ENERGY PROBE INTERROGATORY 12

Issue 2.0

INTERROGATORY

Reference: Exhibit B, Tab 1, Schedule 1, Page 3, Table 2

a) Please provide in a single table, the historic forecast and actual (2011-2016) and 2017 forecast TWh for the three user classes.(Domestic, Export/import and Embedded)

b) Based on historic experience, please provide a sensitivity analysis for 2017 for the charge determinants for the three components and discuss the result.

c) How will IESO "true up" its 2017 fees if one or more of the TWH forecasts is in error?

RESPONSE

a) Provided below is a single table for the historical and forecast (2011-2017) TWh for the domestic, export and embedded user classes.

Year	Source	Ontario Demand (TWh)	Exports (TWh)	Embedded Generation (TWh)
2010	Forecast (18-Month Outlook released 2009/08/25)	141.1	10.0	N/A
	Actual	142.2	15.2	2.3
2011	Forecast (18-Month Outlook released 2010/08/23)	142.9	12.9	N/A
	Actual	141.5	12.8	2.9
2012	Forecast (18-Month Outlook released 2011/08/24)	144.5	15.2	N/A
	Actual	141.3	14.6	3.3
2013	Forecast (18-Month Outlook released 2012/09/12)	141.1	14.2	4.8
	Actual	140.7	18.3	4.3

2014	Forecast (18-Month Outlook released 2013/09/03)	141.0	14.4	5.6
	Actual	139.8	19.1	5.2
2015	Forecast (18-Month Outlook released 2014/09/04)	138.8	13.7	6.7
	Actual	137.0	22.6	6.2
2016	Forecast (18-Month Outlook released 2015/09/21)	138.7	17.9	6.6
	Actual	137.0	21.9	6.5
		134.6	19.9	7.2

b) The three components are added together to form the denominator of the IESO fee. Any change in the components will have an equal impact on the denominator.

c) The IESO utilizes the $10 million contingency fund and/or tracks the amounts and any associated borrowing costs in the Forecast Variance Deferral Account ("FVDA").

ENERGY PROBE INTERROGATORY 13

Issue 2.0

INTERROGATORY

Reference: Exhibit B Tab 1 Schedule 1 Page 5: Exhibit B Tab 1 Schedule 2 Page 3

Preamble: To parse the work of the IESO or to attempt to separate the costs or benefits of the IESO's operations is difficult now and will be increasingly difficult and decreasingly practical in the future.

a) Specifically indicate why the regional and grid planning functions benefit both domestic and export customers.

b) Please explain in detail why embedded generation creates costs for IESO at a different level than managing bulk generation and exports.

RESPONSE

a) The regional and grid planning functions are not allocated to export customers. In their Cost Allocation and Rate Design for the 2016 IESO Usage Fee (Updated with 2016 Financial Details) report which was filed as part of the IESOs evidence in its 2016 Revenue Requirement Submission, Elenchus stated that Transmission Integration was allocated to domestic customers only and described it as shown below:

> *Transmission Integration*
>
> *The responsibilities of the transmission integration group include regional integrated planning, bulk transmission planning, associated community and stakeholder outreaches and providing support to procurements undertaken by the IESO through performing assessments and testing of connections availability.*

The Board approved this cost allocation methodology in its EB-2015-0275 Decision and Order. The IESO has applied the Board-approved cost allocation methodology to its proposed 2017 usage fees.

b) As per the IESO's responses to Energy Probe's Interrogatory 10 part (e) in the IESO's 2016 Revenue Requirement Submission (EB-2016-0275), embedded generation requires management by the IESO in the same manner as the rest of the system, including bulk generation and exports, which is why the IESO has applied to charge one fee for all groups. The IESO does not believe that it is appropriate for customers of LDCs with embedded generation to receive a discount in the amount of usage fee that they pay, given that this discount does not reflect any cost reductions to the IESO for these customers. Please also refer to the response to BOMA interrogatory 28 at Exhibit I, Tab 2.0, Schedule 3.28 in the IESO’s 2016 Revenue Requirement Submission (EB-2016-0275).

VECC INTERROGATORY 3

Issue 2.0

INTERROGATORY

Reference: Exhibit A-2-2, Page 3 of 31

> *At the system level, electricity demand is expected to decline slightly or remain relatively flat over the business planning period as growth in demand from economic expansion and population growth will be mostly offset by conservation*

a) Please provide 2018 electricity demand forecast.

b) Please provide an update of the 2017 forecast based on actual demands as of August 1, 2017.

c) Please a comparison of the 2017 monthly forecast and the actual and remaining year-end forecast.

RESPONSE

a) While the 2018 electricity demand forecast is beyond the scope of this proceeding, the information is available and is 136.4 TWh, based on the IESO's 18-Month Outlook (Q2 from July 2017 to December 2018) published June 22, 2017.

b) For an update of the IESO's 2017 forecast please see updated Table 1 below based on updated Q2 data with actuals to the end of July.

Table 1: Updated Calculation of associated energy volumes with actuals to July 31, 2017

	2017 – Domestic (TWh)	**2017 – Export (TWh)**
18 Month Outlook demand forecast	133.7	**19.8**
Embedded generation	6.9	
Domestic transmission losses	-2.6	
Exports transmission losses		-0.3
Energy Volumes	**138.0**	**19.5**
Total Energy Volumes	**157.5**	

c) Please see Table 2 below for the 2017 monthly actuals and comparing Q1 data available at the time of the IESO's pre-filed evidence, updated with Q2 data with actuals to the end of July.

Table 2

Month	Ontario Demand pre-filed evidence (TWh)	Ontario Demand Q2 update (TWh)	Less Transmission Line Losses pre-field evidence (TWh)	Less Transmission Line Losses Q2 update (TWh)	Exports pre-filed evidence (TWh)	Exports Q2 update (TWh)	Embedded Generation pre-filed evidence (TWh)	Embedded Generation Q2 udate (TWh)
Jan-17	12.1	12.1	0.3	0.3	1.9	1.9	0.5	0.5
Feb-17	10.6	10.6	0.2	0.2	1.5	1.5	0.5	0.5
Mar-17	11.8	11.6	0.3	0.3	1.7	1.7	0.6	0.6
Apr-17	10.4	9.8	0.2	0.2	1.5	1.6	0.7	0.6
May-17	10.6	10.2	0.2	0.2	1.7	1.6	0.8	0.6
Jun-17	11.2	10.7	0.2	0.2	1.6	1.5	0.8	0.6
Jul-17	12.0	11.6	0.3	0.3	1.6	1.6	0.7	0.6
Aug-17	12.1	12.1	0.3	0.3	1.6	1.6	0.7	0.7
Sep-17	10.5	10.5	0.2	0.2	1.5	1.5	0.7	0.7
Oct-17	10.9	10.9	0.2	0.2	1.7	1.7	0.6	0.6
Nov-17	11.4	11.4	0.3	0.3	1.7	1.7	0.5	0.5
Dec-17	12.3	12.3	0.3	0.3	1.8	1.8	0.5	0.5
2017								
2017 (pre-filed evidence)	135.9		3.0		19.8		7.5	
2017 (Q2 update) to end of July		133.7		2.9		19.8		6.9

Actuals
Forecast

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VECC INTERROGATORY 17

EXHIBIT A

Issue 2.0

INTERROGATORY

Reference: Exhibit A-3-1, Page 7 of 55

a) Please provide the 2016 Ontario Planning Outlook.

b) Please provide the 2016 IESO Operability Assessment Report

RESPONSE

a) A copy of the 2016 Ontario Planning Outlook is provided as Attachment 1.

b) A copy of the 2016 IESO Operability Assessment Report is provided at Exhibit I, Tab 1.1, Schedule 2.20, Attachment 1.

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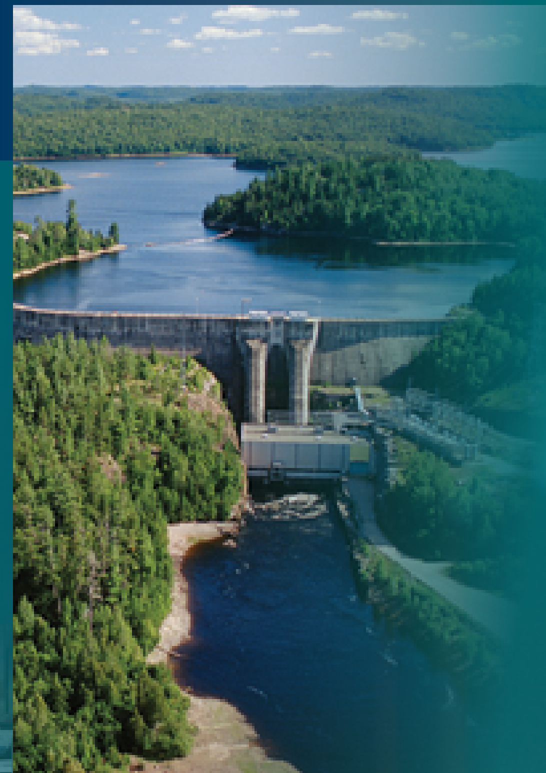


Ontario Planning Outlook

A technical report on the electricity system prepared by the IESO

SEPTEMBER 1, 2016

ieso
Connecting Today.
Powering Tomorrow.

Table of Contents

Foreword

1

This report responds to the June 10, 2016 request from the Minister of Energy for a technical report from the Independent Electricity System Operator (IESO) pursuant to Section 25.29 (3) of the *Electricity Act, 1998* on the adequacy and reliability of Ontario's electricity resources in support of the development of the Long-Term Energy Plan (LTEP) (see Appendix A). This report presents the IESO's planning outlook for the 2016 through 2035 period and includes a range of demand outlooks.

Looking forward, Ontario's electricity system is well positioned to continue to meet provincial needs, while at the same time adapting to significant change across the sector. Over the past decade, the coal fleet has been retired and replaced with wind, solar, bioenergy, waterpower, refurbished nuclear and natural gas-fired resources. These resources, combined with investments in conservation and transmission:

- have addressed the reliability concerns of a decade ago
- have reduced greenhouse gas emissions in Ontario's electricity sector by more than 80 percent
- with current planned investments, will help to meet the province's needs well into this planning period.

Implementation of the province's climate change policies, consistent with the Climate Change Action Plan, the *Climate Change Mitigation and Low-Carbon Economy Act, 2016*, and the *Vancouver Declaration,* will have an impact on the demand and supply of electricity including through greater electrification of the economy.

This report begins with an overview of the current state of Ontario's electricity system. As per the Minister's request, it also examines the outlook for demand; the potential for resources such as conservation, wind, solar, bioenergy, waterpower, and nuclear, as well as new emerging distributed energy resources to meet that demand; the risks associated with those various resources; and the costs of the electricity system. The report looks at the needs of the electricity system over the next two decades associated with capacity, reliability, market and system operations, transmission and distribution. It also provides an outlook for emissions from the electricity sector.

2 The State of the System: 10-Year Review

Investments over the last decade have established a firm foundation for Ontario's electricity system. Between 2005 and 2015, the province saw a net growth in electricity supply: over six gigawatts (GW) of installed coal-fired capacity was shut down and replaced with more than 14 GW of renewable, natural gas-fired, nuclear and demand response resources (Figure 1). This has driven a significant change in the province's electricity supply mix, with the share from fossil-fuelled resources decreasing while the share of supply from non-fossil-fuelled resources increased.

Renewable energy now comprises 40 percent of Ontario's installed capacity and generates approximately one-third of the electricity produced in the province. When combined with nuclear resources, which account for one-third of Ontario's installed capacity and produce nearly 60 percent of its electricity, these non-fossil sources now generate approximately 90 percent of the electricity in Ontario (Figure 2).

While the electricity system has traditionally been characterized by the flow of electricity from large central generating stations through bulk transmission lines to load centres, the last decade saw an increasing amount of generation embedded within the province's distribution systems. Distributed energy resources typically include renewable resources such as solar, wind, waterpower or bioenergy or combined heat and power (CHP) facilities and demand response (DR) resources. Supply from embedded resources connected to the distribution system was negligible in 2005. But by the end of 2015, the amount of embedded resources had grown to approximately 3,600 megawatts (MW) of installed supply.[2]

Demand measured on the province's bulk power grid has declined over the last 10 years (Figure 3) as a result of conservation, distributed energy resources, changes in the economy and pricing effects. Non-weather-corrected grid demand in Ontario was approximately 10 percent lower in 2015 than it was 10 years previously, dropping from 151 terawatt-hours (TWh) in 2006 to

Figure 1: Ontario Installed Supply Mix in 2005 and 2015

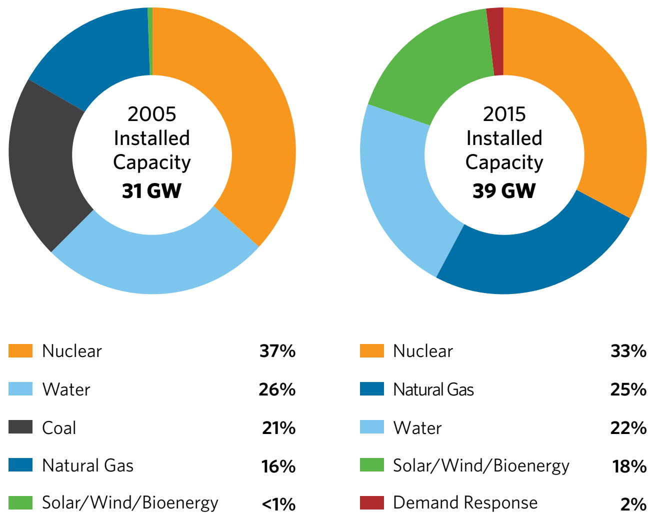
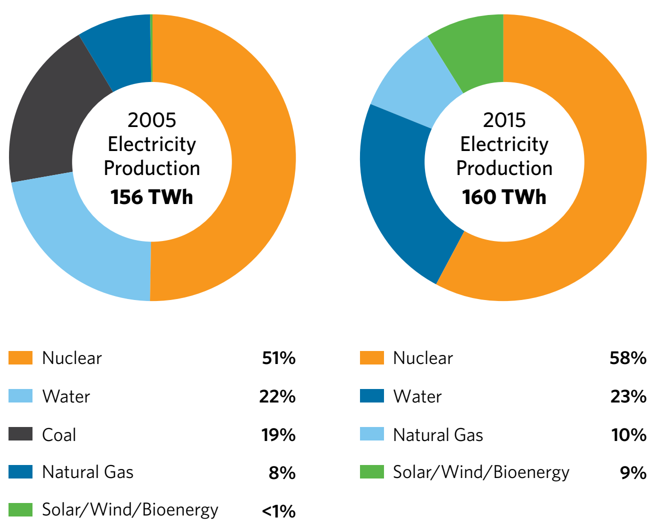


Figure 2: Ontario Electricity Production in 2005 and 2015[1]



[1] Includes electricity produced to meet Ontario demand, including embedded generation (which brings the total to 143 TWh in 2015), and exports (17 TWh in 2015).

[2] Embedded resources are small-scale supply resources located within the distribution system and are not part of the IESO-controlled grid. At the end of 2015, there were approximately 2,900 MW of embedded generation (mostly solar PV) and 700 MW of embedded demand response resources.

Figure 3: Historical Ontario Energy Demand[3]

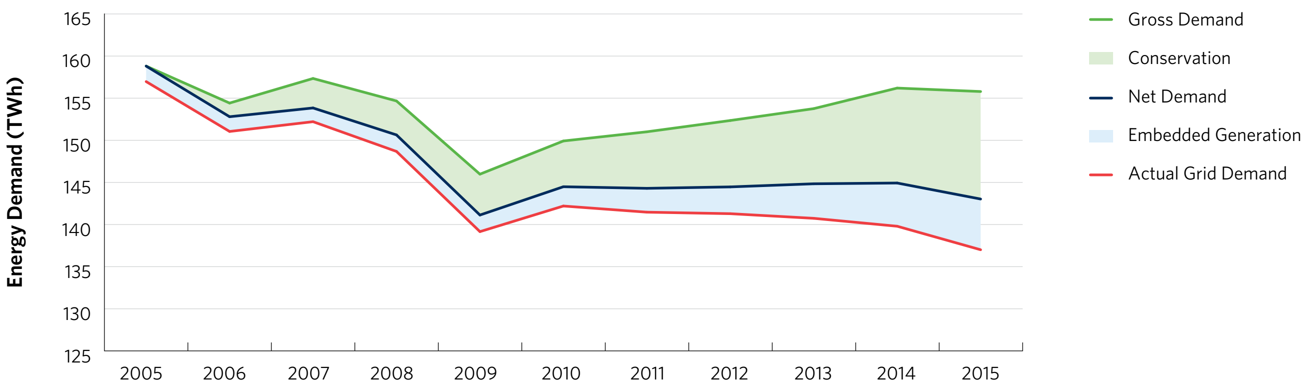


Figure 4: Conservation Savings in 2015

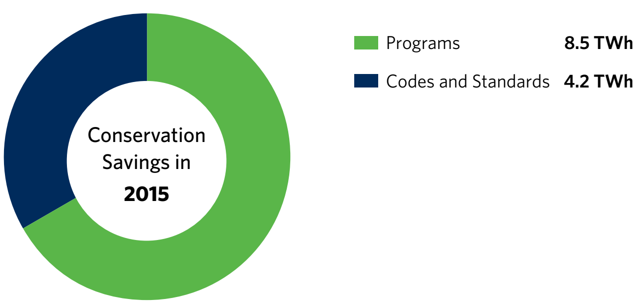
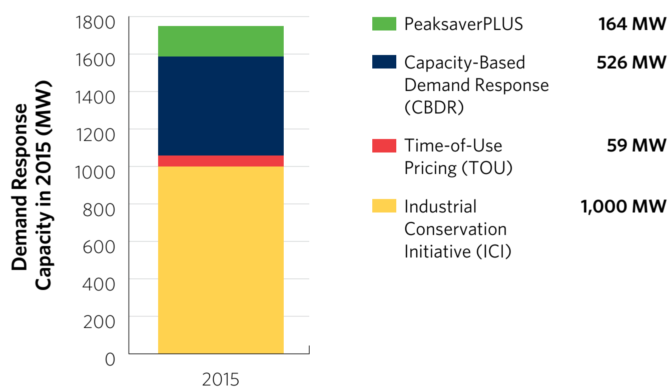


Figure 5: Demand Response Capacity in 2015



137 TWh in 2015. As a result of the additional supply and reduction in demand, there has been a sizeable appreciation of Ontario's capacity margins, and the capacity deficits that existed in the early 2000s have been eliminated.

Conservation and demand management played an increasing role in reducing both energy and peak demands over the 2006-2015 period, with the province achieving 12.7 TWh of electricity savings through conservation programs and changes to codes and standards (Figure 4).[4]

Demand response initiatives have combined to reduce peak demand on summer days. The grid peak demand of 27,005 MW on August 1, 2006 continues to be the all-time highest provincial grid peak demand. By comparison, the grid peak demand in 2015 was 22,516 MW.[5] The IESO has introduced demand response into the market where it can be called upon like other resources to meet provincial needs. The first capacity-based demand response auction conducted in December 2015 is contributing 391.5 MW for the 2016 summer season and 403.7 MW for the 2016-17 winter season. Demand response resources together amounted to approximately 1.8 GW in 2015 (Figure 5).

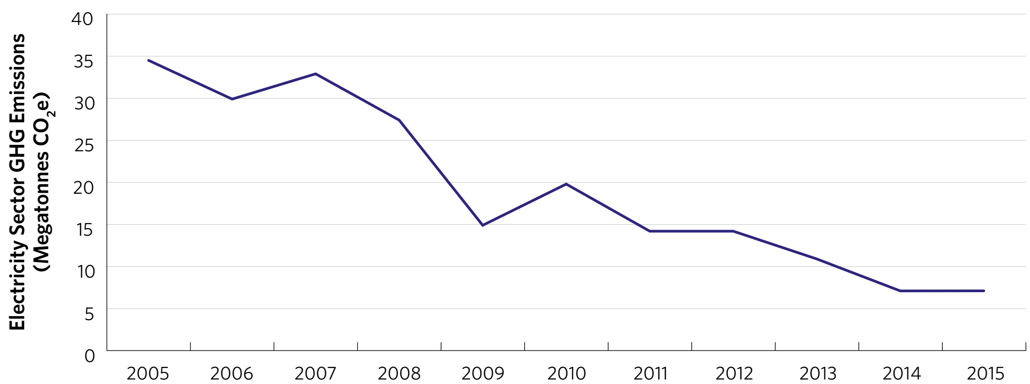
The operability of the system has also evolved over the past decade. In response to surplus baseload generation conditions, the IESO has enhanced its processes to maintain supply-demand balance through dispatching down grid-connected wind and solar facilities and manoeuvering nuclear units. The IESO's Renewable Integration Initiative (RII) introduced centralized resource forecasting to help

[3] "Grid demand" is delivered on the bulk system to wholesale customers and local distribution customers. "Net demand" is the grid demand plus output from embedded resources on the distribution system. "Gross demand" is the need for electricity prior to the effects of conservation and reflects net demand with conservation savings added back to it.

[4] 2015 conservation results have not yet been verified.

[5] Weather-corrected net peak demand in 2006 was 25,162 MW and in 2015 was 23,965 MW. All demand outlooks presented in this report refer to weather-corrected net peak demand unless described otherwise.

Figure 6: Electricity Sector GHG Emissions[6]



reduce forecast errors for variable generation. The IESO also started to explore the use of storage and demand response to provide regulation services.

Due to the retirement of coal-fired generation and the reduced demand for electricity, the greenhouse gas (GHG) emissions from Ontario's electricity sector has fallen by 80 percent since 2005 (Figure 6). Carbon emissions from the electricity sector now make up approximately four percent of the province's total emissions or approximately seven megatonnes of GHG emissions in 2015.

"Due to the retirement of coal-fired generation and the reduced demand for electricity, the greenhouse gas (GHG) emissions from Ontario's electricity sector fell by 80 percent since 2005."

The evolution over the past decade in the amount and nature of Ontario's electricity supply was supported by increased investment in transmission. This investment served several purposes: facilitating Ontario's off-coal policy, enabling the incorporation of new renewable energy resources, enhancing the reliability of the power system across the province and expanding access to neighbouring electricity markets.

In real terms, the total cost of electricity service grew by 32 percent between 2006 and 2015, primarily because of new investments in generation and distribution infrastructure.[7] The cost is now approximately $20 billion per year in current dollars. Over the same period, reductions in overall demand increased the average unit cost of electricity in real terms by 3.9 percent per year; it is now approximately $140 per megawatt-hour (MWh) in current dollars. As described in Section 3.7, these unit costs are expected to stabilize through the planning period.

[6] 2015 emissions are estimated.

[7] 2005 was an anomalous year due to unusual weather and tight supply conditions which led to very high demand and record market prices for power.

