacts.

339 We were also told that the customer information system stabilization would continue into March 2015 and that as of January 19, 2015, **7,600** customers still remained affected by issues, with **1,400** still not receiving bills for over 90 days, and **6,200** receiving estimated bills for more than three billing cycles.

340 As one representative told us, the vast majority of issues are under control, but there are still problems. He used the metaphor of a duck viewed from above the water:

> Looks all calm … but underneath, the legs are frantically paddling to keep it going. So yes, certainly internally there's additional activities, effort, labour, scrutiny being put towards it, but from the customer-facing aspect, the vast majority of items have stabilized.

341 In a March 11, 2015 press release, issued in response to my investigation update of the same day, Hydro One stressed its successes and set out various statistics demonstrating improvement. These can now also be found on its website in a section entitled "Our Customer Service: Then and Now."[29] Hydro One has a penchant for describing the number of those affected by billing issues as small, and using only percentages. This announcement was one of the rare occasions when it also used actual numbers of customers affected. It noted that a year after my investigation was launched, the tally of customers who hadn't received a bill for more than three months had dropped from 5% (**53,495**) to 0.1% (**475**). Its complaints backlog had also been reduced from 513 to 104, and only **4,681** customers were receiving estimated bills for a prolonged period of time, as opposed to **30,899** in February 2014. Its public message ended on a positive and poetic note:

> Going forward, we continue to make things right for our customers, one customer at a time.

[29] http://www.hydroone.com/OurCompany/News/Pages/Customer-service-then-and-now.aspx

342 In a letter to me on March 12, 2015, the Chief Executive Officer also wrote:

> (T)he technical issues associated with our billing system are now resolved. The system is operating normally and performing better than the system it replaced. With those issues behind us, we are now focused on transforming our culture and building positive, constructive relationships with our customers.

343 There is no doubt that Hydro One's billing and customer service situation has improved since I commenced my investigation in February 2014. However, I hesitate to agree that Hydro One's problems have been fully resolved. The company has highlighted its success since February 2014, when there were **84,394** customers either not receiving bills or receiving estimated bills for a prolonged period. However, if one adds up the customers affected by errors and defects experienced since May 2013, the number climbs to well over **100,000**. While the rate of billing problems has diminished significantly, according to the company there are still more than **5,000** customers faced with the frustration of going months without bills or receiving multiple bills based on estimates, leading to the prospect of large catch-up bills in future. This might not seem like a big number to Hydro One, and it isn't necessarily a large percentage of its total customer base, but it represents thousands of individuals who are not receiving dependable and predictable customer service. In fact, it's a larger number than the population of many municipalities in Ontario.

344 As well, although we did not investigate high electricity rates or general concerns about the various charges included in hydro bills, their impact cannot be overlooked. The billing crisis that followed the installation of the customer information system exacerbated an already difficult financial situation for many Hydro One customers. We encountered seniors on fixed incomes, people with disabilities and families with young children, all facing dire financial straits. Offers of interest-free payment plans and service charge credits were of limited value to those struggling with the choice of paying for food and rent or for electricity. The high rates, billing errors, delays and large catch-up bills, coupled with an exceedingly long and frigid winter, placed many in an untenable position, particularly those who were thrown into panic when threatened with disconnection. Hydro One's customers deserve better.

345 Fewer complaints about Hydro One are arriving at my Office now, but there is still a steady stream of about a dozen a day. Many of the latest cases are are no less egregious than those we heard about in fall 2013. For instance, a **Pickle Lake** woman told us she received 12 high bills in June 2014, which made no sense to her. Then in December she received 18 bills, all for different amounts. The total owing was **$49,578.23,** even though she normally pays about $4,000

per year. She called Hydro One to dispute the amount and was told that it would set up a payment plan for her. The matter was recently resolved. After billing adjustments and the application of service credits, the woman now owes $**4,244.54** and has been offered an interest-free installment payment plan to satisfy the balance.

346 Unfortunately, Hydro One's organizational hubris is still apparent in the way it continues to tout its success in recovering from crisis, rather than entering into sober reflection on the morass it is still working to escape. Hydro One has not yet finished learning its lessons from the corporate catastrophe of the new customer information system. One of the first subjects for instruction is the need for humility and greater insight regarding the needs of those it serves. It must jettison its monopolistic tunnel vision and see each customer concern as singularly important and potentially reflective of systemic malfunction.

347 Hydro One should use this experience, as well as my observations and recommendations, to instruct its executive, managers and staff to help ensure that the future of hydro services is truly brighter for Ontario's citizens and radiates the public sector values of openness, transparency and accountability.

Recommendation 64
Hydro One Inc. should use the customer relations fallout associated with the new customer information system as a learning tool for its managers.

348 I also intend to closely monitor Hydro One's progress in implementing my recommendations to ensure that the momentum for change continues.

Recommendation 65
Hydro One Inc. should report back to my Office in six months' time on the progress in implementing my recommendations, and at six-month intervals thereafter until such time as I am satisfied that adequate steps have been taken to address them.

Current Events and Hydro One's Future

349 The Ontario government recently announced plans to significantly modernize Hydro One, including disposing of 60% of the utility, while retaining a 40% ownership interest. A new chair of the board of directors was also appointed in April 2015. The government has indicated that its proposed changes would require Hydro One to create a dedicated ombudsman to replace the independent oversight of my Office.

350 The government's decision to privatize Hydro One and insulate it from my investigative authority has not been without criticism from opposition members of provincial parliament and members of the public. In the wake of the billing and customer service fiasco chronicled in this report, relying on an in-house complaint body to resolve customer concerns when it is beholden to its corporate employer hardly inspires confidence for the future provision of hydro-electric services through a privatized utility.

351 In recent years, Ontarians have spoken out against the limited accountability of private corporations such as Ornge and Tarion, which deliver significant public services, but operate outside of Ombudsman oversight. Given Hydro One's track record, the province should exercise caution in following the path of removing the public right to complain to my Office about billing and customer service issues.

352 As my investigation has demonstrated, Hydro One has historically not lived up to principles of good public administration. During its billing crisis, its conduct fell far below any reasonable standards of customer service. The government of Ontario should ensure that in introducing structural changes to Hydro One's operations, the recommendations set out in this report are taken into consideration and that the public interest in fair, timely and effective customer service is preserved, including the right of recourse to my Office.

Recommendation 66
The Government of Ontario should consider my recommendations in moving forward with any restructuring of Hydro One Inc. and ensure that the public interest in fair, timely and effective customer service is preserved, including recourse to the Ontario Ombudsman.

Opinion

353 Technical problems associated with Hydro One's new customer information system triggered a bevy of billing errors, negatively affecting tens of thousands of its customers and leading to an outpouring of complaints. However, it was Hydro One's lack of appreciation for its customers and what they were experiencing that eventually spawned widespread public backlash. Unfortunately, from system planning to responding to defects and errors to dealing with complaints to media spinning, Hydro One failed to identify with its customers and forgot that its primary purpose as a provincial corporation is to serve the public good. It sought refuge in subterfuge and statistical manipulation instead of promoting the principles of openness, transparency and accountability expected of a public agency.

354 It is my opinion that Hydro One's conduct in planning, implementing and addressing issues relating to its new customer information system, as well as its general response to billing and customer service issues, was unreasonable and wrong under the *Ombudsman Act*.

Recommendations

355 Accordingly, I am making the following recommendations to promote cultural, operational and organizational change at Hydro One, to better serve its customers.

Hydro One, Inc.

Considering customers

Recommendation 1
Hydro One Inc. should ensure that it considers the impact on customers as its first priority throughout all project planning phases and develops appropriate mitigation strategies and contingency plans.

Recommendation 2
Hydro One Inc. should ensure that it keeps track of the cumulative total of customers affected by various systems issues and provides clear, accurate and constant descriptions of the various problem categories.

Communicating openly and transparently

Recommendation 3
Hydro One Inc. should adopt a proactive, transparent, open and accountable approach to communications with stakeholders and oversight and regulatory bodies.

Recommendation 4
Hydro One Inc. should ensure that any provider of outsourced services communicates with stakeholders and oversight and regulatory bodies in a transparent, open, and accountable manner.

Recommendation 5
Hydro One Inc. should monitor call centre communications to ensure that they reflect the transparency, openness and accountability expected of a provider of public services.

Improving staff training and supports

Recommendation 6
Hydro One Inc. should ensure that it implements comprehensive staff training before introducing any initiatives with potential impact on customers.

Recommendation 7
Hydro One Inc. should consult with and obtain timely feedback from individuals responsible for contact with customers to ensure that training is effective and supplemented if necessary.

Recommendation 8
Hydro One Inc. should consider providing additional training to call centre and customer relations centre staff in technical and other operational issues to enable them to resolve customer service concerns more effectively.

Recommendation 9
Hydro One Inc. should ensure that it regularly provides clear, timely and accurate scripts for use by call centre staff to address billing and other customer service issues as they arise.

Recommendation 10
Hydro One Inc. should consult technical and front line call centre staff in the development of scripts to ensure that it provides the tools necessary to ensure effective customer communications.

Recommendation 11
Hydro One Inc. should ensure that evaluation of staff and call centre agents readiness is included in pre-implementation business readiness assessments preceding major system changes that impact customers.

Enhancing call intake and quality monitoring

Recommendation 12
Hydro One Inc. should conduct research on call intake practices, and revise its performance measures to reflect public sector best practices and greater emphasis on the quality of calls and customer outcomes.

Recommendation 13
Hydro One Inc. should engage in more robust monitoring of the quality of call centre calls through more extensive sampling of recorded calls, live call monitoring, random spot checks, and the introduction of "secret shopper" calls.

Recommendation 14
Hydro One Inc. should engage an independent external third party to assist in conducting random audits of call quality.

Recommendation 15
Hydro One Inc. should review and update its call evaluation and call quality scoring standards to ensure that they reflect its goal of customer-centered service.

Recommendation 16
Hydro One Inc. should develop customer service quality standards for the customer relations centre.

Recommendation 17
Hydro One Inc. should record customer relations centre calls and develop a call monitoring program for the centre, including live call monitoring, random spot checks and secret shopper calls.

Recommendation 18
Hydro One Inc. should continue to have managers located in the main call centre to ensure robust on-site monitoring.

Recommendation 19
Hydro One Inc. should conduct research and consult with customers and other stakeholders to evaluate whether there are other, more accurate means of measuring and reporting on customer satisfaction, and change its survey and reporting practices accordingly.

Recommendation 20
Hydro One Inc. should conduct customer satisfaction surveys of those using the customer relations centre and use the results to plan for operational improvements.

Transforming corporate culture and governance

Recommendation 21
Hydro One Inc. should establish strategic objectives for its corporate scorecard, as well as for individual managers, related to changing its organizational culture to reflect public sector values.

Recommendation 22
Hydro One Inc. should ensure that timely risk assessments and "lessons learned" evaluations take place throughout all stages of project planning, implementation and stabilization. It should consider whether the impact on customers has been appropriately identified and addressed through mitigation and contingency planning, as well as communication strategies.

Recommendation 23
Hydro One Inc. should ensure that executive management and the board of directors are immediately alerted to any signs of systemic customer service and billing problems, including rising complaint levels.

Recommendation 24
Hydro One Inc. should ensure that, in addition to regular briefings on complaint statistics, its executive management and board of directors routinely receive information about complaints and inquiries from all sources, as well as details of problem trends and individual cases reflecting egregious customer service and errors.

Recommendation 25
Hydro One Inc. should ensure that executive managers and the board of directors are regularly and fully briefed about the cumulative impact and nature of customer service and billing issues.

Recommendation 26
Hydro One Inc. should continually reinforce for its staff, through training and direction, that the purpose of preparing billing and customer service statistics is to enable the company to have a clear, objective and accurate understanding of how well it is serving its customers.

Recommendation 27
Hydro One Inc. should prepare statistics in a consistent, clear, and standardized format, accompanied by meaningful and honest analysis.

Recommendation 28
Hydro One Inc. should create a customer service committee of the board of directors to highlight the significance of issues affecting its customers, meet with customers and customer groups to gain a better understanding of customer service issues, and effectively address systemic concerns.

Recommendation 29
Hydro One Inc. should ensure that its board of directors receives sufficient training to understand technical aspects of the company's operations, key performance indicators and other information relevant to customer service.

Recommendation 30
Hydro One Inc. should ensure that it has adequate customer service and technical resources to address customer service issues.

Improving customer service practices

Recommendation 31
Hydro One Inc. should develop a system to ensure that timely refunds are available to customers who have overpaid their accounts, through inadvertence or system error.

Recommendation 32
Hydro One Inc. should redesign its bills to ensure maximum clarity.

Recommendation 33
Hydro One Inc. should consider best billing practices and consult its customers and other stakeholders in redesigning its bills to ensure that any revisions actually meet customer needs.

Recommendation 34
Hydro One Inc. should prepare a single itemized bill, rather than multiple bills, to address rebilling because of mistakes, prolonged estimates or other circumstances, along with accompanying correspondence setting out a clear explanation as to why the account has been reconciled.

Recommendation 35
Hydro One Inc. should post a clear explanation of the complaint process, including information about call centre and customer relations centre escalations, and reference to external referrals.

Recommendation 36
Hydro One Inc. should ensure that the customer relations centre staff consistently provide external referrals to the Ontario Energy Board, the Ontario Ombudsman and other relevant bodies where appropriate.

Recommendation 37
Hydro One Inc. should develop a procedure to ensure that customers are consistently offered clear, detailed and accurate explanations as well as apologies for poor service.

Recommendation 38
Hydro One Inc. should ensure that its efforts to resolve billing issues are adequately monitored and co-ordinated to prevent duplication, inconsistency and negative impact on its customers.

Committing to customers

Recommendation 39
Hydro One Inc. should ensure that its customer commitments initiative has strong senior leadership and robust project planning, monitoring and reporting.

Recommendation 40
Hydro One Inc. should post regular status updates on the progress of its customer commitment initiative on a prominent place on its website for public consultation.

Recommendation 41
Hydro One Inc. should post the final customer commitment document in a prominent place on its website.

Recommendation 42
Hydro One Inc. should set timelines for the completion of the service metrics and public scorecard to accompany the customer commitment document, and ensure that these are prepared on an expedited basis.

Recommendation 43
Hydro One Inc. should post service metrics and the public scorecard related to the customer commitment document prominently on its website and ensure that these are regularly updated.

Recommendation 44
Hydro One Inc. should ensure that it provides clear and transparent explanations for the statistical information and other evaluations that it posts about its success in meeting its customer commitments.

Recommendation 45
Hydro One Inc. should post examples of cases where it has met and/or failed to meet its commitments to promote organizational learning, public accountability and transparency.

Recommendation 46
Hydro One Inc. should ensure that the customer service advisory panel is provided with sufficient information and opportunities to enable it to function effectively.

Recommendation 47
Hydro One Inc. should publish information about the customer service advisory panel's activities and the contribution it has made to customer service initiatives.

Improving collection practices

Recommendation 48
Hydro One Inc. should publish disconnection moratorium dates annually, refer to them in communications about collections during the winter months, and abide by them.

Recommendation 49
Hydro One Inc. should develop a process that ensures individual circumstances are consistently and fairly taken into account when resolving collection matters.

Recommendation 50
Hydro One Inc. should ensure that all changes in bill collection initiatives are thoroughly researched and planned, and include pre-implementation consideration of customer service impacts, risks and mitigation strategies.

Clarifying classifications

Recommendation 51
Hydro One Inc. should post clear and easily accessible information on its website informing customers about the significance of different density classifications and their relationship to rates.

Recommendation 52
Hydro One Inc. should post information about the density classification review process on its website.

Recommendation 53
Hydro One Inc. should develop a clear, consistent and fair policy for retroactive adjustment of accounts that have been subject to an inaccurate density classification.

Recommendation 54
Hydro One Inc. should ensure that whenever a customer request results in a density reclassification, neighbouring properties are reviewed to assess whether the same adjustment should apply to them.

Recommendation 55
Hydro One Inc. should inform individual customers, in clear language, of the significance of their rate classifications in terms of billing, and include information about how to request a change in classification if they believe their property is misclassified.

Recommendation 56
Hydro One Inc. should post clear information about the different rate classifications (such as general service) and their impact on billing on its website, and include information about how customers can request a change in classification if they believe their property is misclassified.

Recommendation 57
Hydro One Inc. should ensure that call centre agents are instructed to confirm the use being made of the property when setting up or transferring accounts that are classified as general service, to ensure proper classification.

Recommendation 58
Hydro One Inc. should ensure that when accounts are created online, the nature of the service is confirmed to ensure proper classification.

Recommendation 59
Hydro One Inc. should develop a transparent and consistent process for providing retroactive credits and refunds when it is discovered that an account has been misclassified, and post information about this process on its website.

Recommendation 60
Hydro One Inc. should ensure that it does not issue retroactive bills in contravention of the *Retail Settlement Code*, and should train call centre and

customer relations centre staff so that they understand and apply the two-year billing limit.

Recommendation 61
Hydro One Inc. should prominently post information on its website about the two-year restriction for collecting charges from residential customers for underbilling.

Recommendation 62
Hydro One Inc. should revise its goodwill credits policy to eliminate reference to "goodwill," post the revised document on its website, and ensure that it is applied consistently.

Recommendation 63
Hydro One Inc. should take steps to revise its conditions of service to provide customers with a right to receive service charge credits if they do not receive bills, or receive erroneous bills.

Lessons learned

Recommendation 64
Hydro One Inc. should use the customer relations fallout associated with the new customer information system as a learning tool for its managers.

Progress reports

Recommendation 65
Hydro One Inc. should report back to my Office in six months' time on the progress in implementing my recommendations, and at six-month intervals thereafter until such time as I am satisfied that adequate steps have been taken to address them.

Government of Ontario

Recommendation 66
The Government of Ontario should consider my recommendations in moving forward with any restructuring of Hydro One Inc. and ensure that the public interest in fair, timely and effective customer service is preserved, including recourse to the Ontario Ombudsman.

Response

356 Hydro One and the Ministry of Energy were both provided with an opportunity to review and respond to my preliminary findings, opinion, and recommendations.

357 On behalf of Hydro One, the President and Chief Executive Officer accepted all of the **65** recommendations addressed to the corporation. He also detailed the actions Hydro One had already taken to improve billing and customer service and that would be undertaken in future to respond to my recommendations. A copy of this response is appended to this report. I will continue to closely monitor Hydro One's progress in implementing my recommendations.

358 The Deputy Minister of the Ministry of Energy responded to Recommendation 66, which focuses on ensuring that momentum for the improvements I have recommended and Ombudsman oversight continues as the government's restructuring initiative progresses. He referred to the government's plan to have oversight responsibilities of the Officers of the Legislature, including my Office, "fall away with a transition period," and discussed establishment of the corporation's own "Ombudsperson's office." A copy of this response is appended to this report. I am disappointed by the Ministry's response and intend to encourage the Government of Ontario to retain independent and impartial external oversight of Hydro One through my Office and other accountability mechanisms, rather than rely on an in-house complaints office.

André Marin
Ombudsman of Ontario

Appendix A – Ministry Response

Ministry of Energy

Office of the Deputy Minister

Hearst Block, 4th Floor
900 Bay Street
Toronto, ON M7A 2E1
Tel: 416-327-6758
Fax: 416-327-6755

Ministère de l'Énergie

Bureau du sous-ministre

Édifice Hearst, 4e étage
900, rue Bay
Toronto, ON M7A 2E1
Tél: 416-327-6758
Téléc.: 416-327-6755

Ontario

May 11, 2015

Mr. André Marin
Ombudsman of Ontario
Bell Trinity Square
483 Bay Street
10th Floor, South Tower
Toronto ON M5G 2C9

Dear Mr. Marin:

Thank you for providing me with a copy of your Preliminary Report on Hydro One. I am writing to you today with the Ministry of Energy's response to Recommendation 66 of the Preliminary Report.

To allow Hydro One to operate in the same way as other publicly traded companies, the oversight and control of the company must be modified. Oversight responsibilities for Officers of the Legislature, including the Ontario Ombudsman, would fall away with a transition period. The Ombudsman would have six months to complete any outstanding reviews, but could still issue a report after that date. This will ensure that Hydro One is subject to the same rules and oversight as other publicly traded companies. Similar changes took place in other instances when ownership was broadened, including Air Canada, CN Rail, Petro-Canada and the Nova Scotia Power Company.

To maintain public trust throughout the Initial Public Offering (IPO), former Auditor General of Canada Denis Desautels has agreed to serve as Special Advisor to the Minister of Energy to provide advice about the processes related to the engagement of financial advisors and other service providers for the IPO. Hydro One would also be required to establish a dedicated Ombudsperson similar to those found at other public companies. Mr. Desautels will provide advice on how best to establish this dedicated Ombudsperson's office to ensure transparency, objectivity and accountability. In addition, the Ontario Energy Board (OEB) would continue to protect the public interest, and the powers of the OEB would be further enhanced, including the creation of a consumer advocacy role.

Thank you again for providing me with copy of your Preliminary Report on Hydro One.

Sincerely,

Serge Imbrogno
Deputy Minister

Appendix B – Hydro One Response

Hydro One Inc.
483 Bay Street, 8th Floor
Toronto, ON M5G 2P5
www.hydroone.com

Carmine Marcello
President &CEO

May 11, 2015

André Marin
Ombudsman Ontario
483 Bay Street, South Tower
10th Floor
Toronto, Ontario
M5G 2C9

Delivered by Hand

Dear Mr. Marin,

I am writing in response to your preliminary report entitled: *Investigation into the transparency of Hydro One's billing practices and the timeliness and effectiveness of the process for responding to customer concerns.*

Hydro One appreciates the opportunity to review and comment on your preliminary report and accepts its associated recommendations. We are committed to becoming the company our customers expect us to be and I believe we are making real progress towards that achievement.

Hydro One's move to a new Customer Information System (CIS) in 2013 was a major initiative intended to improve Hydro One's efficiency, productivity and ultimately, its customer service offerings. The goal was the right one but I agree with your observation in the report that the experience of our customers in the months following the implementation of our billing system was unacceptable. In response to these issues, Hydro One has initiated a number of actions that we believe, address most of your report recommendations.

