



September 22, 2017

Mr. Mark Lanigan  
Island Regulatory and Appeals Commission  
PO Box 577  
Charlottetown PE C1A 7L1

Dear Mr. Lanigan:

**2018 Capital Budget Filing Docket UE20726  
Response to Interrogatories from the Government of PEI**

Please find attached the Company's response to the Interrogatories filed by the Government of PEI with respect to the 2018 Capital Budget filing. An electronic copy will follow.

Yours truly,

MARITIME ELECTRIC

A handwritten signature in blue ink, appearing to read "Enrique Riveroll".

Enrique Riveroll  
Manager, Regulatory & Financial Planning

ER06  
Enclosure

September 22, 2017

Ms. Kim Horrelt  
Director, Energy and Minerals Division  
PEI Dept. of Transportation, Infrastructure and Energy  
PO Box 2000  
Charlottetown PE C1A 7N8

Dear Ms. Horrelt:

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ER05  
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**1. Section 4.0 – Generation**

- **Given that the new submarine cables between PEI and NB are now operational; can long term layup of the CTGS be expedited? If so, would this achieve any cost savings?**

**Response:**

1. The new submarine cables were commissioned and placed into service in July 2017. The Company believes it is prudent to retain the Charlottetown Thermal Generating Station (“CTGS”) as an available capacity resource for a period of time as a precaution to ensure the interconnection facilities operate as designed.

The new submarine cables do not supply any system capacity requirements. However, the CTGS provides back-up capacity under the existing Energy Purchase Agreement (“EPA”), which means its capacity has value and serves to meet the utility’s system capacity requirements. The annual value of the avoided capacity and operating reserve purchases supplied by the CTGS is in excess of \$4 million, based on the current EPA with NB Power that is in effect until February 28, 2019. If the decommissioning of the CTGS was expedited, the existing EPA with NB Power would have to be amended so that CTGS capacity could be purchased on the market. In addition, the most recent depreciation study filed with IRAC and the resulting depreciation rates approved by the Commission contemplate the availability of the facility until 2021.

The Company will be filing a Decommissioning Plan with the Commission in June 2018 which will outline how the CTGS assets will be retired through a staged approach. Maritime Electric will seek approval of this Plan from the Commission. Over the period of the CTGS decommissioning, operating costs will be managed and reduced to achieve cost minimization.

**2. Section 4.3a – Upgrade CT3 Turbine Controls**

- **Is there or will there be a regular schedule of CT3 turbine control updates to prevent obsolesce in the future?**

**Response:**

2. Maritime Electric monitors development in the evolution of the GE LM6000 combustion turbine (CT3) by attending user conferences and communicating with the Original Equipment Manufacturer on enhancements of the unit. At this time, there is no regular schedule for CT3 turbine control enhancements as these updates are driven by technology improvements.

**3. Section 5.2 – Distribution Transformers**

- **Please break down the \$2,989,000 budget into the following categories:**
  - **New customers**
  - **Load growth for existing customers**
  - **Replacements of deteriorated or damaged units**

**Response:**

3. Maritime Electric’s Customer Information System does not distinguish between a new customer and a customer that upgraded their service due to load growth. Table 1 categorizes the breakdown of the transformer budget for new customers, load growth, replacement due to deterioration or damage. On average, Maritime Electric installs 1,500 polemount transformers and 35 padmount transformers per year due to new service installations, deterioration and damage during storms and vehicle accidents. Included in the budget is the replacement of 4 translosures with padmount transformers to align with today’s standards and 200 polemount transformers as part of the Spill Prevention Program.

<b>Table 1: Budget Breakdown for Distribution Transformers</b>		
a.	New customers and load growth	\$1,800,000
b.	Replacements due deterioration/damage	\$1,189,000
	<b>Total</b>	<b>\$2,989,000</b>

**4. Section 5.6a – Bridge Meter Pilot Project**

- **If AMI technology is the most current, then why not pilot AMI meters as opposed to “half-measure” bridge meters? Is a pilot project necessary? Is there not enough experience in the industry with regard to integrating more advanced metering?**

**Response:**

4. Bridge meters are not “half-measure” meters, but rather are dual purpose meters capable of operating as part of a Radio Integrated (“RI”) system with the existing ‘drive-by’ meter reading system the Company currently uses and as also part of Advanced Metering Infrastructure (“AMI”) system.

The purpose of the pilot project is to investigate the capability and functionality of Bridge meters. The outcome of the pilot project may result in the purchase of Bridge meters in future capital budgets. The 2014 Auditor General of Ontario’s report on Smart Metering Initiative (Appendix A) in that Province describes the downside of aggressively adopting AMI Technology. The audit found that Smart Metering was aggressively rolled out without sufficient planning and monitoring. Without properly assessing these meters through a pilot project to fully understand the costs involved in their implementation, an economically justifiable business case cannot be developed. After this assessment is completed, any Bridge meters installed as part of the pilot project would not need to be replaced with AMI meters.

**5. Section 5.6b – Watt-hour Meters**

- **If AMI technology is the most current, then why continue to invest in RF meters (i.e. “old technology”) for new service installations, replacements, etc.)?**
- **Would the use of AMI technology affect the budget for system equipment? If so, how?**

**Response:**

5. As discussed in the response to question # 4, the Company does not currently have an economically justifiable business case to convert to Advanced Metering Infrastructure (“AMI”) technology. If the Company were to convert to AMI meters for new service installations and replacements, this would require investing in the required two-way communication infrastructure and a Meter Data Management System (“MDMS”) for the high volume of interval data that would be required.

The use of Bridge meters may be a prudent approach for the future transition to AMI technology for the following reasons:

- They are capable of working with the Company’s existing ‘drive-by’ meter reading system.
- They do not require AMI communication infrastructure or MDMS.
- They are also AMI capable and would not need to be replaced should the Company convert to AMI in the future.

It is not expected that adopting AMI technology will affect the system equipment budget (section 5.7a). This budget is for the replacement of aged equipment used to provide voltage support, communications, and protection and control of the Company’s transmission and distribution assets. Communication infrastructure for AMI technology would most likely be budgeted under System Meters (section 5.6).

**6. Section 7.0 – Corporate**

- **The 2018 corporate capital budget is more than double the amount spent in previous years. Why has there been such a large increase? Is this increase an anomaly or is it expected to represent the norm into the future?**

**Response:**

6. The Corporate Services budget provides for the investment in the Company's main facilities to ensure they meet health, safety and environmental standards. Historically, capital expenditures in these facilities have been between \$100,000 and \$300,000; however, in 2016 a multi-year upgrade plan for the West Royalty Service Centre was developed to address safety and environmental concerns and to ensure the facility continues to effectively operate as the Company's main Operations facility. These concerns were prioritized accordingly with the higher priority items comprising the basis of the Corporate Services section of the 2018 Capital budget Application (section 7.1). It is not expected that similar levels of budget expenditures for facility upgrades will regularly occur in the future; however, the Company believes that it is prudent to continue to upgrade its facilities to meet today's safety and environmental standards, which may result in specific upgrade projects above historical spending from time to time.

**7. Section 7.1b – West Royalty Service Centre Upgrade Plan**

- **The breakdown provided in Table 5 presents Contractor Services and Contingency together as one line item. How much of the budget is allocated to Contingency only?**

**Response:**

7. In Table 5 (West Royalty Service Centre Upgrades Plan – 2018), \$76,000 of the total \$209,300 estimated for contractor services and contingency has been allocated to contingency only.

**8. Section 7.2a – Hardware Acquisitions**

- **How many personal computers are planned for replacement under the \$57,000 budget and what proportion of MECL’s total number of computers does that represent? How often are personal computers replaced?**

**Response:**

8. The category of personal computers under section 7.2a includes both computers and tablets. There are approximately 220 computers and tablets deployed throughout the Company. The budget provides for the purchase of approximately 40 - 50 personal computers and tablets required due to failure, lack of performance or for new employees. The Company does not have a formal computer replacement program; however, the Company uses the Average Service Life Methodology as accepted under Canadian Accounting Standards for Private Enterprises to calculate depreciation on various classes of assets. The current amortization rate used by the Company in the 2014 Depreciation Study performed by Gannett Fleming for personal computers is 20%, which implies a five year cycle.

**9. Section 7.2d – Meter Reading System**

- **Will the new meter reading system be compatible with not only the current RF meters but more technologically advanced meters (e.g. bridge and AMI meters)? If not, how long is the new system expected to be in place before it becomes obsolete and needs to be replaced?**

**Response:**

9. The meter reading system upgrade planned for 2018 is a necessary upgrade to the existing ‘drive-by’ meter reading technology that the Company currently uses to read Radio Integrated (RI) meters. This ‘drive-by’ meter reading system upgrade will have the capability to read both RI meters and Bridge meters. Bridge meters are capable of operating as part of a ‘drive-by’ meter reading system or an Advanced Metering Infrastructure (AMI) system. If the Company were to deploy a complete AMI system in the future, the ‘drive-by’ meter reading system would eventually be replaced with the necessary communication infrastructure to allow for near real-time and two-way communications to the AMI capable meters.

**10. Section 7.2e – Turbine Maintenance Software**

- **Why is an evaluation of the turbine maintenance software required? Are there issues with the current system?**

**Response:**

10. The Company currently uses a vendor supplied product, Maximo, for generating plant maintenance. This software has been used for over 15 years to track the maintenance and operation of plant assets. The Maximo software is due to be upgraded and with the future decommissioning of the Charlottetown Thermal Generating Station, it is considered prudent to evaluate other possible solutions that may be a better fit going forward to track maintenance and operation of the remaining generation assets, namely the combustion turbines.

**11. Section 7.2f – Customer Self Service**

- **What savings in annual Call Centre expenses are expected to be realized from the \$150,000 investment in customer self-service options?**

**Response:**

11. The benefits of the project can be more appropriately characterized as customer service improvements as opposed to cost savings. The Company is planning to modernize and fully integrate online self-serve options for customers in response to evolving customer expectations and improvements in digital technology. The Company's corporate website is currently being redesigned to be a more modern and omni-platform website that is customer-focused. The Company's internal research indicates strong support for improvement of customer service related web-based technologies. Sixty five percent of Maritime Electric customers, mostly within the ages of 18 to 44, support the use of web-based technology.

The Company expects to achieve outcomes such as improvements in customer service, online services, and storm outage management and response. Reductions in the existing manual processes and improved efficiency for Customer Service Representatives will allow for an increased focus on other value-added customer interactions such as email and social media while maintaining quality service for the traditional customer, who continue to value phone and personal service.

**12. Section 8.0 – Capitalized General Expense**

- **What is the overhead capitalization rate applied by MECL? What is the rationale for this particular rate? How does it compare to the rate used by other electric utilities in Canada?**

**Response:**

12. The Company does not apply an overhead capitalization rate in preparation of its capital plan. The proposed 2018 budget for General Expense Capital (“GEC”) of \$527,000 represents purchasing and inventory management costs that are not specific to any one project but are incurred in support of the overall capital plan. Such costs include internal labour costs as well as the associated equipment and supplies costs required by the related employees in the performance of their duties.

Although GEC is a widely used and generally accepted utility industry accounting practice, the methodology used and amounts capitalized are subject to regulatory approval and vary significantly by jurisdiction. Therefore meaningful comparative information with other utilities in Canada is not available.

**13. Section 9.0 – Interest During Construction**

- **What proportion of the 2018 capital budget is expected to be financed through debt vs. equity?**

**Response:**

13. The Company expects to finance up to 60% of the proposed 2018 capital budget through debt and the remaining 40% through equity in accordance with Electric Power Act Section 12.1 which states:

“Maritime Electric Company, Limited shall, as determined in accordance with generally accepted accounting principles,

(a) maintain at all times not less than 35 per cent of its capital invested in the power system in the form of common equity; and

(b) ensure that, for the year, not more than 40 per cent of its capital is invested in the power system in the form of common equity.”

**14. Other**

- **Please provide MECL's 2016 Capital Budget Variance Report.**
- **Does MECL perform multi-year integrated resource planning? If yes, please provide copies of relevant documents. If no, why not?**

**Response:**

14. A copy of the 2016 Capital Budget Variance Report, as filed with the Commission on February 28, 2017, is attached hereto as Appendix B.

MECL developed an Integrated System Plan in advance of filing the 2018 Capital Budget. It provides a roadmap for future capital expenditures in the areas of generation, transmission and distribution. The plan will be updated periodically based on system conditions and changing technologies. The Integrated System Plan will be filed with the Commission in the near future.

**APPENDIX A**

**Response to Interrogatory 4**

## Chapter 3

Ministry of Energy

### Section 3.11

# Smart Metering Initiative

## Background

In April 2004, the Ontario government announced a plan to reduce energy consumption in the province by creating a culture of conservation. One aspect of the plan was the provincial Smart Metering Initiative (Smart Metering)—the first and the largest smart-meter deployment in Canada—to install new “smart” electricity meters throughout the province to measure both how much and when electricity is used. The new meters would make it possible to introduce time-of-use (TOU) pricing to encourage ratepayers to shift their electricity use to times of lower demand. Smart Metering reflected the intention of the Ministry of Energy (Ministry) to manage demand for electricity in Ontario so as to more efficiently use existing power-generating capacity in the province while reducing reliance on out-of-province power purchases.

The Ministry set aggressive Smart Metering implementation targets, including an interim goal of 800,000 smart-meter installations by 2007 and complete coverage for all residential and small-business ratepayers by 2010. Entities involved in Smart Metering included the Ministry, the Independent Electricity System Operator (IESO), the Ontario Energy Board (OEB) and Ontario’s 73 local electricity distribution companies, including Hydro One.

Key roles and responsibilities of each entity are summarized in **Figure 1**, while **Figure 2** shows key events in implementation of Smart Metering.

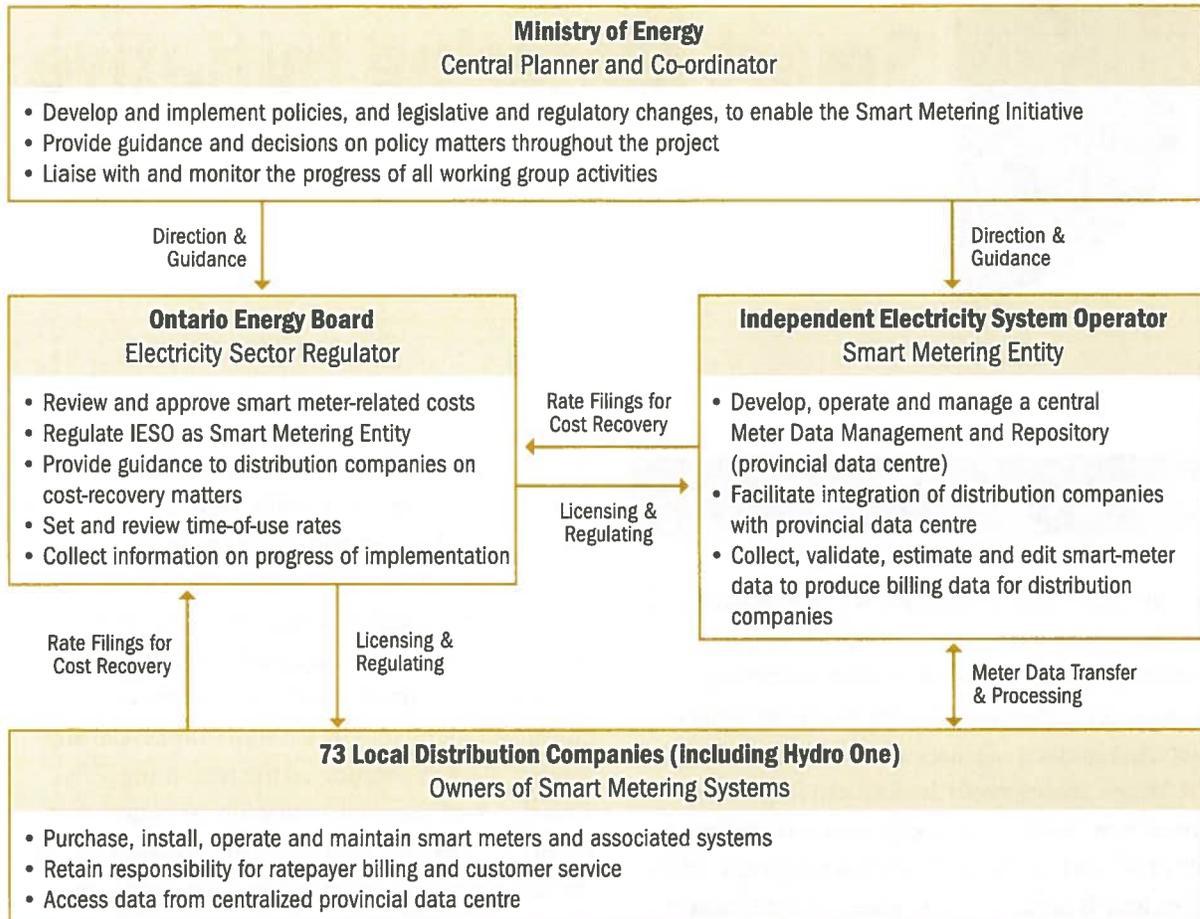
As of May 2014, there were about 4.8 million smart meters installed across Ontario, covering almost all residential and small-business ratepayers, and accounting for 45% of all electricity consumed in the province (large commercial and industrial users account for the remaining 55%). Smart meters resemble conventional meters, but differ with respect to how consumption data is displayed, measured, recorded and communicated, as illustrated in **Figure 3**.

Smart meters are the base infrastructure for developing a smart grid, which is the application of information and communications technology to improve the functioning of the electricity system and optimize the use of natural resources to provide electricity. In the *Electricity Act, 1998*, the smart grid and its objectives are set out as the information-exchange systems and equipment used together to improve the flexibility, security, reliability, efficiency and safety of the power system, particularly for the purposes of increasing renewable generation; expanding provision of price information to electricity customers; and enabling innovative energy-saving technologies.

Under TOU pricing, electricity rates charged are highest during the day, but drop at night, on

**Figure 1: Key Roles and Responsibilities of Entities Involved in the Provincial Smart Metering Initiative**

Prepared by the Office of the Auditor General of Ontario



weekends and holidays. The combination of smart meters and TOU pricing was expected to encourage electricity conservation and reduce demand during peak times by providing ratepayers with information and incentives to manage their electricity use by:

- moving consumption from peak to off-peak times (for example, running the dishwasher or dryer at night rather than in the afternoon); and
- reducing consumption during peak times (for example, setting the air conditioner a few degrees warmer on summer afternoons).

The Ministry set several targets to reduce peak electricity demand: a 1,350MW reduction by 2007; a further 1,350MW drop by 2010; and an additional 3,600MW reduction by 2025. The

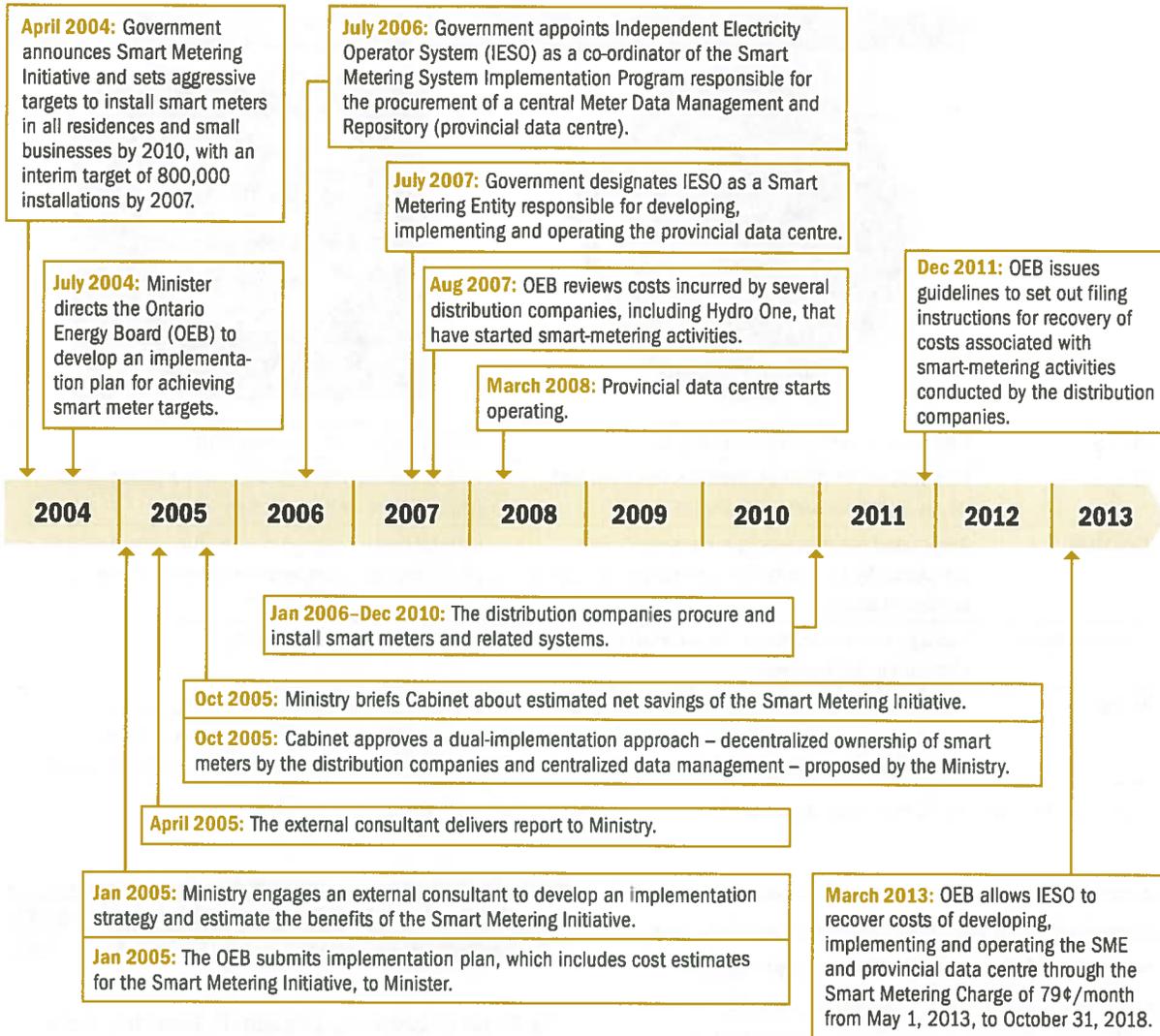
potential reduction in peak demand was intended to lighten the burden on electricity infrastructure, which in turn could reduce the need to build new power plants, expand existing ones, or enter into additional power-purchase agreements. It was also expected to help bring about the closing of coal-fired power plants, which were typically only used during periods of peak demand.

