Chapter 3

Section

3.06 Hydro One—Management of Electricity Transmission and Distribution Assets

1.0 Background

1.1 Overview

Hydro One Inc., one of the largest electricity delivery systems in North America, has three key reportable segments:

- **Transmission**: Hydro One Networks Inc. transmits electricity through its 29,000-kilometre high-voltage transmission network that sends electricity from power generators to approximately 90 large industrial customers and 47 of the 71 local distribution companies (LDCs), or utilities, in Ontario, as well as to Hydro One's local distribution business;
- **Distribution**: Hydro One Networks Inc. also delivers and sells electricity to residential and industrial customers through its 123,000-kilometre low-voltage distribution system that serves as the LDC for about 1.4 million customers mostly in smaller municipalities and rural areas throughout the province and serving 28% of all customers in Ontario. (This is different than most other distributors, which typically service larger urban and surrounding areas. Hydro One has an average of 11 customers for each kilometre of distribution line, whereas the average for the four largest LDCs in Ontario is 51.) It also sends electricity to the remaining 24 smaller LDCs not directly serviced by the transmission network; and
- **Telecommunications**: Hydro One Telecom Inc. manages a telecommunications system that allows Hydro One to monitor and remotely operate its transmission system equipment. Telecommunications services are also sold to large resellers and corporate users.

The Ontario electricity grid is a network of power generators and consumers connected by high-voltage transmission towers and lines and low-voltage distribution lines. Hydro One owns and operates 96% of the province's electricity transmission system, with the remaining 4% being owned by four private-sector corporations. The transmission system collects electricity from generators and sends it via high-voltage transmission towers and lines to transformer stations, where the electricity is converted to a lower voltage and then travels from the transformer station to an LDC or a large industrial client.

LDCs own and operate the low-voltage lines that distribute or deliver power to homes and businesses. As of December 31, 2014, there were 71 LDCs across the province that were mainly owned by the municipalities they service, in addition to Hydro One Networks distribution system operations (for the rest of this report, we refer to 72 LDCs because we include Hydro One Networks as an LDC). This includes Hydro One Brampton Networks Inc., a wholly owned subsidiary of Hydro One Inc., which operates as a standalone LDC serving the City of Brampton area. In addition, Hydro One Remote Communities Inc. operates standalone generation and distribution systems for 21 remote northern Ontario communities serving 3,500 customers.

Figure 1 shows the organization and the roles and responsibilities of key entities, including Hydro One, involved in the electricity system in Ontario, covering policy formulation, planning, generation, pricing, regulation, transmission and distribution. (See **Section 3.05** of this year's Annual Report for our audit of the Ministry of Energy's Electricity Power System Planning.)

Hydro One's mandate is to be a safe, reliable and cost-effective transmitter and distributor of electricity. The corporation is subject to direction from its sole shareholder, the government of Ontario, and operates in accordance with governing legislation and regulations, particularly the *Electricity Act, 1998*. The board of directors is responsible for the stewardship of the company and supervision of management.

Hydro One's transmission and distribution businesses are licensed and regulated by the Ontario Energy Board (OEB) under the authority of the *Ontario Energy Board Act, 1998*. The OEB sets transmission and distribution rates and issues licences to Hydro One for both systems.

Hydro One is bound by the terms of its transmission and distribution licences, as well as the requirements of the Transmission System Code and Distribution System Code, both issued by the OEB. The codes provide the minimum conditions a transmitter or distributor must meet in carrying out its obligation to operate and maintain each system.

Hydro One's earnings are principally generated from its regulated transmission and distribution businesses. For the year ending December 31, 2014, Hydro One's total revenues were $6.548 billion, and its operating and other costs were $5.801 billion, resulting in a net income of $747 million. Hydro One's transmission, distribution and telecommunication net fixed assets were valued at about $16.2 billion. At the end of 2014, Hydro One had 5,500 permanent staff and had employed 2,100 temporary workers during the year. The temporary workers are mainly seasonal, working from April to October on construction projects and to supplement Hydro One lines and forestry groups.

1.2 Transmission System

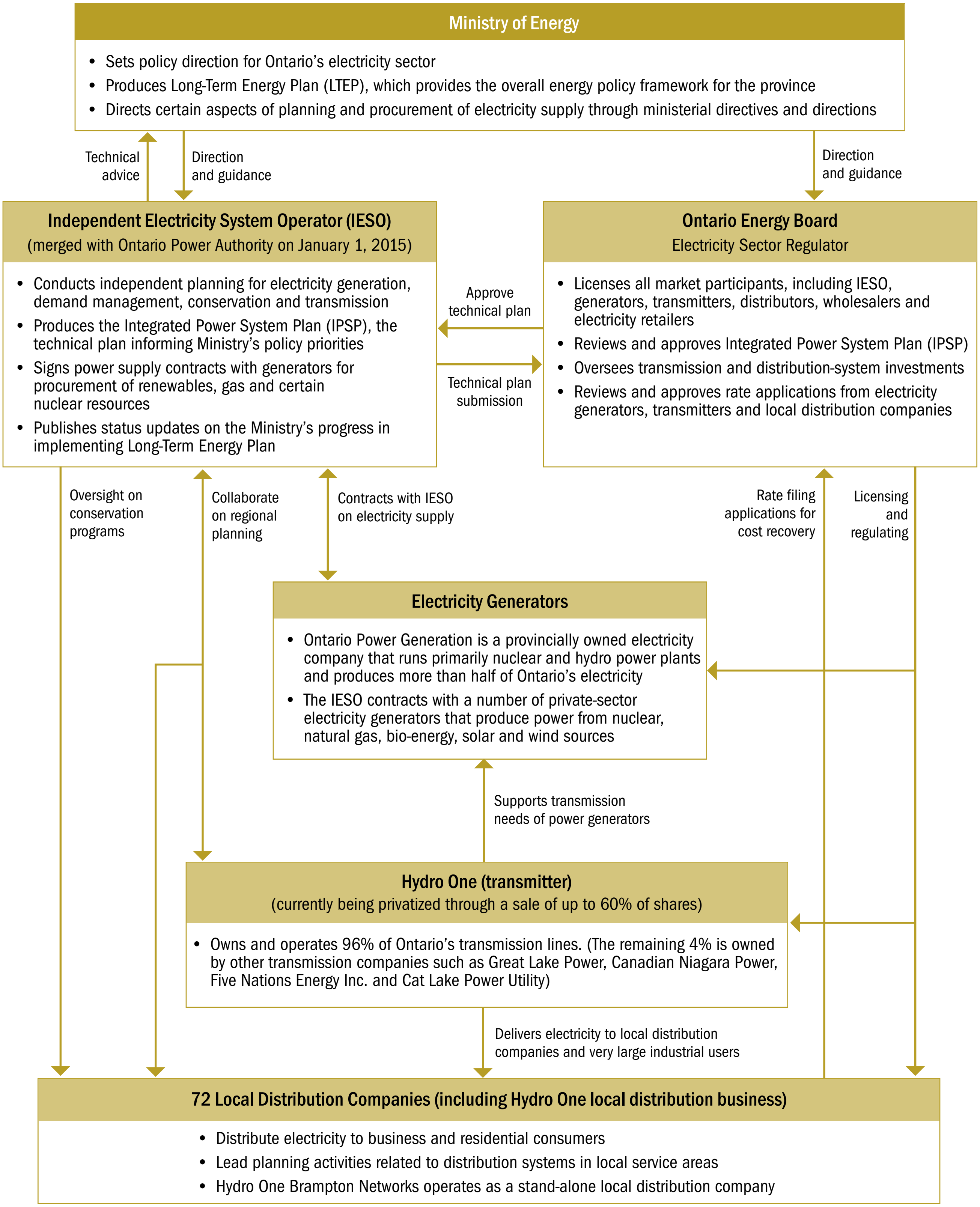
Hydro One's transmission system had net tangible capital assets (for example, lines, towers and transformer stations) valued at $9.3 billion as of December 31, 2014. The transmission system operates over long distances and links electricity generating facilities to LDCs and end-user transmission customers, such as mines, automobile manufacturing facilities and petro-chemical plants via transmission towers and lines connected to transformer stations. The transmission system is linked to five adjoining jurisdictions: Quebec, Manitoba, New York, Michigan and Minnesota. These interconnections are designed to facilitate the transfer of electricity between Ontario and other jurisdictions.

High-voltage transmission towers and lines operate at 500,000 volts, 230,000 volts and 115,000 volts. Almost all lines are overhead, as opposed to underground. Key components of high-voltage transmission lines include the lines, overhead conductors, steel support structures (towers) and grounding systems. Hydro One owns and operates 299 transformer stations that contain 722 power transformers, 4,604 power circuit breakers and 14,000 switches, along with protection and control equipment. There is also physical infrastructure, such as buildings, roads and security fences within a station's boundaries.

Unplanned power outages on the transmission system are primarily caused by weather, particularly lightning strikes, and by equipment failures. Approximately 70% of the delivery points (which receive over 85% of all electricity) on Hydro One's

Figure 1: Roles and Responsibilities of Key Entities Involved in the Electricity System in Ontario

Prepared by the Office of the Auditor General of Ontario



transmission system are multi-circuit delivery points, meaning they have more than one line available to provide power to customers along that line. The remainder of the transmission system features single-circuit delivery points. Where there are multiple transmission towers and lines connected to a customer, a power outage on one line will not disrupt the power supply to a customer because the other operational line still provides electricity.

(Please see the **Appendix** at the end of this report for a glossary of terms we have used.)

Hydro One must adhere to reliability standards established by the North American Electricity Reliability Corporation (NERC). NERC's mission is to ensure the overall reliability of the bulk electricity system in North America. As the North American transmission system is interconnected, its utilities share a common set of standards that govern the reliability of their operations. Working with the continent's approximately 1,400 bulk electricity transmitters, including Hydro One, NERC establishes and monitors these standards.

The transmission system is monitored, controlled and managed centrally by the Ontario Grid Control Centre (Control Centre) in Barrie. The Control Centre monitors the system around the clock electronically, responds to alarms caused by equipment, and can restore, divert and interrupt power transmission remotely. The Control Centre also authorizes all planned outages (such as when maintenance needs to be performed on transmission system equipment), and it dispatches repair crews to deal with unplanned outages.

Total transmission revenues for Hydro One in 2014 were $1.6 billion. Transmission revenue is based on the transmission tariffs set by the OEB, for which Hydro One makes rate applications every two years. The tariff is designed to recover from large industrial customers and LDCs enough revenue to support Hydro One's costs to operate and maintain the transmission system.

1.3 Distribution System

Hydro One's distribution system spans 75% of Ontario geographically and serves 28% of the province's customers. It serves approximately 1.4 million retail customers, 44 large industrial users and 24 smaller LDCs. Hydro One is the largest LDC in Ontario by both number of customers served and geographic area covered.

The distribution system's net tangible capital assets are valued at $5.9 billion. The system is composed of 123,000 kilometres of distribution lines that operate below 50,000 volts, 1.6 million wooden poles, 500,000 pole-top transformers and approximately 1,200 distribution stations. Distribution stations typically include equipment such as transformers, switches and protection and control equipment, and may include buildings, roads and security fences. From 2012 to 2014, Hydro One installed at a cost of $660 million approximately 1.2 million smart meters, which allows it to remotely receive individual customers' usage data over its telecommunications system.

The Control Centre is also responsible for overseeing the distribution system. However, the system is generally not equipped to monitor service electronically for outages. When a power outage occurs, the Control Centre receives service disruption calls from its customers, and it dispatches local work crews throughout the province to repair service. Unplanned power outages on the distribution system are often due to fallen trees and branches (31%), equipment failure (25%)and miscellaneous incidents such as accidents involving motor vehicles or wildlife (27%). On the other hand, outages on the transmission system, which feeds electricity to the distribution system, cause less than 1% of outages on the distribution system. In addition, planned outages for maintenance work account for 17% of outages.

Total revenue for the distribution business was approximately $4.9 billion in 2014. Similar to the transmission system, distribution revenue is based on distribution tariffs set by the OEB, which are based on separate rate applications that Hydro One submits, typically covering periods of one to three years.

1.4 Telecommunications System

Hydro One's high-speed telecommunications system throughout its transmission and distribution networks had net tangible capital assets of $541 million. The system is used to provide telecommunications for the monitoring, protection and control equipment of Hydro One's transmission system, as well as for corporate data and voice networks and smart meter operations for its distribution system. The system allows the Control Centre to receive real-time data on the performance of the transmission system and operate transmission protection equipment remotely. Use of the telecommunications system is also sold to telecommunications carriers and commercial customers, which in 2014 generated revenues of $57 million.

1.5 Privatization of Hydro One Inc. and Sale of Hydro One Brampton Networks Inc.

The government passed the *Building Ontario Up Act* in June 2015 to permit the sale of up to 60% of the province's common shares in Hydro One. The government announced plans for the fiscal year ending March 31, 2016, to release an initial public offering of approximately 15% of the common shares in Hydro One. The legislation requires the province to retain at least 40% the common shares in Hydro One, and no other single shareholder would be allowed to hold more than 10% of the total equity. In April 2015, the Premier's Advisory Council on Government Assets estimated Hydro One's valuation at $13.5 to $15 billion; using this estimate, selling 60% of Hydro One could bring up to $9 billion to the province, the sole shareholder.