In summary, we have:

- established more rigorous tracking, monitoring, and reporting of customer service metrics and performance indicators to ensure real-time visibility of customer service health
- strengthened corporate governance and oversight of customer service performance for large-scale customer-facing projects and initiatives
- changed the service-provider that manages our call centres and call centre staff
- changed how we work with our service provider to place a stronger emphasis on the engagement and training of our call centre agents and quality monitoring of call centre operations

- launched a major call quality improvement program to improve customer service
- initiated a project to improve bill clarity, including a bill redesign project

I was pleased that your report acknowledges Hydro One's billing and call handling practices are markedly improved from where they were when you initiated your investigation. I am proud of the progress we have made so far. We have tackled the issue of customers not receiving a bill for prolonged periods of time and reduced that number from a high of 53,495 to a current result of 360. We have improved first call resolution in our call centre from 69% to 82%. We will intensely track both these measures of service health as part of our comprehensive customer monitoring program and work hard to continue improving all our customer scores.

We are pleased with our progress to-date but we fully understand that meeting our customers' expectations involves much more than simply improving our billing and call centre performance. In responding to these concerns we recognized that the issues went deeper than the implementation of new technologies. We acknowledge that Hydro One's culture was at the heart of our customer service failings. We are committed to changing that culture to become one of service and pride that puts the focus on ensuring that Hydro One is the company the people of Ontario need us to be.

In the fall of 2014, Hydro One established a Customer Service Advisory Panel (the Panel). The Panel acts as an independent body that will ensure the Company is living-up to specific measureable customer service commitments. We have been working diligently with the Panel to finalize a comprehensive set of customer commitments as well as the means by which the Panel will assess and report on our progress against the commitments to ensure the Company is accountable to the highest standards. Over the longer-term, we will also look to the Panel to advise Hydro One leadership with respect to establishing and implementing new/revised customer service policies, approaches and products.

Our aim throughout this process has been to provide your investigation team with timely and open access to the people, systems and documents required to complete your investigation. I would like to acknowledge the professionalism of your investigation team as they carried out their specific duties.

Thank you for allowing Hydro One this opportunity to provide comment on your preliminary report. A copy of our responses to each of your recommendations is appended to this letter. I commit to providing you an update on our progress in the months ahead.

Regards,

Carm Marcello
President and CEO,
Hydro One Inc.

Hydro One - Response to Recommendations

Topic	#	Recommendation	Response
Considering Customers	1	Hydro One Inc. should ensure that it considers the impact on customers as its first priority throughout all project planning phases and develops appropriate mitigation strategies and contingency plans.	Hydro One has modified its project delivery methodology to ensure we have a more customer centric focus. In addition, the new Vice President, Customer Service founded the Customer Governance Committee in the Q3 of 2014 Committee to include leadership from all divisions in ensuring that customer impact of all actions and projects is considered at all stages and mitigation strategies are in place.
	2	Hydro One Inc. should ensure that it keeps track of the cumulative total of customers affected by various system issues and provides clear, accurate and constant descriptions of the various problem categories.	Whenever undertaking potentially customer-disruptive initiatives, Hydro One will keep track of the total number of customers affected by system issues and the nature of the disruptions.
	3	Hydro One Inc. should adopt a proactive, transparent, open and accountable approach to communications with stakeholders and oversight and regulatory bodies.	Since early 2014, Hydro One has increased the transparency and openness of interactions with stakeholders and regulators. For example, throughout the customer recovery project, Ontario Energy Board (OEB) and Hydro One staff met biweekly, to provide a close perspective and a real-time view on the issues and gave OEB staff the ability to build understanding and ask informed questions. The regulator was also invited to and took part in multiple teletownhalls with customers throughout 2014, helping them gauge the perspective of Hydro One customers.
	4	Hydro One Inc. should ensure that any provider of outsourced services communicates with stakeholders and oversight and regulatory bodies in a transparent, open, and accountable manner.	Hydro One works closely with our outsourced service provider to ensure that there is clear, transparent, open, accountable communication between our organizations. As the license holder, Hydro One Inc. is accountable for regulatory compliance, we will continue to communicate directly with regulators on matters of performance of our outsourced services.
	5	Hydro One Inc. should monitor call centre communications to ensure that they reflect transparency, openness and accountability expected of a provider of public services.	Hydro One monitors call centre communications on a continuous basis and is committed to being open and transparent with customers in every interaction. In August of 2014, Hydro One Inc. implemented 100% voice recording for all calls to the centre, allowing for monitoring of all call centre communications for conformance to performance standards.

Hydro One - Response to Recommendations

Topic	#	Recommendation	Response
Improving Staff Training and Supports	6	Hydro One Inc. should ensure that it implements comprehensive staff training before introducing any initiatives with potential impact on customers.	Hydro One now ensures full training of call centre staff for new initiatives, changes, or issues. For example, in April of 2014 Hydro One Inc. overhauled and implemented new bill literacy training for call centre agents to greatly increase their ability to have informed discussions regarding Hydro One bills in anticipation of a high volume of customer inquiries regarding bills that were larger than average due to the colder than average temperatures this past winter. Call agents can now capably explain, using an online tool, the direct relationship between temperature and electricity consumption. They now have access to an online tool that tracks daily temperature in the customer's area and correlates it directly to the customer's energy consumption.
	7	Hydro One Inc. should consult with and obtain timely feedback from individuals responsible for contact with customers to ensure that training is effective and supplemented if necessary.	Prior to overhauling "bill literacy" training in the spring of 2014 and revamping our entire quality monitoring program shortly after, input was obtained from frontline staff through focus groups and roundtable discussions. This approach has continued for all subsequent agent training materials development.
	8	Hydro One Inc. should consider providing additional training to call centre and Customer Relations Centre staff in technical and other operational issues to enable them to resolve customer service concerns more effectively.	Hydro One has provided additional training to both call centre and complaints-handling staff on technical matters as well as current or emerging issues. This began early in the spring of 2014 and continued throughout the year on topics that included larger than average bills, setup of payment arrangements, and "soft" skills for helping customers with billing concerns or particular hardships. This will be an ongoing process.
	9	Hydro One Inc. should ensure that it regularly provides clear, timely and accurate scripts for use by call centre staff to address billing and other customer service issues as they arise.	In April 2014, Hydro One undertook a full review of call centre agent scripts, with the most frequently used scripts reviewed first (i.e. payment arrangements, estimated bills). Going forward, Hydro One is providing scripts or information on any billing or customer service issues that arise as soon as they become known. Call centre agents are also more empowered to focus on the quality of the conversation and follow the spirit of the script rather than directly reading it.
	10	Hydro One Inc. should consult technical and front line call centre staff in the development of scripts to ensure that it provides the tools necessary to ensure effective customer communications.	Hydro One revamped its quality assurance program in the spring of 2014, utilizing frequent focus groups with staff in both call centres. Obtaining call agent staff feedback is now a part of Hydro One's training and scripting development process so that agents can take ownership of the scripts and guide the company's efforts to resolve customers' issues.
	11	Hydro One Inc. should ensure that evaluation of staff and call centre agents readiness is included in pre-implementation business readiness assessments proceeding major system changes that impact customers.	For major customer facing system changes, including other initiatives mentioned in this plan (such as Bill redesign), Hydro One will ensure that a readiness assessment is completed prior to changes being implemented.

Hydro One - Response to Recommendations

Topic	#	Recommendation	Response
Enhancing Call Intake and Quality Monitoring	12	Hydro One Inc. should conduct research on call intake practices, and revise its performance measures to reflect public sector best practices and greater emphasis on the quality of calls and customer outcomes.	Hydro One and its new outsource provider are looking to best practices to guide customer service efforts and quality assurance. Information gathering goes beyond utilities and looks to what is the highest standard. Customer Satisfaction and First Contact Resolution measures are built into the outsourcer's performance agreement and are monitored and reviewed daily by Hydro One management. The new speed-of-answer service level standard Hydro One now operates under and achieves is top quartile within the industry.
	13	Hydro One Inc. should engage in more robust monitoring of the quality of call centre calls through more extensive sampling of recorded calls, live call monitoring, random spot checks, and the introduction of "secret shopper" calls.	As early as March 2014 and throughout the year, Hydro One staff listened to and evaluated calls and engaged in "secret shopper" activities. Feedback the company collected was leveraged in updating agent scripts, training, and the revamped quality program. Hydro One's executive 'Call A Customer' program, introduced in July of 2014, includes live call monitoring. Hydro One also randomly spot checks calls as a part of its recently-revamped call quality program.
	14	Hydro One Inc. should engage an independent external third party to assist in conducting random audits of call quality.	Hydro One currently has an independent quality team within its outsourcer conduct random sample audits of call quality using an agreed upon standard. Once the new quality program is mature, Hydro One will bring in a third party to audit call quality to ensure that these measures and efforts will ensure a high standard of performance.
	15	Hydro One Inc. should review and update its call evaluation and call quality scoring standards to ensure that they reflect its goal of customer-centered services.	Hydro One began revamping its quality assurance program in the spring of 2014 and the rollout of the program is nearing completion. This effort included a total redevelopment of call evaluation and call quality scoring standards to reflect a stronger focus on the customer experience.
	16	Hydro One Inc. should develop customer service quality standards for the Customer Relations Centre.	Hydro One is developing a set of standards for calls and case work in the Customer Relations Centre (CRC) with the help of external expertise. These standards will be implemented in the summer of 2015.
	17	Hydro One Inc. should record Customer Relations Centre calls and develop a call monitoring program for the call centre, including live call monitoring, random spot checks and secret shopper calls.	Call recording, live monitoring, and spot checks are being implemented in the Customer Relations Centre to support the evaluation of calls and case work to the customer service quality standards.
	18	Hydro One Inc. should continue to have managers located in the main call centre to ensure robust on-site monitoring.	Hydro One managers have been located on the call centre floor and actively engage the service provider and the call centre staff on a daily basis.
	19	Hydro One Inc. should conduct research and consult with customers and other stakeholders to evaluate whether there are other, more accurate means of measuring and reporting on customer satisfaction, and change its survey and reporting practices accordingly.	Hydro One uses two established market research firms to conduct customer satisfaction transactional and perception surveys. The company continually refines these programs to ensure that they depict an accurate picture of customer experience. Hydro One now places greater emphasis on transactional surveys, so that current information on customer experience is obtained immediately after-the-fact and corrections to in-flight programs can be made. In instances where a surveyed customer says they are dissatisfied with a service or interaction, the research firms probe deeper for root cause and collect verbatim comments from the customer; this information is provided directly to Hydro One for analysis and action.
	20	Hydro One Inc. should conduct customer satisfaction surveys to those using the Customer Relations Centre and use the results to plan for operational improvements.	Starting in the week of May 10, 2014, Hydro One implemented customer satisfaction surveys for Customer Relations Centre-handled complaints.

Hydro One - Response to Recommendations

Topic	#	Recommendation	Response
Transforming Corporate Culture and Governance	21	Hydro One Inc. should establish strategic objectives for its corporate scorecard, as well as for individual managers, related to changing its organizational culture to reflect public sector values.	In June of 2014, Hydro One's President and CEO introduced all Hydro One employees to Five Core Values: Customer Caring, Safe Workplace, Execution Excellence, People Powered and One Company. Performance Management for all management staff incorporates all five core values and they are accountable to work with their manager to set specific and measurable goals under this framework. 2015 is the first year that management performance will be measured in this new context and the company commits to improving the process to foster a positively changed corporate culture as evidenced by improved customer experience.
	22	Hydro One Inc. should ensure that timely risk assessments and "lessons learned" evaluations take place throughout all stages of project planning, implementation, and stabilization. It should consider whether the impact on customers has been appropriately identified and addressed throughout mitigation and contingency planning, as well as communication strategies.	Hydro One will undertake formal risk assessments at key milestones for all major customer-facing initiatives. Hydro One appointed a new Chief Risk Officer in April 2015; this position reports directly to the CEO and has accountability for ensuring compliance with this requirement. Hydro One has adjusted its risk tolerances for customer impacts to increase focus on customer risk and ensure mitigation and contingency planning.
	23	Hydro One Inc. should ensure that executive management and the board of directors are immediately alerted to any signs of systemic customer service and billing problems, including rising complaint levels.	Regular reports to the Executive Committee now include customer service "health" metrics. Board and Board Committee reporting also include emerging customer service issues and measures of customer service process "health".
	24	Hydro One Inc. should ensure that, in addition to regular briefings on complaint statistics, its executive management and board of directors routinely receive information about complaints and inquiries from all sources, as well as details of problem trends and individual cases reflecting egregious customer service and errors.	Backlog of complaints is a statistic reported regularly to the Executive and Board Committee level. Patterns and emerging trends in complaints are included as appropriate. Since March of 2014, the Vice President of Customer Service has received daily complaints statistics and any identified trends; this process will continue.
	25	Hydro One Inc. should ensure that executive managers and the board of directors are regularly and fully briefed about the cumulative impact and nature of customer service and billing issues.	Regular reports to the Executive Committee now include customer service "health" metrics, and this will continue. Board and Board Committee reporting includes emerging customer service issues and measures of customer service process "health", including volumes, complaint backlogs and other cumulative customer service impacts.
	26	Hydro One Inc. should continually reinforce for its staff, through training and direction, that the purpose of preparing billing and customer service statistics is to enable the company to have a clear, objective and accurate understanding of how well it is serving its customers.	In early 2014, the company made operational and customer statistics a core part of routine discussions and communications with staff. In the call centre this includes the display of relevant billing and call handling statistics on television screens and display boards throughout building, starting at the entrance. In addition, key related metrics such as customer satisfaction and first call resolution are part of corporate performance targets.
	27	Hydro One Inc. should prepare statistics in a consistent, clear, and standardized format, accompanied by meaningful and honest analytics.	Hydro One has standardized its method for presenting its metrics in a clear, consistent format.
	28	Hydro One Inc. should create a customer service committee of the board of directors to highlight the significance of issues affective its customers, meet with customers and customer groups to gain a better understanding of customer service issues, and effectively address systemic concerns.	The Business Transformation Committee of Hydro One 's Board of Directors currently includes customer service performance as an element of its mandate. This includes oversight of Management's activities specific to customer issues and trends. Future Board Committee mandates and structures are the purview of the Board.
	29	Hydro One Inc. should ensure that its board of directors receives sufficient training to understand technical aspects of the company's operations, key performance indicators and other information relevant to customer service.	Board Education on customer service operations and metrics is provided.
	30	Hydro One Inc. should ensure that it has adequate customer service and technical resources to address customer service issues.	Hydro One 's Customer Service team now has the authority to pull-in additional service or technology resources from elsewhere in the company to address customer service issues as they arise. This was implemented in 2014 and was particularly valuable in resolving the backlog of complaints escalated to the Customer Relations Centre.

Hydro One - Response to Recommendations

Topic	#	Recommendation	Response
Improving Customer Service Practices	31	Hydro One Inc. should develop a system to ensure that timely refunds are available to customers who have overpaid their accounts, through inadvertence or system error.	Hydro One offers customers the option of a refund cheque or credit upon request for inadvertent or system errors. The company is taking steps to ensure that these are issued in a timely manner.
	32	Hydro One Inc. should redesign its bills to ensure maximum clarity.	Hydro One is performing an extensive review and redesign of the bill format in 2015, with a plan to implement a new bill in 2016. The bill redesign will be based on industry best practices, and will leverage significant customer and front line employee feedback to ensure maximum clarity. Note that, as this is a major customer-facing initiative, Hydro One will incorporate all the lessons learned from the recent billing issues to protect customer experience and mitigate disruption.
	33	Hydro One Inc. should consider best billing practices and consult its customers and other stakeholders in redesigning its bills to ensure that any revisions actually meet customer needs.	The 2015 bill redesign process will include multiple input opportunities and design iteration checkpoints with customers and employees. Hydro One will look to current/recent successful bill redesign initiatives in the sector for guidance.
	34	Hydro One Inc. should prepare a single itemized bill, rather than multiple bills, to address rebilling because of mistakes, prolonged estimates, or other circumstances, along with accompanying correspondence setting out a clear explanation as to why the account has been reconciled.	System changes to generate a "single itemized bill" are under evaluation, with anticipated implementation in the first quarter of 2016.
	35	Hydro One Inc. should post a clear explanation of the complaint process, including information about call centre and Customer Relations Centre escalations, and reference to external referrals.	Hydro One has a formal process for complaints management; any customer has the right to have an issue escalated. Hydro One will clarify its complaint process on its website.
	36	Hydro One Inc. should ensure that the Customer Relations Centre staff consistently provide external referrals to the OEB, the Ontario Ombudsman and other relevant bodies where appropriate.	Hydro One refers matters to external agencies responsible for relevant topics (e.g. OEB, IESO, Ombudsman) where appropriate. This is an area that has been emphasized in recent script revisions and quality training for call centre agents.
	37	Hydro One Inc. should develop a procedure to ensure that customers are consistently offered clear, detailed and accurate explanations as well as apologies for poor service.	When Hydro One revamped "bill literacy" training in the spring of 2014, these key call handling concepts and approaches were incorporated. This was rolled out to staff using a specific service model that emphasizes listening, acknowledgment, and apology as a way of recovering a situation and building rapport with customers. This was built into the revamped quality training program in 2014 and continues to be reinforced.
	38	Hydro One Inc. should ensure that its efforts to resolve billing issues are adequately monitored and coordinated to prevent duplication, inconsistency and negative impact on its customers.	Monitoring and coordination of billing resolution was implemented in April 2014 to provide visibility on all customer facing billing issues in order to drive timely resolution and a consistent customer treatment.

Hydro One - Response to Recommendations

Topic	#	Recommendation	Response
Committing to Customers	39	Hydro One Inc. should ensure that its customer commitments initiative has strong senior leadership and robust planning, monitoring, and reporting.	In the fall of 2014, Hydro One established a Customer Service Advisory Panel (the Panel). The Panel acts as an independent body that will ensure the Company is living-up to specific measureable customer service commitments. We have been working diligently with the Panel to finalize a comprehensive set of customer commitments as well as the means by which the Panel will assess and report on our progress against the commitments to ensure the Company is accountable to the highest standards. Over the longer-term, we will also look to the Panel to advise Hydro One leadership with respect to establishing and implementing new/revised customer service policies, approaches and products. Hydro One's panel includes the President of Credit Canada Debt Solutions, the President of Laurentian University, the former Chief of the Saugeen Ojibway Nation, and the President and CEO of the Forest Products Association of Canada.
	40	Hydro One Inc. should post regular status updates on the progress of its customer commitment initiative on a prominent place on its website for public consultation.	In the fall of 2014 Hydro One posted draft commitments on its website and invited customers to participate in their refinement. Over 60,000 customers responded to the survey. Once the Customer Service Advisory Panel has completed its review of Hydro One's Customer Commitments, including customer feedback obtained during this survey process, the commitments will be posted publicly .
	41	Hydro One Inc. should post the final customer commitment document in a prominent place on its website.	Once the Customer Service Advisory Panel has completed its review of Hydro One's Customer Commitments, they will be posted prominently on the company's website.
	42	Hydro One Inc. should set timelines for the completion of the service metrics and public scorecard to accompany the customer commitment document, and ensure that these are prepared on an expedited basis.	Hydro One is working very closely with our Customer Service Advisory Panel to finalize the customer commitments. Hydro One anticipates this work will be completed in mid-2015.
	43	Hydro One Inc. should post service metrics and the public scorecard related to the customer commitment document prominently on its website and ensure that these are regularly updated.	The service metrics will be posted on Hydro One's website once they are finalized. Additionally, the Panel will produce an independent report on its assessment of Hydro One's customer improvement activities.
	44	Hydro One Inc. should ensure that it provides clear and transparent explanations for the statistical information and other evaluations that it posts about success in meeting its customer commitments.	Hydro One's progress in meeting our commitments will be evaluated by the independent Customer Service Advisory Panel members. Hydro One will provide full explanations of all metrics and evaluations.
	45	Hydro One Inc. should post examples of cases where it has met and/or failed to meet its commitments to promote organizational learning, public accountability and transparency.	Hydro One's success in meeting our commitments will be evaluated by the independent Customer Service Advisory Panel members. Their conclusions will be shared publicly, to increase accountability and transparency.
	46	Hydro One Inc. should ensure that the customer service advisory panel is provided with sufficient information and opportunities to enable it to function effectively.	Education for the Customer Service Advisory Panel has been an ongoing priority since the fall of 2014. A subject matter expert on global best practices in Utility Customer Service is also serving as an advisor to the Panel to support this effort.
	47	Hydro One Inc. should publish information about the customer service advisory panel's activities and the contribution it has made to customer service initiatives.	Once the Customer Service Advisory Panel has completed their initial report, the findings will be shared publicly. Their ongoing contribution, the metrics and the Commitments will become a continuous improvement process.
Improving Collection Practices	48	Hydro One Inc. should publish disconnection moratorium dates annually, refer to them in communications about collections during the winter months, and abide by them,	Hydro One will ensure customers are aware of Hydro One's voluntary winter moratorium and when their service may or may not be disconnected for non-payment.
	49	Hydro One Inc. should develop a process that ensures individual circumstances are consistently and fairly taken into account when resolving collection matters.	Hydro One's collections program needs to balance compassion for customers and fairness for all ratepayers. Steps will be taken to ensure individual circumstances are taken into account, especially customers in financial difficulty, but ultimately customers need to pay for the electricity they consume as the cost of unpaid bills is borne by other customers.
	50	Hydro One Inc. should ensure that all changes in bill collection initiatives are thoroughly researched and planned, and include pre-implementation consideration of customer service impacts, risks and mitigation strategies.	As Hydro One restarts its collection program, we will ensure that the appropriate care is given to minimize customer service impacts.