## Audit Objective and Scope

Our audit objective was to assess whether effective systems and procedures were in place to:

**Figure 2: Timeline of Key Events Relating to Implementation of the Provincial Smart Metering Initiative**

Prepared by the Office of the Auditor General of Ontario



- ensure that the Smart Metering Initiative (Smart Metering) was planned, implemented and managed economically and efficiently, and in compliance with applicable policies and requirements; and
- measure and report on whether the objectives of Smart Metering were met in a cost-effective way.

Senior management at the Ministry of Energy (Ministry), the Independent Electricity System Operator (IESO) and the Ontario Energy Board (OEB) reviewed and agreed to our objective and

associated audit criteria. We conducted this audit from October 2013 to May 2014.

In conducting our audit, we reviewed applicable legislation, regulations, policies, studies and other documents; analyzed electricity consumption and billing data; and interviewed appropriate staff at the Ministry, the IESO and the OEB. We surveyed 60 of Ontario's 73 distribution companies, with a response rate of over 70%, and interviewed staff from the remaining 13 distribution companies, including Hydro One, the only distribution company owned by the province. **Appendix 1** contains the

Figure 3: Comparison of Smart Meter and Conventional Meter

Prepared by the Office of the Auditor General of Ontario

	Smart Meter	Conventional Meter
		
Display	Digital meter with numerical display	Analog meter with spinning dials
Measure	How much and when electricity is used (typically hourly with date and time stamp)	How much electricity is used over a billing period (typically one or two months)
Recording	Automated meter reading: meters send data electronically to distribution companies through a wireless network*	Manual meter reading: distribution company staff physically visit ratepayer premises to record data
Communication	Two-way communication between meters and distribution companies*	No communication capability
Pricing	Time-of-use pricing (a three-tiered rate structure: on-peak, mid-peak, and off-peak) to reflect changing electricity costs throughout the day	Two-tiered pricing, with one rate applied to consumption up to a threshold and a second rate for electricity consumed in excess of this threshold

\* See Figure 11 for data flow between the distribution company's smart-metering system and the IESO's provincial data centre.

questions posed to the distribution companies we interviewed and surveyed, and summarizes their responses. We also reviewed data and studies from the Ontario Power Authority, which has been involved in co-ordinating and assessing province-wide energy conservation efforts, including time-of-use (TOU) pricing enabled by smart meters. As well, we met with the Electricity Distributors Association, which represents all distribution companies across the province. In addition, we conducted research on smart-metering programs in other jurisdictions to identify best practices, and we engaged on an advisory basis the services of an independent expert with knowledge of smart metering.

## Summary

The Ontario government's Smart Metering Initiative (Smart Metering) is a large and complex project that required the involvement of the Ministry of Energy (Ministry), the Ontario Energy Board (OEB), the Independent Electricity System Operator (IESO), and 73 distribution companies, including Hydro One. Our audit found that Smart Metering was rolled out with aggressive targets and tight timelines, without sufficient planning and monitoring by the Ministry, which had the ultimate responsibility to ensure that effective governance and project-management structures were in place to oversee planning and implementation. As yet, many of the anticipated benefits of Smart Metering

have not been achieved and its implementation has been much more costly than projected.

Our report highlights the difficulties that have been experienced in rolling out Smart Metering, which represents an initial step towards creating a smart grid—using information and communications technology to improve the functioning of the electricity system and optimize the use of natural resources to provide electricity. We hope that lessons learned from implementing smart meters can be applied to the government’s ongoing efforts to develop a smart grid in Ontario.

Some of our key observations related to Smart Metering are as follows:

#### **Decision to Mandate Smart Metering Not Supported by Appropriate Cost-benefit Study**

The government announced Smart Metering in April 2004, and shortly thereafter the Minister of Energy issued a directive to the OEB under the *Ontario Energy Board Act, 1998*. The directive required the OEB to develop an implementation plan to achieve the government’s targets of 800,000 smart-meter installations by 2007 and complete coverage for all residential and small-business ratepayers by 2010. The Ministry did not complete any cost-benefit analysis or business case prior to making the decision to mandate the installation of smart meters. This is in contrast to other jurisdictions, including British Columbia, Germany, Britain and Australia, which all assessed the cost-effectiveness and feasibility of their smart-metering programs. As well, even though the electricity market in Ontario continued to change, the Ministry never adjusted the smart-meter implementation plan.

#### **Subsequent Cost-benefit Study Flawed**

After the government announced the rollout of Smart Metering in April 2004, the Ministry prepared a cost-benefit analysis of Smart Metering, and submitted it to Cabinet in October 2005. However, the analysis was flawed; its projected net benefits of approximately \$600 million over 15 years were significantly overstated by at least \$512 million because it excluded an annual net

increase in the projected operating costs of distribution companies. In other words, the projected net benefits should have been reflected as only \$88 million over 15 years.

#### **Smart Metering Costs to Date Exceed Projected Costs and Benefits**

The Ministry has neither updated the projected costs and benefits of Smart Metering, nor tracked its actual costs and benefits, to determine the actual net benefits being realized. Up to the end of 2013, our analysis shows that total smart metering-related costs incurred only by the distribution companies had already reached \$1.4 billion—well in excess of the Ministry’s initial total projected costs of \$1 billion. When costs of the Ministry, the OEB and the IESO are included, we noted that total costs relating to implementation of Smart Metering had reached almost \$2 billion at the time of our audit. Additional costs are expected in the future because some distribution companies had not yet incorporated all of their implementation costs into their charges to ratepayers (these additional costs will be subject to OEB review and approval). As well, the benefits of Smart Metering in reducing distribution companies’ operating costs and reducing electricity bills to ratepayers were so far limited: Of the distribution companies we consulted, 95% said they realized no savings and their operating costs actually rose, and over half said they received a high volume of ratepayer complaints about “increased bills with no savings.”

#### **Significant Smart Metering System Development and Integration Challenges Encountered**

In other jurisdictions, mass deployment of smart meters was carried out by only a few distribution companies, or even just one. The challenge in Ontario was that 73 distribution companies were each separately responsible to purchase, install, operate and maintain smart meters, as well as to bill ratepayers. This made it difficult to ensure a cost-effective implementation of Smart Metering. Three-quarters of the distribution companies we consulted ranked data management and system

integration as one of the top three challenges of Smart Metering, and 83% said it was difficult and costly to integrate their systems with the provincial data centre. There have been many system upgrades, including changes made in order for Ontario to comply with Measurement Canada's billing disclosure requirements after smart meters were installed.

#### **Peak-demand Reduction Targets Not Met**

The purpose of Smart Metering was to enable time-of-use (TOU) pricing, which was expected to reduce electricity demand during peak periods. The Ministry set several targets to reduce peak electricity demand (a 1,350MW reduction by 2007, a further 1,350MW drop by 2010, and an additional 3,600MW reduction by 2025). However, the initial target of reducing peak demand by 1,350MW was irrelevant to Smart Metering anyway because it was supposed to be achieved by 2007, three years before full installation of smart meters was to be completed. With respect to the second target of an additional 1,350MW reduction by 2010, peak electricity demand did not fall, but actually rose slightly by about 100MW between 2004 and 2010.

#### **Ontario's Surplus Power Exported to Other Jurisdictions at Less than Cost**

The reduction of electricity demand during peak times was intended to delay the need to expand power-generating capacity in Ontario, along with the related costs. In the decade since the Ontario government announced Smart Metering, peak demand has remained essentially unchanged, but the Ministry has approved significant increases in new power generation, such as renewable energy, creating power surpluses in Ontario. The overall financial impact has been that other jurisdictions are able to buy this surplus power from Ontario at a price considerably lower than what it actually cost Ontario to produce this power. The total cost of producing the exported power was about \$2.6 billion more than the revenue Ontario received from exporting that power between 2006 and 2013.

#### **Electricity Billing Amounts Varied by Distribution Company**

Ratepayers pay different amounts for the same power usage depending on where they live in Ontario, mainly due to different delivery costs of the 73 distribution companies. For example, a typical residential electricity bill could vary anywhere between \$108 and \$196 a month, mainly due to the variation in delivery costs ranging from \$25 to \$111 a month charged by different distribution companies to ratepayers. Implementation of Smart Metering significantly impacted the costs for each of the distribution companies, which chose different smart meters and IT solutions for their in-house systems. The cost per meter therefore varied with each distribution company, ranging from \$81 per meter to \$544 per meter, depending mainly on geography and the amount of upfront costs. For example, Hydro One, the only distribution company owned by the province, incurred significant costs to implement its smart-metering project. By the end of 2013, Hydro One accounted for \$660 million, or almost 50%, of the \$1.4-billion implementation costs incurred by all 73 distribution companies. However, it installed 1.2 million smart meters, which represented only about 25% of the 4.8 million smart meters installed in Ontario.

Of the \$660 million spent by Hydro One, more than \$125 million went to a private-sector vendor with whom it signed multiple contracts for services, such as system integration and project management, and approved a number of change orders. Hydro One selected this vendor based on several criteria, including price. However, pricing evaluation was not based on the overall contract cost. Hydro One explained the contract cost could not be fixed due to the "unknown nature of all the business requirements at the time of the Request for Proposal (RFP)." Granting a contract through the RFP process without acquiring enough knowledge about the business requirements would lead to risks of significant cost increases due to change orders.

### Time-of-use (TOU) Pricing Model Has Had Minor Impact on Reducing Peak Demand

Smart Metering was undertaken to enable the introduction of time-of-use (TOU) rates to encourage people to shift power use to Off-Peak periods. However, TOU rates and periods may not be designed effectively to reduce peak demand as intended. Specifically:

- The difference between the On-Peak and Off-Peak rates has not been significant enough to encourage a change in consumption patterns. When TOU rates were introduced in 2006, the On-Peak rate was three times higher than Off-Peak; by the time of our audit, that differential had fallen to 1.8 times, due to significant increases in the Global Adjustment, another component of electricity bills in Ontario. In particular, the Off-Peak rate increased the most, by 114%, while On-Peak increased the least, by 29%. As a result, the difference between On-Peak and Off-Peak rates has narrowed, thus undermining TOU pricing as an incentive for ratepayers to shift power use to Off-Peak periods.
- The distribution of On-Peak, Mid-Peak and Off-Peak periods does not fully reflect actual patterns of electricity demand. In particular, in response to amendments to Ontario Regulation 95/05, the OEB moved the start of Off-Peak in 2010 from 9 p.m. to 7 p.m. on weeknights, making the early evening hours of 7 p.m. to 9 p.m. Off-Peak, even though demand at those times is high.

In 2013, separate studies released by the Ontario Power Authority and the OEB indicated that TOU pricing had a modest impact on residential ratepayers, reducing their peak demand by only about 3%, but a limited or unclear effect on small businesses, and none at all on energy conservation. Our review also found that:

- Of about 1.8 million ratepayers on TOU rates that we reviewed, only 35% of residential ratepayers and 19% of small businesses reduced their consumption during On-Peak periods,

while a majority of them (65% of residential and 81% of small businesses) did not.

- About 77,000 ratepayers with smart meters paid set rather than TOU rates because they signed fixed-price contracts with electricity retailers, who do not charge based on time of use. Consumption patterns of retail and TOU ratepayers were about the same, suggesting that TOU pricing provided no more incentive to change usage behaviour than retail contracts.

### Significant Impact of Global Adjustment on TOU Rates Not Transparent to Ratepayers

The Electricity Charge on ratepayer electricity bills is composed of two parts: the electricity market price and the Global Adjustment, added to the market price mainly to cover the guaranteed prices paid to contracted power generators in Ontario. From 2006 to 2013, the Global Adjustment increased almost 1,200%, while the average market price actually dropped 46%. The impact of the Global Adjustment has been significant on ratepayer electricity bills as follows:

- The total Global Adjustment paid by Ontario ratepayers has grown from \$654 million in 2006 to \$7.7 billion in 2013. More contracted generators, especially producers of higher-priced renewable power, will soon be coming online, so the total Global Adjustment is expected to increase even more. Between 2006 and 2015, the 10-year cumulative actual and projected Global Adjustment stands at about \$50 billion, equivalent to almost five times the 2014 provincial deficit of \$10.5 billion. In essence, the \$50 billion is an extra payment covered by ratepayers over and above the actual market price of electricity.
- The vast majority of residential and small-business ratepayers pay for electricity based on the three TOU rates—Off-Peak, Mid-Peak and On-Peak—which were seen as critical in encouraging ratepayers to shift power use to times of lower demand. The Global Adjustment now accounts for about 70% of each of

the three TOU rates. While the Global Adjustment has increased significantly and accounts for a substantial proportion of TOU rates, its impact is not transparent to ratepayers because it is embedded in TOU rates and does not appear as a separate line on most electricity bills (the Global Adjustment appears separately only on bills of those ratepayers who have signed contracts with electricity retailers, who do not offer TOU rates).

#### **Ratepayer Complaints Stemmed from Time-of-use (TOU) Rates and Billing Errors**

Many distribution companies did not track or log the nature or type of complaints they received. They were therefore unable to quantify the volume of complaints they received before and after smart-meter implementation; nor could they separate smart meter-related concerns from billing-system issues. Without proper tracking and monitoring of ratepayer concerns, key information could not be collated to identify and resolve common or recurring problems on a timely basis. Those distribution companies that did track complaints found that most ratepayers were upset about TOU pricing, which they believed resulted in higher electricity bills than previously. Our work at Hydro One also noted complaints from ratepayers about estimated bills or no bills for extended periods due to Hydro One's billing-system problems and connectivity issues between smart meters and associated communication systems; and about bills based on errors arising from smart meters connected to incorrect addresses.

#### **Duplication of Services by Provincial Data Centre and Local Distribution Companies' In-house Systems**

Under Smart Metering, the IESO is recovering the cost of its \$249-million provincial data centre, called the Meter Data Management and Repository (provincial data centre), from all residential and small-business ratepayers through a Smart Metering Charge of 79¢ per month that began in May 2013 and was set to end in October 2018. These costs were not included in the initial cost

projection of \$1 billion made by the OEB for implementing Smart Metering.

Of the 4.8 million smart meters installed across the province, approximately 812,000 have not transmitted any data to the provincial data centre for processing. Although these ratepayers have never benefited from the provincial data centre, they still have to pay the monthly Smart Metering Charge of 79¢, totalling about \$42.1 million up to October 2018.

The IESO has exclusive authority to develop and operate a provincial data centre in which to process smart-meter data for the province. However, the goal of operating the provincial data centre as a central system to ensure standard and cost-effective data processing has not been met because most distribution companies have used their own systems to process smart-meter data (before transmitting it to, or after receiving it from, the provincial data centre) for billing purposes. The provincial data centre was not available when some distribution companies started to roll out smart meters. Of the distribution companies we consulted, 88% indicated that the provincial data centre and their own systems have similar functions, resulting in redundancy. The costs of this duplication—one system at the provincial level and another locally—are passed on to ratepayers. The monthly operating cost for the local systems is, on average, about 21¢ per meter, which is being borne by ratepayers on top of the 79¢-a-month Smart Metering Charge.

#### **Limitations of Provincial Data Centre and Distribution Companies in Processing Smart-Meter Data**

Several limitations in processing smart-meter data by the provincial data centre and the business processes at the distribution companies have affected the quality and usefulness of smart-meter data, which in turn can affect billings to ratepayers. These limitations were associated with situations such as meter replacements and power blackouts. Also, half the distribution companies we consulted indicated that the provincial data centre has limited capabilities for data retrieval and querying. In

August 2013, the IESO reported to its board that the provincial data centre was able to manage data queries during its early stage of implementation, but it was not designed to support the expected increases in volume of data-retrieval requests from distribution companies.

#### **Contract Terms for Operating Fee of Provincial Data Centre Not Clear**

The IESO and a private-sector vendor signed a five-year contract in 2006, with an option to extend for another two years, for developing, implementing and operating the provincial data centre. The IESO paid the vendor \$81.7 million for services up to March 2013. However, the \$13.4-million-a-year contract fee for the two-year extension period was almost double the \$6.8-million-a-year cost of the previous five years. The IESO attributed a portion of the fee increase to the additional costs associated with changes made to the provincial data centre and the higher number of meters being put in service during the two-year extension period. We found that the fee increase was due mainly to an error stemming from a contract amendment that did not clarify the fee for the two-year extension period. The IESO noted that this was an oversight on the part of the vendor, the IESO and their counsels, and that since the vendor incurred losses on the contract, the error offered the vendor an opportunity to improve its commercial position.

#### **Monitoring of Smart Metering-related Fire Safety Risk Not Sufficient**

There have been cases of fires arising from smart meters in Ontario and in other jurisdictions. However, no accurate and complete information on smart meter-related fires was available in Ontario to determine and monitor the scope and extent of the problem across the province. Only anecdotal evidence was available, which indicated three possible root causes for the fires: improper installation of smart meters, defective smart meters and problems with old meter bases where smart meters are mounted.

## **OVERALL MINISTRY RESPONSE**

Electricity systems around the world are adapting to meet the new and complex demands of technology advances and customer expectations. In 2004, the province took a critical step towards modernizing Ontario's electricity grid with the announcement of the Smart Metering Initiative.

The Ministry acknowledges that given the ambitious timeline to install smart meters by 2010 and the inherent structure of the distribution industry, with over 70 local distribution companies, that the initiative was both complex and challenging.

Faced with these challenges, the Ministry, the IESO, the OEB and local distribution companies worked collaboratively to make Ontario one of the first jurisdictions in North America to roll out smart meters.

The deployment of 4.8 million smart meters has brought a number of benefits to the province, including the ability of consumers to respond to price signals. Going forward, smart meters, as the base technology for a modern grid that enables emerging technologies and applications like electric vehicles, electricity storage and innovations to make Ontario homes smarter, will continue to deliver value to Ontario.

The Ministry will incorporate the recommendations of the Auditor General's report when working in partnership with our agencies and the broader sector to deliver future smart meter initiatives and related investments.

## **Detailed Audit Observations**

### **Governance and Oversight of Planning and Implementation**

In April 2004, the Ontario government announced the Smart Metering Initiative (Smart Metering)—the first and the largest smart-meter deployment in

Canada—and set aggressive targets to install smart meters at the premises of all residential and small-business ratepayers by 2010, with an interim target of 800,000 installations by 2007. Given the size and complexity of Smart Metering, the Ministry of Energy (Ministry) had, and continues to have, an ongoing and ultimate responsibility as a central planner to ensure that effective governance and project management are in place to monitor planning and implementation.

### Insufficient Justification and Planning for Smart Metering

A key principle of effective governance and project management is the use of comprehensive and relevant information about costs, benefits and risks to assess whether a proposed project is cost-effective and viable on an ongoing basis. This helps ensure that money is invested only if there is a continuing net benefit. Typically, cost-benefit analyses and business cases are two ways to evaluate the cost-effectiveness of a project, ensure that prudent decisions are made, and determine how stakeholders, and in this case electricity ratepayers, could be affected. As noted in the following sections, we found that the justification and planning for Smart Metering were insufficient.

#### Cost-benefit Analysis Not Done Before Public Announcement of Smart Metering

All key parties involved in implementing Smart Metering, including the Ministry, the Ontario Energy Board (OEB) and the Independent Electricity System Operator (IESO), confirmed to us that no cost-benefit analyses or business-case studies were done before the government announced Smart Metering in April 2004. Specifically, the OEB said it did not undertake any cost-benefit study because the Minister directed it only to develop an implementation plan (see **Figure 2**). The OEB plan noted, however, that many stakeholders and ratepayers expressed concern about the lack of a

cost-benefit analysis and felt that, in particular, smart meters would not be justified for ratepayers using low volumes of electricity. In addition, senior IESO management asked the Ministry several times for a business case to support Smart Metering, but never got one.

From our research, we noted that other jurisdictions have initially and continuously assessed the cost-effectiveness and feasibility of their smart-metering programs. For example:

- British Columbia began a smart metering program in 2011 after BC Hydro developed a business case in 2006, which it updated in 2010 because of the continued evolution of the smart-metering industry and technologies. The business case summarized the cash flows for costs and benefits over a 20-year term, and estimated the annual impact on electricity bills. In response to ratepayers who did not want smart meters, BC Hydro announced in July 2013 that anyone could opt out of the smart-metering program by paying a monthly fee to cover the cost of manual meter readings.
- The government in Victoria, Australia, commissioned two cost-benefit studies in 2004 and 2005 that became the basis for its 2006 decision to mandate the rollout of smart meters to all homes and small businesses. However, the Australian Government Productivity Commission concluded in 2012 that inadequate cost-benefit analysis had been done and that, overall, the decision to roll out smart meters appeared to be premature and/or poorly planned, with inadequate knowledge about smart-meter technologies, their costs and associated risks.
- In Germany, the government published a study in July 2013 that analyzed the costs and benefits of a full rollout of smart meters. The study concluded that smart meters were not cost-efficient for small ratepayers because they would cost more to buy, install and operate for average households than the

potential savings they would generate. The German government concluded it was not in the interest of ratepayers to implement a 2009 European Union recommendation that member states provide smart meters to 80% of ratepayers by 2020, and suggested instead a rollout tailored to different ratepayer groups, based on how much electricity they consume.