Electricity System 20-Year Outlook

3

3.1. Demand Outlook

The demand for electricity is the starting point used in assessing the outlook for the electricity system. There is uncertainty in any demand outlook, as future demand will depend on the economy, demographics, policy and other considerations (Figure 7). Electricity planning explicitly recognizes the uncertainties in any of these drivers by addressing a range of potential futures.

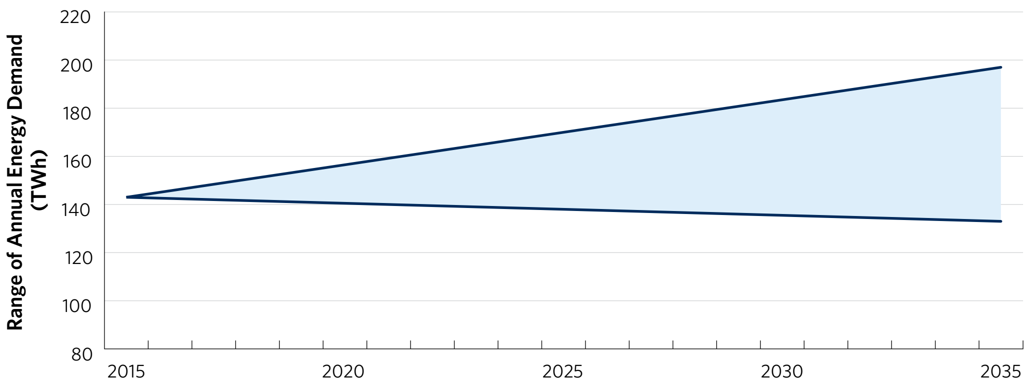
In preparing this report, the IESO considered a range for electricity demand in Ontario, from 133 TWh to 197 TWh in 2035, compared to 143 TWh in 2015 (Figure 8). This range is reflected in four outlooks that provide context for long-term integrated planning and discussion. The outlooks all reflect the actions identified in the government's recently announced Climate Change Action Plan.[8]

The four outlooks for Ontario's electricity demand are:

- Outlook A (or "low demand outlook"), which explores the implications of lower electricity demand
- Outlook B (or "flat demand outlook"), which explores a level of long-term demand that roughly matches the level of demand that exists today
- Outlooks C and D (or "higher demand outlooks"), which explore higher levels of demand driven by different levels of electrification associated with policy choices on climate change.

The peak demand in the summer differs in the four outlooks, from 22.6 GW to 28.5 GW by 2035 (Figure 9). The winter peak ranges from 20.6 GW to 35.4 GW (Figure 10). Outlooks C and D would see Ontario return to being a winter-peaking jurisdiction as a result of an increased use of electricity for space heating.

Figure 7: Demand Uncertainty



[8] Ontario Climate Change Action Plan (June 2016) https://www.ontario.ca/page/climate-change-action-plan

Figure 8: Ontario Net Energy Demand across Demand Outlooks

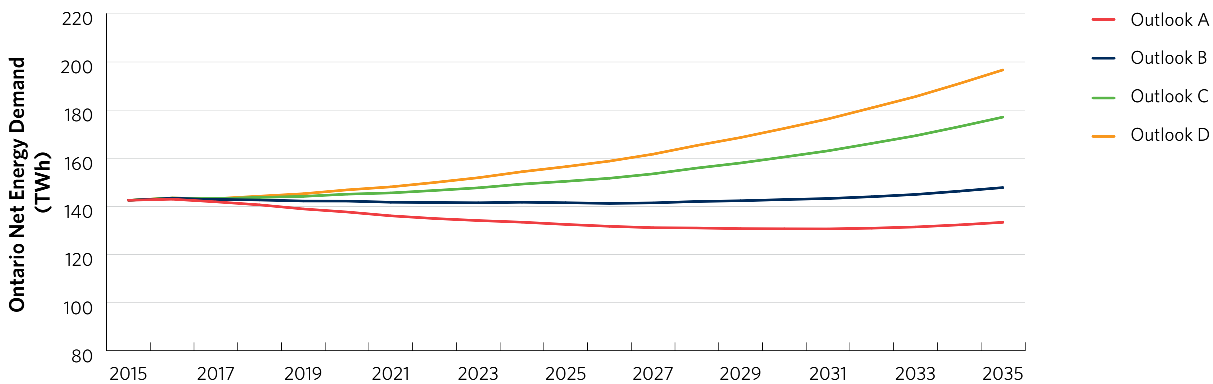


Figure 9: Ontario Net Summer Peak Demand across Demand Outlooks

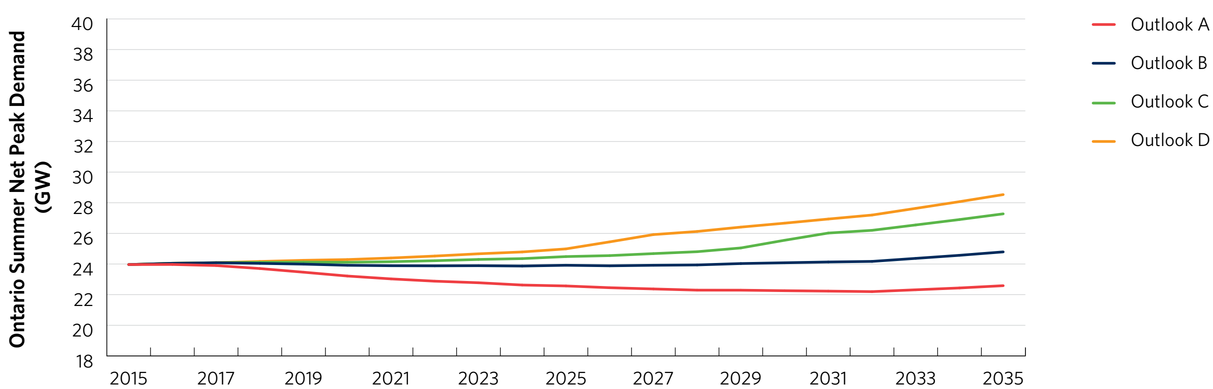


Figure 10: Ontario Net Winter Peak Demand across Demand Outlooks

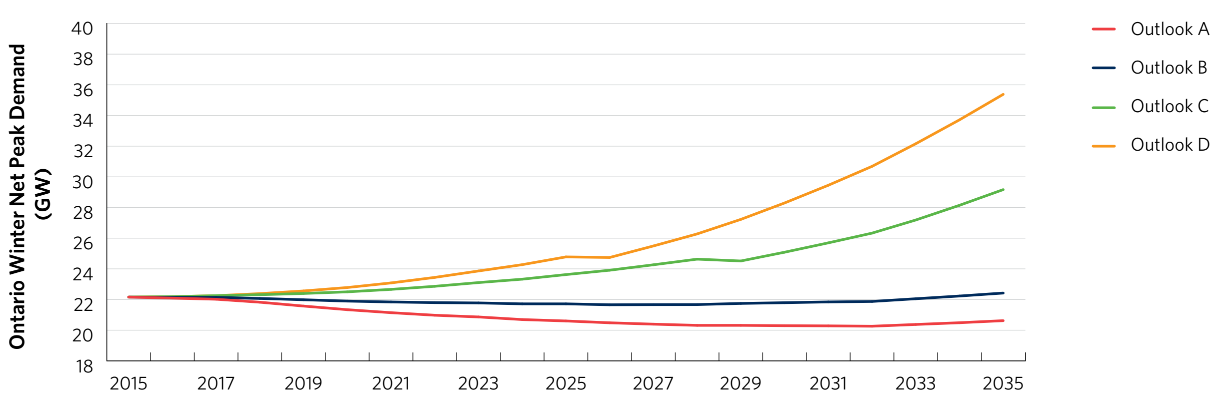


Table 1: Assumptions across Demand Outlooks

Sector	Outlook A	Outlook B	Outlook C	Outlook D
Residential (52 TWh in 2015)	48 TWh in 2035	51 TWh in 2035	Oil heating switches to heat pumps, electric space and water heating gain 25% of gas market share (58 TWh in 2035)*	Oil heating switches to heat pumps, electric space and water heating gain 50% of gas market share (64 TWh in 2035)
Commercial (51 TWh in 2015)	49 TWh in 2035	54 TWh in 2035	Oil heating switches to heat pumps, electric space and water heating gain 25% of gas market share (63 TWh in 2035)	Oil heating switches to heat pumps, electric space and water heating gain 50% of gas market share (69 TWh in 2035)
Industrial (35 TWh in 2015)	29 TWh in 2035	35 TWh in 2035	5% of 2012 fossil energy switches to electric equivalent (43 TWh in 2035)	10% of 2012 fossil energy switches to electric equivalent (51 TWh in 2035)
Electric Vehicles (<1 TWh in 2015)	2 TWh in 2035	3 TWh in 2035	2.4 million electric vehicles (EVs) by 2035 (8 TWh in 2035)	2.4 million EVs by 2035 (8 TWh in 2035)
Transit (<1 TWh in 2015)	1 TWh in 2035	1 TWh in 2035	Planned projects, 2017-2035 (1 TWh in 2035)	Planned projects, 2017-2035 (1 TWh in 2035)
Other**	5 TWh	5 TWh	5 TWh	5 TWh
Total* (143 TWh in 2015)**	**133 TWh in 2035**	**148 TWh in 2035**	**177 TWh in 2035**	**197 TWh in 2035**

Note: Outlooks C and D assume the same economic drivers as Outlook B.

* By 2035, of the number of natural gas-fuelled space and water heating equipment being sold in Outlook B (due to existing equipment reaching end of life and new additions driven by growth in the residential and commercial sectors), 25 percent of this stock in Outlook C and 50 percent in Outlook D is replaced with air-source heat pumps.

** "Other" represents demand from agriculture, remote communities, generator demand, the Industrial Electricity Incentive (IEI) program and street lighting.

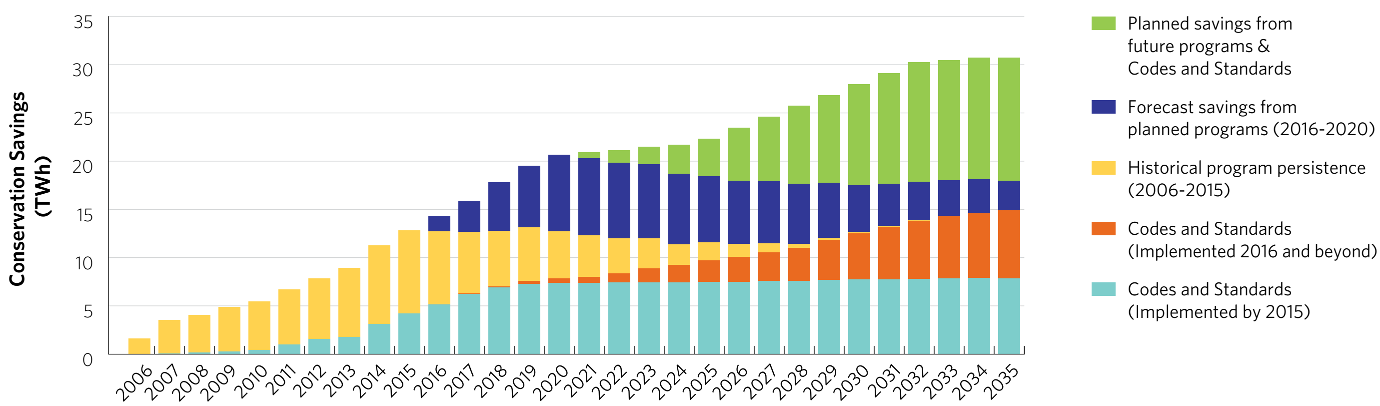
*** Total may not add up due to rounding.

Assumptions across the demand outlooks are summarized in Table 1.

In June 2016, the government released its Climate Change Action Plan (CCAP), which includes a number of policy objectives to encourage reductions in the use of fossil fuels in Ontario. Electrification potential exists in nearly every part of the energy system. Electrification of the transportation sector has been garnering much attention over the last few years with its potential to be an economical and clean alternative to fossil-fuel powered engines. Potential also exists for fuel switching in other sectors, particularly where oil or natural gas is the primary fuel.

The early focus of the CCAP is on programs over the next five years, although it is anticipated that the CCAP will be regularly updated. Each of the four demand outlooks in this report reflects the impacts that near-term actions in the CCAP would have on the electricity sector. In the longer term, there is uncertainty with respect to the pace of electrification.

Figure 11: Conservation Achievement and Outlook to Meet the 2013 LTEP Target



3.2. Conservation Outlook

All four outlooks incorporate the achievement of the target established in 2013 LTEP of 30 TWh by 2032 and the near-term target set in the Conservation First Framework and Industrial Accelerator Program of 8.7 TWh by 2020. The long-term target is achieved through a combination of conservation programs and building codes and equipment standards (Figure 11). Approximately 60 percent of this is expected to be achieved through programs implemented to date, those programs that are a part of the current Conservation First Framework, and codes and standards. To achieve the longer-term target, it is assumed that conservation programs will continue to be made available to customers after the Conservation First Framework ends. The focus and design of future programs will be determined based on future sector and market conditions and on the experience gained in the current framework.

In June 2016, the IESO completed an Achievable Potential Study (APS) to assess the electricity conservation potential in Ontario. The APS considered the potential for energy-efficiency programs and for behind-the-meter generation projects. The APS concluded that within the current budget assumptions, approximately 7.4 TWh of conservation can be achieved by local distribution companies (LDCs) by 2020. The APS also found that in the longer term about 19 TWh can be achieved from distribution- and transmission-connected customers by 2035. Incremental conservation may be achievable at higher budget levels. The APS considered conservation measures and technologies that are currently feasible. It is likely that new and possibly disruptive technologies will become available and will change the outlook for conservation achievement. The IESO will continue to update its assessments in order to understand conservation potential for integration into future plans.

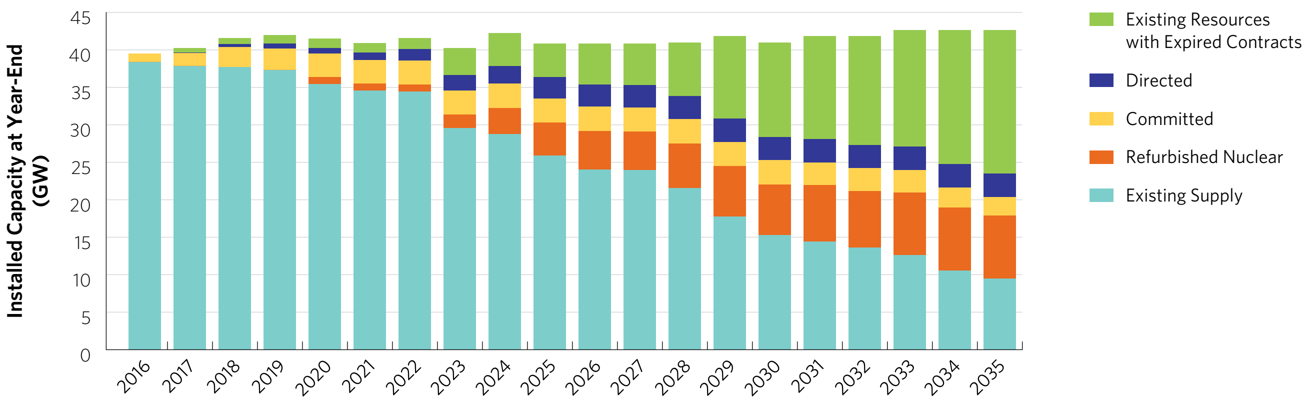
Opportunities for conservation will also vary with increases and decreases in demand. In the higher demand outlooks, demand growth is assumed to come from the electrification of key end uses such as space heating and water heating. In developing these outlooks, the IESO assumed that customers would switch from oil and natural gas to efficient electric technologies such as air-source heat pumps. As such, a considerable amount of incremental conservation has been assumed to occur in these outlooks. There may be some opportunity for conservation beyond that already assumed as the value of conservation will be higher than in the flat demand outlook, particularly in the period following 2025 as new resources are required to meet demand. The nature of programs in these outlooks would need to focus on meeting winter peak requirements. However, more study is required to identify incremental conservation potential under different demand outlooks.

3.3. Supply Outlook

As previously discussed, Ontario is in a strong starting position to reliably address any of the demand outlooks presented in this report. This starting position is shaped by three factors:

- The combined capability of resources that exist today ("existing resources")
- Resources that have been procured but are not yet in service ("committed resources")
- Resources not yet procured or acquired but have been directed to meet government policy objectives outlined in the 2013 LTEP and elsewhere ("directed resources")

Figure 12: Outlook for Installed Capacity to 2035



If all existing resources were to continue to operate after the expiry of their contracts, and if nuclear refurbishments, committed resources and directed resources come into service as scheduled, Ontario would have a total installed capacity of nearly 43 GW by 2035 (Figure 12). In contrast, if all existing resources are removed from service after contract expiry, Ontario would have a total installed capacity of approximately 25 GW by 2035.

There are a number of risks that could affect the availability of supply over the planning outlook. This includes the risk of implementation delays, including with the nuclear refurbishment program, and the effect of aging on the performance of the generation fleet.

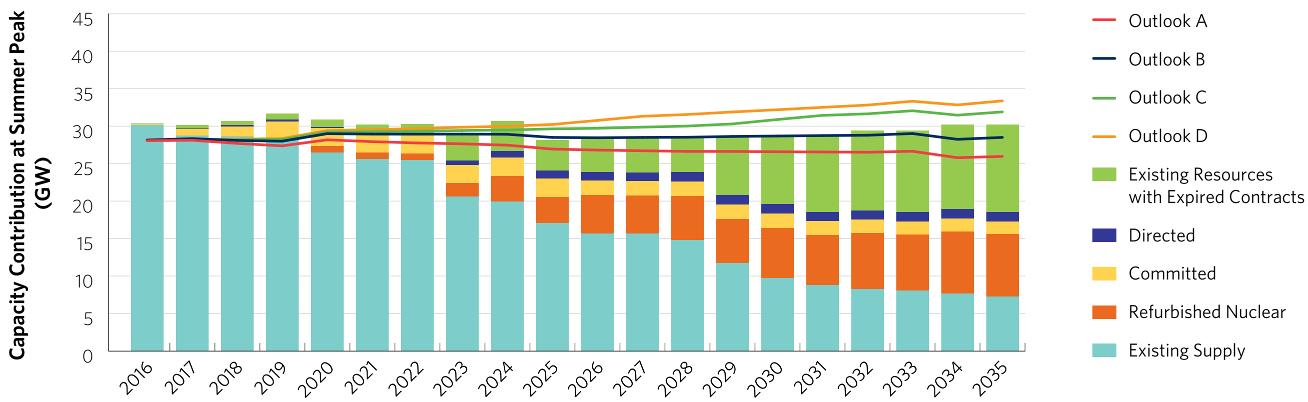
Provided that the planned resources come into service and existing resources continue to operate, Ontario's existing, committed and directed resources would be sufficient to meet the flat demand outlook. There would also be enough flexibility to address a lower growth in demand or to adapt to new opportunities or priorities. Additional resources would be required to meet any increased growth in demand such as in demand outlooks C and D (Figure 13).

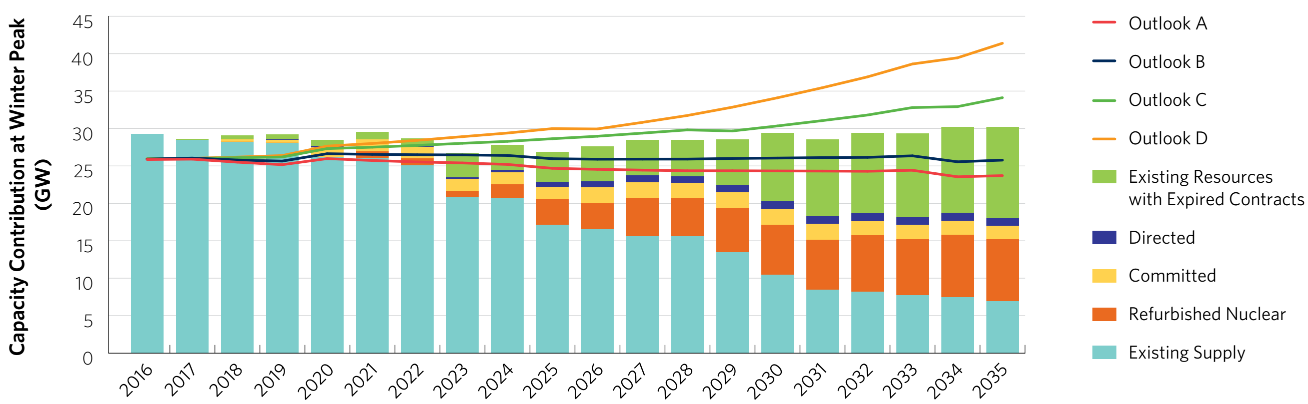
"Provided that the planned resources come into service and existing resources continue to operate, Ontario's existing, committed and directed resources would be sufficient to meet the flat demand outlook. There would also be enough flexibility to address a lower growth in demand or to adapt to new opportunities or priorities."

3.3.1. Supply Outlook under Low Demand (Outlook A)

Ontario could adapt to lower demand outlooks by not re-contracting with generation facilities when contracts expire. Ontario also has the option of exercising nuclear refurbishment off-ramps in response to sustained low demand resulting from structural or disruptive technological change. These provide the ability to align future investments with the province's evolving needs, opportunities and priorities.

Figure 13: Available Supply at the Time of Peak Demand Relative to Total Resource Requirements[9]





For example, contracts for approximately 18 GW of existing supply will reach the end of their terms by 2035. About half of this supply, made up of natural gas-fired resources, will reach contract expiry in the mid-to-late 2020s. The other half of this supply is made up of renewable resources (Figure 14).

Ontario also has the option of exercising nuclear refurbishment off-ramps in certain circumstances. In the case of the refurbishment of units at the Bruce Nuclear Generating Station, these circumstances are spelled out in the contract between Bruce Power and the IESO. They include where changes in supply or demand for electricity have resulted in there no longer being a need to refurbish the remaining units or where there are more economic electricity supply alternatives.

These give Ontario the ability to align future investments with the province's evolving needs, opportunities and priorities. They also give it additional opportunities to diversify its commitments for supply resources, including through the use of mechanisms such as capacity auctions. Most of Ontario's contracts for natural gas-fired and renewable supply have been committed for terms of 20 years but, with some reinvestment, have a design life extending well beyond the term of their contracts. New mechanisms for acquiring capacity would provide a balance of short-term, medium-term and longer-term commitments, giving Ontario additional flexibility to adapt to changing circumstances and harness evolving opportunities as described in Section 3.3.4.

[9] The total resource requirement is the amount of supply needed to meet peak demand plus reserve requirements (to account for generator outages and variability in demand due to weather).