Hydro One - Response to Recommendations

Topic	#	Recommendation	Response
Clarifying Classifications	51	Hydro One Inc. should post clear and easily accessible information on its website informing customers about the significance of different density classifications and their relationship to rates.	This information is already posted on Hydro One's website at www.hydroone.com/MyHome/MyAccount/UnderstandMyBill/Pages/DeliveryRates.
	52	Hydro One Inc. should post information about the density classification review process on its website.	Hydro One will post this information on its website.
	53	Hydro One Inc. should develop a clear, consistent and fair policy for retroactive adjustment of accounts that have been subject to inaccurate density classification.	The policy was developed in March of 2015, following the Ontario Energy Board's decision on density classification.
	54	Hydro One Inc. should ensure that whenever a customer request results in a density reclassification, neighboring properties are reviewed to assess whether the same adjustment should apply to them.	A review process is being developed, with anticipated implementation by the end of 2015.
	55	Hydro One Inc. should inform individual customers, in clear language, of the significance of their rate classifications in terms of billing, and include information about how to request a chance in classification if they believe their property is misclassified.	Hydro One's Conditions of Service and other appropriate communication vehicles will be enhanced to provide additional clarity for customers.
	56	Hydro One Inc. should post clear information about the different rate classifications (such as general service) and their impact on billing on its website, and include information about how customers can request a change in reclassification if they believe their property is misclassified.	Information on rate classifications is available on Hydro One's website at http://www.hydroone.com/MyHome/MyAccount/UnderstandMyBill/Pages/ServiceTypes.aspx. Hydro One will add instructions on how customers can request a review if they believe they have been incorrectly classified.
	57	Hydro One Inc. should ensure that call centre agents are instructed to confirm the use being made of the property when setting up or transferring accounts that are classified as general service to ensure proper classification.	This existing process was enhanced in January 2015.
	58	Hydro One Inc. should ensure that when accounts are created online, the nature of the service is confirmed to ensure proper classification.	Hydro One agrees with this recommendation. Hydro One will evaluate the recommendation to determine how best to implement, with anticipated implementation by the end of 2015.
	59	Hydro One Inc. should develop a transparent and consistent process for providing retroactive credits and refunds when it is discovered that an account has been misclassified, and post information about this process on its website.	Hydro One agrees with this recommendation. Hydro One will evaluate the recommendation to determine how best to implement, with anticipated implementation by the end of 2015.
	60	Hydro One Inc. should ensure that it does not issue retroactive bills in contravention of the Retail Settlements Code, and should train call centre and Customer Relations Centre staff so that they understand and apply the two-year billing limit.	An interim process was implemented in December 2014. A long term solution is scheduled to be implemented in mid-2015.
	61	Hydro One Inc. should prominently post information on its website about the two-year restriction for collecting charges from residential customers for under billing.	Hydro One will post information about the two year limitation on collecting charges from customers who have been under-billed.
	62	Hydro One Inc. should revise its goodwill credits policy to eliminate reference to "goodwill", post the revised document on its website, and ensure that is it applied consistently.	Hydro One revised its policy in 2014 to provide for greater consistency in applying credits associated with failing to provide acceptable service, and will continue to monitor for consistent application of the policy.
	63	Hydro One Inc. should take steps to revise its conditions of service to provide customers with a right to receive service charge credits if they do not receive bills, or receive erroneous bills.	As noted in the Report, this has been our practice since early 2014. This will be communicated in the next revision of our Conditions of Service.
Lessons Learned	64	Hydro One Inc. should use the customer relations fallout associated with the new CIS as a learning tool for its managers.	As noted in the Report, the "Call a Customer" executive training program was introduced in the summer of 2014. This program includes a detailed review of the CIS experience and lessons learned. To date, over 150 managers and executives have completed the program.
Progress Reports	65	Hydro One Inc. should report back to my Office in six months' time on progress in implementing my recommendations, and at six-month intervals thereafter until such time as I am satisfied that adequate steps have been taken to address them.	Hydro One will be open and transparent in its efforts to improve customer service and will report back to the Office of Ombudsman on this investigation as scheduled.

This is Exhibit "U" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK

Scorecard - Hydro One Networks Inc.

9/28/2015

Performance Outcomes	Performance Categories	Measures	2010	2011	2012	2013	2014	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time	90.90%	92.00%	95.70%	97.40%	97.40%	↑	90.00%	
		Scheduled Appointments Met On Time	92.70%	93.90%	98.60%	98.40%	99.30%	↑	90.00%	
		Telephone Calls Answered On Time	69.70%	81.40%	83.40%	63.90%	69.60%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution				78.30%	79%			
		Billing Accuracy				4.40%	94.63%	→	98.00%	
		Customer Satisfaction Survey Results				87%	85%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public awareness [measure to be determined]								
		Level of Compliance with Ontario Regulation 22/04	NI	NI	NI	NI	NI	→		C
		Serious Electrical Incident Index — Number of General Public Incidents	6	8	6	7	4	↓		4
		Serious Electrical Incident Index — Rate per 10, 100, 1000 km of line	0.050	0.066	0.051	0.059	0.033	↓		0.036
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted	9.00	21.17	10.58	26.57	9.42	↑		at least within 9.00 - 26.57
		Average Number of Times that Power to a Customer is Interrupted	2.91	3.93	3.15	4.23	2.96	↑		at least within 2.91 - 4.23
	Asset Management	Distribution System Plan Implementation Progress				Under Review	104			
	Cost Control	Efficiency Assessment			5	5	5			
		Total Cost per Customer [1]	$1,052	$1,072	$1,041	$1,046	$1,069			
		Total Cost per Km of Line [1]	$10,471	$11,064	$10,741	$10,682	$10,916			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) [2]		15.43%	27.96%	53.57%	78.35%	●		213.66MW
		Net Cumulative Energy Savings (Percent of target achieved)		29.61%	45.46%	59.59%	79.48%	●		1,130.21GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time	100.00%	95.79%	99.39%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time				99.71%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from efficiencies are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	1.01	0.99	0.99	1.00	0.99			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.44	1.34	1.30	1.35	1.31			
		Profitability: Regulatory Return on Equity — Deemed (included in rates)		9.66%	9.66%	9.66%	9.66%			
		Profitability: Regulatory Return on Equity — Achieved		8.80%	8.72%	8.00%	6.26%			

Notes:

1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings include any persisting peak demand savings from the previous years.

Legend: ↑ up ↓ down → flat ● target met ● target not met

Appendix A – 2014 Scorecard Management Discussion and Analysis ("2014 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2014 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: statements regarding ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives; statements about the company's strategy; and statements regarding future capital investments. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "can", "believe," "seek," "estimate," 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. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no severe damage to our facilities caused by adverse weather conditions, natural disasters or catastrophic events; anticipated numbers of new customers and renewable energy projects materializing; availability of required services and/or materials; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. 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: severe weather conditions, natural disasters or catastrophic events; an inability to procure required services and/or materials; and the risk that anticipated numbers of new customers and renewable energy projects do not materialize.

Scorecard MD&A - General Overview

For 2014, Hydro One Networks' performance was better than target in all areas, except for billing accuracy, conservation & demand management, and one of the public safety measures. In addition to ongoing operations, a major focus in 2014 was investing in improvements to our customer call centre and billing operations. This was in response to poor customer service arising from implementation in 2013 of a new billing system. As a result, we were able to improve our billing accuracy and customer service, but not yet up to our own standards and targets. In 2014, our billing accuracy measured 94.63 per cent, falling short of the industry target of 98 per cent. The billing-related issues that some of our customers had experienced in 2014 also contributed to a lower level of customer satisfaction – about 2 percentage points lower than in 2013, and many customers who indicated that they were not yet in a position to confirm that our performance had improved to their standards. Having fixed the technical issues that caused our customer service disruption, our focus now is to consistently improve our performance, win back the confidence of our customers, and provide them with an ever-improving experience. Based on discussions with our customers, and on feedback from them, we plan to continue developing targeted products and services that respond to our customers' unique needs. This includes realizing value from our new Customer Information System ("CIS"), simplifying and shortening timeframes for the delivery of services, and enhancing accessibility (in person, by phone, through our web portal, and using our mobile application) to allow effective self-service for simple transactions. We are also committed to delivering programs to help our customers manage their energy consumption. We have also formed a third-party Customer Service Advisory Panel and launched our draft Customer Commitments, to allow us to develop and clearly articulate our promises to our customers and to hold us accountable for keeping those promises.

Service Quality

- **New Residential/Small Business Services Connected on Time**

In 2014, Hydro One Networks processed 14,967 new connection requests for residential and small business low-voltage customers (those with service less than 750Volts). 97.4 per cent of these requests were completed within five business days (or as agreed to by the customer and the distributor), exceeding the requirements of the Ontario Energy Board's Distribution System Code ("DSC") and also exceeding the industry target of 90 per cent for the fifth consecutive year. Although the number of connections remained steady compared to 2013, our performance in this area has improved over the last five years, from about 91 per cent in 2010.

- **Scheduled Appointments Met On Time**

Hydro One Networks scheduled 26,783 appointments in 2014. This measure applies to appointments where customer presence is required, and also to those where customers do not need to be present. When a customer requests an appointment, the appointment must be scheduled within five business days (or as agreed to by the customer and the distributor). If customer presence is required, the distributor must commit to, and arrive within a four-hour window for the appointment; if customer presence is not required, the distributor must arrive on the scheduled date. The Company recorded a 99.3 per cent success rate in meeting these requirements, exceeding the industry target of 90 per cent for the fifth consecutive year. Performance in meeting scheduled appointments has improved steadily over

the past five years, from about 92.7 per cent in 2010. Hydro One remains committed to meeting our customers' expectations in this area.

- **Telephone Calls Answered On Time**

Hydro One Networks' Call Centre agents received about 1.4 million phone calls from customers in 2014. The Ontario Energy Board's ("OEB") Distribution System Code requires call centre staff to answer calls within 30 seconds, 65 per cent of the time, whenever the customer reaches an agent either directly or by means of a transfer, or where the customer has selected the option to speak to an agent via our automated Interactive Voice Response ("IVR") system. In 2014, we met this requirement 69.6 per cent of the time, exceeding the industry target, and improving by 5.7 percentage points from 2013. In the past two years, our performance was lower than both 2011 and 2012 levels, mainly due to our work to implement our new billing system, higher call volumes related to a storm in December 2013, and to bill payments and collections in late 2014. The Company expects our Call Answering performance to improve with the support of our new call centre service provider (for the 2015-18 period), which includes targets to answer calls within 20 seconds, 80 per cent of the time. Our call centre's ability to answer calls in a timely manner is of course a function of call volumes, which are especially affected by unexpected events and extreme weather conditions.

Customer Satisfaction

- **First Contact Resolution**

First Contact Resolution ("FCR") reports the success of the distributor in resolving the issue during the first contact. Hydro One measures First Contact Resolution based on transaction surveys that are performed within five days of a customer contact. The results for the year were 79 per cent, representing an improvement of 0.7 percentage points from 2013. For 2015, the Company has set its own First Contact Resolution target of 83 per cent. Hydro One Networks has achieved significant improvements in its call centre and billing operations following the implementation of our new billing system. Recognizing that the call centre is the primary contact point for most customers, we continue to enhance its capabilities and service quality. For example, the company implemented a new customer service quality assurance program, which includes recording all call activity for quality assurance purposes, and regularly surveying our customers to solicit feedback on our own performance.

- **Billing Accuracy**

In 2013, Hydro One Networks' billing accuracy was reported based on the percent of estimated bills, with 4.4 per cent of bills based on estimates. In late 2014, the metric was redefined by the OEB, and Hydro One Networks has modified its reporting to align with the redefinition. However, due to this redefinition of how billing accuracy is measured and reported, our 2014 results of 94.63 per cent cannot be compared to 2013. Also, in 2014, the OEB exempted us from applying Time of Use ("TOU") billing for about 170,000 customers, whose meters are "hard-to-reach" and unable to communicate reliably on our smart meter network due to poor cellular coverage. We have asked the OEB to exclude these same accounts from the billing accuracy requirements, and if granted, this exemption would result in a billing accuracy of 97.86 per cent for 2014. A decision is expected from the OEB on the exemption later in 2015.

- **Customer Satisfaction Survey Results**

Customer satisfaction results for the year were 85 per cent, 2 percentage points below our 2013 results. The measure records customer satisfaction with Hydro One at a "transactional" level, and also our customers' perceptions of us, using customer surveys for both. While customers' satisfaction with their transactions with Hydro One Networks has improved, the perception results were poorer as a result of low scores from our Large Distribution Accounts customers. Also, poorer 2014 results were attributable to the billing-related customer service issues that Hydro One experienced earlier in 2014. Our plan to improve customer satisfaction has taken into account discussions with our customers and reflects the planned development and delivery of targeted products and services that respond to our customers' unique needs. This includes realizing value from our new Customer Information System, simplifying and shortening timeframes for the delivery of services, enhancing accessibility (in person, by phone, through our web portal and using our mobile application) to ensure effective self-service for simple transactions, and delivering programs which help customers better manage their energy consumption. In addition, to further improve our customer service performance culture as a transparent, accountable and customer-focused organization, we have recently announced two new initiatives – a third party expert Customer Service Advisory Panel and our draft Customer Commitments. Our Customer Commitments will form the basis of our promises to our customers, and the Customer Service Advisory Panel will provide advice and help hold us accountable to the promises we make to our customers. Once our Customer Commitments are finalized with input received from our customers, our employees and our Customer Service Advisory Panel, we will develop a public scorecard and use it to report on our performance.

Safety

- **Public Safety**

In April 2015, the Electrical Safety Authority ("ESA") made recommendations to the OEB for a scorecard public safety measure that includes three main components: 1) Public Awareness of Electrical Safety, 2) Compliance with Ontario Regulation 22/04, and 3) the Serious Electrical Incident Index. The OEB accepted the recommendations and has instructed all distributors that the first reporting to include all three components will be on the scorecards for 2015.

- **Component A – Public Awareness of Electrical Safety**

This component of the public safety measure will not have performance data for the 2014 scorecard since the survey results are not available. The year 2016 will be the first year that the data will be reported on the scorecard for the 2015 results. An industry target for the metric has not been set, but will be established once three years of data is gathered from the distributors.

- **Component B – Compliance with Ontario Regulation 22/04**

Following recommendations from the Electrical Safety Authority, Ontario Regulation 22/04 was introduced in early 2004 to ensure electrical safety and to track and report the safety records and compliance of electricity distributors. The regulation relies on objective-based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems. Distributors are required to submit declarations of compliance with the regulation, signed by an officer of the company, on an annual basis. An external auditor is engaged by the company to audit and report on the company's compliance with various safety, equipment, planning, and construction clauses from the regulation. The auditor's report along with the signed declaration of compliance is submitted to the Electrical Safety

Authority. The performance target for compliance with Ontario Regulation 22/04 is for the distributor to be fully compliant, and is recorded as Compliant ("C"), Non-Compliant ("NC"), or Needs Improvement ("NI"). For 2014 and as in previous reporting periods, Hydro One was assessed as "NI", or Needs Improvement. Hydro One is committed to continuous improvement in the area of public safety. Throughout the year, Hydro One takes an active role in educating our customers and the public through various safety-related media campaigns, through social media and press releases, using our mobile state-of-the-art interactive Electricity Discovery Center (which helps customers manage usage and costs while educating children on electrical safety), providing tips on emergency preparedness and seasonal safety, and working proactively to reduce theft-related injuries by replacing copper grounding elements with a steel composite.

- **Component C – Serious Electrical Incident Index**

The Serious Electrical Incident Index is a component of Regulation 22/04 and is meant to address the resultant impact in improving public electrical safety on the distribution network over time. The measure normalizes serious electrical incidents per 10, 100, or 1,000km of line, and both the actual number and rate per kilometer are reported. The Regulation requires the distributor and any of its contractors or operators to report to the Electrical Safety Authority any serious electrical incident within 48 hours. A serious electrical incident is defined as any electrical contact or any fire or explosion that caused or may have caused injury or death in any part of the distribution system operating at greater than 750 Volts (except as caused by lightning strikes). For 2014, Hydro One's target based on the previous five years and our total kilometers of distribution lines, generated an index value of 0.036, or four incidents per 1,000km of line. The company's Electrical Safety Authority audited reports identified four serious electrical incidents in 2014, converting to an index of 0.033, slightly better than target. The company's performance represents an improvement in safety of our distribution system of about 44 per cent from last year, and about 34 per cent since 2010, coinciding with three fewer serious electrical incidents than 2013, and two fewer than in 2010.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

The metric represents the duration of interruptions, as the ratio of the total customer hours of interruption to the total number of customers served, expressed as the average time in hours over the reporting period. The measure captures all planned and unplanned interruptions of one minute or longer (including events caused by *force majeure* and excluding outages caused by the upstream loss of electrical supply). For the year 2014, the average distribution system interruption was 9.42 hours, at the lower end and well within the distributor range of 9.00 to 26.57 hours (the range is set using the lowest and highest results during the past four-year period). The duration of interruptions showed a significant reduction from 2013 by about 17 hours. The improvement was mainly attributable to a decreased frequency of *force majeure* events in 2014, defined as those interruptions affecting at least 10 per cent of our distribution customers. Two such events on September 5-6 and November 24-25 were categorized as *force majeure*. September's event was the result of a severe thunderstorm passing through southern Ontario with winds exceeding 75 km/h, carrying with it heavy rainfall and large hail. The storm affected about 137,000 (nearly 11 per cent) of our customers in most regions across Ontario. The storm of November 24-25 affected northern regions of Lake Erie and Lake Ontario, central Ontario, Grey Bruce region, and the GTA with snow accumulation of about 30cm and periods of freezing rain affecting northeastern Ontario. About 238,000 (nearly 18 per cent) of our customers were affected by that storm. In 2014 we made capital investments totaling $1,530 million to improve our transmission and distribution systems' reliability and performance, address our aging power system infrastructure, facilitate new generation, and improve service to our customers.

- **Average Number of Times that Power to a Customer is Interrupted**

Frequency of customer outages was reported at 2.96 outages per customer for 2014, a 30 per cent improvement from 2013, with the frequency of outages in 2014 sitting at lower end of the distributor range of 2.91 to 4.23 outages per customer. The distributor range is defined in the same manner as that for the duration metric above. The company's progress on this metric is attributable mostly to a reduction in the number of incidents of trees coming into contact with power lines, and fewer *force majeure* events in 2014. For additional details on the causes and impacts of specific events, please refer to the preceding section on *Average Number of Hours that Power to a Customer is Interrupted*.

Asset Management

- **Distribution System Plan Implementation Progress**

Distribution System Plan ("DSP") implementation progress is a new performance measure instituted by the OEB, effective in 2013. Consistent with other new measures, utilities were given an opportunity to define it in the manner that best fits their organization. The Distribution System Plan outlines Hydro One Networks' forecasted capital expenditures over the next five years, required to maintain and expand the company's electricity system to serve current and future customers. Progress is measured as the ratio of actual total capital expenditures made in a calendar year to the total amount of planned capital expenditures for the same year. For 2014, the company exceeded its planned project expenditures by 4 per cent.

Cost Control

- **Efficiency Assessment**

Cost control metrics are evaluated on behalf of the OEB by an independent party, the Pacific Economics Group LLC ("PEG"). The study attempts to segment electrical distributors into five groups based on a benchmarking evaluation of cost efficiency as measured by the difference between actual costs and PEG's prediction of costs. Group 1 distributors are considered most efficient, with actual costs 25 per cent or more below predicted costs and Group 5 distributors are considered least efficient, according to the PEG methodology, with actual costs 25 per cent or more above predicted costs. For 2014 and for the third consecutive reporting period, Hydro One's results place the company in Group 5, along with Algoma Power Inc., Toronto Hydro-Electric System Ltd., West Coast Huron Energy Inc., and Woodstock Hydro Services Inc.

- **Total Cost per Customer**

The total cost per customer is defined as the total Capital and Operations, Management, & Administration ("OM&A") costs, divided by the total number of customers served. This includes certain adjustments prescribed by the PEG methodology. In 2014, Hydro One's total cost per customer was $1,069, which is 2.2 per cent higher than in 2013 and about 1.5 per cent higher than the four-year average, resulting from our increased expenditures to address billing and other customer service issues, and to improve service for our customers following the implementation of our new billing system.

- **Total Cost per km of Line**

The total cost per kilometer of line is defined as the total Capital and OM&A costs, divided by the total number of kilometers of line operated to serve customers, along with certain PEG prescribed adjustments. In 2014, Hydro One's total cost per kilometer of line was $10,916, or about 2 per cent higher than 2013 and about 1.6 per cent higher than the four-year average. As noted above, these increased costs reflected our efforts and commitment to address customer service issues and improve the experience for our customers in 2014.

Conservation & Demand Management (CDM)

- **Net Annual Peak Demand Savings (Percent of target achieved) &**
- **Net Cumulative Energy Savings (Percent of target achieved)**

Hydro One had submitted its forecast to the OEB in September 2014, advising that we would be below the 80 per cent target in this area. The achieved Peak Demand reduction results of 167.4MW represents 78.35 per cent of the demand target. Achieved Cumulative Energy savings of 898.4GWh represent 79.48 per cent of the energy target. These achievements represent our planned results as laid out in Hydro One Networks' 2010 strategy submission to the OEB. The shortfall from target is due to allocated Time of Use Demand savings of 8.8MW falling much below the provincial forecast, and also due to the fact that the Ontario Power Authority ("OPA") province-wide CDM programs were launched later than expected, thereby reducing their impact.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

For 2014, Hydro One Networks completed 344 Connection Impact Assessments ("CIA") and for the second consecutive year achieved a 100 per cent on-time completion rate (completing the CIA within 60 days). A CIA is used to assess the impact of a new connection on the distribution system, and is applicable to facilities that are greater than 10kW.

- **New Micro-embedded Generation Facilities Connected On Time**

Results for 2014 improved by 0.29 percentage points compared to 2013, resulting in a 100 per cent success rate for on-time connection of micro-embedded generation facilities. The metric measures the company's success in connecting micro-embedded generation facilities (less than 10kW) 95 per cent of the time within a five business day window.

Financial Ratios

The basis for these financial ratios is the company's Distribution Business Financial Statements December 31, 2014 filed with the OEB under the Electricity Recording & Record-Keeping Requirements (RRR) submission.

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

The company measures current ratio as the ratio of its current assets to its current liabilities. Current assets are defined as cash or other assets to be converted to cash within the year and which can be used to fund daily operations and pay ongoing expenses. Current liabilities are defined as short term debts or financial obligations that become due within the year. For 2014, the current ratio was reported as 0.99, which is 0.01 points lower than in 2013. This result indicates that for every one dollar of debt due within the year, the company has $0.99 in cash or cash equivalents to cover the obligations.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The debt-to-equity ratio is a measure of the company's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors, while remaining within the OEB-mandated 60 per cent to 40 per cent debt-to-equity structure (a ratio of 1.5). For 2014, the company's debt-to-equity ratio was 1.31, representing a 0.04 point decrease compared to 2013 and 0.19 points lower that the OEB target.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

Hydro One Networks' deemed regulatory return on equity for 2014, as in previous years, was 9.66 per cent. The distribution rates approved by the OEB are based in part on the deemed return on equity.

