Chapter 3
Section
3.05

Ministry of Energy

Electricity Power System Planning

1.0 Background

1.1 What Is Electricity Power System Planning?

Electricity power system planning involves managing the long-term demand for electricity and deciding how to meet that demand through various generation, conservation and transmission solutions:

- Generation—Ontario has a diverse mix of energy sources (called the "supply mix") including nuclear, hydropower, natural gas, wind, solar and bioenergy.
- Conservation—Ontario encourages consumers to reduce or shift consumption away from peak times and to use energy more efficiently, with the intent to avoid the need for increased electricity generation and to avoid or defer the need for significant investment in new electricity infrastructure.
- Transmission—Ontario's transmission system moves electricity at high voltages over long distances, from generation sites to the local distribution companies who deliver electricity to consumers.

1.2 Key Players Involved

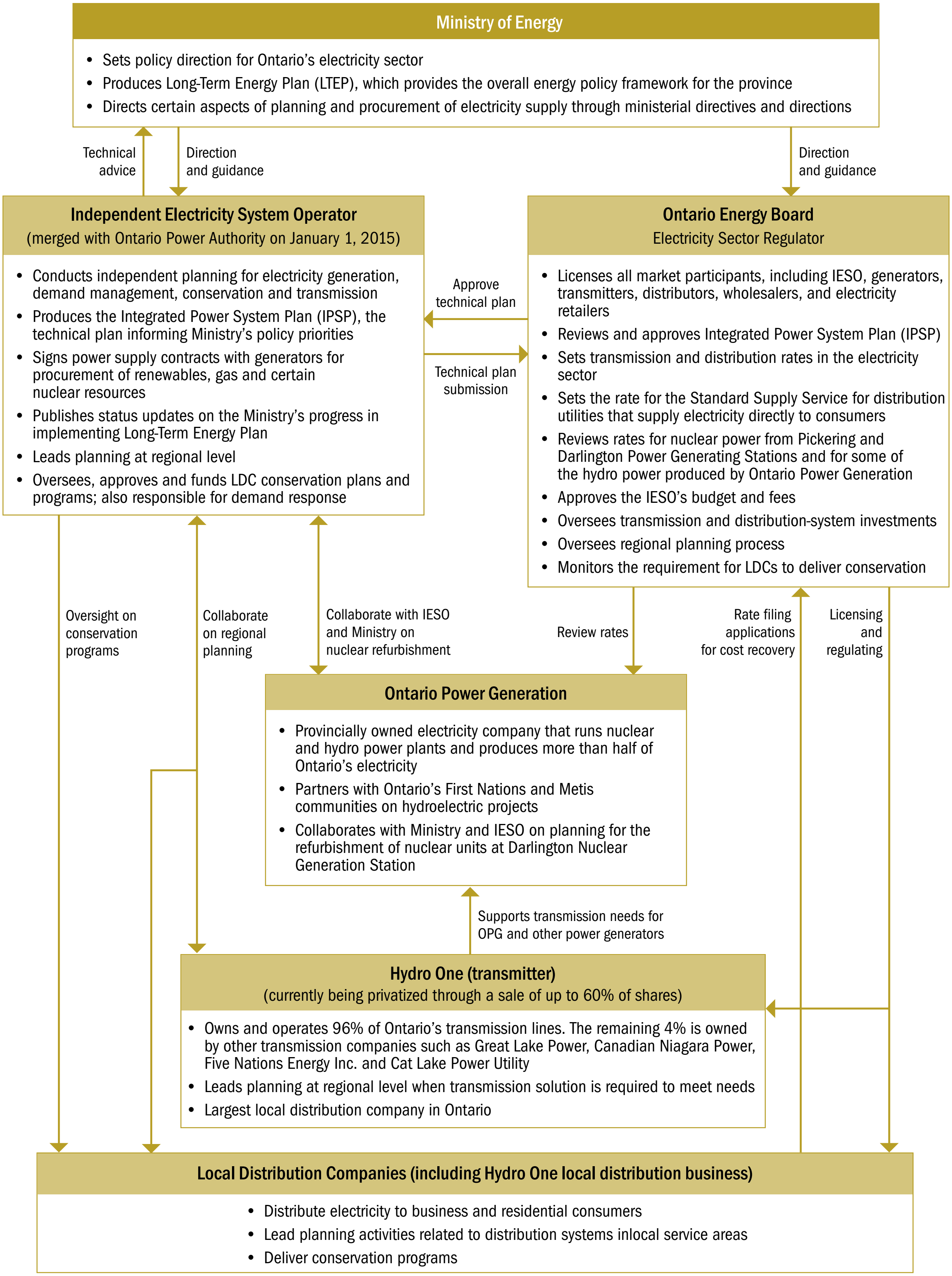
The entities involved in power system planning in Ontario include the Ministry of Energy (Ministry), the Independent Electricity System Operator (IESO), the Ontario Energy Board (OEB), Ontario Power Generation (OPG), Hydro One, a major transmitter and distributor (see **Section 3.06** of this year's Annual Report for our audit of Hydro One's Management of Electricity Transmission and Distribution Assets), four other small licenced transmitters and approximately 70 local distribution companies. **Figure 1** shows the key roles and responsibilities of each.

The Ministry and the IESO are the key players in power system planning at the provincial level. Their plans aim to ensure adequate supply, bulk transmission planning and interaction with local distribution companies. Under the *Electricity Act, 1998*, the Minister has the authority to issue directives (which require cabinet approval) on the supply mix, and directions (which do not require cabinet approval) on other matters relating to electricity planning.

The January 1, 2015, amalgamation of the Ontario Power Authority (OPA) and the IESO came about through an amendment to the *Electricity Act, 1998*, which made the new IESO responsible for power system planning. Before the amalgamation, the OPA had been responsible for conducting independent planning for electricity generation,

Figure 1: Roles and Responsibilities of Key Entities Involved in Electricity Power System Planning

Prepared by the Office of the Auditor General of Ontario



conservation and transmission in Ontario. The OPA was also responsible for developing an Integrated Power System Plan (IPSP), a plan for achieving the province's energy goals over a 20-year period. **Appendix 1** summarizes the key events relating to power system planning in more detail.

At the regional level, the IESO, Hydro One, four other small licenced transmitters and approximately 70 local distribution companies jointly evaluate the needs of 21 electricity regions spread over 10 transmission zones in Ontario and plan for how to meet those needs. Hydro One and approximately 70 local distribution companies across the province are also responsible for assessing the current distribution system and delivery of electricity in their service areas.

As the regulator of the province's energy sector, the Ontario Energy Board (OEB) is supposed to play a significant role in power system planning, including reviewing and approving technical plans (although this role has been diminishing, as will be discussed further in this report).

The OEB's other responsibilities include licensing and overseeing energy companies, including utilities, generators and electricity retailers that offer energy under contract; approving the rates that utilities can charge their customers (through public hearings); writing rules and guidelines for the companies it licenses and rate-regulates; setting time-of-use prices and times; providing information and tools to help consumers make informed choices about energy matters; and approving new construction of or changes to existing natural gas pipelines and storage facilities, and electricity transmission lines that are more than two kilometres long.

1.3 Ontario's Changing Supply Mix

The supply mix is the combination of power sources that are used to generate the province's electricity.

Eliminating Coal as a Power Source in Ontario

In June 2006, the Ministry issued its first supply mix directive to the OPA. This directive would fulfill a commitment the Ministry had made to replace all coal-fired generation with cleaner renewable energy sources, such as wind, solar, biomass and hydroelectricity. At that time, about a quarter of Ontario's electricity was supplied by coal. The OPA noted that the sources of power that would replace coal should be cleaner, but to maintain system reliability they should also have characteristics similar to coal—flexibility and sustained production of energy.

Between 2003 and 2014, Ontario eliminated 7,546 megawatts (MW) that came from coal and added 13,595 MW of new capacity (6,580 MW of renewables, 5,674 MW of natural gas and 1,341 MW of nuclear) to the supply mix. **Figure 2** shows how Ontario's supply mix has changed since 2003 and projects what the supply mix will look like in 2032.

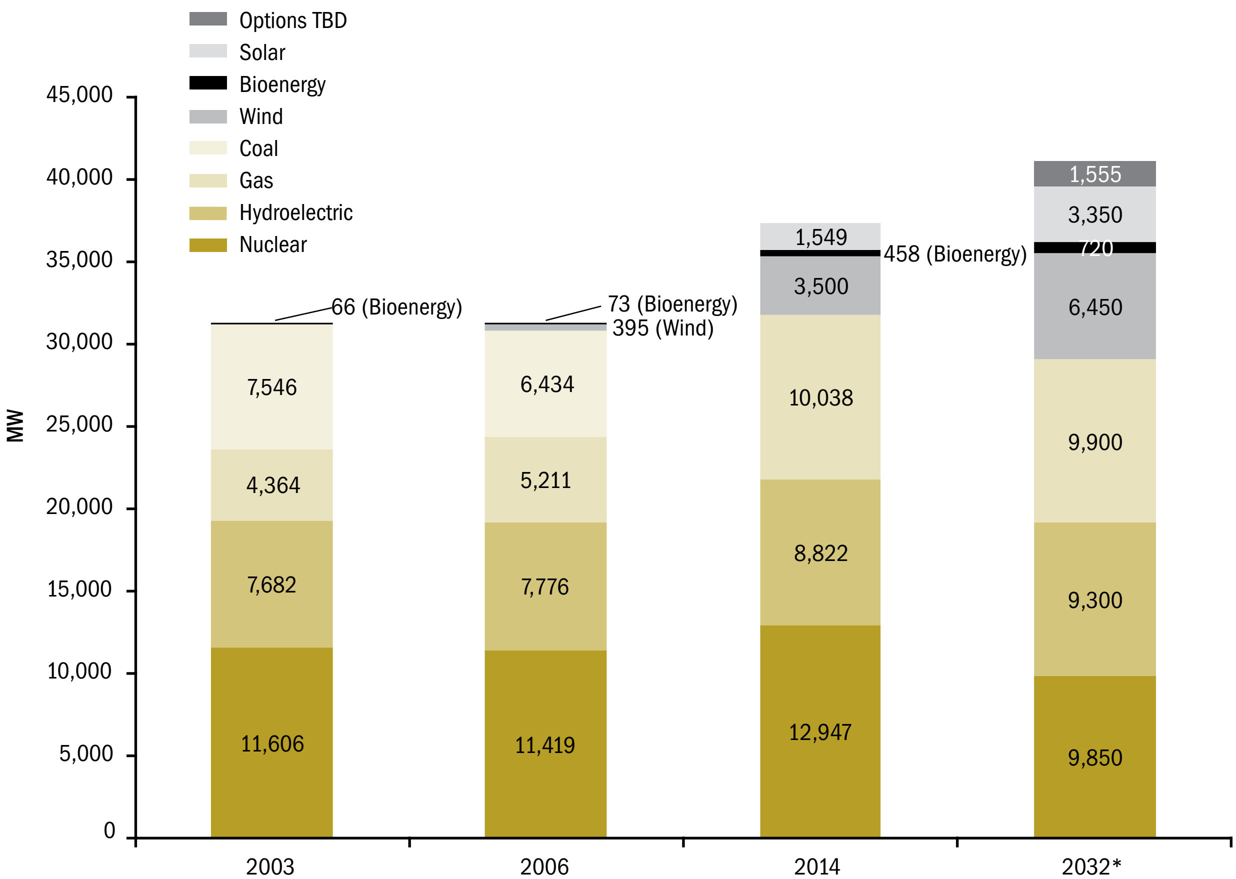
Procurement of Renewable Energy Sources

Before 2009, the OPA procured renewable energy through competitive bidding and a guaranteed-price program that provided fixed prices to renewable generators. These procurement efforts were successful and renewable generation targets were achieved in record time.

In 2009, upon the passing of the *Green Energy Act*, the Ministry directed the former OPA to create a new guaranteed-price program (called "FIT," which stands for "feed-in tariff") to promote greater use of renewable energy sources like wind and solar for new electricity-generating projects. Compared to the previous program, the new guaranteed-price program was wider in scope and offered generators significantly higher prices. Initially, the *Green Energy Act* required guaranteed-price renewable projects to have made-in-Ontario components, but the government amended the legislation following a 2013 World Trade Organization ruling. As a result, made-in-Ontario components are no longer required for guaranteed-price renewable projects with contracts signed after July 25, 2014. The guaranteed-price program is divided into two streams: one stream (FIT) is for projects that are larger than 10 kilowatts (kW); the other stream (microFIT) is for projects 10 kW or less. Subsequently, in 2013, the Ministry directed the OPA to develop a new competitive procurement program for large renewable projects.

Figure 2: Installed Capacity of Different Energy Sources in 2003, 2006, 2014 and 2032

Source of data: Independent Electricity System Operator



* Projected by the Ministry of Energy.

Less Nuclear Power

The Ministry has projected a 13% decrease in nuclear production, as a percentage of overall energy production, from 57% in 2013 to 44% by 2032. There are three nuclear power generating stations in Ontario: Pickering Nuclear Generating Station, with six operating nuclear-reactor units; Darlington Nuclear Generating Station, with four operating nuclear-reactor units; and Bruce Nuclear Generating Station, with eight operating nuclear-reactor units.

In 2013, the Ministry deferred its plan to build new nuclear units. Pickering is scheduled to be shut down by 2020, and four nuclear units at Darlington and six nuclear units at Bruce are scheduled to be refurbished in stages from 2016 to 2028.

1.4 How Electricity Supply Meets Demand

To meet the system's demand there must be a sufficient supply of electricity at any given time. There are three components to the available electricity supply: baseload resources, intermediate and peaking resources, and reserves. (See **Appendix 2** for a list of Ontario's generation facilities, by type of energy resource, installed capacity and location.)

Baseload Resources

Baseload resources are usually reliable resources with lower operating costs that can be run consistently throughout the year to supply the continuous minimum demand for electricity. The energy sources that supply the baseload are typically large-scale and reliable, such as nuclear energy and run-of-river hydroelectric. In Ontario, wind and solar energy are treated as baseload resources by the IESO. They are used whenever they are available. While wind and solar energy cannot easily be stored for future use, the IESO has the ability to curtail these resources based on system need.

Intermediate and Peaking Resources

Intermediate and peaking resources typically include natural gas and some hydroelectric sources (only those with reservoir storage). These more flexible resources are dispatchable, which means that their generation levels can be more easily changed to match changes in demand.

Planning and Operating Reserve

Electricity system planners have different reserve requirements for long-term planning compared to real-time operations. From a planning perspective, planning reserves are required to ensure there are sufficient resources to reliably satisfy future demand. Planning reserves account for both operational uncertainties (such as generator unavailability and deliverability of resources) and demand uncertainties (such as economic and weather forecasts). From a real-time operations perspective, operating reserve is standby power for dealing with unplanned events that upset the balance of supply and demand, such as the loss of a power source. Operating reserve requirements must adhere to reliability standards established by the North American Electric Reliability Corporation and Northeast Power Coordinating Corporation. For example, Ontario's operating reserve typically provides enough standby power to make up for a potential loss of one and a half of the province's largest generators. Planning reserves are higher than operating reserves because there is greater uncertainty about expected demand levels and the availability of supply the further out from real-time.