Figure 14: Installed Capacity of Future Contract Expirations

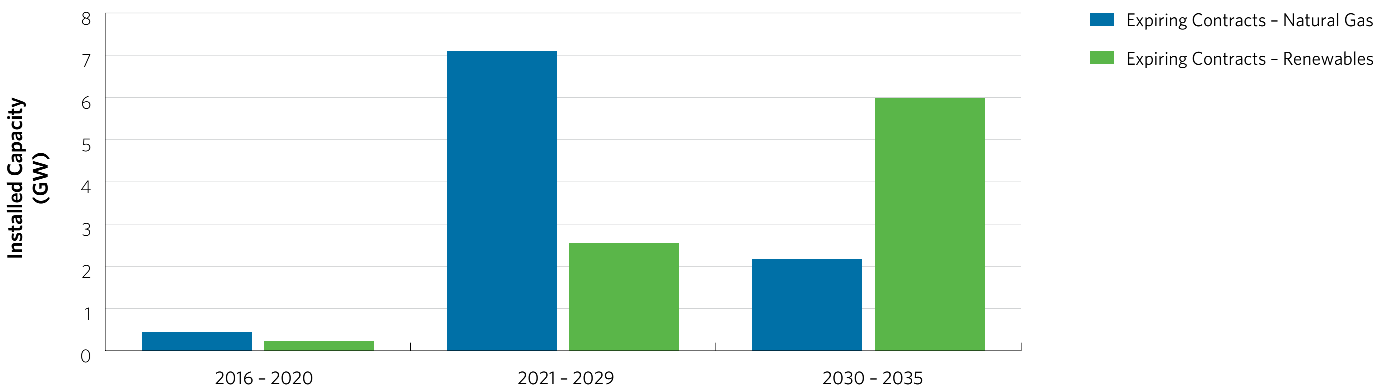
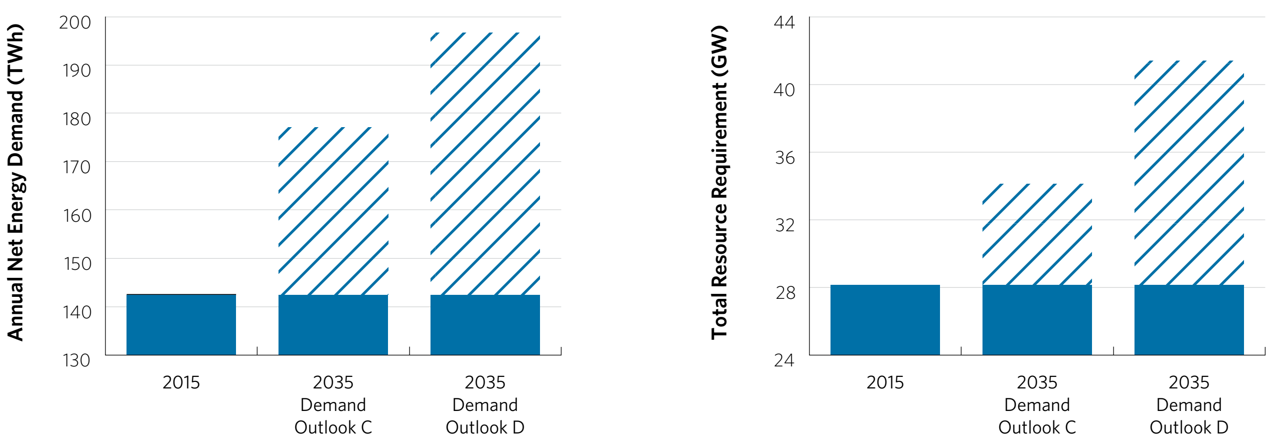


Figure 15: Electricity Supply Requirements in Outlooks C and D



3.3.2. Supply Outlook under Flat Demand (Outlook B)

As with lower demand, Ontario has a number of options for meeting flat demand or for meeting growth in electricity demand that remains at or near today's levels. The options include using Ontario's existing, committed and directed resources, provided that planned resources come into service and arrangements can be made for the continued operation of resources following contract expiry.

Ontario could also meet flat demand by taking advantage of improvements in technology performance and costs that may emerge to replace existing resources as contracts expire. Such new resources could include conservation, demand response, renewable and storage technologies, distributed energy resources and clean energy imports. As in the case for addressing reductions in electricity demand, Ontario's expiring resource contracts and off-ramps for nuclear refurbishment enable the province to take advantage of a wide range of future opportunities.

3.3.3. Supply Outlook under Higher Demand (Outlook C & D)

Ontario would require more electricity resources than it has today to serve higher levels of electricity demand growth. For perspective, energy demand under Outlook C and D by 2035 would be approximately 30 TWh and 50 TWh, respectively, higher than today. These quantities are roughly equivalent to between 20 percent and 40 percent of Ontario's current annual electricity demand. The total resource requirement in Outlook C and D increases to 34 GW and 41 GW, respectively, relative to approximately 28 GW today (Figure 15).

As illustrated in Figure 13, the IESO projects that Ontario will have sufficient resources to meet demand requirements generally over the next decade across all outlooks. Beyond the next decade, while there is increased uncertainty about the need for new resources, available technologies are likely to expand.

Table 2: Current Technology Characteristics

	Capacity	Energy	Operating Reserve	Load Following	Frequency Regulation	Capacity Factor	Contribution to Winter Peak	Contribution to Summer Peak	LUEC ($/MWh)
Conservation	Yes	Yes	No	No	No	Depends on Measure	Depends on Measure	Depends on Measure	$30-50
Demand Response	Yes	No	Yes	Yes	Limited	N/A	60%	85%	N/A
Solar PV	Limited	Yes	No	Limited	No	15%	5%	30%	$140-290
Wind	Limited	Yes	No	Limited	No	30%	30%	10%	$65-210
Bioenergy	Yes	Yes	Yes	Limited	No	40-80%	90%	90%	$160-260
Storage	Yes	No	Yes	Yes	Yes	Depends on technology/ application	Depends on technology/ application	Depends on technology/ application	Depends on technology/ application
Waterpower	Yes	Yes	Yes	Yes	Yes	30-70%	75%	71%	$120-240
Nuclear	Yes	Yes	No	Limited	No	85-95%	90-95%	95-99%	$120-290
Natural Gas	Yes	Yes	Yes	Yes	Yes	up to 65%	95%	89%	$80-310

Source: IESO. LUEC: Levelized Unit Energy Cost.

While higher demand could create a need for additional resources in the longer term, these needs are not projected to occur until the mid-2020s, with significant increases in resource requirements beyond 2030. Higher demands also provide greater potential for conservation. The value of conservation is greater in the higher demand outlooks as conservation can avoid the construction of new electricity infrastructure in these outlooks. This increased value of conservation could unlock conservation potential from existing end-uses that were otherwise uneconomic, supporting higher investment in more efficient technologies than under low demand outlooks.

3.3.4. Supply Resources

Ontario faces sizeable and increasing opportunities for further deployment of cleaner technologies including distributed energy resources to meet higher demand outlooks. These opportunities are being driven by technological advancements, evolutions in policy and market design and increasing customer engagement.

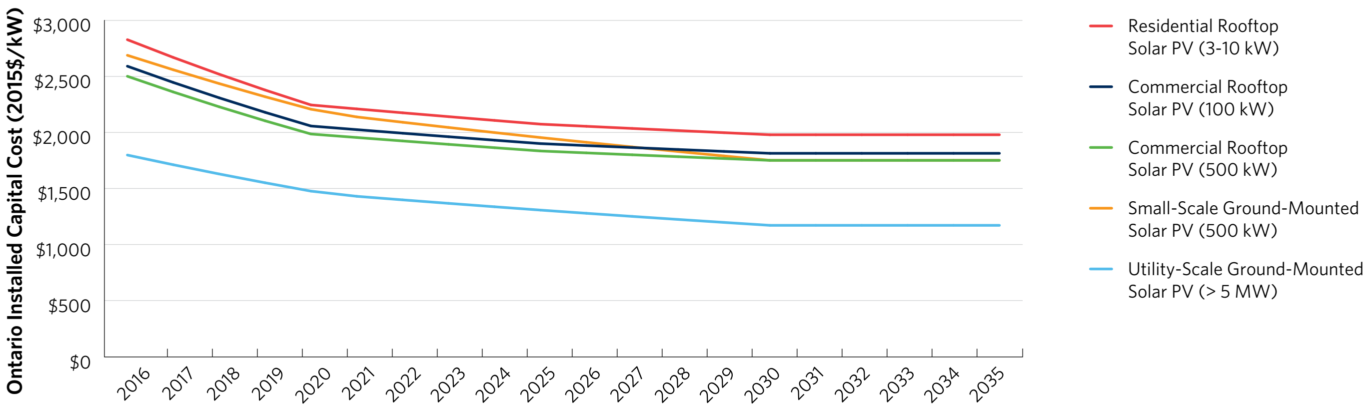
It is important to note that no single resource option can meet all customer needs at all times (Table 2). Some resources are baseload in nature; others are peaking. Some resources have higher operating costs but are dispatchable, while others have low operating costs but are highly variable. Electricity needs can relate to one or several types of products or services such as energy, capacity, regulation and ramping. Maintaining a diverse resource mix, where the different resources are complementary to each other, is an effective way to provide the various services necessary to support reliable and efficient operations.

The characteristics of each of these current technologies are discussed above.

Conservation: Conservation represents savings from energy efficiency programs and building codes and equipment standards. Conservation as a resource is described more fully in Section 3.2. Levelized unit energy cost (LUEC) values in Table 2 reflect the current range of costs to procure conservation.

Demand Response: Opportunities also exist for demand response (DR) resources. The 2013 LTEP included a DR goal of 10 percent by 2025 (approximately 2.5 GW). DR resources amounted to approximately 1.8 GW in 2015. The extent to which additional DR resources become available will depend on the demand outlook and the types of loads that can contribute in the event that Ontario becomes a winter-peaking system.

Figure 16: Installed Solar PV Cost Projections in Ontario



Solar Photovoltaic (PV): Solar PV is an example of a technology that is evolving. Solar PV module prices have declined by 70-80 percent over the past decade in line with improvements in efficiency, manufacturing and growing economies of scale. Solar PV prices are expected to continue to decline in the future (Figure 16), and applications for the technology, such as building-integrated solar PV (where solar PV is integrated into the building envelope), are also expected to diversify.

Ongoing evolution in solar PV technology and prices will increase options for customer participation in the electricity system, including those available in conjunction with other technologies and systems such as electricity storage, demand management and smart energy networks.

There are limitations on the role that solar PV might play in meeting winter peak needs. Solar output tends to be less aligned with peak electricity demands in the winter, which usually occur during dark mornings and dark evenings; this invites further consideration of how technologies such as solar PV might be effectively coupled with other enabling elements such as storage.

Wind Power: Wind turbine technologies continue to evolve. Turbines are generally getting taller and rotor diameters are becoming larger, which has helped boost output and drive down per-unit costs. This has resulted in reduced project footprints (same output with fewer turbines). The average output of a wind turbine has tripled over the past 20 years, and the cost of installed wind capacity has followed a declining trend worldwide. Given the maturity of the technology, the rate of cost decline is expected to be slower than in the past.

Bioenergy: Bioenergy refers to the conversion of energy in organic matter to produce electricity. This could include directly combusting organic fuel (biomass) or allowing the organic matter to decompose to produce methane gas (biogas or landfill gas), which in turn is combusted. Ontario has plentiful sources of bioenergy including residual materials from forestry operations that are left to decay on the forest floor, waste matter from agricultural production and animal livestock activities, by-products of food-processing operations, and municipal waste from landfills, compost and water treatment facilities. A number of bioenergy conversion technologies exist employing a variety of processes. Some technologies, such as landfill gas, are well-established while other technologies are still in the research phase. Challenges for bioenergy development include relatively high capital costs. Feedstock costs are generally zero since they are produced as a waste by-product although there may be a cost associated with transporting the fuel. Projects can benefit from being located close to where the feedstock is produced (such as at a farm or mill). This makes them suitable in rural and remote applications.

Electricity Storage: While some electricity storage technologies, such as pumped hydro storage, have been in operation around the world for over a century, a variety of newer technologies such as flywheels, batteries and compressed air facilities are gaining adoption. These technologies vary considerably in terms of their size and scale, how energy is stored, how long energy can be stored and their response time. At the same time, the costs of these technologies have been declining and are expected to further decline, they tend to be less geographically constrained as far as siting is concerned, and they involve shorter development lead times. Storage can also provide a number of services, for example, to help manage variable generation, provide bulk system services such as regulation or voltage control, or help manage outages.

Waterpower: Assessments over the years have identified significant remaining waterpower potential in the province. However, most of the potential exists in relatively remote regions of northern Ontario that lack transmission access. The cost of developing this potential is expected to be higher than in the past and projects require relatively longer lead times to develop. However, waterpower could be a significant source of non-carbon emitting energy and would provide opportunities to partner with First Nation and Métis communities. While Ontario's greatest remaining waterpower potential is in the north, there are also opportunities in the south, including redevelopments at existing water control structures (dams).

Nuclear: Nuclear power plants are baseload resources and carbon-free in operation. They produce electricity on a continuous basis with limited but increasing capability to vary output as demand varies (i.e., load follow). Opportunities for baseload resources, including nuclear, will be limited by the extent to which there is growth in baseload demand.

Construction cost of new nuclear plants has generally been increasing, and cost is an area of considerable uncertainty.

The refurbishments of Darlington and Bruce units are proceeding, consistent with the principles outlined in the 2013 LTEP.

Figure 17: Existing Interconnections

Additional information on Ontario's existing interconnections can be found in the Ontario Transmission System section of the IESO's 18-Month Outlook
http://www.ieso.ca/Documents/marketReports/OntTxSystem_2016jun.pdf

Gas-fired Resources: Gas-fired resources produce lower GHG emissions than coal-fired resources and can complement a low-carbon supply mix. The gas fleet provides significant flexibility to respond to the intermittency associated with renewable generation.

Many of the current technologies outlined here could also support firm electricity imports or be deployed as distributed energy resources.

Firm Electricity Imports: In addition to opportunities within the province, opportunities also exist for greater electricity trade between Ontario and its neighbours. Ontario currently has interconnections with five of its neighbours: Quebec, Manitoba, Minnesota, Michigan and New York. These interconnections facilitate the import and export of electricity (Figure 17). Electricity trade now provides operational and planning flexibility and enhances the reliability and cost-effectiveness of the Ontario electricity system. Interties can also be used to obtain firm capacity to support resource adequacy as well as energy to meet consumption where they can be pursued at costs below domestic resources (factoring in transmission). As an example, Ontario recently entered into a seasonal capacity swap agreement with Quebec for the next decade. Under the terms of the deal, Ontario provides firm capacity to Quebec in the winter (when Ontario has its greatest surplus) and Quebec provides firm capacity in the summer (when Quebec has its greatest surplus). The introduction of competition for capacity from resources located outside of Ontario offers further opportunity to lower costs and support reliability. Taking advantage of available supply through existing interconnections could have the effect of reducing Ontario-based resource requirements. The scale and economics of any potential firm import capacity deal will depend greatly on the need for additional transmission infrastructure on both sides of the border.

Distributed Energy Resources (DERs): Evolutions in technology and policy are also expanding opportunities for customer engagement and participation in the Ontario electricity system and are driving a transition towards a system more characterized by two-way flows and a growing prevalence of distributed energy resources. The utility-customer relationship is becoming more complex against this backdrop as an increasing number of products and services are becoming available to customers. Some of these products and services compete directly with utility services. For example, a wide range of home energy technologies and smart home appliances are now available, and the competition to become the provider of the home "internet-of-things" ecosystem is growing. A number of communities are now developing community energy plans, and distributed energy resources have become a key component of those plans. Distributed energy resources are also being promoted by some communities in the context of ongoing regional planning activities across the province.

The higher demand outlooks provide greater opportunities for harnessing DERs without stranding assets as the risk of underutilizing assets becomes less of an issue. DERs can be part of the solution in addressing higher demands and reducing the need for new grid-connected resources. DERs can also enhance supply security and resiliency. This potential is illustrated by the experience of New York City during Hurricane Sandy. The storm left eight million people without power in New York, and some of the hardest hit areas were left without power for two weeks. In the heart of New York City, however, NYU's Washington Square campus remained powered by a 13.4 MW natural gas-fired combined heat and power (CHP) system that had recently been installed. In Ontario, several customers (for example, Metrolinx) have installed small CHP systems in their facilities that are capable of providing heat and power during an interruption of grid power. At the same time, distributed energy resources and other local solutions are receiving greater attention with greater involvement of customers and communities in regional planning. Addressing barriers to the adoption of distributed energy resources, such as cost allocation and integration issues, could help to better realize their potential benefits.

Pilot programs and lessons learned from other jurisdictions can help Ontario to better understand available or emerging options and identify barriers that might hinder their broader realization.

While there are many potential benefits in evolving to an electricity system that relies more on distributed energy resources, care must be taken in managing this evolution to ensure that it does not result in higher ratepayer costs, stranding of existing assets or increased GHG emissions.

3.4. Market and System Operations Outlook

Over the planning period, a number of foreseeable changes are expected to result in a power system that is increasingly variable and complex to operate on a day-to-day basis. Changes such as increases in variable renewable generation and distributed energy resources, nuclear decommissioning and refurbishments, and changing customer demand patterns will change the flow patterns on the bulk system. New facilities, tools and/or measures will need to be in place to help maintain system reliability and operability through this significant transition period.

"Over the planning period, a number of foreseeable changes are expected to result in a power system that is increasingly variable and complex to operate on a day-to-day basis."

The IESO has successfully integrated over 6,000 MW of wind and solar PV into Ontario's electricity system. The IESO has made strides in integrating significant amounts of variable generation while maintaining reliable operations of the power system. This has been achieved through efforts such as the Renewable Integration Initiative (RII), which brought in centralized forecasting of variable generation and the capability to dispatch variable generators.

While the IESO is working on methods for improving short-term forecasting, measures are also being taken to maintain reliable and efficient operations in the face of an evolving power system. These measures include additional frequency regulation, flexibility, control devices, and system automation. Greater coordination between the grid operator and embedded resources, directly or through integrated operations with LDCs, could also improve visibility into the distribution system and reduce short-term forecast errors.

Load-following capability is primarily provided by peaking water-power resources, the Sir Adam Beck Pump Generating Station and natural gas-fired generation, and is sufficient in the near term. However, the need for flexibility will increase over time. In addition to existing mechanisms for acquiring ancillary services, consideration is being given to expanded markets that would allow for more dynamic real-time coordination.

Going forward, regulation and flexibility requirements will be assessed on an ongoing basis, along with the resource fleet available to provide these services. Electricity markets will play a stronger role in ensuring adequate supply of flexible resources through signals that price and dispatch these services. It is anticipated that many resource types will be able to compete to provide regulation and/or flexibility, including resources such as energy storage and aggregated loads. Some of these newer technologies can provide operability characteristics that are not achievable from some traditional resources, such as very fast ramp rates, which may allow efficiency improvements in how these services are currently dispatched.

3.5. Transmission and Distribution Outlook

Current transmission projects already at various stages of planning and implementation are outlined in Table 3.

No significant new transmission investments would be required in an outlook of flat electricity demand served by existing and currently planned resources. However, additional transmission or local resources to address specific regional needs may be identified in the future as regional planning continues across the province.

The need to replace aging transmission assets over coming years will also present opportunities to right-size investments in line with evolving circumstances. This could involve up-sizing equipment where needs exist such as in higher demand outlooks; downsizing, to reduce the risk of underutilizing or stranding assets; or even removing equipment that is no longer required, such as in the low demand outlook or in parts of the province that have seen reduced demand. Such instances may also present opportunities to enhance or reconfigure assets to improve system resilience and allow for the integration of variable and distributed energy resources.

In higher demand outlooks, investments in transmission will be required to accommodate new resources. Transmission to integrate those resources would have significant lead time requirements of up to 10 years. Much of Ontario's undeveloped renewable resource potential is located in areas with limited transmission capacity – new investments in Ontario's transmission system would be required to enable further resource developments in the province or significant imports into the province. For example, incorporation of renewable resources located in northern Ontario would require reinforcements to the major transmission pathway between northern and southern Ontario, the North-South Tie. A number of transmission upgrades within Northern Ontario would also be required to alleviate constraints within the region. To facilitate any potential large firm import capacity arrangement from Quebec/Newfoundland, major system reinforcements in eastern Ontario would be required – a new high-voltage direct current (HVDC) intertie to Lennox would be an example. The incorporation of new resources in Southwestern Ontario would require reinforcement of the transmission system, such as in the West of London area, as well as additional enabling facilities. Similarly, investments in new resources in the Greater Toronto Area might also trigger the need to reinforce the bulk transmission system.

In the near term, the system can manage increases in electricity demand driven by electrification. However, LDCs and transmitters may be more significantly impacted as local peak demands grow.

Table 3: Status and Drivers of Transmission Projects in Outlook B[10]

		Drivers			
Projects	Status	Maintaining Bulk System Reliability	Addressing Regional Reliability and Adequacy Needs	Achieving 2013 LTEP Policy Objectives	Facilitating Interconnections with Neighbouring Jurisdictions
East-West Tie Expansion	Expected to be in service in 2020.	●		●	
Line to Pickle Lake	Plan is complete; expected to be in service in early 2020.		●	●	
Remote Community Connection Plan	Draft technical report released; development work underway for connection of 16 communities; engagement with communities is ongoing.		●	●	
Northwest Bulk Transmission Line	Hydro One is carrying out early development work to maintain the viability of the option.	●		●	
Supply to Essex County Transmission Reinforcement	Expected in-service date of 2018.		●		
West GTA Bulk reinforcement	Plan is being finalized.	●			
Guelph Area Transmission Refurbishment	Expected to be in service in 2016.		●		
Remedial Action Scheme (RAS) in Bruce and Northwest	Under development. Northwest RAS targeted for late 2016 in-service; Bruce RAS early 2017.	●			
Clarington 500/230kV transformers	Expected to be in service in 2018.	●			
Ottawa Area Transmission Reinforcement	Project has been initiated; expected to be in service 2020.		●		●
Richview to Manby Transmission Reinforcement	Expected to be in service in 2020.		●		

[10] A merchant 1 GW bi-directional, high-voltage, direct current Lake Erie underwater transmission link is currently being proposed by ITC Holdings Corp. It would directly connect the Ontario transmission system at the Nanticoke Transformer Station with the PJM market in Pennsylvania. The proposed in-service date of the project is 2019. This is a merchant project that was not identified by the IESO as being needed to meet system requirements.