- **Profitability: Regulatory Return on Equity – Achieved**

For the year 2014, Hydro One Networks achieved a return on equity of 6.26 per cent for its Distribution business. This result is below the deemed return on equity by 3.40 percentage points. Compared to 2013, the reduction in return on equity is 1.74 percentage points and the overall result is lower than our historical average of 8.46 per cent return on equity, mainly attributable to an increase in expenses related to customer service, reflecting our efforts in 2014 to address billing and other customer service issues.

Note to Readers of 2014 Scorecard MD&A

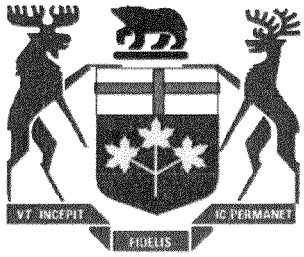
The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgment on the reporting date of the performance scorecard, and could be markedly different in the future.

This is Exhibit "V" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Lisa Lutwak

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK



Ontario

Ontario Energy Board

RETAIL SETTLEMENT CODE

Revised on October 8, 2015

Table of Contents

1 GENERAL AND ADMINISTRATIVE PROVISIONS

1.1 Purpose of the Code

This Code sets the minimum obligations that a distributor and retailer must meet in determining the financial settlement costs of electricity retailers and consumers and in facilitating service transaction requests where a competitive retailer provides service to a consumer. These obligations arise through sections 26 through 31, inclusive, of the *Electricity Act, 1998* and the conditions of distributions' licences and retailers' licences.

1.2 Definitions

"Act" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B.

"affiliate" with respect to a corporation, has the same meaning as in the *Business Corporations Act*.

"Affiliate Relationships Code" means the code, approved by the Board and in effect at the relevant time, which among other things, establishes the standards and conditions for the interaction among electricity distributors or transmitters and their respective affiliates.

"ancillary services" means services necessary to maintain the reliability of the IMO-controlled grid; including frequency control, voltage control, reactive power and operating reserve services.

"Board" means the Ontario Energy Board.

"building" means a building, portion of a building, structure or facility.

"competitive electricity costs" are those costs billed through the IMO or paid by the distributor to embedded retail generators or neighbouring distributors that cover competitive electricity services. Such costs will apply to electricity supply whether such supply is provided via SSS or a competitive retailer.

"competitive electricity services" means those services provided through the IMO, embedded retail generators or neighbouring distributors that are deemed by the Board to be competitive as set out in Appendix A.

"competitive retailer" is a person who retails electricity to consumers who do not take SSS.

"consumer" means a person who uses, for the person's own consumption, electricity that the person did not generate.

"customer" means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial subdivisions.

"cycle billing" means the practice of billing a block of consumers whose meters are read according to a common meter-reading cycle as if all meters were read on the same day, even though meter-reading practices result in some meters being read within a few days, plus or minus, of the target read date.

"distribute" with respect to electricity, means to convey electricity at voltages of less than 50 kilovolts.

"distribution services" means services related to the distribution of electricity and the services the Board has required distributors to carry out, for which a charge or rate has been approved by the Board under section 78 of the Act.

"distribution system" means a system for distributing electricity at voltages less than 50 kilovolts and includes any structures, equipment or other things used for that purpose.

"Distribution System Code" ("DSC") means the code, approved by the Board and in effect at the relevant time, which, among other things, establishes the obligations of distributors with respect to the services and terms of service to be offered to consumers and retailers and provides minimum technical operating standards for distribution systems.

"distribution system losses" are energy losses resulting from the interaction of intrinsic characteristics of the distribution network, such as electrical resistance with network voltages and current flows.

"distribution system loss factor" means a factor(s) by which metered loads must be multiplied such that when summed equal the total measured load at the supply point(s) to the distribution system.

"distributor" means a person who owns or operates a distribution system.

"Electricity Act" means the *Electricity Act, 1998*, S.O. 1998, c.15, Schedule A.

"Electronic Business Transaction System" or "EBT System" means the authorised computer-based transaction mechanism for transmitting common format data among market participants.

"eligible low-income customer" has the same meaning as in the Distribution System Code.

"embedded distributor" means a distributor who is not a wholesale market participant and that is provided electricity by a host distributor.

"embedded generation facility" means a generation facility which is not directly connected to the IESO-controlled grid but instead is connected to a distribution system, and has the extended meaning given to it in section 1.9 of the Distribution System Code;

"embedded retail generator" means a customer that:

(a) is not a wholesale market participant or a net metered generator (as defined in section 6.7.1 of the Distribution System Code);
(b) owns or operates an embedded generation facility, other than an emergency backup generation facility; and
(c) sells output from the embedded generation facility to the Ontario Power Authority under contract or to a distributor;

"embedded wholesale consumer" is a consumer who is a wholesale market participant and whose facility is not directly connected to the IMO-controlled grid but is connected to a distribution system.

"embedded wholesale generator" is a generator who is a wholesale market participant and whose generation facility is connected to the distribution system.

"generate" with respect to electricity, means to produce electricity or provide ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system.

"generation facility" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system and includes any structures, equipment or other things used for that purpose.

"generator" means a person who owns or operates a generation facility.

"host distributor" means the registered wholesale market participant distributor who provides electricity to an embedded distributor.

"IMO" means the Independent Electricity System Operator established under the Electricity Act.

"IMO Controlled Grid" means the transmission systems with respect to which, pursuant to agreements, the IMO has the authority to direct operations.

"interval meter" means a meter that measures and records electricity use on an hourly or sub-hourly basis.

"load transfer" means a MIST-metered, network supply point of one distributor that is supplied through the distribution system of another distributor and where this supply is not considered a wholesale supply point.

"lock-box arrangement" means an arrangement where a financial institution (typically a bank or some other financial institution) is designated by the parties to accept payment from consumers on behalf of the parties and to distribute the collected revenue to the parties according to prescribed rules.

"Market Rules" means the rules made under section 32 of the Electricity Act.

"meter installation" means the meter and, if so equipped, the instrument transformers, wiring, test links, fuses, lamps, loss of potential alarms, meters, data recorders, telecommunication equipment and spin-off data facilities installed to measure power past a meter point, provide remote access to the metered data and monitor the condition of the installed equipment.

"metering evolution period end date" means, in relation to a distributor, the date determined for that purpose by the Board;

"MIST meter" means an interval meter from which data is obtained and validated within a designated settlement timeframe. MIST refers to "Metering Inside the Settlement Timeframe."

"MOST meter" means an interval meter from which data is only available outside of the designated settlement timeframe. MOST refers to "Metering Outside the Settlement Timeframe."

"non-competitive electricity costs" means costs for services from the IMO that are not deemed by the Board to be competitive electricity services plus costs for distribution services, other than SSS.

"non-competitive electricity services" means those services received from the IMO that are not deemed to be competitive electricity services, plus distribution services, other than SSS.

"non-interval meter" means a device that measures and records electrical usage cumulatively over the meter reading period.

"power factor" means a variable equal to the ratio of kW and kVa demand.

"prepaid meter" means a meter that allows a consumer to purchase a credit for a certain amount of electricity at a fixed price from a distributor or retailer by having the amount posted to the meter at the consumer's location. When the purchased amount of

electricity has been used, the meter will automatically interrupt electricity supply to the location.

"primary metered customer" means a customer whose meter point is located on the primary side of a distribution transformer.

"rate" means any rate, charge or other consideration and includes a penalty for late payment.

"Rate Handbook" means the document approved by the Board that outlines the regulatory mechanisms that will be applied in the setting of distributor rates.

"registered facility" means a facility registered with the IMO that is capable of supplying physical services and/or capacity reserve.

"registered wholesale meter" means a meter that the IMO has registered in accordance with the Market Rules for the purpose of wholesale settlements "retail" with respect to electricity means:

(a) to sell or offer to sell electricity to a consumer,
(b) to act as agent or broker for a retailer with respect to the sale or offering for sale of electricity, or
(c) to act or offer to act as an agent or broker for a consumer with respect to the sale or offering for sale of electricity.

"Retail Settlement Code" or "Code" means this code approved by the Board and in effect at the relevant time, which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers.

"Retail Settlement Variance Account" or "RSVA" means the variance account referred to in this Code.

"retailer" means a person who retails electricity.

"secondary metered customer" means a customer whose meter point is located on the secondary side of a distribution transformer.

"Service Agreement" means the agreement that sets out the relationship between a licensed retailer and a distributor, in accordance with the provisions of Chapter 12.

"service area" with respect to a distributor, means the area in which the distributor is authorised by its licence to distribute electricity.

"service transaction request" or ("STR") means a written authorisation, unless otherwise provided for in the Code, that initiates a change from current service provision to alternative service provision.

"smart meter" means a meter that is part of an advanced metering infrastructure that meets the functional specification referenced in the Criteria and Requirements for Meters and Metering Equipment, Systems and Technology Regulation, O. Reg. 425/06;

"Standard Supply Service" ("SSS") means the service approved by the Board and in effect at the relevant time, which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act.

"supply facility losses" are the energy losses that occur as a result of the difference between the point of delivery of energy from the transmission system and the metered delivery point for a distributor.

"supply facility loss factor" means the factor(s) by which delivery point metered loads must be multiplied such that when summed equal the total measured load at the delivery point(s) to the distribution system .

"time-of-use meter" means a device that measures and records electrical usage during pre-specified periods of the day cumulatively over a meter reading period.

"total losses" means the sum of all energy losses including distribution system losses, supply facility losses and unaccounted for energy.

"transmission system" means a system for transmitting electricity and includes any structures, equipment or other things used for that purpose.

"transmitter" means a person who owns or operates a transmission system.

"unaccounted for energy" means all energy losses that cannot be attributed to distribution system losses or supply facility losses. These losses include measurement error, errors in estimates of distribution system losses or supply facility losses and unmetered loads, energy theft and non-attributable billing errors.

"unmetered loads" means electricity consumption that is not metered and is billed based on estimated usage.

"wholesale consumer" means a person that purchases electricity or ancillary services in the IMO-administered markets or directly from a generator, other than an embedded retail generator.

"wholesale market participant distributor" or "WMPD" means a distributor who is a wholesale market participant, including a distributor who is provided electricity by a neighbouring distributor through a registered wholesale meter.

"wholesale market participant" means a person that sells or purchases electricity or ancillary services through the IMO-administered markets.

"wholesale settlement costs" mean costs for both competitive and non-competitive electricity services billed to a distributor by the IMO or a host distributor, or provided by an embedded retail generator or by a neighbouring distributor.

"wholesale supplier" means a person who sells electricity or ancillary services through the IMO-administered markets or directly to another person, other than a consumer.

"written authorisation" includes authorisation given by electronic mail or any other similar technology, but does not include authorisation given verbally.

1.3 Interpretation

1.3.1

Unless otherwise defined in this Code, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act as the case may be. Headings are for convenience only and shall not affect the interpretation of this Code. Words importing the singular include the plural and vice versa. A reference to a document or a provision of a document includes any amendment or supplement to or any replacement of that document or that provision of that document. An event that is required under this Code to occur on or by a stipulated day which is not a business day may occur on, or by, the next business day.

1.3.2

[Revoked by amendment, effective October 8, 2015.]

1.3.3

[Revoked by amendment, effective October 8, 2015.]

1.4 To Whom This Code Applies

This Code applies to all electricity distributors licensed by the Board under Part V of the Act. This Code also applies to electricity retailers licensed by the Board under Part V. These entities are obligated to comply with the Code as a condition of their licences.

1.5 Hierarchy of Codes

The order of hierarchy for this Code in relation to other codes, subject to any specific conditions of any licence that apply to a distributor or a retailer, is as follows:

1. Affiliate Relationships Code
2. Distribution System Code
3. Retail Settlement Code
4. Standard Supply Service Code

1.6 Amendments to This Code

This Code may only be amended in accordance with the procedures set out in the licence issued to a distributor or a retailer.

1.7 Coming into Force

This Code and any amendments to this Code shall come into force on the date that the Board publishes the Code or an amendment to the Code by placing it on the Board's website, except where it is expressly stated otherwise and except for the following provisions that shall come into effect on the date that subsection 26(1) of the Electricity Act comes into force: Chapters 3 through 8; and sections 10.6.1 and 10.6.2. Further, no STR related to a change in competitive electricity service provider shall take effect until subsection 26(1) of the Electricity Act has come into force. The amendments to sections 1.2 (definition of "customer") and 7.7 come into force on April 1, 2011. The further revisions to section 7.7.5 come into force on April 1, 2011.

The amendments to sections 1.2 (definitions of "eligible low-income consumer, "Emergency Financial Assistance" and "Social Service Agency or Government Agency"), 1.3.1, 1.3.2, 1.3.3, 7.7.4.1 and 7.7.4.2 come into force on October 1, 2011.

1.8 Requirements for Board Approvals

Any matter under this Code requiring a determination of the Board may be determined by the Board without a hearing or through an oral, written or electronic hearing, at the Board's discretion.

1.9 Special Provisions for RPP Consumers and New SSS Code

1.9.1

The following definitions apply for the purposes of this section 1.9:

(a) "competitive retailer" means a person who retails electricity to consumers, but does not include a person who retails electricity to consumers who take SSS other than transitional consumers;

(b) "RPP consumer" means a consumer that pays the regulated price;

(c) "regulated price" means the commodity price for electricity referred to in section 3.3 or 3.4 of the SSS Code;

(d) "SSS Code" means the code issued by the Board and in effect at the relevant time which, among other things, establishes the manner in which a distributor must meet its obligation to sell electricity under section 29 of the Electricity Act; and

(e) "transitional consumer" means a consumer:

i. who entered into or renewed a contract with a retailer on or before December 9, 2002 with respect to which a service transaction request is or has been implemented to enable the consumer to purchase electricity from a competitive retailer;

ii. whose contract referred to in paragraph (i) is in effect but has not been renewed since December 9, 2002;

iii. who is, in accordance with regulations made under the Act, eligible to pay the regulated price; and

iv. who is not an electing spot consumer (as defined in the SSS Code).

1.9.2

Notwithstanding any other provision of this Code, the commodity price per kilowatt hour for electricity payable by an RPP consumer shall be determined by a distributor, or by a competitive retailer in the case of a transitional consumer that is being billed using retailer-consolidated billing, in accordance with the SSS Code. All provisions of this Retail Settlement Code that apply to an RPP consumer shall be interpreted accordingly.

1.9.3

The following sections of the SSS Code apply to a competitive retailer that is billing a transitional consumer using retailer-consolidated billing:

(a) sections 1.7.2 to 1.7.5;

(b) section 2.6.1;

(c) sections 3.3.5 and 3.3.6;

(d) section 3.4.3; and

(e) section 3.7.

A competitive retailer shall comply with the obligations contained in those sections (if they are expressed in mandatory terms) to the same extent as if they were contained in this Code and referred to a competitive retailer rather than to a distributor.

1.9.4

Nothing in this Code shall be interpreted as allowing a distributor to provide standard supply service (as defined in the SSS Code) through a third party unless the distributor is authorized to do so by or under the SSS Code.

1.9.5

This section 1.9 shall come into force on the first term commencement date (as defined in the SSS Code).

2 SUMMARY OF SETTLEMENT OBLIGATIONS

All licensed distributors that are required to adhere to this Code as a condition of their licence shall provide the services summarised in sections 2.1 through 2.7 according to the detailed rules and procedures outlined in Chapters 3 through 12. These services shall be provided to all consumers located within a distributor's service area and to all retailers serving such consumers. All services described in this Code must be provided without discrimination or preference to each retailer, generator or consumer who requests such services.

2.1 Determine Wholesale Settlement Costs

A distributor shall determine the wholesale settlement costs for consumers, including consumers served under SSS, connected to the distributor's distribution system. Wholesale settlement costs shall be determined in accordance with Chapters 3 and 4. A distributor is not obligated to determine the settlement costs relating to competitive electricity services or non-competitive electricity services for which another wholesale market participant is obligated to pay to the IMO.

2.2 Determine Distribution Charges

A distributor shall determine the charge for distribution services associated with electricity delivery in accordance with Chapter 4 for all consumers, including wholesale market participants, connected to the distributor's distribution system.

2.3 Implement Service Transaction Requests Involving Retailers

A distributor shall accept and process STRs according to the rules and procedures described in Chapter 10. This Code prescribes rules associated with STRs when a consumer's electricity supply is already provided by a competitive retailer or when this STRs will be provided by a competitive retailer once the STR has been processed. Specific services covered by this Code are listed in section 10.1.

2.4 Maintain Consumer Records

A distributor shall maintain records for all consumers for which it determines settlement costs.

2.5 Provide Access to Current Meter and Price Data

A distributor shall make available to a consumer, or to a competitive retailer designated by a consumer, validated meter usage information according to the standards and schedule delineated in sections 5.2 and 11.1. If requested to do so by a retailer, a distributor also shall make available to the retailer the hourly price data used to calculate competitive electricity costs for the billing period over which a consumer is billed (e.g., as calculated in equation 3.3.1(b)), hourly price information from the IMO, or the host distributor as the case may be, and net system load data for each calendar day.

2.6 Provide Access to Historical Consumer-Specific Information

A distributor shall maintain and be able to provide historical consumer-specific information to a consumer, or to any party designated by the consumer, regardless of whether the consumer is served under SSS or by a competitive retailer. Information that must be maintained and provided as directed by a consumer is delineated in section 11.3 and includes information on electricity use, regulated rates under which a consumer is served, meter characteristics and payment information.

2.7 Establish Service Arrangements With Competitive Retailers

A distributor shall enter into a Service Agreement with any licensed retailer who wishes to provide electricity services to consumers connected to the distributor's distribution system and to utilise retail settlement services offered by the distributor.

3 DETERMINING SETTLEMENT COSTS FOR COMPETITIVE ELECTRICITY SERVICES

A distributor shall determine the cost of competitive electricity services purchased by a consumer for which, in accordance with section 2.1, it has settlement responsibility, according to the procedures described in sections 3.1 through 3.10.

3.1 Competitive Electricity Costs

The Market Rules provide that wholesale market participant distributors will be charged by the IMO for electricity delivered to the distributor at prices determined in the IMO-administered wholesale market. The IMO will also charge distributors for ancillary services, transmission services, IMO administrative services and other services required to operate the IMO-administered wholesale market and direct the operations and maintain the reliability of the IMO-controlled grid. The subset of IMO-billed services deemed by the Board to be competitive electricity services are identified in Appendix A.

An embedded distributor shall be billed by a host distributor based on charges determined by the host distributor in accordance with sections 3.2 and 3.3. The host distributor shall provide all data to an embedded distributor according to the schedule and methods described in section 5.1.

3.2 Distribution Losses and Unaccounted for Energy

When determining retail settlement costs, a distributor shall adjust measured consumption at a consumer's meter for total losses. The sum of total losses for a distribution system equals the difference between wholesale energy delivered to a distributor (including supply from embedded retail generators and load transfers) and the total energy measured at all retail and wholesale consumers' meters connected to the distribution system.

A distributor shall calculate the sum of distribution system losses and unaccounted for energy using the following equation 3.2(a):

Equation 3.2(a)

$$L_{d_x} + UFE_{d_x} = E^{in}_{d_x} - \left[(1 - PAF)E^{pm}_{d_x} + E^{sm}_{d_x} + E^{um}_{d_x}\right]$$

Where L_{d_x} = Distribution losses for distributor d_x

UFE_{d_x} = Unaccounted for energy for distributor d_x

$E^{in}_{d_x}$ = total electricity supplied to distributor d_x measured at all registered wholesale meters connected to a WMPD's distribution system or at all bulk supply meters through which an embedded distributor is supplied, plus electricity supplied by embedded wholesale generators (adjusted for distribution transformation losses), plus all supply provided by embedded retail generators connected to the distributor's system (adjusted for distribution transformation losses), plus all supply provided through load transfers

$E^{pm}_{d_x}$ = total load for all primary-metered consumers in distributor d_x's service area measured at the consumer's meter, including primary-metered load transfers

$E^{sm}_{d_x}$ = total load for all secondary-metered consumers in distributor d_x's service area measured at the consumer's meter, including secondary-metered load transfers

PAF = Primary adjustment factor, which equals either 1 percent or a distributor-specific value approved by the Board

$E^{um}_{d_x}$ = Estimated consumption for unmetered load billed by distributor d_x

This calculation includes distribution system losses associated with the distribution transformation from primary to utilisation voltage. Alternatively, a distributor may calculate losses up to the primary transformation level, if the result is mathematically equivalent to equation 3.2(a).

The distribution loss factor (DLF) is equal to the value by which the sum of end-use metered loads must be multiplied to equal the total energy supplied to distributor d_x. A distributor shall calculate the DLF for secondary-metered customers using equation 3.2(b).

Equation 3.2(b)

$$DLF_{d_x}^{sm} = 1 + \left[\frac{\left(L_{d_x} + UFE_{d_x}\right)}{(1 - PAF) E_{d_x}^{pm} + E_{d_x}^{sm} + E_{d_x}^{um}} \right]$$

Where $DLF_{d_x}^{sm}$ = the distribution loss factor for secondary-metered consumers

A distributor shall calculate the distribution loss factor for primary-metered consumers using equation 3.2(c).

Equation 3.2(c)

$$DLF_{d_x}^{pm} = DLF_{d_x}^{sm} \bullet (1 - PAF)$$

Where $DLF_{d_x}^{pm}$ = the distribution loss factor for primary-metered consumers

For secondary-metered consumers who own their own transformation equipment or who have additional stages of transformation prior to loads being metered (e.g., some individual metered apartments), a site-specific loss factor (SSL) may be more accurate than that assumed in PAF. A distributor, upon receiving approval from the Board, may calculate the DLF adjusted for site-specific losses, using equation 3.2(d).

Equation 3.2(d)

$$DLF_{d_x}^{SSL} = DLF_{d_x}^{sm} \bullet \left[(1 - PAF) \Big/ (1 - SSL) \right]$$

Where $DLF_{d_s}^{SSL}$ = the site-specific adjusted distribution loss factor

A distributor shall calculate its weighted average supply facility loss factor by summing energy delivered at each of the supply facility points plus associated supply facility losses, including all supplies from the transmission system, supplies from all embedded generators and supplies from host distributors which sum shall be divided by the total energy delivered at all of the supply facility delivery points. Each of these supplies shall be adjusted for the appropriate loss factor representing the energy losses between the meter point and the defined point of sale. A distributor shall purchase energy from an embedded retail generator within its service area where such embedded retail generator has indicated that it intends to generate electricity for delivery and sale directly to the distributor, provided that the embedded retail generator has obtained such licences from the Board as may be required. The price at which such energy sales shall be settled will be the competitive electricity price as described in Appendix "A" to the Code. Notwithstanding any other provision of this Code, where an embedded retail generator has a contract with the Ontario Power Authority under which the Ontario Power Authority is purchasing output from the embedded generation facility, a distributor shall settle all applicable payments or charges associated with the contract, and shall do so in accordance with the pricing provisions of the contract and with such rules as may be determined by the Board. A distributor shall calculate the supply facility loss factor using equation 3.2(e).