Effective December 4, 2015, the *Building Ontario Up Act* also removed the ability of the Office of the Auditor General to conduct and report on value-for-money audits on the operations of Hydro One Inc. As a result, this audit of Hydro One's management of electricity transmission and distribution assets, which commenced prior to the tabling of the *Building Ontario Up Act*, will be the last value-for-money audit released by the Office.

The government is also proceeding with the sale of Hydro One Brampton Networks, expected to bring the province about $607 million, net of any price adjustments. In April 2015, the government announced that it had agreed to an unsolicited offer by three other LDCs, Enersource Corporation, Powerstream Holdings Inc. and Horizon Holdings Inc., to form a merger with Hydro One Brampton Networks.

On August 31, 2015, Hydro One declared a dividend transferring all its shares in Hydro One Brampton Networks to the province. The sale was still in progress as of September 2015 and subject to approval of the local municipalities that own the other LDCs and the Ontario Energy Board.

2.0 Audit Objective and Scope

Our audit objective was to assess whether Hydro One had adequate systems and procedures in place to manage and maintain its transmission and distribution assets efficiently and cost-effectively in accordance with relevant Hydro One policies and regulatory requirements, and to ensure the system was reliable for its customers.

Senior Hydro One management reviewed and agreed to our audit objective and criteria.

Our audit work included interviews with Hydro One management and staff, as well as review and analysis of relevant files, asset databases and other IT systems, policies and procedures, and Hydro One's transmission and distribution regulatory filings to the Ontario Energy Board.

Our work was primarily conducted at Hydro One's head office in Toronto. However, we also visited several transmission and distribution stations, the Ontario Grid Control Centre in Barrie and the Central Maintenance Shop in Pickering. During our visits we interviewed operations staff and we also held discussions with several key staff responsible for vegetation management throughout the province. We also met with representatives from the Association of Major Power Consumers in Ontario, the Canadian Electricity Association, and the Ontario Society of Professional Engineers. We reviewed past Hydro One Internal Audit reports, which also contained findings consistent with our own report.

The scope of our work did not include Hydro One Brampton Networks, which is managed and operated as a standalone LDC and is separate from Hydro One Networks, its distribution system. This audit also did not cover the government's recent decisions to privatize Hydro One Inc. and sell Hydro One Brampton Networks; both of these transactions had not been fully executed at the time our field work was completed in July 2015. We also did not cover Hydro One Remote Communities because its communities are not connected to Ontario's electricity grid.

Our audit fieldwork was conducted from January to July 2015, and we primarily focused on Hydro One activities over the three calendar years from 2012 to 2014.

3.0 Summary

Hydro One's mandate is to be a safe, reliable and cost-effective transmitter and distributor of electricity. Hydro One's customers instead have a power system for which reliability is worsening while costs are increasing. Customers are experiencing more frequent power outages, largely due to an asset management program that is not effective or timely in maintaining assets or replacing aging equipment, and an untimely vegetation-management program that has not been effectively reducing the number of outages caused by trees.

Some of the more significant areas we noted for improvement in transmission reliability included:

- **Transmission system reliability has deteriorated**: Hydro One's transmission system reliability has worsened for the five years from 2010 to 2014. Outages are lasting 30% longer and occurring 24% more frequently. In the same period, Hydro One's spending to operate the transmission system and replace assets that are old or in poor condition increased by 31%. While Hydro One's overall transmission system reliability compares favourably to other Canadian electricity transmitters, it has worsened in comparison to U.S. transmitters.
- **Equipment outages increasing, backlog of preventive maintenance growing**: Hydro One has a growing backlog of preventive maintenance orders to be performed on its transmission system equipment, and this lack of maintenance led to equipment failures. The backlog of preventive maintenance orders for transmission station equipment increased by 47%, from 3,211 orders as of 2012 to 4,730 orders as of 2014. At the same time, the number of equipment outages on the transmission system increased by 7%, from 2,010 in 2012 to 2,147 in 2014. The cost to clear the backlog of preventive maintenance work orders has grown 36%, from $6.1 million as of December 31, 2012, to $8.3 million as of December 31, 2014.
- **Hydro One not replacing very high-risk assets, contrary to its rate applications**: We found Hydro One was not replacing assets it determined were in very poor condition and at very high risk of failing, and it used these assets in successive rate applications to the Ontario Energy Board to justify and receive rate increases. Power transformers that are identified as being in very poor condition should be replaced at the earliest time possible; however, Hydro One replaced only four of the 18 power transformers it deemed to be in very poor condition in its 2013-2014

application used to obtain rate increases, and instead replaced other old transformers rated in better condition. These transformers are at a higher risk to fail, and we found two power transformers rated as being in very poor condition that failed and resulted in outages to customers lasting 200 minutes in 2013 and 220 minutes in 2015. Hydro One's transmission system rate application for the two-year period 2015-2016 listed 34 power transformers as rated "very high risk" for failure; however, the application did not indicate that Hydro One was planning to replace only eight of these over this period. In choosing not to use the additional funds from rate increases approved by the OEB to replace 26 transformers in very poor condition, Hydro One will have to seek $148 million again in the future to carry out the overdue replacement.

- **Significant transmission assets that are beyond their expected service life still in use**: Hydro One's risk of power failures can increase if it does not have an effective program for replacing transmission assets that have exceeded their planned useful service life. The number of key transmission assets, such as transformers, circuit breakers, and wood poles, in service beyond their normal replacement date ranged from 8% to 26% for all types of assets in service. Replacing these assets will eventually cost Hydro One an estimated $4.472 billion, or over 600% more than its $621-million capital sustainment expenditure for 2014.
- **Funding requests made to Ontario Energy Board not supported by reliable data**: The asset condition ratings provided by Hydro One in its 2013-2014 and 2015-2016 rate applications to the OEB were inaccurate and contained errors because of unreliable internal systems for reporting on the condition of assets. We found that 27 of the 41 transformers replaced in 2013 or 2014 had been wrongly identified in the rate applications as being in good or very good condition, yet Hydro One had plans at the time to replace several of these transformers due to their old age or poor condition. Similarly, we noted that 24 of the 43 transformers inaccurately reported in the 2015-2016 rate application as having a low or very low risk of failure were already scheduled to be replaced during this period.
- **Asset Analytics System not accurately considering all factors related to asset replacement decisions**: Key information is often not included, or incorrectly weighted, in the Asset Analytics system, Hydro One's new asset investment planning IT system implemented in 2012 to replace older systems. As a result, assets that need replacing are not being accurately identified. We found that the Asset Analytics database does not incorporate qualitative factors, such as technological or manufacturer obsolescence information, known asset defects and health and safety concerns. For example, oil leaks are one of the leading reasons for replacing a transformer. However, this information has only a minor impact in Asset Analytics for determining the risk of the asset failing and the need to replace it. In its reporting to OEB, Hydro One assigns oil leaks an impact on a transformer's condition rating of only 15% in determining whether an asset is classified as being in very good to very poor condition overall.
- **Limited security for electronic devices increases risk of power outages**: Hydro One's approach to ensuring proper security over transmission system electronic devices did not ensure a robust, high level of security for all of its electronic devices. Only certain devices in its transmission system receive higher levels of security in order for it to meet North American Electricity Reliability Corporation (NERC) standards for the bulk electricity system, which includes those major transmission lines and transformer stations that are linked to other states and provinces.

Hydro One is required to apply NERC standards related to electronic devices to only 18% of its transmission stations, and only to critical devices, which make up less than 17% of the electronic devices at these stations. All other electronic devices that are used for transmission within Ontario and don't impact the bulk electricity system are covered by Hydro One's weaker security policy, which was not applied consistently to devices. This increases the risk of service disruptions for Ontario customers due to sabotage, vandalism, software viruses and unauthorized or unintentional changes to device software or controls.

Some of the more significant areas we noted for improvement in distribution reliability are as follows:

- **Distribution reliability poor and costs have increased**: Hydro One's distribution system has consistently been one of the least reliable among large Canadian electricity distributors between 2010 and 2014. The average duration of outages reported by members of the Canadian Electricity Association (CEA) between 2010 and 2014 was about 59% less than Hydro One over the same period, while average frequency of outages among CEA members was 30% lower. In a scorecard published by the Ontario Energy Board in 2014, Hydro One was ranked worst and second worst of all distributors in Ontario for duration and frequency of outages in 2013. Over the same period, spending increased by 18% to operate and maintain the distribution system or replace assets that were old or in poor condition.
- **Hydro One not clearing vegetation (forestry) around distribution system in timely way, thus increasing the risk of outages and system reliability**: The top reason for distribution system outages from 2010 to 2014 was broken lines caused by fallen trees or tree limbs. A key factor in this was that Hydro One operates on a 9.5-year vegetation-management cycle, while the average such cycle for 14 of Hydro One's peer utilities was 3.8 years. Hydro One's own analysis indicates that by not operating on a vegetation-management cycle similar to its peers, the vegetation-management work it did in 2014 cost $84 million more than it would have under a four-year vegetation management cycle and customers would have experienced fewer outages caused by trees, and, therefore, had 36 minutes less in total outage time for the year.
- **Improper prioritization of vegetation-management work resulted in more tree-caused outages**: The system used by Hydro One to designate distribution lines for vegetation management does not put priority on those areas where tree-related outages have caused disruptions. We found examples where vegetation management was performed on distribution lines that had had few tree-caused outages, at the expense of distribution lines that had had significantly more tree-caused outages. This resulted in the number of tree-caused outages increasing by 5% from 2010 to 2014 (from 7,747 in 2010 to 8,129 in 2014), while vegetation management spending increased by 14% over the same period ($161 million in 2010 to $183 million in 2014).
- **Asset Analytics ratings information for distribution assets is incomplete and unreliable**: As of July 2015, Hydro One's Asset Analytics system, a key tool in making replacement decisions, had incomplete and unreliable data for distribution assets. We found that three years after the implementation of the Asset Analytics database, it contained incomplete or erroneous data for distribution system assets. For example:
  - there was limited data available to evaluate all 152 distribution station breakers; and
  - 14 distribution station power transformers that are under 10 years old were mistakenly

assigned age scores of 100, which would be past the 40-year expected service life of such transformers.

- **Significant distribution assets that are beyond their expected service life still in use**: Hydro One increases the risk of power failures by not replacing distribution system assets that have exceeded their planned useful service life. Hydro One's planned service life for wood poles is 62 years, but 202,000 poles, or 13% of the total, were older than that. Replacing these poles will eventually cost $1.76 billion. Only about 12,000 poles are replaced each year, much less than the number needed to address the risk of poles falling and much less than the number that are in service beyond their expected service life. In addition, it will eventually cost another $158 million to replace the 243 station transformers beyond their 50-year expected service life.
- **Smart meters not used to proactively identify power outages**: Hydro One installed 1.2 million smart meters on its distribution system at a cost of $660 million, yet it has not implemented the related software and capabilities to improve its response times to power outages. Currently, smart meters are used by Hydro One predominantly for billing purposes and not to remotely identify the location of power outages in the distribution system before a customer calls to report an outage. Such information from smart meters would make dispatching of work crews timelier and more efficient, leading to improved customer service and cost savings.

Some of the other significant areas we noted for improvement pertaining to both the transmission and distribution systems are as follows:

- **Excessive number of spare transformers in storage**: Hydro One did not have a cost-effective strategy for ensuring it had an appropriate number of spare transformers on hand, resulting in it having too many spare transformers in storage. While typically only about 10 transformers fail annually, Hydro One had 200 spare transformers—60 transmission transformers and 140 distribution transformers—valued at around $80 million in storage at the Central Maintenance Shop in Pickering. Thirty-five of these transformers had been in storage for at least 10 years. Hydro One itself estimates that by standardizing transformers and improving forecasting, it could reduce the number of spare transformers by up to 35% and save up to $20 million over the next 10 years. We estimate this savings could be much higher with better management, ranging from $50-$70 million.
- **Power quality issues are not corrected proactively**: Major transmission and distribution customers are concerned about the quality of their power, such as having stable voltage levels, but Hydro One addresses power quality issues only if customers complain. Hydro One has received 150 power quality complaints from 90 large industrial transmission customers alone since 2009. To measure fluctuations and assess the frequency and location of power quality events, Hydro One has installed 138 power quality meters across its transmission and distribution systems since 2010. However, Hydro One is not monitoring and analyzing the data from these meters to improve system reliability for its customers unless a customer first calls to complain.
- **Weak management oversight processes over capital project costs**: While Hydro One spent over $1 billion annually from 2012 to 2014 on capital projects to sustain its transmission and distribution systems, we noted it had weak oversight processes to minimize projects costs. For instance, up to 55% of projects costs are internal charges, since Hydro One primarily uses its own employees to carry out construction projects; however, it does not regularly analyze or benchmark its internal costs to industry standards to assess whether they are reasonable.

We also found that all capital project estimates used for approving projects included on average a 20% contingency charge allowance and an 8% escalation charge allowance, which gave Hydro One staff little incentive to complete a project at its original project cost estimate, or develop more accurate cost estimates for projects. We asked Hydro One management to prepare a report that compared the original project approval, including allowances, with the actual project costs for all projects completed for the years 2013 to 2015. The report we received in June 2015 was incomplete, and only included 61 of the 105 projects approved for over $1 million. Using the incomplete report, we estimate Hydro One spent on average 22% more than the original project cost estimates and used the allowances to complete these projects. This amounted to a total of $150 million more spent on the projects than the original project cost estimates.