The extent to which the transmission and distribution system will be impacted will depend on the location of electrification driven demand growth. The low voltage distribution system is expected to be impacted to a much greater degree. For example, some distribution infrastructure is designed for a five kilowatt (kW) peak household load. On a cold day, one household equipped with an air-source heat pump could consume as much as 15 kW. Though the system as a whole could supply this need, transmission and distribution infrastructure in some regions would be challenged by rapid and widespread conversions from gas to electric heating. This could be compounded by the effect of home charging of EVs, whose impact on peak demand can also vary substantially with charging patterns. Some LDCs have already undertaken analysis of their systems to determine the potential impact that high saturation of EVs will have on their system and what measures could be taken to manage emerging needs in the most cost-effective manner. These measures include a focus on customer-based solutions such as the use of load control devices, DER and storage integrated with the local and provincial utility control systems. While the impact of electrification in space heating, water heating and transportation will increase electricity requirements across the province, the impact would be the most prominent in urban centres, with implications for regional transmission systems that will need to be considered as part of the regional planning processes.

The increased penetration of DERs will have implications for distribution and transmission systems. A number of facilities, tools and measures will be needed to ensure that the power system can continue to be reliably operated amid increasing amounts of DERs. In some cases, DER technologies themselves can help address some of these requirements. Pilot projects are building experience and capability with DERs within the sector. Strategies and options for using DERs to address local issues could be laid out in regional planning processes, working together with transmitters and LDCs.

"In the near term, the system can manage increases in electricity demand driven by electrification. However, LDCs and transmitters may be more significantly impacted as local peak demands grow... The low voltage distribution system is expected to be impacted to a much greater degree."

3.6. Emissions Outlook

With the phase-out of coal-fired generation, the carbon emissions from Ontario's electricity fleet now come primarily from natural gas-fired generation.

Emissions are expected to continue to decline over the next five years as additional renewable generation enters service. Beyond this period, emissions will depend on the level of electricity demand and the extent to which energy production from the existing natural gas-fired fleet is displaced.

In the flat demand outlook, emissions would rise slightly following the retirement of the Pickering Nuclear Generating Station but would remain well below historical levels and stay relatively flat through to 2035 (Figure 18).

When Ontario's cap-and-trade system takes effect in 2017, the electricity sector will see the cost of carbon reflected in the wholesale electricity price when natural gas-fired resources are on the margin. The Ontario market price for carbon will also be applied to electricity imports. This will provide a level playing field for Ontario generators in the IESO market and reduce imports from higher-emitting sources. At the same time, imports to Ontario from non-emitting jurisdictions such as Quebec could increase, other things being equal.

On the other hand, the addition of a carbon price to emitting Ontario generators would reduce the amount of electricity exported from natural gas-fired generators and so reduce Ontario GHG emissions, with the impact depending on whether the receiving jurisdictions adopt similar carbon pricing as Ontario and Quebec.

Under the higher demand outlooks, the effects on carbon emissions will depend on the extent to which the existing natural gas-fired fleet is used to meet increases in demand. The existing natural gas-fired combined-cycle fleet has considerable capability to ramp up energy production should it be required. However, increased utilization of the existing combined-cycle fleet would increase emissions. Therefore, in this report, consideration of how to address the higher demand outlooks was based on keeping GHG emissions in the electricity sector low or declining.

Figure 18: Electricity Sector GHG Emissions in Outlook B

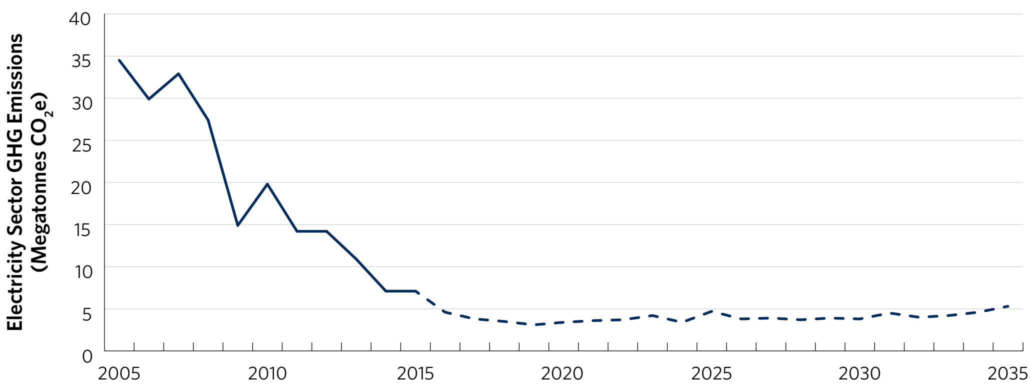


Figure 19: Total Cost of Electricity Service in Outlook B

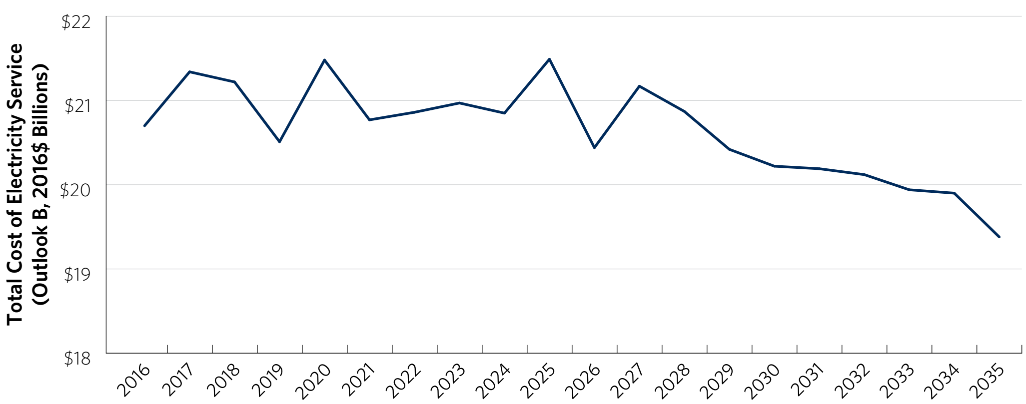


Figure 20: Average Unit Cost of Electricity Service in Outlook B

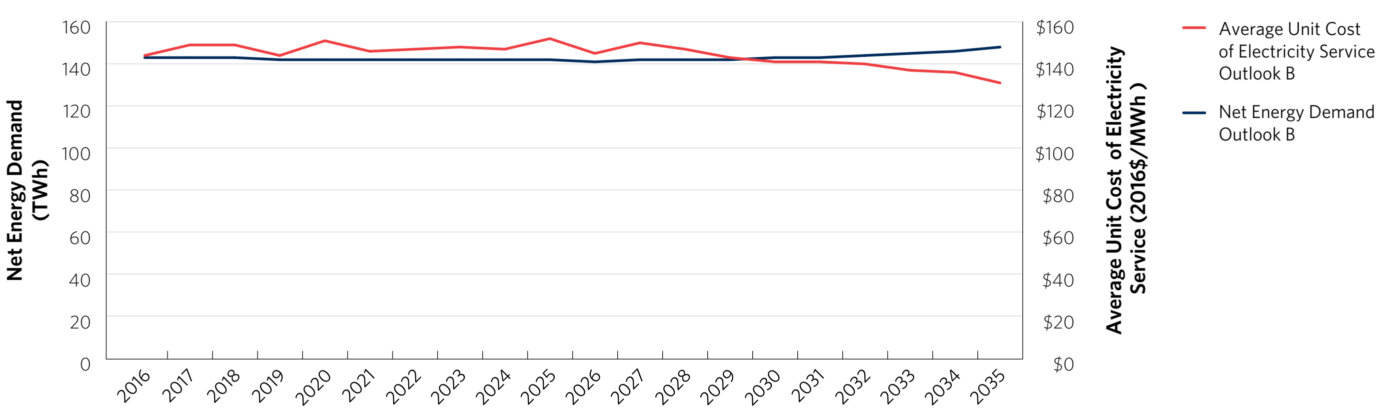
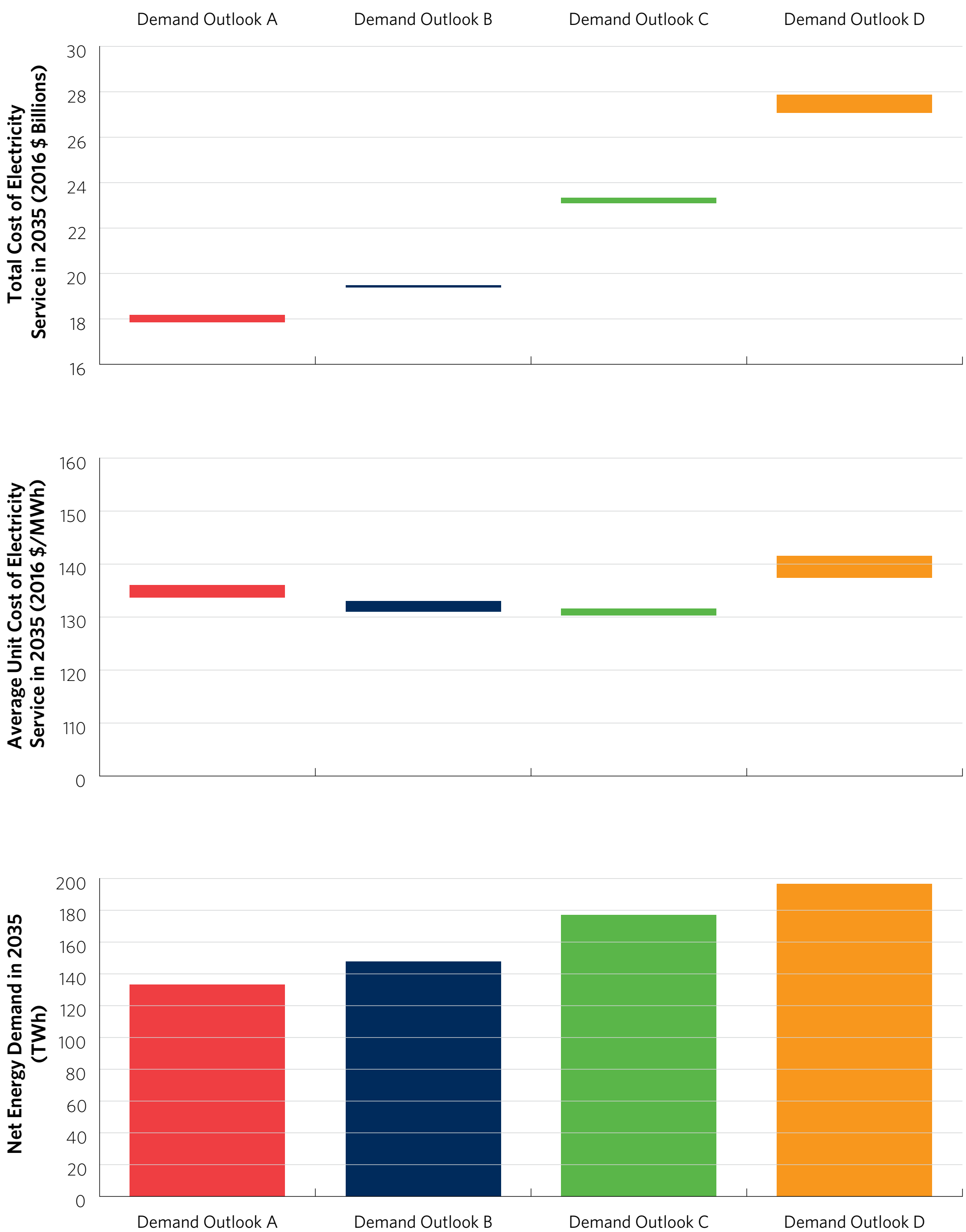


Figure 21: Cost of Electricity Service across Demand Outlooks



3.7. Electricity System Cost Outlook

The total cost of electricity service over the planning outlook will be a function of demand growth, the cost of operating the existing system and the investments required in new resources to meet potential needs.

In the flat demand outlook, the total cost of electricity service would average approximately $21 billion per year (2016$) over the next 10 years and is estimated to decrease to approximately $19 billion per year by 2035 (Figure 19). Cost reductions are premised on expectations of lower revenue requirements among generators whose existing contracts have expired but continue to operate at costs below existing contract rates.

The average unit cost of electricity service decreases by an average annual 0.3 percent per year (2016$) over the 20-year period. Ongoing investments lead to increases in the first 10 years of the outlook at an average annual rate of 0.4 percent per year (Figure 20). Unit rates decrease over the last 10 years of the outlook due to reduced investments in electricity resources.

In higher demand outlooks, additional investments in new resources (conservation, generation and transmission) would be required to meet the increase in demand (peak and energy requirements) and to keep emissions within the range of the flat demand outlook. The annual cost of electricity service would rise by approximately $4 billion to $10 billion by 2035 (2016$) (Figure 21). However, this would be associated with an increase in energy consumption in the province. As a result, the average unit cost of electricity service would be within the range of the flat demand outlook.

"The existing natural gas-fired combined-cycle fleet has considerable capability to ramp up energy production should it be required. However, increased utilization of the existing combined-cycle fleet would increase emissions."

Conclusion

4

Actions taken over the past 10 years have left Ontario well positioned to meet future provincial needs. However, Ontario's electricity sector will face significant change over the next 20 years as it moves forward to achieve conservation and demand response targets, manages nuclear refurbishment, brings into service the remaining committed and directed supply resources, while addressing the impact of the rapid pace of technological evolution and the effect on demand of government climate change policies.

Looking ahead, the IESO has considered a range of potential long-term electricity demands and options for addressing them. Evolutions in policy, technology and markets along with rising customer engagement are happening across the sector, including in the areas of low-carbon technologies and distributed energy resources. Expiring electricity resource contracts, nuclear refurbishment off-ramps and transmission assets reaching replacement age provide Ontario with flexibility to take advantage of options as they arise. Positioning Ontario to take advantage of future opportunities and mitigate future risks will require ongoing efforts. Considerations in this regard include:

- Maintaining situational awareness: Developments in technology and policy need to be monitored as well as information about drivers of risk for the sector, such as resource availability uncertainty and demand uncertainty. Situational awareness would be assisted by ongoing and proactive engagement with sector participants, communities, customers and stakeholders.
- Assessing opportunities and risks in an integrated way: It is important to consider individual opportunities within the context of broader systems and to consider both benefits and risks. Assessing options in an integrated way can deepen our understanding of potential synergies, barriers and implementation requirements.
- Resolving barriers: Barriers may exist to the deployment or procurement of new technologies or approaches. Regulatory frameworks and procurement processes would need to continue to evolve to address changing circumstances and technologies.

In the IESO's higher demand outlook, electrification of end-uses in support of climate change actions could be met in a variety of ways. While Ontario would require additional electricity resources to meet the associated higher levels of demand growth, it has a variety of options available, including distributed energy resources and enhanced conservation. Higher demands could be served in ways that sustain recent reductions in electricity sector emissions while significantly reducing carbon emissions in the broader economy, including through the greater substitution of electricity for fossil fuels in residential and commercial space and water heating, light duty vehicles, public transit and in some industrial applications.

Electrification-driven demand growth possibilities underscore the challenge of scale and integration that could be brought by significantly higher needs. For instance, the magnitude of growth associated with Outlooks C and D would exceed the contribution that any single electricity resource option could provide on its own. Meeting this scale of electricity demand growth would require the coordinated deployment of multiple low-carbon options.

The development of low-carbon resources to address the higher demand outlooks would also require significant investments in Ontario's transmission system. Electrification and the growth of distributed energy resources would also drive the need for significant investments at the distribution level.

The scale, cost and practical challenges of implementing options to address greater electrification further highlights the importance of conservation as a method of moderating electricity demand growth. Capturing those conservation opportunities would be central to meeting high electrification options.

Transmission development activities should be considered when making supply decisions. This could include activities to incorporate resources in northern Ontario and to unlock resource potential in the eastern and southwestern regions of the province.

While significant new investments would be required to address the higher demands in Outlooks C and D, with the increase in energy consumption, the average unit cost of electricity service would remain within the range of the flat demand future.

In brief, Ontario has access to options for meeting electrification-driven demand growth in ways that result in significant economy-wide carbon emission reductions. In addressing the associated planning issues, the IESO is committed to supporting the Ministry's consultations as the new LTEP is developed.

The IESO engaged in discussions with key stakeholder and community groups and invited input into this planning outlook through the its Stakeholder Advisory Committee (SAC). Written comments were posted to the IESO SAC webpage along with material to illustrate the IESO's consideration of the input received.

The IESO wishes to thank the members of the SAC and the many stakeholder and community groups involved in these discussions.

Appendices and Modules

5

Appendices

Appendix A: June 10, 2016 Letter from the Minister of Energy to the IESO re: Technical Report

Appendix B: Data Tables for the OPO Technical Report

Modules

The following modules can be found on the IESO website: ieso.ca

Module 1: State of the Electricity System: 10-Year Review

Module 2: Demand Outlook

Module 3: Conservation Outlook

Module 4: Supply Outlook

Module 5: Market and System Operations & Transmission and Distribution Outlook

Module 6: Emissions Outlook

Module 7: Electricity System Cost Outlook

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Appendix A

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Ministère de l'Énergie

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Ontario

Friday June 10, 2016

Mr. Bruce Campbell
President and Chief Executive Officer
Independent Electricity System Operator
1600–Adelaide Street West
Toronto ON M5H 1T1

Dear Mr. Campbell,

RE: IESO Technical Report

The Government of Ontario plans to issue a new Long-Term Energy Plan (LTEP) that will set out and balance Ontario's goals of cost-effectiveness; reliability; clean energy; community and indigenous engagement; and emphasis on conservation and demand management. As you know, Bill 135, the *Energy Statute Law Amendment Act, 2016*, has received Royal Assent. To support the development of the LTEP, we anticipate that the IESO will submit a technical report on the adequacy and reliability of Ontario's electricity resources, pursuant to section 25.29(3) of the *Electricity Act, 1998*, as that section will be amended (the "Act").

The technical report shall provide a ten-year review (2005-2015) and a twenty year forecast (2016-2035) of the electricity system with respect to:

- Costs of the electricity system
- Conservation
- Demand
- Supply resources including electricity storage
- Capacity
- Reliability
- Market and System Operations
- Transmission and Distribution
- Air emissions from the electricity sector

The forecasts shall consider existing supply commitments and directions, as well as other related government commitments, including, but not limited to, the recently released Climate Change Action Plan, the *Climate Change Mitigation and Low-Carbon Economy Act, 2016*, and the *Vancouver Declaration*.

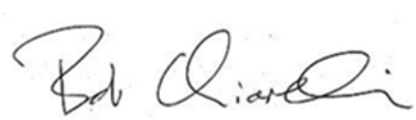
…/cont'd

The technical report will provide an objective baseline and help facilitate the formal consultation process for the development of the LTEP. In accordance with the Act, the technical report will be posted on a publicly-accessible Government of Ontario website. Consistent with the Open Data Directive, datasets and key assumptions used to develop the technical report will also be made available to the public. I encourage you to work with my staff to ensure the technical report and underlying data meet Web Content Accessibility Guidelines.

The Act will require the technical report to be posted publicly prior to the Ministry undertaking any LTEP consultations. I therefore request that the report be submitted to the Ministry no later than September 1, 2016.

If you should have any questions about this request or require further clarity, please do not hesitate to contact me.

Sincerely,



Bob Chiarelli
Minister

c: Tim O'Neill, Chair, Independent Electricity System Operator
Serge Imbrogno, Deputy Minister, Ministry of Energy
Independent Electricity System Operator Board Members
Independent Electricity System Operator Stakeholder Advisory Committee

Data Tables for the OPO Technical Report

September 2016

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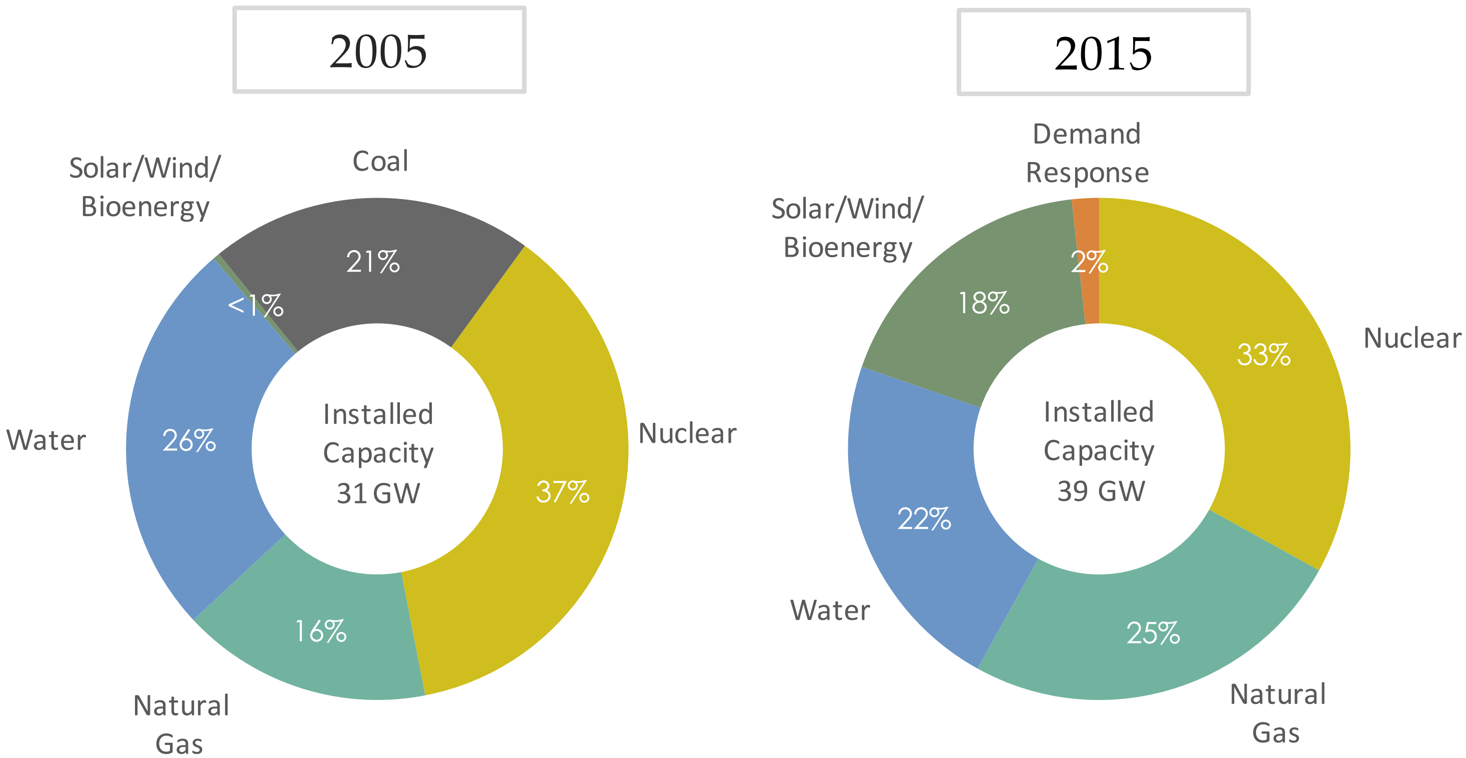
Figure 1: Ontario Installed Supply Mix in 2005 and 2015