- The British government began preparatory work on its smart-metering program in 2009 and a business case was approved two years later. The government conducted further assessments in January 2014 to update the initial cost and benefit estimates, and it developed an overall strategy in mid-2014 to install smart meters in all homes and small businesses by 2020.

Compared to the experience in these other jurisdictions, the implementation of Smart Metering in Ontario without proper cost-benefit analysis to support the initial decision to install smart meters significantly exposed the province to unanticipated risks and unknown costs.

### OEB's Role as Independent Regulator Set Aside

Shortly after the government announced Smart Metering in April 2004, the Minister of Energy (Minister) issued a directive to the OEB under the *Ontario Energy Board Act, 1998 (Act)*, requiring it to develop an implementation plan to achieve the government's smart-meter targets. Under the Act, the Minister has the authority to direct the OEB to promote electricity conservation in a manner consistent with government policy. The Ministry also contracted with an external consultant in January 2005 to analyze different implementation strategies and to estimate the benefits of Smart Metering.

Both the Act and the directive essentially provided the Minister with the authority to set aside the regulatory role of the OEB (an independent Crown corporation responsible for regulating Ontario's electricity and natural-gas sectors in the public interest) in Smart Metering. The OEB's

mandate includes protecting the interests of ratepayers with respect to electricity prices. However, instead of conducting a cost-benefit analysis to justify its decision, and submitting the analysis to the OEB for independent review and objective evaluation, the Ministry, as a proponent of Smart Metering, directed the OEB to develop the implementation plan and project the costs of Smart Metering, as noted in the following section.

### Cost-benefit Analysis, Prepared After Public Announcement of Smart Metering, Flawed

In the implementation plan it submitted to the Ministry in January 2005, the OEB projected the total cost of implementing Smart Metering at \$1 billion, plus a net increase of \$50 million a year to the operating costs of the province's distribution companies. A separate consultant's report, delivered to the Ministry three months after the OEB submitted its implementation plan, projected total benefits of Smart Metering would be approximately \$1.6 billion over 15 years from four sources as shown in Figure 4, which indicated that about half of the projected benefits would result from a reduction in distribution companies' operating costs and a reduction in ratepayers' energy costs, and half

**Figure 4: Summary of Projected Net Benefits of Smart Metering Initiative (\$ billion)**

Source of data: Ministry of Energy

	Approximate Amount
Reduction in distribution companies' operating costs	0.4
Reduction in ratepayers' energy costs	0.4
Avoidance of expanding power generating capacity	0.6
Deferral or avoidance of expanding transmission and distribution systems	0.2
<b>Total Projected Benefits<sup>1</sup></b>	<b>1.6</b>
<b>Total Projected Implementation Cost<sup>2</sup></b>	<b>(1.0)</b>
<b>Projected Net Benefits</b>	<b>0.6</b>

1. Benefits projected by an external consultant engaged by the Ministry.

2. Cost projected by the OEB.

from deferring or avoiding the expansion of power generating capacity as well as transmission and distribution systems.

After considering the OEB's implementation plan and the separate consultant's report, as well as consulting the distribution companies, the Ministry requested Cabinet approval to proceed with smart metering based on a dual-implementation approach: decentralized ownership of smart meters by the distribution companies, and centralized data management by a provincial agency (see **Figure 2** and the section **Smart-meter Data Processing Systems and Costs**). In its October 2005 request to Cabinet, the Ministry indicated to Cabinet that Smart Metering could yield net benefits of close to \$600 million over 15 years. As shown in **Figure 4**, the Ministry arrived at this number simply by subtracting the projected implementation cost of \$1 billion in the OEB plan from the projected benefits of \$1.6 billion over 15 years in the consultant's report. However, we found that the \$600 million in net benefits was overstated, because it did not include the OEB plan's projected net increase of \$50 million a year to distribution companies in operating costs. By taking the \$50-million-a-year figure into account, we calculated that the projected net benefits over 15 years would be reduced seven-fold, from \$600 million to \$88 million in today's dollars.

### Ineffective Implementation and Oversight of Smart Metering

Given the large scale of Smart Metering and the high risk associated with new technology, its implementation should have warranted strong governance and oversight. However, we identified the following issues regarding the targets of reducing peak electricity demand, the assessment of changes in the electricity market, and the monitoring of costs and benefits of Smart Metering.

### Peak-demand Reduction Targets Not Met

The key objective of Smart Metering was to reduce peak electricity demand, and therefore defer the need to expand power-generation capacity in Ontario. In the decade since Smart Metering was announced, the province approved significant increases in new generation, including renewable energy, and the supply of power actually rose 12%. During this same period, average electricity demand also dropped 8% due to a slowing economy and other conservation efforts, including, for example, newer energy-efficient appliances. Despite the reduction of average demand, peak demand has remained essentially unchanged over the same period.

The Ministry indicated that Smart Metering was only a component of the government's overall electricity conservation plan, and so there was no other specific target for Smart Metering. Instead, the Ministry set several peak-demand reduction targets to measure overall electricity conservation, including a 1,350MW reduction by 2007, an additional 1,350MW drop by 2010, and a further 3,600MW reduction by 2025. We found that:

- The initial 1,350MW targeted reduction in peak demand was irrelevant to Smart Metering anyway because it was supposed to be achieved by 2007, three years before full installation of smart meters was to be completed.
- The second target of reducing peak demand by an additional 1,350MW by 2010, for a total reduction of 2,700MW, was also irrelevant to Smart Metering, which had not been fully implemented by 2010. While approximately 4.6 million ratepayers had smart meters installed by the end of 2010, only about one-third (or 1.6 million) of them were being billed based on time-of-use (TOU) pricing. Actual peak demand in fact rose slightly by about 100MW, from 24,979MW in 2004 to 25,075MW in 2010. In measuring against the target, the Ministry indicated that as of December 31, 2010, peak demand was

reduced by about 1,800MW when measured against forecast and weather-adjusted peak demand data rather than actual demand data, but the 2010 reduction target of 2,700MW still was not met. Since 2010, actual peak demand has remained relatively stable.

### Ongoing Changes in Electricity Market Not Properly Assessed or Addressed

The pace of change in the electricity sector has been rapid, so proper and adequate planning, with ongoing assessment and monitoring of plans, is important to prepare for potential risks and costs in implementation of any new electricity initiative. However, we noted that Smart Metering was implemented without sufficient periodic re-evaluation of Ontario's electricity supply and demand positions throughout the implementation period.

During the early implementation stage of Smart Metering in 2006, demand for electricity fell in Ontario as a result of an economic recession and other conservation efforts. However, instead of adjusting to this fall in demand, the province approved significant new increases in power-generation capacity to replace coal, and maintained the aggressive timelines set for implementation of Smart Metering. As a result, the supply of available power has steadily increased, and has been consistently higher than peak demand, thereby reducing the effectiveness of Smart Metering and other conservation programs. Although the IESO is required to maintain an operating reserve of between 1,300MW and 1,600MW for contingencies and other uncertainties, we noted that since 2009, the available surplus power of between 4,000MW and 5,900MW was considerably more than the required reserve. The IESO expected that the surpluses will continue in 2015, but could decline in the latter half of this decade when several nuclear plants will be refurbished or retired.

Ontario has been exporting most of its surplus power to the United States through the transmission grid connecting it to neighbouring

jurisdictions, including New York, Michigan and Minnesota. We noted that net exports have grown by 158%, from 5.2TWh in 2006 to 13.4TWh in 2013, representing 3% and 9% of Ontario's total generation, respectively.

However, the export price has been well below the actual cost of generating this power. On average, other jurisdictions paid only about three to four cents per kWh for power that cost Ontario ratepayers more than 8¢ per kWh to produce because of the Global Adjustment, an extra charge on top of the electricity market price (see the section **Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers**). The total cost of producing the exported power was about \$2.6 billion more than the revenue Ontario received from exporting that power between 2006 and 2013. However, given that Ontario ratepayers would still have to pay for the production of surplus power even if that power was not exported, revenue from exports did help Ontario ratepayers pay for part of the Global Adjustment.

### Costs and Benefits Not Monitored

The Ministry has neither updated the projected costs and benefits prepared in early 2005 during evolution of the implementation process, nor tracked the actual costs and benefits in order to monitor the amount of net benefits realized. We conducted our own analysis to determine the actual costs and benefits to date, and found as follows:

- With respect to costs, the OEB confirmed that there was no process to check or update its projected implementation cost of \$1 billion and compare it against actual costs because the Minister never formally approved the OEB's implementation plan. We calculated that, based on our review of information submitted by the distribution companies to the OEB, the total cost incurred by the distribution companies to implement Smart Metering was about \$1.4 billion up to the end of 2013, or \$400 million more than the cost projection

in the OEB plan. The final total will be higher still because some distribution companies were still carrying out implementation at the time of our audit and had not yet submitted all of their costs to the OEB for review. The OEB also indicated that the Ministry, the IESO and the distribution companies incurred additional costs for activities brought in after the OEB's implementation plan was prepared, including the development, implementation and operation of a provincial data centre at a cost of about \$249 million (see the section **Ratepayers Charged for Redundant or Unused Provincial Data Centre Service**). As shown in **Figure 5**, we noted that as of May 2014, the total approximate costs of implementing Smart Metering had reached almost \$2 billion.

- With respect to benefits, only 5% of the distribution companies we consulted reported operational savings, mainly from no longer having to send staff to read meters manually, and all of these were of modest size; the other 95% said they realized no savings and their operating costs relating to smart-metering activities since implementation had actually risen. As well, the savings achieved by ratepayers were so far limited, contrary to government communications to the public that smart meters and TOU pricing would help “save money” and “lower electricity bills” if appliances were run during Off-Peak hours. In fact, over half of the distribution companies we consulted received a high volume of complaints about “increased bills with no savings” from ratepayers with smart meters who paid TOU rates (see **Appendix 1**). In addition, several large distribution companies analyzed a sample of their residential ratepayers and found that a majority would see no reduction in their bills after implementation of TOU pricing. Therefore, of the four sources of projected benefits shown in

**Figure 4**, two of them (reduction of distribution companies' operating costs and reduction in ratepayers' energy costs) have not been achieved. The remaining two sources of benefits (avoiding expansion of power-generation capacity and deferring or avoiding expansion of transmission and distribution systems) have yet to be seen because, as noted previously, the 2010 peak-demand reduction target was not met and actual peak demand has remained relatively stable since 2010.

## RECOMMENDATION 1

To ensure that any future major initiative in the electricity sector is implemented cost-effectively and achieves its intended purposes, the Ministry of Energy should:

- conduct cost-benefit analysis or business cases prior to implementing an initiative to assess costs, benefits and risks;
- review the role of the Ontario Energy Board as an independent regulator when ministerial directives that impact electricity rates are issued;
- consider different scenarios or alternatives as part of the planning process to assess possible risks and uncertainties; and
- re-evaluate and update the implementation plan periodically to identify and respond to changing conditions and unforeseen events in the electricity market.

## MINISTRY RESPONSE

In line with best practice, the Ministry will ensure that the proper analysis is completed ahead of implementing major initiatives. In addition, the Ministry will continue to work with the relevant sector participants in a partnership approach to ensure that cross-sector initiatives are appropriately planned and consider the respective roles of those involved.

Also in line with best practice, the Ministry respects the need to evaluate programs on a regular basis to maximize efficiencies. To this end, the Ministry will work with its agencies to

re-evaluate the implementation of smart meters, including the potential benefits they could enable through the development of a smart grid in Ontario.

**Figure 5: Summary of Costs Incurred by Entities Involved in the Smart Metering Initiative, 2005–2014**

Prepared by the Office of the Auditor General of Ontario

Entity	Date	Cost Description	Approx. Cost (\$ 000)	Report Section (if applicable)
Ministry of Energy	Jan. 2005– Apr. 2005	Engaging an external consultant to develop an implementation strategy and to estimate the benefits of Smart Metering	160 <sup>1</sup>	Ineffective Implementation and Oversight of Smart Metering Initiative
	Nov. 2005– Apr. 2006	Engaging experts for technical, system and legal supports during early implementation stage of Smart Metering	400 <sup>1</sup>	
	2006–2010	Developing Communication templates and materials for use by the distribution companies to raise public awareness and understanding of Smart Metering	640 <sup>1</sup>	
Ontario Energy Board (OEB)	Jul. 2004– Jan. 2005	Developing the implementation plan for Smart Metering Initiative requested by the Minister	420	Ineffective Implementation and Oversight of Smart Metering Initiative
	Nov. 2010– May 2014	Engaging an external consultant to set time-of-use (TOU) rates	410	Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers
	Mar. 2013– Mar. 2014	Engaging an external consultant to assess the impact of TOU rates on consumption patterns	180	Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers
Independent Electricity System Operator (IESO)	2006–2014	Developing, implementing and operating a Smart Metering Entity and a provincial data centre	160,000 <sup>1,2</sup>	Ratepayers Charged for Redundant or Unused Service
Local Distribution Companies	2006–2013	Implementing Smart Metering	1,400,000 <sup>3</sup>	Ineffective Implementation and Oversight of Smart Metering Initiative
	2005–2014	Scrapping conventional analog meters	400,000 <sup>4</sup>	Additional Costs of Implementing Smart Metering Initiative
<b>Total</b>			<b>1,962,210<sup>5</sup></b>	

- Covers activities added after OEB's 2005 implementation plan, or those outside the original scope of the Smart Metering Initiative.
- Total approved by the OEB was \$249 million up to 2017. This cost is being recovered from ratepayers through a monthly smart-metering charge of 79 cents. The amount up to 2014 was approximately \$160 million.
- Hydro One accounted for more than \$660 million of the \$1.4 billion spent by all 73 distribution companies. About \$500 million (mainly from Hydro One) of the \$1.4 billion is under review by the OEB and has yet to be approved by the OEB.
- We reviewed the OEB's 2005 estimate. In our view, this is a reasonable estimate of total stranded costs.
- See Figure 15 for other system-related costs incurred by the distribution companies that we interviewed and surveyed.

## Billing Impacts on Electricity Charge to Ratepayers

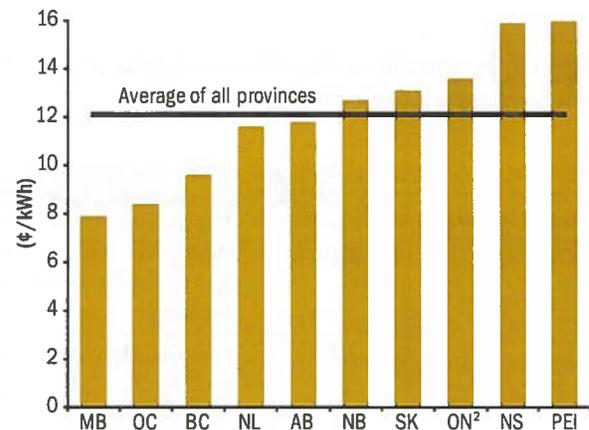
Our research noted that the average electricity bill for residential and small-business ratepayers in Ontario has been among the highest in Canada, as shown in Figure 6. Ontario's typical electricity bill for residential and small-business ratepayers contains four categories of charges: Electricity, Delivery, Regulatory and Debt Retirement. Smart Metering has had an impact on the two biggest categories, Electricity and Delivery, as described in Figure 7. There are three key pricing methods for the Electricity Charge, as illustrated in Figure 8. Over 90% of residential and small-business ratepayers pay this charge based on time-of-use (TOU) pricing, which is enabled by smart meters to measure the exact time when electricity is used. The remaining 10% pay either a two-tiered rate, often because they live in places where it is not technically feasible or cost-effective to install smart meters, or fixed-contract prices to electricity retailers, who do not offer TOU rates.

### Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers

The Electricity Charge accounts for more than half of a typical residential electricity bill, as shown in Figure 7, and is made up of two components: the electricity market price and the Global Adjustment. The Global Adjustment is an extra charge, resulting from a government policy decision, that is tacked onto the electricity market price mainly to cover the gap between the guaranteed prices paid to contracted power generators and the electricity market price. It exists because most power generators in Ontario have contracts with the province that pay them more than the market price. For example, most renewable-energy generators such as wind and solar have contracted with the Ontario Power Authority under the Feed-in Tariff program that offers wind-power generators 11.5¢/kWh and solar power generators between 28.8¢/kWh and

Figure 6: Comparison of Average Electricity Bill (Excluding Taxes) for Residential and Small-business Ratepayers<sup>1</sup> by Province, as of April 1, 2014

Source of data: Hydro Quebec



1. Residential electricity bill was based on average ratepayer with consumption of 750 kWh/month. Small-business electricity bill was based on average ratepayer with power demand of 40 kW/month.
2. Ontario figure includes Ontario Clean Energy Benefit, which is a 10% rebate on the total electricity bill, as illustrated in Figure 7.

39.6¢/kWh. These contract prices are considerably higher than the average electricity market price of about 3¢/kWh.

Our review of trends in the Electricity Charge noted that the Global Adjustment has continued to increase to the point where it now significantly exceeds the electricity market price. This is the result of many new generators, especially in the renewable-energy sector, coming online with long-term contracts just as the market price has fallen due to oversupply of power and thus been insufficient to cover guaranteed contract prices. As shown in Figure 9, the Global Adjustment increased by a dramatic 1,200% between 2006 and 2013, from 0.4¢/kWh to 5.5¢/kWh, and is expected to grow to 6.7¢/kWh by 2015. During the same period, the average electricity market price has dropped by 46%, from 4.9¢/kWh to 2.7¢/kWh, and is expected to fall to 2.4¢/kWh by 2015 due to increasing electricity supply.

The total Global Adjustment charged to ratepayers has grown from \$654 million in 2006 to \$7.7 billion in 2013, as shown in Figure 10. With more new contracted generators, especially of renewable

energy, expected to begin producing energy at higher contract prices, the total Global Adjustment is expected to grow further, to \$8.5 billion in 2014 and \$9.4 billion in 2015. From 2006 to 2015, the 10-year cumulative actual and projected Global

Adjustment is about \$50 billion—an extra charge to ratepayers over and above the market price of electricity. To put this into perspective, \$50 billion is:

- sufficient to cover the 2014 provincial deficit of \$10.5 billion almost five times;

**Figure 7: Components of Electricity Bill with Examples, 2013**  
(Average Typical Residential Ratepayer Consuming 800 kWh/Month)

Source of data: Ontario Energy Board (OEB)

Bill Component	Description	Examples		Avg. of all Distribution Companies (\$)
		Distribution Company A (\$)	Distribution Company B (\$)	
Electricity Charge	The cost of the actual electricity consumed. Presentation of this charge on bills varies, depending on whether the ratepayer buys electricity from a distribution company or has signed a contract with a retailer. Over 90% of low-volume power use ratepayers (residential and small businesses) pay power charges based on time-of-use pricing, enabled by installation of smart meters (see Figure 6).	71.1	71.1	71.1
Delivery Charge*	The cost of delivering electricity from power-generating facilities to ratepayers via high-voltage (transmission) and low-voltage (distribution) systems. Transmission is handled primarily by Hydro One and distribution is handled by the distribution companies, including Hydro One. Costs of implementing and operating smart meters are included in this line and vary from one distribution company to another, usually with higher charges in rural and remote locations.	24.9	110.6	43.6
Regulatory Charge	The cost to operate the electricity market and maintain the reliability of the provincial grid. This includes the operational costs of the IESO and the Ontario Power Authority as well as a portion of administrative costs of local distribution companies.	4.9	5.1	5.0
Debt Retirement Charge	Charge mandated by the government to help pay off the residual stranded debt of the old Ontario Hydro that could not be funded by other revenues. The 2014 Budget proposed to eliminate this charge for residential ratepayers after December 31, 2015.	5.6	5.6	5.3
<b>Electricity bill before tax and benefit</b>		<b>106.5</b>	<b>192.4</b>	<b>125.0</b>
Harmonized Sales Tax	The 13% tax that took effect on July 1, 2010, replacing the federal goods and services tax (GST) and the provincial sales tax (PST).	13.9	25.0	16.3
Ontario Clean Energy Benefit	A 10% rebate on the total electricity bill for the first 3,000 kWh/month of electricity consumed. Rebate is in effect from 2011 to 2015. Annual cost of rebate is funded by taxpayers.	(12.0)	(21.8)	(14.1)
<b>Total Electricity Bill</b>		<b>108.4</b>	<b>195.6</b>	<b>127.2</b>

\* See Appendix 2 for the Delivery Charge of each distribution company in Ontario.

- enough to pay the annual salary of about 2.3 million Ontarians working full time at the provincial minimum wage; or
- about 7.5 times more than the \$6.6-billion spent in the 2012/13 fiscal year on social-assistance programs such as the Ontario Disability Support and Ontario Works programs

administered by the Ministry of Community and Social Services.