Given that the Office of the Auditor General will no longer have jurisdiction over Hydro One as of December 4, 2015, we have made the following recommendation, requesting that the Ontario Energy Board take the observations we have made in this report into consideration during its regulatory processes:

- That the Ontario Energy Board, on behalf of electricity ratepayers in Ontario, as part of its regulatory oversight of Hydro One, review this report, the recommendations, and future actions taken by Hydro One to improve the reliability and cost-effectiveness of its transmission and distribution systems.

This report contains 17 recommendations to Hydro One, consisting of 37 actions, to address the findings noted during this audit.

OVERALL ONTARIO ENERGY BOARD RESPONSE

As part of its regulatory regime, the Ontario Energy Board (OEB) uses processes to hold all utilities, including Hydro One, to a high standard of efficiency and effectiveness. The recommendations made by the Auditor General in this report are useful in further supporting our efforts and in holding Hydro One accountable for prudently managing its resources and improving its service.

The OEB is committed to using all key information available for its deliberations and decision-making processes, and will, as appropriate, consider the areas of improvement identified by the Auditor General in future as it exercises its regulatory functions to ensure that Hydro One undertakes appropriate planning and investing, and optimal maintenance of its systems, and that it benchmarks itself against external comparators.

The report highlights a number of areas where Hydro One can improve the quality of its planning and the cost-effectiveness of its execution of those plans. The OEB likewise places a high priority on delivering value to electricity customers for the rates they pay. In 2012, the OEB developed the renewed regulatory framework for electricity (RRFE) distributors, which places a focus on rigorous asset management and capital planning in support of cost-efficient operations. The framework prescribes use of industry benchmarking to ensure improvement in cost performance and contains high expectations of continuous improvement to increase the productivity of operations. Utilities are expected to engage with their customers to understand their needs and preferences and to focus on the achievement of outcomes that take their priorities into account.

In its evaluation of Hydro One's most recent rate-rebasing application (EB-2013-0416), the first such application that it filed under the OEB's renewed framework, the OEB identified certain deficits: among other things, it concluded that Hydro One Networks Inc.'s distribution investment planning does not yet appear to be properly aligned with the actual condition of its assets; that its vegetation management does not show sufficient efficiencies or productivity improvements; and that its productivity commitments do not show the company to have a strong enough orientation toward continuous improvement.

Consequently, the OEB has already secured Hydro One's commitment to measure and report on many of the areas that the Auditor General's report has highlighted in its audit recommendations. In fact, in light of its concerns as to whether Hydro One's distribution investment priorities had been optimized, in Hydro One's last rate application, the OEB approved only three years of a proposed capital spending plan rather than the five years Hydro One requested, and indicated that further approvals will be contingent on the quality of Hydro One's supporting evidence.

The OEB decision in this application took further steps to ensure that Hydro One addresses shortcomings in its planning and benchmarking, many of which intersect directly with the recommendations of the Auditor General. Specifically, the OEB has ordered or otherwise secured Hydro One's commitment, among other things, to:

- conduct external benchmarking on the unit costs of its distribution pole replacement and station refurbishment plans;
- consider external review of its distribution system planning;
- report on achieved in-service investments relative to plan;
- undertake a total factor productivity study of Hydro One's own productivity, including data from 2002 and following years at a minimum; and
- explore best practices in vegetation management, considering changes in labour mix and innovation opportunities, as well as conduct a trend analysis of the vegetation management program showing year-over-year variations in unit costs.

Similar focus has also fallen on Hydro One's transmission business. As part of its most recent transmission rate application (EB-2014-0140), Hydro One has committed to benchmark its transmission cost performance relative to similar companies. The OEB is also working toward the implementation of the RRFE framework for transmission in Ontario as part of its continued commitment to ensure that the owners and operators of electricity networks in Ontario provide reliable, cost-effective service at rates that represent good value to customers.

OVERALL HYDRO ONE RESPONSE

Managing Hydro One's massive and complex transmission and distribution system requires considerable engineering expertise and dynamic asset management strategies that result in timely and disciplined investments to maintain or improve reliability and optimize equipment performance and cost. The Company recognizes there is always room to do better in this regard, so it makes continuous improvement a primary consideration in all of its asset plans and strategies.

Hydro One has strengthened the oversight of the Company and its operations. Internal Audit, reporting directly to the Audit Committee of the independent Board of Directors, will review this report and will oversee the Company's implementation of the recommendations where Hydro One believes they enhance reliability while balancing service and cost.

Hydro One's transmission and distribution businesses are regulated by the Ontario Energy Board (OEB), and the Company must comply with the conditions of service within the transmission and distribution system codes as part of its license. Hydro One places a high priority on its obligation to provide the OEB with complete, accurate and supportable evidence in its rate applications. Additionally, the Company acts on the recommendations and direction of the OEB as outlined in successive rate decisions.

Going forward, Hydro One is focused on delivering improved business performance and superior customer service as the Company prudently invests in Ontario's electricity transmission and distribution infrastructure. The Company will continue to do so while balancing service with cost.

Hydro One appreciates the work of the Auditor General and her staff, and the opportunity to respond to the findings within the audit. The recommendations provided as a result of this audit are being carefully considered as the Company moves forward.

4.0 Detailed Audit Observations

4.1 Transmission System

4.1.1 System Reliability Worsened from 2010 to 2014

Hydro One's transmission system customers expect their system to be reliable. However, we found that the system became less reliable from 2010 to 2014, with longer and more frequent outages. Hydro One's overall transmission system reliability compares favourably to other Canadian electricity transmitters; however, its reliability has worsened compared to U.S. transmitters.

Transmission system reliability is measured by two main metrics: the duration of outages and the frequency of outages. The System Average Interruption Duration Index (SAIDI) (average duration of outages) measures the average number of minutes per year each delivery point on the transmission system has experienced an outage, while the System Average Interruption Frequency Index (SAIFI) (average frequency of outages) measures the average number of outages per delivery point per year.

Hydro One measures system reliability separately for areas that are serviced by single-circuit delivery points, where a customer has only one line delivering electricity, and multi-circuit delivery points, where a customer has multiple towers and lines delivering electricity. Transmission outages are less likely to occur in areas that have multiple towers and lines since electricity can be supplied uninterrupted using an alternative line should one become out of service. Hydro One publicly reports on the performance of its transmission system based only on its areas serviced by multi-circuit delivery points, which cover over 85% of the electricity it delivers.

The difference in reliability between areas serviced by single or multiple lines was significant. As shown in **Figure 2**, single-circuit areas averaged 217.5 minutes in outages per year from 2010 to 2014, and the number of minutes varied significantly between years. In comparison, multi-circuit areas averaged 9.9 minutes in outages per year. Similarly, the number of outages averaged 3.22 per year per delivery point for the single-circuit transmission system compared to only 0.31 per year for the multi-circuit transmission system.

We found 47% of transmission outages from 2010 to 2014 occurred in Northern Ontario, even though this is where fewer than 20% of Hydro One's delivery points are located. In Northern Ontario, 86% of the delivery points are single circuit supplied. As it is costly to build additional towers and lines, Hydro One does not attempt to convert rural single-circuit delivery points that serve fewer, or smaller, customers to multi-circuit delivery points because it does not consider it cost effective to do so, even if it would improve system reliability for these customers.

For multi-circuit areas of the transmission system, Hydro One's reliability performance has deteriorated significantly since 2010. **Figure 2** shows that average duration of outages and average frequency of outages worsened (increased) by

Figure 2: Hydro One Transmission System Outages, 2010–2014

Source of data: Hydro One

	2010	2011[1]	2012	2013	2014[2]	Five-year Average	% Change Between 2010 and 2014
Multi-circuit Delivery Points							
SAIDI (minutes per delivery point)	9.1	8.9	6.8	12.9	11.8	9.9	30
SAIFI (outages per delivery point)	0.29	0.33	0.28	0.30	0.36	0.31	24
Unplanned outages	176	203	175	189	228	194	30
Single-circuit Delivery Points							
SAIDI (minutes per delivery point)	165.2	410.0	224.9	192.4	95.2	217.5	–42
SAIFI (outages per delivery point)	2.99	3.25	3.59	3.55	2.73	3.22	-9
Unplanned outages	820	851	947	945	737	860	–10

1. Hydro One indicated that 2011 was an extraordinary year for power outages for areas serviced by single-circuit delivery points because of forest fires in northern Ontario. Forest-fire-triggered outages accounted for 234 minutes out of the total 410 minutes incurred during that year.
2. Hydro One indicated that 2014 performance improved significantly for power outages for areas serviced by single-circuit delivery points primarily because of relatively less adverse weather during the year.

approximately 30% and 24% respectively from 2010 to 2014, and unplanned outages increased by 30%. Hydro One's records indicate this deterioration in reliability is primarily due to an increase in the number of unplanned outages, such as those caused by equipment failure or weather, that occurred at the same time as planned outages for such work as refurbishing or replacing aging transmission system assets, which temporarily rendered the alternate lines inoperative. If the alternate lines had been in operation at the time, those customers would likely not have experienced outages. These types of outages increased by 27% from 2010 to 2014 (from 74 outages in 2010 to 94 outages in 2014).

Despite the fact that Hydro One's recent transmission system reliability has worsened, it still compares favourably to other Canadian transmitters. The Canadian Electricity Association (CEA) collects information on the system reliability of Canadian electrical transmitters. Annually from 2010 to 2014, Hydro One's average duration and frequency of outages were generally better than the CEA average each year.

4.1.2 Transmission System Reliability is Poor Compared to the U.S.

As part of the bulk electricity system in North America, Hydro One's transmission system is integrated with transmitters in the United States. Hydro One participates in an annual transmission system reliability benchmarking study with transmitters in the United States, and the results indicate the reliability of Hydro One's system was generally worse than other transmitters. Other provinces' transmitters that are also on the bulk electricity system do not participate in these studies.

The study compares various metrics, including the average frequency and duration of outages, of a transmitter's entire system. In the 2011 report, based on outage data from 2006 to 2010, Hydro One's average duration and frequency of outages ranked only 21st and 22nd respectively out of the 25 participants. Similarly, in the 2015 study, based on outage data from 2010 to 2014, Hydro One was ranked only 10th and 13th for the average duration and frequency of outages out of 14 participants, and both averages were higher (worse) than the scores from the 2011 report.

The study also compares the reliability of only the portion of each transmitter's system that is part of the bulk electricity system. In the 2011 report, Hydro One's average duration of outages for its bulk electricity system was ranked 21st out of 24, and in the 2015 report, it ranked only 12th out of 14. In the 2011 report, Hydro One's average frequency of outages for its bulk electricity system was ranked only 21st out of 24, and in the 2015 report, it ranked only 13th out of 14.

4.1.3 Transmission System Availability Has Worsened from 2006 to 2014 Compared to Other Provincial and U.S. Transmitters

Comparison to Other Provincial Utilities

The Canadian Electricity Association (CEA) collects data from and reports to its provincial utility members on an availability metric for their transmission systems. The metric identifies how often electricity was unavailable, in system minutes, on the transmission system.

The CEA's data shows that Hydro One's availability is generally better than the CEA average of other provincial transmitters, with Hydro One unavailability at 16.4 system minutes compared to the CEA's average of 19.5 minutes using the average unavailability during the period 2010-2014.

Nevertheless, Hydro One's availability has worsened over time. While the CEA's 2011 report found that from 2006 to 2010, Hydro One's unavailability was 14.6 system minutes on average per year, this increased to 16.4 system minutes on average per year in the 2015 report, which reports on data from 2010 to 2014. While Hydro One's unavailability increased by 12% between the 2011 and 2015 reports, the CEA average unavailability decreased slightly during the same period, from 20.2 system minutes to 19.5 system minutes.

Transmission system availability is impacted by both planned and unplanned outages. It appears that Hydro One may have had more scheduled outages due to increased spending for maintenance, repairs and improvements, and therefore availability was negatively impacted when primary or back-up lines were shut down.

Comparison to U.S. Transmitters

The transmission system reliability benchmarking study Hydro One participates in with transmitters in the United States indicates that the unavailability of Hydro One's system is higher than other participating transmitters.

The study compares an overall Transmission Availability Composite Score (TACS), which measures the availability of electricity (how often transmission customers had electricity available for their use compared to how often they desired electricity). In the 2011 report, based on outage data from 2006 to 2010, Hydro One's TACS ranked it 23rd out of 25 participants. Similarly, in the 2015 study, based on outage data from 2010 to 2014 from 14 participants, Hydro One scored worse than it had in 2011 and placed last, including being behind the two transmitters that had a worse TACS than Hydro One in 2011.

On the other hand, Hydro One's availability for only the portion of each transmitter's system that is part of the bulk electricity system has improved compared to others U.S. transmitters surveyed. While Hydro One's system availability decreased (worsened) between the 2011 and 2015 reports, Hydro One's overall ranking improved from 13th of 24 in the 2011 report to fourth of 14 in the 2015.

We asked Hydro One management why U.S. transmitters generally have more reliable systems, and were advised that they typically have shorter distances to deliver electricity than Hydro One, and that Ontario's geography is larger and more challenging to service. However, no detailed analysis was available that studied these reasons or how to overcome the differences.

RECOMMENDATION 1

To ensure the reliable operation of the transmission system and to reduce the number of power outages experienced by customers, Hydro One should:

- set multi-year targets and timetables for reducing the frequency and duration of power outages that would lead to it having a system reliability and availability that compares favourably to other utilities in North America, establish an action plan and strategy for achieving these targets, and regularly report publicly on its efforts to achieve these targets;

- set targets and timetables, and cost-effective action plans, to improve the poor performance of its single-circuit transmission system; and
- more thoroughly analyze outage data on both its single- and multi-circuit systems to correct the main issues that are contributing to the system's declining reliability.