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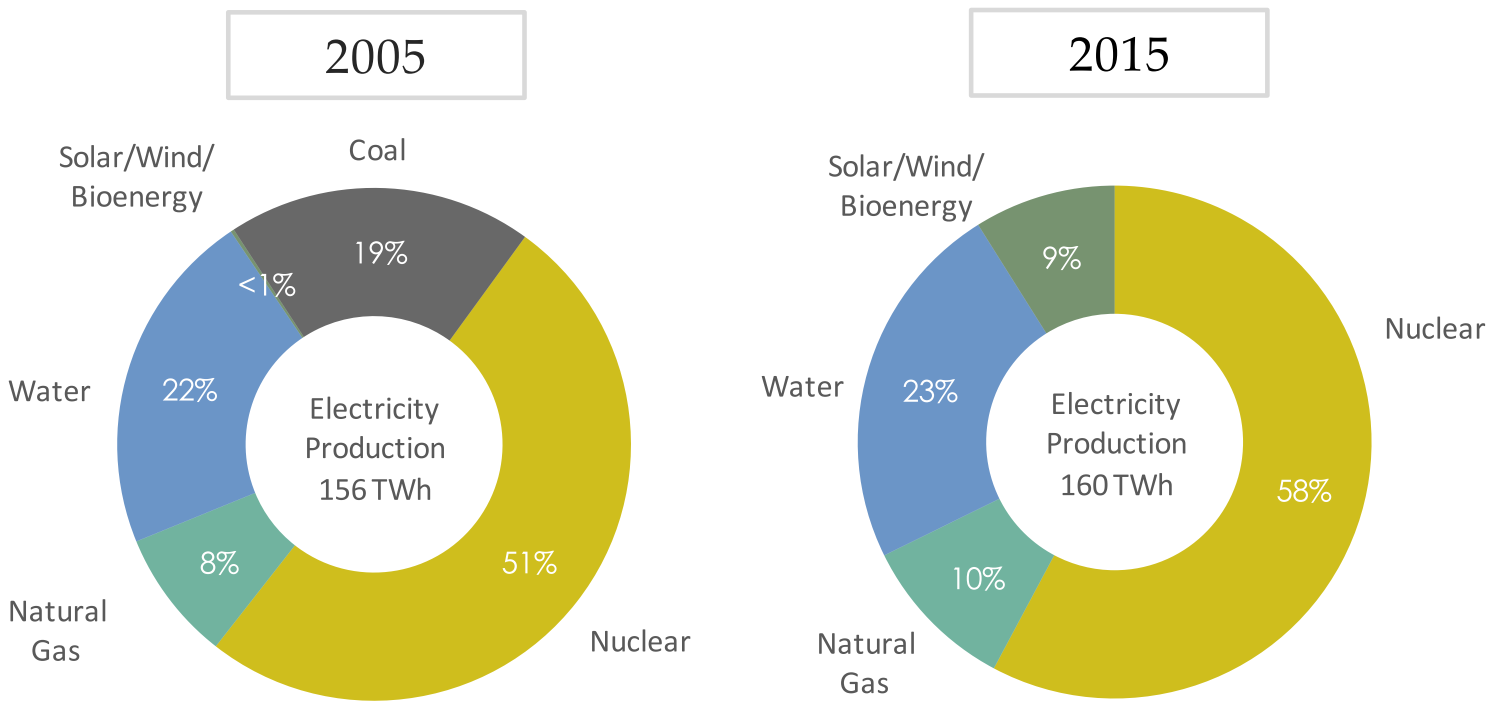
Data for Figure 1: Ontario Installed Supply Mix in 2005 and 2015

MW	2005	2015
Nuclear	11,397	13,014
Natural Gas & Oil	4,976	9,852
Water	7,910	8,768
Solar/Wind/Bioenergy	134	7,068
Coal	6,434	0
Demand Response	0	690

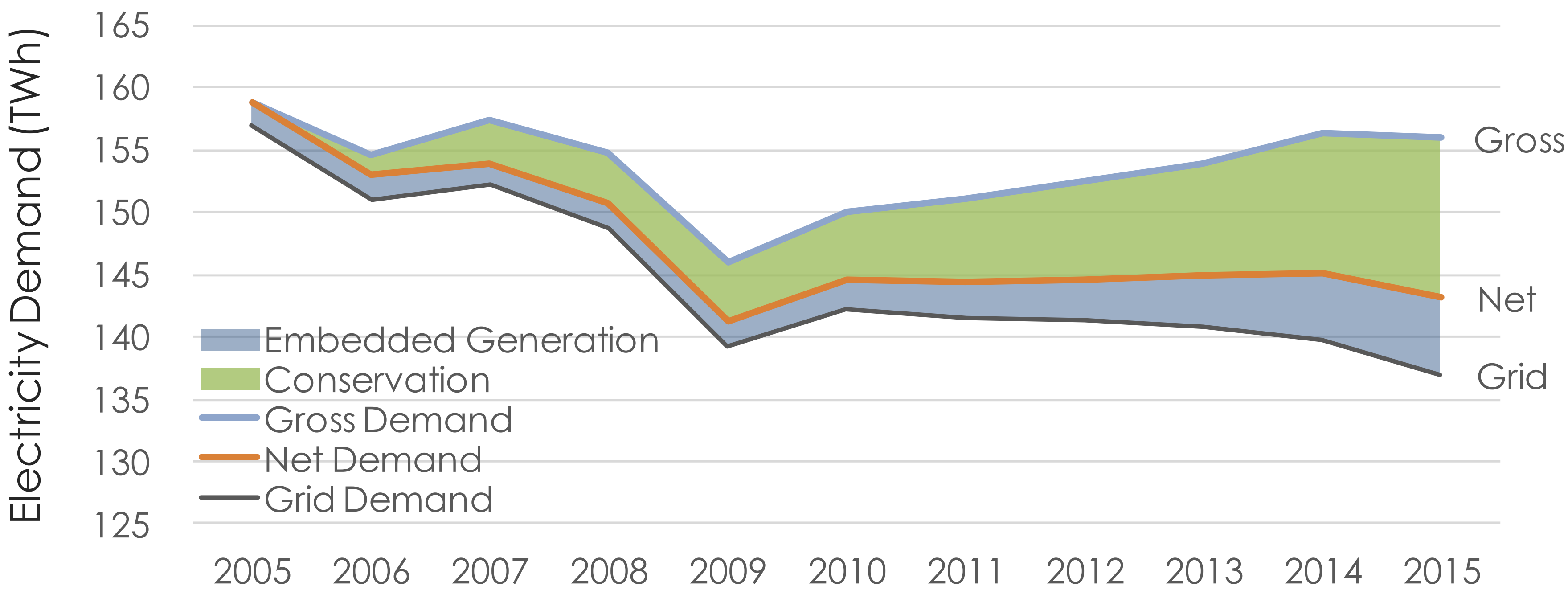
Figure 2: Ontario Electricity Production in 2005 and 2015



Data for Figure 2: Ontario Electricity Production in 2005 and 2015

TWh	2005	2015
Nuclear	79.0	92.3
Natural Gas & Oil	12.9	15.9
Water	34.0	37.3
Solar/Wind/Bioenergy	0.3	14.2
Coal	30.0	0.0

Figure 3: Historical Ontario Energy Demand



Gross Demand is the total demand for electricity services in Ontario prior to the impact of conservation programs
Net Demand is Ontario Gross Demand minus the impact of conservation programs
Grid Demand is Ontario Net Demand minus the demand met by embedded generation. It is equal to the energy supplied by the bulk system to wholesale customers and local distribution companies

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Data for Figure 3: Historical Ontario Energy Demand

TWh	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Gross Demand	158.8	154.4	157.3	154.7	146.0	149.9	151.0	152.3	153.8	156.2	155.8
Conservation	0.0	1.6	3.5	4.0	4.9	5.4	6.7	7.9	8.9	11.3	12.8
Net Demand	158.8	152.8	153.8	150.6	141.1	144.5	144.3	144.5	144.8	144.9	143.0
Embedded Generation	1.8	1.7	1.6	2.0	2.0	2.3	2.8	3.2	4.1	5.1	6.0
Grid Demand	157.0	151.1	152.2	148.7	139.2	142.2	141.5	141.3	140.7	139.8	137.0

Figure 4: Conservation Savings in 2015

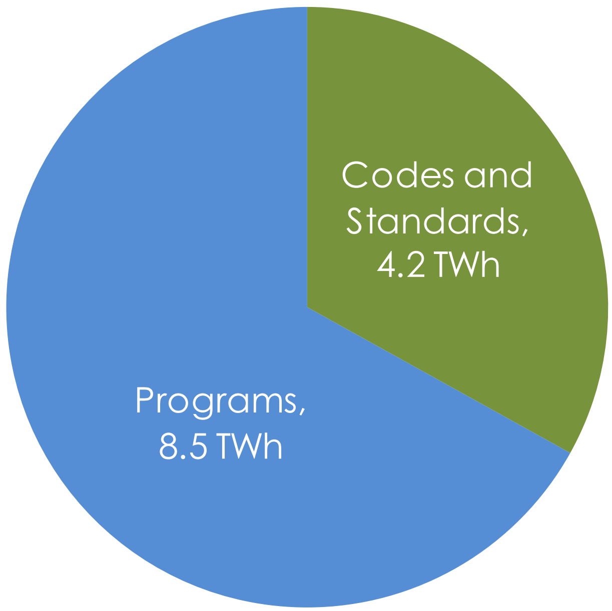
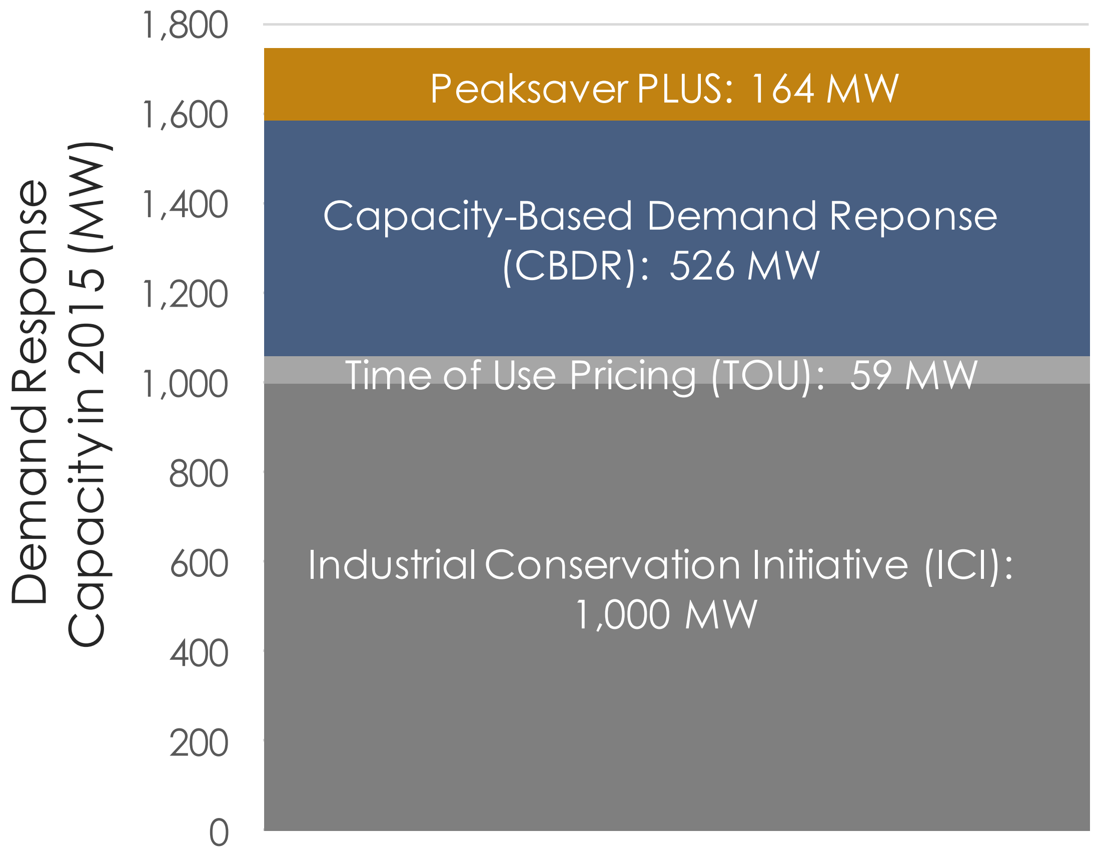


Figure 5: Demand Response Capacity in 2015



Peaksaver PLUS and CBDR can controlled by system operators. These programs are treated elsewhere as supply resources totalling 690 MW

TOU pricing and ICI reflect customer response to prices. These programs are considered as part of the net demand forecast

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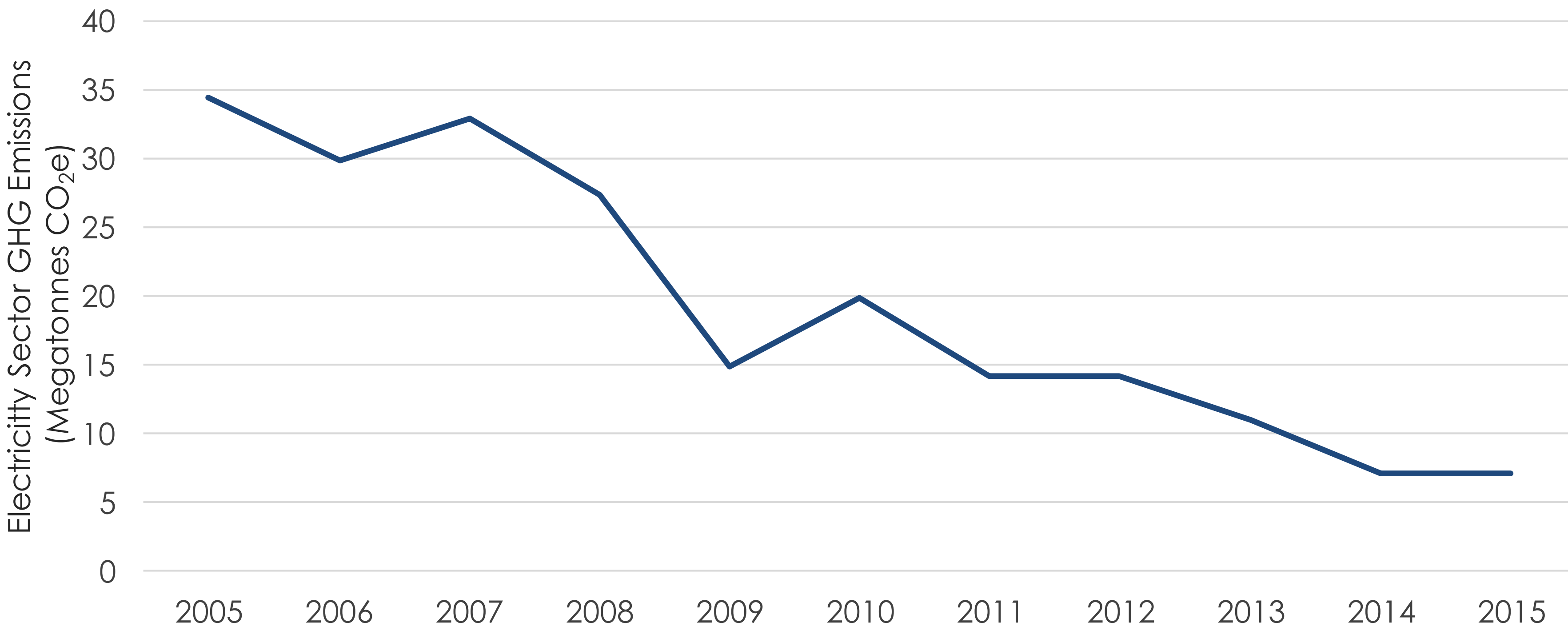
Data for Figure 5: Demand Response Capacity in 2015

Category	MW
TOU	59
ICI	1,000
Peaksaver PLUS	164
CBDR	526

Figure 6: Electricity Sector GHG Emissions

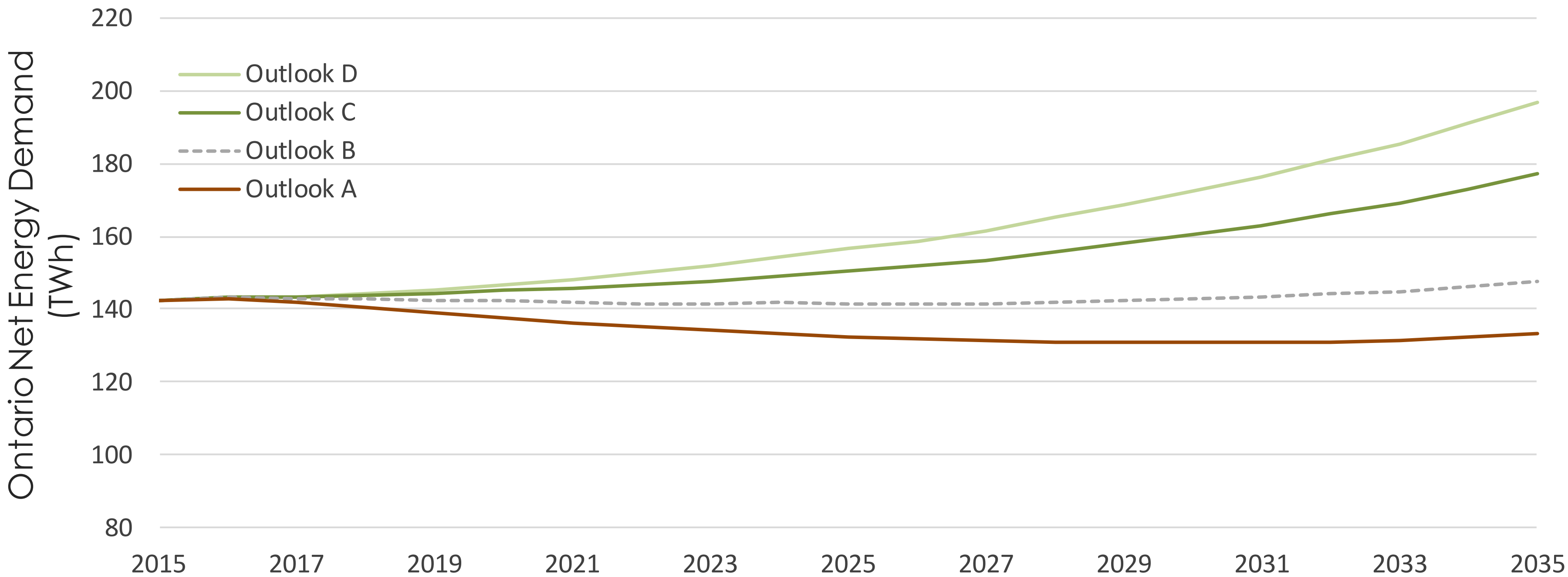


Note: GHG emissions for 2015 is an estimate

Data for Figure 6: Electricity Sector GHG Emissions

MT CO_2e	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Electricity Sector GHG Emissions	34.5	29.9	32.9	27.4	14.9	19.8	14.2	14.2	10.9	7.1	7.1

Figure 8: Ontario Net Energy Demand across Demand Outlooks

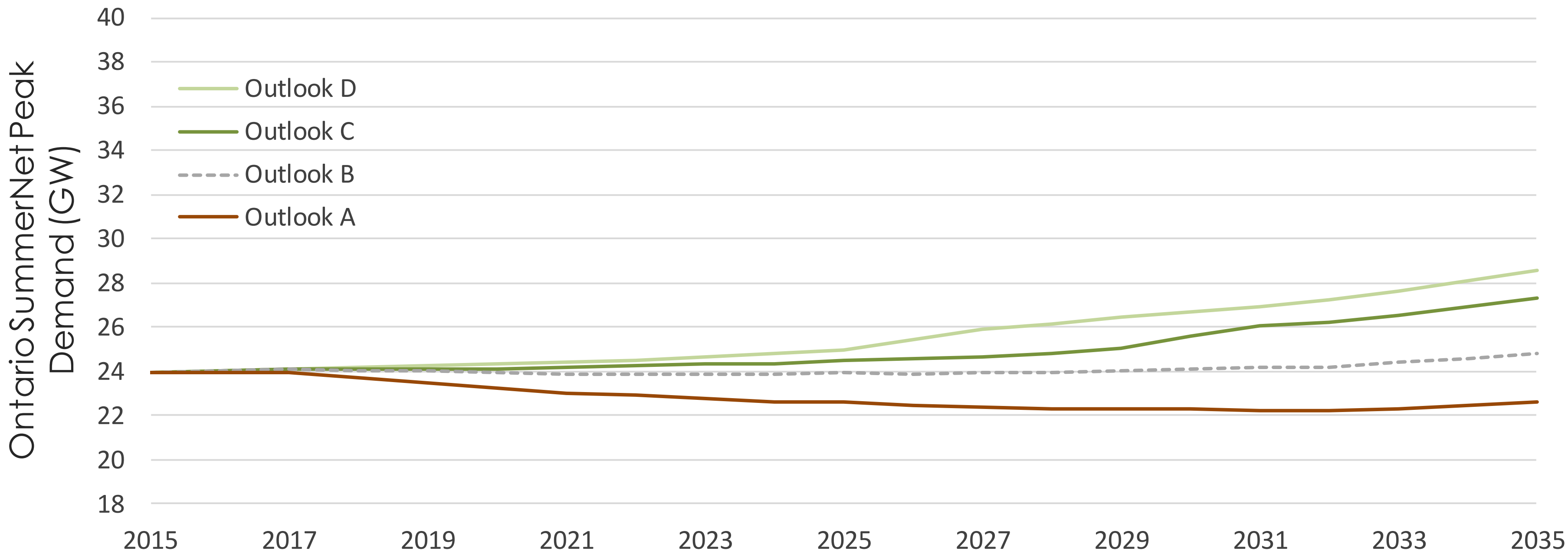


Data for Figure 8: Ontario Net Energy Demand across Demand Outlooks

Energy (TWh)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Outlook A	142.5	143.0	141.9	140.6	138.9	137.7	136.1	135.0	134.1	133.5	132.5
Outlook B	142.5	143.4	142.9	142.7	142.2	142.2	141.7	141.6	141.5	141.7	141.5
Outlook C	142.5	143.5	143.2	143.7	144.2	145.1	145.6	146.6	147.7	149.3	150.4
Outlook D	142.5	143.5	143.2	144.3	145.3	146.9	148.1	149.9	151.9	154.4	156.5

Energy (TWh)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Outlook A	131.7	131.2	131.0	130.8	130.7	130.7	131.0	131.5	132.3	133.4
Outlook B	141.2	141.5	142.1	142.4	142.8	143.3	144.0	145.0	146.3	147.8
Outlook C	151.7	153.5	155.9	158.0	160.5	163.1	166.2	169.4	173.1	177.1
Outlook D	158.8	161.7	165.3	168.6	172.4	176.3	181.0	185.6	191.0	196.7