For ratepayers whose Electricity Charge is based on TOU pricing, the Global Adjustment now accounts for about 70% of each TOU rate. Even though the Global Adjustment has increased significantly and accounts for a substantial proportion of

**Figure 8: Pricing Methods for Electricity Charge**

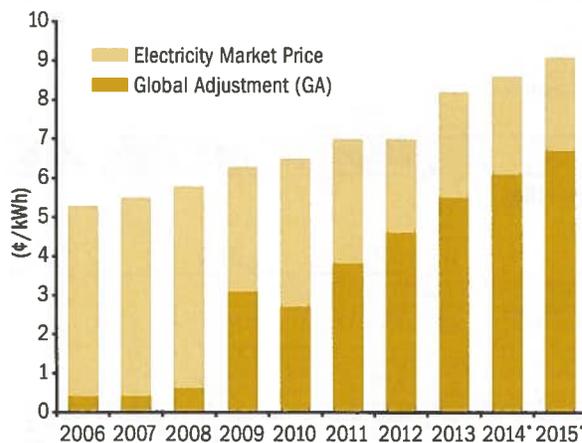
Source of data: Ontario Energy Board (OEB)

Pricing Method	Time-of-Use (TOU)	Tiered	Retail Contract
Electricity Provider	Local Distribution Company	Local Distribution Company	Electricity Retailer
Electricity Charge based on Time-of-Use?	YES Rates vary depending when electricity is used, reflecting that electricity costs more as demand rises (highest during the day on weekdays and lowest in evenings, at night, on weekends and holidays).	NO Rates are fixed in two tiers regardless of when electricity is used (a lower rate for monthly usage up to a threshold and a higher rate for usage over the threshold).	NO Rates are fixed by contracts that ratepayers sign with retailers no matter what time of day electricity is used.
Electricity Charge Regulated by Ontario Energy Board (OEB)?	YES OEB reviews and sets TOU and tiered rates twice a year (May 1 and Nov 1) based on future electricity prices estimated by an external consultant.		NO
Global Adjustment* Shown Separately on Bill?	NO Global Adjustment is blended into TOU and tiered rates, and embedded in the Electricity Charge line on electricity bill.		YES Global Adjustment appears as a separate line on electricity bill.

\* The Global Adjustment is an extra charge designed to cover the contract prices paid to power generators, such as renewable energy generators, and the cost of conservation programs.

**Figure 9: Historical and Projected Electricity Charge in Ontario, 2006–2015**

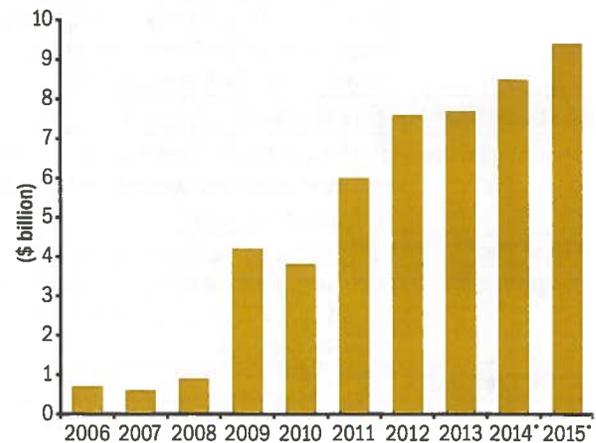
Source of data: Independent Electricity System Operator and Ontario Power Authority



\* projected

**Figure 10: Historical and Projected Total Annual Global Adjustment Charged to Electricity Ratepayers in Ontario, 2006–2015**

Sources of data: Independent Electricity System Operator and Ontario Power Authority



\* projected

the TOU rates, its impact is not transparent to most ratepayers because it does not appear on electricity bills as a separate line; instead, it is embedded in the TOU rates used to calculate the Electricity Charge (As shown in Figure 8, the Global Adjustment only appears separately on bills of those ratepayers who have signed contracts with electricity retailers).

### Ineffective Design of Time-of-use Rates and Periods

As part of Smart Metering, there are three time-of-use (TOU) rates: On-Peak, Mid-Peak and Off-Peak, consistent with the TOU design in other jurisdictions. As illustrated in Figure 11, TOU rates vary, depending on the time of the day, day of the week, and season, to reflect the assumption that as demand rises, electricity costs more to supply. Like many cell phone plans, TOU rates are lowest in the evenings, on weekends and holidays; and highest

during the day on weekdays. The combination of smart meters and TOU pricing was expected to encourage energy conservation by giving ratepayers information and incentives to manage their electricity usage.

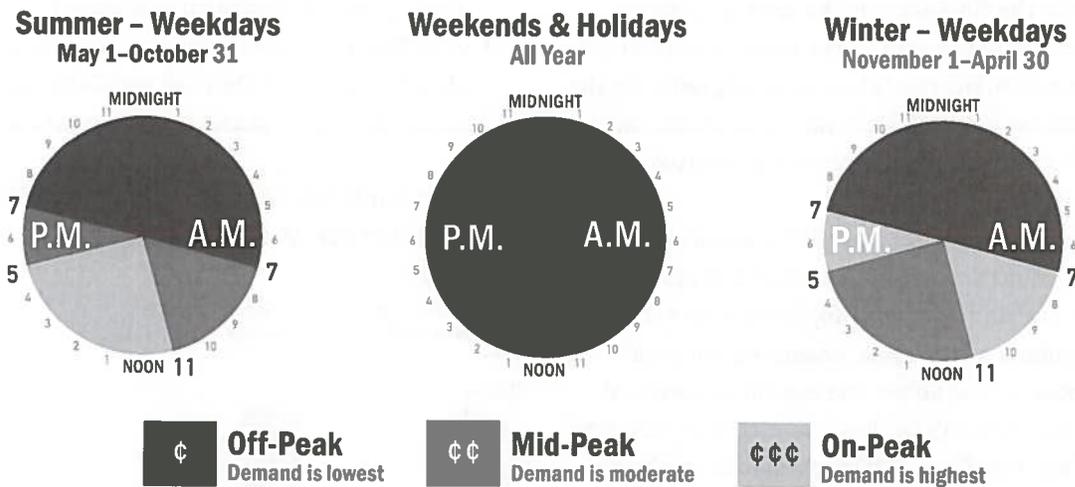
To account for seasonal variations in electricity consumption patterns, the OEB reviews and sets TOU rates every May and November, based on consumption and cost projections made by an external consultant with whom it contracted. Ontario Regulation 95/05 requires that the OEB set the TOU rates to meet three objectives:

- recover from ratepayers the full cost of electricity supply;
- reflect the differences in the costs of supplying electricity at different times and seasons; and
- provide ratepayers with incentives to change their time of use.

In order to encourage conservation and reduce peak electricity demand, TOU rates and periods

Figure 11: Time-of-use Pricing Periods in Ontario for Residential and Small-business Ratepayers

Source of data: Ontario Energy Board (OEB)



Summer Weekdays (May 1–October 31)	Weekends & Holidays (All Year)	Winter Weekdays (November 1–April 30)
One On-Peak period in the afternoon (11 a.m.–5 p.m.), mainly due to the increase in air conditioner use during the hottest hours.	No On-Peak period and all hours Off-Peak, mainly because of comparatively lower overall demand.	Two On-Peak periods, mainly due to less daylight. <ul style="list-style-type: none"> <li>• In the morning (7 a.m.–11 a.m.) when people turn on lights and appliances.</li> <li>• In the evening (5 p.m.–7 p.m.) when people get home from work.</li> </ul>

must be set to provide an incentive to reduce usage during On-Peak times, when both demand and price are high, or shift it to Off-Peak times, when both demand and price are low.

With respect to the TOU rates, the greater the difference between On-Peak and Off-Peak rates, the higher the likelihood that ratepayers will change their usage patterns. However, we noted that the difference between On-Peak and Off-Peak rates in Ontario may not be significant enough to provide ratepayers with an incentive to change their electricity-use behaviour. Specifically:

- When TOU pricing was introduced in 2006, the initial On-Peak-to-Off-Peak ratio was three-to-one, meaning that On-Peak power cost three times as much as Off-Peak. However, the ratio had dropped to 1.8-to-one at the time of our audit due to the impact of the substantial growth of the Global Adjustment, as discussed in the section **Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers**. In particular, the Off-Peak rate rose the most, by 114%, and the On-Peak rate the least, by 29%, as shown in Figure 12. As a result, the difference between the two rates narrowed, reducing the On-Peak-to-Off-Peak ratio and undermining TOU pricing as an incentive for ratepayers to shift to Off-Peak.
- In 2010, the OEB commissioned an external consultant to study TOU rates around the world and assess the appropriateness of Ontario's TOU rates. Consistent with our observation above, the consultant reported that Ontario's On-Peak-to-Off-Peak ratio was "low relative to TOU programs in other jurisdictions and will likely produce modest ratepayer response or bill savings." The average ratio elsewhere was four-to-one, compared to Ontario's 1.8-to-one. The Ontario ratio could deliver only about a 1% drop in the average ratepayer's peak demand, while a four-to-one ratio could potentially yield a drop three times greater. The study proposed several options to

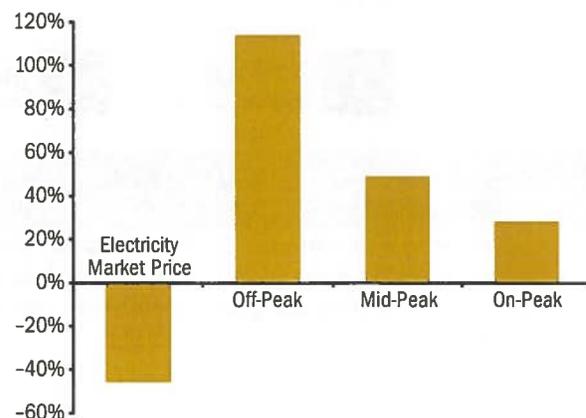
increase the ratio. However, following a consultation in 2011, the OEB chose not to make any change because a majority of stakeholders said such a move would be premature in the absence of robust and reliable Ontario-based empirical data.

With respect to the TOU periods, we noted that the distribution of On-Peak, Mid-Peak and Off-Peak periods did not fully reflect actual patterns of electricity use. Specifically:

- There has been a mismatch between demand and TOU rates on weekday early-evening hours (7 p.m.–9 p.m.), when demand is high but ratepayers pay the Off-Peak, or lowest, rate. The OEB initially set the Off-Peak period on weekday evenings to begin at 10 p.m., and then moved it to 9 p.m. in November 2009 to better reflect actual patterns of demand. However, in response to amendments to Ontario Regulation 95/05 in December 2010, the OEB set the start of Off-Peak at 7 p.m., making the early evening hours of 7 p.m. to 9 p.m. Off-Peak, even though demand remained high at those times, as illustrated in Figure 13.
- A 2013 study by an Ontario university found that the choices of On-Peak and Off-Peak times, number of seasons, and season start

**Figure 12: Percentage Change of Time-of-use (TOU) Rates and Electricity Market Price in Ontario, 2006–2014**

Source of data: Ontario Energy Board and Independent Electricity System Operator



and end times used in Ontario’s TOU pricing were far from optimal. The study echoed our observation that the distribution of On-Peak, Mid-Peak and Off-Peak periods did not properly reflect the actual distribution of demand. The study also found that while the current TOU pricing structure has two seasons (summer: May 1-October 31, and winter: November 1-April 30), the optimal number of seasons should be four, beginning March 11 (spring), May 20 (summer), September 16 (fall) and November 4 (winter). If the current two-season pricing structure is to be maintained, the study said, summer should start on April 15 rather than May 1, and winter on October 14 rather than November 1.

### Limited Effectiveness of Time-of-use Pricing Model

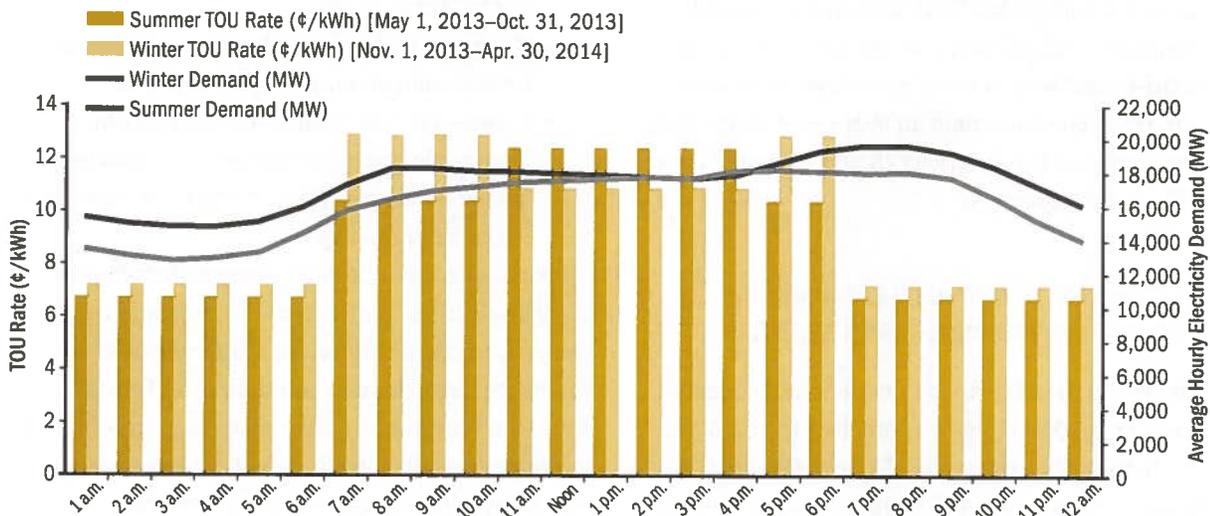
At the time of our audit, the distribution companies we consulted said they did not conduct studies to examine the changes in consumption after implementation of TOU pricing. The impacts of TOU pricing were evaluated in 2013, when the Ontario Power Authority (OPA) and the OEB contracted with external consultants to examine the

effectiveness on a sampling of ratepayers of TOU pricing in encouraging conservation and reducing peak demand. Both agencies released their studies in late 2013 with similar findings: TOU pricing has had a modest impact on reducing peak demand among residential ratepayers, a limited or unclear effect on small businesses, and no impact at all on energy conservation. Specifically:

- In November 2013, the OPA released its study, based on 105,000 residential ratepayers in four distribution companies, and 32,000 small businesses in two distribution companies. The study found that TOU pricing had a far smaller impact on reducing peak demand of small businesses than it did for residential ratepayers. Depending on the distribution company, the drop in peak demand during the summer ranged from 2.6% to 5.7% for residential ratepayers, but only from 0% to 0.6% for small businesses. The study also found that the impact of TOU pricing on energy conservation was “limited, being very small or zero,” for residential ratepayers, and “negligible and generally insignificant” for small businesses.
- In December 2013, the OEB released its study, based on a sample of 10,000 residential ratepayers and 4,000 small businesses in

**Figure 13: Time-of-use (TOU) Rates and Average Hourly Electricity Demand in Ontario, May 2013–April 2014**

Sources of data: Independent Electricity System Operator and Ontario Energy Board



16 distribution companies. The study found that TOU pricing reduced peak demand by about 3.3% for residential ratepayers while its impact on small businesses was “ambiguous.” The study also found that TOU pricing had no significant impact on energy conservation in the summer.

We performed further analyses based on more current data and larger sample sizes. Specifically, we reviewed consumption patterns of about 1.8 million ratepayers (1.7 million residential ratepayers and 86,000 small businesses in 50 of 73 distribution companies), who paid TOU rates. While 35% of residential ratepayers and 19% of small businesses reduced their consumption during On-Peak periods, the remaining 65% of residential and 81% of small businesses did not.

Since the aforementioned studies by the OPA and the OEB did not specifically cover ratepayers with smart meters who signed fixed-price contracts with energy retailers and so do not pay TOU rates, we examined the consumption patterns and bills of about 77,000 of these ratepayers. Given that they paid fixed prices regardless of time of use, these ratepayers have little or no incentive to confine their consumption to Off-Peak periods, when TOU rates were lowest. However, we noted that consumption patterns of ratepayers paying fixed-contract prices to electricity retailers, and of ratepayers paying TOU rates, were about the same, indicating that TOU rates did not provide ratepayers with sufficient incentive to shift usage to Off-Peak. We also noted that those ratepayers with retail contracts paid an average of about \$500 more per year for electricity than they would have without the contracts.

### Ratepayer Complaints Stemmed from Time-of-use Pricing and Billing Errors

Ratepayers usually raised questions and concerns about Smart Metering by contacting the OEB and the distribution companies. Since 2008, the OEB has received about 2,400 enquires and complaints

relating to smart meters and TOU pricing; about two-thirds of them questioned the TOU pricing structure and whether it would save them money. Given that ratepayers get their bills directly from the distribution companies, the companies received even more enquiries and complaints.

Many distribution companies we consulted did not track enquiries and complaints separately, nor did they log the nature or type of complaints. They were thus unable to quantify the volume of complaints relating to Smart Metering before and after its implementation, and could not separate concerns about smart meters from those about billing. Without proper tracking and monitoring of ratepayer concerns, key information could not be collated to identify and resolve common or recurring problems on a timely basis.

Those distribution companies that had tracked the nature of complaints reported that a majority of the concerns raised by ratepayers related to TOU pricing and fell into the following categories (see **Appendix 1**):

- Ratepayers were upset about high electricity bills or “increased bills with no savings,” which they believed were caused by faulty smart meters, but were in fact due to the increase of TOU rates as a result of the significant growth of the Global Adjustment (see section **Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers**).
- Ratepayers had “limited understanding and information about TOU pricing;” and
- Ratepayers had “limited or no ability to change electricity consumption,” especially small businesses and individuals at home during most of the day.

For Hydro One, Ontario’s largest distribution company and the only one owned by the province, we performed additional detailed reviews of ratepayer enquiries and complaints. In February 2014, four months after we began our audit, the Ontario Ombudsman also began an investigation into complaints at Hydro One. In order to avoid

duplication with that undertaking, we modified our audit scope to focus on identifying the root causes of billing issues potentially relating to smart meters and TOU pricing. Of the complaints we examined at Hydro One, most related to high electricity bills due mainly to TOU rates and not to defective smart meters, just like the other distribution companies noted above. In addition to the high-bill concerns relating to TOU rates, we also identified a number of complaints about billing anomalies that fell into the following categories:

- **Billing System Problems:** In May 2013, Hydro One transitioned to a new billing system. However, the transition was not smooth. At the time of our audit, Hydro One was adapting to and working on some technical issues with its new system, but more complex issues had yet to be fixed. We identified complaints about erroneous bills, prolonged estimated bills, delayed bills, multiple bills or no bills at all, that were due to problems with the billing system. For example:
  - In September 2013, a ratepayer received a bill for about \$37 million as a result of an error made in calculating electricity consumption, but Hydro One's billing system did not catch this error. In January 2014, the company cancelled the bill and revised the amount owing to about \$35,000.
  - In September 2013, a ratepayer with a smart meter received an estimated bill covering electricity usage for seven months. After that, the ratepayer received no bills for five months due to billing-system problems. In April 2014, Hydro One issued 12 bills, all on the same date and for a total of over \$4,900. Of these 12 bills, seven were to correct the under-estimated bill issued in September 2013 and five were to "catch-up" on the no-bill period since October 2013.
  - A smart meter installed in March 2012 was found to be malfunctioning, and was replaced in October 2012. However, the ratepayer was not billed until April 2013 due to problems in the billing system. In April 2013, the ratepayer received a "catch-up" bill of about \$4,000 for usage between March 2012 and April 2013.
- **Communication System Problems:** Ratepayers did not receive any bills, or received only estimated bills, for extended periods, because actual consumption data was not available due to connectivity issues between the smart meters and associated local communication systems. The problems could be caused by non-communicating smart meters or by seasonal variations in system performance. With respect to the latter, Hydro One's service territory includes rugged terrain and extensive foliage that could block meter signals from reaching the systems, depending on the season. Communication systems in one region may work well in the fall and winter when most trees are bare of leaves, for example, but it may not function properly in the spring when trees have new leaves.
  - In December 2013, a ratepayer complained about receiving estimated bills for seven months, ranging from \$400 to \$500 per month, which was about two to three times higher than the previous monthly bills. Hydro One found that the smart meter was working properly, but it could not capture actual meter readings because its communication system was not producing a signal. Hydro One then corrected the over-estimated bills and credited the ratepayer for about \$1,300 against future bills.
  - In December 2013, another ratepayer complained about receiving high estimated bills for nine months. Hydro One found that the bills were based on estimates rather than actual meter readings because the smart meter was not communicating with the system. Hydro One then cancelled the over-estimated bills and issued a credit of about \$2,700 to the ratepayer.

- **Mixed or Cross-Metering Issues:** Ratepayers were billed based on errors arising from smart meters connected to wrong addresses during installation. Hydro One indicated that these issues also existed prior to the installation of smart meters but occurred rarely. Most ratepayers did not notice these issues because the amount of the errors was usually not significant; in other cases, however, they were. For example:
  - In response to a January 2012 query from a ratepayer about a high bill, Hydro One found that four smart meters in the same building had been mistakenly wired into the wrong addresses, and that the ratepayer who complained had been overbilled by about \$1,000.
  - In response to an enquiry from another ratepayer in April 2013, Hydro One found that a smart meter in an apartment was erroneously connected to another address, and that the ratepayer was overbilled by about \$200 from November 2012 to March 2013, when the smart meter was incorrectly connected.
- **Seasonal High Bills:** Unlike other distribution companies, Hydro One has wider geographic coverage and more seasonal ratepayers who own residential properties, such as cottages in rural or remote areas, in addition to their primary residence. Even though seasonal ratepayers used their properties mainly on weekends and holidays, they still received high electricity bills. For example, in February 2014, a ratepayer complained of bills totalling \$7,000 a year on a cottage that was only used six months a year. The ratepayer attributed the high bills to a faulty smart meter, but Hydro One found that the smart meter was functioning properly. We identified other similar complaints that were caused by one or all of the following reasons:
  - The Electricity Charge on seasonal ratepayer bills rose because of the increases

of all three TOU rates (see section **Significant Impact of Global Adjustment on Time-of-use Rates Not Transparent to Ratepayers**).

- The Delivery Charge to seasonal ratepayers was higher than for typical residential ratepayers because delivering power to remote seasonal properties through forests and around lakes requires more infrastructure, such as poles, lines and transformers, and is therefore more expensive than service to more populated areas.
- Seasonal ratepayers were surprised by the unanticipated consequence of billing changes after smart-meter installation. For example, before installing smart meters, Hydro One would issue four bills a year to seasonal ratepayers—one based on an actual meter reading carried out by Hydro One staff at the ratepayer's premises, and three based on estimates. After the installation of smart meters, which enable TOU pricing to measure the exact time when electricity is used, seasonal ratepayers began to receive much higher bills in the summer and lower bills in the winter.