HYDRO ONE RESPONSE

Hydro One agrees with the Auditor General's recommendation and has started setting multi-year reliability targets in its 2015 Corporate Scorecard. The 2015 Corporate Scorecard included both 2015 and 2019 targets to signal the Company's drive to continuous improvement.

Hydro One will continue to make reliability a key priority by reducing the number of planned outages. It will do so by combining planned maintenance activities undertaken during the outage. This will reduce the risk of customer interruptions.

Hydro One's single circuit delivery points, by design, are not as reliable as delivery points served by multiple circuits. Single-circuit delivery point reliability has increased over the 2010–14 time horizon, as shown by the improved SAIDI and SAIFI results and lower unplanned outages.

Hydro One does respond to customer requests to improve reliability, providing the customer is prepared to pay the costs of the necessary investments in accordance with the Ontario Energy Board's (OEB's) Transmission System Code (TSC). The TSC requires affected customers to consent to pay their respective shares of the cost of the additional circuit. Customers have generally not provided such consent in Ontario, where such costs tend to be high due to low customer density and long lines.

Hydro One will continue to analyze outage data to identify issues relating to reliability. Hydro One carries out investments to improve customer reliability in accordance with the Customer Delivery Point Performance Standard issued by the OEB. This standard sets out thresholds for inadequate performance and appropriate funding levels based on minimum improvement levels and size of the customer load. The investments balance costs and benefits, and consider the degree of the improvement and the size of the load that is impacted.

Hydro One will undertake network expansions to provide redundant supplies and improve reliability to electrical areas that serve multiple customers when electricity demand in the area meets the criteria established by the Independent Electricity System Operator's Ontario Resource Transmission Assessment Criteria standard. The objective of the standard is to balance cost, customer benefit and ratepayer impacts.

4.1.4 Growing Backlog of Preventive Maintenance on Equipment Reduced System Reliability

A lack of preventive maintenance can lead to a shorter expected service life of equipment and premature equipment failure, which is the second-most common cause of outages (16% of all outages from 2010 to 2014). We found that the growth in the backlog of preventive maintenance on transmission system equipment from 2012 to 2014 likely contributed to an increase in the number of equipment outages on the transmission system. The backlog increased by 47%, from 3,211 orders as of 2012 to 4,730 orders as of 2014. During the same period, the total number of equipment outages on the transmission system increased by 7%, from 2,010 instances in 2012 to 2,147 instances in 2014.

Almost half (48%) of the preventive maintenance backlog in 2014 relates to the two most critical assets within a transmission station—transformers and circuit breakers. The backlog of preventive maintenance for these assets increased by 320% and 393%, respectively, from 2012 to 2014. During the same period, the increase in the number of transformer and circuit breaker outages on the transmission system increased by approximately 14% and 36%, respectively. We identified instances where a key piece of equipment for the transmission system failed that had backlogged preventive maintenance work.

Hydro One advised us that the backlog exists because it does not have sufficient staff available to perform all scheduled maintenance. The situation has worsened since 2012 as maintenance staff have been assigned to complete capital projects to repair or refurbish Hydro One's aging transmission system. We estimate from the preventive maintenance work orders in the backlog that the cost to clear the backlog has grown 36%, from $6.1 million as of December 31, 2012, to $8.3 million as of December 31, 2014. We believe that an $8.3-million backlog should have been manageable and eliminated long ago by Hydro One, given their multi-billion dollar annual operating budgets; instead, it is growing and impacting system reliability.

RECOMMENDATION 2

To ensure that Hydro One has an effective preventive maintenance program for all its critical transmission system assets to ensure they operate reliably and their expected service life is not shortened, Hydro One should:

- establish a timetable that eliminates its growing preventive maintenance backlog as soon as possible; and
- improve its oversight of preventive maintenance programs to ensure maintenance is completed as required and on time.

HYDRO ONE RESPONSE

Hydro One agrees that more diligence is required to ensure that the records contained in its management information system are reflective of actual outstanding maintenance. Consistent with industry practice, Hydro One maintains a catalogue of planned maintenance work that may have completion dates that extend well into the future. These maintenance orders are released well in advance of required completion dates to allow Hydro One to bundle work effectively (thus avoiding the need for multiple planned outages). Reducing the number and duration of planned outages reduces the risk of customer interruptions.

All critical preventative maintenance is completed when required. Maintenance activities that need to comply with industry standards are confirmed through Hydro One's Internal Compliance Program.

Hydro One will continue to prioritize work to enhance reliability and optimize work efficiency, while at the same time balancing service and cost.

4.1.5 Hydro One Not Replacing Transmission Assets that Are at Very High Risk of Failure

We found that the assets that Hydro One replaced or planned to replace from 2013 to 2016 were not the ones that it reported to be in very poor condition and at very high risk of failure in its bi-annual transmission rate applications to the Ontario Energy Board (OEB). In its rate application for 2013-2014, Hydro One stated that it had a program to replace power transformers and circuit breakers that had reached the end of their useful service lives, which was determined by evidence including the condition and age of the asset and its operating history. The rate application noted that the condition of an asset is the main indicator of its risk of failing, and that replacing assets that are in poor condition as soon as possible is key to maintaining the reliability of the system.

Based on Hydro One's report of its aging and deteriorating transmission transformers, as presented in its rate applications, the OEB approved increased capital sustainment funding for the period 2013 to 2016. As a result, Hydro One's transmission transformer replacement spending increased to more than $280 million over the two years 2013 and 2014 from $180 million over 2011 and 2012. Hydro One also planned to spend about $225 million on transformer replacements over 2015 and 2016.

In its 2013-2014 transmission rate application filed in May 2012, Hydro One reported that 18 of its 719 power transformers as of December 2011 were rated as being in very poor condition and at a very high risk of failure. Most of these 18 power transformers were at or past their expected service life of 40 to 60 years, with their average age being over 60 years.

However, as **Figure 3** shows, Hydro One replaced only four of the 18 power transformers deemed to be in very poor condition in 2013 and 2014, and replaced 37 other old power transformers, including 14 rated as being in very good condition and 13 in good condition. Of the four power transformers in very poor condition that were replaced, one failed prior to its replacement in 2013, causing a major power outage of 200 minutes on September 12, 2013, in an eastern Ontario town. One of the remaining 14 power transformers rated as being in very poor condition that was not replaced also failed in 2015, causing a major outage of 220 minutes on February 13, 2015, affecting customers in Toronto.

In its 2015-2016 transmission rates application filed in June 2014, indicating it wanted to replace 43 transformers, Hydro One informed the OEB that it now had 34 power transformers deemed as being at very high risk of failure. The application did not state that the 34 transformers included 13 that had been identified in the previous rate application as being in very poor condition, but had not yet been replaced. However, information for 2015-2016 provided to us by Hydro One indicated that of the 43 transformers it indicated it wanted to replace, it planned to replace only eight of the 34 in very poor condition. By not replacing 26 transformers in very poor condition, even though the OEB approved rate increases to fund these replacements, Hydro One will have to seek $148 million again in the future for their eventual overdue replacement.

Similarly, as **Figure 3** shows, Hydro One did not replace circuit breakers during 2013 and 2014 in accordance with the condition ratings it submitted to the OEB. While 153 circuit breakers were replaced at a cost of $123 million, only one of the 16 circuit breakers reported as being in very poor condition was replaced, and 63% of breakers replaced were in fair, good or very good condition. In addition, Hydro One's planned replacement lists for 2015-2016 indicate that the 85 circuit breakers

Figure 3: Condition Ratings and Replacements of Transformers and Circuit Breakers

Source of data: Hydro One

	Condition Rating					
	Very Good	Good	Fair	Poor	Very Poor	Total
Transformers						
# as of December 2011*	374	203	68	56	18	**719**
# replaced in 2013–2014	14	13	6	4	4	**41**
Circuit Breakers						
# as of December 2011*	908	1,715	975	648	16	**4,262**
# replaced in 2013–2014	12	50	34	56	1	**153**

* This is the number reported in Hydro One's transmission rate application for 2013/14 filed with the Ontario Energy Board in May 2012.

to be replaced will include only 21 that were rated as having a high or very high risk of failure.

We asked Hydro One asset management staff why assets in very poor condition were not replaced while others in reportedly better condition were. We were advised that Hydro One generally does not rely solely on reports from its Asset Analytic system (discussed later in **Section 4.1.6**) to decide which transmission assets to replace. Instead, asset management staff prepare a business case for assets that cost more than $20 million and need replacing, and a shorter project execution summary for all other replacements. These reports consider factors not covered by Asset Analytics, such as health and safety issues, and an onsite inspection of the asset is made. However, we found that Hydro One did not use the results of this more in-depth process for its rate applications to the OEB, instead using the unreliable information from Asset Analytics.

Nevertheless, we confirmed with Hydro One that those assets reported to the OEB as being in very poor condition and very high risk during rate applications between 2013 and 2016 were accurately reported and in need of replacement as soon as possible. This still leaves us questioning decisions made by Hydro One asset management staff on how they prioritize transmission assets for replacement when assets known to be in very poor condition and very high risk are not replaced. We also question why they continue to report inaccurate information to justify rate increases in their applications to the OEB.

Transmission Assets in Service Beyond Their Expected Life Increases Risk of Power Outages

Hydro One increases the risk of power failures because it does not have an effective program for replacing transmission assets that have exceeded their planned useful service life. **Figure 4** shows the percentages of Hydro One's key transmission assets that are in service beyond their expected service life and the estimated replacement cost that Hydro One will incur to replace these assets. The number of key transmission assets in service beyond their normal replacement date ranged from 8% to 26% of all assets in service. Replacing these assets will cost Hydro One an estimated $4.472 billion, or over 600% higher than its $621 million capital sustainment expenditure for 2014.

For transformers and circuit breakers, Hydro One acknowledged in its June 2014 rate application for

Figure 4: Transmission Assets in Use Beyond Their Expected Service Life, as of June 2014
Source of data: Hydro One

Asset	# or Distance Covered as of June 2014	Years of Expected Service Life	% Assets in Use in June 2014 That Were Beyond Their Expected Service Life	Estimated Cost to Replace Assets That Were Beyond Their Expected Service Life ($ million)
Stations				
Transformer	722	40, 50 or 60*	24	988
Circuit breaker	4,604	40 or 55*	8	325
Protection system	12,135	20, 25 or 45*	17	224
Lines				
Overhead conductor and hardware	30,000 km	70	19	1,908
Wood pole structure	42,000	50	26	378
Steel structure	50,000	80 to 100*	21	397
Underground cable	290 km	50	16	252
Total				**4,472**

* There are different types of this asset, each with different years of expected service life.

2015-2016 that its transformer and circuit breaker reliability lagged behind Canadian Electricity Association (CEA) averages for 33 large utilities.

In addition, we noted that the expected service life that Hydro One sets for its transformers exceeds the average expected service life used by other CEA member utilities. Hydro One sets its expected service life at 40 to 60 years depending on the type of transformer, while the CEA average is 40 years.

RECOMMENDATION 3

To reduce the risk of equipment failures that can cause major power outages on the transmission system, Hydro One should:

- ensure that its asset replacement program targets assets that have the highest risk of failure, especially those rated as being in very poor condition;
- reassess its practice of replacing assets that are rated as being in good condition before replacing assets in very poor condition; and
- replace assets that have exceeded their planned useful service life.

HYDRO ONE RESPONSE

Hydro One agrees that an asset in good condition should not be replaced before an asset in poor condition unless justified by one or more additional factors in the asset replacement process (for example, customer requirements, inadequate capacity, known manufacturer defect and so on).

Hydro One's asset replacement program is supported by asset condition information, detailed engineering assessments and a prioritization process to manage risks (safety, reliability) and achieve execution efficiency (outage availability, resources, bundling with other work).

Hydro One considers equipment condition and defects as a leading indicator of major equipment performance.

Other factors that inform the decision to replace an asset include equipment obsolescence, criticality, utilization, maintenance costs, performance and demographics. The Company does not replace assets that, while old, are in good working condition.

RECOMMENDATION 4

Hydro One should ensure that its applications for rate increases to the Ontario Energy Board provide accurate information on its asset replacement activities, including whether it actually replaced assets in poor condition that were cited in previous applications and whether the same assets in poor condition are being resubmitted to obtain further or duplicate rate increases in current applications.

HYDRO ONE RESPONSE

Information about transformer age and condition, filed with the Ontario Energy Board as part of rate filings, is intended to establish overall fleet condition. This information alone is insufficient to establish plans for individual transformer replacements. Rather, it informs the investment plan and helps determine the size of the program.

Hydro One exercises discretion, based upon specific information and circumstances, in selecting, prioritizing and adjusting the timing (including deferral) of capital work. Consequently, a proposed investment can appear in subsequent rate applications.

In future rate submissions, Hydro One will provide evidence of what it accomplished relative to the previously filed /approved rate application.

4.1.6 Information Systems on Asset Condition Not Reliable

The system Hydro One uses to record the condition of transmission assets contained erroneous and incomplete information, and did not adequately support Hydro One staff decisions on when to replace assets. Hydro One also used unreliable information from its systems to report asset condition and age on OEB rate applications to justify its requests for rate increases. The OEB considers and approves rate increases for Hydro One to charge its customers based on this information for the period covered by the application. If the information is inaccurate, OEB cannot adequately assess Hydro One's need for replacement assets, and accurately approve rate changes, either decreases or increases, to meet Hydro One's needs and be fair to its customers.