Notwithstanding any other provision of this Code, where an embedded retail generator that has a contract issued under the feed-in-tariff program referred to in section 25.35 of the Electricity Act is connected on the customer side of a connection point (as set out in section 1.9 of the Distribution System Code), the charges for competitive electricity costs payable by the associated load customer shall be calculated based on the total amount of electricity consumed at the load customer's premises, whether withdrawn

from the distribution system or supplied by the embedded retail generator. This rule applies regardless of the electrical configuration of the load and generation meters.

Equation 3.2(e)

$$SFLF_{dx} = \frac{\sum\left(E^{s}_{PRWM} + SSL^{s}_{dx_{PRWM}}\right)}{\sum E^{s}_{PRWM}} + \frac{\sum((E^{y}_{RWM} + SSL^{y}_{RWM}) \bullet TLF_{dx_y})}{\sum E^{y}_{RWM}} + \frac{\sum E_{REG}}{+\sum E_{REG}} + \frac{\sum E_{WMG}}{+\sum E_{WMG}} + \frac{\sum E^{dy}_{LT} \bullet TLF_{dy}}{+\sum E^{dy}_{LT}}$$

Where: $SFLF_{dx}$ = the supply facilities loss factor for distributor d_x where supply facilities include all points of energy delivery to distributor d_x.

E_{PRWM} = hourly energy measured at all primary registered wholesale meters for directly connected distributor d_x as provided by the IMO minus any load delivered to wholesale customers within d_x's territory.

E_{REG} = hourly energy supplied by retail embedded generators to distributor d_x adjusted for each generator's losses that occur as a result of the difference between the location of the generator's meter and the assigned supply facility delivery point. The distributor's loss adjustment shall treat retail generator's in an equivalent manner to the loss adjustments for wholesale generators. All retail embedded generators that are supplying energy into distributor d_x's distribution system shall be settled using the price set out in Appendix "A" for the purposes of calculating the competitive electricity costs of consumers.

E_{WMG} = hourly energy supplied by all embedded wholesale market generators in distributor d_x service areas as measured by the IMO adjusted for each generator's site–specific connection facility loss factor.

$SL^{s}_{d_x}$ = a distributor's allocation of site-specific facilities losses at supply point s as provided by the IMO

$TLF^{s}_{d_y}$ = the total loss factor of host distributor d_y.

E_{LT} = Hourly energy supplied to distributor *dx* under a load transfer arrangement with distributor *dy* where the amount is measured by an interval meter

E_{RWM} = hourly energy supplied to distributor d_x by a host distributor

The weighted average supply facility loss factor shall be multiplied by the applicable DLF calculated in accordance with equations 3.2 (b) and (c) to equal the total loss factor for the distributor to be applied to a consumer's energy consumption for the purposes of calculating competitive energy costs. The intent of the total loss factor is to ensure an appropriate allocation of both distribution system losses and supply facility losses to all loads within the distributor's service area. A distributor shall calculate its Total Loss Factor using equation 3.2(f).

Equation 3.2(f)

$$TLF_{dx} = SFLF_{dx} \bullet DLF_{dx}$$

Where: TLF_{dx} = the total loss factor for distributor d_x

A distributor shall calculate an annual average loss factor for the determination of site-specific supply facility losses. A distributor shall calculate a SFPLF on an annual basis using estimated data and shall record the differences between the annual average estimate supply facility loss factor and the actual monthly billed loss factor from the IMO and/or host distributor(s) in the RSVA. A distributor shall record the difference between the DLF and its actual distribution system losses in the RSVA. For the purposes of calculating either the DLF or SFLF a distributor may use historical data or estimated data, subject to such estimated data being reasonable.

Unless stated otherwise in the Rate Handbook, the DLF is not intended to be calculated as a rolling, five-year average but rather as a value held constant in between rate

proceedings or over some other period of time specified in the Rate Handbook. The appropriate total loss factor shall be applied to all consumers, whether wholesale or retail and regardless of meter type. If a distributor wishes to estimate losses separately from UFE, the distributor must obtain approval from the Board.

3.3 Methodology for Determining Settlement Costs for Competitive Electricity Services

The methodology a distributor shall use to determine settlement costs for competitive electricity services differs depending on whether the consumer has an interval meter or a non-interval meter and whether the distributor is a WMPD or an embedded distributor.

3.3.1 Consumers With Interval Meters

Both WMPD and embedded distributors shall determine settlement costs for consumers with interval meters in a manner mathematically equivalent to equation 3.3.1(a) for both remotely and manually read interval meters. For settlement purposes, interval-metered load transfers and supply to embedded distributors shall be treated by the host distributor as if they were an end-use customer.

Equation 3.3.1(a)

Calculation of Settlement Costs for Interval-Metered Customers

$$CEC_B^r = \left[\sum_{h=1}^{B} P_h^{d_x} \bullet E_h^r\right] \bullet TLF_{d_x}$$

Where CEC_B^r = Competitive electricity costs for interval-metered consumer *r* for billing period B ($)

E_h^r = energy use in hour *h* measured by an interval meter at consumer *r*'s location (kWh/h)

$P_h^{d_x}$ = hourly electricity price for distributor d_x ($/kWh/h) determined in accordance with Appendix A.

TLF_{d_x} = total loss factor for distributor d_x as defined in equations 3.2(b) or 3.2(c), depending upon whether a consumer is primary or secondary metered multiplied by the delivery point loss factor for distributor d_x calculated in accordance with eqaution 3.2(e).

B = the number of hours in billing period B for consumer r

3.3.2 Consumers With Non-Interval Meters

Both WMPD and embedded distributors shall determine settlement costs for consumers with non-interval meters in a manner mathematically equivalent to equation 3.3.2(a).

Equation 3.3.2(a)

Calculation of Settlement Costs for Non-Interval-Metered Customers

$$CEC_B^t = \left[\sum_{h=1}^{B} P_h^{d_x} \bullet NSLS_h^A\right] \bullet TLF_{d_x} \bullet E_B^t$$

Where all terms not previously defined are defined as follows:

CEC_B^t = Competitive electricity service costs for kilowatt-hour-metered consumer t served by distributor d_x for billing period B

E_B^t = Cumulative energy use by consumer t in billing period B

$NSLS_h^A$ = the share of the cumulative net system load in billing period B attributable to hour h based on the load shape in settlement area A, of which d_x is a part, as calculated in accordance with equations 3.4(A) through 3.4(c).

A distributor shall use the procedures described in section 3.4 to determine the net system load shape share.

3.3.3 Consumers With Smart Meters

Until the metering evolution period end date, a distributor shall determine settlement costs for consumers with smart meters in accordance with section 3.3.2.

3.4 Determining the Net System Load Shape

As indicated in sections 3.3.1 and 3.3.2, determining settlement costs for competitive electricity services requires weighting hourly wholesale prices by hourly usage for individual consumers. Until the metering evolution period end date, a smart meter shall be treated as a non-interval meter for the purposes of this section. For an interval-metered consumer, hourly usage data are obtained from the consumer's meter. For a non-interval-metered consumer, hourly weights must be estimated. A distributor shall use the net system load shape (NSLS) to compute hourly shares of consumption for non-interval-metered consumers. The NSLS for a given period equals the hourly loads for all hours in that period.

A distributor shall calculate the net system load for a single hour in a manner mathematically equivalent to equation 3.4(a). The energy values for unmetered loads and MIST metered loads used in equation 3.4(a) shall be adjusted to reflect the appropriate total loss factors.

Equation 3.4(a)

Hourly Net System Load Calculation for A Single Distributor

$$NSL_h^{d_x} = \left[\sum_{s=1}^{S_{d_x}} \left(E_{d_x}^{s} + \sum_{k=1}^{K_{d_x}^{s,k}} E_{d_x}^{s,k} - \sum_{d_y=1}^{D_y} \sum_{l=1}^{L_{d_x,d_y}^{s}} E_{d_x,d_y}^{s,l} \right) + \sum_{d_y=1}^{D_y} \sum_{s=1}^{S_{d_y}} \sum_{l=1}^{L_{d_y,d_x}^{s}} E_{d_y,d_x}^{s,l} \right] - \sum_{r=1}^{R_{d_x}} E_{d_x}^{r,im} - \sum_{usl=1}^{USL} E_{d_x}^{usl}$$

Where:

$E_{d_x}^{r,im}$ = the energy use per hour for consumer *r* measured by an interval meter (*im*) that is read within the settlement time frame (i.e., a MIST meter) adjusted for the appropriate total loss factor.

R_{d_x} = the number of interval-metered customers with MIST type meters

$E_{d_x}^{usl}$ = the energy use per hour by an unmetered street lighting customer, *usl*, based on a "deemed profile" approved by the Board adjusted for the appropriate total loss factor.

USL = the number of unmetered street lighting customers

$E_{d_x,d_y}^{s,l}$ = the hourly electricity supplied by distributor d_x to distributor d_y through load transfer point *l* which is located on the portion of d_x's distribution system that is supplied from the IMO-administered market through supply point *s* adjusted for the appropriate total loss factor.

$E_{d_y,d_x}^{s,l}$ = the hourly electricity supplied by distributor d_y to distributor d_x through load transfer point *l* which is located on the portion of d_y's distribution system that is supplied from the IMO-administered market through supply point *s* adjusted for the appropriate total loss factor

L_{d_x,d_y}^{s} = the number of load transfers from distributor d_x to distributor d_y through load transfer point *l* which is located on the portion of d_x's distribution system that is supplied from the IMO-administered market through supply point *s*

L_{d_y,d_x}^{s} = the number of load transfers from distributor d_y to distributor d_x through load transfer point *l* which is located on the portion of d_y's distribution system that is supplied from the IMO-administered market through supply point *s*

D_y = the number of distributors with whom distributor d_x has a load transfer arrangement, either for supply into or out of d_x

S_{dy} = the number of supply points through which distributor d_y receives electricity from the IMO-administered wholesale market

Two or more distributors holding separate distribution licences may use a common NSLS as long as the annual average price of competitive electricity service based on the common NSLS differs by less than 1 percent from the annual average price that would result from using the net system load shape representing each individual distributor's service area. In assessing the difference between the common NSLS price

and the individual NSLS price, a distributor shall calculate the load-weighted average wholesale price for the most recent year for which relevant data are available using the net system load shape for its service area and the combined net system load shape for the multiple distributors with which it is considering combining. Before adopting a shared NSLS, the distributors shall notify the Board. A distributor shall include the two calculations relating to the differences in average prices as part of its notification to the Board. If the difference in average prices exceeds 1 percent, a distributor shall obtain approval from the Board before using a common net system load shape across multiple distributors. In the event of a material change to a distributor's service area (e.g. an amalgamation), the distributor shall confirm that the annual average price of competitive electricity service based on the common load shape continues to differ by less than 1 percent from the annual average price that would result from using the net system load shape representing each individual distributor's service area after the change in service area.

When two or more distributors are permitted to use a common load shape, in accordance with the provisions of the previous paragraph, the distributors shall use equation 3.4(b) for determining the net system load for a single hour. A distributor that does not combine with other distributors shall use equation 3.4(a) to estimate hourly load.

Equation 3.4(b)

Hourly Net System Load Calculation for an Aggregate Group of Distributors

$$NSL_h^A = \sum_{d_x=1}^{D^A} NSL_h^{d_x}$$

Where NSL_h^A = the net system load in hour *h* for settlement area *A*, which is a compilation of several licensed distribution areas

D^A = the number of licensed distributors, d_x, in settlement area *A*

For any selected billing period, a distributor shall use equation 3.4(c) to calculate the hourly NSLS weight for each hour that shall be used in equation 3.4(a).

Equation 3.4(c)

Calculation for Hourly Load Shares for a Billing Period

$$NSLS_h^A = NSL_h^A \div \sum_{h=1}^{B} NSL_h^A$$

Where $NSLS_h^A$ = the hourly net system load shape weighted for each hour of a billing period.

3.5 Variations Due to Differences in Meter Reading Practices and Billing Cycles

The average price paid for competitive electricity services will vary across billing periods due to the hourly variation in prices, NSLS and usage. This variation requires minor differences in the manner in which settlement costs for competitive electricity supply are calculated, depending on whether costs are based on actual or estimated electricity usage.

3.5.1 Settlement Based on Actual Meter Reads

A distributor shall calculate settlement costs based on actual metered usage amounts, determined from actual meter reads, at both the start and end of a billing period according to equation 3.3.2(a) (or any mathematically equivalent approach). When performing this calculation, a distributor shall assume that the starting and ending meter reads for the period occurred at 12:00:01 a.m. on the day of the actual meter read.

3.5.2 Settlement Based on Cycle Billing

Distributors who use cycle billing may, when calculating the load-weighted average price for a billing period, treat all consumers whose meters are read according to the same meter reading cycle as if all of their meters were read on the same day, as long

as the difference between the actual read date and assumed read date is four days or less.

3.5.3 Settlement Based on Estimated Usage

There are two common situations in which distributors issue bills based on estimated rather than actual metered usage:

1. A distributor regularly bills consumers on a cycle that differs from the consumer's meter reading cycle.
2. A distributor is unable to read a meter during the normal meter reading cycle.

A distributor may determine settlement costs when usage is based on an estimated usage followed by an actual meter read by calculating a bill using the NSLS weighted average price for the entire period between actual meter reads and then deducting any amount previously billed based on estimated usage amounts. This calculation is shown in equations 3.5.3(a) and (b) below. Alternatively, a distributor may determine settlement costs by calculating costs incurred since the date of the prior estimated value based on the net system load shape weighted average price for the period between the date the estimate was made and the date the meter was read. This calculation is shown in equations 3.5.3(c) and (d) below.

Equation 3.5.3

Option 1—Preferred

$$\text{(a) } CEC_{t,t+1} = \left(EMR_{t+1} - AMR_t\right) \bullet AP_{t,t+1}$$

$$\text{(b) } CEC_{t+1,t+2} = \left(AMR_{t+2} - AMR_t\right) \bullet AP_{t,t+2} - CEC_{t,t+1}$$

Option 2

$$\text{(c) } CEC_{t,t+1} = \left(EMR_{t+1} - AMR_t\right) \bullet AP_{t,t+1}$$

$$\text{(d) } CEC_{t+1,t+2} = \left(AMR_{t+2} - EMR_{t+1}\right) \bullet AP_{t+1,t+2}$$

Where $CEC_{t,\,t+1}$ = costs for competitive electricity services covering the billing period from date t to date t+1

$AP_{t,\,t+1}$ = net-system-load-weighted average price during the billing period from date t to date t+1

AMR_t = usage based on an actual meter read on date t

EMR_{t+1} = estimated usage on date t+1

When determining settlement costs based on estimated usage, a distributor shall make available, upon request from a retailer or consumer, a description of the estimation method used.

3.6 Consumers With Time-of-Use Meters

A distributor shall determine competitive electricity service costs for time-of-use-metered consumers in the same manner as for other non-interval metered consumers according to the provisions of section 3.3.2. Upon request by a retailer or consumer, a distributor shall make a good faith effort to develop the capability to calculate settlement costs for consumers with time of use meters according to equation 3.6(a) and shall recover the incremental cost of providing such services from the requesting party in accordance with a rate approved by the Board under section 78 of the Act.

Equation 3.6(a)

$$CEC_B^t = \left[\sum_{h=1}^{T_1^B} P_h^{d_x} \bullet NSLS_h^A \bullet E_B^{t,T_1} + \sum_{h=T_1^B}^{T_2^B} P_h^{d_x} \bullet NSLS_h^A \bullet E_B^{t,T_2} \right. \\ \vdots \\ \left. + \sum_{h=T_{n-1}^B}^{T_n^B} P_h^{d_x} \bullet NSLS_h^A \bullet E_B^{t,T_n} \right] \bullet TLF_{d_x}$$

Where E_B^{t,T_n} = the cumulative energy used in billing period *B* for the time-of-use block ending in hour T_n

$\sum_{h=T_{n-1}^B}^{T_n^B}$ = the summation across all hours in billing period B for the time-of-use block ending in hour T_n

3.7 Consumers With Demand Meters

A distributor shall determine competitive electricity costs for demand metered consumers in the same manner as for other non-interval metered consumers, according to the provisions of section 3.3.2

3.8 Consumers With Controlled Loads

A distributor shall determine settlement costs for loads that are constrained through either centralised or decentralised load control procedures in the same manner as if the loads were uncontrolled.

3.9 Consumers With Prepaid Meters

A distributor shall determine competitive electricity costs for prepaid meters in the same manner as for other non-interval metered consumers, according to the provisions of section 3.3.2.

3.10 Unmetered Loads

With the exception of street-lighting loads on public roadways, a distributor shall determine settlement costs for unmetered loads based on distributor specified, cumulative usage estimates for the relevant billing period and the net system load weighted average electricity price for the relevant billing period. Cumulative usage estimates for all unmetered loads shall be adjusted by the total loss factor of the distributor. For street-lighting loads, a distributor shall determine settlement costs using a load weighted average price for the billing period based on a load profile approved by the Board. The street lighting load shall be uplifted for total losses.

4 DETERMINING SETTLEMENT COSTS FOR NON-COMPETITIVE ELECTRICITY SERVICE

4.1 Services Provided Through the IMO or a Host Distributor

In addition to charges for competitive electricity services computed based on prices in the IMO-administered wholesale market, invoices from the IMO to distributors will, in accordance with the Market Rules, include charges for ancillary services, transmission services, IMO administrative costs and other services required to support the wholesale market. All charges from the IMO other than competitive electricity services shall be considered non-competitive electricity costs. Both WMPD and embedded distributors shall settle non-competitive wholesale service costs based on rates approved by the Board under section 78 of the Act. A distributor shall adjust a consumer's usage by the applicable total loss factor for the purpose of determining the consumer's non-competitive electricity costs. A distributor shall record, in its RSVA, the difference between the amount billed by the IMO to the distributor for non-competitive electricity services and the amount billed by the distributor to consumers, retailers and embedded distributors, in aggregate, for the same set of services.

Notwithstanding any other provision of this Code, where an embedded retail generator that has a contract issued under the feed-in-tariff program referred to in section 25.35 of the Electricity Act is connected on the customer side of a connection point (as set out in section 1.9 of the Distribution System Code), the charges for non-competitive electricity costs payable by the associated load customer shall be calculated based on the total amount of electricity consumed at the load customer's premises, whether withdrawn from the distribution system or supplied by the embedded retail generator. This rule applies regardless of the electrical configuration of the load and generation meters.

4.2 Distribution Services

Each distributor shall charge for the cost of distribution services associated with electricity delivery in accordance with distribution rates approved by the Board under

section 78 of the Act. Charges for distribution services shall apply to all consumers connected to a distributor's system, regardless of whether the consumer is served under SSS or by a competitive retailer.

Notwithstanding any other provision of this Code, where an embedded retail generator that has a contract issued under the feed-in-tariff program referred to in section 25.35 of the Electricity Act is connected on the customer side of a connection point (as set out in section 1.9 of the Distribution System Code), the charges for distribution services payable by the associated load customer shall be calculated based on the total amount of electricity consumed at the load customer's premises, whether withdrawn from the distribution system or supplied by the embedded retail generator. This rule applies regardless of the electrical configuration of the load and generation meters.

5 SETTLEMENT TIME LINE

5.1 Timing of Information from the IMO

The determination of settlement costs for a consumer or retailer depends on the receipt of hourly price and usage data from the IMO by a WMPD and from the host utility in the case of an embedded distributor. In accordance with the Market Rules, hourly price and usage data for the trading day are provided by the IMO on a preliminary basis 10 business days after the trading day and on a final basis 20 business days after a trading day. A WMPD may not hold up settlement invoicing while awaiting the delivery of final data from the IMO required for a complete billing cycle. All settlement calculations shall be based on preliminary data. A distributor shall issue settlement invoices to retailers as soon as practical following receipt of preliminary price and usage data provided by the IMO or by the host distributor for the last trading day in the billing period covered by the settlement invoice. A distributor shall record in the RSVA any variances in settlement costs resulting from differences in preliminary and final data.

A host distributor must provide an embedded distributor with access to hourly data for all variables contained in equation 3.3.1(d) via the EBT System or via an alternative method agreed to between the host and embedded distributors.

5.2 Timing and Availability of Valid Meter Information

A distributor shall read all MIST meters at least once during a weekly period. The distributor shall complete the validation, editing and estimation (VEE) process for 100 percent of the hourly interval data obtained from MIST meters for the prior week according to procedures described in the Distribution System Code, and shall deliver the data to the EBT System by noon on the fourth business day after the meter reading day.

A distributor shall read all MOST meters, and non-interval meters according to a meter-reading cycle established by the distributor. The distributor shall complete the VEE process for 100 percent of the meter-usage data according to procedures described in

the Distribution System Code, and shall deliver the data to the EBT System by noon on the fourth business day after the scheduled meter reading day.

The distributor shall make available the information described in section 11.1 to retailers according to the schedule outlined above.

5.3 Timing of Settlement Invoices to Retailers

A distributor shall issue settlement statements to retailers according to the same meter reading and billing cycles as if the consumers served by the retailer were served under SSS. A distributor shall not impose billing or payment cycles on a different retailer than those imposed on the consumers served by the retailer unless the retailer agrees to such terms or unless the differences are due solely to differences in timing resulting from the ability to bill consumers more rapidly under fixed-price standard supply than to compute settlement costs for retailers.

5.4 Payment by Distributors to Retailers

Under distributor-consolidated billing (see section 7.2) a distributor shall collect revenue from consumers on behalf of a retailer. A distributor shall pay relevant amounts to a retailer on the same date that payment is due to the distributor from a consumer.

6 RETAIL SETTLEMENT VARIANCE ACCOUNT

A distributor shall establish a RSVA for the purpose of recording variances between the amount owed to the IMO by a WMPD or to a host distributor by an embedded distributor and the amount collected from consumers and retailers, that are created by the settlement process required under the Code. The manner and timing of disposition of the balances in the RSVA shall be determined by the Board.