Figure 9: Ontario Net Summer Peak Demand across Demand Outlooks



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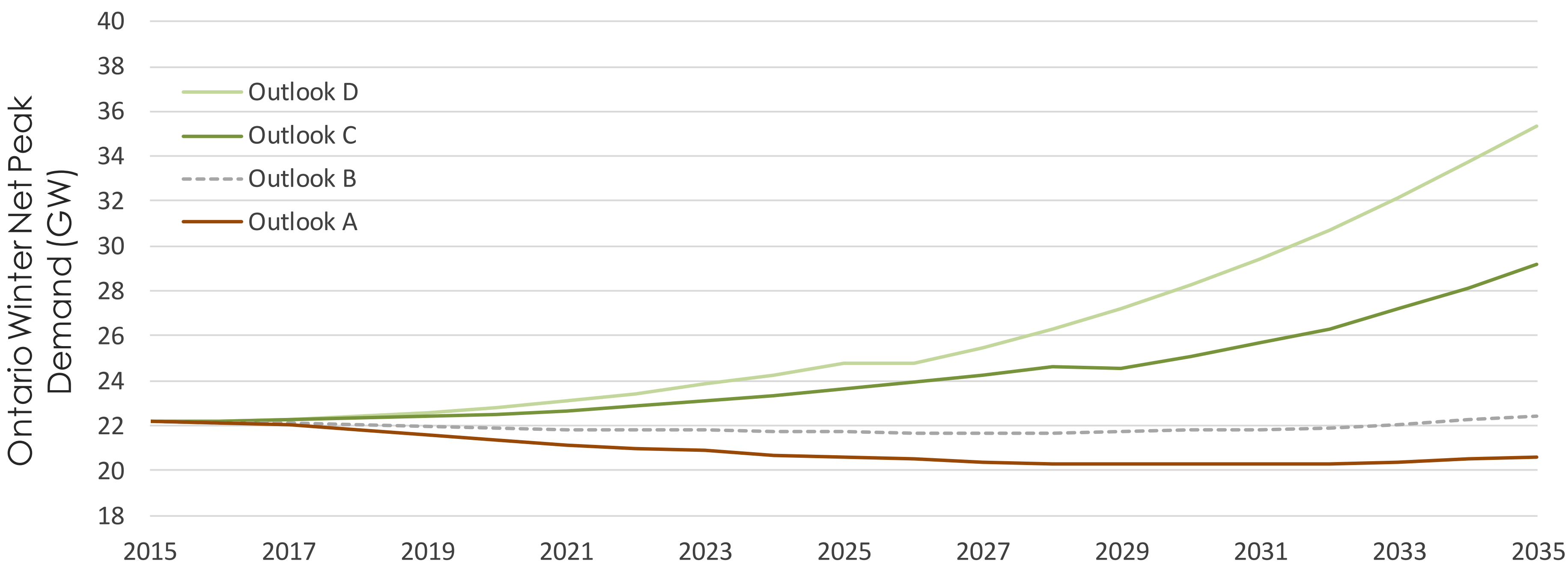
Data for Figure 9: Ontario Net Summer Peak Demand across Demand Outlooks

Summer Peak Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Outlook A	23,965	23,971	23,900	23,705	23,465	23,216	23,029	22,879	22,777	22,628	22,568
Outlook B	23,965	24,046	24,083	24,041	23,993	23,916	23,889	23,881	23,890	23,868	23,918
Outlook C	23,965	24,048	24,088	24,108	24,124	24,112	24,152	24,216	24,298	24,353	24,486
Outlook D	23,965	24,048	24,088	24,166	24,242	24,291	24,393	24,520	24,667	24,788	24,987

Summer Peak Demand (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Outlook A	22,453	22,372	22,295	22,292	22,258	22,231	22,198	22,317	22,436	22,586
Outlook B	23,882	23,918	23,940	24,030	24,082	24,133	24,171	24,369	24,568	24,792
Outlook C	24,549	24,680	24,804	25,049	25,550	26,022	26,199	26,551	26,902	27,276
Outlook D	25,446	25,921	26,124	26,410	26,667	26,937	27,197	27,633	28,071	28,532

Figure 10: Ontario Net Winter Peak Demand across Demand Outlooks



Data for Figure 10: Ontario Net Winter Peak Demand across Demand Outlooks

Winter Peak Demand (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Outlook A	22,159	22,093	22,020	21,825	21,574	21,338	21,143	20,976	20,864	20,694	20,602
Outlook B	22,159	22,140	22,143	22,072	21,985	21,898	21,841	21,799	21,778	21,718	21,718
Outlook C	22,159	22,190	22,251	22,315	22,395	22,501	22,661	22,863	23,105	23,326	23,626
Outlook D	22,159	22,190	22,251	22,385	22,560	22,783	23,083	23,442	23,862	24,273	24,779

Winter Peak Demand (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Outlook A	20,483	20,394	20,315	20,316	20,295	20,282	20,260	20,375	20,488	20,622
Outlook B	21,659	21,668	21,672	21,746	21,794	21,844	21,875	22,052	22,229	22,422
Outlook C	23,911	24,265	24,633	24,513	25,085	25,695	26,330	27,185	28,144	29,167
Outlook D	24,742	25,492	26,277	27,226	28,296	29,451	30,683	32,158	33,716	35,379

Table 1: Assumptions across Demand Outlooks

Sector	Outlook A	Outlook B	Outlook C	Outlook D
Residential (52 TWh in 2015)	48 TWh in 2035	51 TWh in 2035	Oil heating switches to heat pumps, electric space and water heating gain 25% of gas market share (58 TWh in 2035)*	Oil heating switches to heat pumps, electric space and water heating gain 50% of gas market share (64TWh in 2035)
Commercial (51 TWh in 2015)	49 TWh in 2035	54 TWh in 2035	Oil heating switches to heat pumps, electric space and water heating gain 25% of gas market share (63 TWh in 2035)	Oil heating switches to heat pumps, electric space and water heating gain 50% of gas market share (69 TWh in 2035)
Industrial (35 TWh in 2015)	29 TWh in 2035	35 TWh in 2035	5% of 2012 fossil energy switches to electric equivalent (43 TWh in 2035)	10% of 2012 fossil energy switches to electric equivalent (51 TWh in 2035)
Electric Vehicles (<1 TWh in 2015)	2 TWh in 2035	3 TWh in 2035	2.4 million electric vehicles (EVs) by 2035 (8 TWh in 2035)	2.4 million EVs by 2035 (8 TWh in 2035)
Transit (<1 TWh in 2015)	1 TWh in 2035	1 TWh in 2035	Planned projects, 2017-2035 (1 TWh in 2035)	Planned projects, 2017-2035 (1 TWh in 2035)
Other**	5 TWh	5 TWh	5 TWh	5 TWh
Total* (143 TWh in 2015)**	**133 TWh in 2035**	**148 TWh in 2035**	**177 TWh in 2035**	**197 TWh in 2035**

Note: Outlooks C and D assume the same economic drivers as Outlook B.
* By 2035, of the number of natural gas fuelled space and water heating equipment being sold in Outlook B (due to existing equipment reaching end of life and new additions driven by growth in the residential and commercial sectors), 25 percent of this stock in Outlook C and 50 percent in Outlook D is replaced with air-source heat pumps.
** Others = Agriculture, Remote Communities, Generator Demand, IEI and Street Lighting
*** Total may not add up due to rounding

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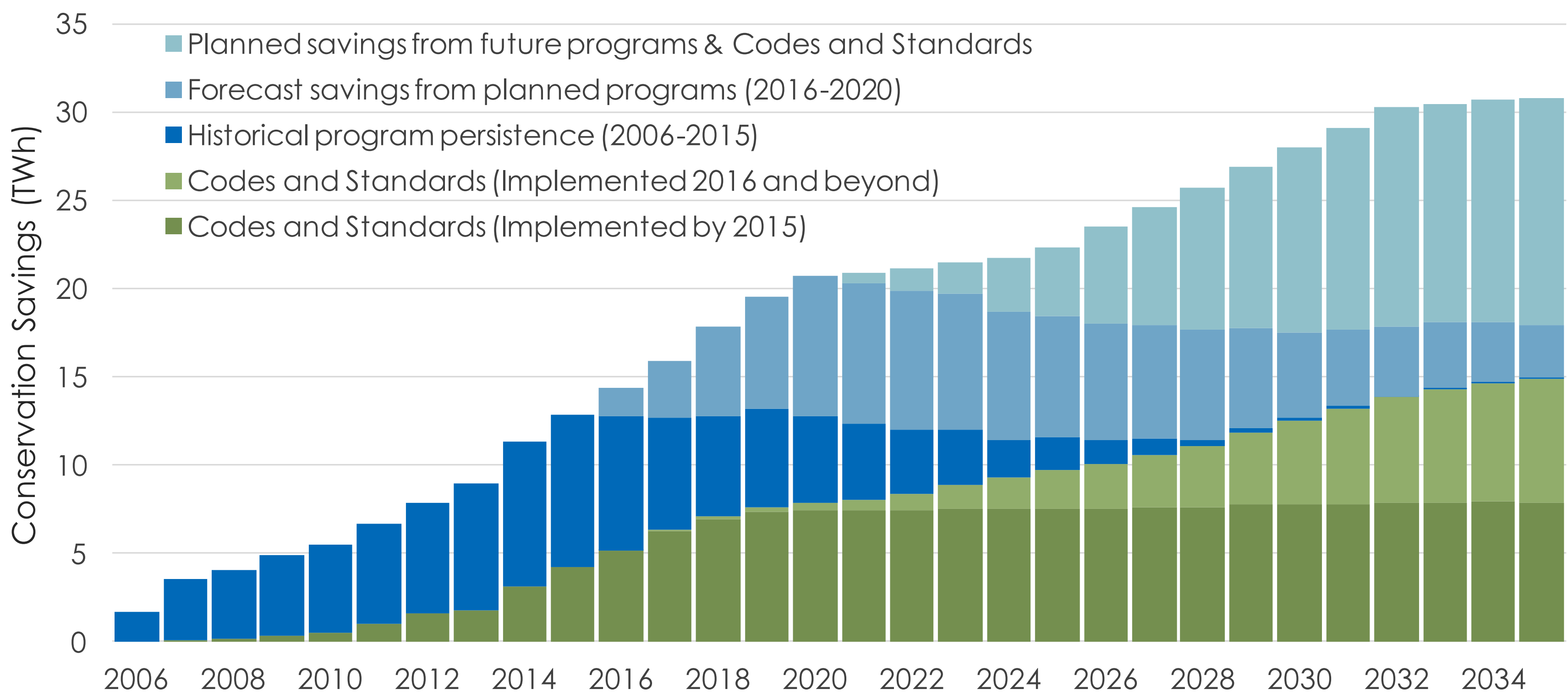
Figure 11: Conservation Achievement and Outlook to Meet the 2013 LTEP Target



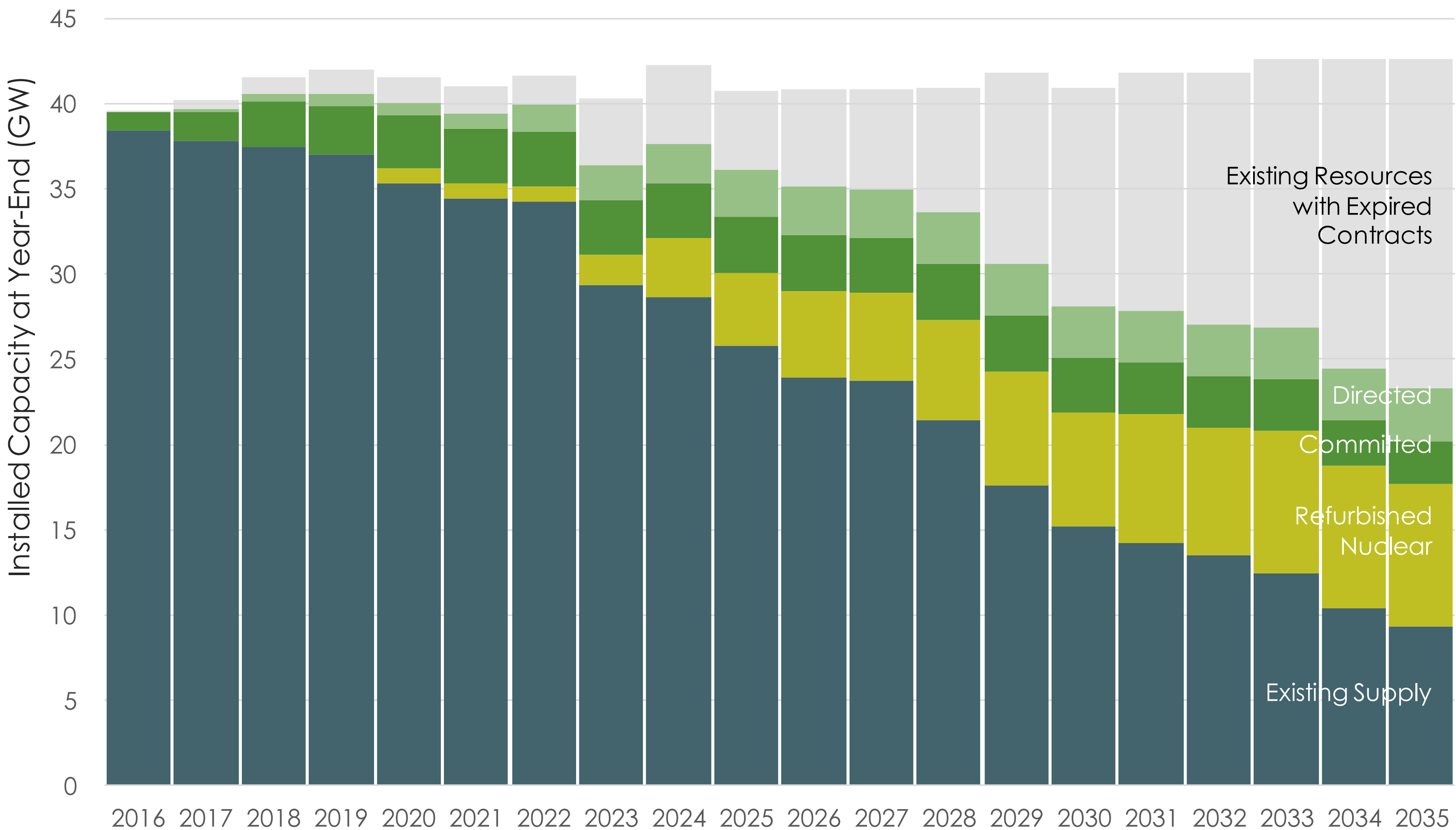
Data for Figure 11: Conservation Achievement and Outlook to Meet the 2013 LTEP Target

Savings (TWh)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Codes and Standards (Implemented by 2015)	-	0.1	0.2	0.3	0.5	1.0	1.6	1.8	3.1	4.2
Codes and Standards (Implemented 2016 and beyond)	-	-	-	-	-	-	-	-	-	-
Historical program persistence (2006-2015)	1.6	3.4	3.9	4.6	5.0	5.7	6.3	7.1	8.1	8.6
Forecast savings from planned programs (2016-2020)	-	-	-	-	-	-	-	-	-	-
Planned savings from future programs & Codes and Standards	-	-	-	-	-	-	-	-	-	-

Savings (TWh)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Codes and Standards (Implemented by 2015)	5.2	6.3	6.9	7.3	7.4	7.4	7.4	7.5	7.5	7.5
Codes and Standards (Implemented 2016 and beyond)	0.0	0.0	0.2	0.3	0.4	0.6	0.9	1.4	1.8	2.2
Historical program persistence (2006-2015)	7.5	6.4	5.7	5.5	4.9	4.4	3.6	3.1	2.1	1.9
Forecast savings from planned programs (2016-2020)	1.6	3.3	5.0	6.4	7.9	8.0	7.8	7.7	7.3	6.8
Planned savings from future programs & Codes and Standards	-	-	-	-	-	0.6	1.3	1.8	3.0	3.9

Savings (TWh)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Codes and Standards (Implemented by 2015)	7.5	7.6	7.6	7.7	7.8	7.8	7.8	7.8	7.9	7.9
Codes and Standards (Implemented 2016 and beyond)	2.6	3.0	3.4	4.1	4.8	5.4	6.0	6.4	6.7	7.0
Historical program persistence (2006-2015)	1.4	0.9	0.4	0.3	0.1	0.1	0.1	0.0	0.0	0.0
Forecast savings from planned programs (2016-2020)	6.6	6.4	6.2	5.7	4.8	4.3	4.0	3.7	3.4	3.0
Planned savings from future programs & Codes and Standards	5.5	6.7	8.1	9.1	10.5	11.5	12.4	12.4	12.6	12.8

Figure 12: Outlook for Installed Capacity to 2035

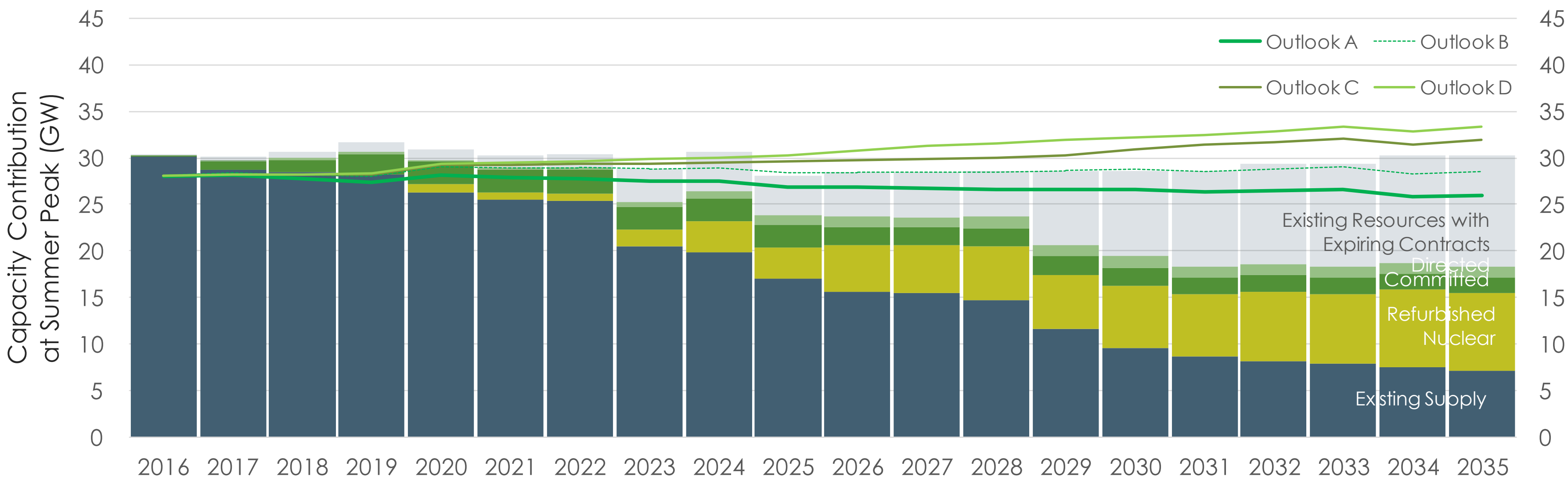


Data for Figure 12: Outlook for Installed Capacity to 2035

Installed Capacity (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Existing Supply	38,417	37,868	37,510	37,056	35,307	34,425	34,288	29,405	28,620	25,756
Committed, Not Yet Online	1,078	1,678	2,655	2,811	3,194	3,194	3,230	3,229	3,244	3,244
Directed Procurements	0	125	433	683	683	963	1,563	2,047	2,287	2,767
Expired Contracts	32	581	939	1,492	1,548	1,548	1,684	3,875	4,661	4,689
Refurbished Nuclear	0	0	0	0	881	881	881	1,762	3,465	4,346

Installed Capacity (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Existing Supply	23,903	23,789	21,440	17,599	15,155	14,254	13,471	12,443	10,401	9,345
Committed, Not Yet Online	3,244	3,244	3,244	3,239	3,238	3,021	3,021	2,991	2,696	2,517
Directed Procurements	2,855	2,855	3,033	3,033	3,033	3,033	3,033	3,033	3,033	3,033
Expired Contracts	5,719	5,832	7,376	11,221	12,843	13,961	14,744	15,803	18,140	19,375
Refurbished Nuclear	5,127	5,127	5,900	6,722	6,722	7,544	7,544	8,366	8,366	8,366

Figure 13a: Available Supply at the Time of Peak Demand Relative to Total Resource Requirements (Summer)



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Data for Figure 13a: Available Supply at the Time of Peak Demand Relative to Total Resource Requirements (Summer)

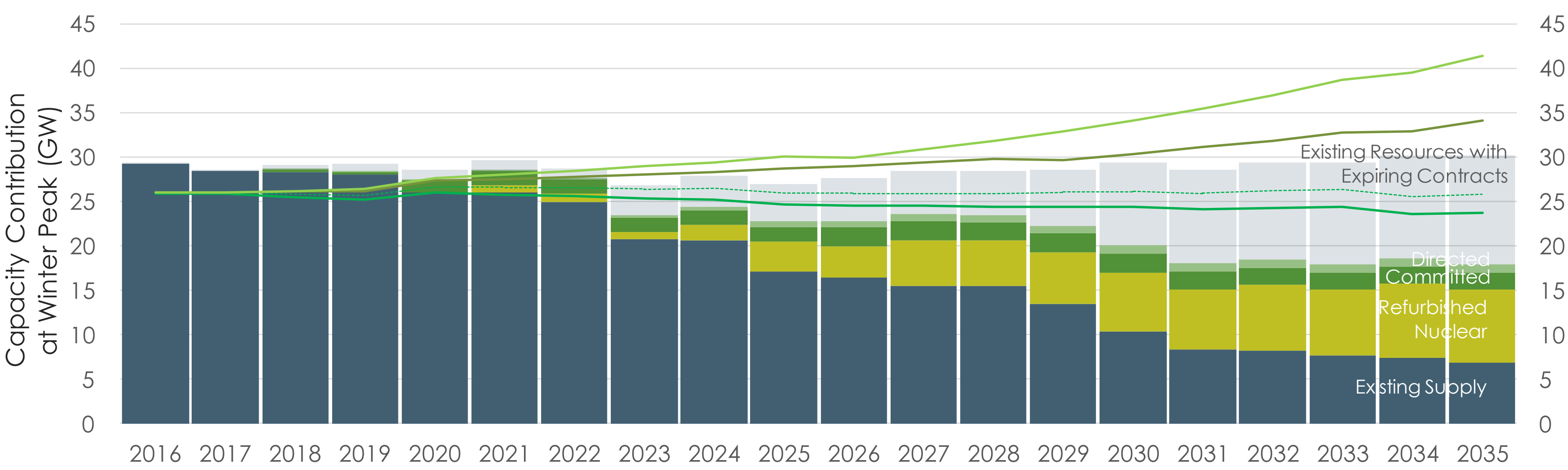
Capacity Contribution at Summer Peak (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Existing Supply	30,122	28,724	28,477	28,198	26,336	25,456	25,337	20,497	19,793	16,951
Refurbished Nuclear	0	0	0	0	878	878	878	1,756	3,453	3,453
Committed, Not Yet Online	183	899	1,305	2,147	2,360	2,427	2,451	2,451	2,452	2,452
Directed Procurements	0	17	199	318	136	255	315	559	752	993
Expired Contracts	31	477	725	1,087	1,252	1,263	1,381	3,560	4,265	4,276