Inaccurate Information Provided to OEB in Rate Applications

The condition ratings provided by Hydro One in its rate applications to the OEB for the periods 2013-2014 and 2015-2016 were inaccurate and contained errors. As **Figure 3** shows, we found that 27 of the 41 transformers replaced in 2013 or 2014 had been identified in the rate applications as being in good or very good condition, yet Hydro One had plans at the time to replace several of these transformers due to their old age or poor condition. Similarly, we noted that 24 of the 43 transformers reported in the rate applications for 2015-2016 as having a low or very low risk of failure were already scheduled to be replaced during this period. The main reason Hydro One reported inaccurate asset condition and age to OEB is because it uses information from its unreliable internal systems.

Asset Analytics System Incomplete and Inaccurate

Hydro One maintains information on its transmission assets and scheduled maintenance primarily on its asset inventory module as part of its financial system. In 2012, Hydro One began using a new investment planning information technology system called Asset Analytics. Using data from Hydro One databases, including the financial system, Asset Analytics applies six factors to evaluate the condition of the asset and assess the risk of it failing: age of the asset; its condition; the amount spent on repairs on it; how much it is used compared to its capacity; its performance reliability based on unplanned outages; and its importance based on the number of customers it serves. Asset Analytics weighs all six factors for each asset type to generate a composite risk score that tells Hydro One which assets are at high risk of failing and should be considered for replacement.

We noted Asset Analytics was incomplete or inaccurate for a number of reasons:

- There are a number of key factors that are not recorded and considered by the system, including technological or manufacturer obsolescence information, known defects in the assets, environmental impact and health and safety concerns.
- The system does not properly weigh the risk posed by certain conditions that may shorten the life of the asset. For example, oil leaks are one of the leading reasons for replacing a transformer; however, the detection of a leak accounts for only about 15% of the transformer's condition rating and only 3.75% of the transformer's composite score.
- In 2013, a report by Hydro One's internal auditors found that 21% of notifications of defective equipment recorded by maintenance staff did not accurately identify the transmission asset that had the deficiency. For example, field staff may have discovered and recorded a transformer oil leak at a transmission station, but failed to record which specific transformer at the station was defective. As a result, the database could not be updated for the specific asset. The problem still existed in 2015; for the period January 1 to May 30, 2015, our testing noted that 13% of defective equipment notifications did not accurately identify the specific piece of equipment that was defective.

While we discussed earlier in **Section 4.1.5** that Hydro One's asset management staff generally do not rely on Asset Analytics for accurate asset condition reporting, Hydro One still uses the system's unreliable information to report to the OEB in its rate applications on asset condition to justify its requests for rate increases.

RECOMMENDATION 5

To ensure Hydro One is replacing assets that are at the highest risk of failure as determined through accurate asset condition ratings, Hydro One should:

- enhance its Asset Analytics system to include information on all key factors that affect asset investment decisions, including those related to technological/manufacturer obsolescence, known defects, environmental impact and health and safety;
- review and adjust current weighting assigned to risk factors in Asset Analytics to more accurately reflect their impact of asset condition and risk of failure;
- make changes to its Asset Analytics system and procedures so that updates to its data are complete, timely and accurate;
- conduct a comprehensive review of the data quality in Asset Analytics to update any incomplete or erroneous information on its assets and to ensure the information can support its asset replacement decision-making process; and
- investigate why known deficiencies in the reliability of the Asset Analytics system, such as those found two years earlier by internal audits, have not been corrected by management in a timely manner.

HYDRO ONE RESPONSE

Hydro One acknowledges that Asset Analytics data and algorithms continue to be developed and improved.

A data remediation project is under way to address the data gaps. In addition, data input and the change control process, along with data population and data quality dashboard metrics, will ensure data is populated in a complete, timely and accurate manner.

Hydro One has always intended to revisit the risk factors algorithms once a suitable post-deployment time period elapsed to provide enough results for the comprehensive review.

Hydro One intends to add health and safety and obsolescence factors to the tool.

Hydro One is addressing any outstanding internal audit recommendations regarding the Asset Analytics tool.

RECOMMENDATION 6

Hydro One should ensure that its applications to the Ontario Energy Board for rate increases include accurate assessments of the condition of its assets.

HYDRO ONE RESPONSE

Hydro One places a high priority on its obligation to provide the Ontario Energy Board with complete, accurate and supportable evidence in its rate applications.

The Company agrees that there is an opportunity to continuously enhance the quality and quantity of data in the Assets Analytics tool and has, for some time, been working toward this goal. The Asset Analytics tool represents only one input into the asset planning process and cannot replace decisions made by qualified engineers in conjunction with physical inspections.

A project is under way to address data improvement in the Asset Analytics tool with a focus on the transmission data to support the upcoming rate application. Its functionality will also be reviewed in 2016 to identify improvement opportunities.

4.1.7 Overall Spending to Maintain and Operate the Transmission System Has Increased, but Reliability Has Deteriorated

Hydro One's overall increased spending to maintain and operate the transmission system from 2010 to 2014 did not result in improved system reliability.

Costs related to the transmission system can be broken down into three main categories:

- Capital sustainment: refurbishment or replacement of components of the system to allow it to function as originally designed;
- Capital development: construction of new stations or lines, as well as upgrades to existing stations or lines to increase their capacity or capability; and
- Operations, Maintenance & Administration (OM&A): day-to-day costs related to operating the system.

Of the three cost categories, capital sustainment spending is expected to have the biggest overall impact on improving system reliability, followed by OM&A. Capital sustainment and OM&A spending are at the discretion of Hydro One. As shown in **Figure 5**, transmission capital sustainment spending increased by 74% from 2010 to 2014 ($356 million to $621 million) while OM&A decreased slightly ($421 million to $400 million). Overall spending in these two categories increased by $244 million (31%) from 2010 to 2014.

Decisions for Hydro One's capital development work generally involves either the Independent Electricity System Operator, government, Ontario Energy Board and/or customers, which may direct or help inform Hydro One where and when to increase transmission capacity by building new or replacing transmission lines and transformer stations. The addition of newer assets and upgrades also help to improve reliability. From 2010 to 2014, capital development spending decreased by 75% (from $523 million to $132 million).

However, the spending did not improve the reliability of the system. As shown earlier in **Figure 2**, the average frequency of outages of Hydro One's multi-circuit transmission system (covering 85% of electricity usage) increased 24% over this period. This was primarily due to an increase in the number of unplanned outages, such as those caused by equipment failure or weather, that occur at the same time as planned outages to replace aging transmission system assets. Some improvement was noted in the frequency of outages for all other areas covered by single circuit lines.

Hydro One Does Not Perform Cost Benchmarking against Comparable Utilities

Hydro One has acknowledged that its transmission cost measures can be benchmarked against those of other utilities, but it has not attempted to do so since 2009.

Until 2009, the Canadian Electricity Association (CEA) annually compared costs of all major Canadian transmitters. Thirteen types of costs were compared, including total cost incurred per energy transmitted (in megawatt hours) and per peak capacity (highest demand period measured in megawatt hours), and total OM&A costs per kilometre of transmission line and per transmission asset. The CEA's results from 2009 indicated that Hydro One spent less in eight categories and more in five categories than the CEA average, and that its system reliability ratings were better than the CEA average. The annual benchmarking study was discontinued by the CEA's board of directors because it was concerned that the data was being used by provincial regulators to set transmission rates.

Figure 5: Transmission System Costs, 2010–2014

Source of data: Hydro One

Cost	2010 ($ million)	2011 ($ million)	2012 ($ million)	2013 ($ million)	2014 ($ million)	% Change Between 2010 and 2014
Transmission operating, maintenance and administrative	421	415	415	388	400	–5
Transmission capital sustainment	356	333	389	480	621	74
Total	**777**	**748**	**804**	**868**	**1,021**	
Overall percentage increase						**31**

We compared Hydro One's 2014 costs with the 2009 costs for the same 13 types of costs, and noted that its costs have increased in 12 categories, ranging from 2% to 82% over the period. The only cost type that decreased was in spending on OM&A, by 15%, which is a concern due to the number of assets it has in use that were beyond their expected service life (see **Figure 4**).

In its recent rate applications to the OEB, Hydro One included a study by a consultant it hired that compared Hydro One's staff compensation levels (i.e., salary, incentives and benefits) to those of other regulated transmission and distribution utilities in North America. In the 2013 study, Hydro One's staff compensation levels were found to be 10% higher than the median of other utilities. This was an improvement from the 2008 and 2011 studies, which showed Hydro One's compensation being 17% and 13% higher, respectively.

The OEB has recognized the need for comparison of Hydro One's costs with other similar transmitters. As part of the OEB's January 2015 decision to award Hydro One a transmission system rate increase for 2015-16, Hydro One agreed to complete an independent transmission cost benchmarking comparison study, and to provide it to the OEB in spring 2016 as part of its next rate application for 2017-2018. The study is to "provide a high level set of benchmarks and comparisons of Total Cost (defined as Capital and OM&A) and Business Performance (generally defined as service delivery effectiveness and efficiency) for Hydro One among North American peer organizations."

RECOMMENDATION 7

To ensure that its maintenance expenditures on the transmission system are cost-effective, and activities produce more timely improvements to the reliability of the transmission system, Hydro One should conduct:

- an assessment of its past maintenance expenditures and activities to determine what changes and improvements can be made to more effectively focus its efforts on the critical factors that improve system reliability and how its planned maintenance and capital improvements work can be completed with less risk of service disruption;
- benchmark cost assessments with other similar North American transmitters to compare its results with those that have reasonable expenditures and that maintain reliability; and
- a study of other leading cost-effective transmitters and consider implementing their best practices to quickly improve Hydro One's reliability and improve its costs.

HYDRO ONE RESPONSE

Hydro One will conduct an assessment of its past maintenance expenditures and activities, with a focus on critical factors and contributors to the transmission reliability measure.

Consistent with a recent Ontario Energy Board decision, Hydro One is undertaking a total cost benchmarking review for transmission.

4.1.8 Weak Security over Electronic Devices Increases the Risk of Unauthorized Use

We found that the security Hydro One has in place for most of the electronic devices on its transmission system is weak. The devices include the electronic controls for transformers, circuit breakers and reclosure equipment, as well as the controls for physical security and access to stations. Effective security is key to preventing sabotage, vandalism, software viruses, and unauthorized or unintentional changes to device software or controls, all of which can disrupt service or cause power outages that could impact hundreds to possible millions of customers, shut down businesses, government services, and transportation and communications networks. As well, if protection equipment is disabled, a system component could become overloaded and damaged or destroyed.

Hydro One manages security risk by adhering to Hydro One policies, one of which uses standards required by the North American Electricity Reliability Corporation (NERC) for critical IT assets. However, NERC's mandate is to ensure the reliability of the North American bulk electricity system, which includes transmission system assets of any of the continent's utilities that could have an impact on other jurisdictions' electrical systems. Assets at facilities are identified as critical for NERC purposes by the Independent Electricity System Operator. For instance, a major power outage on the bulk electricity system occurred on August 14, 2003, when a transmitter in one U.S. state caused cascading blackouts that affected 55 million people in seven other U.S. states and in Ontario. Most of Hydro One's transmission system has no impact on other jurisdictions, so many components of its system, particularly most transmission stations, do not fall under NERC's jurisdiction, and Hydro One therefore does not have to manage the security risks in a way that is compliant with NERC standards. We found that Hydro One's security standards for all other assets are less rigorous than NERC's even though damaged or modified equipment at stations not covered by NERC could still result in power outages to major industrial customers and small or large communities in Ontario, disrupting the economy and putting individuals at risk.

Only Hydro One's Ontario Grid Control Centre (Control Centre) and 53 (18%) of its 299 transmission stations fall under NERC's jurisdiction and therefore must meet NERC standards. The remaining 246 transmission stations do not impact other jurisdictions' electrical systems and do not have to meet NERC standards. As well, since NERC standards apply only to devices classified as critical to the operation of the bulk electricity system, only 35% of the devices at the Control Centre and 17% of the devices at the 53 relevant transmission stations must comply with NERC standards.

NERC maintains strict standards for restricting user access to devices and changes to software, assessing security vulnerabilities and implementing device back-up and recovery procedures. NERC also requires annual testing to certify that the standards are being met. Hydro One's security policies have less rigorous requirements for most electronic devices of the transmission system that would not be covered by NERC, but are still vital to Ontario's electrical grid. There was also no requirement for the Hydro One security policies to be tested periodically to ensure compliance. For example:

- Even though NERC standards and Hydro One's own policies for authentication require complex passwords and periodic changing of passwords, we noted that passwords for most devices at transmission stations considered non-critical by NERC came from a limited number of standard terms that were shared and known by most field staff. Passwords were not periodically changed to limit access to current authorized users. This severely reduces the effectiveness of passwords as an access control and increases the risk of these devices being accessed by unauthorized people.
- Hydro One does not conduct regular security risk assessments, as required for NERC covered devices, to determine how vulnerable its other transmission system devices are to security breaches and what kind of service disruptions could occur as a result. Without conducting assessments, Hydro One does not know the extent of the security risk posed by these devices. Hydro One does not know how many devices have not had a security assessment.
- Changes, whether authorized or unauthorized, to the settings on devices are not monitored at all stations not covered by NERC. Changes to settings could result in the devices not functioning properly or their security being compromised, and any changes should be recorded in either manual or system audit logs and the logs periodically reviewed to ensure changes correspond to authorized work orders.
- Only 34% of computers at transmission stations had virus protection installed, which could result in a disruption of operations or even a power failure. Hydro One informed us

that it could recall only one instance of a virus found on a computer at a transmission station, and that the stations' other computers either do not support virus protection or it had not been installed for fear it would affect the operation of the computers. However, Hydro One could not provide any security assessments that had been conducted for each type of electronic device to validate whether anti-virus software was or was not needed, and whether the devices were still vulnerable.