7 SETTLEMENT AND BILLING OPTIONS

A distributor shall have the ability to accommodate three billing options:

1. Retailer-consolidated billing;
2. Distributor-consolidated billing; and,
3. Split billing.

The selection of a billing option shall be determined by the consumer and the retailer. The retailer shall notify the distributor of the desired option in accordance with the procedures described in Chapter 10.

7.1 Retailer-Consolidated Billing

The provisions that relate to retailer consolidated billing are set out in sections 7.1 to 7.1.3. If a consumer is being billed by way of retailer consolidated billing, the distributor shall bill the designated retailer for all competitive and non-competitive electricity costs incurred on behalf of the consumer, calculated in accordance with the provisions outlined in Chapters 3 and 4. A distributor shall not directly bill a consumer who is to be billed under retailer-consolidated billing except for certain customer-specific, irregularly recurring, miscellaneous, non-energy charges that have been itemized in a list provided to a retailer by a distributor. Charges described in section 9.3 of the Electricity Distribution Rate Handbook, with the exception of charges described in section 9.3.15, shall be billed by the retailer.

7.1.1 Information Flow From Distributor to Retailer

A distributor shall deliver settlement invoices to retailers using the EBT System. Unless other arrangements are agreed to in the Service Agreement established between the parties, a distributor shall itemise the costs attributable to each individual consumer served by a retailer. Costs for each consumer shall, at a minimum, be unbundled in the following manner, as appropriate:

- Competitive electricity service costs;
- Non-competitive electricity service costs;
- Distribution charges itemised in terms of the billing determinants used to calculate it (e.g. a fixed charge, usage charge and/or demand charge);
- Competition transition charge, if applicable;
- Rural rate protection charges or credits, if applicable;
- Market power mitigation credit;
- All applicable taxes itemized in accordance with the applicable legislation; and
- Avoided cost credits (e.g. for metering or billing services not provided by the distributor).

A distributor shall also provide a retailer with the following information at the same time as the distributor delivers the settlement invoice to the retailer:

- Individual consumer usage for the billing period for all consumers;
- Individual consumer peak demand for the billing period for all demand-metered consumers;
- The net-system-load-weighted average price used to calculate commodity costs for each individual consumer;
- Summary of the net amount owed to the distributor by the retailer for the entire invoice; and
- Payment due date.

A distributor shall also bill retailers periodically for transaction fees and other administrative costs incurred by the distributor on behalf of the retailer. Some of these costs will be consumer-specific (e.g. customer transfer costs, final meter read costs, etc.) while others may apply only to the retailer in aggregate (e.g. account set-up charges). Consumer-specific costs shall be itemised by consumer account number and by type of service. A distributor may invoice these charges according to a different

schedule (e.g. monthly) rather than according to the schedule associated with settlement for services that are billed based on usage and, therefore, depend upon a distributor's meter-reading and billing cycle.

In all cases, the specific payment and billing schedule for settlement processing with retailers shall be clearly delineated in the Service Agreement that is required between distributors and retailers.

7.1.2 Consumer Non-Payment Risk

Under retailer-consolidated billing, the retailer is solely responsible for consumer non-payment risk. Any retailer providing services to consumers under retailer-consolidated billing shall pay the consumer's distributor for all of the competitive and non-competitive service costs incurred by the consumer regardless of whether or not the retailer is paid by the consumer. In the event that a retailer is not paid by a consumer served under this billing option, the retailer may submit an STR to a distributor to return the consumer to SSS. A distributor shall process this request in the same manner and according to the same schedule as any other STR according to the rules and procedures outlined in Chapter 10. A retailer shall be responsible to the distributor for all costs that the non-paying consumer incurs before the transfer process has been completed. A distributor may collect payment from the retailer even if the non-paying consumer is disconnected or no longer receives services from the retailer. A retailer may not order a distributor to disconnect a consumer for non-payment of a retailer's bill.

7.1.3 Distributor/Consumer Communication

For consumers served under retailer-consolidated billing, a distributor shall refer all billing inquiries to the consumer's retailer, including inquiries about distribution costs on the consumer's bill. A distributor shall directly address any consumer inquiries about meter accuracy, distribution rates and safety and reliability. Inquiries about usage, including how usage might be modified to lower bills, may be addressed either by the distributor or referred to the consumer's retailer.

7.2 Distributor-Consolidated Billing

The provisions that relate to distributor-consolidated billing are set out in sections 7.2 through 7.2.4. If a consumer is billed by way of distributor-consolidated billing, the distributor shall issue a bill to the consumer that includes the full cost of delivered electricity with the portion of the bill attributable to competitive electricity costs based on the contract terms between the consumer and their retailer. Under this option the distributor shall bill and collect from consumers on behalf of retailers. The charge for such billing services shall be approved by the Board under section 78 of the Act.

Two forms of distributor consolidated billing are possible; bill-ready and rate-ready. Under bill-ready billing, the portion of the bill covering competitive electricity services for each consumer is calculated by a retailer and the information is transmitted to the distributor for inclusion on the consumer's bill. Under rate-ready billing, a distributor calculates the portion of the bill covering competitive services based on the price and terms provided by the retailer. In both cases, a distributor is responsible for calculating the portion of the bill covering non-competitive services. Also in both cases, the distributor must determine settlement costs attributable to the competitive electricity service portion of the bill according to the provisions outlined in Chapter 3. The distributor shall bill or credit the retailer for the difference in settlement costs calculated according to the provisions in Chapter 3 and according to the retailer's contract terms with the consumer.

A distributor shall provide bill-ready billing as a mandatory service upon request by a retailer. A distributor may provide rate-ready billing as an optional service and, upon request from a retailer, shall make a good faith effort to provide rate-ready billing.

7.2.1 Information Flow From Distributor to Retailer

A distributor shall issue settlement statements to retailers covering the difference between the cost of competitive electricity services calculated according to the provisions in Chapter 3 and the amount billed to consumers on behalf of the retailer. Settlement statements shall include charges for any settlement services provided by the

distributor to a retailer at rates approved by the Board under section 78 of the Act. A distributor shall issue settlement statements on each business day in accordance with the meter-reading and billing cycle associated with the consumers being billed and the availability of necessary information from the IMO or from the host distributor. Settlement statements shall be communicated according to the EBT System.

7.2.2 Information Flow from Retailer to Distributor

Under bill-ready, distributor-consolidated billing, the distributor shall be capable of accepting at least one separate bill amount from a retailer for each individual consumer for each billing cycle. All metered and unmetered service points with respect to a particular account shall be aggregated by a retailer when providing a distributor with bill amounts. The amount shall be posted separately on the consolidated bill, along with a brief description of the services to which the amount pertains. The description provided by the retailer must fit within a single line on the bill using the distributor's standard bill format.

Retailers shall provide distributors with bill amounts for each of the retailer's customers connected to the distributor's distribution system in a timely manner so that billing to the consumer is not delayed. A data delivery schedule shall be set out in the Service Agreement. All bill information provided by a retailer to a distributor must be communicated according to the EBT System.

7.2.3 Consumer Non-Payment Risk

Note: Section 7.2.3 revoked by amendment, effective August 3, 2004.

7.2.4 Distributor/Consumer Communication

A distributor shall address consumer inquiries concerning distribution service, meter accuracy and bill calculation errors. A distributor shall refer all inquiries pertaining to retailer pricing or contract terms to the relevant retailer. Inquiries about usage, including

how usage might be modified to lower bills, may be addressed either by the distributor or referred to the relevant retailer.

7.3 Split Billing

The provisions that relate to split billing are set out in sections 7.3 to 7.3.3. If a consumer is billed by way of split billing, the distributor shall issue one bill to the consumer that covers all non-competitive electricity costs, less any administrative costs that are paid by the retailer. The consumer's retailer is responsible for the issuance of the other bill that covers the cost of competitive electricity services based on the price and other contractual terms agreed to by the consumer and the retailer. The requirement for distributors to provide a split billing option as set out in this section 7.3 shall be implemented on a date to be determined by the Board.

Under split billing, a distributor shall issue settlement statements to the consumer's retailer that charge for the competitive electricity costs calculated as described in Chapter 3, as well as any other relevant settlement costs or credits according to rates approved by the Board.

7.3.1 Information Flow from Distributor to Retailer

A distributor shall issue settlement statements to retailers covering the cost of competitive electricity services and other relevant costs and credits calculated as described in Chapters 3 and 4. A distributor shall issue settlement statements on each business day according to the meter reading and billing cycle associated with the consumers being billed. Settlement statements shall be communicated according to the EBT System.

7.3.2 Consumer Non-Payment Risk

A distributor and a retailer shall each be responsible for consumer non-payment risk for the bills that each issues to consumers. Any retailer providing services to consumers under split billing shall pay the consumer's distributor for all competitive electricity costs

incurred by the consumer regardless of whether or not the retailer is paid by the consumer. In the event that a retailer is not paid by a consumer served under this billing option, the retailer may submit an STR to the distributor to return the consumer to SSS. A distributor shall process this request in the same manner and according to the same schedule as any other STR. A retailer shall be responsible to the distributor for all costs that the non-paying consumer incurs before the transfer process has been completed. A retailer may not order a distributor to disconnect a consumer for non-payment of a retailer's bill.

Note: The second paragraph of section 7.3.2 revoked by amendment, effective August 3, 2004.

7.3.3 Distributor/Consumer Communication

A distributor shall address all consumer inquiries concerning distribution service, meter accuracy, usage amounts and calculation errors. A distributor shall refer all inquiries pertaining to retailer pricing or contract terms to the relevant retailer.

7.4 Billing to Standard Supply Service Consumers

Sections 7.4 through 7.4.3 describe the relevant provisions with respect to SSS settlements and billing.

7.4.1 SSS Billing and Settlement Processing Are Not the Same

SSS will be billed according to a rate established by the Board under section 78 of the Act. Regardless of the SSS rate, settlement cost calculations with respect to SSS customers shall be done according to the provisions of Chapters 3 and 4.

7.4.2 Settlement Invoicing to SSS Providers

A distributor shall calculate a settlement invoice for all SSS customers and charge the amount to the distributor's Purchased Power Variance Account if the distributor is

providing SSS directly. If SSS is provided by a third party, the settlement invoice shall be sent by the distributor to the retailer providing SSS.

7.4.3 Consumer Non-Payment Risk Mitigation

Note: Section 7.4.3 revoked by amendment, effective August 3, 2004.

7.5 Disconnection

A distributor may disconnect a property from the distributor's distribution system if any amounts payable by a consumer to the distributor for non-competitive electricity costs are overdue.

A distributor may disconnect a property from the distributor's distribution system if any amounts payable by a consumer for competitive electricity services costs provided under SSS are overdue.

A distributor shall not disconnect a property from the distributor's distribution system at the direction of a retailer or if an amount payable by a consumer to a retailer is overdue.

The provider of competitive electricity services to a consumer does not change solely as a result of a consumer being disconnected in accordance with this section.

Where a distributor disconnects a property in which a consumer is served by a retailer, the distributor shall promptly notify the retailer.

7.6 Reconnection

A distributor may refuse to reconnect a consumer as long as the consumer remains in arrears on payment for competitive electricity services provided under SSS or for non-competitive electricity services. A distributor's right to refuse re-connection may be exercised regardless of whether a consumer requests service under SSS or from a retailer. Where a distributor reconnects a property in which a consumer is served by a retailer, the distributor shall promptly notify the retailer.

7.7 Billing Errors

The following rules apply to billing errors in respect of which Measurement Canada has not become involved in the dispute:

7.7.1

Where a distributor has over billed a customer or retailer by an amount that is equal or exceeds the customer's or retailer's average monthly billing amount, determined in accordance with section 7.7.5, the distributor shall, within 10 days of determination of the error, notify the customer or retailer of the over billing and advise that the customer or retailer may elect to have the full amount credited to their account or repaid in full by cheque, within 11 days of requesting payment by cheque. Where the customer or retailer has not requested payment by cheque within 10 days of notification of the error by the distributor, the distributor may credit the full amount to the account.

7.7.2

Where a distributor has over billed a customer or retailer by an amount that is less than the customer's or retailer's average monthly billing amount, determined in accordance with section 7.7.5, the distributor shall credit the account in the next regularly scheduled bill issued to the customer or retailer.

7.7.3

If there are outstanding arrears on the customer's or retailer's account, the distributor is not required to repay the over-billed amount but may apply it to the arrears on the customer's or retailer's account and credit or repay to the customer or retailer the remaining balance.

7.7.4

Where a distributor has under billed a customer who is not responsible for the error, the distributor shall allow the customer to pay the under-billed amount in equal instalments over a period at least equal to the duration of the billing error, up to a maximum of 2 years.

7.7.4.1

Where a distributor issues a bill to a customer for an under-billed amount, the distributor shall notify the customer that, if the customer is an eligible low-income customer, he or she has the option of paying the under-billed amount as follows:

i) in accordance with section 7.7.4; or

ii) over a period of 10 months where the under-billed amount is less than twice the customer's average monthly billing and over a period of 20 months where the under-billed amount equals or exceeds twice the customer's average monthly billing.

7.7.4.2

For the purposes of section 7.7.4.1, the distributor may notify the customer by way of bill insert, bill message, letter or outgoing telephone message.

7.7.5

For the purposes of sections 7.7.1, 7.7.2 and 7.7.4.1, the customer's or retailer's average monthly billing amount shall be calculated by taking the aggregate of the total electricity charges billed to the customer or retailer in the most recent 12 months, including adjustment for the impact of any known billing error(s), and dividing that value by 12. If the customer has been receiving service from a distributor for less than 12 months, the customer's average monthly billing amount shall be based on a reasonable estimate made by the distributor. For the purposes of this section, "electricity charges"

has the same meaning as in section 2.6.6.3 of the Distribution System Code, subject to any adjustments necessary to take into account other electricity-related charges billed to non-residential customers.

7.7.6

Where a distributor has under billed a customer or retailer who is responsible for the error, whether by way of tampering, willful damage, unauthorized energy use or other unlawful actions, the distributor may require payment of the full under-billed amount by means of a corresponding charge on the next regularly scheduled bill issued to the customer or retailer or on a separate bill to be issued to the customer or retailer responsible for the error. Where disconnection has occurred, the distributor may require payment of such bill prior to the reconnection of service upon request by the customer responsible for the tampering, willful damage, unauthorized energy use or other unlawful actions that caused the under billing.

7.7.7

Where the distributor has under billed a customer or retailer, the maximum period of under billing for which the distributor is entitled to be paid is 2 years. Where the distributor has over billed a customer or retailer, the maximum period of over billing for which the customer or retailer is entitled to be repaid is 2 years.

7.7.8

A distributor may charge interest on under-billed amounts only where the customer or retailer was responsible for the error, whether by way of tampering, willful damage, unauthorized energy use or other unlawful actions. Such interest shall be equal to the prime rate charged by the distributor's bank.

7.7.9

A distributor that has over billed a customer or retailer and the billing error is not the result of a distributor's standard documented billing practices, shall pay interest on the amount credited or repaid to the customer or retailer equal to the prime rate charged by the distributor's bank.

7.7.10

The entity billing a customer, whether it is a distributor or retailer, is responsible for advising the customer of any meter error and of his, her or its rights and obligations under the *Electricity and Gas Inspection Act (Canada)*.The billing party is also responsible for subsequently settling actual payment differences with the customer as described above.

7.7.11

The provisions of section 7.7 do not apply where the distributor has over billed or under billed a customer or retailer but issues a corrected bill within 16 days of the issue date of the original erroneous bill.

8 SECURITY ARRANGEMENTS BETWEEN DISTRIBUTORS AND RETAILERS

A distributor shall enter into security arrangements with each retailer to protect against the risk of payment default by the retailer. The terms of these arrangements, including the magnitude and type of security required and the planned frequency and timing for updating the security arrangements as market share and other determining factors change, shall be set out in the Service Agreement. The amount and type of security required may vary based on estimates of the magnitude of exposure, determined according to the provisions of section 8.1 below, and the creditworthiness of the retailer.

8.1 Estimating the Magnitude of Exposure

The magnitude of exposure that a distributor faces will vary with factors such as: the number of consumers served by a retailer, the average consumption of consumers served by the retailer: the length of the billing cycle (e.g. 30 days, 60 days, etc.); and the type of billing in place (e.g. retailer-consolidated or distributor-consolidated or split billing). A distributor shall apply the rules described in sections 8.1.1 through 8.1.3 when determining the maximum amount of security that can be required from a retailer. A distributor may choose to require security for a lesser amount than is determined based on these rules.

8.1.1 Retailer-Consolidated Billing

A distributor shall use the following processes to determine the maximum allowable amount of security that may be imposed on a retailer who bills consumers using the retailer-consolidated billing option.

Option One

Step 1: Estimate the total bill (e.g. all charges for competitive and non-competitive electricity services settled through the distributor) for a billing period for an average consumer for each class of consumer in which at least one of the class

members is served by the retailer (with the competitive and non-competitive electricity costs determined according to the rules in Chapters 3 and 4). For the purpose of this estimation, the estimated usage for an average consumer in each class shall be the total reasonably estimated usage for the class in the calendar month during the calendar year in which total consumption of electricity in Ontario was the greatest divided by the number of members of the class within the distributor's service area. For the purpose of this estimation, the price estimates used in calculating competitive electricity costs shall be the same as the most recent estimated market prices in the real-time energy market established by the IMO for the purposes of determining maximum net exposures and prudential support obligations for market participants other than distributors, low-volume consumers and designated consumers.

Step 2: Multiply the number of consumers in each class served by the retailer by the estimated total bill calculated in accordance with Step 1 and add the totals for each class together.

Step 3: If a distributor bills a retailer monthly, multiply the amount determined in Step 2 by 2.5. If a distributor bills bimonthly, multiply the amount in Step 2 by 1.75. If a distributor bills quarterly, multiply the amount in Step 2 by 1.5. The resulting value is the maximum amount of security that a distributor may impose on a retailer.

Option Two

Step 1: Estimate the total bill (e.g. all charges for competitive and non-competitive electricity services settled through the distributor) for a billing period for each consumer served by the retailer. The estimate shall be based on the highest usage, for a single billing period, for the consumer in the previous twelve months. For the purpose of this estimation, the price estimates used in calculating competitive electricity costs shall be the same as the most recent estimated market prices in the real-time energy market established by the IMO

for the purposes of determining maximum net exposures and prudential support obligations (the "competitive energy price").

Step 2: Aggregate the amounts calculated in accordance with Step 1 for all individual consumers served by the retailer.

Step 3: If a distributor bills a retailer monthly, multiply the amount determined in Step 2 by 2.5. If a distributor bills bimonthly, multiply the amount in Step 2 by 1.75. If a distributor bills quarterly, multiply the amount in Step 2 by 1.5. The resulting value is the maximum amount of security that a distributor may impose on a retailer.

8.1.2 Split Billing

For the split-billing option, a distributor shall use one of the three-step process outlined in section 8.1.1 to determine the maximum allowable amount of security, except that the magnitude shall be based only on that portion of the bill covering competitive electricity costs, and not on the entire bill for delivered electricity.

8.1.3 Distributor-Consolidated Billing

The following provisions relate to the calculation of the maximum allowable security for distributor consolidated billing.

If a retailer provides specific price information with respect to its contracts with its customers or provides a weighted average price for each class of consumer within the distributor's service area that it serves, the distributor shall use this information in setting the maximum allowable amount of security required from the retailer. For the purpose of calculating the weighted average price, the estimated usage shall be based on an average consumer in each class which shall be calculated by dividing the total reasonably estimated usage for the class in the calendar month during the calendar year in which total electricity consumption is expected to be greatest by the number of members of the class within the distributor's service area. Where a retailer has

provided specific price information or a weighted average price, the distributor shall use one of the three-step process outlined in section 8.1.1 to determine the maximum allowable security, except that the estimate shall be based on the difference between the price estimates which would be used in Step 1 of either option and the forecast amount to be charged to the consumer based on the price information from the retailer.

Where a retailer chooses to not provide specific price information or a weighted average price as described above, the distributor shall calculate the maximum amount of security based on the same amount as if the split bill option was in effected as described in section 8.1.2.

8.2 Updating Security Estimates

A distributor shall periodically update the forecast of aggregate usage based on current estimates of the number and type of consumers served by a retailer. A distributor may update the estimate as frequently as it wishes, but shall update the estimate at least once every three months using the procedures described in sections 8.1.1 through 8.1.3 and the most recent values for number of consumers served by a retailer. If the maximum allowable amount of security has increased by more than 10 percent over the amount currently in place and a distributor wishes to increase the security requirement, a retailer shall meet the new requirement within 20 business days. Where the maximum allowable amount of security has fallen below the amount currently in place by more than 10 percent, the distributor may continue to require the retailer to provide as security no more than the greater of:

(a) the most recent calculation of the maximum allowable amount of security; and

(b) the amount not in excess of the previously calculated maximum allowable amount of security which has been invoiced by the distributor and which is due and owing or will become due and owing within the next forty business days from the date that the maximum allowable amount of security was recalculated.

Where the retailer is entitled to reduce the amount of security provided, the distributor shall notify the retailer immediately.

Where the form of security in place between a retailer and a distributor is a cash deposit held by the distributor, the distributor shall, if requested by the retailer, return the excess amount to the retailer within 20 business days of the date on which the new estimate was determined.

8.3 Type of Security

A distributor may require a retailer to post security for any amount equal to or less than the maximum amount of security calculated according to the provisions described in section 8.1. A distributor shall accept, at the discretion of a retailer, any of the following types of security or any combination thereof: an irrevocable letter of credit, surety bond, cash deposit or a lock-box arrangement. Where the retailer wishes to use a lock-box arrangement, the distributor and the retailer shall agree on the financial institution that is to be used.

If a retailer provides security in the form of a cash deposit, a distributor shall pay interest on the deposit. The interest rate payable shall be the lesser of the rate that a distributor earns from any security deposits provided by consumers and the prime rate charged by the distributor's bank. A retailer may require that cash deposits be held in specified low-risk interest-bearing accounts; however the distributor shall have exclusive access to the funds posted for security.

A distributor may, at its discretion, accept bond ratings or other credit ratings from retailers in lieu of the other types of security described above. In applying this discretion, a distributor shall not discriminate among retailers with comparable risk profiles.