Capacity Contribution at Summer Peak (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Existing Supply	15,558	15,510	14,666	11,601	9,596	8,682	8,128	7,904	7,503	7,145
Refurbished Nuclear	5,084	5,084	5,851	5,851	6,670	6,670	7,488	7,488	8,307	8,307
Committed, Not Yet Online	1,952	1,952	1,952	1,950	1,949	1,823	1,752	1,746	1,726	1,701
Directed Procurements	1,056	1,056	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176
Expired Contracts	4,850	4,898	4,940	8,009	9,195	10,235	10,861	11,091	11,511	11,894

Resource Requirement at Summer Peak (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Outlook A	28,070	28,130	27,711	27,383	28,186	27,944	27,769	27,649	27,475	26,953
Outlook B	28,157	28,345	28,104	28,000	29,006	28,950	28,941	28,951	28,925	28,505
Outlook C	28,137	28,183	28,207	28,225	29,212	29,258	29,332	29,429	29,493	29,648
Outlook D	28,137	28,183	28,275	28,363	29,421	29,540	29,689	29,861	30,002	30,235

Resource Requirement at Summer Peak (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Outlook A	26,821	26,728	26,639	26,636	26,597	26,565	26,527	26,664	25,802	25,973
Outlook B	28,465	28,505	28,531	28,635	28,694	28,753	28,796	29,024	28,253	28,510
Outlook C	29,723	29,876	30,021	30,307	30,894	31,445	31,653	32,065	31,476	31,912
Outlook D	30,772	31,327	31,566	31,900	32,200	32,517	32,821	33,331	32,843	33,383

Figure 13b: Available Supply at the Time of Peak Demand Relative to Total Resource Requirements (Winter)



Data for Figure 13b: Available Supply at the Time of Peak Demand Relative to Total Resource Requirements (Winter)

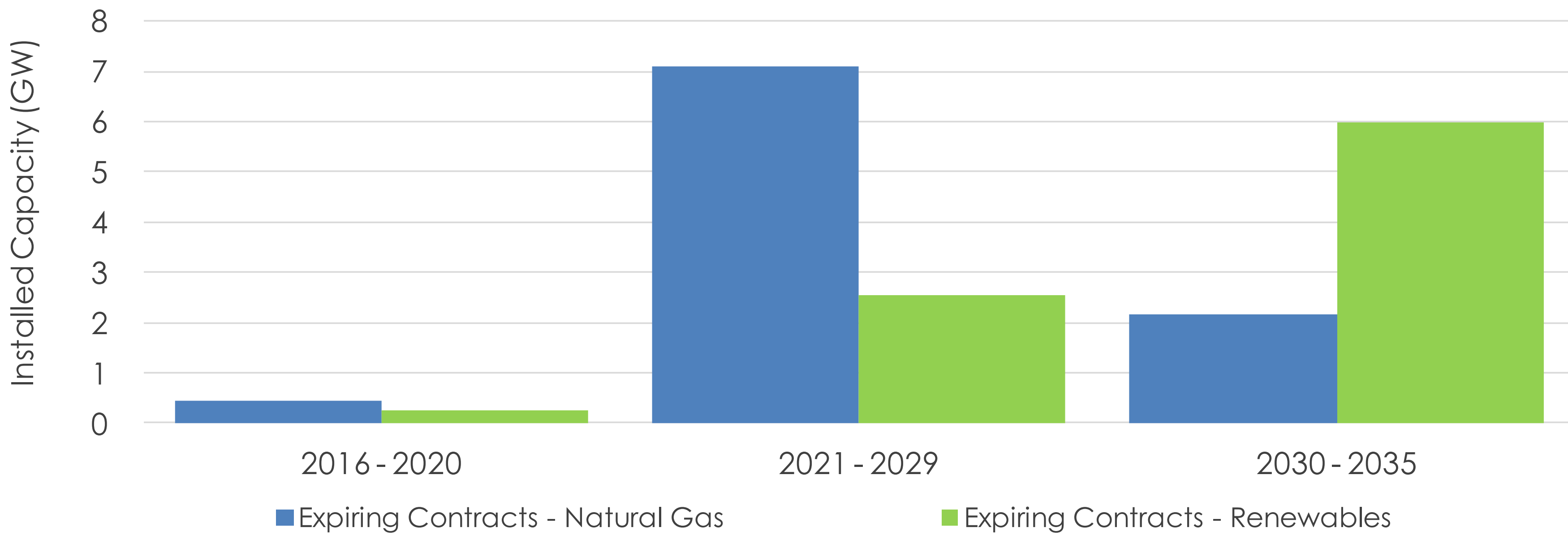
Capacity Contribution at Winter Peak (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Existing Supply	29,268	28,448	28,239	27,981	26,020	25,980	24,983	20,696	20,649	17,057
Refurbished Nuclear	0	0	0	0	0	878	878	878	1,756	3,453
Committed, Not Yet Online	0	0	314	349	1,279	1,587	1,587	1,614	1,613	1,617
Directed Procurements	0	0	2	99	157	8	49	200	367	573
Expired Contracts	31	151	512	769	1,100	1,149	1,267	3,408	3,456	4,216

Capacity Contribution at Winter Peak (MW)	2,026	2,027	2,028	2,029	2,030	2,031	2,032	2,033	2,034	2,035
Existing Supply	16,459	15,525	15,471	13,385	10,337	8,366	8,128	7,633	7,384	6,814
Refurbished Nuclear	3,453	5,084	5,084	5,851	6,670	6,670	7,488	7,488	8,307	8,307
Committed, Not Yet Online	2,117	2,117	2,117	2,114	2,113	2,113	1,906	1,902	1,895	1,790
Directed Procurements	741	807	791	936	936	936	936	936	936	936
Expired Contracts	4,815	4,929	5,000	6,271	9,320	10,472	10,917	11,416	11,672	12,347

Resource Requirement at Winter Peak (MW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Outlook A	25,870	25,917	25,514	25,176	25,987	25,737	25,542	25,411	25,212	24,693
Outlook B	25,926	26,063	25,802	25,657	26,643	26,554	26,505	26,480	26,411	25,975
Outlook C	25,962	26,033	26,108	26,202	27,326	27,514	27,749	28,033	28,292	28,643
Outlook D	25,962	26,033	26,191	26,395	27,656	28,007	28,428	28,918	29,399	29,992

Resource Requirement at Winter Peak (MW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Outlook A	24,555	24,453	24,363	24,364	24,339	24,325	24,299	24,431	23,561	23,715
Outlook B	25,908	25,919	25,922	26,008	26,063	26,120	26,156	26,359	25,563	25,785
Outlook C	28,976	29,390	29,820	29,680	30,349	31,063	31,806	32,806	32,928	34,125
Outlook D	29,948	30,826	31,745	32,854	34,106	35,457	36,899	38,625	39,448	41,393

Figure 14: Installed Capacity of Future Contract Expirations



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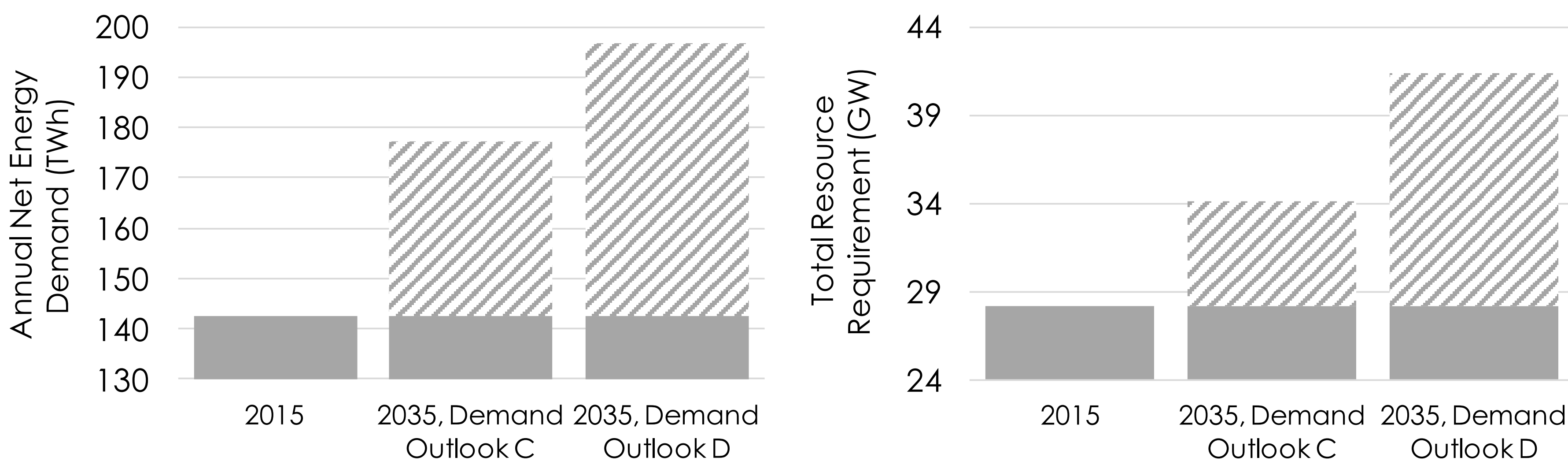
Data for Figure 14: Installed Capacity of Future Contract Expirations

(MW)	2016 - 2020	2021 - 2029	2030 - 2035
Expiring Contracts - Natural Gas	449	7,106	2,161
Expiring Contracts - Renewables	238	2,550	5,993
TOTAL	*687*	*9,656*	*8,154*

Figure 15: Electricity Supply Requirements in Outlooks C and D



Data for Figure 15: Electricity Supply Requirements in Outlooks C and D

	2015	**2035, Outlook C**	**2035, Outlook D**
Annual Energy (TWh)	142.5	177.1	196.7
Total Resource Requirement (MW)	28,157	34,125	41,393

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Table 2: Current Technology Characteristics

	Capacity	Energy	Operating Reserve	Load Following	Frequency Regulation	Capacity Factor	Contribution to Winter Peak	Contribution to Summer Peak	LUEC ($/MWh)
Conservation	Yes	Yes	No	No	No	Depends on Measure	Depends on Measure	Depends on Measure	$30-50
Demand Response	Yes	No	Yes	Yes	Limited	N/A	60-70%	80-85%	N/A
Solar PV	Limited	Yes	No	Limited	No	15%	3-5%	20-35%	$140-290
Wind	Limited	Yes	No	Limited	No	30-40%	20-30%	11%	$65-210
Bioenergy	Yes	Yes	Yes	Limited	No	40-80%	85-90%	85-90%	$160-260
Storage	Yes	No	Yes	Yes	Yes	Depends on technology/ application	Depends on technology/ application	Depends on technology/ application	Depends on technology/ application
Waterpower	Yes	Yes	Yes	Yes	Yes	30-70%	67-75%	63-71%	$120-240
Nuclear	Yes	Yes	No	Limited	No	70-95%	90-95%	95-99%	$120-290
Natural Gas	Yes	Yes	Yes	Yes	Yes	up to 65%	95%	89%	$80-310

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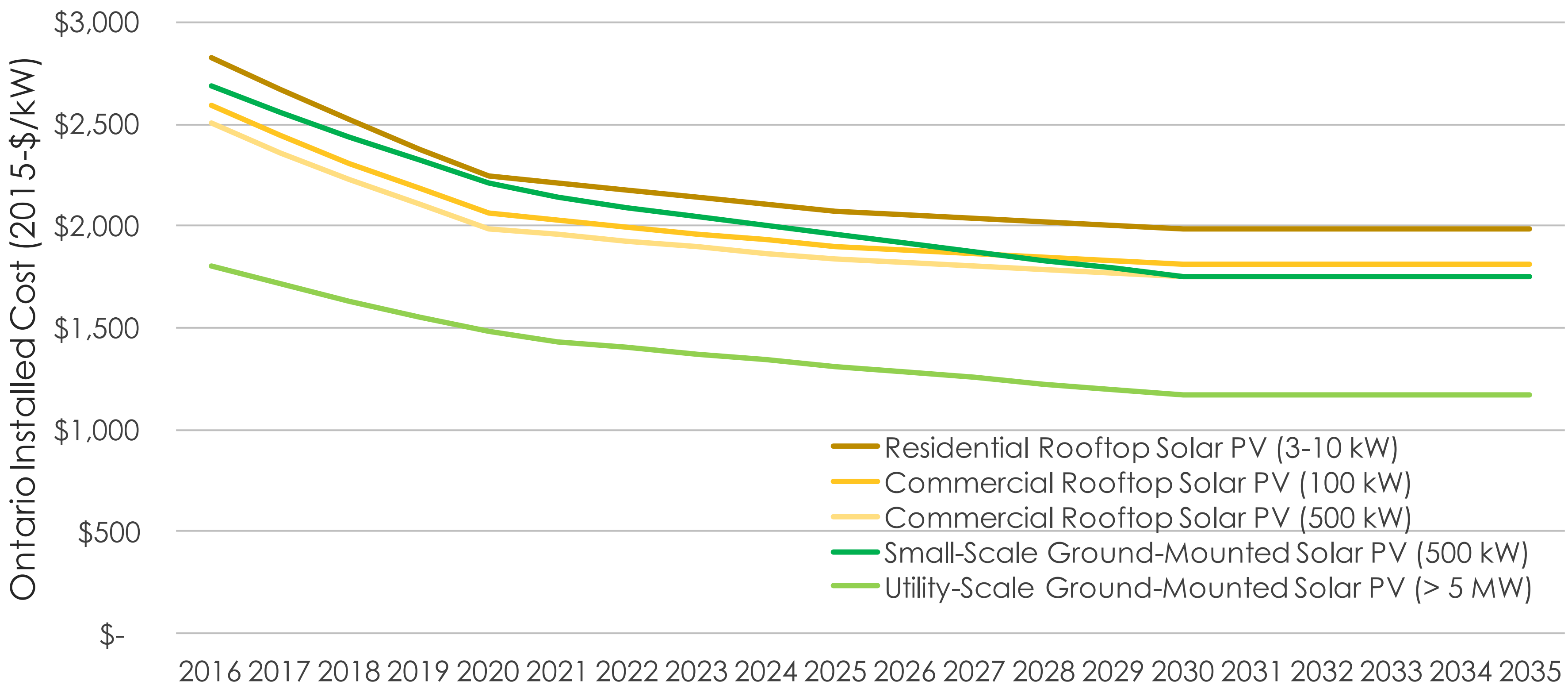
Figure 16: Installed Solar PV Cost Projections in Ontario



Data for Figure 16: Installed Solar PV Cost Projections in Ontario

Installed Cost ($/kW)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential Rooftop Solar PV (3-10 kW)	2,828	2,670	2,521	2,380	2,246	2,211	2,176	2,142	2,109	2,075
Commercial Rooftop Solar PV (100 kW)	2,592	2,447	2,310	2,181	2,059	2,026	1,995	1,963	1,932	1,902
Commercial Rooftop Solar PV (500 kW)	2,502	2,362	2,230	2,105	1,987	1,956	1,926	1,895	1,866	1,836
Small-Scale Ground-Mounted Solar PV (500 kW)	2,689	2,560	2,437	2,320	2,209	2,140	2,092	2,046	2,000	1,956
Utility-Scale Ground-Mounted Solar PV (> 5 MW)	1,800	1,714	1,631	1,553	1,478	1,432	1,400	1,369	1,339	1,309

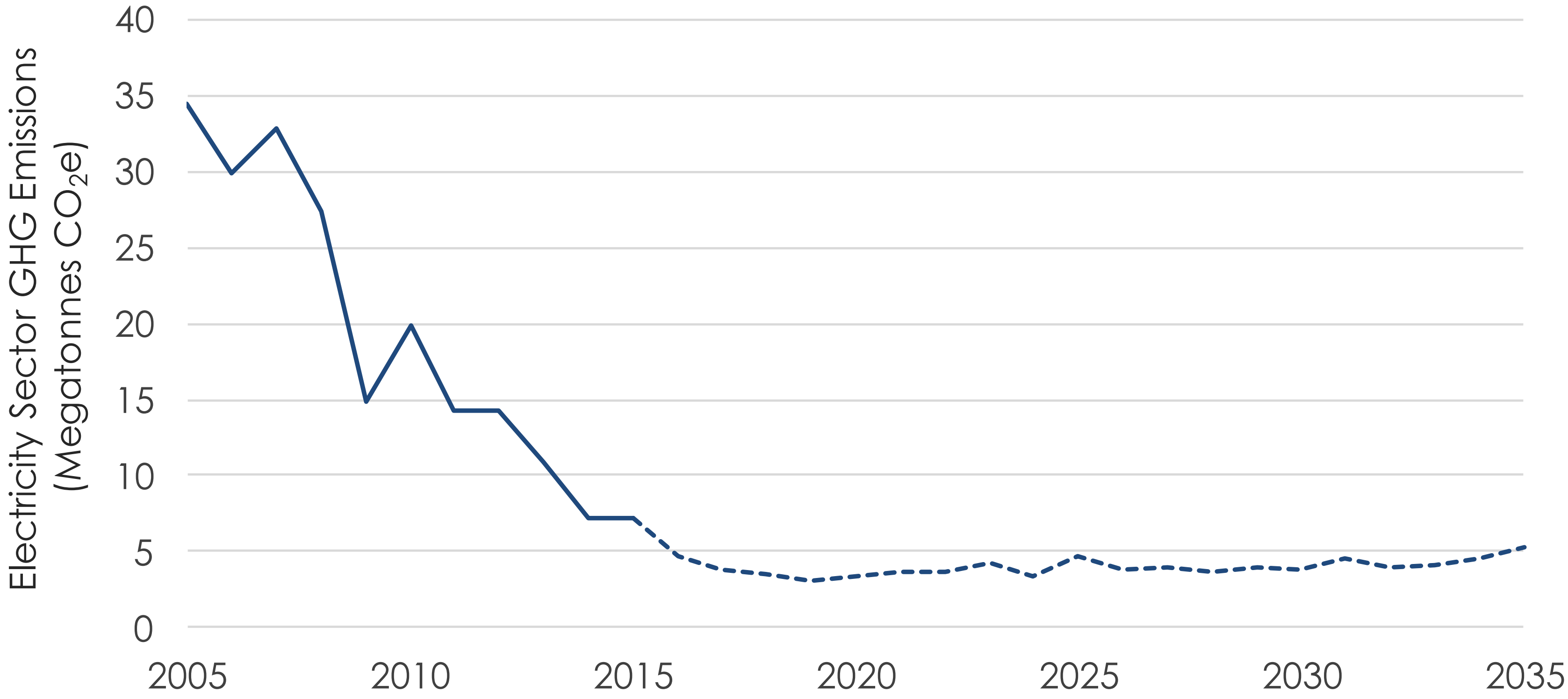
Installed Cost ($/kW)	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Residential Rooftop Solar PV (3-10 kW)	2,056	2,037	2,018	1,999	1,981	1,981	1,981	1,981	1,981	1,981
Commercial Rooftop Solar PV (100 kW)	1,884	1,867	1,850	1,832	1,815	1,815	1,815	1,815	1,815	1,815
Commercial Rooftop Solar PV (500 kW)	1,819	1,802	1,785	1,769	1,752	1,752	1,752	1,752	1,752	1,752
Small-Scale Ground-Mounted Solar PV (500 kW)	1,914	1,872	1,832	1,792	1,753	1,753	1,753	1,753	1,753	1,753
Utility-Scale Ground-Mounted Solar PV (> 5 MW)	1,281	1,253	1,226	1,199	1,173	1,173	1,173	1,173	1,173	1,173

Figure 17: Existing Interconnections

Table 3: Status and Drivers of Transmission Projects in Outlook B

Projects	Status	Drivers			
		Maintaining Bulk System Reliability	Addressing Regional Reliability and Adequacy Needs	Achieving 2013 Long-Term Energy Plan (LTEP) Policy Objectives	Facilitating Interconnections with Neighbouring Jurisdictions
East-West Tie Expansion	Expected to be in service in 2020	X		X	
Line to Pickle Lake	Plan is complete; Expected to be in service in early 2020.		X	X	
Remote Community Connection Plan	Draft technical report released; development work underway for connection of 16 communities; engagement with communities is ongoing.		X	X	
Northwest Bulk Transmission Line	Hydro One is carrying out early development work to maintain the viability of the option.	X		X	
Supply to Essex County Transmission Reinforcement	Expected In-service date of 2018		X		
West GTA Bulk reinforcement	Plan is being finalized.	X			
Guelph Area Transmission Refurbishment	Expected to be in service in 2016		X		
Remedial Action Scheme (RAS) in Bruce and Northwest	Under development. Northwest RAS targeted for late 2016 in-service; Bruce RAS early 2017	X			
Clarington 500/230kV transformers	Expected to be in service in 2018	X			
Ottawa Area Transmission Reinforcement	Project has been initiated; expected to be in service 2020.		X		X
Richview to Manby Transmission Reinforcement	Expected to be in service in 2020		X		