Average Versus Peak Electricity Consumption

Our power system is expected to have sufficient electricity supply to meet peak demands and reserve requirements. Most of the time, the actual amount of electricity consumed is much lower than the maximum or peak demand. For example, the average demand for electricity in Ontario in 2014 was only 15,959 MW, whereas the maximum demand was 22,774 MW. **Figure 3** shows Ontario's available electricity supply at maximum peak times from 2009 to 2014 exceeded the peak demand.

Reducing the peak demand can lighten the burden on electricity infrastructure, which in turn can lessen the need to build new power plants, expand existing ones or enter into additional power-purchase agreements.

Surplus Baseload Generation

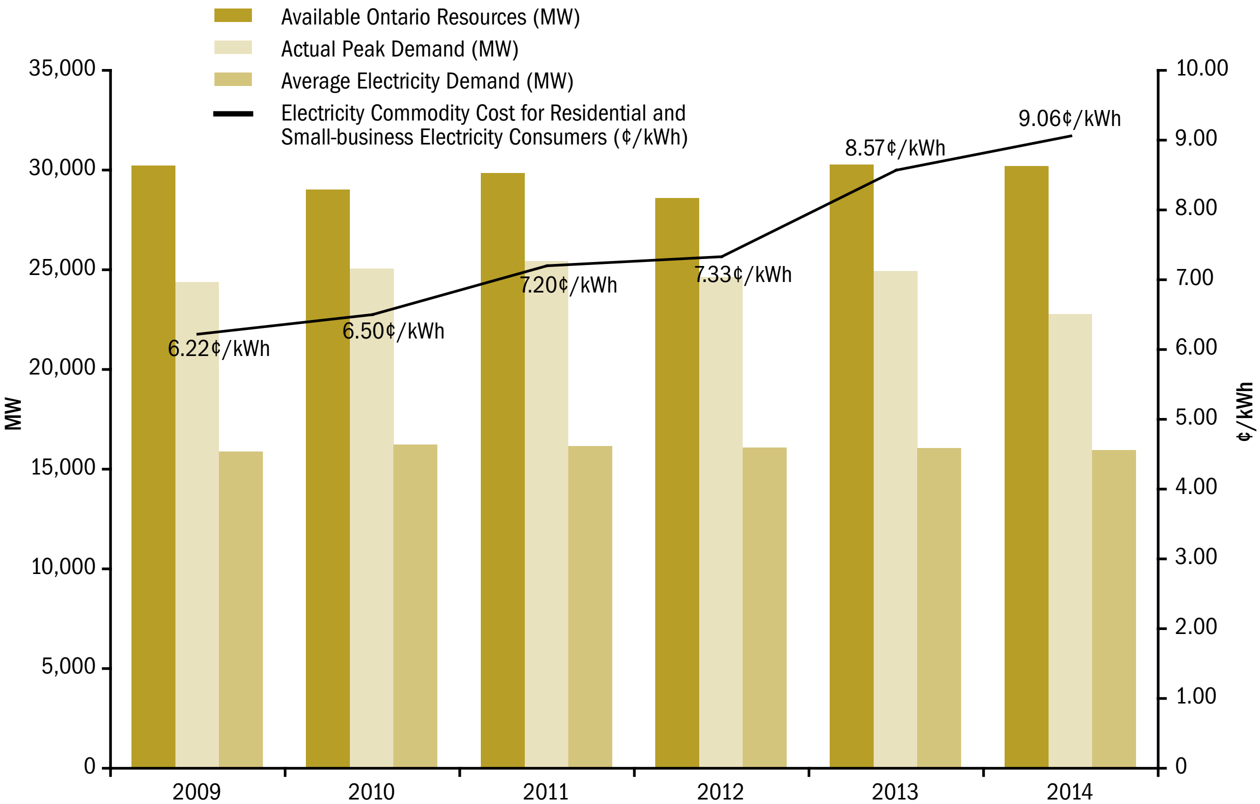
Surplus baseload generation occurs when the electric power produced by baseload generators exceeds the demand for electricity. The IESO manages the surplus by determining how to most efficiently balance supply and demand during real-time operations. This can involve exporting power to other jurisdictions and requesting some baseload generators to reduce (curtail) production or to completely shut down.

1.5 Long-term Demand Forecasting

Demand forecasting is an important aspect of long-term power system planning, because it affects decisions about generation, conservation and transmission solutions. The OPA (now the IESO) develops its 20-year electricity demand forecast by estimating the electricity consumption of end users such as residential, commercial and industrial customers. Once the amount of future electricity consumption is projected, the IESO subtracts the anticipated impacts of conservation from it to calculate the net demand. The net demand is typically the basis for key decisions in the power system planning process.

Figure 3: Electricity Commodity Cost, Available Electricity Resources, Average Electricity Demand and Peak Demand in Ontario, 2009–2014

Source of data: Independent Electricity System Operator



1.6 The Total Cost of Electricity in Ontario

In total, Ontario consumers paid $18.9 billion for electricity service in 2014. This total cost has six components: generation costs, conservation costs, transmission costs, distribution costs, regulation costs and debt-retirement costs.

Figure 4 breaks down Ontario's electricity service costs to consumers for 2014. As shown in the pie chart, generation cost, the largest component at $11.8 billion (or 62%), represents the cost of the electricity supply. **Figure 5** breaks down this generation cost by different types of energy sources. It shows that natural gas and non-hydro renewable energy such as wind, solar and bioenergy account for 16% of our total electricity production (before exports) while they account for 36% of Ontario's total generation cost. In general, generation cost is largely influenced by power system planning decisions regarding supply mix and capacity levels ultimately made by the government.

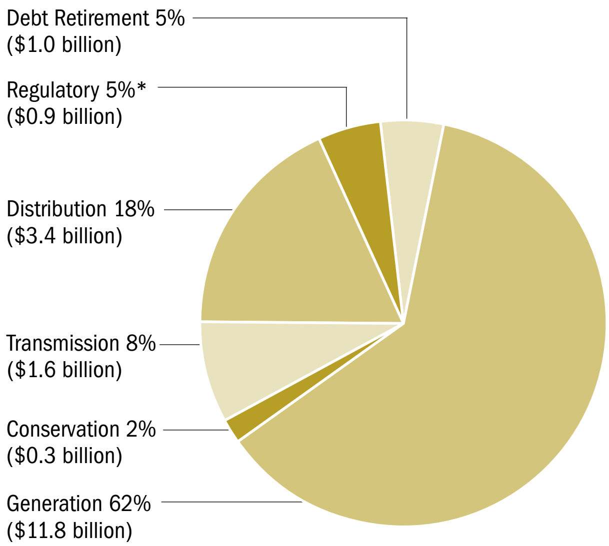
The "Electricity Charge" on Consumers' Electricity Bills

A typical Ontario electricity bill for residential and small-business ratepayers contains four categories of charges: electricity, delivery, regulatory and debt retirement. The electricity charge accounts for more than half of a typical utility bill. Most Ontario consumers pay time-of-use prices, which include the Hourly Ontario Energy Price and the Global Adjustment:

- **The Hourly Ontario Energy Price** is the average market clearing price for each hour based on Ontario's supply of and demand for electricity; it is determined by a competitive process in which generators offer to supply electricity to the market.

Figure 4: Breakdown of Ontario's Electricity Service Costs, 2014

Source of data: Independent Electricity System Operator



* Regulatory charges include a wholesale market service charge that covers services provided by the IESO to operate the wholesale electricity market and maintain the reliability of the high-voltage power grid, and a standard supply service charge that covers part of a utility's administrative costs to provide electricity to customers not served by a retailer.

Figure 5: Breakdown of Generation Cost By Energy Sources, 2014

Source of data: Independent Electricity System Operator

Technology	Cost ($ million)	Total Production (TWh)
Nuclear	5,900	**94.9**
Hydro	1,835	**37.9**
Gas/Oil	2,287	**14.9**
Wind	935	**7.8**
Solar	884	**1.8**
Bioenergy	100	**0.5**
Coal	7	**0.1**
Other*	186	**1.6**
Imports	251	**4.9**
Export (Revenue)	(636)	**(19.1)**
Total Generation Cost	**11,749**	

* Includes electricity produced via storage

- **The Global Adjustment** is mostly made up of the difference between the Hourly Ontario Energy Price and the guaranteed prices paid to regulated and contracted generators. Guaranteed prices are paid to generators, including, but not limited to, nuclear and hydroelectric generators administered by Ontario Power Generation (a provincially owned electricity company), non-utility generators administered by the Ontario Electricity Financial Corporation, and gas-fired, nuclear and renewable energy generators contracted by the former OPA (and now by the IESO). The Global Adjustment also includes conservation costs.

1.7 Interconnections and Electricity Imports

Through our transmission system, Ontario is electrically interconnected with Manitoba, Minnesota, Michigan, New York and Quebec. These interconnections have been of significant benefit to the province because they help to facilitate electricity trade and enhance the power system's reliability. A decade ago, when there was a shortage of domestic electricity supply, Ontario was heavily reliant on these interconnections with other jurisdictions to help meet summer peak demands.

However, Ontario now has a sufficient domestic supply of electricity to meet its own needs, and it currently uses its interconnections with neighbouring jurisdictions to more efficiently manage periods of surplus baseload generation. These interconnections are intended to smooth out normal minute-to-minute power system fluctuations and provide support immediately following emergency events. Ontario has been a net exporter since 2006, but Ontario imports some electricity—an average of about 6 million MWh annually between 2006 and 2014.

2.0 Audit Objective and Scope

The objective of our audit was to assess whether effective processes and procedures were in place to:

- ensure the transparency, accountability and efficiency of Ontario's electricity power system planning process in order to provide for reliable, cost-effective and sustainable power to meet provincial electricity demands within the context of applicable legislation and government policy; and
- measure and report periodically on the progress and results of Ontario's electricity system plans.

In conducting our audit, we reviewed applicable legislation, regulations, policies and studies; analyzed planning documents, including the Integrated Power System Plans and Long-term Energy Plans; and interviewed appropriate staff from the key entities involved in power system planning, including the Ministry of Energy, the Independent Electricity System Operator, the Ontario Energy Board, Hydro One and Ontario Power Generation. Ontario Power Generation is a provincially owned electricity company that runs nuclear and hydro power plants and produces more than half of Ontario's electricity. It collaborates with the Ministry and the IESO on planning for the refurbishment of nuclear units at Darlington Nuclear Generation Station.

We also met with representatives from stakeholder groups, including the Ontario Society of Professional Engineers, the Canadian Electricity Association, the Electricity Distributors Association, the Association of Municipalities of Ontario, and several local utilities. We also interviewed and conducted a survey of former Ontario Power Authority board members and other selected stakeholders. As well, we conducted research on power system planning in other jurisdictions to identify best practices. In addition, we engaged as an advisor an independent consultant with expert knowledge in the technical aspects of power system planning.

Calculation to Reflect Time Value of Money

In this report we present a number of potential savings relating to guaranteed-price renewable contracts based on actual contract values. Since these contracts carry a term of 20 or more years, the IESO has discounted potential savings using varying interest rates to reflect the time value of money. We have included both our calculation and the IESO's calculation in these instances.

3.0 Summary

An enormous amount of technical planning is required for Ontario to determine how it will meet its future electricity demands. The importance of this type of planning is reflected in provincial legislation: The *Electricity Act, 1998*, was amended in 2004 to require the Ontario Power Authority (OPA, now merged with the IESO) to conduct independent planning and prepare an "Integrated Power System Plan," a technical plan to help Ontario meet its future electricity demands. To protect the interests of consumers, the Act also requires the Ontario Energy Board (OEB) to review and approve the technical plan to ensure that it is prudent, cost-effective and consistent with the government's supply mix directive.

But over the last decade, this power system planning process has essentially broken down, and Ontario's energy system has not had a technical plan in place for the last ten years. Operating outside the checks and balances of the legislated planning process, the Ministry of Energy has made a number of decisions about power generation that have resulted in significant costs to electricity consumers.

A great deal of time, effort, and money has been spent on developing technical plans that were never implemented. During the period from 2004 until the time of its merger with the Independent Electricity System Operator (IESO) in 2015, the OPA prepared two technical plans, in 2007 and 2011, at a cost of more than $16 million. Neither of these was ever approved by the OEB. The OEB had to cease its review of the 2007 technical plan after the Minister of Energy issued a new supply mix directive requiring the OPA to prepare a revised plan. In 2011, the OPA submitted a copy of its updated technical plan directly to the Ministry rather than to the OEB. At the same time, a provincial election was held in October 2011 and a new Minister of Energy was appointed. In April 2012, Bill 75, which proposed to merge the OPA and IESO and amend the IPSP planning process, was introduced. Because the legislation does not require the Minister to approve the OPA's technical plan, the Ministry did not respond to the OPA's submission and the technical planning process was halted. And as the OEB was not given an opportunity to review the technical plans as is required under the *Electricity Act*, it has not been able to ensure that Ontario's technical energy planning has been carried out in a prudent and cost-effective manner to protect the interests of electricity consumers over the past ten years.

Meanwhile, the cost of electricity in Ontario has been steadily increasing. From 2004 to 2014, the amount that residential and small-business electricity consumers pay for the electricity commodity portion (includes Global Adjustment fees) of their bill has increased by 80%, from 5.02 cents/kWh to 9.06 cents/kWh. Under the *Ontario Energy Board Act, 1998*, the OEB is responsible for protecting the interests of consumers with respect to prices, adequacy, reliability and the quality of electricity service, but the Act only grants the OEB limited oversight over power generation (Pickering and Darlington nuclear plants along with some hydropower). But not having an approved technical energy plan in place meant that the OPA was able to procure new sources of electricity supply under government directives—without this OEB oversight. New power supply contracts signed by the OPA accounted for about 65% of Ontario's total installed capacity in 2014. With Ontario's changing supply mix, we estimate that the OEB's oversight on power generation costs will decrease even further, to only about a quarter of our expected installed capacity by 2032.