8.4 Default Process

In the event of settlement payment default by a retailer, a distributor shall not access the funds available through the relevant security agreement before a period of five business days has elapsed from the date the settlement payment was due. The day after a settlement payment was due, a distributor shall immediately notify a retailer that payment was not received and work with the retailer to remedy the situation. After 10 business days, if the account remains unpaid and the parties have not agreed on a remedy, the distributor may notify the retailer's consumers that they will become SSS consumers according to a schedule determined by the distributor unless such consumers elect to receive supply from another retailer. If the distributor receives an STR that identifies an alternative retailer prior to switching a consumer to SSS, the distributor shall process the STR and switch the consumer to the new retailer rather than back to SSS.

During a default period, a distributor shall not retain any revenues collected by the distributor on behalf of the retailer as security unless the magnitude of security accessible to the distributor is insufficient to cover the amount of the default.

A distributor may charge a retailer and a retailer may charge a distributor interest on any overdue settlement payments at a rate equal to the prime rate charge by the bank of the party which is owed money plus 2 per cent per annum.

A distributor may charge a retailer for the cost of final meter reads and other allowable transaction costs associated with transferring consumers back to SSS based on the applicable rates approved by the Board under section 78 of the Act.

9 SETTLEMENT DISPUTE PROCEDURES

Any disputes between retailers, embedded retail generators or consumers and distributors concerning the implementation of a distributor's responsibilities under this Code shall be settled according to the dispute mechanism specified by the Board in a distributor's licence. Disputes concerning the settlement amount billed or owed by a distributor to a retailer or an embedded retail generator do not relieve either party from their obligations to make payment in full at the time payment is due. Any deviations between the amount paid at the time due and the amount determined through the dispute resolution process shall be subject to payment of interest. The interest rate shall equal the prime rate charged by the distributor's bank.

10 SERVICE TRANSACTION REQUESTS

A distributor shall accept and process STRs according to the provisions set out in this Chapter.

10.1 Service Transaction Requests Covered by the Retail Settlement Code

This Code addresses the following types of service transaction requests:

- A change from electricity supplied to a consumer through SSS to electricity supplied by a competitive retailer;
- A change in a consumer's supplier of electricity from one competitive retailer to another;
- A change from electricity supplied to a consumer by a competitive retailer to electricity supplied through SSS;
- A change in a consumer's metering or billing options for consumers currently served by a retailer;
- A change in consumer location (either within a distributor's service area or a move to another distributor's service area); and
- A request to deliver consumer-specific information (as defined in section 11.3) to a consumer or to one or more retailers.
- Any request for a change or modification in service that is not included in the above list is governed by other codes or by a distributor's normal business practices.

10.2 Consumer Authorisation

With the exceptions noted in the remainder of this paragraph, all STRs listed in section 10.1 must be based on a consumer's written authorisation. There are three STRs where a consumer's written authorisation is unnecessary. The first is a request to deliver historical, consumer-specific information to a consumer's service or billing address, which may be implemented based on verbal authorisation. A request to release consumer-specific information to a retailer or to any address other than the service or billing address must be made in writing. The second is a request by a retailer to transfer a consumer to SSS, which shall be implemented according to the procedures described in section 10.5.4. The third concerns the exercise of a distributor's right to transfer a consumer back to SSS in the event of payment default by a retailer as described in section 8.4.

A retailer who submits STR on behalf of a consumer is not required to submit to a distributor a physical or electronic copy of the consumer's written authorisation in order for the STR to be processed. However, when the retailer obtains the written authorisation from a consumer to modify service arrangements, a retailer shall also obtain written authorisation to act as the consumer's agent for the purpose of advising a distributor that the person wishes to obtain the service being requested. When a retailer submits an STR to a distributor, the retailer shall state explicitly that written authorisation has been obtained from the consumer for both the indicated transaction and for the authority of the retailer to act as the consumer's agent in submitting the STR. A retailer shall retain records to validate these claims and shall submit a copy of the authorisation to the distributor if requested by the distributor to do so. A distributor shall retain records of all STRs received from retailers or consumers.

10.3 Service Transaction Request Information Requirements

A distributor shall be capable of processing the following information as part of the STR process:

- The consumer's name;
- Service address for which the change in service is requested;
- An indication of whether or not a retailer will accept all accounts operating under the same name at a single address if multiple accounts are found and if the service request does not identify all account numbers at the address;
- Consumer postal code;
- Distributor account number(s);
- Meter identification number;
- The requesting retailer's consumer account number;
- The requesting retailer's account number with the distributor;
- The earliest date after which transfer of the account is acceptable to the retailer and/or consumer or the specific date on which the transfer is requested;
- The preferred method for finalising the account (e.g., next scheduled read date, special read, last actual read if allowed and whether a card, phone-in or estimated read is agreeable to all relevant parties). In the absence of such information, a distributor shall check its retailer account set-up file to determine whether or not there is a default position regarding how to handle final reads;
- Identification of the desired meter services (e.g., replace the existing meter, change to an interval meter, specific optional meter services, etc.), including the date upon which any change in service is desired;
- Identification of the intended billing option;
- Identification of any consumer-specific information desired (e.g., usage history, meter information, credit information); and

- For a change in customer location, whether or not the customer wishes to retain the same retailer, including an SSS provider.

10.4 Initial Screening of Service Transaction Requests

A distributor shall process STRs in the order in which they are received. A distributor shall complete the initial screening process described in this subsection within five business days of receipt of the STR from a retailer or consumer.

A distributor shall accept an STR from certain parties and through specific communication channels depending upon the type of transaction in accordance with the following rules:

1. A request to transfer a consumer from SSS to a competitive retailer, or from one retailer to another, shall be submitted by the retailer who will serve the consumer if the transaction is completed (referred to here as the new retailer). If a request is submitted either by a consumer or the current retailer, a distributor shall notify the new retailer to determine if the request is valid.

2. A request to transfer a consumer from supply by a competitive retailer to SSS may be submitted by a consumer or the consumer's current retailer.

3. A request to change service location may be submitted by either the consumer or the consumer's current retailer.

4. A request to change billing options or meter services when a consumer is currently served by a competitive retailer may only be submitted by the current retailer. If the request is submitted by the consumer, a distributor may, at its option, either notify the consumer to have its retailer submit the request or notify the retailer that a request has been received from its customer and inquire as to the position of the retailer with respect to the STR.

Once a distributor has received an STR from the appropriate party, the distributor shall continue processing the request if the STR has a valid entry for the retailer's account number and has valid entries for the following information : consumer's account number with the distributor, and one of the following : the consumer's name or the, consumer's postal code (the validation terms). If an account number has not been assigned to a consumer the distributor shall not process the STR unless valid information for the two remaining validation terms is provided. In the absence of meeting this requirement, the distributor shall reject the STR and notify the requesting party that the request cannot be processed. A distributor shall treat the initial request as if it were never received. If a new STR is submitted subsequently by the same party, the new STR will be processed in the appropriate order vis-à-vis other STRs based on the date of the subsequent submission.

If an STR has valid entries for the validation terms identified in the previous paragraph, a distributor shall attempt to identify the consumer to whom the request applies by matching the submitted information with information contained in the distributor's customer information system. If the validation terms identified in the previous paragraph match the corresponding information contained in a distributor's customer database, the distributor shall tag the STR as "pending." An STR will remain pending until the transfer request has been completed, has been withdrawn by the requesting party or by the consumer in response to various notifications and processing steps identified below, or has been terminated by the distributor for valid reasons identified below. If the validation terms do not match the corresponding information in the distributor's customer database, a distributor shall notify the requesting party and identify the invalid information. An STR shall not receive pending status until there is a valid match between the information it contains and the corresponding information contained in the distributor's information system.

Once an STR has been tagged as pending, a distributor shall determine whether or not the remaining information required to implement the request is complete. If the information is incomplete, the distributor shall notify the retailer or consumer about the

specific deficiencies contained in the request and will await a reply. This process of checking, notification and rechecking information will continue until the distributor has all of the necessary information to move to subsequent stages of the transfer process.

Initial submission of an STR by a retailer, and all standard communication associated with the process outlined above, must be done using the EBT System. A distributor shall allow consumers to transmit STRs via the postal system, facsimile transmission or electronically via the Internet if the distributor has such capability. Communication from a distributor to a consumer may be handled through any mutually agreeable method, including postal service, telephone, facsimile transmission or some other electronic means.

10.5 Rules and Procedures for Processing Service Transactions Involving a Change in Electricity Service Provider

Of the six types of STRs identified in section 10.1, the first three involve a change in competitive electricity service provider. Sections 10.5 through 10.5.6 describe the procedures for STRs that involve a change in competitive electricity service provider.

There are five generic activities involved in processing an STR:

1. Assessing the nature of a request and determining what actions are required to complete the transaction;
2. Completing a final meter read;
3. Under specific circumstances, notifying selected parties of the status of the transaction;
4. Updating databases concerning the new service provider relationships; and
5. Posting the relevant charges to retailer and or consumer accounts to cover transaction-related costs and issuing a final settlement bill.

Some procedures in these five areas are common across all transactions involving a change in service provider while others are specific to the transaction type. Common procedures are addressed below and in sections 10.5.1 and 10.5.2. Sections 10.5.3 through 10.5.5 contain the rules and procedures that pertain to a specific transaction type. Nothing in sections 10.5 to 10.5.5 should be interpreted as in any way interfering with the contractual rights or obligations of retailers or consumers or the remedies available to retailers or consumers to enforce those contractual rights or obligations.

In determining whether to process an STR involving a change in a consumer's electricity supply arrangements, a distributor may consider whether or not a retailer has sufficient security in place to indemnify the distributor against retailer default risk, taking into consideration the factors outlined in Chapter 8.

In determining whether to process an STR involving a change in a consumer's electricity supply arrangements, a distributor may also consider whether or not a consumer is in arrears on payment to the distributor. A distributor may refuse to process an STR if a consumer is currently in arrears on payment to the distributor. Should a distributor choose to process the STR in spite of the consumer being in arrears or if a distributor discovers new arrears after an STR has been processed, the distributor retains the right to pursue collection of the amount in arrears even if the customer is currently served by a retailer.

Upon completion of an STR, a distributor shall modify its information databases to reflect the current status of service relationships. Accurate and current information shall be maintained concerning who the electricity service provider is and what billing option is in place.

A distributor shall post relevant charges for service transaction activities to a retailer's or a consumer's account and issue the final settlement bill to consumers and/or retailers. The Board will approve rates for transaction activities such as special meter reads and the administrative cost of transfer processing.

Subject to the rules and procedures outlined in this Code and payment of relevant transaction fees approved by the Board, there is no limitation on the frequency with which consumers can change electricity suppliers.

10.5.1 Meter Reads

Subject to sections 10.5.1 and 10.5.3 to 10.5.5, a service transfer from one retailer to another, including a transfer from or to an SSS provider, shall only take effect on the date of an actual meter read Despite the requested service transfer set out in an STR, a distributor may specify in its Service Agreement with a competitive retailer a number of days prior to any next scheduled meter read where, if a distributor receives an STR requesting a change in service provider less than the number of days specified in the Service Agreement before the next scheduled meter read, the distributor is not obligated to change service provider until the scheduled meter read following the next scheduled meter read. The number of days specified in the Service Agreement shall not exceed twenty business days before the next scheduled meter read. The requesting party may request the distributor to schedule a special meter read.

Where a service transfer is scheduled to take effect on the date of the next scheduled meter read date, a distributor shall notify the requesting party of the scheduled date unless the requesting party has advised the distributor that notification is unnecessary. If the requesting party is a consumer, the distributor shall also notify the retailer of the scheduled date. When notified of the scheduled date, the requesting party may request a special meter read.

If a transfer is to occur on the next scheduled meter read date and the meter read is not successful, within five business days following the missed read, a distributor shall undertake a special meter read at no charge to the requesting party unless past meter reading records indicate that the likelihood of a successful meter read is low. A distributor shall also notify the requesting party that the meter read, and therefore the supply transfer, was not successful and inform the requesting party of the steps that will be taken to remedy the situation. In the event that a special meter read is unlikely to be

successful or is attempted and fails, a distributor shall, depending on which option it has chosen in its Service Agreement with a competitive retailer, process the transfer using an estimated read, use estimates provided by customers in lieu of an estimated read, or negotiate a different course of action. Where a distributor chooses more than one of the options set out above in its Service Agreement, the competitive retailer may, where the circumstance described above arises, choose whichever one of the options available from the distributor that it wishes. If a transfer request involves a special meter read scheduled for a specific date, a distributor shall undertake the meter read on the requested date or notify the requesting party why this is not possible. A special meter read will be paid for by the requesting party based on a rate approved by the Board under section 78 of the Act. If a special meter read is unsuccessful, a distributor shall immediately notify the requesting party and agree upon a process for completing or terminating the transfer. If a transfer is terminated because of a failure to complete a special meter read, the requesting party shall not be charged for the failed meter read attempt.

If a transfer request is for a change from SSS to competitive supply, it may be done based on a historical, actual meter read as long as the distributor has not issued an estimated bill to the consumer since the date of the last actual read.

Where all affected parties agree, a service transfer may take effect on a date other than the date of a future actual meter read. The final bill may be based on one of the methods set out below which all affected parties have agreed to in writing:

1. historical actual meter read;
2. card or phone-in customer read;
3. estimated read.

For the purposes of these options the parties include the current retailer, the consumer and the distributor. For the purposes of a transfer from one competitive retailer to a competitive new retailer, the affected parties shall also include the new retailer.

10.5.2 Mandatory Notices

A distributor shall issue notices to various parties as part of the process of implementing STRs. Notices have three purposes:

1. To inform current service providers or a consumer that a request to change service arrangements has been received;

2. To inform various market participants what actions they must take before a transfer will be implemented (e.g., if they are in arrears or if security arrangements are inadequate); and

3. To keep various market participants apprised of the timing and status of the transfer process.

Mandatory notices vary with the type of transaction and are delineated in subsections 10.5.3 through 10.5.6.

10.5.3 Processing a Change From SSS to a Competitive Retailer

An STR requesting the transfer of a consumer from SSS to a competitive retailer shall be submitted by the retailer who will become the new supplier if the STR is implemented. Upon receipt of the STR, a distributor shall check to see if electricity supply is currently being provided by a competitive retailer or if a request to transfer to another retailer is currently pending. If the consumer is currently served under SSS and no transfer is pending, the distributor shall proceed to process the transfer. Where an STR is received (the second STR) and a consumer is presently served by SSS yet an STR is pending, the second STR shall be rejected by the distributor with a notice that there was a pending STR for the consumer.

A distributor has no specific notification requirements associated with a transfer from SSS to a competitive retailer, other than those related to meter reads as specified in section 10.5.1, unless the consumer turns out to be served by a competitive retailer, rather than being an SSS consumer, or unless there is also a pending request.

10.5.4 Processing a Change From One Competitive Retailer to Another

An STR involving a transfer from one competitive retailer to another shall be submitted by the retailer to whom the consumer will be transferred if the process is completed. A distributor shall notify the current retailer that a transfer request has been received and wait twenty business days before continuing transfer processing. If no response is received from the current retailer, the request will be processed. If, at the end of the twenty business day period, the distributor has not received written authorisation from any party to cease processing, the transfer request shall be completed. If the new retailer, the consumer or the current retailer (acting upon specific written authorisation from the consumer to terminate the transfer) notifies the distributor, by way of written authorisation that the transfer request should be terminated, the distributor shall cease processing the transfer. Whichever party submits the termination request, the distributor shall notify the other two parties that processing of the transfer has terminated.

In the event that an STR for a consumer (the second STR) is received by a distributor and there exists for the same consumer, a pending STR (the initial STR), the distributor shall notify the retailer that filed the second pending STR that it has been rejected as there is already a pending STR waiting for the supplier change to proceed.

A service transfer date shall coincide with the date of the final meter read based on the option designated in the STR or the default option agreed to between a distributor and retailer. Final meter read options allowed for in this scenario include all options identified in section 10.5.1. However, the historical meter read option can only be used if all three parties, the two retailers and the consumer, agree in writing. If a transfer is to be based on an estimated value or on a consumer read, all four parties, the distributor, both retailers and the consumer, must agree in writing to the terms of the arrangement.

10.5.5 Processing a Change From a Competitive Retailer to SSS

An STR involving a transfer from a competitive retailer to SSS may be submitted either by the current retailer or the consumer.

If the STR is submitted by the current retailer, a distributor shall notify the consumer that a transfer is taking place and the scheduled transfer date but the consumer may not unilaterally terminate this request.

If the STR is submitted by a consumer, a distributor shall notify the current retailer and delay processing ten business days unless the current retailer responds that no delay is necessary. If, during the ten-day waiting period, a distributor is notified, by way of written authorisation, by the consumer or the current retailer (acting upon specific written authorisation from the consumer to terminate the transfer) that processing should be terminated, the distributor shall cease transfer processing. A distributor shall notify the retailer and the consumer that the transfer will not be completed.

Where all affected parties agree, a service transfer may take effect on a date other than the date of an actual meter read. The final bill may be based on one of the methods set out in section 10.5.1.

For the purposes of section 10.5.5, the affected parties are the retailer, the consumer and the distributor.

10.5.6 Transitional Arrangements

Prior to the EBT System becoming operational, a distributor shall accept STRs related to a change in competitive electricity service provider by any of the following means of communication: an electronic file transmitted by way of an e-mail, a diskette or the Internet. Where a distributor is unable to accept electronic files, it shall accept paper copies of such STRs received through Canada Post, courier, or by facsimile. Such STRs shall be in a form and contain information as set out in Appendix B, or an equivalent form designed by the distributor. A distributor shall not require information beyond that set out in Chapter 10.

Prior to the EBT System becoming operational, a distributor shall be required to process STRs related to changes in competitive electricity service provider in an expeditious

manner, and at a minimum shall record the date and time that individual STRs are received by the distributor.

10.6 Rules and Procedures for Processing Service Transactions Requests That Do Not Involve a Change in Electricity Provider

There are transaction types governed by this Code that do not necessarily involve a change in electricity service provider:

1. A move by a consumer to another location either inside or outside a distributor's licensed service territory,
2. A change in metering or billing service; and
3. A request for historical customer-specific information.

Rules and procedures governing these transactions are covered in the next three subsections.

10.6.1 Processing a Request for Disconnection or Relocation When a Retailer Provides Service

An STR involving a consumer relocation when electricity is currently supplied by a competitive retailer may be submitted either by the consumer or the retailer. Time permitting, if the consumer submits the transfer request, the distributor shall notify the retailer that the consumer is terminating service at one location and, if relevant, re-instituting service at another location. The retailer will inform the distributor whether the contract between the retailer and consumer shall be terminated or shall continue at the new location. A distributor shall not delay processing a consumer's request to relocate pending a reply from a retailer or if the consumer's request does not allow sufficient time to notify and receive a reply from a retailer. In this event, a distributor shall assume that service at the new location will be with the same retailer and under the same terms as were in effect at the previous location, unless informed differently by the consumer.

The only allowable final meter reading option associated with a disconnection or

relocation is a special meter read coinciding with the termination date. If a consumer is moving from one location to another within a distributor's service territory and the consumer is not on retailer-consolidated billing, the distributor shall bill the consumer according to the normal practices and schedule. If a consumer is moving out of a distributor's service territory, a distributor may issue a bill immediately upon completion of the final meter read even if all of the price information required to normally compute such a bill is not available. In this event, a distributor shall use the price forecast for the relevant billing period approved by the Board for use in SSS billing.

10.6.2 Processing a Change in Billing or Metering Service

If a retailer, or a consumer being served by a retailer, wish to change their billing or metering option a request for such a change shall be submitted by the retailer. If the request is submitted by the consumer, the distributor may, at its option, either notify the consumer to have their retailer submit the request or notify the retailer that a request has been received from their customer and inquire as to whether or not the request should be honoured. A request for a change in meter service must be submitted a minimum of ten business days prior to the desired date of the meter service change.

If a change in metering service involves a change in the settlement method (e.g., from NSLS-based settlement to settlement based on interval metering or vice versa), the distributor shall issue a final settlement bill based on a meter read at the time of the change in meter service. If a change in meter service does not involve a change in the settlement method (e.g., a change from standard kilowatt-hour metering to time-of-use or prepaid metering), the distributor is not required to issue a final settlement bill corresponding to the date of the new meter installation.

A request to change from one billing option to another shall coincide with an actual meter read unless otherwise agreed to between the distributor and retailer.

If a change in billing option results in a change in the maximum allowable amount of security required to be posted by a retailer or in the risk mitigation procedures (e.g.,

customer deposits) used by a distributor to manage consumer non-payment risk, the distributor may choose not to implement the billing option change until the new risk mitigation requirements have been addressed by the relevant party.

10.6.3 Processing a Request for Historical Consumer Information

Consumers have the right upon request to have historical usage information, information about their meter configuration and payment information sent to their service address or to any designated retailer or third party. The specific information that distributors must provide is described in section 11.3.

A request to release consumer information may be submitted either by a consumer or a retailer. A retailer's request must be based on written authorisation from the consumer. A retailer need not transmit a physical or electronic copy of the written authorisation from the consumer in order for a distributor to process the request unless specifically requested to do so by the distributor. A request to deliver information to a consumer's service or billing address may be submitted orally. A request to send information to any other location must be submitted according to the same rules that apply to a request to transfer electricity service provider, as described in section 10.2. A consumer's authorisation to release usage information will be construed to also authorise release of meter data as defined in section 11.3. Release of payment information must be based on separate authorisation.

All consumer-specific information must be provided to the designated party by a distributor in a common format to be developed in accordance with the EBT System.

Requests to transfer consumer-specific information via the EBT System shall be completed by the distributor within five business days of receiving the request. Prior to the implementation of the EBT System, a distributor shall complete such requests in an expeditious manner. The distributor shall complete all other information requests within ten business days of receiving the request.

Provision of consumer-specific information to retailers shall be done at no charge until the EBT System is operational. Provision of consumer-specific information to retailers and consumers through the EBT System shall be done at no charge. Once the EBT system is operational, requests to deliver data directly to retailers and consumers if not delivered electronically through the EBT System shall be honoured twice a year at no direct charge to a retailer or consumer. Additional requests shall also be honoured by a distributor but a distributor may, at its discretion, charge a reasonable fee for such additional requests. A request is considered to be data delivered to a single address. Thus, a single request to send information to three locations is considered three requests.