At the time of our audit, we noted that Hydro One had been taking some actions to resolve the existing billing issues. For example, Hydro One was improving its training to customer-service staff; providing refund options (a cheque or a credit on account) to ratepayers who were overbilled; waiving late payment charges; and not sending disconnection notices to ratepayers who experienced billing issues caused by Hydro One.

## RECOMMENDATION 2

To ensure that the combination of smart meters and time-of-use (TOU) pricing is effective in changing ratepayer electricity-usage patterns to reduce peak electricity demand and related infrastructure costs, and that ratepayers understand the impacts of TOU pricing on their

electricity bills, the Ministry of Energy should work with the Ontario Energy Board and/or the distribution companies to:

- evaluate TOU pricing design, including TOU rates, TOU periods and the allocation of the Global Adjustment across the three TOU rates;
- monitor trends in ratepayer electricity consumption to evaluate the effectiveness of TOU pricing over time; and
- disclose the components of the TOU rates (electricity market price and Global Adjustment) separately on electricity bills so that the impact of the Global Adjustment is transparent to ratepayers.

### MINISTRY RESPONSE

As established in the *Ontario Energy Board Act, 1998* and prescribed in Ontario Regulation 95/05, the OEB is responsible for setting rates for residential and small business customers on the Regulated Price Plan (RPP), which includes time-of-use (TOU) pricing.

TOU rates continue to evolve as the province balances both system and customer benefits, and as we learn more about how consumers are responding to TOU rates.

Further analysis is under way and the Ministry looks forward to the OEB's planned review of the RPP and TOU pricing that is currently under way.

The OEB's RPP review is timely in that it will build on the robust analysis of the actual impacts of TOU prices in Ontario that have been completed by the OEB and OPA.

### OEB RESPONSE

The OEB is undertaking a review of TOU pricing. That review will consider all of the matters identified by the Auditor General, including the structure of the TOU periods, the TOU prices, and the forecasting of the costs and the Global Adjustment to be recovered in those

prices. We anticipate that this review will be completed during the OEB's 2014/15 fiscal year. The OEB would be pleased to work with other agencies and with the Ministry regarding any further review of TOU prices that the Ministry may consider appropriate in the circumstances.

### RECOMMENDATION 3

To ensure that ratepayer concerns are addressed properly and in a timely manner, and that clear, timely and accurate bills are issued to ratepayers, the Ministry of Energy should work with the Ontario Energy Board, Hydro One and other distribution companies to:

- improve tracking of the nature and details of ratepayer enquiries and complaints to identify and monitor common or recurring concerns;
- better educate ratepayers about the impacts of time-of-use (TOU) pricing and other factors on electricity bills, as well as the root causes of potential metering or billing issues and what is being done to address them; and
- identify and fix any problems with their billing systems and local communication systems on a timely basis, and monitor the performance of those systems over time to reduce ratepayer complaints triggered by these problems.

### MINISTRY RESPONSE

In accordance with the *Ontario Energy Board Act, 1998*, the OEB is responsible for protecting the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

In line with these objectives, the OEB has made customer focus one of four principal outcomes for local distribution companies (LDCs) as part of its Renewed Regulatory Framework for Electricity.

The Ministry welcomes the introduction of specific metrics related to customer satisfaction

as part of its scorecard to measure and benchmark LDC performance on an annual basis.

In particular, from 2014 on, LDCs will be required to report to the OEB on their effectiveness at addressing customer complaints, customer satisfaction survey results and performance with respect to targets for billing accuracy.

The Ministry will ask the OEB to consider whether any additions or revisions to its new framework are required in light of this recommendation.

## HYDRO ONE RESPONSE

Hydro One serves over 1.2 million ratepayers across Ontario and issues over 1 million bills monthly. The implementation of Hydro One's new billing system in May 2013 has led to billing issues for about 6% of its customers. Hydro One has been working to communicate with ratepayers and make them aware of its plans to fix the technical issues and improve customer service. At the time of this audit, approximately 1.8% of customers were impacted. Since February 2014, Hydro One has taken several actions to improve its customer service, including:

- reducing the number of ratepayers who have not received a bill for a prolonged period of time to 0.8%, improved from 5%;
- decreasing the number of ratepayers who have received only estimated bills for a prolonged period of time (currently 1% of Hydro One's customer base);
- introducing a 10-day commitment for resolving customer issues, with a resolution within 10 days or by a promised date;
- changing call-centre training, increasing the number of customer-service-centre agents, and introducing new policies such as interest-free payment plans for customers who have received bills covering long billing periods and waived service charges for ratepayers affected by billing issues;

- adding a new section to Hydro One's website to improve ratepayer understanding of billing and metering issues; and answer ratepayers' common questions on high bills, the impact of cold weather on electricity consumption, meter readings, meter accuracy, smart meters and the smart-meter network;
- enhancing customer call tracking to identify and resolve emerging issues;
- exploring the implementation of a new customer commitment tracking and monitoring solution;
- establishing a Service Champion Advisory Panel; and inviting external experts to provide advice to Hydro One's president and CEO, review Hydro One's customer-service performance, and make performance results public; and
- continuing to fix and monitor the technical problems with its new billing system, improve call centre staff capabilities to address customer service needs, and resolve the associated complaints fairly and promptly by providing payment arrangement options and waiving late payment charges or any other penalties to ratepayers who were affected by these technical problems.

## Billing Impacts of Delivery Charge on Ratepayers

There are three major types of costs associated with Smart Metering: capital costs (for meters, communication infrastructure, installation and data systems); ongoing operating costs for meter reading and services; and stranded costs for scrapping old analog meters. These costs are recovered from ratepayers through the Delivery Charge, which is the second largest component of a typical ratepayer electricity bill, and which varies from one distribution company to another, as illustrated in **Figure 7** and **Appendix 2**.

## Variations in Delivery Charge between Distribution Companies

As illustrated in **Figure 7**, a typical residential electricity bill varies between \$108 per month and \$196 per month, depending on where the ratepayer lives and which distribution company provides the service. Of the four categories of charges (Electricity, Delivery, Regulatory and Debt Retirement) that make up the electricity bill, the Delivery Charge accounts for the largest variation in costs among distribution companies, ranging from about \$25 a month to \$111 a month, with the average at about \$44 per month, as shown in **Figure 7** and **Appendix 2**.

In 2012, the Minister of Energy established the Ontario Distribution Sector Review Panel to advise the government on how to improve efficiency in the distribution companies with the aim of reducing the cost to ratepayers of electricity distribution. The panel's research and analysis showed that the current approach to delivering electricity has been costing ratepayers more than it should. In particular, compared to their larger counterparts, smaller distribution companies tended to have higher per capita operating costs, which were passed on to ratepayers through the Delivery Charge line on electricity bills. As a result, ratepayers of smaller distribution companies paid more for their electricity than ratepayers of larger distribution companies. Given the varying sizes of the distribution companies, and their varying Delivery Charge, the panel's key recommendation was to merge the existing distribution companies into eight to 12 larger ones to improve cost-efficiency and ensure price stability, fairness and value for money in the electricity-distribution sector. The panel expected that consolidation would help reduce sector-wide operating costs by 20% in areas such as customer service, billing, facilities maintenance and administration.

However, we noted that the panel excluded the two largest distribution companies with high costs, Hydro One and Toronto Hydro, when comparing the costs of different distribution companies. Given

that these two distribution companies have Delivery Charges higher than the provincial average, it would be worthwhile for the Ministry, in conjunction with the OEB, to study the cost implication for ratepayers from consolidation to reduce the variations in distribution-company costs.

## Variations in Smart-metering Costs between Distribution Companies

The distribution companies recover all costs associated with the implementation and operation of their smart-metering systems from ratepayers through the Delivery Charge line on electricity bills, as discussed in the section **Variations in Delivery Charge between Distribution Companies**. There are 73 distribution companies across Ontario, each responsible for procuring, installing and operating smart-meter systems. Each distribution company negotiated with different vendors to procure systems for their regions. As a result of the different costs incurred by distribution companies, we noted that the average cost per meter was about \$190, but varied significantly, ranging from \$81 per meter at one distribution company to \$544 per meter at another. Such wide variation was due mainly to geographical issues in service areas and the degree of upfront expenses, such as project-management and system-integration costs. These two factors were particularly significant at Hydro One, Ontario's only provincially owned distribution company.

At the time of our audit, we noted that the costs incurred by Hydro One in implementing its smart-metering project were significant. In December 2006, Hydro One's Board of Directors approved \$670 million for the project. By the end of 2013, Hydro One had spent over \$660 million (including about \$490 million on procurement and installation of smart meters and associated communication systems, and about \$170 million on system development, integration and automation), which was about 50% of the \$1.4-billion total province-wide implementation cost—and more than the other 72 distribution companies combined

(see the section **Ineffective Implementation and Oversight of Smart Metering Initiative**). However, Hydro One installed 1.2 million smart meters, which represents only about 25% of the 4.8 million smart meters installed in Ontario. Of the \$660 million spent by Hydro One, our review of the OEB's records noted that about \$440 million has yet to be reviewed and approved by the OEB.

Hydro One's high costs were partly the result of installing smart meters and establishing communications infrastructure across its large and diverse geographic service area, which includes a mix of urban, rural and remote regions. Another factor was the high contract fee paid to a private-sector vendor for system integration.

In August 2007, the OEB also noted that the cost incurred by Hydro One at that time to implement its smart-metering project was already high compared to other distribution companies. The OEB indicated that a special comment was warranted with respect to Hydro One's substantial expenditures on a contract for project management with a private-sector vendor. In particular, the OEB reported a concern raised by one stakeholder group: Hydro One had substantial internal management resources and was likely the most experienced distribution company in dealing with big projects, so it was hard to understand why it had to retain the vendor at such a large contract cost. At the time of our audit, we reviewed the contracting process and noted the following:

In March 2005, Hydro One issued a Request for Proposals (RFP) to select vendors in four areas: smart meters, communications, meter-data management, and system integration (including project management and various consulting services associated with back-office functions and operations).

With respect to the system-integration contract, eight vendors bid on the contract, and Hydro One set up an RFP Evaluation Team to assess each proposal. We noted that Hydro One did not effectively manage its vendor-selection process, governance structure and contract costs. Specifically:

- The proposals submitted by different vendors were not comparable, and so it was

inappropriate to assess them together. In particular, not all vendors submitted prices up to 2010. When we asked for more details and explanation, Hydro One management said they could provide only speculation and anecdotal responses, because the key employees in the RFP Evaluation Team who worked on the initial stage of the project were no longer with Hydro One. When we interviewed these former employees, they confirmed that, apart from the RFP Evaluation Team's scoring sheet, there was no other documentation on file to explain how the scores were assigned.

- The RFP Evaluation Team selected the system-integration vendor based on several criteria, including price. However, pricing evaluation was not based on the overall contract cost. Hydro One explained that since the smart-metering project would span multiple years based on new technology, the overall contract cost could not be fixed due to the "unknown nature of all the business requirements at the time of the RFP." An appropriate RFP process would require Hydro One to understand and know more about what it wants in its smart metering project, and to specify the requirements for the vendors in sufficient detail so that they could develop an approach to the project. Granting a contract through the RFP process without acquiring enough knowledge about the business requirements could lead to risks of significant cost increases due to change orders. Carrying out a Request for Information (RFI) process, which is designed to collect more information from a broad base of potential vendors prior to the RFP procedure, would help reduce such risks, particularly for a project of this size involving emerging technology.
- In April 2005, Hydro One selected the system-integration vendor. Since then, Hydro One entered into multiple contracts with this same vendor, and approved a number of change orders. The costs associated with these contracts have increased significantly, which in

turn contributed to Hydro One's higher cost per meter than other distribution companies. Specifically:

- At the time of our audit, the total contract cost paid by Hydro One to the vendor exceeded \$125 million. Our review of Hydro One's board minutes noted that the board received no specific details on contract fees paid to this vendor. Hydro One explained that the board delegated the responsibility to oversee cost details to Hydro One management. Hydro One also indicated that it managed the contract and project execution according to a program governance plan. However, our review of this plan noted that it was developed by the vendor and did not include Hydro One's board in the governance structure.
- The initial contract set the fee at a maximum of about \$1.1 million, and specified that the scope was to support the rollout of 25,000 smart meters, and to continue design, proof-of-concept and planning activities. The contract ended up supporting the deployment of just 2,000 smart meters, but the actual fee paid by Hydro One amounted to \$1.7 million, which included additional costs arising from change requests and reimbursements for travel and other expenses.
- Hydro One, as a Crown corporation, is required to follow the government's procurement policy, which says that any contract between the organization and a successful vendor must be formally defined in a signed written document before goods or services are provided. However, Hydro One signed the initial contract with the vendor on April 25, 2006, three months after the vendor had already started work. Similarly, a second contract was signed on August 31, 2006, two months after the vendor had already commenced work.
- After the first two contracts, Hydro One signed multiple contracts with the same vendor from 2007 to 2010 without a competitive process, even though both the initial and second contracts stipulated that Hydro One had the option to look for other suppliers to complete subsequent work. If Hydro One did not use the same vendor again for subsequent work, both the initial and the second contracts specified that Hydro One would have to pay an additional \$462,000 and \$650,000 respectively that the vendor had initially offered to Hydro One as a discount, and could not use certain products delivered by the vendor for any RFP or other procurement processes in the future. Hydro One explained that the smart-metering project was a multi-phase one, with each phase proceeding on completion of the previous phase and at the sole discretion of Hydro One. Hydro One further indicated that since the initial contract had been awarded through a competitive process, there was no requirement to conduct separate competitive processes for subsequent phases.

### Additional Costs of Implementing Smart Metering

Apart from smart-meter capital and operating costs, there were other expenses relating to implementation of Smart Metering, including the disposal of analog meters and the future replacement of smart meters, that will have a significant impact on electricity bills.

The installation of about 4.8 million smart meters in Ontario rendered millions of conventional analog meters obsolete, making it necessary to retire and dispose of them sooner than planned. The distribution companies we consulted said the analog meters they had to scrap were still in good shape and could have been used for another five to 16 more years. The expense of scrapping analog

meters became part of the so-called stranded costs, added to the costs of procuring, installing and operating smart-metering systems. The OEB allows distribution companies to fully recover stranded costs from ratepayers through the Delivery Charge on electricity bills. As of January 2011, total stranded costs would be about \$400 million, which represents the net book value of the obsolete analog meters as reported in the 2005 OEB implementation plan. As such, this \$400 million more reliably captures stranded costs than the \$185-million amount in stranded costs that the distribution companies had reported in their smart-meter-cost-recovery applications to the OEB at the time of our audit. In our view, this \$185-million amount is incomplete because it represents only the costs the distribution companies are recovering through the application process to the OEB but not the costs that they are recovering through other means, such as writing off the value of their analog meters outright and accelerating the depreciation of their analog meters.

Apart from the stranded cost, another additional cost is related to the replacement of smart meters, which will likely further increase the Delivery Charge on electricity bills because smart meters would be subject to earlier and more frequent replacement than analog meters. The estimated useful life for a typical smart meter is 15 years, compared to 40 years for an analog meter. The distribution companies we consulted said the 15-year estimate is overly optimistic because smart meters:

- are subject to significant technological changes, making it difficult to maintain hardware and software for the first-generation meters, which do not have the advanced functions of newer models;
- have complex features, such as radio communications and digital displays, which are subject to higher malfunction and failure rates;
- are similar to other types of information technology, computer equipment and electronic devices in that they are backed by short warranty periods and require significant upgrades

or more frequent replacements as the technology matures; and

- will likely be obsolete by the time they are re-verified as required by the federal agency Measurement Canada every six to 10 years.

Costs relating to replacements will be subject to OEB review and approval. If the OEB does not allow the distribution company to recover these costs from ratepayers, the distribution company will seek recovery through other means (for example, passing the costs on to taxpayers and/or reducing the dividends that the distribution company pays to the municipality). At the distribution companies we visited, we noted cases of mass replacements of smart meters triggered by technological advances and malfunctions. For example:

- In 2013, one large distribution company notified the OEB that 96,000 first-generation smart meters installed in 2006 had to be replaced prior to their normal retirement date to take advantage of improved functionality provided by updated technology. The new meters have 10 times the memory retention of first-generation meters, and provide a “last gasp” function that allows them to detect imminent power outages. The distribution company forecast that 37,000 first-generation meters would be replaced by the end of 2020, and projected a \$2.5-million loss on disposal of these older smart meters. The total cost of replacing these meters was set at \$11 million.
- In 2012, another large distribution company identified a communication defect in a specific batch of 71,000 smart meters, and had to replace them all regardless of whether they malfunctioned, because they would eventually fail. The distribution company had already replaced about 62,000 of them and expected to complete the job by the end of 2014. From 2013 to April 2014, the distribution company incurred \$8.7 million in replacement costs, but it expected to recover at least \$2.3 million of that cost from the vendor under the commercial terms of the warranty.

## RECOMMENDATION 4

To ensure that the unanticipated costs incurred by distribution companies in implementing the Smart Metering Initiative are justified, and that any significant cost variations among distribution companies are adequately explained, the Ontario Energy Board should perform detailed reviews of distribution-company costs, including an analysis of cost variations for similar services among different distribution companies.

## OEB RESPONSE

The OEB has reviewed the prudence of smart-meter costs incurred by most distribution companies through the OEB's hearing process. These reviews took into account the requirements of Ontario Regulation 426/06, the costs incurred by the distribution companies seeking approval and the variations of the costs incurred by different distribution companies. Accordingly, the OEB does not anticipate undertaking additional analysis of those smart-meter costs that have already been reviewed through the OEB's hearing process. However, several distribution companies, including Hydro One, have not yet applied for recovery of all of the smart-meter costs they have incurred. Once those distribution companies apply for such recovery, the OEB will review the prudence of those costs in accordance with the factors set out above.

## RECOMMENDATION 5

To improve cost-efficiency of the distribution companies and reduce variations in distribution companies' costs, the Ministry of Energy, in conjunction with the Ontario Energy Board, should formally conduct a cost-benefit analysis into consolidating distribution companies as recommended by the Ontario Distribution Sector Review Panel.

## MINISTRY RESPONSE

The Minister of Energy has committed that government will not legislate or force consolidation within the distribution sector. The government is focused on delivering ratepayer savings through voluntary consolidation on a commercial basis and in the best interest of ratepayers.

The government sought input from the local distribution companies (LDCs) to create efficiencies and deliver savings to ratepayers while at the same time positioning the distribution sector to meet the challenges of the future. The government continues to challenge LDCs to do more to improve efficiency and reduce costs for ratepayers.

Hydro One and its large distribution customer base can act as a catalyst for consolidation by seeking acquisition and partnership opportunities. The government expects that Hydro One will only pursue opportunities that are economically viable and in the best interest of ratepayers.

Any change of ownership in the local distribution sector is subject to Ontario Energy Board approval.

## OEB RESPONSE

The OEB has undertaken a number of initiatives to improve the cost-efficiency of distribution companies and to address any regulatory barriers to consolidate the distribution companies. The OEB would be pleased to work with the Ministry regarding any further cost-benefit analysis of distribution-company consolidation that the Ministry may consider appropriate in the circumstances.

## RECOMMENDATION 6

To ensure that any future project is implemented cost-effectively and in compliance with sound business practices, Hydro One should

review and improve its contracting and procurement activities, such as retaining adequate documentation to justify vendor selection and evaluation and acquiring enough knowledge about a project's business requirements before issuing a Request for Proposal, to minimize the risks of significant contract-cost increases.

## HYDRO ONE RESPONSE

The Request for Proposal (RFP) process for Hydro One's smart-metering project was completed in April 2005. Subsequent to the RFP process and the Auditor General's audit on Hydro One's Acquisition of Goods and Services in 2006, Hydro One developed an evaluation guideline, which requires documentation of detailed notes to substantiate the evaluation scores.

Hydro One agrees that it is subject to the government's procurement directives. Hydro One has complied with such directives and associated amendments since the first directive was issued in July 2009. In 2009 and 2010, Hydro One also changed its internal policies to comply with the government's travel and expense and procurement directives. For example, Hydro One no longer reimburses its consultants for meals, hospitality or incidentals, and continues to reimburse expenses related to flights, train and car travel and hotel rooms only if such expenses are agreed to in the contracts and pre-approved by Hydro One.

Hydro One also agrees that a Request for Information (RFI) process is a useful tool to assess the market, determine business requirements, and/or estimate project costs. Responses to RFIs contribute to the content of an eventual RFP document. The RFI is a procurement tool that Hydro One now employs.

## Smart-meter Data Processing Systems and Costs

Data collection and management is an important component of Smart Metering to ensure that accurate and timely meter-reading data is available from which to prepare TOU-based bills for ratepayers.

In July 2006, the government appointed the Independent Electricity System Operator (IESO) as co-ordinator of the Smart Metering System Implementation Program. A key IESO responsibility was to establish the Meter Data Management and Repository (provincial data centre), to provide a common and central platform for processing, storing and managing smart-meter data to support TOU pricing.

In July 2007, the government designated the IESO as a Smart Metering Entity, making it responsible to manage the development, implementation and operation of the provincial data centre, and to facilitate the integration of smart-meter data within the centre. The aim was to enable distribution companies to bill ratepayers accurately for consumption. The data flow between the distribution companies and the IESO within the smart-metering system is illustrated in **Figure 14**.