The Ministry has issued a total of 93 directives and directions to the OPA between 2004 and 2014. Through them, it has made a number of decisions about power generation—decisions that sometimes went against the OPA's technical advice. It is our view that the Ministry did not fully consider the state of the electricity market or the long-term effects different supply mix scenarios would have on Ontario's power system in making some of these decisions. A number of them have resulted in significant costs to electricity consumers:

- **Expensive wind and solar energy**—We calculate that electricity consumers have had to pay $9.2 billion (the IESO calculates this amount to be closer to $5.3 billion, in order to reflect the time value of money) more for renewables over the 20-year contract terms under the Ministry's current guaranteed-price renewable program than they would have paid under the previous program. Before 2009, Ontario already had several successful procurement programs for renewable energy that achieved renewable generation targets in record time. Nevertheless, in 2009 the Ministry directed the OPA to create a new guaranteed-price program that offered significantly more attractive contract prices to generators. At the same time, the OPA had made a suggestion to the Ministry to use a competitive procurement process for large renewable energy projects, but the Ministry decided against it. After procuring about 200 large renewable projects, which accounted for $4.7 billion of the $9.2 billion mentioned above, the Ministry directed the OPA to develop a new competitive procurement process for large renewable projects. With wind and solar prices around the world beginning to decline around 2008, a competitive process would have meant much lower costs. We found that the prices under Ontario's guaranteed-price renewable program were still double the market price for wind and three and a half times the market price for solar energy in 2014. Because wind and solar energy are intermittent, other resources, such as natural gas, are still needed to meet Ontario's supply requirements. Increasing the amounts of wind and solar in Ontario's supply mix also means that only about 80% of our total generation capacity is available for meeting peak-period demands. In other words, we can only count on 80% of the electricity generation that Ontario has invested in because not every day will be windy or sunny enough to provide reliable renewable energy during peak-demand periods when we need power the most. And since the Ministry plans to increase the proportion of wind and solar in the supply mix, this percentage is projected to fall further, to 70% by 2032.

- **OPA directed to proceed with costly hydro project**—In January 2010, the OPA expressed concerns to the Ministry after the Lower Mattagami hydro project's estimated costs increased substantially since its initial estimate, by $1 billion. The Ministry directed the OPA to proceed with the project because it would assist in meeting the Ministry's renewable targets and investing in Aboriginal communities and the economy of northern Ontario. The average cost of electricity produced at this hydro facility is $135/MWh, while the average cost of electricity produced at two other recent hydro projects outside of the Mattagami River area in Ontario is $46/MWh. One of the projects involved adding an extension to an existing facility and had a lower cost of $35/MWh; the other project involved building a brand-new facility and had a higher cost of $56/MWh. Our review of other recent hydro projects in other Canadian jurisdictions show that the $56/MWh is comparable.
- **Conversion of coal plant to biomass facility not cost-effective**—The Ministry directed the OPA to convert a Thunder Bay coal plant into a biomass facility despite OPA's advice that the conversion was not cost-effective. The Ministry cites facilitating economic growth and job creation in the forestry industry as its reasons for going ahead with the project despite the fact that this facility uses imported forestry resources that can only be purchased from outside of Canada. The cost of electricity from this facility is $1,600/MWh—25 times higher than the average cost at other biomass facilities in Ontario.
- **Costly cancellation of natural gas plants**—The Ministry directed the OPA to cancel contracts for two gas plants that had been planned for the southwest Greater Toronto Area, where the need for them was greatest, and relocate them to Napanee and Lambton. Our 2013 special reports on the Oakville and Mississauga power plant cancellations projected cancellation costs to be $950 million.

Ontario currently has an oversupply of electricity. From 2009 to 2014, the province's available electricity supply exceeded its maximum hourly consumption by 5,160 MW per year, on average—an amount that approximates the total existing power generation capacity of the province of Manitoba. And the IESO forecasts Ontario's baseload generation from 2015 to 2020 to exceed the province's demand by a total of 52.3 million MWh—an amount that would be enough to power the province of Nova Scotia for about five years. We are concerned that the Ministry continues to invest in conservation efforts when Ontario already has significant surplus power. In fact, system costs could be more effectively reduced by a decrease in peak consumption paired with an increase in off-peak consumption, which would flatten the overall load. However, overall, the conservation program has been more successful in achieving its electricity consumption targets than its peak demand targets.

- **Conservation during surplus power period contributes to expensive electricity curtailments and exports**—Ontario has spent approximately $2.3 billion in conservation programs and initiatives from 2006 to 2014, and has committed to spending another $2.6 billion over the next six years. But investing in conservation does not necessarily mean saving money during periods of surplus because energy savings from conservation efforts can add to Ontario's surplus, contributing to an oversupply of electricity that means increasing exports and/or curtailing production. Since power is exported at prices below what generators are paid, and curtailed generators are still paid even when they are not producing energy, both of these options are costly. From 2009 to 2014, Ontario had to pay generators $339 million for curtailing 11.9 million MWh of surplus electricity; during the same period, Ontario exported 95.1 million MWh of power to other jurisdictions, but the amount it was paid was $3.1 billion less than what it cost to produce that power. In 2014 alone, 47% of Ontario's total power exports were related to surplus generation, with low-cost and low-carbon-emission energy, such as hydropower and nuclear-generated electricity, being exported. As well, from 2009 to 2014, there were also almost 2,000 hours in which the Hourly Ontario Electricity Price was negative, and Ontario paid exporters a net total of $32.6 million to take our power.

We also found that the lack of a structured, coordinated planning process has had ongoing negative effects on the performance of the transmission system:

- **Outstanding capacity and reliability issues**—A number of regions, including Kitchener-Waterloo-Cambridge-Guelph and Windsor-Essex, have capacity and reliability issues. The majority of transmission lines delivering power to these areas have exceeded, reached or are close to reaching their capacity, and are not expected to be capable of meeting significant increases in peak demand. The OPA identified these issues in its 2007 Integrated Power System Plan that was never approved or implemented. Although work was underway on projects to address these needs, at the time of our audit the issues remained unresolved.
- **Lack of capacity to connect renewable generators**—A total of 2,545 small guaranteed-price (microFIT) renewable projects could not proceed because there was not enough transmission capacity to accommodate the number of project applications that flooded in. To deal with this, the Ministry directed the OPA to allow those applicants to combine their projects and reapply under the larger guaranteed-price program (FIT) while still offering them the higher microFIT contract price set for small projects. We calculate that this will cost electricity consumers $239 million more for these contracts over their 20-year contract terms (the IESO calculates this amount to be closer to $126 million, in order to reflect the time value of money).
- **Generators compensated for constrained outputs**—In Ontario, generators may be entitled to compensation payments (in addition to the market price they receive for producing energy) when they are asked by the IESO to supply more or less power as the system requires. From 2009 to 2014, a total of $407.6 million had been paid to compensate generators for either increasing or not producing power on demand. In 2014 alone, generators were paid $117.3 million—an increase of 77% since 2009. Overall, we found that generator-constrained volumes have significantly increased (by 36%) while electricity demand has remained relatively stable. The IESO informed us that changes in regional demand and changes in supply mix to support the phasing out of coal along with the significant increases of renewable energy have changed the flow patterns in the power system, contributing to increases in transmission constraints in recent years, especially in the Bruce and North East regions.

- **Electricity imports not given due consideration when they were needed**—Importing power would have been a viable alternative to procuring renewable energy sources to meet electricity demands. However, the OPA's planning process did not include a cost/benefit analysis of increasing transmission capacity to accommodate contracted hydro imports from neighbouring jurisdictions (compared to signing expensive renewable wind and solar contracts), and the Ministry has only considered contracted imports more recently. The government has decided to sign a contract with Quebec committing to exchange electricity starting in late 2015, and it is also considering importing electricity from Newfoundland and Labrador.

Most of the responses to our recommendations refer to recently introduced draft legislation (Bill 135). Our Office is not in a position to comment on the merits of this draft legislation, nor at this point in time can we assess whether the changes proposed in the draft legislation would meet the intent of our recommendations.

This report contains five recommendations, consisting of 16 actions, to address the findings noted during this audit.

4.0 Detailed Audit Observations

4.1 Planning Process Has Broken Down

4.1.1 Ontario Does Not Have an Integrated Power System Plan in Place

Under the *Electricity Act, 1998*, the OPA was mandated to conduct independent electricity planning and to regularly prepare an "Integrated Power System Plan," (referred to hereinafter as the "technical plan") a 20-year technical plan to guide the province in achieving its energy goals and to protect the interests of electricity consumers. Although having a technical plan in place has been a legal requirement for over a decade, since 2004, Ontario has never had an approved technical plan in place. The OPA did develop two technical plans, one in 2007 and another in 2011, but neither plan went forward because of changes to government policy. Developing these plans cost the OPA over $16 million.

In 2010, the Ministry published its "Long-term Energy Plan" (referred to hereinafter as the "policy plan") a shorter, more policy-oriented document outlining Ontario's energy goals and supply mix for the next 20 years. Although there is no legislative requirement for the Ministry to prepare such a plan, the Ministry updated its policy plan in 2013, and plans to continue to review and update it every three years. The Ministry told us that a technical plan was no longer warranted following the release of its 2013 policy plan, noting that the technical-planning process is expensive, lengthy and inflexible for responding to market changes. However, while we noted that the Ministry's 2013 policy plan provided more technical information than the 2010 policy plan, we found that this plan was still not sufficient for addressing Ontario power system's needs and for protecting electricity consumers' interests. We noted the following deficiencies:

- **No cost/benefit analysis of other alternatives**—The Ministry's 2010 and 2013 policy plans did not present the detailed cost/benefit analyses of the different scenarios and alternatives included in technical plans, such as the plans the OPA prepared (but which were never approved) in 2007 and 2011.
- **Lack of transparency**—Electricity consumers are not being informed of the reasons behind rising electricity costs. Although the Ministry's 2013 policy plan identified actions the government was taking to reduce electricity costs, it failed to identify the key cost drivers that have had the most significant effect on electricity rates: surplus power and the Global Adjustment.

- **Questionable stakeholder consultation process**—The Ministry undertook a two-month stakeholder consultation process for its 2010 policy plan but could not provide us with a summary of the responses it received. We noted that this plan was released just five days after the consultation period ended, and questioned whether this was enough time for the Ministry to review all the stakeholder feedback it received and consider it fully in preparing the plan.
- **No interim reporting**—In 2011, the Ministry set an interim peak demand reduction target of 4,550 MW by 2015. However, it removed this interim target from its 2013 policy plan without providing the public with any rationale for doing so or setting a new replacement interim target. The 2013 policy plan also did not include a progress report on the interim targets previously set in the 2010 policy plan.

Even if the Ministry's policy plan was a sufficient replacement for OPA/IESO's technical plan, there is still a legislative requirement for a technical plan to be prepared, which the Ministry continues to ignore. In 2013, the OPA wrote to the Ministry to suggest changes to legislation that would have the OPA continue to prepare the technical plan but submit it to the Ministry rather than the Ontario Energy Board for review and approval. The Ministry did not respond to the OPA's recommendation nor provide it with any direction as to whether it continued to have an obligation to produce the technical plan and to whom it should submit the plan.

When the OPA/IESO merger legislation passed in July 2014, it included a provision still requiring the new entity (the IESO) to prepare a technical plan and submit it to the Ontario Energy Board for review. After the merger took place in 2015, the new IESO wrote to the Ministry about potential changes to the long-term planning process. At the time of our audit, the Ministry had not responded or provided the IESO with any direction regarding the preparation of a technical plan.

4.1.2 Limited Ontario Energy Board Oversight Means Limited Consumer Protection

By allowing the technical planning process to break down, the Ministry has effectively cut the Ontario Energy Board (OEB) out of the picture. One of the OEB's key objectives is to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service. But with no oversight on electricity power system planning and only very limited oversight on electricity generation costs, it has been difficult for the OEB to meet this mandate in any meaningful way. We noted the following:

- **OEB could not complete reviews of technical plans**—The *Electricity Act, 1998*, was amended in 2004 to require the OEB to review and approve the OPA's Integrated Power System Plans to ensure that they comply with any directions issued by the Minister and are fiscally prudent. In 2008, the OEB suspended its review of the OPA's 2007 technical plan when the Minister sent a revised directive asking the OPA to revise the plan in response to changes to government policy regarding Ontario's supply mix and provide the revised plan to the OEB for review. However, the OPA did not submit the revised plan to the OEB as directed by the Ministry, but forwarded it directly to the Minister for review in 2011. The OPA indicated that it submitted the plan to the Minister first so that the Minister could review whether the OPA had adequately fulfilled its responsibility of consulting with First Nation and Métis communities in developing the plan, as directed in the 2011 Supply Mix Directive. However, neither the Minister nor the Ministry responded to the OPA's submission and eventually the planning process was abandoned, with no copy provided to the OEB.
- **OEB not authorized to review the Ministry's policy plans**—Unlike the OPA's technical plans, the Ministry's policy plans are

not required by legislation and the OEB is not authorized to review them. This means that neither of the Ministry's two policy plans have been subject to any independent review to ensure that they are fiscally prudent and that electricity consumer interests are protected.

- **Limited OEB oversight over electricity generation costs**—By law, the OEB may only review rates for nuclear power from Pickering and Darlington and for hydropower produced by Ontario Power Generation. This means that OEB's oversight is limited to only about 35% of Ontario's current installed capacity. The other two-thirds are ministry-directed power supply contracts with other nuclear generators and renewable and gas generators, which the OEB has no authority to review. There is currently no OEB oversight on power supply contract pricing to ensure that the contracts signed represent the best value for Ontario electricity consumers. As Pickering approaches its shutdown and as more renewable energy and gas contracts are expected to be signed in the future, we estimate that the OEB's oversight will decrease to only about a quarter of Ontario's installed capacity by 2032.
- **OEB was not consulted in the privatization of Hydro One**—On April 23, 2015, the government announced in its 2015 Budget that it plans to broaden Hydro One ownership through the public offering of 60% of Hydro One shares. This will be one of the largest privatizations of a government-owned generation asset in Canada. With private investors interested in maximizing profits, it is uncertain what the impact on electricity prices will be. The OEB, the protector of consumer interests, was not consulted in this decision-making process. At the same time, the government passed the *Building Ontario Up Act* on June 4, 2015, under which Hydro One Inc. and its subsidiaries are deemed not to be agencies of the Crown.

RECOMMENDATION 1

To ensure that electricity power system planning better protects the interests of electricity consumers, the Ministry of Energy should comply with provincial legislation and:

- clarify the roles of the Ministry of Energy and the Independent Electricity System Operator in preparing future technical plans;
- require full technical plans to be prepared on time and ensure that they are submitted to the Ontario Energy Board for review and approval;
- provide more public information for electricity consumers about the cost drivers of increasing electricity rates and the impact that various decisions have on electricity costs; and
- review the role of the Ontario Energy Board to determine how it can be made more effective in protecting the interests of electricity consumers.

MINISTRY RESPONSE

The Ministry agrees with the Auditor General's recommendations.

On October 28, 2015, the Minister of Energy introduced the *Energy Statute Law Amendment Act, 2015* (Bill 135) that, if passed, would replace the current Integrated Power System Plan (IPSP) process with an enhanced Long Term Energy Plan (LTEP) process. If passed, the proposed legislation would do the following:

- It would clarify the roles of the Ministry of Energy and the Independent Electricity System Operator (IESO) in developing future long-term energy plans. The Ministry recognizes IESO's technical knowledge and expertise with respect to the electricity sector and is committed to maintaining an IESO role in the development of future energy plans.
- It would kick off the LTEP process with the development of a technical plan by the

IESO that would be used by the province in consultations on and the development of the LTEP. The proposed legislation would also provide for the development of implementation plans by the IESO and the Ontario Energy Board (OEB).