RECOMMENDATION 8

To ensure a robust and high level of security for the transmission system to mitigate the risk of service disruptions due to sabotage, vandalism, software viruses, and unauthorized or unintentional changes to device software or controls, Hydro One should develop a comprehensive security framework to cover all its electronic devices. The framework should include best practices for security over electronic devices, including establishing standards similar to those set by the North American Electricity Reliability Corporation, performing security vulnerability risk assessments on all electronic devices, establishing appropriate actions and controls to mitigate security risks to an acceptable level, and conducting regular audits to validate that the security framework has been adhered to.

HYDRO ONE RESPONSE

Hydro One acknowledges that a comprehensive security framework for electronic devices will help to mitigate security risks to the system. Hydro One is developing, and has already implemented certain aspects of, a new comprehensive security program that will apply to all electronic devices.

The North American Electricity Reliability Corporation (NERC) sets standards to protect the most critical grid components against likely threats, including man-made or natural phenomena.

Hydro One is in compliance with current and applicable NERC standards.

Security hardening is part of Hydro One's engineering standard for all deployed devices, all of which are currently being converted to the standard as dictated by their life-cycle replacement.

4.2 Distribution System

4.2.1 Poor Distribution-system Reliability Has Not Improved

From 2010 to 2014, Hydro One has been among the worst-performing large Canadian electricity distributors. Hydro One's average duration of outages and average frequency of outages (referred to in the industry as SAIDI and SAIFI, respectively) have remained in the fourth quartile (worst performing), according to the Canadian Electricity Association's (CEA) composite data. The average duration of outages and average frequency of outages of other utilities were 59% and 30% better, respectively, than Hydro One's over the same period.

As shown in **Figure 6**, Hydro One's distribution system reliability did not improve from 2010 to 2014. The total number of power outages on the distribution system increased by 11% over the period, from 27,360 in 2010 to 30,260 in 2014. Outages increased primarily due to equipment failures.

In 2014, the Ontario Energy Board (OEB) published a distributor scorecard for each local distribution company (LDC) in Ontario, which contained, among other things, various 2013 metrics for reliability and cost. Hydro One's average duration of outages and average frequency of outages for its distribution system were ranked worst and second-worst respectively among the 72 LDCs assessed.

Hydro One's website says that "the fewer people who live in [an] area, the more it takes to bring reliable energy and the higher the cost." Hydro One is primarily a distributor for rural communities,

Figure 6: Hydro One Distribution System Outages, 2010–2014

Source of data: Hydro One

	2010	2011	2012	2013	2014	% Increase Between 2010 and 2014
SAIDI (minutes per customer)	426	411	420	408	444	4
SAIFI (outages per customer)	2.6	2.6	2.6	2.5	2.7	4
Unplanned outages	21,757	22,825	23,221	21,037	24,095	11
Planned outages[1]	5,603	5,621	6,160	5,820	6,165	10
Total outages[2]	**27,360**	**28,446**	**29,381**	**26,857**	**30,260**	**11**

1. Hydro One must plan outages to do preventive maintenance or capital project work. Since most of the distribution system is single circuit, no alternative line is available to serve customers while this work is being done, and there is an outage until the work is completed.
2. Total outages do not include outages that Hydro One could not control that impacted more than 10% of its customers (for example, distribution system outages that resulted from outages on the transmission system or *force majeure* events such as storms). When these discounted outages *are* included, the % increases between 2010 and 2014 (the rightmost column in this figure) are as follows: SAIDI outage minutes per delivery point increased by 4% (from 542 minutes in 2010 to 564 minutes in 2014); SAIFI outages per delivery point increased by 2% (from 2.94 outages in 2010 to 3.0 outages in 2014); and total outages increased by 10% (from 30,181 in 2010 to 33,201 in 2014).

which is different from most other distributors, which typically service larger urban and surrounding areas. In Ontario, Hydro One has an average of 11 customers for each kilometre of distribution line, whereas other LDCs range from 6 to 81 customers, with the average for the four largest LDCs in Ontario being 51. The rural nature of Hydro One's customer base makes it more expensive to add additional distribution lines for individual customers, something that would improve the reliability of the system. As well, due to the longer distances involved, it takes Hydro One longer to respond to customer outages than it does LDCs operating in urban settings.

According to Hydro One, a customer survey in 2013 indicated that on average 83% were satisfied with the reliability of their electricity provider for the price they were paying. Only a few customers indicated they would be willing to pay more for better reliability. As a result of this survey, Hydro One said in its distribution system rate application for 2015-2019 to the OEB that it planned to maintain reliability for its customers at existing levels. It said it would not be cost effective to improve its reliability ratings compared to other utilities and its customers would not want to pay the cost associated with the improvements. In its decision, the OEB stated it "considers Hydro One's stance on its performance to be misplaced. Rather than argue that it would be too expensive to move up the ladder in comparison to those that are in the first, second and third quartile, Hydro One should be finding cost effective ways to improve its performance and provide evidence intended to convince the OEB that it has identified more appropriate benchmarks to which it can and will compare itself for continuous improvement tracking purposes."

RECOMMENDATION 9

In order to improve the reliability ratings for its distribution system, Hydro One should:

- establish more ambitious performance goals, targets and benchmarks for system performance; and
- develop short- and long-term strategies for new and enhanced activities and cost-effective investments that will improve its overall reliability record.

HYDRO ONE RESPONSE

Hydro One has now set multi-year reliability targets. The 2015 Corporate Scorecard included both 2015 and 2019 targets to signal the

Company's drive to continuous improvement. Further, for its distribution business Hydro One will continue to report its scorecard performance results annually to the Ontario Energy Board, as per its requirement.

Hydro One's strategies to improve distribution reliability include:

- increasing programs for line renewal and distribution station renewal;
- moving the location of rebuilt lines from off-road line sections to road allowances to improve access and facilitate fault-finding;
- enabling control room visibility and controllability of many devices, which will allow for faster restoration as the Company renews line-switching devices and distribution stations; and
- prioritizing vegetation management programs to focus on reliability to large commercial/industrial customers.

These initiatives are being incorporated into Hydro One's ongoing programs as this is the most cost-effective means of implementing them.

4.2.2 Vegetation-management Cycle Too Long, Reduces System Reliability

Hydro One's Has a 9.5-year Cycle for Clearing Vegetation Compared to 3.8 Years for Other Utilities

Hydro One's cycle for clearing vegetation (forestry) under, around and above distribution lines is more than twice as long as that of comparable utilities. Because trees are not trimmed back as often, Hydro One experiences more outages caused by fallen trees or tree limbs. We noted that line breaks caused by trees were the main cause of distribution outages from 2010 to 2014, responsible for 31% of all outages.

Hydro One's goal is, by 2023, to maintain an eight-year vegetation-management cycle for its distribution system, meaning it will complete vegetation management on all lines within eight years. Hydro One established this goal after a 2009 consultant's report found that the average vegetation-management cycle for 14 similar utilities was 3.8 years. In 2015, SaskPower, B.C. Hydro and Hydro-Québec had distribution system vegetation-management cycles ranging from two to five years. As of July 2015, we noted, Hydro One is operating on a 9.5-year vegetation-management cycle—over double the length of the cycles in use by similar utilities. Even its long-term goal to achieve an eight-year cycle is still double that of the average of other utilities.

At the time of our audit, Hydro One was focused on reducing the backlog of distribution lines that had not been cleared of vegetation in more than eight years. As time goes by, it takes longer to clear those lines because of the overgrowth over many years. From 2010 to 2014, Hydro One's spending on vegetation management increased by about 14%, from $161 million to $183 million. Over this same period, the number of tree-related outages on Hydro One's distribution system grew by 5%, from 7,747 in 2010 to 8,129 in 2014.

Hydro One Has Not Adopted a Shorter Vegetation-management Cycle, Even Though It Would Reduce Costs

Hydro One's own analysis has shown that a longer vegetation-management cycle is more costly and results in more power outages than a shorter one. Using this analysis, we estimate that if it had a four-year cycle, similar to those of comparable utilities, it would have been able to do its 2014 clearing work for $99 million, or $84 million less (a 46% reduction in accordance with their analysis) than the $183 million it actually spent, because there would have been less growth to clear. Hydro One's analysis also showed that a four-year cycle would reduce the duration of tree-caused outages by 30%, which would have decreased Hydro One's 2014 average duration of outages by 36 minutes (from 444 minutes on average per customer to 408 minutes).

In addition, we noted that the OEB has pointed out to Hydro One that its vegetation-management costs are too high. As a result, the OEB decided to reduce the amount Hydro One can spend on vegetation management for the 2015-2017 period by $39 million. The OEB expected Hydro One to find cost efficiencies to keep to its goal of an eight-year vegetation-management cycle.

Improper Prioritization of Vegetation-management Work Resulted in More Outages Caused by Trees

Hydro One could do a better job prioritizing the distribution lines that require vegetation management, and directing forestry staff (381 full time equivalent positions in 2014) on which lines to clear each year. By doing so, it could reduce the number of power outages caused by trees.

To determine which distribution lines need to be cleared of vegetation each year, Hydro One uses a ranking system that considers four factors: the frequency and duration of tree-caused outages on the line, the number of years since the line was last cleared, the number of unresolved tree-related problems reported on the line by Hydro One employees, and the number of unresolved tree-related problems reported by customers.

Hydro One's own analysis shows that the number of outages caused by trees on a distribution line is reduced by over 45% in the three years after vegetation is cleared; however, outages increase by 4% each year after that until vegetation is cleared again on that line. This indicates that to effectively reduce the number of such outages experienced by customers, Hydro One should prioritize its vegetation-management work on the distribution lines that have experienced the most outages caused by trees. However, we found that Hydro One's Asset Management group, which decides on the distribution lines that local forestry work crews will perform vegetation management on each year, gives the lowest weighting (15%) to the data on tree-related outages in scheduling lines.

This rating system has led to examples where vegetation was cleared on lines that had had fewer tree-caused outages than others in the same region. For example, forestry staff in northern Ontario were directed to clear vegetation on three lines in 2014. The line that was cleared first had had no tree-related outages in the previous three years, and the line cleared second had had four such outages in that time. Work on the third line, which had had 11 tree-related outages in the previous three years, started in September 2014 and was only a little bit more than half done by December of that year, and that line experienced tree-related outages in October 2014 and January 2015.

RECOMMENDATION 10

To lower costs and ensure Hydro One's vegetation-management program is effectively reducing the number of tree-related outages experienced by its distribution system customers, Hydro One should:

- shorten its current 9.5-year vegetation-management cycle to a more cost-effective cycle of less than four years, in line with other similar local distribution companies; and
- change the way it prioritizes lines that need clearing so that lines with more frequent tree-related outages are given higher priority and work crews are dispatched sooner.

HYDRO ONE RESPONSE

Hydro One has plans to shorten its current 9.5-year vegetation-management cycle. Hydro One's strategy to keep costs affordable to the ratepayer, while getting feeders to an eight-year cycle over the longer term, is appropriate and reasonable. The increased initial short-term cost of moving to a four-year forestry cycle is not consistent with Hydro One's strategy to keep rates affordable.

The Company will continue to review its vegetation-management program and improve its prioritization model to support decision-making.

4.2.3 Information on Condition of Key Distribution System Assets Not Reliable

Incomplete and unreliable data leads to poor asset-replacement decisions. We found that, as with the transmission system, the Asset Analytics information system could not be relied on for decision-making relating to key distribution system assets. For instance:

- data for evaluating the 152 distribution station circuit breakers is limited, and there are no ratings on the condition of these breakers. When older circuit breakers are in need of replacement, Hydro One exchanges them with new reclosure equipment, costing $114,000 each. We also found there was no data on the age of more than half the 2,235 pieces of reclosure equipment already installed at distribution stations;
- fourteen distribution station transformers that were less than 10 years old, with a replacement cost of $650,000 each, were mistakenly assigned age scores of 100, which would be past their 40-year expected service life; and
- data such as information on performance, use or age was missing for all 51 mobile transformer units, which have replacement costs of $2 million each.

RECOMMENDATION 11

To ensure that management decisions on replacing distribution system assets are made using reliable and complete information, Hydro One should take the actions needed to ensure its Asset Analytics system provides timely, reliable, accurate and complete information on the condition of assets.

HYDRO ONE RESPONSE

Hydro One acknowledges that Asset Analytics data and algorithms continue to be developed and improved. The Assets Analytics tool continues to be enhanced to address recognized data gaps and process deficiencies.

As noted earlier, a project is under way to address data improvement in the tool. Its functionality will also be reviewed in 2016 to identify improvement opportunities.