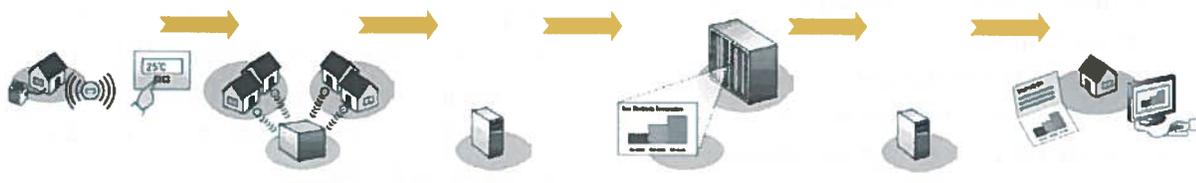
### Ratepayers Charged for Redundant or Unused Provincial Data Centre Services

The *Energy Conservation Responsibility Act, 2006*, permits the IESO to recover costs associated with the development, implementation, and operation of the provincial data centre, as well as the integration of the distribution companies into the provincial data centre. In March 2013, the OEB approved an IESO application to recover from all residential and small-business ratepayers the \$249-million cost for the period from 2006 to 2017 (including \$100 million in actual costs from 2006 to 2012 and the \$149-million projected costs from 2013 to 2017) through a new Smart Metering Charge (Charge) of 79¢ a month. This monthly Charge has been included in the Delivery Charge on electricity bills

Figure 14: Smart Metering System and Data Flow in Ontario

Source of data: Independent Electricity System Operator (IESO)

73 Local Distribution Companies			IESO	73 Local Distribution Companies	
Smart Meters	Data Collector	Data Transfer	Data Processing*	Billing System	Data Access
Smart meters installed by a distribution company track hourly electricity usage data.	Data is sent by wireless connection, phone or power line to a regional collector owned by the distribution company.	Regional collector relays data to a system operated by the distribution company.	Provincial data centre collects data from distribution company and calculates electricity usage during on-peak, mid-peak and off-peak hours.	The distribution company receives data from the provincial data centre and prepares electricity bills from its billing system.	Ratepayers have access to their data through electricity bills and online through distribution company's website.



\* Almost all of the distribution companies have also used their own systems to process smart-meter data (before transmitting it to, or after receiving it from, the provincial data centre) for billing purposes, as illustrated in the section *Duplication of Systems and Costs*.

since May 1, 2013, and will continue until October 31, 2018.

About 4.8 million smart meters have been installed by distribution companies across Ontario, but approximately 812,000 of them, or about one in six, have not transmitted any data to the provincial data centre for processing. However, these 812,000 ratepayers still have to pay the monthly Charge of 79¢, totalling about \$42.1 million up to October 2018. Specifically:

- In August 2008, one large distribution company implemented its own system to process smart-meter data, with functions similar to the provincial data centre. In April 2009, the Ministry and this distribution company signed a Letter of Understanding allowing the company to use its own system on an interim basis to accelerate the introduction of TOU pricing. The distribution company initially agreed to begin transmitting its smart-meter data to the provincial data centre by the end of 2010. In February 2013, the company deferred its plan for full integration with the provincial data centre to the end of 2015. Currently, this company has about 700,000 ratepayers with smart meters, but still has not transmitted any data to the provincial data centre. While these 700,000 ratepayers have never benefited from the provincial data centre, each still has to pay the 79¢-a-month Charge; they have paid a total of about \$7.7 million up to mid-2014, and will pay \$28.6 million more by October 2018. On top of the monthly Charge, these ratepayers also cover the cost of the distribution company's own data system.
- Another large distribution company has about 112,000 ratepayers with smart meters, but has not transmitted any data to the provincial data centre due to internal network connectivity issues with the company's smart-metering system. Although these 112,000 ratepayers have never benefited from the provincial data centre, they must also pay the monthly Charge of 79¢—a total of \$1.2 million up to mid-2014 and another \$4.6 million by October 2018.

## Duplication of Systems and Costs

The *Energy Conservation Responsibility Act, 2006* and Ontario Regulation 393/07 designated the IESO as the Smart Metering Entity, with “exclusive authority” to carry out the following functions through development and operation of the provincial data centre:

- collect, manage and store meter data;
- perform validation, estimating and editing activities to identify and account for missed or inaccurate meter data;
- operate one or more databases to facilitate collecting, managing, storing and retrieving meter data; and
- prepare data that is ready for use by distribution companies to bill ratepayers.

In February 2007, the Program Definition Document, which established the responsibilities for the Ministry and the IESO in the design and delivery of provincial data centre functionality, also stated that “centralization of the [provincial data centre] functions will ensure a standardization of data validation, estimating and editing processes across the province and facilitate a cost-effective implementation of such processes.”

However, when the IESO began developing the provincial data centre in 2007, some distribution companies had already procured and begun to install their own smart meters and associated systems, which varied from one company to another. As a result, we noted that the use of the provincial data centre as a central system has not been cost-effective, because most of the distribution companies have used their own systems to process smart-meter data (before transmitting it to, or after receiving it from, the provincial meter data management system) for billing purposes.

In interviews with and surveys of distribution companies, we found that 96% have been using their own systems to process smart-meter data, and 88% said their own systems and the provincial data centre perform similar functions, resulting in redundancy. For example, before transmitting data

to the provincial data centre, the distribution companies use their systems to perform data validation, estimating and editing services—all key functions of the provincial data centre.

The costs of this duplication—one system at the provincial level and another locally—are all being passed on to ratepayers. The monthly operating cost associated with each distribution company’s own system, about 21¢ per meter on average, is being borne by ratepayers on top of the 79¢ monthly Smart Metering Charge (see the section **Ratepayers Charged for Redundant or Unused Provincial Data Centre Service**).

Based on our review of comments submitted by distribution companies and stakeholders in June 2006, during the Ministry’s consultation, we noted consistent concern about system duplication. Examples of comments:

- “Centralization of part of the customer billing functions and accountabilities as proposed are unnecessary and incomprehensible given the complexities and issues that give rise to exceptions in determining meter reading and billing quantities on a daily basis.”
- “Vesting that responsibility [validation, editing and estimating (VEE) function of smart-meter data] in the [provincial data centre] is tantamount to duplication of efforts and operational inefficiencies that will lead, in turn, to incremental costs.”
- “The customers will call us when they have questions or problems. It is critical that the [local distribution companies] have free and open access to our customer data, the right to archive data for billing and operational usage, and continue to be the sole point of contact for our retail customers.”
- “[Local distribution companies] have never been given a reasonable explanation as to why the data needs to be gathered, stored and redistributed back to [local distribution companies] from such a massive central storage base... Customers will be calling their local distributors for information that will be

primarily housed at a central [provincial data centre].”

- “Validation, editing and estimating (VEE) will be performed centrally. This central assumption is of great concern to [local distribution companies]. As the [local distribution company] has the local customer relationship and knowledge, it is in the best position to know the unique specifics of their individual customers and therefore provide the most accurate edits and estimations of customer data.”
- “As the LDCs’ Customer Information System (CIS) is the source of the relationship between customer, location and meter, CIS will now also have to manage that relationship including the new [provincial data centre]. This will require programming changes within CIS systems... This approach seems to be one which would result in significant duplication of data in order to maintain these relationships.”

### Significant System Development and Integration Challenges

Tight and aggressive timelines set by the government, as noted in the section **Governance and Oversight of Planning and Implementation**, along with the complex structure of Ontario’s electricity sector involving numerous distribution companies, have created significant challenges in the system-development and integration aspects of implementation of Smart Metering.

#### Aggressive Smart Metering Implementation Timelines

According to the OEB’s 2005 implementation plan for Smart Metering, many stakeholders expressed concern over an aggressive timetable that could lead to mistakes and higher costs. The OEB plan also warned that Smart Metering was both challenging and complex, requiring an intense and well-co-ordinated effort between key players over several years, plus the co-operation of ratepayers.

We found that aggressive timelines created challenges in the development of the provincial data centre and its integration with different systems at the distribution companies. For example, senior IESO management indicated that the timelines were tight from the start and that development of the provincial data centre was a large undertaking being done too quickly, especially in 2007 and 2008, when the IESO encountered software and technical issues. The IESO expressed concerns about the tight timelines to the Ministry, but there was no change to the original summer 2007 deadline. The IESO did not meet that deadline, and delivery of the provincial data centre was delayed to March 2008. Some distribution companies had started installing smart meters for ratepayers prior to 2007. The provincial data centre was not ready to process smart-meter data for TOU pricing when the first smart meter went online.

The OEB also indicated that 40 out of 73 distribution companies applied for extensions to their mandated implementation dates of TOU pricing due to operational or technical problems, including delays in integrating with the provincial data centre and data-quality issues with certain smart meters.

In addition, 40% of the distribution companies we consulted ranked “implementation timelines” as one of the top three challenges (see **Appendix 1**). Some of the distribution companies commented that:

- “The province should have provided more time for testing and implementation of smart meter technology as opposed to rushing unproven technology into service.”
- “Integration with the [provincial data centre] presented challenges as the system design and timelines continued to evolve during the implementation.”
- “Meeting timelines was difficult due mainly to integration challenges.”
- “Implementation timelines were aggressive given all the testing and paper-work that was required.”

### Complicated Structure of Electricity Sector for Smart Metering Implementation

In other jurisdictions, mass deployment of smart meters was carried out by only a few distribution companies, or even just one. The challenge in Ontario was that 73 different distribution companies were each responsible to purchase, install, operate and maintain smart meters, as well as to bill ratepayers.

The fact that a relatively large number of distribution companies operate in Ontario's electricity sector has made it challenging to ensure cost-efficient implementation of Smart Metering, in part because it required significant system integration between the provincial data centre and different smart-metering systems as well as billing systems at individual distribution companies. To ensure compliance with system interface and data-transfer requirements, each distribution company had to upgrade its existing systems, or acquire new ones, and perform a series of hardware and software tests. Specifically, we noted that:

- Seventy-five per cent of the distribution companies we consulted ranked “data management and system integration” as one of the top three challenges, and 83% said it was difficult and costly to integrate their systems with the provincial data centre (see **Appendix 1**).
- Sixty per cent of distribution companies indicated that changes to the provincial data centre required them to implement “frequent system changes and upgrades.” The IESO said that between 2009 and 2012, three major changes were made to the provincial data centre to correct defects, deliver new functions, and address the issue flagged by Measurement Canada (see section **Non-compliance with Measurement Canada's Data Requirements**). Apart from the three major changes, the provincial data centre was also modified during 2008 and 2009 to support changes to distribution company systems and operating practices. Distribution companies that tracked these costs reported spending a total of about \$47 million to change their internal systems to ensure proper integration and compatibility with the provincial data centre (see **Figure 15**). Some of the distribution companies commented as follows:
- “Integration with [the provincial data centre] required multiple upgrades and ongoing testing beyond testing required with the IESO.”
- “Testing with the [provincial data centre] was a very onerous task.”
- “Significant time and effort went into systems integration to ensure proper data flow between the [provincial data centre] and the distribution companies.”
- “This was a costly and time-consuming exercise to integrate the distribution companies' systems and the [provincial data centre].”

**Figure 15: System-related Costs Incurred by Local Distribution Companies**

Prepared by the Office of the Auditor General of Ontario

Date	Cost Description	Approx. Cost <sup>1</sup> (\$ 000)	Report Section (if applicable)
2006–2013	Upgrading local systems to enable the implementation of TOU pricing	47,000 <sup>2</sup>	Significant System Development and Integration Challenges
2006–2013	Developing web presentment portals to allow ratepayers to access their electricity use and billing data online	1,100	
2010–2012	Fixing local systems to comply with Measurement Canada's requirements	800	Non-compliance with Measurement Canada's Data Requirements

1. Amount understated because some of the distribution companies we interviewed and surveyed did not separately track these costs. Many of the distribution companies we consulted treated these smart metering-related costs as their normal operating costs and recovered these costs through their regular rate applications to the OEB rather than through their smart-meter-cost-recovery applications.

2. About \$40 million of this \$47-million amount was incurred by Hydro One.

Aggressive implementation timelines and a complex electricity sector made it challenging to implement Smart Metering smoothly and cost-effectively.

### Insufficient Oversight of Provincial Data Centre Costs and Services

The IESO initially contracted in December 2006 with a private-sector vendor, following a competitive bidding process, for the development, implementation and operation of the provincial data centre. That initial contract was for the five years from December 2006 to March 2012, with an option for another two years to March 2014, which it exercised. In December 2012, following a competitive bidding process, the IESO entered into a new contract with the same vendor for another five years, to March 2019, with an option to extend for five more years, to March 2024. The IESO has already paid this vendor about \$81.7 million for the period from January 2007 to March 2013. Apart from using personnel supplied by this vendor and internal staff, the IESO incurred about \$16 million in costs by the end of 2013 for other consultants to develop, implement and operate the provincial data centre.

#### Contract Terms for Operating Fee of Provincial Data Centre Not Clear

Our review of the contract fee paid by the IESO to the vendor for operating the provincial data centre showed that the average annual fee of \$13.4 million for the two-year extension period between 2012 and 2014 was almost double the \$6.8-million-a-year rate of the original contract period for the five previous years.

The IESO attributed a portion of the fee increase to the additional costs associated with the changes made to the provincial data centre. However, we noted that these additional costs were mainly incurred prior to 2012, before the two-year extension, to deal with major changes made to the provincial data centre. The IESO also attributed a portion of the fee increase to the higher number of

smart meters. However, the government had set the target of installing smart meters for all residential and small-business ratepayers, so the IESO should have been aware of the number of smart meters that had to be installed.

We noted that the IESO and the vendor negotiated and agreed upon the higher contract fee as a result of the ambiguity of contract terms for the two-year extension period. Specifically, when the IESO prepared in June 2011 to exercise the two-year extension option under the original contract, it discovered an error that resulted in an underestimation of the cost projection for the two-year extension period by \$13.9 million. As a result, IESO management informed the Board of Directors that the error stemmed from an amendment that failed to clarify the contract fee applicable to the two-year extension. IESO management also informed its legal counsel that this was an oversight on the part of the vendor, the IESO and their counsels, and that since the vendor had incurred losses on the contract, the “ambiguity around contract extension offered opportunities to improve the vendor’s commercial position and stem their losses going forward.”

#### Continued to Contract for Service Not Being Used

Under the original contract, the IESO required the vendor to provide Interactive Voice Response (IVR) service that enables ratepayers to check their electricity usage by telephone. The IVR service was available for use in March 2008, when the provincial data centre began operating. However, only two of the 73 distribution companies chose to register and configure themselves for IVR, and they reported only limited ratepayer use of the service. For example, only 25 ratepayers at these two distribution companies used IVR from February 2012 to March 2013. Even though there has been very little use of IVR since its start-up in March 2008, the IESO still included IVR in the new contract signed with the vendor in December 2012.

While almost 80% of the distribution companies integrated their systems with the provincial data centre in 2011 and early 2012, the IESO indicated that it did not have sufficient information on the actual use of the IVR service prior to 2013. As such, the IESO did not retire IVR until September 2013, and it consequently negotiated a credit of \$390,000 to be applied against future deliverables from this vendor. Adequate and proper monitoring of service usage on a timely basis would have terminated the IVR service sooner and eliminated the associated cost, which was not specified in the contracts and could not be estimated.

### RECOMMENDATION 7

To ensure that ratepayers are not burdened with the duplicated and ongoing costs of system development and integration, the Ministry of Energy should work with the Independent Electricity System Operator (IESO), the Ontario Energy Board (OEB) and the distribution companies to re-evaluate options around operating the provincial data centre and/or having separate local systems at individual distribution companies in order to determine the cost-effectiveness of various options and avoid continued duplication of systems and costs.

### MINISTRY RESPONSE

The Ministry has ensured that the necessary regulatory framework, in particular Ontario Regulations 393/07 and 426/06, is in place to restrict cost duplication for services which are within the exclusive authority of the Meter Data Management and Repository.

The Ministry will continue to investigate opportunities to build on the value already provided by the provincial data centre.

### IESO RESPONSE

If requested by the Ministry of Energy, the IESO will work with the Ministry and the OEB

to encourage distribution companies' compliance with existing regulation and reduce the reported duplication of the functions that the IESO has exclusive authority over, and that are fulfilled by the provincial data centre.

Similarly, if requested by the Ministry of Energy, the IESO will work with the Ministry and distribution companies to identify and evaluate opportunities for leveraging existing investments and economies of scale of the provincial data centre in order to reduce the operating costs of distributors and costs to the ratepayer.

### OEB RESPONSE

The OEB would be pleased to work with the Ministry of Energy and others in any assessment that the Ministry may initiate in respect of options regarding the cost-effective use of the resources of the provincial meter data management system and the local distribution systems.

### RECOMMENDATION 8

To ensure that any future province-wide project involving the complex electricity distribution sector is implemented cost-effectively, the Ministry of Energy should work with the relevant electricity sector organizations to set appropriate and reasonable implementation targets and timelines in order to minimize the costs and risks associated with system development and integration for numerous distribution companies.

### MINISTRY RESPONSE

The smart meter and time-of-use (TOU) rollout was completed via a partnership approach. Each organization, namely the Ministry, the IESO, the OEB and local distribution companies were responsible for certain aspects of the rollout, and significant consultation took place along the way.

The Ministry will ensure that projects in the electricity distribution sector are rolled out in a prudent, collaborative and cost effective manner.

## Smart-meter Data Accuracy and Quality

To minimize billing estimates and adjustments, as well as ratepayer complaints, smart-meter data has to be processed accurately and completely to produce correct and timely billing data.

### Non-compliance with Measurement Canada's Data Requirements

Measurement Canada is the federal agency responsible for ensuring that ratepayers receive fair and accurate measurement in transactions involving goods and services, including measurement of electricity consumption and billing. Generally, electricity consumption and billing can be measured using two types of smart-meter data: “register read” or “interval read.”

- “Register read,” recorded by both analog and smart meters, is the meter’s internal memory or external display showing the total cumulative consumption from the date it was installed, similar to a car odometer’s record of kilometres travelled. Prior to installing smart meters, distribution company staff manually read analog meters by visiting ratepayer premises. The cumulative meter reading on electricity bills should match the numbers on the meters.
- “Interval read” is logged only by a smart meter, and is a time-based record of electricity usage (hourly or shorter period) by ratepayers.

Measurement Canada requires the cumulative meter reading to be used in calculating the billing amount, and to be displayed on both the meter and the bill. These requirements ensure transparency by providing information on electricity bills that enable ratepayers to look at their meter’s display and then reconcile it to the amounts on their bills. However, Measurement Canada advised both the IESO and the Ministry in November 2009 that its requirements were not being met in Ontario, because the cumulative meter reading from smart

meters was not being captured by the provincial data centre or by the distribution companies’ systems. In January 2010, Measurement Canada reiterated its concerns and instructed the IESO to take corrective action by January 1, 2012. Consequently, both the IESO and the distribution companies changed their systems to address Measurement Canada’s concern. The IESO spent \$13.7 million to make necessary adjustments to the provincial data centre.

Apart from the IESO, the distribution companies also incurred costs to fix the problem at their end. In August 2010, the IESO indicated to the media that only about 150,000 ratepayers at five distribution companies were affected by this issue. However, we noted at the time of our audit that, in fact, all distribution companies were affected and had incurred additional costs to fix the problem. Of the distribution companies we consulted, only 20 of them tracked their costs for this—a collective total of more than \$800,000 to correct the problem (see **Figure 15**). One distribution company noted that the Measurement Canada issue has “negatively impacted the costs associated with [provincial data centre] integration.” Another said the billing systems of all distribution companies “had to be re-engineered to remove ‘register reads’ when the [provincial data centre] was first implemented and then re-engineered again to put the ‘register reads’ back ... there really seemed to have been a misunderstanding with the Ministry or IESO as the system should have been designed to show ‘register reads’ right from the beginning.”

### Questionable Quality and Usefulness of Meter-reading Data

Several limitations in processing smart-meter data by the provincial data centre and the business processes at the distribution companies have affected the quality and usefulness of smart-meter data. For example:

- When distribution companies change or replace meters, they must follow a proper

business process that requires them to send two sets of consumption data to the provincial data centre: one set from the old meter and one from the new. Given that some distribution companies did not follow this process, there is no guarantee of the quality and completeness of data they submitted to the provincial data centre, creating a risk that incorrect billing data could be generated.

- Not all smart meters are equipped with technology to notify the provincial data centre when power outages occur. The Ministry also indicated that the provincial data centre is not intended to have a real-time outage management function to help identify blackouts. As a result, ratepayers who lose power during outages could still receive electricity bills based on estimates made by the provincial data centre or the distribution companies. In December 2013, for example, a severe ice storm caused massive power outages in southern Ontario. Based on our review of usage data from one large distribution company affected by the blackouts, some ratepayers with no power still had to pay electricity bills based on estimates of their historical consumption patterns, and the distribution company had to correct the bills in subsequent billing periods.
- Almost all distribution companies have their own systems as noted in section **Duplication of Systems and Costs**. Apart from using these internal systems to process smart-meter data, companies also use it to query and retrieve usage data for ratepayers and for internal analysis. According to half the distribution companies we consulted, they do this because the provincial data centre has limited capabilities for data retrieval and querying. In August 2013, the IESO also reported to its Board of Directors that the provincial data centre was able to manage data queries during its early stage of implementation, but it was not designed to support the expected increases in volume of data-retrieval requests. This has,

in turn, reduced the value and usefulness of the provincial data centre, which had been expected to facilitate storage and retrieval of meter data when it was first developed.

## RECOMMENDATION 9

To ensure the accuracy, quality and usefulness of smart-meter data, the Independent Electricity System Operator should:

- work with the distribution companies to review the limitations and the billing problems associated with the provincial data centre and the distribution companies' business processes, including improving the procedures of processing smart-meter data during meter replacements and power blackouts, as well as enhancing the data retrieval and querying capability of the provincial data centre; and
- educate the distribution companies about the proper business processes that have to be followed.

## IESO RESPONSE

The IESO has provided training sessions for all distribution companies on processing meter replacements and power blackouts within the provincial data centre. The IESO will provide additional training sessions and assistance to those distribution companies that need such training to improve the procedures of processing smart-meter data.