- It would enshrine extensive consultations with consumers, stakeholders and Aboriginal groups, and the creation of the plan will be consistent with the principles of cost-effectiveness, reliability, clean energy, community and Aboriginal engagement, and with an emphasis on conservation and demand management. It would also require the publication of the LTEP and other key information and data used in its development on a Government of Ontario website.

In addition, on June 2, 2015, the Ministry introduced the *Strengthening Consumer Protection and Electricity System Oversight Act, 2015* (Bill 112) that would enhance the OEB's mandate and organization to regulate the energy sector and protect consumers. The proposed legislation would, if passed, enhance the OEB's role in the protection of Ontario energy consumers by creating further opportunities to enhance consumer representation in OEB proceedings, ban the sale of retail energy contracts at the door and provide the OEB with an improved ability to ensure continuity of service for electricity consumers.

4.2 Extensive Use of Ministerial Directives and Directions

In the absence of an approved technical plan, it has been the Ministry's practice to communicate its energy policy objectives by issuing directives and directions to the OPA, the OEB, OPG and Hydro One. **Figure 6** summarizes the more significant ministerial directives and directions issued to the OPA prior to 2015. Although the *Electricity Act, 1998,* gives the Minister of Energy the authority to issue directives on supply mix (which require cabinet approval) and directions (which do not require cabinet approval) on all other matters related to electricity, we found that the Ministry's reliance on directives and directions has affected the electricity power system planning process in a number of ways:

- **No OEB oversight**—The OEB cannot perform a regulatory review of decisions made through ministerial directives and directions. This means another area of the planning process where the OEB has no oversight, which ultimately means that consumer interests may not be fully represented. For example, when the Ministry directed that its guaranteed-price renewable program offer generators prices significantly higher than market rates for renewable energy, the OEB had no say in the matter because it does not regulate renewables.
- **Increasing costs for consumers**—We found that many of the Ministry's directives and directions to the OPA relating to the procurement of electricity from renewable energy, natural gas and nuclear resources presented a significant cost impact to Ontario electricity consumers. Annual electricity consumption in Ontario has decreased from 151.1 million MWh in 2006 to 139.8 million MWh in 2014 (see **Figure 7**). Despite this decrease in consumption, Ontario's generation capacity has increased by 19% over the same period. **Figure 8** shows that electricity charges for residential and small-business electricity consumers have increased by 70%, from 5.32 cents/kWh in 2006 to 9.06 cents/kWh in 2014. Most of the increase in what consumers pay for electricity has come from generation-cost increases, which currently account for about 60% of the overall cost of electricity. Generation costs have increased by 74% over the last decade, from $6.7 billion in 2004 to $11.8 billion in 2014, and they are expected to grow to $13.8 billion by 2022. In particular, Global Adjustment fees have increased significantly, from $650 million in 2006 to $7.03 billion in 2014. From 2006 to

Figure 6: Summary of Key Ministerial Directives and Directions to Ontario Power Authority

Source of data: Independent Electricity System Operator

Month, Year	Directives	Key Directives Summarized
June 2006	Supply Mix Directive	OPA to create an Integrated Power System Plan (IPSP) to meet demand reduction from conservation by 6,300 MW by 2025, and increase installed capacity of new renewable energy sources by 15,700 MW by 2025.
September 2008	Supply Mix Directive	Amends previous Supply Mix Directive. Requires the OPA to revisit the IPSP with a view to establishing new targets in a number of areas, including renewable energy sources and conservation.
February 2011	Supply Mix Directive	Replaces previous Supply Mix Directives. Requires OPA to develop an IPSP to meet the government's specific goals and targets, such as the refurbishment of nuclear stations and procurement of two new nuclear generating units; installed capacity of 10,700 MW of non-hydro renewable by 2018; and achieving conservation peak demand reduction target of 7,100 MW and an energy savings target of 28 TWh by the end of 2030.
Month, Year	**Directions**	**Key Directions Summarized**
March 2006	Guaranteed Price Renewable Program	Assume responsibility for the development of a guaranteed-price renewable program for small renewable generators to be in place by the fall of 2006.
August 2007	Procurement of up to 2,000 MW Renewable Energy Supply	Procure up to 2,000 MW of renewable generation projects greater than 10 MW in size through competitive procurement.
December 2007	Hydroelectric Energy Supply Agreements with Ontario Power Generation Inc.	Assume responsibility for negotiating with OPG on a number of specific hydro projects selected by the government.
September 2009	New Guaranteed Price Renewable Program	Develop a new guaranteed-price renewable program that is wider in scope with specific domestic content requirements.
April 2010	Green Energy Investment Agreement	Negotiate one or more power purchase agreements with Korean Consortium, substantially similar to the guaranteed-price renewable program contract and rules, with necessary modifications to reflect the terms of the government's Green Energy Investment Agreement (GEIA). OPA is further directed to give priority to GEIA projects when assessing transmission availability.
August 2010	Atikokan Biomass Energy Supply Agreement with Ontario Power Generation	Make reasonable efforts to complete the negotiation of a long-term energy supply contract to convert the Atikokan Generating Station from coal to biomass.
September 2010	Green Energy Investment Agreement	Hold 500 MW of transmission capacity to be made available in the Bruce area in reserve for phase two projects of the Korean Consortium.
August 2011	Constrained Small Guaranteed Price Renewable Projects	The constrained applicant may combine and relocate, to any one new property, up to 50 constrained projects, up to 500 kW. The constrained applicant must sign an agreement with the OPA, for which the agreement provides for the same prices as in the conditional offers for the constrained projects.
November 2012	Industrial Electricity Program	Develop and implement the Industrial Electricity Incentive Program to improve load management and the management of electricity demand in Ontario. Sets out specific program design and eligibility criteria.
December 2012	Southwest GTA Supply	Enter into negotiations for a Clean Energy Supply Contract with TransCanada Energy Limited (TCE) with respect to a gas-fired generation facility on the lands of the Lennox Generating Station. The contract is to be consistent with the Memorandum of Understanding entered into between the Province, TCE and the OPA on September 24, 2012.

Month, Year	Directions	Key Directions Summarized
December 2013	Supply Agreement with Ontario Power Generation for the conversion of Thunder Bay Generating Station	Negotiate and enter into a contract with OPG for the procurement of electricity from advanced biomass from one converted unit at the Thunder Bay generating station, subject to the parameters provided in the direction.
March 2014	Procuring Energy Storage	Pursue the procurement of 50 MW of energy storage by the end of 2014. Through a letter dated February 24, 2014, the Minister expressed a preference that as much as 36 MW be procured through IESO-led procurement efforts, and the balance through OPA-led procurement efforts. (This direction is to OPA to begin its phase of the procurement.)
March 2014	Large Renewable Procurement	Complete work on the draft Request for Qualifications and draft Request for Proposals for the Large Renewable Procurement Process. Future ministerial direction will define particular features of the final RFP.
April 2014	Industrial Electricity Program	Expand eligibility to certain other energy-intensive sectors and extend the contract term to a period with no surplus to attract applicants.

Figure 7: Annual Grid-connected Energy Consumption in Ontario, 2006–2014

Source of data: Independent Electricity System Operator

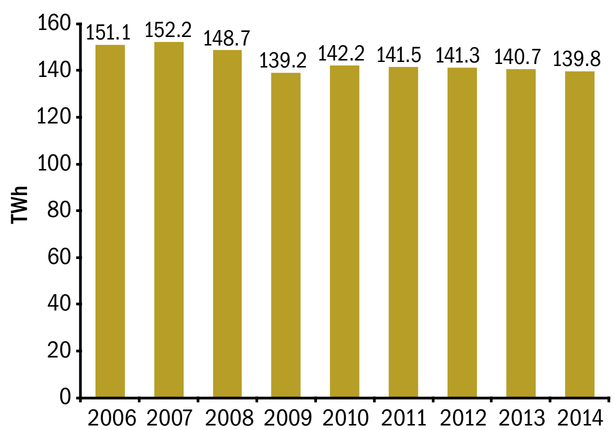
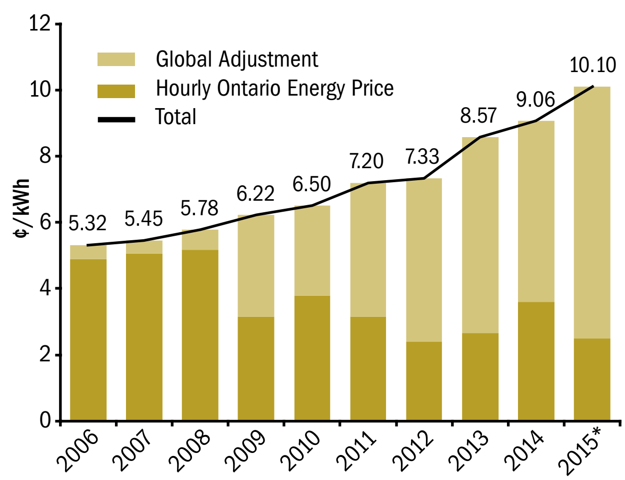


Figure 8: Ontario Electricity Charges for Residential and Small-business Customers, 2006–2015

Source of data: Independent Electricity System Operator



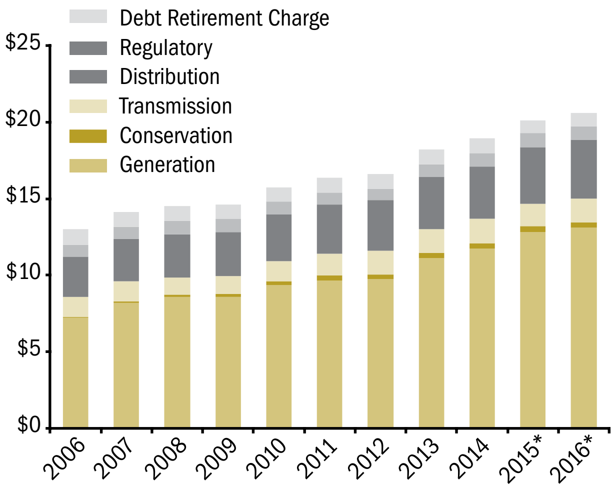
* Projections taken from the Ministry's 2013 Long Term Energy Plan.

2014, electricity consumers have already paid a total of $37 billion, and they are expected to pay another $133 billion in Global Adjustment fees from 2015 to 2032. **Figure 9** shows the actual and projected total cost breakdown of electricity service in Ontario from the year 2006 to 2016.

- **Limiting the independent planner's role**—Although it was the OPA's mandate to conduct "independent" electricity planning for Ontario, seven different Ministers of Energy have issued three directives on supply mix and 90 directions to the OPA since the time of its creation in 2004 to the time of its merger with the IESO in 2015. In one of its communications to the Ministry, the OPA indicated that the Minister's 2011 supply mix directive (which called for a renewable energy capacity of 19,700 MW by 2018) in particular had significantly reduced the amount of discretion left to the OPA. In our survey of former OPA board members, all respondents reported that because there were sometimes policy disagreements, the OPA requested directions

Figure 9: Annual Total Cost of Electricity Service in Ontario, 2006–2016 ($ billion)

Source of data: Independent Electricity System Operator



1. Regulatory charges include a wholesale market service charge that covers services provided by the IESO to operate the wholesale electricity market and maintain the reliability of the high-voltage power grid, and a standard supply service charge that covers part of a utility's administrative costs to provide electricity to customers not served by a retailer.
2. Generation cost includes Global Adjustment fees.
3. Projections taken from the Ministry's 2013 Long Term Energy Plan.

from the Ministry on several occasions before implementing a certain policy or executing a certain contract. For example, the OPA requested directions on the guaranteed-price renewable program's contract pricing and on the conversion of the Atikokan coal plant into a biomass facility.

- **Lack of transparency**—The Ministry's use of directives and directions to make major decisions has resulted in a process that is less than open and transparent—both to the key players in the electricity-sector and to the public. The OPA's mandate was to be Ontario's technical planner with expert knowledge of the power system, but it often could not apply its expertise because the rationale behind many of the directives and directions it received from the Ministry was not apparent. We found no evidence that ministerial directives and directions were supported by public consultations or economic analyses disclosed to the public. In our survey of former OPA board members, 83% of respondents felt that the Ministry's directives had negative impacts on the overall quality (i.e., accountability and transparency) of electricity planning.

RECOMMENDATION 2

To ensure that ministerial directives and directions fully consider both the technical-system impacts and economic impacts that affect electricity consumers, the Ministry of Energy should:

- regularly engage with the Independent Electricity System Operator and other technical expert advisors during the decision-making process; and
- make the decision-making process more transparent and accountable by providing information to the public on directives, directions and rationales for decisions made.

MINISTRY RESPONSE

The Ministry agrees with the Auditor General's recommendation.

On October 28, 2015, the Minister of Energy introduced the *Energy Statute Law Amendment Act, 2015* (Bill 135) that, if passed, would replace the current Integrated Power System Plan (IPSP) process with an enhanced Long Term Energy Plan (LTEP) process. If passed, the proposed legislation would do the following:

- It would clarify the roles of the Ministry of Energy and the Independent Electricity System Operator (IESO) in developing future long-term energy plans. The Ministry recognizes IESO's technical knowledge and expertise with respect to the electricity sector and is committed to maintaining an IESO role in the development of future energy plans. The IESO, as proposed in the legislation, will develop a technical report to kick off the LTEP process and, both agencies, the Ontario Energy Board (OEB) and the IESO will develop implementation plans detailing how they would implement the LTEP's objectives.

- It would enshrine extensive consultations with consumers, stakeholders and Aboriginal groups, and the creation of the plan will be consistent with the principles of cost-effectiveness, reliability, clean energy, community and Aboriginal engagement, and with an emphasis on conservation and demand management. The proposed legislation would also require the publication of the LTEP and other key information and data used in its development on a Government of Ontario website.

In addition, the directives and directions sent to the IESO contain key background information and rationale on policy objectives. The directives and directions are also publicly posted on the IESO's website, and, as when it implements the directives and directions, the IESO consults with stakeholders and the public to ensure that the program objectives, rationale and process are transparent.