4.2.4 Distribution Assets in Service Beyond Their Expected Life Increases the Risk of Power Outages

Hydro One increases the risk of power failures by not replacing distribution system assets that have exceeded their planned useful service life. In addition, it sets the planned useful life for assets longer than other comparable LDCs. For example, we noted the following:

Wood Poles

Fallen poles and those at risk of falling often create a public safety hazard that requires emergency action to replace the pole. Hydro One has approximately 1.6 million wood poles in its territory, and 202,000, or 13%, of those poles have exceeded their expected life of 62 years. From 2010 to 2014, there were 47 outages caused by fallen wood poles. The cost to replace the 202,000 poles would be about $1.76 billion. Moreover, other LDCs use an expected service life of only 44 years for wood poles; Hydro One has 413,000 poles, or 26%, that are from 45 to 62 years old, that would cost an additional $3.59 billion to replace.

Hydro One assesses the condition of each pole every six years and bases its replacement strategy on the age and condition of the poles. As of June 2015, approximately 61,000 wooden poles were rated as being in poor or very poor condition, and therefore as having the highest probability of failure. Only about 12,000 poles are replaced each year, much less than are needed to address the risk of poles that fall or that are in service beyond their expected service life.

Station Transformers

The distribution system includes 1,214 station transformers with a replacement value of $650,000 each. Hydro One sets a 50-year expected service life for these transformers, and 243 units, or 20%, were in service beyond their expected service life. The cost to replace the 243 transformers would be $158 million. Furthermore, we noted that other LDCs use 45 years as the expected service life. Hydro One has another 157 station transformers, or 13%, that are from 46 to 50 years old and would cost $102 million to replace.

RECOMMENDATION 12

To reduce the risk of equipment failures that can cause power outages on the distribution system, Hydro One should:

- replace assets that have exceeded their planned useful service life; and
- reassess its planned expected service life for assets and justify any variances in the years used by Hydro One compared to other similar local distribution companies.

HYDRO ONE RESPONSE

Hydro One acknowledges that assets beyond their service life have a greater risk of failure. However, Hydro One considers a number of factors when making decisions on pole replacements, including pole condition and expected service life. The Company's aim is to maximize the life expectancy of an asset and optimize work efficiency in order to derive the most value from its investments and to manage costs that are borne by customers.

Hydro One has a pole replacement program that considers a service life based on its experience and the operations, maintenance and conditions under which the asset is used.

The Company's experience is that our expected service life for various assets is appropriate given the operations, maintenance and conditions under which they are used. Hydro One does not replace assets that, while old, are in good working condition.

4.2.5 Increased Spending on Distribution System Did Not Result in Improved Reliability

Hydro One's increased spending on capital sustainment and operations, maintenance and administration (OM&A) from 2010 to 2014 for its distribution system did not result in improved system reliability.

Figure 7 shows the changes in spending on OM&A and capital sustainment from 2010 to 2014. Because spending in these two areas relates to operating the system and repairing and replacing equipment, it should have the biggest impact on the reliability of the system. Hydro One spent about 9% more on capital sustainment in 2014 than it did in 2010 ($314 million in 2010 compared to $343 million in 2014) as well as 22% more in OM&A ($551 million in 2010 compared to $675 million in 2014). While Hydro One's 18% overall increase

Figure 7: Distribution System Costs, 2010–2014

Source of data: Hydro One

Cost	2010 ($ million)	2011 ($ million)	2012 ($ million)	2013 ($ million)	2014 ($ million)	% Change Between 2010 and 2014
Distribution operating, maintenance and administrative	551	554	553	611	675	22
Distribution capital sustainment	314	274	262	323	343	9
Total	**865**	**828**	**815**	**934**	**1,018**	
Overall percentage increase						**18**

in spending in these two areas from 2010 to 2014 would have been expected to improve system reliability, especially as the repair or replacement of old system equipment should result in fewer equipment failures, outages actually increased by 11% over the same period (see **Figure 6**).

As mentioned earlier, Hydro One's OM&A and capital sustainment costs are higher than other similar utilities partly as a result of staff compensation that is 10% higher, according to a 2013 study. As well, because its business is in largely rural areas, Hydro One has little control over certain other costs. For example, Hydro One needs more assets per customer than do large urban LDCs, which increases overall costs. It has about one customer per wood pole on its distribution system, compared to a range of up to nine customers per pole for other LDCs in Ontario. Nevertheless, we compared Hydro One's 2014 costs, reliability, and the rates that its customers pay with the eight other rural LDCs in Ontario that have fewer than 20 customers per kilometre of line and found that Hydro One:

- had the third-highest operating costs per customer; and
- was the second-worst in reliability; while
- residential customers paid the second-highest rates.

In 2010 (the last year that comparative cost information was collected for the distribution system), the Canadian Electricity Association found that Hydro One had higher costs than the average of its members from 2006 to 2010. As well, in 2014, the OEB gave Hydro One its lowest cost-efficiency ranking among distributors. Hydro One's actual costs were more than 25% higher than what the OEB expected, indicating that Hydro One should be able to find cost efficiencies to perform the same amount of work it currently does at a lower overall cost.

RECOMMENDATION 13

To ensure that its capital sustainment and maintenance expenditures on the distribution system are cost effective and produce more immediate improvements to the reliability of the distribution system, Hydro One should:

- conduct an assessment of its past maintenance expenditures and activities to determine how to focus efforts on more critical factors that affect the system; and
- benchmark cost assessments with other similar local distribution companies (LDCs) in Ontario and Canada, and consider implementing the best practices of the leading cost-effective LDCs.

HYDRO ONE RESPONSE

Hydro One will conduct an assessment of its past maintenance expenditures and activities, with a focus on critical factors and contributors to the distribution reliability measure. Hydro One continues to prudently manage its distribution investments to address targeted improvements in reliability over the long term. This approach also allows the Company to manage rate increases for its customers by balancing reliability investments with rate increases.

Hydro One is undertaking several benchmarking studies, as directed by the Ontario Energy Board (OEB), to support its approaches to investment, maintenance and sustainment activities.

In addition, and at the direction of the OEB, the Company will also undertake a third-party review of its distribution system plan that will provide unit cost validation for forestry, pole replacement and station refurbishment.

4.2.6 Smart Meter Capabilities Not Used to Improve Response to Power Outages

By 2014, Hydro One had installed 1.2 million smart meters on its distribution system based on direction from the provincial government. The total cost of the installation was $660 million. We noted that Hydro One uses the smart meters predominantly to provide electronic information remotely for billing purposes, and has not turned on the feature that enables a smart meter to let it know whether a customer's power is on or off. Hydro One relies on customers calling to report that they do not have power, and this information is often neither timely, complete, nor accurate. If it received the information from smart meters, Hydro One's field crews would be better able to pinpoint the location and area of an outage, rather than having to patrol the entire distribution line. Better information would save money by eliminating inefficient or unnecessary work crew dispatches, and service to customers would be restored sooner.

During our audit, Hydro One was conducting a pilot project to assess using the information from smart meters to identify customers with power outages, although it had not established a timetable for completing the project or using smart meters this way for all its customers.

Hydro One has improved its communications with customers on outages by providing real-time updates on its website and through its mobile app. However, the information on outages is still limited to what the utility finds out from customer calls and then from periodic updates from work crews. Information from smart meters would provide more timely and accurate information on where power has or has not been restored.

RECOMMENDATION 14

To lower its repair costs and improve customer service relating to power outages through more accurate and timely dispatches of its repair crews, Hydro One should develop a plan and timetable for using its existing smart meter capability to pinpoint the location of customers with power outages.

HYDRO ONE RESPONSE

In recognition of the opportunity to leverage some of the additional capabilities of its smart meters for storm response, the Company initiated a pilot project two years ago that has been testing smart meter functionality to validate customer-reported outages. This functionality was used in 25,000 instances, allowing the Company to avoid more than 5,800 crew dispatches.

Further validation of pilot results may allow the Company to make a supportable investment case for integration with the Company's outage management system.

4.3 Spare Transformers in Storage Not Aligned with Hydro One's Needs

Hydro One keeps a number of spare transformers in case it needs to quickly replace any of the 1,900 it has in service. However, the number of spares it keeps in storage is excessive and this costs it more than necessary to maintain spares.

From 2010 to 2014, the failure rate of transformers was only 10 per year, or 0.5% failure rate, but Hydro One maintains 200 spare transformers—140 for the distribution system and 60 for the transmission system—valued at $80 million at its Pickering Central Maintenance Shop. This works out to be almost an 11% ratio of spares to in-service transformers. Transformers in storage also require maintenance with an annual cost of $2.3 million.

Over the same period, Hydro One increased its inventory by purchasing 20 new spare transformers per year, or double the number it needed to replenish its spares inventory. As well, it mostly used the newer transformers in storage to replace ones that failed, leaving older ones in storage. By August 2015, there were 96 transformers in storage that were no longer covered by the manufacturers' five-year warranty, including 35 that had been in storage for at least 10 years.

Hydro One told us it has to stock spare transformers because it takes on average 210 days to order and receive replacement distribution system transformers from suppliers, and 320 days for larger transmission system transformers. However, if it maintained a lower number of spare transformers, it could reduce costs and still respond to transformer failures in a timely manner.

Hydro One uses a model to help forecast the number of transformers to keep in storage. The model considers asset type, past failure rate, age and number of transformers in service, and delivery time for replacements from suppliers. However, Hydro One does not apply the model to the vast majority of types of distribution system transformers—45 of the 60—it uses, nor to two of the 16 types of transmission system transformers. As well, Hydro One has not followed the model to determine the number of spares to stock, even for those types to which it applies the model. For instance, the model showed it needed to stock 28 spares for the types of transmission system transformers for which it uses the model, but Hydro One stocks 44. Similarly, Hydro One stocks 84 instead of the 43 distribution system transformers recommended for the types for which it uses the model.

Following our inquiries, Hydro One senior management acknowledged it could reduce the number of spare transformers it has on hand by 69, or 35%, and save $20 million over the next 10 years based on current net book value of these assets. However, senior management said Hydro One could only achieve the reductions if it were to standardize the transformers in service to reduce the number of different types. For instance, since 2009, it has reduced the number of types of transformers it uses on its transmission system from 30 to 16, with plans to further reduce that to 14 types. Hydro One said this standardization had already saved $50 million to $60 million in procurement costs since 2009, or 15%, through volume discounts from vendors. However, we noted that no similar plans were in place for standardizing distribution system transformers, so we estimate that another $25 million in procurement savings over 10 years could be forgone if no changes are made to standardize distribution system transformers.

Given its inventory levels and the relatively low failure rate of transformers, we estimate that Hydro One requires only 120 spare transformers in total. By not buying more spare transformers than it needs over the next 10 years, Hydro One would save $50 million to $70 million in purchase costs for transformers, as well as $1 million annually in maintenance costs. This is in addition to the $25 million savings possible over the next 10 years we noted above from standardizing distribution system transformers.

RECOMMENDATION 15

To reduce its excess inventory of spare transmission and distribution system transformers to an appropriate cost-effective level, and to lower costs while still being able to replace failed transformers in a timely manner, Hydro One should:

- improve the forecasting model it uses for predicting transformer failures, and maintain its inventory levels of spare transformers in accordance with the forecasts; and
- develop a plan to standardize in-service transformers as much as possible, and set targets and timelines for achieving savings from better managing both spare and in-service transformers.

HYDRO ONE RESPONSE

Hydro One agrees that improving forecasting of requirements and standardizing its transformer fleet will allow for a future reduction in transformer inventories. Standardization of distribution transformers and the associated reduction to the spares inventory will occur over time as end-of-life transformers are replaced with standardized units.

The Company is leveraging its current strategy for its transmission transformers to develop and implement a comparable strategy for its distribution transformers.

Hydro One expects that this initiative will include improvements to the forecasting model it uses to predict transformer failures.

4.4 Data from Power Quality Meters Not Used to Help Customers Avoid Disruptions

Hydro One could be monitoring and analyzing power quality events—episodes when voltage levels fluctuate—on its transmission and distribution networks to proactively improve service to its large industrial customers, but it instead waits until customers complain before it takes any action. Major transmission customers, especially automotive and petrochemical businesses that receive power directly from the transmission network, expressed concern about their power quality in a 2014 Hydro One customer satisfaction survey. Fluctuations in voltage levels can disrupt the operation of customers' production equipment or a utility's distribution system. This concern had been expressed in previous surveys.

Hydro One's large industrial customers have suffered production losses as a result of power quality events. For example, two large customers that are on the same distribution line in eastern Ontario complained publicly about their local power supply being unreliable. One plant claimed to have lost $1.2 million in profits since it opened in 2009 because of power quality issues that interrupted plant production. In March 2015, the customer reported five power quality events and a nearby customer reported six.

Hydro One has received 150 power quality complaints from its 90 major industrial customers on its transmission system since 2009. At the time of our audit, Hydro One had figured out what caused the events—including lightning strikes and defective equipment—in all but 13 of the cases. Some complaints were two years old and were still being investigated.

For the distribution system, Hydro One does not formally track or monitor the number of power quality complaints it receives from its large industrial customers on its distribution system. However, it told us it knew of five such customers that had complained about power quality in 2013 and 2014.

To locate, record, analyze and help resolve power quality events, Hydro One needs power quality meters across its distribution and transmission systems. Since 2010, Hydro One has installed 138 of these—at a cost of $8.2 million—in places where problems were occurring, albeit covering only a small area of their systems.

Even with the meters installed, Hydro One is only responding to specific customer complaints, rather than periodically or in real time analyzing the data from the meters and taking immediate action.