Subsequent to the audit, the IESO enhanced the data retrieval and querying capability of the provincial data centre. Also, the IESO and the Ministry have been working together to develop a business case for a project that will support the evolving needs for data access and retrievals for research and analysis purposes.

## Smart-meter Security and Safety Risks

The expanding use of smart meters has led to questions and concerns about possible security risks relating to privacy, and safety risks associated with fire hazards. As part of our audit, we examined these concerns in Ontario.

### Insufficient Security and Access Controls on Meter-reading Data

The ability of smart meters to track electricity use on an hourly basis for residential and small-business ratepayers has raised security and privacy concerns regarding unauthorized access to and use of smart-meter data. Smart meters enable the collection of massive amounts of personal electricity-use data, allowing ratepayers and distribution companies—as well as anyone else with access to the data—to see exactly what makes up a ratepayer’s electricity use. The smart-meter data could reveal when people are out, daily routines and changes in those routines. As a result, electricity-use patterns could be mined, for example, for marketing and advertising purposes.

In Ontario, about 800 distribution company employees and/or their agents have access to specific functions in the provincial data centre that include viewing and editing meter data through an encrypted interface from any computer connected to the Internet. The IESO’s existing controls to prevent and detect unauthorized data access include an annual audit of the provincial data centre by external auditors and an annual risks-and-controls assessment by IESO staff. However, we noted that data security could be improved further. Specifically:

- The provincial data centre automatically grants access to users through a login process that requires a name and password. However, no additional authentication code is required. Based on our research, and consultation with an independent expert in information security

and smart metering, the best practice for more secure remote access of privacy-sensitive information is two-step verification. This requires users to provide an authentication code generated by a security device issued to them, in addition to user name and password.

- The IESO has engaged external auditors to conduct an annual audit to provide reasonable assurance that its controls over the provincial data centre are suitably designed and operate effectively. Since this audit is not designed to cover the distribution companies, it is limited to provincial data centre operations and controls specified by the IESO. We noted that data from the provincial data centre could still be exposed to potential security risks at the distribution-company level because:
  - As noted in the section **Duplication of Systems and Costs**, almost all distribution companies we consulted use their own systems to process smart-meter data. Also, about 85% of them indicated that they have not performed any Privacy Impact Assessment (PIA), a formal risk-management tool used to identify the actual or potential effects that a proposed or existing system may have on ratepayer privacy. The PIA is considered a “best privacy practice” for organizations with significant existing or new systems containing personal information.
  - Our review of a sample of 200 staff at different distribution companies who had access to the provincial data centre found that eight who had left the distribution companies did not have their access revoked in a timely manner. The IESO indicated that it is up to distribution companies to advise it when access rights need to be modified or ended. The IESO also said it does not have the jurisdiction, responsibility or ability to review the appropriateness of users to whom distribution companies wish to grant access. Therefore, there

could be security risks at the distribution-company level that the IESO was not aware of and over which it had no control.

### Lack of Tracking and Monitoring of Smart Meters-related Fire Incidents

At the time of our audit, we found instances of Ontario ratepayers reporting fires arising from smart meters. From our research, we also noted that other jurisdictions, such as British Columbia, Saskatchewan and Pennsylvania, also reported cases of smart meters catching fire. However, no accurate or complete information on smart meters-related fires was available in Ontario to determine the scope and extent of the problem across the province. Specifically:

- The Office of the Fire Marshal (OFM), Ontario's principal adviser on fire protection policy and safety issues, indicated that it is aware of fires involving smart meters in Ontario, elsewhere in Canada, and in the United States. However, some distribution companies and fire departments do not report such cases to the OFM, so more information is needed to assess the extent of the problem in Ontario. From May 2011 to March 2013, for example, the OFM recorded 14 fires involving either meters or the bases on which they were mounted. However, the OFM indicated that its incident-reporting system could not specifically identify what type of device was involved— analog or smart meter—because it did not collect specific details about the meters. Based on anecdotal evidence, the OFM identified three possible root causes for the fires:
  - old meter base connections may have been loose or otherwise unfit for a seamless exchange to a new smart meter;
  - new smart meters may have been improperly installed; or
  - new smart meters may have had defects that caused electrical failures or misalignment with the old meter base.
- The Electrical Safety Authority (ESA), the agency with a mandate to enhance public electrical safety in Ontario, is delegated by the government to be responsible for the regulation that applies to meter installation. Any meter failure resulting from incorrect installation by the distribution company falls under the ESA's regulatory oversight. In February 2007, and again in October 2012, the ESA indicated that it has been aware of potential fire risks in smart meters, and incidents of property damage involving smart meters and/or meter bases. To address these concerns, the ESA surveyed the distribution companies, asking them to provide information on such incidents. However, the ESA indicated that it has not received sufficient information to conclude on the severity of the issue or the types of meters causing problems. Due to recent smart meters-related fires in Saskatchewan, the ESA started reviewing those incidents in the summer of 2014 to determine if there could be any concerns in Ontario.
 

The federal Industry Canada department oversees the certification of radio communication devices, including smart meters, which must be tested and certified against Industry Canada standards before they can be sold in this country. At the provincial level, the ESA acts on behalf of the Ontario government, with specific responsibility for electrical safety. As part of its mandate, the ESA administers the Ontario Electrical Safety Code and regulations associated with electricity-distribution-system safety, electrical product safety and licensing of electricians. However, there has been a lack of clarity on the safety standards relating to smart meters at the provincial level. Specifically:

  - The ESA indicated that according to an Ontario Electrical Safety Code bulletin in May 2012, federal legislation does not give ESA any jurisdiction over revenue billing devices (i.e., smart meters and associated transformers) and does not require the

revenue billing devices to be approved provincially as required by the Canadian Electrical Code or Ontario Electrical Safety Code.

- The ESA further noted that the Ontario Electrical Safety Code applies to meter bases and mounting devices, but not to revenue billing devices such as the actual smart meters. Therefore, smart meters and associated transformers are deemed acceptable if they have an approval number provided by Measurement Canada, a federal agency. However, we noted that Measurement Canada is mandated to ensure the integrity and accuracy of measurement, including electricity consumption and billing data, but not the safety, of measuring devices such as smart meters.

Insufficient tracking and monitoring of smart meters-related fire incidents has made it difficult to determine the scope and extent of the problem across the province as well as to address the problem accordingly, creating safety risks in Ontario.

### RECOMMENDATION 10

To ensure that smart-meter data is processed and stored securely, the Independent Electricity System Operator should work with the distribution companies to improve their system and data-security controls in order to prevent and detect unauthorized access to smart-meter data.

### IESO RESPONSE

Subsequent to the audit, the IESO introduced new capabilities in June 2014 to help distribution companies manage their users' access to the provincial data centre. The IESO provides the distribution companies with additional information that allows them to identify required changes to their users' access permissions. Based on this additional information, the distribution

companies are to notify the IESO of any necessary changes.

In addition, the IESO will review the data-security controls in place at the IESO and the controls that should be in operation at the distribution companies to prevent and detect unauthorized access to smart-meter data. The IESO will also work with the distribution companies to review the "Building Privacy into Ontario's Smart Meter Data Management System" paper published by the IESO and the Information and Privacy Commission of Ontario.

### RECOMMENDATION 11

To ensure that potential fire risks of smart meters are addressed appropriately and in a timely manner, the Ministry of Energy should work with relevant entities, such as the distribution companies, the Office of the Fire Marshal and the Electrical Safety Authority, to track and monitor information on smart meter-related fire incidents so as to identify and understand their causes in Ontario.

### MINISTRY RESPONSE

The Ministry has not received information from the appropriate authorities or local distribution companies (LDCs) to indicate that there is a safety risk with smart meters in Ontario.

The Ministry will support efforts by the appropriate entities such as the Office of the Fire Marshal, the Electrical Safety Authority and LDCs to ensure that any concerns or incidents related to electricity meter safety are tracked and monitored accordingly.

The Ministry continues to monitor the concerns and actions related to meter safety in Saskatchewan and consider any implications for Ontario.

## Appendix 1—Questions to and Responses from Distribution Companies in Ontario

Prepared by the Office of the Auditor General of Ontario

Selected Questions	Responses	
	% of Distribution Companies Responded "Yes"	% of Distribution Companies Responded "No"
Did your distribution company realize any net savings in operations since implementing the Smart Metering Initiative?	5	95
Did your distribution company conduct any study to examine the bill impact since the implementation of smart meters and time-of-use (TOU) rates?	9	91
Did your distribution company conduct any study to examine the changes of electricity consumption since the implementation of smart meters and TOU rates?	0	100
Does your distribution company have a system, performing similar functions as the central Meter Data Management and Repository, to process smart meter data?	96	4
Did your distribution company perform any Privacy Impact Assessment when implementing the Smart Metering Initiative?	15	85
<b>% of Distribution Companies Indicated as Concerns</b>		
Please indicate your distribution company's concerns with the Meter Data Management and Repository (provincial data centre)	88% – Redundant functionality with the systems at distribution company	
	83% – Difficult and costly to integrate distribution companies' systems with the Meter Data Management and Repository	
	60% – Frequent changes and upgrades of the Meter Data Management and Repository	
	50% – Limited capacity or capability for data retrieval and query	
<b>% of Distribution Companies Ranked as Top 3 Challenges</b>		
Please rank the challenges that your distribution company has faced in implementing the Smart Metering Initiative.	75% – Costly data management and system integration	
	44% – Lengthy procurement process	
	40% – Tight implementation timeline	
<b>% of Distribution Companies Indicated as Top 3 "High Volume" Complaints</b>		
Please indicate the volume (High/Low) of ratepayer complaints relating to smart meters and TOU pricing since the implementation of Smart Metering Initiative in your distribution company.	51% – Increased bills with no savings	
	33% – Limited understanding and information on TOU pricing	
	24% – Limited or no ability to change electricity consumption	

## Appendix 2—Delivery Charge on Monthly Electricity Bill by Distribution Company<sup>1</sup>

Source of data: Ontario Energy Board

Distribution Company	Delivery Charge (\$)	Distribution Company	Delivery Charge (\$)
1. Algoma Power Inc.	59.4	37. Kitchener-Wilmot Hydro Inc.	35.0
2. Atikokan Hydro Inc.	65.5	38. Lakefront Utilities Inc.	36.7
3. Bluewater Power Distribution Corporation	45.8	39. Lakeland Power Distribution Ltd.	53.4
4. Brant County Power Inc.	40.8	40. London Hydro Inc.	38.3
5. Brantford Power Inc.	31.8	41. Midland Power Utility Corporation	48.7
6. Burlington Hydro Inc.	40.1	42. Milton Hydro Distribution Inc.	40.3
7. Cambridge and North Dumfries Hydro Inc.	36.5	43. Newmarket-Tay Power Distribution Ltd. (Newmarket) <sup>2</sup>	41.7
8. Canadian Niagara Power Inc. (Fort Erie) <sup>2</sup>	52.6	Newmarket-Tay Power Distribution Ltd. (Tay) <sup>2</sup>	24.9
Canadian Niagara Power Inc. (Port Colborne Hydro Inc.) <sup>2</sup>	53.8	44. Niagara Peninsula Energy Inc. (Niagara) <sup>2</sup>	39.6
9. Centre Wellington Hydro Ltd.	41.6	Niagara Peninsula Energy Inc. (Peninsula) <sup>2</sup>	42.7
10. Chapleau Public Utilities Corporation	53.2	45. Niagara-on-the-Lake Hydro Inc.	41.8
11. COLLUS PowerStream Corp.	34.9	46. Norfolk Power Distribution Inc.	53.1
12. Cooperative Hydro Embrun Inc.	39.7	47. North Bay Hydro Distribution Limited	40.4
13. E.L.K. Energy Inc.	30.9	48. Northern Ontario Wires Inc.	51.2
14. Enersource Hydro Mississauga Inc.	36.8	49. Oakville Hydro Electricity Distribution Inc.	43.5
15. Entegrus Powerlines Inc.	41.0	50. Orangeville Hydro Limited	42.3
16. EnWin Utilities Ltd.	41.6	51. Orillia Power Distribution Corporation	41.3
17. Erie Thames Powerlines Corporation	44.2	52. Oshawa PUC Networks Inc.	33.8
18. Espanola Regional Hydro Distribution Corporation	51.1	53. Ottawa River Power Corporation	36.5
19. Essex Powerlines Corporation	43.6	54. Parry Sound Power Corporation	61.0
20. Festival Hydro Inc. (Hensall) <sup>2</sup>	45.0	55. Peterborough Distribution Incorporated	37.4
Festival Hydro Inc. (Main) <sup>2</sup>	45.6	56. PowerStream Inc. (Barrie) <sup>2</sup>	35.5
21. Fort Frances Power Corporation	36.2	PowerStream Inc. (South) <sup>2</sup>	35.1
22. Greater Sudbury Hydro Inc.	37.9	57. PUC Distribution Inc.	31.7
23. Grimsby Power Incorporated	40.1	58. Renfrew Hydro Inc.	37.5
24. Guelph Hydro Electric Systems Inc.	41.9	59. Rideau St. Lawrence Distribution Inc.	43.1
25. Haldimand County Hydro Inc.	57.3	60. Sioux Lookout Hydro Inc.	55.0
26. Halton Hills Hydro Inc.	39.0	61. St. Thomas Energy Inc.	39.8
27. Hearst Power Distribution Company Limited	31.7	62. Thunder Bay Hydro Electricity Distribution Inc.	33.3
28. Horizon Utilities Corporation	40.9	63. Tillsonburg Hydro Inc.	38.6
29. Hydro 2000 Inc.	43.6	64. Toronto Hydro-Electric System Limited	46.9
30. Hydro Hawkesbury Inc.	28.0	65. Veridian Connections Inc. (Gravenhurst) <sup>2</sup>	52.8
31. Hydro One (Low Density) <sup>2,3</sup>	110.6	Veridian Connections Inc. (Main) <sup>2</sup>	38.7
Hydro One (Medium Density) <sup>2,3</sup>	69.5	66. Wasaga Distribution Inc.	27.3
Hydro One (Urban High Density) <sup>2,3</sup>	54.2	67. Waterloo North Hydro Inc.	38.0
32. Hydro One Brampton Networks Inc.	35.6	68. Welland Hydro-Electric System Corp.	41.9
33. Hydro Ottawa Limited	40.1	69. Wellington North Power Inc.	50.3
34. Innisfil Hydro Distribution Systems Limited	49.6	70. West Coast Huron Energy Inc.	55.2
35. Kenora Hydro Electric Corporation Ltd.	37.3	71. Westario Power Inc.	43.8
36. Kingston Hydro Corporation	41.4	72. Whitby Hydro Electric Corporation	44.4
		73. Woodstock Hydro Services Inc.	45.3

1. This list of 73 distribution companies was based on 2013 Yearbook of Electricity Distributors issued by the OEB. The Delivery Charge data was based on 2014 data from the OEB website.

2. These distribution companies with larger geographic coverage have different Delivery Charge in different regions within their service areas.

3. Hydro One's Delivery Charge varies, depending on the location of ratepayers and the number of ratepayers in an area. The fewer people in the area, the higher the cost of delivering power to that area.



**APPENDIX B**

**Response to Interrogatory 14**

**MARITIME ELECTRIC COMPANY, LIMITED**

**2016 CAPITAL BUDGET VARIANCE REPORT**

**February 28, 2017**

**MARITIME ELECTRIC COMPANY, LIMITED**  
**2016 CAPITAL BUDGET VARIANCE REPORT**

**SECTION:**

1	Introduction
2	Summary
3	Generation
4	Distribution
5	Transmission
6	Corporate
7	Capitalized General Expense
8	Interest During Construction
Appendix I	Schedule of Deferred Capital Budget Items
Appendix II	Schedule of Capital Budget Expenditures From Prior Years Completed in 2016

**MARITIME ELECTRIC COMPANY, LIMITED  
2016 CAPITAL BUDGET VARIANCE REPORT**

**INTRODUCTION**

On November 3, 2015, the Island Regulatory and Appeals Commission issued Order UE15-01 approving an Application by Maritime Electric Company, Limited (“Maritime Electric” or the “Company”) in respect of its 2016 Capital Budget. This report provides a description of the variances of the actual expenditures from the approved 2016 Capital Budget.

Total capital expenditures (net of contributions in aid of construction) for 2016 were \$3,413,861, or approximately 11 per cent, under the approved budget. The Company has deferred certain 2016 capital projects, totaling \$4,364,000, to 2017 (Appendix I). The total capital expenditure variance, after consideration of projects deferred to 2017, is \$950,139 over budget (see Summary Table on Page 2-1). The over budget variance of \$950,139 was driven primarily due to higher than planned expenditures on distribution replacements due to storms, collision, fire and road alterations (\$956,000); higher than planned costs for distribution line extensions and rebuilds net of contributions (\$525,000); higher costs incurred for the Y-104 transmission project (\$382,000); and higher than budgeted Interest During Construction charges (\$206,000).

These over budget variances were partially offset by lower than planned expenditures on generation asset improvements (\$57,000); lower than planned installations of distribution transformers (\$352,000); lower than planned costs for system meters (\$169,000); lower than planned costs for services and street lighting (\$333,000); lower than planned costs for transportation (\$22,000); lower than planned costs for transmission line projects (\$139,000); lower than planned costs for transmission substation projects (\$31,000); and lower than planned capitalized general expense (\$16,000).

In 2016, the Company completed \$1,101,732 of previously approved capital project work that was in progress at the end of 2015. A schedule of these projects is provided in Appendix II. In addition, the Company has deferred certain 2015 capital projects, totaling \$1,233,000 to 2017 (Appendix I).

**MARITIME ELECTRIC COMPANY, LIMITED**  
**2016 CAPITAL BUDGET VARIANCE REPORT**

**SUMMARY**

	<b>Approved 2016 Budget</b>	<b>2016 Expenditures</b>	<b>Estimated Expenditures in 2017</b>	<b>Total Expected Expenditures</b>	<b>Variance From Budget</b>	<b>Approved 2017 Budget</b>
<b>Generation</b>	\$ 1,215,000	\$ 1,157,692	\$ -	\$ 1,157,692	\$ (57,308)	\$ 1,253,000
<b>Distribution</b>	17,538,000	18,146,976	857,000	19,003,976	1,465,976	18,030,000
<b>Transmission</b>	10,399,000	7,329,918	3,282,000	10,611,918	212,918	8,641,000
<b>Corporate</b>	1,214,000	990,441	225,000	1,215,441	1,441	1,068,000
<b>Capitalized General Expense</b>	494,000	477,714	-	477,714	(16,286)	491,000
<b>Interest During Construction</b>	<u>200,000</u>	<u>405,915</u>	<u>-</u>	<u>405,915</u>	<u>205,915</u>	<u>316,000</u>
<b>Sub-Total</b>	\$31,060,000	\$ 28,508,656	\$ 4,364,000	\$ 32,872,656	\$ 1,812,656	\$ 29,799,000
<b>Less: Contributions in Aid of Construction</b>	<u>(400,000)</u>	<u>(1,262,517)</u>	<u>-</u>	<u>(1,262,517)</u>	<u>(862,517)</u>	<u>(400,000)</u>
<b>Net Total</b>	<u>\$30,660,000</u>	<u>\$ 27,246,139</u>	<u>\$ 4,364,000</u>	<u>\$31,610,139</u>	<u>\$ 950,139</u>	<u>\$ 29,399,000</u>

**MARITIME ELECTRIC COMPANY, LIMITED**  
**2016 CAPITAL BUDGET VARIANCE REPORT**  
**GENERATION**

**Generation – Summary**

	<u>Approved 2016 Budget</u>	<u>2016 Actual</u>	<u>2016 Variance</u>	<u>Approved 2017 Budget</u>
<b>4.1 Charlottetown Plant Buildings and Services Projects</b>	\$ 98,000	\$ 116,886	\$ 18,886	\$ 88,000
<b>4.2 Charlottetown Plant Boiler Projects</b>	283,000	133,839	(149,161)	154,000
<b>4.3 Charlottetown Plant Turbine-Generator Projects</b>	680,000	166,632	(513,368)	876,000
<b>4.4 Borden Plant Projects</b>	<u>154,000</u>	<u>740,335</u>	<u>586,335</u>	<u>135,000</u>
<b>Total</b>	<u>\$1,215,000</u>	<u>\$1,157,692</u>	<u>\$ (57,308)</u>	<u>\$1,253,000</u>

**4.1 Charlottetown Plant Buildings and Services Projects** **Variance \$18,886**

The Generation 4.1 budget category was \$18,886 or 19 per cent over budget. The \$52,000 budget for Charlottetown Plant Roof Replacements was over budget by \$14,900 due to further damage found once the project began that required additional spending. Also, a section of city fire and water piping that supplies the ECC and Plant buildings had to be replaced due to corrosion discovered in mid-2016 at a cost of \$12,400 which was not included in the 2016 budget. These increases were partially offset by lower than budgeted expenditures in safety equipment, parts storage improvements, and door and window replacements of \$8,400.

**4.2 Charlottetown Plant Boiler Projects** **Variance \$(149,161)**

The Generation 4.2 budget category was \$149,161 or 53 per cent under budget. The 4.2 category for 2016 consisted of miscellaneous boiler projects at the Charlottetown Plant. The budget amounts for Boiler Improvements, Large Motor Refurbishments and Tool Replacements were provisional based on past experience; however, no major issues materialized during the year resulting in lower than budgeted expenditures of

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**GENERATION**

approximately \$64,700. Additionally, the Waste Water Treatment Sand Filter Replacement project was scaled back, following internal inspections, to a replacement of the filter media within the unit instead of the complete refurbishment and replacement of the sand filter unit. This resulted in a reduction of \$78,000 compared to budget. The Boiler Insulation Replacement budget was underspent by \$6,500 due to the reduced availability of contract employees to perform this work.