4.3 Problems with Generation Procurement Decisions

4.3.1 Electricity Surpluses Mean Higher Electricity Costs for Consumers

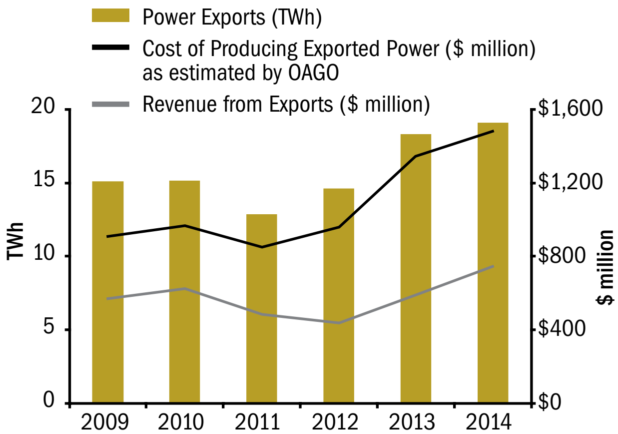
With no approved technical plan in place, the Ministry directed the then OPA (now the IESO) to procure renewable, natural gas and nuclear resources on an "as and when required" basis. But, as the sections that follow will show, this method of procurement has contributed to an oversupply of electricity in the province. Ontario has experienced more days with surplus electricity generation in recent years, from 172 days in 2011 to 319 days in 2014—an 85% increase over four years. From 2009 to 2014, the province's available electricity supply exceeded its maximum demand by 5,160 MW per year, on average—an amount that approximates the total existing power generation capacity of the Province of Manitoba. In 2014 alone, Ontario's available electricity supply exceeded the peak demand by about 7,500 MW. As part of the North American Electric Reliability Corporation requirement, the IESO has to take into consideration both operating and planning reserves. From 2009 to 2014, Ontario's electricity supply on average exceeded the peak demand and operating reserve by over 3,600 MW per year; when allowing for greater planning reserve, Ontario still has a surplus of about 2,500 MW per year on average. Our review found that the IESO's planning reserve was based on an optimistic demand forecast that did not anticipate or subsequently adjust for the global recession in 2008, and that did not fully incorporate the decrease in electricity consumption from conservation initiatives.

The IESO manages surplus electricity generation by exporting power to other jurisdictions, and by requesting some Ontario baseload generators to curtail or completely shut down production. But both export and curtailment drive up Ontario's overall electricity costs:

- **Exporting power is not profitable**—The price that Ontarians pay for electricity is significantly higher than the price Ontario charges its export customers. Export prices are determined by supply and demand in the electricity market, and they are not charged the Global Adjustment fee that Ontario customers pay. From 2009 to 2014, Ontario exported a total of 95.1 million MWh of power to other jurisdictions. The total cost of producing this power was about $3.1 billion more than the revenue Ontario received for exporting it. However, these exports allow Ontario to recover part of the fixed costs that otherwise would have to be paid by Ontario electricity consumers. **Figure 10** shows the amount of power Ontario exported to other jurisdictions from 2009 to 2014, as well as the amount of revenue Ontario received from these exports compared to what the generators are paid to generate the exported power. In 2014 alone, 8.9 million MWh of the 19.1 million MWh (47%) of Ontario's total power exports related to surplus baseload generation. In some

Figure 10: Power Exports and their Related Cost and Revenue, 2009–2014

Source of data: Independent Electricity System Operator



cases, surplus generation was so high that the Hourly Ontario Electricity Price went negative, which meant that Ontario either had to pay other jurisdictions to take its power or simply had to give it away for free. A negative Hourly Ontario Electricity Price indicates that electricity sellers are willing to pay buyers to take their power. This situation is most likely to occur in markets with large amounts of inflexible generation and low demand. An example of inflexible generation is nuclear. It is very hard for nuclear generators to curtail their output. They would incur significant costs if they shut down their facilities—it is cheaper for them not to. Other types of generators, such as renewable generators, are paid fixed prices for their output regardless of hourly energy market conditions, so a negative Hourly Ontario Electricity Price is not an incentive for them to reduce their production (see the next point). From 2009 to 2014, there were 1,952 hours (861 hours in 2014 alone) where Ontario experienced a negative market price and paid exporters a net total of $32.6 million to take our power.

- **Curtailing generation does not curtail costs**—When the IESO asks generators to curtail or shut down their production because there is a surplus of electricity, those generators still have to be paid. From 2009 to 2014, surplus generation of 11.9 million MWh has cost Ontario electricity consumers approximately $339 million.

According to the IESO's electricity production forecast, baseload generation in Ontario from 2015 to 2020 is expected to continue to exceed demand by a total of 52.3 million MWh, an amount that would be enough to power the province of Nova Scotia for about five years. Of this, 41.7 million MWh is expected to be exported through the competitive market while the remaining 10.6million MWh is expected to be curtailed. Ontario's electricity cost is expected to further increase in the future as a result of costly exports and curtailments. **Figure 11** shows the IESO's projected surplus management plan for the period from 2015 to 2025. Although surplus generation is projected to decrease, between the years 2021 and 2032 surplus generation would still be about 2.8 million MWh on average per year, after taking into consideration the shutdown of Pickering and the refurbishment of Darlington and Bruce nuclear units.

4.3.2 Excessive Prices Paid for Renewable Energy

The *Green Energy and Green Economy Act, 2009*, gave the Minister of Energy the authority to expedite the development of renewable energy by superseding many of the government's usual planning and regulatory oversight processes. Since that time, the Ministry has significantly increased the proportion of renewable energy in Ontario's supply mix, but it has done so without fully evaluating the impact, trade-offs and alternatives through a comprehensive business case analysis.

The situation that Ontario is facing now, of rising costs and excess power supply, could likely have been minimized if a proper planning process, drawing on the technical expertise of the OPA and other engineering expertise, and the check-and-balance function of the OEB, had been followed.

Unfortunately, it is electricity consumers who have to cover the rising electricity costs.

Ontario Still Paying Too Much for Renewables

In 2006, Ontario already had a guaranteed-price program for renewable energy whose prices were competitive with market prices. This program was expected to develop 1,000 MW over 10 years, but it exceeded that target in a little more than a year. Despite the program's tremendous success, the Ministry directed the OPA to replace it with a new guaranteed-price renewable program in 2009 (the FIT or Feed-in Tariff Program) to create more clean energy jobs and attract investment to Ontario in the midst of a global recession.

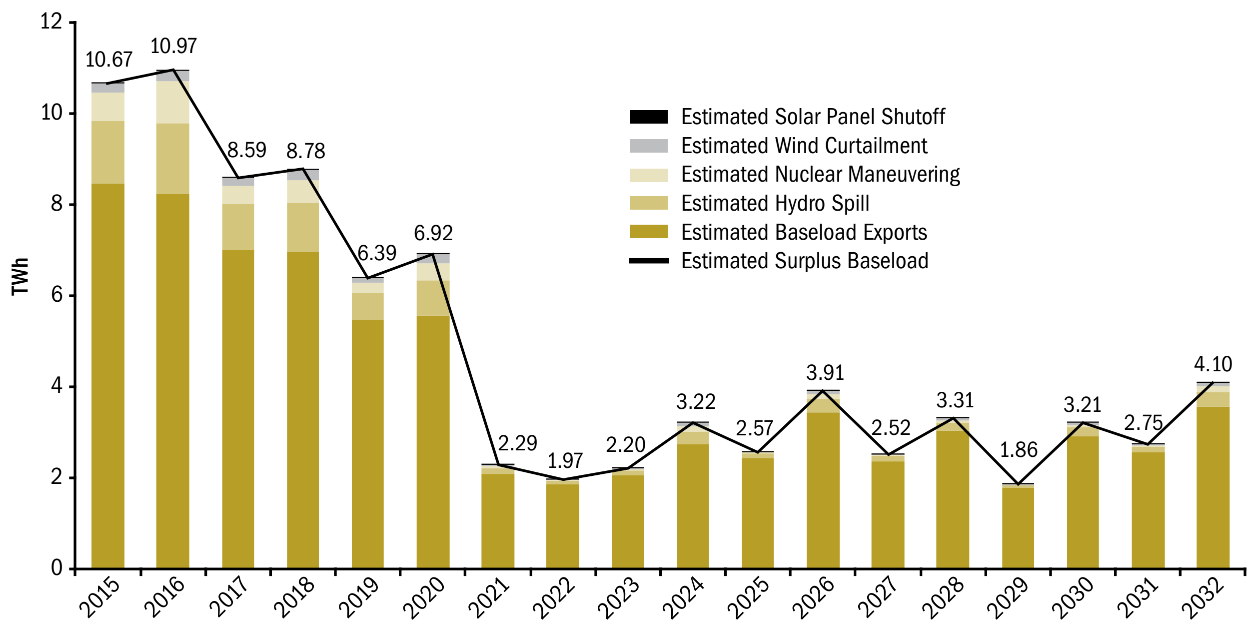
Although global renewable market prices had started to decrease rapidly in 2009 because of technological advances and competition, the Ministry instructed the OPA to offer guaranteed prices that were even higher than those offered by the former guaranteed-price program: 29% higher for solar roof-top projects; 60% higher for solar ground-mounted projects; 73% higher for offshore wind projects; and 23% higher for onshore wind projects.

Not surprisingly, the OPA received an overwhelming response—more than 16,000 applications within the first 10 months of the new guaranteed-price renewable program's launch. We audited renewable energy initiatives in 2011, and in our Annual Report that year we highlighted the lack of regular price adjustments to reflect changing market conditions. Following our audit, the OPA dropped the guaranteed prices for renewables in 2012 and again in 2014. However, we found that Ontario's guaranteed prices in 2014 were still double the current average cost for wind and three and half times the current average cost for solar energy. The Ministry's attractive guaranteed prices program has been one of the main contributors to the surplus power situation Ontario has faced since 2009, in that it has procured too many renewable projects, too quickly, and at too high a cost.

Ontario's current guaranteed-price renewable program prices are still too high. **Figure 12** shows the historic average cost of solar and wind projects

Figure 11: IESO's Surplus Baseload Management Plan, 2015–2032

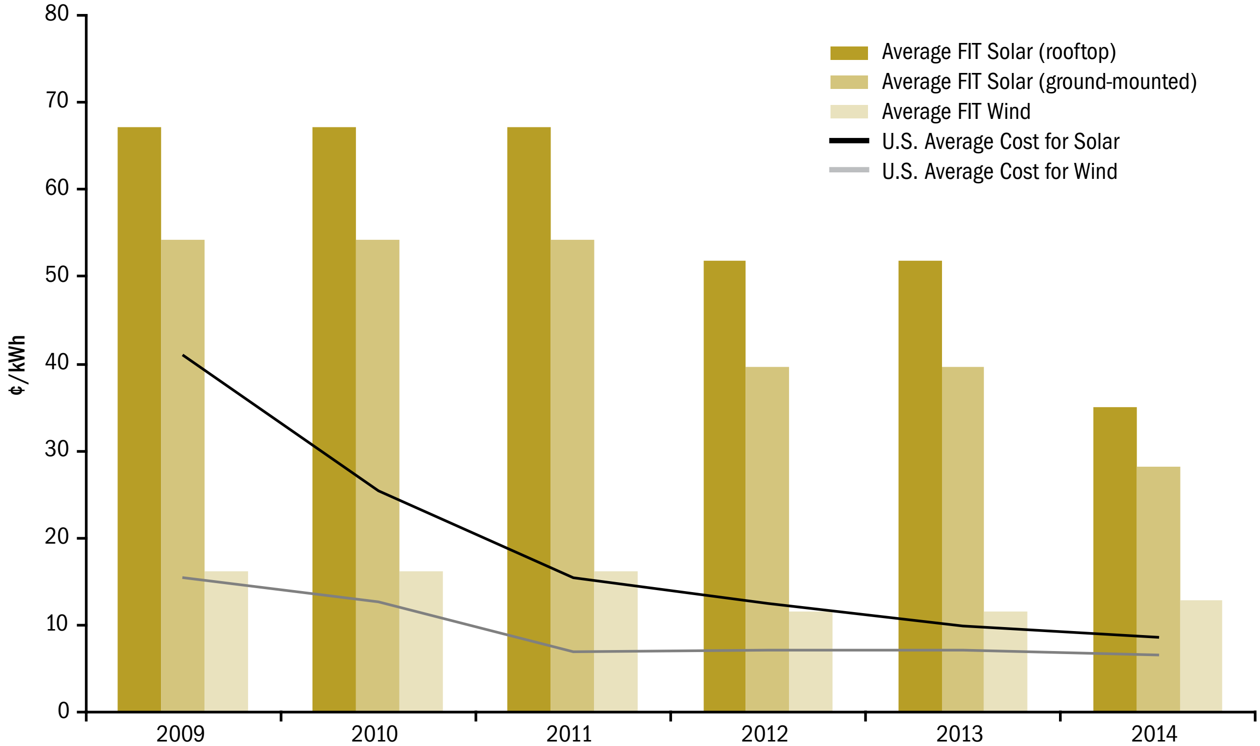
Source of data: Independent Electricity System Operator



Note: This graph shows Ontario's estimated surplus baseload from 2015 to 2032. IESO plans to manage this surplus by either exporting the excess power or requesting some generators (such as hydro, nuclear, wind or solar) to reduce production.

Figure 12: Historical U.S. Average Cost Versus FIT Guaranteed-price Program Prices for Wind and Solar Energy, 2009–2014

Source of data: Independent Electricity System Operator and Lazard Ltd.*



* Lazard Ltd., founded in 1848, is a financial advisory and asset-management firm that operates in 43 cities across 27 countries.

Note: Subsequent to our fieldwork, the IESO announced a price cut for solar projects effective January 2016. The average FIT price for solar rooftop projects decreased by 27% from 34.77¢/kWh to 25.37¢/kWh; for solar ground mount projects, the average FIT price dropped by 25% from 28.20¢/kWh to 21.15¢/kWh.

in the United States. The chart clearly shows that the average costs have dropped significantly, by 78% for solar and 58% for wind since 2009, to reflect technological advances. In comparison, Ontario's guaranteed-price renewable program prices for solar and onshore wind have only decreased by 48% and 5%, respectively. In fact, the current guaranteed-price renewable program price paid to wind producers is even higher than the one offered in the previous 2006 guaranteed-price renewable program.

Renewable Energy Not Procured Competitively

In our 2011 audit of renewable energy initiatives, we calculated that expensive guaranteed-price renewable contracts would cost Ontario electricity consumers about $4.4 billion more over the 20-year contract term than they would have under the former program's guaranteed prices. Taking into consideration new contracts signed since our 2011 report, we estimate this cost has increased to $9.2 billion (the IESO calculates this amount to be closer to $5.3 billion, in order to reflect the time value of money).

If large-scale renewable energy projects had been procured using a competitive procurement process at market prices for wind and solar (see **Figure 12**), the cost to electricity consumers would have been much lower. But, as we noted in 2011, not only did the government not follow the competitive procurement process the OPA recommended for large renewable projects, it offered additional economic incentives along with the already attractive prices offered under the guaranteed-price renewable program to a foreign consortium without first consulting with the OPA.

As well, the Minister of Energy's directions on the guaranteed-price renewable program clearly went beyond policy direction by including instructions on how much renewable energy to procure and the method of procurement to be used.

In 2013 the Ministry revised the guaranteed price renewable program and directed the OPA to develop a new competitive procurement program for large renewable projects. However, by that time the OPA had already procured about 200 projects through the guaranteed-price renewable program (a total of 4,064 MW of power). Using the prices from the previous competitive renewable procurement program, we calculate that if these 200 projects had been competitively procured from the start, Ontario's electricity consumers could have saved approximately $4.7 billion over the life of the contracts (the IESO calculates this amount to be closer to $1.9 billion, in order to reflect the time value of money).