As an example, an industrial transmission customer in the forestry sector was experiencing repeated power quality problems that caused production to be interrupted. Hydro One started investigating only after the customer complained. Data from the nearby power meter helped demonstrate that lightning was causing the disruptions and that Hydro One needed to improve the grounding of a nearby power supply line. It also inspected a transmission line nearby and found that two transmission towers had surge arrestors that failed. Hydro One retrofitted the towers with new surge arrestors, which minimized the impact of lightning on the customer's power supply. If Hydro One had proactively analyzed its power quality meter in the area, it could have used the information to help find and correct this issue before the customer complained, thus providing the customer with a more reliable power supply.

RECOMMENDATION 16

To minimize the number and impact of power quality events for its large customers, Hydro One should proactively use the data collected by its power meters to help assess the frequency and location of power quality events on its transmission and distribution systems and thereby improve the reliability of the power supply.

HYDRO ONE RESPONSE

The Company agrees that power quality (PQ) incidents are of concern to some of its large transmission and distribution customers.

The Company is implementing initiatives to address large customer PQ issues more proactively by providing PQ information to customers; and working with the information to estimate the frequency, duration, and magnitude of potential events that could have an adverse effect on its equipment and processes.

4.5 Weak Management Oversight Processes over Capital Project Costs

4.5.1 No Comparison of Project Costs to Industry Standards

Hydro One has not assessed whether what it pays for capital construction projects is reasonable or competitive with industry standards. Hydro One manages its own projects and uses its own staff for most of its construction work, but it has never compared the cost of its projects to what it would pay if its contracts were offered to external bidders.

Hydro One spent $1.05 billion, $1.12 billion and $1.20 billion in 2012, 2013 and 2014, respectively, on transmission and distribution capital construction projects, including replacing or building new transformer stations, and installing switching and circuit breaker equipment, lines and cabling, and steel towers and wood poles. We found individual project estimates included internal charges ranging from 40% to 55% of total approved costs, as Hydro One's own employees filled many roles in the projects, including engineering, construction, project management and project commissioning. The remaining costs were generally paid to external vendors for supplies, materials and equipment procured through a competitive bidding process. Generally, entire projects from design to construction have not been tendered out, although Hydro One had plans during our audit to start doing this for certain projects. As a result, it is hard to assess the reasonableness of Hydro One's project costs because so much of the cost is internal.

In addition, we found that all estimates used for approval of capital construction projects included large contingency and escalation charge allowances, over and above the original project cost estimates. These allowances significantly increased the projects' approved cost before construction. The allowances were included to fund additional costs, either internal or external, that could be incurred by the project. Contingency charges added 10% to 30%, or 20% on average, to the original project cost estimate, and escalation charges added on average 8%, based on 3% to 5% per year of construction. For two transmission capital projects, for example, contingency and escalation charges added more than $4 million to each project's original project cost estimate, or more than 19% and 28%, respectively.

The large allowances minimized any incentive for staff to complete a project at its original project cost estimate. We noted that a similar large utility in Alberta, which says it follows industry practices, includes contingencies of only 8% to 12% of project costs in its capital construction project budgets.

Following discussions during our audit, Hydro One told us that, effective June 2015, the escalation charge for all items in cost estimates would be 2.5% per year, and that this new rate is consistent with the one used by B.C. Hydro, Manitoba Hydro and Hydro-Québec.

A consultant's report commissioned by the Ontario government to review Hydro One's operations in 2014 recommended the use of industry benchmarks to improve the accuracy of the utility's cost estimates for capital projects and to challenge project delivery teams to decrease project implementation costs. Using benchmarks also increases the transparency of cost estimates. Hydro One told us that in 2015 it aimed to deliver capital work projects for 2.5% to 4% less than the previous year, through a tighter estimating process.

4.5.2 Management Does Not Compare Actual Project Costs and In-service Dates with Original Estimate to Determine If Projects Are Completed On-time and within Budget

We found that the reports that senior management received about the progress of capital projects did not include enough detail about costs and timelines to allow them to effectively assess how well a project was being managed. For instance, these reports included either the most recently approved or final budgets and project completion dates, rather than using the figures from the original approvals, so that projects typically appeared as having been done on budget and on time. The project management reporting system was not designed to compare original cost estimates and completion dates with the final costs and dates, something that would provide senior management with more accurate information on how projects were managed from start to finish. Instead, monitoring by senior management was limited only to ensuring that projects were completed within the budgets approved.

Hydro One management told us that reviewing individual project files to see whether capital projects were delivered in accordance with the original project approvals and completion dates would take too much time. We asked them to prepare us a report that compared the original project approval, including allowances, with the actual project cost for each project completed for the years 2013 to 2015, in order to determine the extent to which large allowances, on average at 28%, were used up. The report we received in June 2015 was incomplete, and only included 61 of the 105 projects approved for over $1 million. The incomplete report showed these 61 projects were approved for a total of $1.027 billion and cost $963 million to complete, indicating that on average, projects used up an allowance of 22% more than the original project cost estimate, or an estimated $150 million more in total.

4.5.3 Actual Project Costs Exceeding Initial Approved Budget

Despite the fact that capital project budgets already included an average 20% contingency charge allowance and 8% escalation charge allowance, we found several completed projects with cost overruns. **Figure 8** shows three such projects.

Figure 8: Capital Construction Projects with Large Cost Overruns
Source of data: Hydro One

Project	Date Project Approved	Original Approved Budget ($ million)	Date Project Completed	Project's Actual Cost ($ million)	Amount by Which Project Over Budget ($ million)	% by Which Project Over Budget	Primary Reasons for Costs Over Budget
Replace circuit breakers of transmission system at Toronto south transformer station	July 2011	6.7	June 2014	9.1	2.4	36	Project magnitude was underestimated and key tasks omitted in original estimate.
Replace circuit breakers of transmission system at Toronto east transformer station	April 2011	19.0	November 2014	31.2	12.2	64	Estimate was based on another similar project without a proper assessment of the requirements for this project.
Construct a new relay room and replace equipment at Toronto south transformer station	December 2010	8.6	December 2014	13.3	4.7	55	Certain engineering, materials and construction labour costs were omitted in the original estimate.

We reviewed projects that had undergone changes to their scope and cost projections and noted common causes that included:

- the complexity and magnitude of the work was significantly underestimated at the planning stages, resulting in increased cost and delays to the project's completion date;
- in-depth site visits were either not conducted or were insufficient for understanding the magnitude of the project and the complexity of the work required; and
- unit costs used in the estimation process were not current.

We noted that another project, ongoing at the time of our audit with a projected completion date of December 31, 2015, had an original cost estimate of $55.1 million that was released in June 2013 with the understanding that there were certain risk factors that could increase project costs. In October 2014, Hydro One revised the cost estimate to $90.3 million, requiring a variance approval of just over $35 million. The original cost estimate assumed that only eight kilometres of road had to be built, but the revised project included construction of 55 kilometres of road and three bridges, as well as increasing the height of 35 existing steel towers. Because there had been insufficient site visits before the budgeting process began, the original estimate failed to account for the number of kilometres of roads to be built through extremely difficult terrain, and hence, the full scope of the project.

RECOMMENDATION 17

To ensure that management can better manage and monitor capital projects that use its own workforce, as well as lower project costs, Hydro One should:

- use industry benchmarks to assess the reasonableness of capital construction project costs, and whether using internal services and work crews is more economical that contracting out capital projects;
- use and adhere to contingency and escalation allowances that are more in line with industry norms for capital construction projects;
- improve its management reporting and oversight of project costs by regularly producing reports that show actual project costs and actual completion dates compared to original project cost estimates, cost allowances used, original approved costs, subsequent approvals for cost increases, and planned completion dates; and
- regularly analyze its success in preparing project estimates by comparing them with final project costs.

HYDRO ONE RESPONSE

The Company has taken steps to improve its estimating process by increasing the amount of pre-engineering work to provide more accurate project estimates.

Further, Hydro One has implemented a project closure process for larger projects to ensure work is completed as planned, project estimates are compared against actuals, all variances are explained and learnings are incorporated into future projects.

Hydro One provided Auditor General staff with access to all reports available but did not have a report that existed in the format requested. Hydro One is updating its standard reporting to include originally approved budget and in-service dates.

Hydro One is also reviewing the allowances used in project estimates. Given the complexity in this area, Hydro One is committed to continuing to find improvements in its processes.

Appendix—Glossary of Terms

Prepared by the Office of the Auditor General of Ontario

Asset Analytics—An information system implemented by Hydro One in 2012 that contains data on its transmission and distribution assets (including their age, criticality and performance) and assists Hydro One in ranking the relative condition of assets when making decisions on replacing them.

bulk electricity system—The portion of an electricity provider's transmission system that transfers electricity above 100,000 volts that can have a direct or indirect impact on other jurisdictions' electrical systems.

Canadian Electricity Association (CEA)—A national body made up of Canadian electricity generators, transmitters and distributors that allow members to share operational best practices and system reliability data.

circuit breaker—Equipment used in the transmission and distribution system designed to automatically interrupt power when there is an overload, which is when more power is flowing through the circuit than the circuit is designed to handle.

delivery point—Used in the transmission system to refer to a point of connection between a transmission station and a transmission customer's facilities. This can be single-circuit (only one line connecting a transmission station to a customer) or multi-circuit (multiple redundant lines).

distributor/Local Distribution Company (LDC)—Local utility that purchases electricity from Hydro One or another transmitter and distributes electricity on its own distribution network at voltages below 50,000 volts to residential or industrial customers in their area.

Independent Electricity System Operator (IESO)—Administrator of the Ontario wholesale electricity market to match electricity supply with demand. Also responsible for forecasting Ontario's long- and short-term electricity requirements and providing direction to electricity transmitters and distributors over capital work needed to increase the capacity of Ontario's electricity system.

Ministry of Energy—The Ministry of Energy is responsible for setting the legislative and policy framework to assure a clean, reliable and affordable energy system for all Ontarians. It develops and advises on all aspects of energy policy for Ontario, including policies for electricity, natural gas and oil. It oversees the Ontario Energy Board (OEB) and the Independent Electricity System Operator (IESO), and represents the shareholder—the provincial government—in dealings with Hydro One and Ontario Power Generation (OPG).

North American Electricity Reliability Corporation (NERC)—A not-for-profit regulatory authority whose mission is to assure the reliability of North America's bulk electricity system. NERC develops and enforces reliability standards that must be followed by North American electricity transmitters, including Hydro One.

Ontario Energy Board (OEB)—The regulator of electricity in Ontario, OEB's objective is to promote a viable, sustainable and efficient energy sector that serves the public interest and assists consumers in obtaining reliable energy services at a reasonable cost. It licenses electrical generators, transmitters and distributors, which must follow established codes to remain licensed. It also approves the rates that electrical utilities can charge their customers, as well as the construction of any electrical transmission lines that are more than two kilometres long.

Ontario Grid Control Centre (OGCC)—Hydro One's around-the-clock central control centre, which remotely monitors and operates transmission equipment, responds to alarms caused by equipment failures and can restore, divert and interrupt power transmission. The OGCC also reviews, approves and authorizes all planned outages, and co-ordinates response activities for unplanned outages on the transmission system. The OGCC receives calls from the public and dispatches work crews to respond to distribution power outages.

power generators—Power generators are companies that produce electricity and feed electricity into the Ontario electricity grid. Ontario Power Generation (OPG), a Crown corporation, is Ontario's largest power generator, operating electricity-producing stations throughout Ontario. Over the North American bulk electricity system, electricity can also be received from out-of-province power generators.

rate application—Made by all transmitters or distributors to the Ontario Energy Board to obtain approval for funding by way of the rates it charges its customers to operate and expand the electrical system. OEB's approval of the revenue required by the transmitter or distributor sets part of the electricity rate paid by electricity consumers.

reclosure equipment—A somewhat more complex form of circuit breaker, which protects electrical transmission systems from temporary voltage surges and other unfavorable conditions. In addition to preventing electrical overloads from passing through a circuit, reclosures can automatically "reclose" the circuit and restore normal power transmission once the problem is cleared.

Smart Meter—An electronic device that records consumption of electricity in intervals of an hour or less and communicates that information back to the utility for billing and monitoring. This allows for time-of-use pricing to encourage customers to shift their electricity use to times of lower demand.
System Average Interruption Duration Index (SAIDI)—A measure of reliability that uses the average length of outages experienced by customers or delivery points on an electrical system.
System Average Interruption Frequency Index (SAIFI)—A measure of reliability that uses the average frequency of outages experienced by customers or delivery points on an electrical system.
transformer—A device used to change the voltage level of electric current. Transformers can either step up (increase) or step down (decrease) voltage. Hydro One mostly uses step-down transformers to convert high voltage levels to lower voltage levels for consumer usage.
transmitter—An electrical utility, such as Hydro One, that transfers electricity over long distances at voltages above 100,000 volts between electricity generators (such as Ontario Power Generation) and LDCs or large industrial users.
vegetation-management cycle—The number of years it takes to perform tree-cutting and bush-clearing around the entire electrical system.
volts or voltage—In simple terms, electricity is measured and expressed in volts. The voltage between two points is the force that drives electrical current between those points. Electricity at higher voltages travels long distances more efficiently. Electricity voltage is stepped down when it has to travel shorter distances and for practical use by end users, such as LDCs or industrial or residential customers. The current is measured in amperage or amps, and represents the amount of electricity available for usage or the amount used. The voltage times the amperage equals the amount of watts of electricity used. Ontario's power usage is commonly measured in kilowatt/hours (1,000 watts per hour) and megawatt/hours (1 million watts per hour).