**4.3 Charlottetown Plant Turbine-Generator Projects** **Variance \$(513,368)**

The Generation 4.3 budget category was \$513,368 or 75 per cent under budget.

The Turbine/Generator Overhaul on Unit No. 7 project was scaled back from a complete overhaul and refurbishment of the unit. The results of an assessment by an independent expert, ROS Consulting Inc., concluded that the overhaul could be deferred indefinitely provided temperature and vibration monitoring were installed at a substantially lower cost. This change resulted in savings of approximately \$376,000 which were reallocated, in consultation with the Commission in May 2016, to perform an emergency refurbishment on Combustion Turbine 1 (“CT1”) at the Borden Generating Station (see 4.4 budget category below).

Several projects (i.e. Steam Turbine Improvements; Combustion Turbine Improvements; and Turbine Insulation Replacements) included in this category were under budget by a total of \$137,000 due to lower than expected costs for materials and labour.

**4.4 Borden Plant Projects** **Variance \$586,335**

The Generation 4.4 budget category was \$586,335 or 381 per cent over budget. The increase was driven by unplanned emergency refurbishments related to CT1 that were identified late in 2015, after the 2016 Capital Budget had been prepared and submitted to the Commission. During a biennial borescope inspection of CT1, wear and damage to

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GENERATION**

the nozzle guide vanes and exhaust outer cone bushings of the unit were identified and initially estimated to cost \$250,000 to refurbish.

During the strip down of the CT1 engine and the removal of the parts, additional internal components were discovered that required replacement to ensure the safety and reliability of the unit. The Commission was advised of this development in July 2016. This resulted in increased costs from the original estimate of \$250,000 to the final cost of \$657,000.

This increase was partially offset by not undertaking the planned \$58,000 project to replace the roof on the Borden Service Building. It was determined that the application of a spray coating, at a cost of \$3,000, would extend the life of the roof for an estimated ten years. Other costs savings included a \$12,600 decrease in budgeted expenditures on the provisional amount for Miscellaneous Borden Projects, and savings in the 4.2 and 4.3 budget categories as discussed previously.

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**2016 CAPITAL BUDGET VARIANCE REPORT**  
**DISTRIBUTION**

**Distribution – Summary**

	<u>Approved 2016 Budget</u>	<u>2016 Actual</u>	<u>2016 Variance</u>	<u>Approved 2017 Budget</u>
<b>5.1 Replacements due to Storms, Collision, Fire and Road Alterations</b>	\$ 1,042,000	\$ 1,997,881	\$ 955,881	\$ 1,400,000
<b>5.2 Distribution Transformers</b>	3,219,000	2,866,611	(352,389)	3,388,000
<b>5.3 Services and Street Lighting</b>	4,623,000	4,289,762	(333,238)	4,369,000
<b>5.4 Line Extensions</b>	2,344,000	3,135,552	791,552	1,963,000
<b>5.5 Line Rebuilds</b>	3,145,000	2,915,755	(229,245)	3,862,000
<b>5.6 System Meters</b>	635,000	466,266	(168,734)	542,000
<b>5-7 Distribution Equipment</b>	1,778,000	1,744,897	(33,103)	1,571,000
<b>5.8 Transportation Equipment</b>	<u>752,000</u>	<u>730,252</u>	<u>(21,748)</u>	<u>935,000</u>
<b>Sub-Total</b>	\$17,538,000	\$18,146,976	\$ 608,976	\$18,030,000
<b>Less: Contributions in Aid of Construction (CIAC)</b>	<u>(400,000)</u>	<u>(1,262,517)</u>	<u>(862,517)</u>	<u>(400,000)</u>
<b>Total</b>	<u>\$17,138,000</u>	<u>\$16,884,459</u>	<u>\$ (253,541)</u>	<u>\$17,630,000</u>

**5.1 Replacements - Storms, Collision, Fire and Road Alterations      Variance \$955,881**

The 5.1 budget category was \$955,881 or 92 per cent over budget. The increase over budget is primarily the result of severe and successive snow, ice and wind storms that occurred over the period November 27, 2016 to December 1, 2016. These storms resulted in significant damage to the transmission and distribution system with approximately 165 broken poles, 15 damaged transformers, 5 kilometres of conductor requiring replacement and widespread power outages in Central and Eastern PEI. The restoration lasted 6 days and involved up to 51 crews, including contracted crews from

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New Brunswick Power, City of Summerside, Allteck, Tri-wire, GSD and H-Line contractors.

**5.2 Distribution Transformers** **Variance \$(352,389)**

The 5.2 distribution transformer category was \$352,389 or 11 per cent under budget. This is primarily driven by lower new service activity than provided for in the budget.

**5.3 Services and Street Lighting** **Variance \$(333,238)**

The 5.3 budget category was \$333,238 or 7 per cent under budget. The variance is the result of lower than average new overhead and underground services completed which were 16 per cent and 6 per cent lower in 2016, respectively, than the 5 year average. The 2017 approved budget for Services and Street Lighting is 5 per cent lower than 2016 budget to account for the lower than average trend in new services.

**5.4 Line Extensions** **Variance \$791,552**

The 5.4 line extensions budget category was \$791,552 or 34 per cent over budget. This budget category included a \$500,000 provision to allow the construction of distribution line feeders for the New Glasgow area substation which, as discussed further below, was not completed in 2016. When this \$500,000 provision is considered, the original budget category is \$1,291,552 over budget.

The variance is due to several significantly-sized customer-driven line extensions that were completed in 2016. These projects included extensions on the Murray Harbour Road (2.5 kilometres), Conway Road, Milligan's Wharf, Burleigh Road, and Foster Sharp Road (combined 12.5 kilometres) and Heatherdale Road (7 kilometres). These expenditures were substantially offset by Contributions in Aid of Construction ("CIAC") from customers (presented at the bottom of the Distribution Summary Schedule on Page 4-1) reflected in the \$862,517 positive CIAC variance.

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**DISTRIBUTION**

As noted in Appendix I (Project 5.4), a carryover to 2017 of \$825,000 is required to complete the necessary distribution line extensions, or feeders, to interconnect the new substation in the New Glasgow area that was originally scheduled for completion in 2016. The completion of this project was deferred to 2017 as the Company submitted a revised Environmental Impact Assessment (“EIA”) application to the Province to propose a change in the original substation location and associated transmission and distribution routing. The revised EIA was subsequently approved in February 2017. The approved 2016 Capital Budget for line extensions, as discussed above, had provided for a line extension budget of \$500,000 to allow construction of distribution line feeders from the original substation location; however, the new substation location (“Bagnall Road”) will require distribution line extensions budgeted at \$825,000. This \$325,000 increase in line extension is offset by a decrease of \$325,000 in the carryover for the transmission construction required to extend Transmission Line T-1 (Project 6.2 (d) in Appendix I). Overall the budgeted cost of the New Glasgow area substation in its new Bagnall Road location will be the same as in the originally proposed location and as approved in the 2016 Capital Budget Application, as summarized in the table below.

<b>Table 1</b>						
<b>Option</b>	<b>Transmission Line</b>	<b>Substation</b>	<b>Transformer</b>	<b>Distribution</b>	<b>Fibre</b>	<b>Total</b>
Originally approved 9.5 km transmission line, feeders and New Glasgow Substation	\$ 1,030,000	\$ 674,000	\$ 700,000	\$ 500,000	-	\$ 2,904,000
Revised 4.5 km transmission line, feeders and Bagnall Road Substation (with fibre)	\$ 450,000	\$ 674,000	\$ 700,000	\$ 825,000	\$ 255,000	\$ 2,904,000

### **5.5 Line Rebuilds**

**Variance \$(229,245)**

The 5.5 budget category was \$229,245 or 7 per cent under budget. Capital resources in the fourth quarter were focused on the additional tree clearing to prepare for the 2017 construction of the Y-104 transmission line (see 6.3) and on the extensive storm

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DISTRIBUTION**

restoration efforts following the storms that occurred over the November 27, 2016 to December 1, 2016 period.

**5.6 System Meters Variance \$(168,734)**

The 5.6 system meters category was \$168,734 or 31 per cent under budget. Lower than expected new services, in-house development of distribution class metering units and the cost savings as a result of a technological change with respect to how Maritime Electric collects load data at the substation level substantially accounts for the variance.

**5.7 Distribution Equipment Variance \$(33,103)**

The 5.7 budget category was \$33,103 or 2 per cent below budget. One project, the SCADA Master Station upgrade, is to be completed in 2017 at a cost of \$32,000. After consideration of this deferral, this project category will be approximately \$1,000 or less than 1 per cent under budget.

**5.8 Transportation Equipment Variance \$(21,748)**

The Transportation 5.8 budget category was \$21,748 or 3 per cent under budget.

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**TRANSMISSION**

**Transmission – Summary**

	<b>Approved 2016 Budget</b>	<b>2016 Actual</b>	<b>2016 Variance</b>	<b>Approved 2017 Budget</b>
<b>6.1 Substation Projects</b>	\$ 4,941,000	\$ 2,238,389	\$(2,702,611)	\$ 2,652,000
<b>6.2 Transmission Projects</b>	2,574,000	1,825,142	(748,858)	3,707,000
<b>6.3 Y-104 Multi-Year Project</b>	<u>2,884,000</u>	<u>3,266,387</u>	<u>382,387</u>	<u>2,282,000</u>
<b>Total</b>	<u>\$10,399,000</u>	<u>\$ 7,329,918</u>	<u>\$(3,069,082)</u>	<u>\$ 8,641,000</u>

**6.1 Substation Projects** **Variance \$(2,702,611)**

The 6.1 budget category was \$2,702,611 or 55 per cent under budget. This under budget variance is the result of deferring several substation related projects, totaling \$2,672,000, to 2017 as follows (see Appendix I – Schedule of Deferred Budget Items for further details).

- i. New Glasgow Substation and Transformer \$1,254,000
- Project 6.1 (a) New Glasgow area substation, as discussed in more detail in Section 5.4, was deferred to 2017 due to delays in EIA process approval. The cost of the substation in its original planned location was approved in the 2016 Capital Budget Application at a cost of \$1,374,000. The budgeted cost of the substation remains unchanged in the new Bagnall Road location (see Table 1 in Section 5.4). A cost of \$120,398 was incurred for this project in 2016 as a result of a 20 per cent down payment for transformer purchasing. The result is a deferral to 2017 of the remaining \$1,254,000 to complete this project.

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**TRANSMISSION**

- |      |                                                                                                                                                                                                                                                                                                                                                                                                                                                            |             |
|------|------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|-------------|
| ii.  | <u>Substation Automation Project</u>                                                                                                                                                                                                                                                                                                                                                                                                                       | \$60,000    |
|      | Project 6.1 (d) Substation Automation was deferred to 2017 as a result of the redeployment of Company engineering resources to the Submarine Cable Interconnection Project.                                                                                                                                                                                                                                                                                |             |
| iii. | <u>Transmission System Capacitors</u>                                                                                                                                                                                                                                                                                                                                                                                                                      | \$1,358,000 |
|      | Project 6.1 (e) Transmission System Capacitors was deferred to 2017 as a result of the redeployment of Company engineering resources to the Submarine Cable Interconnection Project and the need to engage an external consultant to complete a System Resonance Study. This Study has been completed and provided confirmation that with the installation of capacitor banks in Charlottetown and Lorne Valley, the system will not experience resonance. |             |

The approved budget for this project is \$1,661,000. A cost of \$303,491 was incurred in 2016 for this project as a result of preparation work in the Charlottetown Substation to accommodate capacitor banks including purchasing two new Siemens switchgear and the reconfiguration of the existing 13.8 kV distribution feeders. This results in a deferral to 2017 of the remaining \$1,358,000 to complete this project.

**6.2 Transmission Projects** **Variance \$(748,858)**

The 6.2 transmission projects category is \$748,858 or 29 per cent below budget. This budget category included a \$1,030,000 provision to allow the construction of a 9.5 kilometre transmission line for the New Glasgow area substation of which \$95,182 was spent in 2016. When the remaining \$934,818 provision is considered, the original budget category is \$185,960 over budget primarily due to additional labour, materials and off-road equipment costs to complete high priority deficiencies on transmission line Y-109 that were identified during inspection.

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As discussed in Section 5.4 and in Appendix I (Project 6.2(d)), a carryover is required to complete the T-1 transmission line to the New Glasgow area substation. The new New Glasgow area substation location approved under the EIA in February 2017 requires only a 4.5 kilometre T-1 transmission line extension (and not a 9.5 kilometre extension provided for at the original substation location). The budgeted cost of completing this 4.5 kilometre transmission extension including the installation of fibre optic cable required for communication with the substation at the new Bagnall Road location in 2017 is \$610,000 (\$450,000 for transmission line construction plus \$255,000 for fibre installation less a \$95,000 cost incurred in 2016).

**6.3 Y-104 Multi-Year Project**

**Variance \$382,387**

The 6.3 budget category is \$382,387 or 13 per cent over budget. This is primarily due to additional tree clearing that was completed in the Fall of 2016 to prepare for the planned construction of 12 kilometres of transmission line in first half of 2017. One of the stipulations of the EIA for the Y-104 project is that tree clearing is prohibited between May and September because of the bird nesting season. As this is a multi-year project, the decision was made to proceed with the tree clearing in the Fall of 2016 to expedite construction in early 2017.

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**CORPORATE**

**Corporate – Summary**

	<u>Approved 2016 Budget</u>	<u>2016 Actual</u>	<u>2016 Variance</u>	<u>Approved 2017 Budget</u>
<b>7.1 Corporate General</b>	\$ 300,000	\$ 114,862	\$ (185,138)	\$ 300,000
<b>7.2 Information Technology</b>	<u>914,000</u>	<u>875,579</u>	<u>(38,421)</u>	<u>768,000</u>
<b>Total</b>	<u>\$ 1,214,000</u>	<u>\$ 990,441</u>	<u>\$ (223,559)</u>	<u>\$ 1,068,000</u>

**7.1 Corporate General** **Variance \$(185,138)**

The 7.1 budget category was under budget by \$185,138 or 61 per cent and is the result of deferring two projects until 2017.

- i. Substation Entrance Resurfacing – West Royalty \$55,000  
 Project 7.1 (a) - Substation Entrance Resurfacing – West Royalty, budgeted at \$55,000, is being deferred to 2017. The Company did not receive any responses from the four suppliers who were sent requests for proposals due to supplier workloads.
  
- ii. Service Centre Improvement Plan - West Royalty Service Centre \$130,000  
 Project 7.1 (b) - Service Centre Improvement Plan – West Royalty Service Centre (“WRSC”) was under budget by approximately \$130,000 as planned work for 2016 was not completed and is being deferred to 2017. BGHJ Architects, who conducted the original design work on the WRSC property in 1989, were engaged in 2016 to conduct a review of the property and develop a Long-Term Master Planning Report and Recommendations for the reorganization of space and services to facilitate improved efficiency at this location. The report was not complete at year end. Depending on the final recommendation of the Report, the Company may revise its long-term plans for the facility.

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**CORPORATE**

**7.2 Information Technology** **Variance \$(38,421)**

	<u>Approved 2016 Budget</u>	<u>2016 Actual</u>	<u>2016 Variance</u>	<u>Approved 2017 Budget</u>
<b>7.2 (a) Hardware Acquisitions</b>	\$ 450,000	\$ 435,333	\$ (14,667)	\$ 198,000
<b>7.2 (b) Purchased Software and Upgrades</b>	251,000	266,566	15,566	280,000
<b>7.2 (c) Other IT Services/Projects</b>	<u>213,000</u>	<u>173,680</u>	<u>(39,320)</u>	<u>290,000</u>
<b>Total</b>	<u>\$ 914,000</u>	<u>\$ 875,579</u>	<u>\$ (38,421)</u>	<u>\$ 768,000</u>

**7.2 (a) Hardware Acquisitions** **Variance \$(14,667)**

The 7.2 (a) category was under budget by \$14,667 or 3 per cent. This is substantially attributable to labour savings achieved during an equipment upgrade project within the corporate data center.

**7.2 (b) Purchased Software and Upgrades** **Variance \$15,566**

The 7.2 (b) category was over budget by \$15,566 or 6 per cent. This is substantially attributable to an unplanned \$12,000 increase in software licensing fees from ESRI Canada, supplier of geographical information software.

**7.2 (c) Other IT Services/Projects** **Variance \$(39,320)**

The 7.2 (c) category was under budget by \$39,320 or 18 per cent. This is primarily due to the deferral of a remote metering project in the amount of \$40,000. After consideration of this deferral, this budget category will be over budget by approximately \$1,000 or less than 1 per cent.

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**CAPITALIZED GENERAL EXPENSE**

This amount includes a portion of administrative costs that are properly recognized as part of the Company's overall capital expenditure program. These expenditures represent an allocation of administrative costs, not specific to any one capital project, but rather as part of the overall development, implementation and management of the Company's approved annual Capital Budget.

**Capitalized General Expense**

	<b><u>Approved 2016 Budget</u></b>	<b><u>2016 Actual</u></b>	<b><u>2016 Variance</u></b>	<b><u>Approved 2017 Budget</u></b>
<b>Capitalized General Expense</b>	<b><u>\$ 494,000</u></b>	<b><u>\$ 477,714</u></b>	<b><u>\$ (16,286)</u></b>	<b><u>\$ 491,000</u></b>

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**INTEREST DURING CONSTRUCTION (IDC)**

This amount represents an allowance for funds used during the construction of certain assets. It is reflected in the Company's financial results as an offset to financing costs, ultimately charged to fixed assets and recovered through amortization over the life of the assets. The budgetary provision for 2017 for the IDC category was increased to \$316,000 to better reflect costs actually incurred for IDC.

**Interest During Construction**

	<b>Approved <u>2016 Budget</u></b>	<b>2016 <u>Actual</u></b>	<b>2016 <u>Variance</u></b>	<b>Approved <u>2017 Budget</u></b>
<b>Interest During Construction</b>	<b><u>\$ 200,000</u></b>	<b><u>\$ 405,915</u></b>	<b><u>\$ 205,915</u></b>	<b><u>\$ 316,000</u></b>

**MARITIME ELECTRIC COMPANY, LIMITED**  
**2016 CAPITAL BUDGET VARIANCE REPORT**

**SCHEDULE OF DEFERRED CAPITAL BUDGET ITEMS**

The following schedule outlines the projects (approved in Order UE15-01, and in the case of G-3-1 and D-8, approved in Order UE14-04) deferred from 2016. Certain expenditures associated with these projects were incurred in 2015 and 2016 as noted. Outlined are expenditures to complete the projects in 2017.

Original Project ID	Description	Budget	Costs Incurred in		Deferred to 2017	Comments
			2015	2016		
G-3-1	Installation of Snow Hood on CT3	\$ 443,000	\$ -	\$ 83,420	\$ 360,000	Original equipment manufacturer unable to complete the design and fabrication of components in 2016 (Note 1).
D-8	Transportation Equipment 2015	963,000	128,822	-	873,000	Delivery delayed until February 2017 (Note 1).
5.4	New Glasgow Substation Feeders	500,000	-	-	825,000	See Section 5.4
5.7(a)	SCADA Master Station Upgrade	140,000	-	78,478	32,000	See Section 5.7
6.1(a)	New Glasgow Substation	1,374,000	-	120,398	1,254,000	See Section 6.1
6.1(d)	Substation Automation	61,000	-	1,504	60,000	See Section 6.1
6.1(e)	Transmission System Capacitors	1,661,000	-	303,491	1,358,000	See Section 6.1
6.2(d)	T-1 Line Extension to New Glasgow Substation	1,030,000	-	95,182	610,000	See Section 6.2
7.1(a)	Substation Entrance Resurfacing	55,000	-	-	55,000	See Section 7.1
7.1(b)	West Royalty Service Centre Improvement Plan	200,000	-	70,000	130,000	See Section 7.1
7.2(f)	Remote Metering	40,000	-	-	40,000	See Section 7.2
	<b>TOTAL</b>	<b>\$ 6,467,000</b>	<b>\$ 128,822</b>	<b>\$ 752,473</b>	<b>\$ 5,597,000*</b>	

Note 1: These are 2015 Capital projects originally approved in Order UE14-04.

\* Amounts deferred to 2017 include two deferrals (G-3-1- and D-8) from 2015 totaling \$1,233,000 plus deferrals from 2016 totaling \$4,364,000 for a total of \$5,597,000.

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**SCHEDULE OF CAPITAL BUDGET EXPENDITURES FROM PRIOR YEARS COMPLETED IN 2016**

Original Project ID	Description	Budget	Cost Incurred			Total	Variance
			2014	2015	2016		
D-8	Transportation Equipment 2014 (Note 1)	\$ 795,000	\$ 382,823	\$ 359,775	\$ 99,330	\$ 841,928	\$ 46,928
T-1-1	Charlottetown Airport Substation (Note 2)	706,000	-	98,420	629,755	728,175	22,175
T-2-3	T-15 Line Extension to Charlottetown Airport Substation (Note 2)	600,000	-	85,244	323,578	408,822	(191,178)*
C-2-4	Joint Use Management System (Note 2)	56,000	-	34,874	16,936	51,810	(4,190)
C-2-7	Finance System Integration (Note 2)	35,000	-	3,440	32,133	35,573	573
	<b>TOTAL</b>	<b><u>\$ 2,192,000</u></b>	<b><u>\$ 382,823</u></b>	<b><u>\$ 581,753</u></b>	<b><u>\$1,101,732</u></b>	<b><u>\$ 2,066,308</u></b>	<b><u>\$ (125,692)</u></b>

Note 1: This 2014 Capital Project was approved in Order UE13-04.

Note 2: This 2015 Capital Project was approved in Order UE14-04.

\* The original budget contemplated a longer route with a distribution under build to extend the T-15 transmission line. A new, and shorter, route without the requirement of a distribution under build was identified and completed resulting in the budget savings.