Renewable Energy Not the Most Cost-effective Way to Reduce Greenhouse Gas Emissions

IESO data on greenhouse gas emissions shows that the Ministry's decision to significantly increase the amount of renewable energy in Ontario's supply mix was not the most cost-effective method of reducing greenhouse gas emissions in the province. The Ontario Society of Professional Engineers has also indicated that the current supply mix is not optimal for Ontario's power system design, and that it has resulted in Ontario having surplus generation and increasing curtailments of low-carbon-emission energy, such as hydropower and nuclear, at a considerable cost to electricity consumers. In fact, IESO data shows that Ontario electricity consumers have already paid approximately $339 million for about 11.9 million MWh of curtailed electricity resulting from surplus generation, of which $318 million and 10.7 million MWh relates to nuclear and hydropower. Based on our analysis of the most recent IESO data on greenhouse gas emissions, the implied cost of using non-hydro renewables to reduce carbon emissions in the electricity sector was quite high: approximately $257 million for each megatonne of emissions reduced.

In 2012, Ontario's emissions were estimated to be around 167 Mt total. While the electricity sector's share of emissions was only 14.5 Mt (or 9% of total emissions), the transportation sector and the industrial sector created 34% and 30% of Ontario's emissions, respectively. According to the Ontario Society of Professional Engineers, emission reduction is important, but the cost of reducing emissions from the electricity sector should be evaluated against initiatives taken to reduce emissions from other, higher-emitting sectors such as the transportation industry.

Reducing emissions from cars and trucks could very well be more cost-effective than reducing emissions through phasing out coal plants and procuring renewable energy at expensive prices. However, the Ministry has not studied reducing emissions from other sectors.

Renewable Energy Contributes Less to Meeting Peak Demands While Costing More

"Capacity contribution" is the amount of installed capacity that is available to generate power at a time of peak electricity demand. Ontario's total generating capacity contribution is declining as more renewable resources are added to the supply mix, because renewables like wind and solar have lower capacity contributions. In 2003, about 90% of our total generation capacity was available to contribute to meeting peak-period demands, but this percentage is dropping. It currently sits at 80% and is projected to fall further, to 70% by 2032, as more renewables are added to the supply mix.

Compared to other types of energy resources, renewables like wind and solar tend to contribute less than their installed capacity during peak-demand periods; wind and solar energy are not always reliable because wind and sunshine are intermittent by nature. In Ontario, wind and solar energy have capacity contributions of only 14% and 30%, respectively. This means that wind and solar are only available 14% and 30% of the time, respectively, because of less windy and sometimes cloudy days during the summer when electricity demand is highest. As a result, other resources with higher capacity factors, such as natural gas resources, are needed to meet Ontario's supply requirements. This, paired with Ontario's renewable energy costing more than other types of power generation because of high guaranteed prices, has contributed to higher electricity prices.

An alternative to using natural gas as backup is to explore the possibility of storing renewable energy. However, based on the cost of small-scale storage procured by the IESO to date, the current cost of renewable electricity storage in Ontario is approximately $1 million/MW. The costs for large-scale storage are expected to be significantly higher, which does not make it a financially viable option at this time.

4.3.3 Direction to Proceed with Expensive Hydro Project

In its 2007 Integrated Power System Plan (technical plan), the OPA identified several hydro projects that would meet the Ministry's renewable energy targets, and the Ministry directed it to proceed with some of them. In 2007, the initial estimate for the project was $1.4 billion. In January 2010, the OPA noted that the estimated cost for the Lower Mattagami project had increased substantially to $2.56 billion after conducting further engineering studies. The OPA asked the Ministry for directions because it was concerned about the cost of the project, and wanted to confirm with the Ministry whether or not to proceed given the significant projected cost increase. In February 2010, the Ministry sent a letter to the OPA acknowledging that the cost increase was significant but instructing the OPA to go ahead with the project anyway. According to the Ministry, this project was part of the government's plan to meet the Ministry's renewable targets and to invest in Aboriginal communities and the economy of northern Ontario. The target completion date was September 2014, and the project was completed in December 2014 with final costs reaching over $2.4 billion. According to the IESO, the average cost for this hydro facility is $135/MWh compared to the average cost of $46/MWh for two other recent hydro projects in Ontario outside of the Mattagami River: One of the projects was adding an extension to an existing facility and had a lower cost of $35/MWh; The other project involved building a brand-new facility and had a higher cost of $56/MWh. Based on our review of recent hydro projects in other Canadian jurisdictions, we noted that the $56/MWh is comparable.

4.3.4 Biomass Conversions Not Cost-effective

In the 2013 policy plan, the Ministry directed the OPA to convert a coal plant at Thunder Bay into a biomass facility that burns forestry by-products to create energy. Although the OPA's review found that the conversion would not be cost-effective, the Ministry directed it to proceed with the conversion anyway in December 2013. When we interviewed people from the (former) OPA about this project, they indicated that the Ministry wanted to facilitate growth and job creation in both Ontario's forestry industry and in the Thunder Bay region.

The Thunder Bay biomass facility is a peaking resource expected to operate the equivalent of five full-capacity days in a year while employing 60 full-time staff. This plant is expected to generate only about 15,000 MWh in a year, but at a cost of $40 million per year. This puts the cost of electricity from this facility at around $1,600/MWh—25 times higher than the average cost of existing biomass energy from other facilities in Ontario. In addition, since the imported forestry by-products this plant uses as fuel can only be purchased from outside of Canada, we are concerned that it might not be able to facilitate the volume of job growth in Ontario's forestry industry as the Ministry intends.

In August 2010, the Ministry directed the OPA to negotiate with OPG to convert the coal plant at Atikokan into a biomass facility. Interviewees from the OPA indicated that, in this case, the OPA did not evaluate the cost-effectiveness of the conversion versus other alternatives because the Ministry had already made the decision. The Atikokan biomass facility is also a peaking resource, expected to operate the equivalent of 29 full-capacity days per year while employing 64 full-time staff. The plant is expected to generate 140,000 MWh for $74 million per year, putting the cost of electricity from this facility at $528/MWh—about eight times higher than the average cost of existing biomass from other facilities in Ontario. According to the Ministry, the Atikokan plant is part of the government's plan to replace coal generation with emission-free electricity sources and to facilitate the province's biomass industry as this plant is fuelled by resources that come from Ontario.

4.3.5 Costly Cancellation of Natural Gas Plants

The OPA's 2007 Integrated Power System Plan identified the need for new regional gas-fired generation in the southwest Greater Toronto Area (GTA). In 2008, the Ministry directed the OPA to procure a gas plant there, but later cancelled the project in 2010 at a cost of $675 million (see our 2013 special report, *Oakville Power Plant Cancellation Costs*). The Ministry made a policy decision that went against the OPA's advice and requested the replacement gas plant to be located in Napanee, even though it would cost more to deliver gas to Napanee and then transmit electricity back to the southwest GTA where it was needed. At the time of our audit, construction of the Napanee gas plant had just begun and was not expected to be completed until 2018, leaving southwest GTA's needs unmet.

In 2011, another new gas plant was under construction in Mississauga, both to meet overall generation needs for the province and to address supply needs in the southwest GTA. Later that year, the Minister requested the OPA to begin discussions to cancel the Mississauga plant. In 2012, the Minister announced that the Mississauga plant was to be relocated to Ontario Power Generation's Lambton Generating Station site even though the OPA estimated that locating the Mississauga plant to Lambton would result in higher overall transmission system losses than would have been the case if the plant had been located in the southwest GTA. We estimated that the decision to cancel the Mississauga power plant and relocate it cost about $275 million (see our 2013 special report, *Mississauga Power Plant Cancellation Costs*).

RECOMMENDATION 3

To ensure that future power generation decisions are made with sufficient economic and financial information that would best serve electricity consumers and Ontario's electricity power system, the Ministry of Energy should:

- work with the Independent Electricity System Operator, Ontario Power Generation, Hydro One, approximately 70 local distribution companies and other technical experts to determine the optimal supply mix for Ontario; and
- engage the Independent Electricity System Operator, Ontario Power Generation, Hydro One, approximately 70 local distribution companies and other technical experts to consider different scenarios and evaluate cost-effectiveness when making decisions on new projects;
- conduct cost/benefit analyses during the planning process to assess the potential impact of a decision on electricity consumers and the power system; and
- closely monitor, address, and publicly report on the extent and impact of the oversupply of electricity.

MINISTRY RESPONSE

The Ministry agrees with the Auditor General's recommendation.

On October 28, 2015, the Minister of Energy introduced the *Energy Statute Law Amendment Act, 2015* (Bill 135) that, if passed, would replace the current Integrated Power System Plan (IPSP) process with an enhanced Long Term Energy Plan (LTEP) process. If passed, the proposed legislation would do the following:

- It would enshrine extensive consultations with consumers, stakeholders and Aboriginal groups. These consultations would include seeking input from key sector stakeholders and experts such as transmitters and local distribution companies, as well as the general public. The planning process will allow for technical experts, including agencies, to provide input to the planning process.
- It would ensure the plan will be consistent with the principles of cost-effectiveness, reliability, clean energy, community and Aboriginal engagement, and with an emphasis on conservation and demand management. The proposed legislation enshrines the principle of cost-effectiveness of energy supply and capacity as part of LTEP. In addition, it would require the publication of the LTEP and other key information and data used in its development on a Government of Ontario website.

In addition, following the 2013 LTEP, the Ministry initiated the Ontario Energy Report, which is a website updated quarterly to ensure that reliable and up-to-date energy data on energy supply, demand, and costs is publicly available.

4.4 Ineffective Conservation and Demand-management Initiatives

Conservation aims to reduce overall electricity usage while demand management aims to reduce or shift consumption away from peak demand periods. Both are valuable tools when the electricity supply is unable to meet the expected electricity demand and the cost of new power generation is high; however, neither of these are currently problems in Ontario. As discussed earlier, the problem in Ontario is more often the opposite: periods of surplus capacity (even after considering all the reserve requirements) that result in a costly oversupply of electricity. According to the IESO's forecast, Ontario is projected to have long-term energy surpluses, until 2032. Although surplus generation is projected to decrease after 2020, there would still be about 2.8 million MWh surplus generation on average per year from 2021 to 2032, as shown in **Figure 11**.

When the available electricity supply exceeds the maximum hourly consumption plus the reserve requirements, as it has in Ontario for the past six years, reducing electricity consumption through conservation efforts is of little value. Although we recognize that conservation efforts require sustained commitment, investing in conservation during a time of surplus actually costs us more: the first type of cost is for managing the conservation programs and initiatives themselves; the second is for surpluses and the resulting costly oversupply of electricity those conservation efforts contribute to.

Ontario has spent approximately $2.3 billion on energy conservation efforts targeting both residential and business customers from 2006 to 2014, and has committed to spend another $2.6 billion from 2015 to 2020. At the same time, although electricity consumption in Ontario has decreased (partly due to the impact of the global recession since 2008 and to conservation efforts) by 8%, from 153 million MWh in 2004 to 140 million MWh in 2014, our electricity bills are becoming more expensive: the overall electricity cost has increased by 56%, from $12.2 billion in 2004 to $18.9 billion in 2014. In an online survey the Ministry conducted in 2013, when asked how well their local community was doing to reduce electricity demand, about 40% of respondents indicated that they did not see a lot of evidence of conservation efforts in their community.

Since 2003, Ontario has had an average installed capacity of 33,800 MW. Although Ontario's average electricity demand has only been about 16,700 MW over the years, Ontario has built up the power system (as opposed to importing power) to this point so that it can handle peak demands on rare occasions (for example, summer heat waves) and to meet reserve requirements.

The Ontario Society of Professional Engineers has indicated that a more effective strategy for reducing electricity costs would be to flatten the daily electricity demand, which is to shift demand from peak periods to off-peak periods. However, the OPA's conservation programs have not met its peak demand savings target even with the use of smart meters (see **Section 3.11** of our *2014 Annual Report* for a report of our audit of the Smart Metering Initiative), time-of-use billing and other demand-response initiatives.

4.4.1 Peak Demand Consumption Not Effectively Reduced

In its 2005 Supply Mix Advice Report to the Ministry, the OPA estimated achievable conservation potential at somewhere between 1,500 MW and 4,000 MW. According to the Ministry, the OPA chose to rely on the lower end of achievable potential in its advice, because the risk of planning less supply far exceeded the risk of not adjusting to higher conservation. This led the OPA to ultimately advise the Ministry that a peak demand reduction of 1,800 MW by 2025 was a reasonable and prudent conservation target. However, in 2006, the Ministry directed the OPA to take measures to meet a peak demand reduction target of 6,300 MW by 2025. In 2010, the Ministry further increased its peak demand reduction targets, to 6,700 MW by 2025, and 7,100 MW by 2030. It also set an interim target to reduce peak demand 4,550 MW by 2015. However, despite the $2.3 billion spent on conservation initiatives, the amount of peak demand reduction achieved so far is estimated to be only 3,619 MW by the end of 2014, short of the 4,550 MW target. This number is an estimate because peak demand achieved by OPA-managed programs accounts for only 1,512 MW of the 3,619 MW. The remaining 2,107 MW reflects peak demand reductions achieved by programs funded and managed by other entities, such as the federal government and gas utilities. The IESO is not authorized to evaluate these programs because it does not manage or deliver them; therefore it is not able to confirm the 2,107 MW of peak demand reductions achieved.

4.4.2 Many Conservation Initiatives Not Cost-effective or Not Evaluated for Cost-effectiveness

The IESO was accountable for $2.1 billion of the $2.3 billion that was spent on conservation initiatives in Ontario from 2006 to 2014. However, only about $923 million of this $2.1 billion has been evaluated by a third party for cost-effectiveness. Another estimated $400 million of electricity conservation and demand management program spending that occurred in 2014 will be evaluated in 2015. The remaining $758 million, or 36%, has not been subject to a third-party evaluation.

When evaluated collectively at the portfolio level, the conservation initiatives passed the IESO's cost-effectiveness tests. However, on an individual basis, about half (18) of the 37 conservation initiatives that were evaluated did not pass cost-effectiveness tests. The tests compared the cost of designing and delivering programs and customers' costs with the amount of electricity conserved and other supply-side resource costs (a conservation program is regarded as cost-effective only if its cost is less than the avoided cost of electricity). According to the Ministry, between 2006 and 2010, its focus was on building conservation capacity and expanding program delivery to targeted sectors. In 2011, a requirement was put in place to pass cost-effectiveness tests on a portfolio basis.

Furthermore, the IESO's cost-effectiveness calculation only included costs that had already been paid at the time of the evaluation (sometimes, a program completed in 2014 may not be completely paid out until 2015 or 2016—these programs may be evaluated in 2014 using only costs paid up to 2014). The costs incurred on the 37 evaluated conservation initiatives were $1,192 million, but we found that the IESO's cost-effectiveness evaluations only captured $923 million (77%) of the total costs of these initiatives.