11 ACCESS TO CONSUMER INFORMATION

This chapter describes the rights of consumers and retailers to access current and historical valid meter information (i.e., verified meter usage data) and unverified meter data (i.e., raw meter usage data) and related information. This chapter also describes the obligations of distributors in providing access to such information.

Until the metering evolution period end date, a distributor shall for all purposes under sections 11.1 to 11.3 inclusive treat a smart meter as a non-interval meter.

11.1 Customer Access to Valid Meter Information

11.1.1

A distributor shall make the following information available to a consumer within the distributor's service area:

(a) the distributor's meter number for the meter or meters located at the consumer's service address

(b) the consumer's service address;

(c) the distributor's account number;

(d) the date of the most recent meter reading;

(e) the date of the previous meter reading;

(f) multiplied kilowatt-hours recorded at the time of the most recent meter reading;

(g) multiplied kilowatt-hours recorded a the time of the previous meter reading;

(h) multiplied kW for the billing period (if demand metered);

(i) multiplied kVA for the billing period (if available);

(j) valid usage (kWh/h) for each hour during the billing period for interval-metered customers;

(k) an indicator of the read type (e.g., distributor read, consumer read, distributor estimate, etc.); and

(l) average distribution loss factor for the billing period.

11.1.2

Upon written authorization from a consumer located within the distributor's service area, a distributor shall make the information listed in section 11.1.1 available to a retailer that provides electricity to that consumer. A distributor shall make the information listed in section 11.1.1 available to retailers through the EBT System in accordance with section 5.2.

11.2 Customer Access to Unverified Meter Data

11.2.1

A consumer has the right to access his or her meter in order to obtain unverified meter data, or to assign this right to others, in accordance with any relevant technical specifications and codes.

11.2.2

If a consumer desires regular access to his or her meter in order to obtain unverified meter data, a distributor shall provide access under the following conditions:

(a) a consumer shall pay the reasonable cost of any software, hardware or other services required for a consumer to obtain direct access to unverified meter data (which may include costs for the installation of a secondary meter access system);

(b) the timing of consumer access to the meter is negotiable with the distributor; however, a distributor has priority when selecting access windows for the purpose of reading the meter;

(c) if a distributor's access to the meter is hindered or a consumer's access to the meter corrupts unverified meter data, a distributor may suspend a consumer's right to access until any outstanding problems are resolved;

(d) a consumer shall bear any cost incurred by a distributor to correct problems caused by a consumer's direct access to the meter; and

(e) if a consumer assigns his or her right to direct meter access to a third party, the consumer shall remain responsible for the action of the assigned party.

11.3 Providing Historical Information to Designated Parties

Upon written authorisation by a consumer, in accordance with the provisions in section 10.6.3, a distributor shall provide to the consumer or to one or more retailers, usage data, meter data and payment information as defined below. For non-interval-metered consumers, historical usage data are comprised of:

- Distributor's customer account number;
- Consumer's service address;
- Consumer's billing address;
- Identification of the current regulated rates that apply to the consumer (e.g., standard supply rate, distribution service rate, etc.);
- Multiplied kilowatt-hours used in each billing period;
- Multiplied kilowatt-hours used in each TOU consumption period for each billing period, if the consumer has a TOU meter;
- Multiplied kW for each billing period (if demand metered);
- Multiplied kVa for each billing period (if relevant);
- Date of actual or estimated meter read for each billing period;
- An indicator of the read type (e.g., distributor read, consumer read, distributor estimate);
- The next scheduled meter read date (or read-cycle date);
- The next scheduled bill date; and
- Distribution loss factor for the billing period.

For interval-metered consumers, usage data are comprised of the above items except that usage will be reported on an hourly basis for each billing period.

Meter data is comprised of the following:

- Distributor meter number;
- Meter manufacturer;
- Manufacturer's model number;
- Manufacturer's serial number;
- Meter owner (if other than distributor);
- Last seal date; and
- All meter multipliers necessary to calculate a bill, including, but not limited to, relevant PT and CT ratios.

A consumer's payment information is comprised of the following:

- An indication of whether or not the consumer is currently in arrears and, if so, for how long;
- Data on the number of cheques received from a consumer that had to be returned for insufficient funds over a specific period of time designated by the distributor; and
- Data on the number of times the consumer has been disconnected for non-payment over a specific period of time designated by the distributor.

For any of the above information that varies by billing period, a distributor shall provide data for 24 billing periods if the distributor's standard business practice is to keep this many billing periods easily accessible (e.g., "online"). If more than 24 billing periods are available, a distributor may release information for more periods at its discretion. If fewer than 24 billing periods are readily accessible, a distributor shall provide data for no less than one calendar year's worth of information, unless the consumer has been connected to the current distributor's system for less than one year.

12 RETAILER/DISTRIBUTOR RELATIONSHIP

A distributor shall enter into a Service Agreement with each retailer licensed by the Board who wishes to provide electricity services to consumers connected to the distributor's distribution system and who wishes to utilise retail settlement services offered by the distributor. The Service Agreement shall be in the form approved by the Board and set out in Appendix C.

During the period prior to approval by the Board of a Service Agreement, a distributor shall register the name of a licensed retailer that wishes to retail electricity within the distributor's service area. The distributor shall inform each retailer that it registers that the retailer is obligated to pay any approved rates for the processing of STRs. On a date to be determined by the Board, distributors shall have entered into a Service Agreement with all registered retailers, in accordance with the provisions of Chapter 12.

13 RETAIL MARKET READINESS

This Chapter sets out the obligations on distributors to certify that they have met particular retail market readiness requirements.

13.1 Self-Certification Statement #1

13.1.1

A distributor shall, on or before July 6, 2001, complete and test the systems listed below, so that these systems are sufficient, having regard to the volume and frequency of transactions which the distributor is likely to experience given its size, to allow it to be compliant with the relevant provisions of the Code once subsection 26(1) of the Electricity Act comes into force and shall certify that the systems listed below have been completed and tested in accordance with the requirements of this section by filing with the Board, on or before July 6, 2001, a completed Self-Certification Statement in a form approved by the Board ("Statement #1"):

(a) billing systems;

(b) enrollment systems;

(c) metering systems; and

(d) retail settlement systems.

13.1.2

For the purposes of section 13.1.1, a distributor is not required to have completed systems integration testing or have updated its billing systems with rates to be in effect when subsection 26(1) of the Electricity Act comes into force.

13.2 Self-Certification Statement #2

13.2.1

A distributor shall, on or before December 14, 2001, complete integration testing of all necessary systems and processes, so that the integrated system is sufficient, having regard to the volume and frequency of transactions which the distributor is likely to experience given its size, to allow it to be compliant with the relevant provisions of the Code once subsection 26(1) of the Electricity Act, 1998 comes into force and shall certify that integrated testing has been completed in accordance with the requirements of this section by filing with the Board, on or before December 14, 2001, a completed Self-Certification Statement in a form approved by the Board ("Statement #2").

13.2.2

For the purposes of section 13.2.1, a distributor is not required to have updated its billing systems with rates to be in effect when subsection 26(1) of the Electricity Act comes into force.

13.3 Self-Certification Statements

13.3.1

The Self-Certification Statements shall be signed by the President, Chief Executive Officer or Chair of the Board of Directors of the distributor.

13.3.2

Where a distributor fails to file a completed Self-Certification Statement by the required date, the distributor is required to file with the Board by the same date as the distributor was required to file the relevant Self-Certification Statement, a letter signed by the President, Chief Executive Officer or Chair of the Board of Directors of the distributor setting out the reasons why the Self-Certification Statement has not been signed and detailing the extent to which necessary systems, in the case of Statement #1, or necessary systems and processes, in the case of Statement #2, have been completed and tested.

13.3.3

For the purposes of sections 13.1.1 and 13.2.1, a reference to the Code is to the Code as it exists on the date that the distributor files the respective Self-Certification Statement with the Board.

13.3.4

Where a distributor fails to file a completed Statement #2 by December 14, 2001, the distributor shall file the completed Statement #2 with the Board as soon as the distributor is able to attest to the statement in the Statement #2.

13.3.5

Where a distributor fails to file a completed Statement #2 by December 14, 2001, the distributor shall, until such time as it files a completed Statement #2 in accordance with section 13.3.4, file a statement with the Board by the 14th day of every month following December 2001 detailing the extent to which all necessary systems and processes have been completed and tested and estimating the additional time it will require to complete and test all necessary systems and processes so that the integrated system will be sufficient, having regard to the volume and frequency of transactions which the distributor is likely to experience given its size, to allow it to be compliant with the relevant provisions of the Code once subsection 26(1) of the Electricity Act comes into force.

13.3.6

Compliance with the requirements of section 13.3.2, 13.3.4 or 13.3.5 does not remedy a distributor's non-compliance with section 13.1.1 or 13.2.1.

13.4 The Self-Certification Questionnaire

The Board shall issue a Self-Certification Questionnaire (the "Questionnaire") containing questions related to market opening. A distributor shall file in two stages a completed Questionnaire in accordance with the instructions provided by the Board. A distributor shall file the Questionnaire with answers to the Stage One questions on or before July 6, 2001. A distributor shall file the fully completed Questionnaire on or before December 14, 2001.

13.5 Exemptions

13.5.1

This Chapter does not apply to the following classes of distributors, where the relief applied for in the application referred to below has been granted or the application remains outstanding:

(a) distributors which have applied under subsection 86(1) of the Act for Board approval of the sale, lease or other disposition of their distribution system to Hydro One Networks Inc.; and

(b) distributors which are the subject of an application by Hydro One Networks Inc. under subsection 86(2) of the Act.

13.5.2

This Chapter does not apply to the distributors listed below:

1382154 Ontario Limited

1438188 Ontario Inc.

1438189 Ontario Inc.

1438190 Ontario Inc.

1438191 Ontario Inc.

1438192 Ontario Inc.

1438193 Ontario Inc.

Belleville Electric Corporation

Blue Mountain Hydro Service Company Inc.

Clearview Hydro Electric Commission

Hanover Electric Services Inc.

Kapuskasing Wires Inc.

Minto Hydro Inc

13.6 October Filings

13.6.1

In accordance with chapter 12, a distributor shall expeditiously process requests to enter into Service Agreements with licensed retailers that have requested a Service Agreement with the distributor. A distributor shall file a report with the Board, by no later than October 1, 2001, on the status of all requests by licensed retailers to enter into Service Agreements. For all requests where a Service Agreement has not been completed a distributor shall provide an explanation of the status of the request.

13.6.2

Where a distributor intends to be an IMO-administered market participant, it shall have completed the IMO's Uncoupled Operational Dry Run or the IMO's ability testing by no later than September 28, 2001. A distributor shall file written confirmation with the Board that it has completed the IMO's ability testing by no later than October 1, 2001.

13.6.3

A distributor shall complete all necessary systems and testing to have its EBT Standards compliant communication system operating by no later than October 26, 2001. A distributor shall file written confirmation with the Board that it has completed testing of these systems by no later than October 31, 2001.

13.6.4

Where a distributor fails to file in accordance with section 13.6.1. 13.6.2. or 13.6.3., the distributor remains obligated to file the required information with the Board.

13.6.5

Compliance with the requirements of section 13.6.4 does not remedy a distributor's non-compliance with sections 13.6.1,13.6.2 or 13.6.3.

13.7.1

A distributor shall maintain its integrated billing, enrollment, metering and retail settlement system referred to in section 13.2.1 in such condition that it would, if subsection 26(1) of the Electricity Act was in effect, allow it to be compliant with the relevant provisions of the Code.

13.7.2

Section 13.7.1 comes into force on December 14, 2001.

14 PRE-MARKET OPENING ENROLMENT PROCESS

14.1 General

14.1.1

For the purposes of this Chapter, the "customer file" means the customer account number with the distributor, customer name and postal code of a consumer.

14.1.2

All filings and reports made under this Chapter shall be made in accordance with the format approved by the Board.

14.2 Data Scrubbing

14.2.1

A retailer shall file on or before January 25, 2002 with each distributor the customer account number, customer name and postal code of every consumer in the distributor's service area with whom it has entered into a contract and which it wishes to serve as of the date subsection 26(1) of the Electricity Act comes into force.

14.2.2

A distributor shall issue a report on or before February 8, 2002 to a retailer who files in accordance with section 14.2.1 setting out which customer files have been accepted and which customer files have been rejected.

14.2.3

A distributor shall accept a customer file where:

(a) the customer account number filed matches the records of the distributor or matches a prior customer account number for a person who is a current

customer of the distributor at the same postal code as when the customer was served under the prior customer account number; and

(b) one of either the customer name or the postal code matches the information in the records of the distributor.

14.2.4

Where a distributor determines that the customer account number filed matches a prior customer account number for a person who is a current customer of the distributor at the same postal code as when the customer was served under the prior customer account number and the customer file is accepted, the distributor in reporting this acceptance shall provide the retailer with the current account number.

14.2.5

Where a distributor rejects a customer file, the distributor shall report the reason for the rejection by advising the retailer that:

(a) the customer account number in incorrect;

(b) the customer account number is correct but the customer name and postal code are incorrect; or

(c) the account is inactive.

14.2.6

A retailer may on or before February 15, 2002 re-file with the distributor revised information with respect to any customer files which have been rejected.

14.2.7

A distributor shall issue a report on or before March 1, 2002 to a retailer who files in accordance with section 14.2.6 setting out which customer files have been accepted and which customer files have been rejected.

14.2.8

Sections 14.2.3, 14.2.4 and 14.2.5 apply with necessary modifications to a filing made under section 14.2.6.

14.3 Multiple Contract Resolution

14.3.1

The retailers listed below shall agree to a third party (the "third party") who shall be responsible for reviewing information with respect to contracts to determine circumstances in which more than one contract has been entered into with respect to a single customer account and to decide which of these contracts will be accepted.

Direct Energy Marketing Limited

ECNG Inc.

Enron Canada Corp.

G6 Energy Corp.

Ontario Hydro Energy Corp.

Ontario Power Generation Inc.

Toronto Hydro Energy Services Inc.

14.3.2

A retailer shall file with the third party on or before March 5, 2002 the customer account number, customer name, postal code and date that a contract was entered into with respect to every consumer in the distributor's service area with whom it has entered into

a contract and which it wishes to serve as of the date subsection 26(1) of the Electricity Act comes into force and with respect to which the relevant contract:

(a) has been accepted under section 14.2; or

(b) was entered into on or after December 1, 2001.

14.3.3

The third party shall report to a retailer on or before March 15, 2002 on which contracts have been given priority and which contracts have not been given priority.

14.3.4

Where the third party determines that a consumer has entered into more than one contract, the third party shall give priority to the contract which was entered into first and not give priority to any contracts which were entered into subsequently and where the third party determines that a consumer has entered into only one contract, that contract shall be given priority.

14.3.5

The third party shall obtain payment for its services from all retailers who file with it under section 14.3.2 in the manner and the amount determined in accordance with an agreement between it and the retailers listed in section 14.3.1 on the condition that the methodology for determining what amount each retailer is obligated to pay to the third party shall not distinguish between retailers listed in section 14.3.1 and other retailers who file in accordance with section 14.3.2.

14.4 Contracts Not Invalidated

14.4.1

The rejection of a customer file under section 14.2 or the not giving of priority to a contract under section 14.3 in no way invalidates the contract.

14.5 Submitting STRs

14.5.1

Subject to sections 14.5.2, 14.5.4 and 14.5.6 set out below, no STR may be submitted to a distributor prior to the date which is two weeks after the date that subsection 26(1) of the Electricity Act comes into force.

14.5.2

Subject to section 14.5.3, a STR for consumer-specific information as described in section 11.3 with respect to a consumer who has entered into a contract with a retailer may be submitted to a distributor between March 4, 2002 and March 15, 2002 inclusive.

14.5.3

In the period between March 4, 2002 and March 15, 2002 inclusive, a retailer shall not submit STRs on any single business day for more of its contracts in the distributor's service area than the greater of 100 of said contracts and 10% of said contracts.

14.5.4

Subject to section 14.5.5, where a contract has been given priority under section 14.3, a STR with respect to that contract requesting to transfer a consumer from SSS to a competitive retailer may be submitted to a distributor between March 25, 2002 and April 8, 2002 inclusive.

14.5.5

In the period between March 25, 2002 and April 8, 2002 inclusive, a retailer shall not submit STRs on any single business day for more of its contracts in the distributor's service area which have been given priority under section 14.3 than the greater of 100 of said contracts and 10% of said contracts.

14.5.6

In the two week period after the date that subsection 26(1) of the Electricity Act comes into force, a STR requesting a transfer of a consumer from a competitive retailer to SSS, a STR involving a consumer relocation when electricity is supplied by a competitive retailer or a STR requesting a change in billing or metering service may be submitted to a distributor.

14.5.7

Where a STR is filed contrary to section 14.5, the distributor shall not process the STR and shall promptly return it to the retailer.

14.6 Applicability of Chapter 10

14.6.1

Subject to this Chapter, including the specific provisions set out below, Chapter 10 applies with necessary modifications to the submission of STRs under this Chapter.

14.6.2

The references to five business days in the first paragraph of section 10.4 and the fourth paragraph of section 10.6.3 shall be ten business days for those STRs submitted in accordance with this Chapter.

14.6.3

Despite section 10.5.1, a distributor shall not be required to undertake a special meter read with respect to a STR submitted in accordance with this Chapter.

14.6.4

Despite section 10.5.1, the transfer of a consumer with a MIST meter to a competitive retailer where an STR has been submitted in accordance with section 14.5.4 shall take effect on the date that subsection 26(1) of the Electricity Act comes into force.

Appendix A

Competitive Electricity Costs

Section 3.1 of the Retail Settlement Code indicates that the Board shall establish the sub-set of the IMO-billed services that are deemed to be Competitive Electricity Services for the purposes of calculating settlement costs in accordance with Chapter 3 of the Code.

The hourly price to be used in the determination of any of the calculations shall be the Hourly Ontario Energy Settlement Price published by the IMO for the settlement hour. This price shall be used for the purpose of calculating equations 3.3.1(a) and 3.3.2(a) and for the purpose of calculating settlements with retail embedded generators.

This is Exhibit "W" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK

April 8, 2016

Hydro One Billing Complaints Probe Ends, Because Company Is Being Privatized

CP | By The Canadian Press

Posted: 12/04/2015 4:44 pm EST Updated: 12/04/2015 4:59 pm EST

THE CANADIAN PRESS

TORONTO — Ontario's ombudsman has wrapped up investigations into 10,500 complaints about billing errors at Hydro One, but the provincial watchdog can't look into any more problems at the utility because it's being privatized.

The Liberal government sold 15 per cent of Hydro One on the Toronto stock market last month, and plans to privatize 60 per cent of the utility to raise $9 billion to pay down debt and fund infrastructure projects.

Earlier: **Hydro One Overcharged Consumers By $37 Billion, Audtor's Report Finds**

The change from 100 per cent public ownership means the ombudsman's office no longer has any authority to investigate customer complaints about Hydro One, a role the government says will be filled by an in-house ombudsman.

Acting ombudsman Barbara Finlay was given until Friday to wrap up about 600 outstanding complaints about Hydro One as part of the office's largest investigation ever.

Another 648 complaints poured into the Ombudsman's office since June, but Finlay says all of those will have to be dealt with by Hydro One's internal complaints mechanism, which will be established in the new year.

Hydro One owns the province's transmission grid, but also serves as a local electricity distribution company for 1.3 million households, mainly in rural and northern Ontario.

Bonnie Lysyk, Ontario's auditor general, speaks about her 2015 annual report during a press conference at Queen's Park in Toronto on Wednesday, December 2, 2015. (Canadian Press photo)

Auditor general Bonnie Lysyk's annual report this week said Hydro One was among the least reliable electricity distribution systems in Canada, and warned of more and longer power failures because the utility isn't replacing aging assets quickly enough. Lysyk has also lost her ability to investigate Hydro One's finances in the future.

The ombudsman, auditor general, privacy commissioner and all other independent legislative officers banded together in an unprecedented move to condemn the plan to sell Hydro One, warning it would shield the company from public scrutiny.

Former Ombudsman Andre Marin issued a report in March that found Hydro One had threatened to cut off the electricity of customers who were behind on payments, even during winter months, which he called a "blatantly misleading tactic" to collect money.

A new computer system at Hydro One led to billing issues for 100,000 customers, some of whom received no bills for prolonged periods while others got only estimated bills "sometimes for thousand or even millions of dollars," said Marin.

In some cases Hydro One erroneously took thousands of dollars directly from customers' bank accounts, leaving them to pay overdraft charges.

The province's new financial accountability officer has warned that the Hydro One sale will hurt the government's bottom line in the long run, after some initial gains.

Both the Progressive Conservatives and New Democrats condemned the sale as a bad deal for taxpayers — who had been getting about $750 million a year from the utility — and said removing oversight by the ombudsman and auditor general will make things worse for customers, not better.

The government has said the internal ombudsman at Hydro One will deal with complaints in the same way the provincial ombudsman did, but Marin described an in-house watchdog that reports to a board of directors as an "ombuds-weenie."

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Conversations

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Ontarians might want to wake up now, as your Government sells off your assets to distribute to their friends and masters. Same thing Christie Clark is doing in BC.

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Jeff Villemaire · Shawnee High School

RCMP WAKE UP !! OH FORGOT, THERE ON THE PAY ROLL TOO !!

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BILL BENNETT Plaintiff and **HYDRO ONE INC., ET AL.** Defendants Court File No.: CV-15-535019-00CP

ONTARIO
SUPERIOR COURT OF JUSTICE

Proceeding commenced at Toronto

Proceeding under the *Class Proceedings Act, 1992*

CERTIFICATION MOTION RECORD
(Returnable May 9, 2017)

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KOSKIE MINSKY LLP
20 Queen Street West
Suite 900
PO Box 52
Toronto ON M5H 3R3
Kirk M. Baert LS#: 30942O
Tel: (416) 595-2117 / Fax: (416) 204-2889
Garth Myers LS#: 63207G
Tel: (416) 595-2102 / Fax: (416) 204-4024

LAX O'SULLIVAN LISUS GOTTLIEB LLP
145 King St West
Suite 2750
Toronto ON M5H 1J8
Eric R. Hoaken LS#: 35502S
Tel: (416) 645-5075 / Fax: (416) 598-3730
Ian C. Matthews LS#: 55306N
Tel: (416) 598-5365 / Fax: (416) 598-3730
Lisa S. Lutwak LS#: 659851
Tel: (416) 645-5078 / Fax: (416) 598-3730
Lawyers for the Plaintiff