4.4.3 Extending the Industrial Electricity Incentive Program until 2025 Will Cost $300 Million

In 2012, the Ministry directed the OPA to implement an Industrial Electricity Incentive (IEI) Program aimed at increasing industrial electricity usage as a means of reducing surplus power. The IEI program offers contracts to specific industrial consumers for a set amount of energy at reduced electricity rates. The entire program has a cap of up to five million MWh of annual electricity consumption.

The original end date of the IEI program was to coincide with the end of the significant surplus power period in 2020, but the Ministry has extended the program up to the end of 2024 in order to offer a contract term that is sufficiently long to attract applicants. While the IEI program may deter some businesses from leaving the province and moving south where electricity rates are lower, extending it past 2020 when there will no longer be an energy surplus for it to draw on will increase peak demand and, in turn, increase system costs by as much as $300 million, according to the Ministry's estimate.

RECOMMENDATION 4

To ensure that its conservation and demand-management programs are implemented cost-effectively and achieve their intended purposes, the Ministry of Energy should work with the Independent Energy System Operator to:

- assess the effects of conservation and its impact on electricity costs during surplus generation periods;
- evaluate programs, such as various conservation initiatives and the Industrial Electricity Incentive Program, to ensure that they support the Ministry's goals and objectives; and
- set appropriate and reasonable peak-consumption reduction targets, and regularly monitor, track and publicly report on the progress made in meeting them.

MINISTRY RESPONSE

The Ministry and the Independent Electricity System Operator (IESO) are committed to the on-going evaluation of programs to ensure they support provincial needs. The new 2015 Conservation First Framework (CFF) increases the rigour of program cost-effectiveness requirements. As per the requirement of the new Framework, all local distribution companies (LDCs) have submitted Conservation and Demand Management Plans to the IESO. The programs within the plans are all individually subject to cost-effectiveness tests (with specific exceptions, for example, low-income programs) and to a high degree of oversight with ongoing Evaluation, Measurement and Verification by the IESO. Furthermore, the new Framework encourages collaboration among LDCs, and between CFF and natural gas Demand Side Management Framework programs, to achieve efficiencies and convenient integrated programs for customers. The new Framework also recognizes the value of measures that result in peak demand reductions, by accounting for the higher value of savings achieved during peak periods in cost-effectiveness tests.

Public reporting of energy savings and peak demand reduction will continue through quarterly Ontario Energy Reports as well as annual conservation results reports released separately by the IESO and the Environmental Commissioner of Ontario.

Conservation requires a sustained commitment to ensure persistent savings and a reduction of demand for electricity over the long-term. The 2013 LTEP set a conservation target of 30 TWh by 2032 which is expected to result in 5,868 MW of peak demand reduction and a goal to use demand response to meet 10% of peak demand by 2025. Working with the IESO, the Ministry will continue to review Ontario's supply-demand balance as part of the LTEP planning process, adjusting targets as required.

4.5 Problems with Transmission System Planning

4.5.1 Transmission Problems in Some Regions Outstanding for Years

Although there has been a structured regional power system planning process in place since October 2013 that involves the Ministry, the OEB, the IESO, communities, Hydro One, and local distributors, before 2013 regional planning was done on an ad hoc basis, initiated based on priority and following informal processes between the OPA, Hydro One and four other small transmitters, and local distributors. For this reason, many of the projects currently being worked on as part of the new process are specific projects initiated to address short-term needs. The estimated cost of transmission work underway so far in five different regions under the new process is approximately $54 million.

The OPA's 2007 Integrated Power System Plan, which was not reviewed by the Ontario Energy Board, identified capacity and reliability problems in the following regions, which have not yet been resolved:

- **Kitchener-Waterloo-Cambridge-Guelph**—This region needs a number of transmission upgrades. The majority of the transmission lines delivering power to this area have exceeded, reached or are close to reaching their capacity. A three-hour service interruption in this area in 2012 would have been avoided had a transmission refurbishment project been completed on time. At the time of our audit, Hydro One was still working on this project and expected to complete it in spring 2016.
- **Windsor-Essex**—There are supply capacity, transmission capacity and security of supply issues in this region—a large portion of the area has reliability issues. Hydro One is currently working on a $77.4 million transmission reinforcement project in the region, but it is not scheduled to come into service until 2018.

In addition, the electrical infrastructure for the northern part of the Greater Toronto Area West region is nearing capacity and is not expected to be capable of meeting significant increases in peak demand. The 2015 regional plan again identified the need for transmission upgrades in this region, which Hydro One is currently reviewing.

4.5.2 Not Enough Capacity to Connect Renewable Generators

A total of 2,545 non-hydro renewable projects that received conditional offers from the OPA under the microFIT (projects 10kW or less) stream of the guaranteed-price program had to be relocated to other parts of Ontario because there was not enough transmission capacity to connect them to the power grid.

Non-hydro renewable energy projects take about two to three years to complete, but transmission projects take much longer—about four to seven years. When the current guaranteed-price renewable program was first launched in 2009, the OPA gave applicants conditional offers with guaranteed prices before the projects were approved by their local distribution companies to connect to the transmission grid. When it found that the projects could not be connected to the grid, the OPA was directed to compensate these guaranteed-price renewable program applicants by allowing those with more than one constrained project to combine their small (microFIT) projects and relocate to another area with the capacity to connect them. These applicants were still paid the higher guaranteed microFIT contract prices for small projects even though the size of their combined projects now meant that the lower guaranteed FIT contract prices for larger projects should have applied. Electricity consumers could have saved $239 million if these combined projects had been offered the guaranteed prices appropriate to their project size (the IESO calculates this amount to be closer to $126 million, in order to reflect the time value of money).

4.5.3 Significant Increase in Compensation Payments to Generators for Turning Power Generation On or Off

Transmission congestion occurs when power flows are limited by the transfer capability of one or more transmission elements. It is reasonable to expect some transmission congestion, because a congestion-free transmission system would be too costly to maintain and would indicate underutilization of transmission assets. Conversely, a heavily congested transmission system is also costly to operate, because when transmission lines are congested and operating at or near their limits, resources have to be dispatched more often and at higher marginal costs, relatively higher line losses and a higher risk of not being able to serve the load.

The IESO may request generators to turn their power generation on or off (otherwise known as "constraining output") for a number of reasons, including transmission congestion, physical ramping limits, safety/equipment issues, and environmental issues. While the IESO maintains data on generator-constrained volumes, it could not break down that data to identify the reasons for the constraint requests.

Generators are usually entitled to compensation payments when the IESO is required to constrain the output of generation facilities. In recent years, the amount of compensation the IESO has had to pay generators for constraining has increased significantly because the volume of requests to constrain has gone up: from 2009 to 2014, a total of $407.6 million in compensation has been paid out. In 2014 alone, generators were compensated $117.4 million—an increase of 77% since 2009.

We found that constrained volumes have significantly increased, from 4,772 GWh in 2009 to 6,472 GWh in 2014 (an increase of 36%) despite electricity demand remaining relatively stable. The Bruce and North East regions have experienced particularly large increases in constrained volumes (245% and 211%, respectively) from 2009 to 2014. The West region has also been experiencing significant generator output constraints consistently with no improvement over time. The IESO informed us that changes in regional demand and changes in the supply mix to support the phasing out of coal along with significant increases of renewable energy have changed flow patterns in the power system, contributing to increases in transmission constraints in recent years.

In May 2015, the IESO completed a review of Ontario's wholesale energy market pricing system. The review found that opportunities exist to reduce electricity market costs through changes to the current system. In an effort to achieve these cost reductions, the IESO indicated that it intends to engage stakeholders and re-examine some key components of the existing market design.

4.5.4 No Detailed Business Case for Importing Renewable Energy

When the Ministry decided to create the current guaranteed-price renewable program in 2009, it had not fully considered other options for getting more renewable energy into the supply mix, such as importing renewable energy in the form of hydropower from neighbouring provinces such as Quebec and Manitoba. The Quebec intertie has up to 500 MW of import capabilities available, and up to 200 MW from Manitoba could be relied upon to meet local area needs in northwestern Ontario. Although the OPA has conducted a number of assessments to evaluate the benefits of imports, it has never prepared a detailed business case or cost/benefit analysis of increasing Ontario's transmission capacity to accommodate contracted imports against procuring other renewable energy alternatives such as wind and solar.

Six years after creating an expensive Feed-in Tariff Program and procuring significant amounts of renewable energy that consumers will continue to pay for through the Global Adjustment, Ontario has decided to sign a contract with Quebec to exchange electricity and to consider importing power from Newfoundland and Labrador. Starting in late 2015, Ontario will make 500 MW of electricity capacity available to Quebec in the winter, when demand in that province peaks. Likewise, beginning in the summer of 2020, Quebec will make 500 MW available to Ontario when Ontario's demand peaks in hot weather. The government's aim in creating this arrangement is to help Ontario reduce costs by lessening the need to build new electricity generating stations after 2020.

RECOMMENDATION 5

To ensure that Ontario's transmission system has sufficient capacity to reliably transfer electricity from the province's generators to where power is needed, the Ministry of Energy should work with the Independent Electricity System Operator, Hydro One and other local distribution companies to:

- address current capacity and reliability issues, and identify what is required to support future electricity demand growth;
- investigate the root causes of the increasing volume of generator constraints and thereby minimize any unnecessary cost to electricity consumers; and
- perform adequate system planning and analysis prior to undertaking any major initiatives that would impact transmission.

MINISTRY RESPONSE

The Ministry agrees with the Auditor General's recommendation.

On October 28, 2015, the Minister of Energy introduced the *Energy Statute Law Amendment Act, 2015* (Bill 135) that, if passed, would replace the current Integrated Power System Plan (IPSP) process with an enhanced Long Term Energy Plan (LTEP) process. The proposed legislation would, if passed, ensure that the goals and objectives of the LTEP would include respecting the reliability of energy supply and capacity, transmission and distribution. This planning process will consider impacts on generators, transmitters and distributors, as well as the impact the LTEP could have on ratepayers. The Ministry will work with the Independent Electricity System Operator (IESO) and technical experts as well as stakeholders when creating the LTEP.

In addition to the proposed legislation which would create a framework to address system needs, Ontario also began a formalized regional planning process in 2013 governed by the Ontario Energy Board in 21 electricity planning regions. The process, led by the IESO, works with local distribution companies (LDCs) and transmitters to ensure regional issues and requirements are effectively integrated into electricity planning.

The Ontario Power Authority (now the IESO) played a key role in the development of the 2010 and 2013 LTEPs by providing technical advice and analysis, including forecasting electricity demand over the planning period, and recommending development of transmission projects to address forecast demand and maintain system reliability. Hydro One, other transmitters and other LDCs also provided information and input that was used to develop the LTEPs.

Regarding the recommendation to investigate the volume of generator constraints, the Ministry would like to note that in May 2015, the IESO completed a review of Ontario's wholesale energy market pricing system, sometimes referred to as the "two-schedule price setting system," which is used to determine prices and dispatch generators in the IESO-administered market. The review found that opportunities likely exist to reduce electricity market costs through changes to the current system. In an effort to achieve these cost reductions, the IESO intends to engage stakeholders and re-examine some key components of the existing market design.

Appendix 1—Key Events Relating To Electricity Power System Planning

Prepared by the Office of the Auditor General of Ontario

2004

December 2004
Government passes *Electricity Restructuring Act* (Act). Act renames Independent Electricity Market Operator the Independent Electricity System Operator (IESO) and amends IESO's duties to short-term forecasting of electricity demand and resources only. Act also creates Ontario Power Authority (OPA) to address long-term power system planning issues and conduct independent planning for electricity generation, demand management, conservation and transmission. OPA is tasked with developing an integrated long-term electricity plan (IPSP), a 20-year technical plan for achieving the province's energy goals. OPA is to submit IPSP to Ontario Energy Board (OEB) for review and approval and update the plan every three years.

2005

December 2005
OPA issues Supply Mix Advice Report to Minister of Energy.

2006

June 2006
Minister of Energy issues first Supply Mix Directive to OPA.

2007

August 2007
OPA submits first Integrated Power System Plan (IPSP) to OEB.

2008

2008
OEB suspends its review of IPSP in October after Minister of Energy issues amended Supply Mix Directive in September. Global recession begins toward the end of 2008.

2009

2009
Green Energy Act encourages renewable energy generation, energy conservation, and creation of clean-energy jobs.
Ontario launches Feed-in Tariff (FIT) Program.

2010

November 2010
Minister of Energy releases first Long-term Energy Plan (LTEP).

2011

2011
Minister of Energy issues new Supply Mix Directive and directs OPA to prepare updated IPSP. OPA forwards draft IPSP to Ministry for review but it is never submitted to the OEB.

2012

2012
In April, Minister of Energy introduces legislation to merge OPA and IESO and change the process for long-term power system planning. Merger is put on hold when Premier resigns in October.

2013

December 2013
Minister of Energy releases updated LTEP.

2014

2014
Bill 194, an act to implement budget measures, is introduced, calling for OPA and IESO to be amalgamated.

2015

January 1, 2015
Electricity Act, 1998, is amended and post-merger IESO is tasked with power system planning for Ontario.

June 4, 2015
The government passes the *Building Ontario Up Act*, under which Hydro One Inc. and its subsidiaries are deemed not to be agencies of the Crown. As such, as of December 2015, no independent Officer of the Legislative Assembly has the authority to oversee Hydro One's operations (for example, the Auditor General can no longer conduct performance audits of Hydro One or its subsidiaries).

Appendix 2—List of All Generating Facilities in Ontario as of 2014

Source of data: Independent Electricity System Operator

Facility	Fuel Type	Location/Region	Capacity (MW)
Atikokan Generating Station	Bioenergy	Northwest Ontario	205.0
Fort Frances	Bioenergy	Northwest Ontario	47.0
Thunder Bay Condensing Turbine Project	Bioenergy	Northwest Ontario	40.0
Calstock Power Plant	Bioenergy	North/East of Sudbury	38.0
Non-Utility Generators	Bioenergy	GTA	35.0
Becker Cogeneration Plant	Bioenergy	Northwest Ontario	8.0
Chapleau Co-Generation Facility	Bioenergy	East Lake Superior	7.0
Trail Road Landfill Generating Facility (Fallowfield PowerTrail)	Bioenergy	Greater Ottawa	5.0
Eastview Landfill Gas Energy Plant (Campbell)	Bioenergy	Kitchener Waterloo Cambridge Guelph	2.5
DrydenWhrhsr	Bioenergy	Northwest Ontario	2.5
Hamilton (Digester Gas) Cogeneration Project	Bioenergy	Burlington to Nanticoke	1.6
Guaranteed Price Renewable Projects (RESOP, FIT, MicroFit)	Bioenergy, Hydroelectricity, Solar, Wind	Distributed across Ontario	3,235.2
Essar Cogeneration Facility	Gas byproduct	East Lake Superior	63.0
Lennox Generating Station	Gas	Peterborough to Kingston	2,100.0
Non-Utility Generators	Gas	Distributed across Ontario	1,555.4
Greenfield Energy Centre	Gas	Chatham/Lambton/Sarnia	1,153.0
Goreway Station	Gas	GTA West	942.0
Halton Hills Generating Station	Gas	GTA West	757.0
St. Clair Energy Centre	Gas	Chatham/Lambton/Sarnia	678.0
Portlands Energy Centre	Gas	Toronto	639.1
Brighton Beach Power Station	Gas	Windsor/Essex	580.0
Sarnia Regional Cogeneration Plant	Gas	Chatham/Lambton/Sarnia	510.0
York Energy Centre	Gas	GTA North	438.0
Thorold Cogen	Gas	Niagara	287.0
GTAA Cogeneration Plant	Gas	GTA West	117.0
East Windsor Cogeneration	Gas	Windsor/Essex	100.0
London Cogeneration Facility	Gas	London Area	12.0
Great Northern Tri-Gen Facility	Gas	Windsor/Essex	11.3
Sudbury District Energy, Hospital Cogeneration	Gas	Sudbury/Algoma	6.7
Trent Valley Cogeneration Plant	Gas	Peterborough to Kingston	6.7
Sudbury District Energy Cogeneration Plant	Gas	Sudbury/Algoma	5.0
Warden Energy Centre	Gas	GTA North	5.0
Bur Oak Energy Centre	Gas	GTA North	3.3
Birchmount Energy Centre	Gas	GTA North	2.6
Durham College District Energy	Gas	GTA East	2.3
Villa Colombo Vaughan	Gas	GTA North	0.2
Other (back-up generators)	Oil	Distributed across Ontario	50.5

Facility	Fuel Type	Location/Region	Capacity (MW)
Greenhouse Generators in Leamington area	Oil	Windsor/Essex	12.6
Ontario Power Generation Hydro Facilities (65 Facilities)	Hydroelectricity	Distributed across Ontario	6,426.0
Smoky Falls Generating Station (redevelopment)	Hydroelectricity	North/East of Sudbury	264.0
Wells Generating Station	Hydroelectricity	Sudbury/Algoma	242.0
Harmon Generating Station	Hydroelectricity	North/East of Sudbury	219.0
Little Long Generating Station	Hydroelectricity	North/East of Sudbury	212.0
Aubrey Falls Generating Station	Hydroelectricity	Sudbury/Algoma	155.0
Kipling Generating Station	Hydroelectricity	North/East of Sudbury	155.0
Non-Utility Generators	Hydroelectricity	Distributed across Ontario	123.3
DAWatson (McPhail, Dunford, Scott)	Hydroelectricity	East Lake Superior	80.3
Kipling Expansion	Hydroelectricity	North/East of Sudbury	79.0
APIroquois (Island Falls, Iroquois Falls, Twin Falls)	Hydroelectricity	North/East of Sudbury	70.0
MacKay Generating Station	Hydroelectricity	East Lake Superior	58.0
Smoky Falls Generating Station	Hydroelectricity	North/East of Sudbury	53.0
Clergue Generating Station	Hydroelectricity	East Lake Superior	51.9
Andrews Generating Station	Hydroelectricity	East Lake Superior	50.0
Rayner Generating Station	Hydroelectricity	Sudbury/Algoma	47.5
Red Rock Falls Generating Station	Hydroelectricity	Sudbury/Algoma	41.6
Kenora (Kenora, Norman)	Hydroelectricity	Northwest Ontario	31.6
Lac Seul/Ear Falls Generating Station	Hydroelectricity	Northwest Ontario	29.3
Maletkraft	Hydroelectricity	North/East of Sudbury	27.5
Umbata Falls Generating Station	Hydroelectricity	Northwest Ontario	24.0
Hollingsworth Generating Station	Hydroelectricity	East Lake Superior	23.0
Gartshore Generating Station	Hydroelectricity	East Lake Superior	20.0
Domtar, Espanola Mill	Hydroelectricity	Sudbury/Algoma	18.0
Hogg Generating Station	Hydroelectricity	East Lake Superior	16.0
Healey Falls Generating Station	Hydroelectricity	Peterborough to Kingston	15.7
Steephill Generating Station	Hydroelectricity	Northwest Ontario	15.5
Mission Generating Station	Hydroelectricity	East Lake Superior	15.0
Wawaitin Generating Station	Hydroelectricity	North/East of Sudbury	15.0
Lower Sturgeon Generating Station	Hydroelectricity	North/East of Sudbury	14.0
Harris Generating Station	Hydroelectricity	East Lake Superior	12.5
Calm Lake Generating Station	Hydroelectricity	Northwest Ontario	11.0
Fort Frances Generating Station	Hydroelectricity	Northwest Ontario	10.0
Hound Chute Generating Station	Hydroelectricity	North/East of Sudbury	9.6
Chaudiere No. 4 Generating Station	Hydroelectricity	Greater Ottawa	9.3
Sturgeon Falls Generating Station	Hydroelectricity	Northwest Ontario	9.0
Chaudiere No. 2 Generating Station	Hydroelectricity	Greater Ottawa	8.4
Glen Miller Generating Station	Hydroelectricity	Peterborough to Kingston	8.0
Tembec, Smooth Rock Falls Facilities	Hydroelectricity	North/East of Sudbury	8.0
Swift Rapids Generating Station	Hydroelectricity	South Georgian Bay/Muskoka	7.9

Facility	Fuel Type	Location/Region	Capacity (MW)
Heywood Generating Station	Hydroelectricity	Niagara	7.2
Ragged Chute Eco Power Centre	Hydroelectricity	North/East of Sudbury	6.6
West Nipissing Power Generation	Hydroelectricity	North/East of Sudbury	6.5
Sandy Falls Generating Station	Hydroelectricity	North/East of Sudbury	5.5
Auxable	Hydroelectricity	North/East of Sudbury	4.7
London Street Generating Station	Hydroelectricity	Peterborough to Kingston	4.1
Minden Generating Station	Hydroelectricity	South Georgian Bay/Muskoka	4.0
Stanley Adamson Powerhouse	Hydroelectricity	Peterborough to Kingston	3.9
Matthias Generating Station	Hydroelectricity	South Georgian Bay/Muskoka	3.0
Wilson's Falls	Hydroelectricity	South Georgian Bay/Muskoka	2.9
Bracebridge Falls Generating Station	Hydroelectricity	South Georgian Bay/Muskoka	2.6
Jones Falls	Hydroelectricity	St. Lawrence	2.4
1149377 Ontario Limited	Hydroelectricity	Sudbury/Algoma	2.3
Campbellford-Seymour Electric Generation Inc.	Hydroelectricity	Peterborough to Kingston	2.0
Rideau Falls	Hydroelectricity	Greater Ottawa	2.0
Kingston Mills	Hydroelectricity	Peterborough to Kingston	1.9
Chiblow Lake Generating Station	Hydroelectricity	Sudbury/Algoma	1.7
Galetta Eco Power Centre	Hydroelectricity	Greater Ottawa	1.6
Appleton Eco Power Centre	Hydroelectricity	Greater Ottawa	1.4
Moose Rapids Generating Station	Hydroelectricity	Sudbury/Algoma	1.4
Water Street Pumphouse	Hydroelectricity	Peterborough to Kingston	1.3
Parry Sound PowerGen Corporation	Hydroelectricity	South Georgian Bay/Muskoka	1.2
Burk's Falls	Hydroelectricity	South Georgian Bay/Muskoka	1.1
Marmora Generating Station	Hydroelectricity	Peterborough to Kingston	1.0
Renfrew Power Generation Inc. – Lower Plant	Hydroelectricity	Renfrew	1.0
Renfrew Power Generation Inc. – Upper Plant	Hydroelectricity	Renfrew	1.0
Brewers Mills	Hydroelectricity	St. Lawrence	0.9
High Falls Generating Station	Hydroelectricity	South Georgian Bay/Muskoka	0.8
Kagawong Generating Station	Hydroelectricity	Sudbury/Algoma	0.8
Gananoque	Hydroelectricity	St. Lawrence	0.7
Long Slide Generating Station	Hydroelectricity	North/East of Sudbury	0.7
Shand Dam Generating Station	Hydroelectricity	Kitchener Waterloo Cambridge Guelph	0.7
Conestogo Dam Generating Station	Hydroelectricity	Greater Bruce/Huron	0.6
Hurdman Dam	Hydroelectricity	North/East of Sudbury	0.6
Maple Hill	Hydroelectricity	Greater Bruce/Huron	0.6
Truisler Chute Generating Station	Hydroelectricity	South Georgian Bay/Muskoka	0.6
York River Generating Station	Hydroelectricity	Renfrew	0.6
Casselman Generating Station	Hydroelectricity	Greater Ottawa	0.5
Current River Hydro	Hydroelectricity	Northwest Ontario	0.5
Devil's Gap Generating Station	Hydroelectricity	South Georgian Bay/Muskoka	0.5
635294 Ontario Inc.	Hydroelectricity	North/East of Sudbury	0.5

Facility	Fuel Type	Location/Region	Capacity (MW)
Drag River Generating Station	Hydroelectricity	South Georgian Bay/Muskoka	0.3
Enerdu Power Systems Ltd.	Hydroelectricity	Greater Ottawa	0.3
Saugeen Generating Station	Hydroelectricity	Greater Bruce/Huron	0.3
Little Burgess Generating Station	Hydroelectricity	South Georgian Bay/Muskoka	0.2
Stewart Generating Station	Hydroelectricity	Greater Ottawa	0.2
Tweed Generating Station	Hydroelectricity	Peterborough to Kingston	0.2
Washburn	Hydroelectricity	St. Lawrence	0.2
Barrie Small Hydro Limited	Hydroelectricity	Greater Ottawa	0.1
Scone Generator	Hydroelectricity	Greater Bruce/Huron	0.1
Bruce Power Nuclear Generating Station	Nuclear	Greater Bruce/Huron	6,329.0
Darlington Nuclear Generating Station	Nuclear	GTA East	3,524.0
Pickring Nuclear Generating Station	Nuclear	GTA East	3,094.0
South Kent Wind (KoreanConsortium)	Wind	Chatham/Lambton/Sarnia	270.0
Wolfe Island Wind Project	Wind	Peterborough to Kingston	198.0
Enbridge Ontario Wind Farm	Wind	Greater Bruce/Huron	182.0
Grand Renewable Energy Park	Wind	Burlington to Nanticoke	148.6
Melancthon II Wind Plant	Wind	South Georgian Bay/Muskoka	132.0
Kruger Energy Port Alma Wind Power Project	Wind	Windsor/Essex	101.2
Kruger Energy Chatham Wind	Wind	Windsor/Essex	101.1
Erie Shores Wind Farm	Wind	London Area	99.0
Greenwich Wind Farm	Wind	Northwest Ontario	99.0
Prince I Wind Power Project	Wind	East Lake Superior	99.0
Talbot Wind Farm	Wind	Chatham/Lambton/Sarnia	98.9
Prince II Wind Power Project	Wind	East Lake Superior	90.0
Raleigh Wind Energy Centre	Wind	Chatham/Lambton/Sarnia	78.0
Ripley Wind Power Project	Wind	Greater Bruce/Huron	76.0
Melancthon I Wind Plant	Wind	South Georgian Bay/Muskoka	67.5
Gosfield Wind Project	Wind	Windsor/Essex	50.0
Kingsbridge I Wind Power Project	Wind	Greater Bruce/Huron	39.6
Total			**37,313.0**

Appendix 3—Glossary of Terms

Prepared by the Office of the Auditor General of Ontario

Baseload Demand—The continuous minimum demand for electrical power.
Baseload Resources—Generation sources that are designed to operate continuously, such as nuclear and many types of hydro.
Bioenergy—Energy produced from biomass—living or recently living plant or animal sources such as waste wood, agricultural residues, animal manure, food processing by-products, and kitchen waste.
Capacity Contribution—The amount of capacity available to generate power at a time of peak electricity demand.
Curtailment—A reduction in the output of electricity generators ordered by the Independent Electricity System Operator (IESO) to mitigate an oversupply of electricity.
Demand Management—Measures undertaken to control the level of energy use at a given time, by increasing or decreasing consumption or shifting consumption to some other period.
Demand Savings—A reduction in the total supply of electrical resources needed by Ontario to meet peak demand.
Dispatchable Generation—Generation sources that can increase or decrease their output when requested as demand fluctuates or the availability of other sources changes. Dispatchable generators submit offers to supply electricity in different quantities and prices for each hour of the day. They must be able to adjust the amount of electricity they generate in response to new instructions issued every five minutes by the IESO. An example of a dispatchable generation source is natural gas.
Distribution—Moving energy from the transmission system and delivering it to customers. The distribution network includes medium-voltage power lines, substations, pole-mounted transformers, low-voltage wiring, and electricity meters.
Electricity Commodity Charge—Incorporates both the Hourly Ontario Energy Price and Global Adjustment fees, shown on consumer electricity bills as Electricity Charge.
Energy Savings—A reduction in the overall supply of electrical resources needed by homes, businesses and institutions in Ontario.
Guaranteed Price Renewal Program—A program to procure renewable energy launched in September 2009 under the direction of the Minister of Energy, providing renewable energy generators with significantly higher contract prices than the previous standard offer program which it replaced. The program has two streams: the FIT Program is for projects more than 10kW; the microFIT program is for projects 10kW or less.
Installed Capacity—The maximum intended power output from a facility.
Intermittent Power Generation—Sources of electricity that produce power at varying times, such as wind and solar generators whose output depend on wind speed and solar intensity.
Kilowatt (kW)—A standard unit of power equal to one thousand watts (W).
Kilowatt-hour (kWh)—A way of measuring energy production or consumption over time. A Kilowatt-hour measures one thousand watts produced or consumed in one hour.
Load—The electricity used by consumers or devices connected to an electrical generating system.
Local Distribution Company—A utility that owns/operates a distribution system for the local delivery of energy to consumers.
Megawatt (MW)—A standard unit of power equal to one thousand kilowatts (kW) or one million watts (W).
Megawatt-hour (MWh)—A way of measuring energy production or consumption over time. A Megawatt-hour (MWh) measures one million watts produced or consumed in one hour.
Operating Reserves—Standby power for dealing with unexpected power loss.
Peaking Resources—Generation sources typically designed to run only to meet peak demand (periods where demand is significantly higher than the average supply of electricity) during the day, such as natural gas.
Planning Reserves—Standby power to satisfy future demand and account for uncertainties such as economic conditions and weather forecasts.
Smart Meter—An electronic device that records consumption of electricity in intervals of an hour or less and communicates that information back to the utility for billing and monitoring.
Supply Mix—The different types of resources that are used to meet the demand for electricity in a jurisdiction. Ontario has a diversified mix of resources that work together to meet our electricity demands from hour to hour, year-round: bioenergy, hydroelectricity, natural gas, nuclear, solar and wind.
Surplus Baseload Generation (SBG)—When the electrical power produced by Ontario's baseload generators exceeds Ontario's electricity demand.
Terawatt-hour (TWh)—A unit for measuring energy production or consumption over time, equal to one million megawatt-hours. Ontario's electricity consumption in 2014 was 139.8TWh.
Transmission—The movement of electricity at high voltages from generation sites to local distribution systems and consumers.