Figure 18: Electricity Sector GHG Emissions in Outlook B



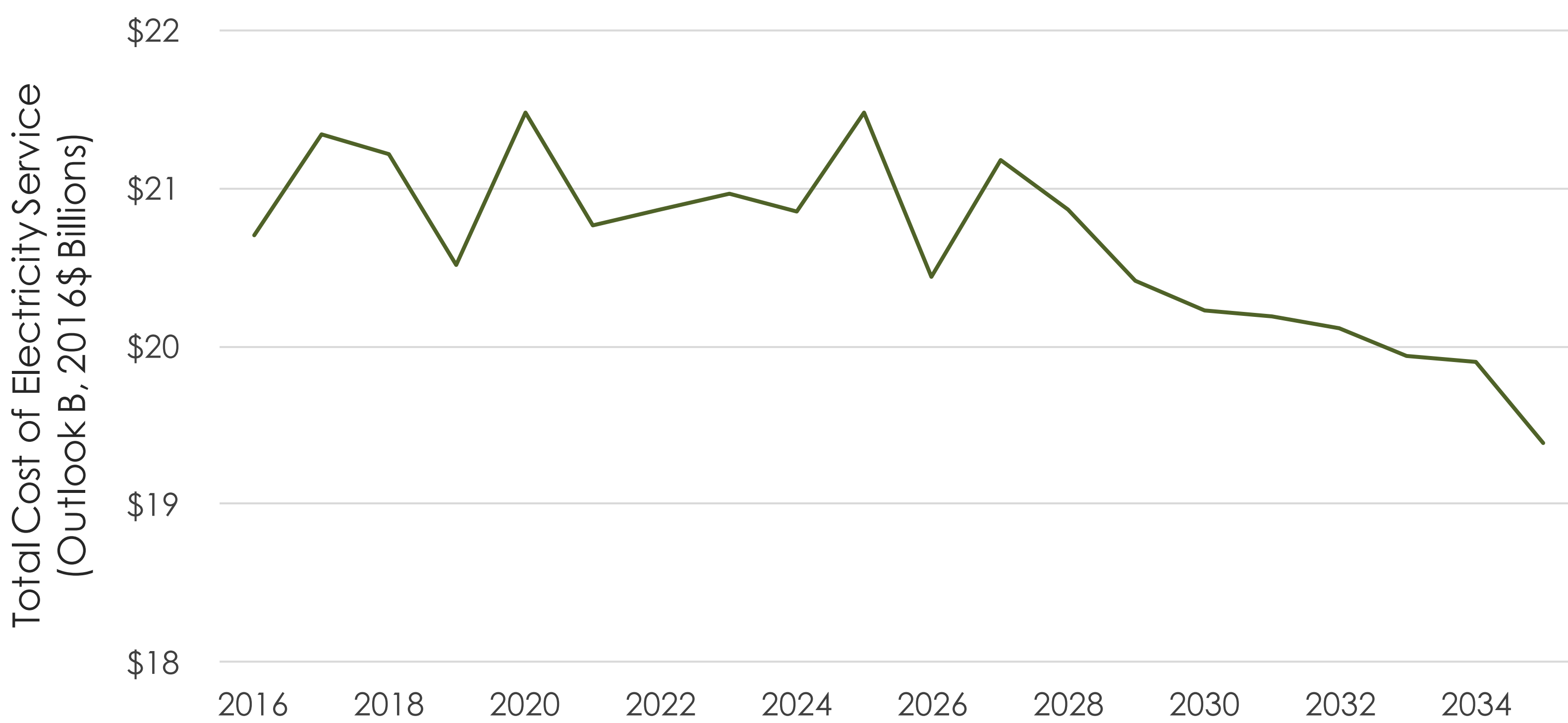
Data for Figure 18: Electricity Sector GHG Emissions in Outlook B

MT CO2e	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Electricity Sector GHG Emissions	34.5	29.9	32.9	27.4	14.9	19.8	14.2	14.2	10.9	7.1	7.1

MT CO2e	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Forecast GHG Emissions (Outlook B)	4.6	3.8	3.5	3.1	3.4	3.6	3.7	4.2	3.4	4.7

MT CO2e	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Forecast GHG Emissions (Outlook B)	3.8	3.9	3.7	3.9	3.8	4.5	4.0	4.2	4.6	5.3

Figure 19: Total Cost of Electricity Service in Outlook B

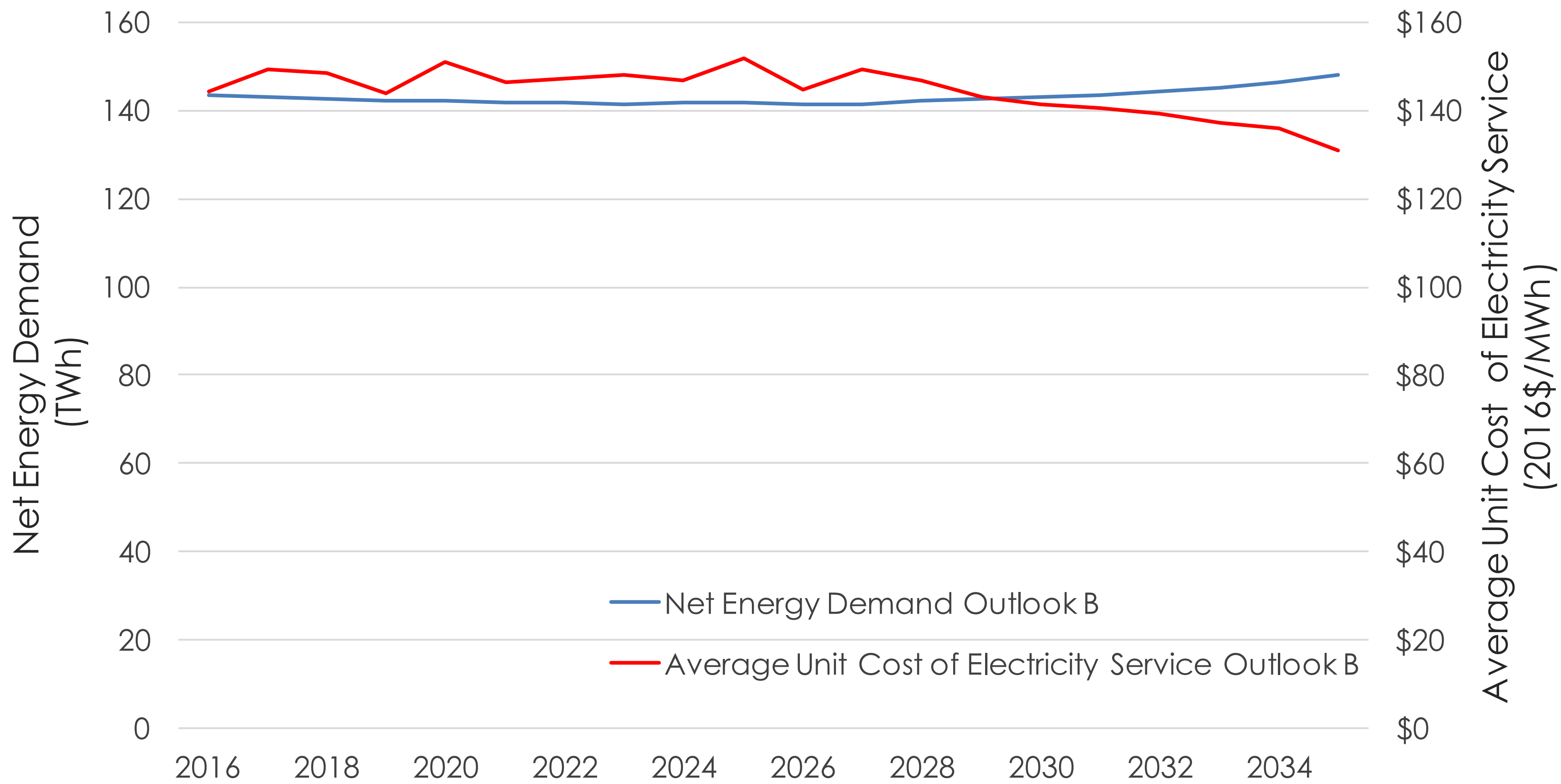


Data for Figure 19: Total Cost of Electricity Service in Outlook B

Total Cost of Electricity Service (2016$ Billions)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Outlook B	20.7	21.3	21.2	20.5	21.5	20.8	20.9	21.0	20.9	21.5

Total Cost of Electricity Service (2016$ Billions)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Outlook B	20.4	21.2	20.9	20.4	20.2	20.2	20.1	19.9	19.9	19.4

Figure 20: Average Unit Cost of Electricity Service in Outlook B



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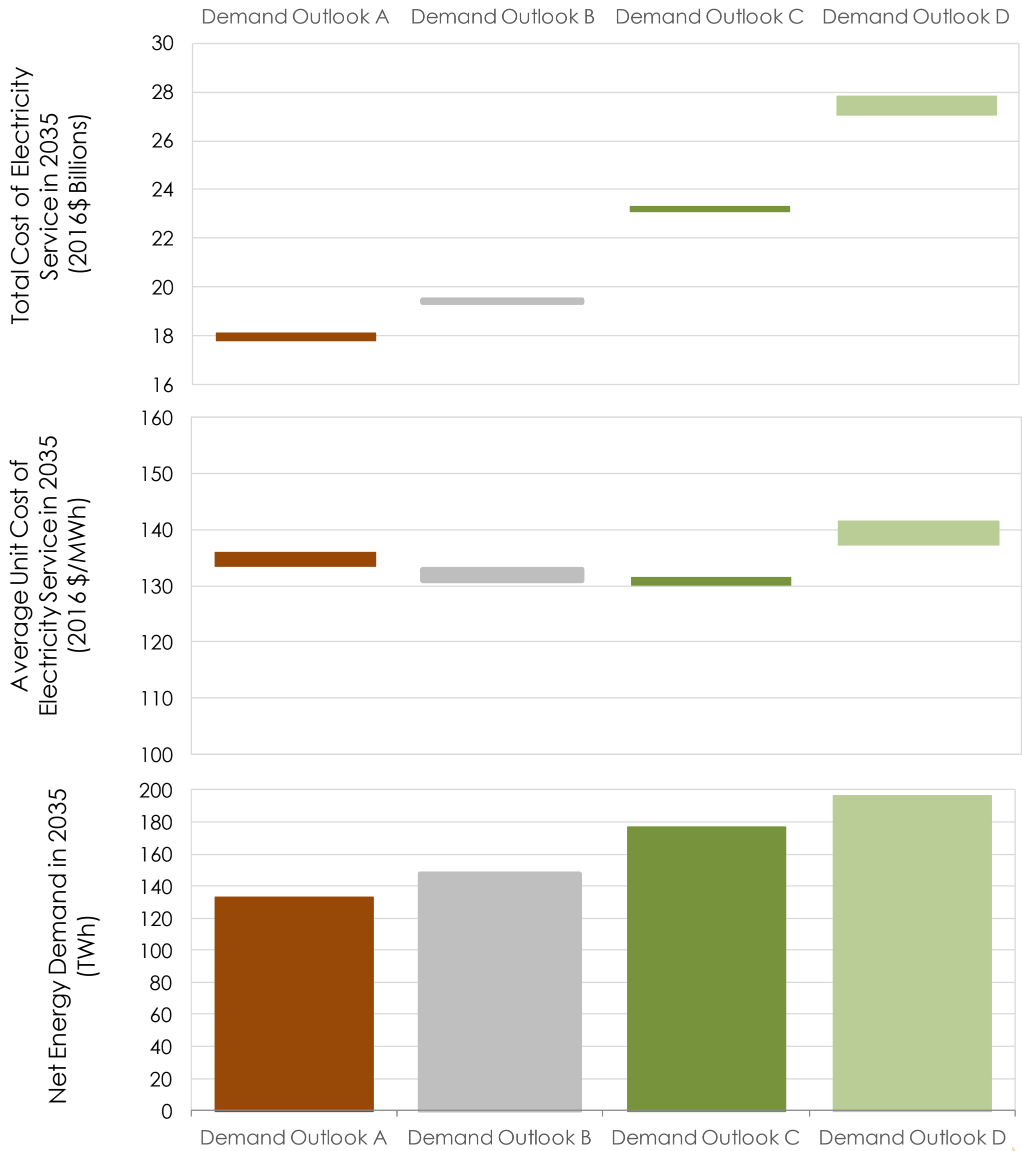
Data for Figure 20: Average Unit Cost of Electricity Service in Outlook B

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Demand Outlook - B (TWh)	143.5	143.0	142.8	142.4	142.4	141.9	141.7	141.6	141.9	141.7
Average Unit Cost - B (2016$/MWh)	144.3	149.2	148.6	144.1	150.9	146.4	147.2	148.0	147.0	151.7

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Demand Outlook - B (TWh)	141.4	141.6	142.2	142.5	143.0	143.4	144.2	145.1	146.5	148.0
Average Unit Cost - B (2016$/MWh)	144.6	149.5	146.8	143.3	141.4	140.8	139.5	137.4	135.9	131.0

Figure 21: Cost of Electricity Service across Demand Outlooks



Data for Figure 21: Cost of Electricity Service across Demand Outlooks

	Outlook A	Outlook B	Outlook C	Outlook D
Minimum System Cost (2016$ Billions)	17.8	19.4	23.1	27.1
Maximum System Cost (2016$ Billions)	18.2	19.4	23.3	27.9
Minimum Unit Cost (2016$/MWh)	134	131	130	137
Maximum Unit Cost (2016$/MWh)	136	131	132	142
Energy Demand in 2035 (TWh)	133	148	177	197

VECC INTERROGATORY 19

EXHIBIT B

Issue 2.0

INTERROGATORY

Reference: Exhibit B, Tab 1, Schedule 1, Page 3 of 11

a) Please explain why embedded generation was included in the past put is proposed to be removed now.

b) Please show the usage fees with and without proposed embedded generation removal

RESPONSE

a) Embedded generation was included in past calculations for forecast losses as the IESO had only one usage fee which was charged to all its customers and therefore only one customer class. As the IESO now has two customer classes with different demand forecasts, it was seen as reasonable to not include embedded generation when calculating and attributing transmission losses as embedded generation is generated and consumed within the LDC's distribution area.

b) As the OEB approved the recovery of the IESO's fee from embedded generation in EB-2013-0275, an IESO usage fee without embedded generation is not relevant in this proceeding.

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VECC INTERROGATORY 20

EXHIBIT B

Issue 2.0

INTERROGATORY

Reference: Exhibit B, Tab 1, Schedule 1, Page 3 of 11

a) Please explain how the domestic and export 2017 demand is derived.

b) Please provide the first 6 month demand for 2017 and the forecast demand for the same period.

c) Please explain how the allocation of losses to the domestic and export customers are calculated.

RESPONSE

a) As described in response to OEB Staff Interrogatory 2 in the IESO's 2016 Revenue Requirement Submission, EB-2015-0275, Ontario demand and embedded generation forecasts are derived from the IESO's 'Ontario Demand Forecast' created as part of development of the 18 Month Outlook. Please refer to Attachment 1 for more detail about the latest 18-month forecast of electricity demand for Ontario.

   A forecast of export volumes is created by the IESO for the purpose of its revenue requirement submission. Export forecasts are a rolling three year average by month, adjusted for unusual market conditions.

b) Please refer to the response to VECC Interrogatory 3 at Exhibit I, Tab 2.0, Schedule 9.03.

c) The IESO has proposed to split losses between domestic and export customer classes based on their proportion of the total 2017 forecast energy volumes before losses. The calculation for losses for each of domestic and export customers is shown in Table 2 on page 3 of Exhibit B-1-1.

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Ontario Demand Forecast

JUNE 22, 2017

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Executive Summary

The IESO is responsible for forecasting electricity demand in Ontario and for assessing whether transmission and generation facilities are adequate to meet Ontario's needs. This document presents the electricity demand forecast for the period from July 2017 to December 2018 and supersedes the previous forecast released in March 2017.

Economic Outlook

Currently, most experts look for Ontario to be at, or near the top, in terms of provincial growth. The expectations are that Ontario will lead in both Gross Domestic Product (GDP) and employment. Ontario had been near, or at the top in growth, the past two years and that has not translated into increased growth for electricity. Both British Columbia and Ontario have led the nation in growth, primarily a result of their strong housing markets, though this has had little impact on electricity demand – more homes will create demand as the housing stock grows, but the impact is relatively small.

Recent data suggests that economic growth will lead to increased electricity demand. Job growth has been across all sectors and across the province, not strictly in the GTA. Broad based job growth across sectors and regions signifies a more sustainable and balanced economic growth pattern. This makes it more robust and less susceptible to shocks or cycles. Manufacturing employment growth and increased factory orders for goods signify growth in the industrial sector which will have a more direct impact on energy demand.

Canada continues to have great economic fundamentals that will help encourage economic expansion. Despite potential increases to interest rates in the near future, they still remain historically low. Inflation is not a threat and debt levels for consumers and business are generally manageable. Add in a low Canadian dollar and strong U.S. economy and Ontario is positioned to see strong export demand. However, there remains significant downside risk.

The renegotiation of NAFTA would not impact all provinces equally. Ontario would be vulnerable to protectionist measures that would inhibit the trade of manufactured goods. Fortunately, Canada has endeavored to expand its export markets with the CETA and TPP. However, the benefits of those agreements are a number of years off while the negative aspects of renegotiating NAFTA could be closer at hand.

Actual Weather and Demand

Since the last Ontario Demand Forecast document was published, actual demand reported for the six months of December through May was down 1.7 percent over the same period a year earlier. After adjusting for changes in the weather and the additional leap year day in last year's data, the growth rate is relatively unchanged at -1.6 percent.

For the past six months, distributor loads have dropped by 1.9 percent compared to the same months a year earlier. Distributor loads see the direct impact of conservation and the growth in embedded generation production, which contributes to the year-over-year drop. Once again, after adjusting for weather and the leap day, the year-over-year change was a reduction of 1.3 percent.

Wholesale customers' consumption decreased by 1.2 percent. Here the impact of the leap day is a little more pronounced and the adjusted change is a 0.6 percent decline. Declines in the pulp and paper sector accounted for much of the decline whereas the other sectors remained fairly flat.

The 2016-17 winter peak demand occurred on December 15, which was the third coldest day of the month. Both January and February were milder than normal and January's coldest days were buried on a weekend. Thus the winter peak landed in December for the first time since the winter of 2005-06. In both cases, the weather-corrected winter peak was pushed back to the following January indicating it was a function of January's mild weather.

The weather over the course of the spring was a bit of a mixed bag. March and May were cooler than normal while April was warmer than normal. Additionally, the amount of precipitation set records across the province. The peak occurred in March which is typical in spring unless there is a hot spell at the end of May. Since spring peaks can be either cold- or warm-weather driven, the timing of weather plays a key role. In the case of spring 2017, the cold temperatures of early March (-8.1°C) had a much bigger impact than the warm temperatures of late May (29.6°C). This seems to be the pattern over the last couple of years as the winter weather has been mild – particularly at the beginning of winter – with cold weather drifting into early spring. Recent spring weather has been cooler than normal.

Demand Forecast

In the 18-Month Outlook, the impacts of conservation, embedded generation and prices are incorporated into the demand forecast, resulting in reducing demand. Conversely, demand response programs are included in this analysis as a resource under the category of demand measures. Load modifiers – conservation, embedded generation and prices – and demand measures are discussed in section 4.4 of this document.

Table 1 summarizes the annual peak and energy demand forecast for the period covered in this 18-month forecast. Summer peaks are expected to continue their downward trajectory over the forecast. Though winter peaks will face downward pressure from gains in lighting efficiency and embedded wind generation, summer peaks will face greater downward pressure from numerous sources – improved air conditioning efficiency, the expanded Industrial Conservation Initiative (ICI) impacts and growth in solar embedded generation.

Grid-supplied energy demand is expected to show a small decrease in 2016 as weak actual demand through the first part of the year impacts the growth rate. An improving economy and increased industrial activity is expected to lead to a small rebound in 2018.

Table 1: Peak and Energy Demand Forecast

Season	Normal Weather Peak (MW)	Extreme Weather Peak (MW)
Summer 2017	22,493	24,880
Winter 2017-18	21,727	22,884
Summer 2018	22,381	24,709
Year	**Normal Weather Energy (TWh)**	**% Growth in Energy**
2006	152.3	-1.9%
2007	151.6	-0.5%
2008	148.9	-1.8%
2009	140.4	-5.7%
2010	142.1	1.2%
2011	141.2	-0.6%
2012	141.3	0.1%
2013	140.5	-0.6%
2014	138.9	-1.1%
2015	136.2	-1.9%
2016	136.2	0.0%
2017 (Forecast)	135.4	-0.6%
2018 (Forecast)	136.4	0.7%

- End of Section

Caution and Disclaimer

Table of Contents

List of Tables

List of Figures

1.0 Introduction

1.1 Outlook Documents

The Ontario Electricity Market Rules (Chapter 5 Section 7.1) require that a demand forecast for the next 18 months be produced and published on a quarterly basis. This Ontario Demand Forecast meets this requirement and covers the period from July 2017 to December 2018. It supersedes the previous forecast released in March 2017 and the previous Ontario Demand Forecast document released in December 2016.

1.2 Demand Forecast Document

This document provides an 18-month forecast of electricity demand for Ontario, based on the stated assumptions and using the methodology described in the document "Methodology to Perform Long-Term Assessments," found on the IESO website at http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/methodology_rtaa_2017jun.pdf. Readers may envision other scenarios, recognizing the uncertainties associated with various input assumptions, and are encouraged to use their own judgement in considering possible future scenarios. This forecast provides a base upon which changes in assumptions can be considered.

Ontario demand is the sum of coincident loads plus the losses on the IESO-controlled grid. This demand forecast was based on actual demand, weather and economic data through the end of March 2017. Data for April and May have been incorporated into the tables and figures of this document. This document is divided into the following sections:

Section 2.0 summarizes the forecast results

Section 3.0 looks at historical demand

Section 4.0 describes the assumptions used in this forecast of electricity demand.

All the tables in this report are contained in the 18-Month Outlook Tables (http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/18monthoutlooktables_2017jun.xls) spreadsheet posted alongside the Outlook documents. The spreadsheet's historical tables contain data back to market opening, which would not be practical in a printed document.

Readers are invited to provide comments or suggestions regarding the content of this or future reports. To do so, please call the IESO Customer Relations at 905-403-6900 or 1-888-448-7777 or send an email to customer.relations@ieso.ca.

Electronic copies of the forecast and weather scenarios are available upon request.

- End of Section -

2.0 Demand Forecast

This section presents the demand forecast for the Outlook period. Additional tables are included in the 18-Month Outlook Tables spreadsheet.

Table 2.1 contains the forecast of system weekly peak, energy demand and the load forecast uncertainty (LFU) for the weekly peak. The LFU is a measure of variability in load due to the volatility of weather. Figures 2.1 and 2.2 show the historical weekly energy and peak demand along with the projected forecast.

Table 2.1: Weekly Peak and Energy Demand Forecast

Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)	Week Ending	Normal Peak (MW)	Extreme Peak (MW)	Load Forecast Uncertainty (MW)	Normal Energy Demand (GWh)
02-Jul-17	22,058	23,891	1,016	2,642					
09-Jul-17	22,493	24,880	814	2,740	08-Apr-18	17,836	18,373	471	2,489
16-Jul-17	22,099	23,805	838	2,772	15-Apr-18	17,095	18,065	496	2,433
23-Jul-17	21,892	23,787	1,035	2,669	22-Apr-18	16,648	16,875	531	2,392
30-Jul-17	21,931	24,614	841	2,754	29-Apr-18	16,650	17,036	721	2,371
06-Aug-17	22,376	24,569	958	2,774	06-May-18	17,533	20,176	849	2,344
13-Aug-17	21,966	24,628	985	2,728	13-May-18	17,377	19,714	845	2,358
20-Aug-17	21,241	24,385	1,362	2,704	20-May-18	18,508	21,795	1,175	2,386
27-Aug-17	21,389	23,409	1,413	2,707	27-May-18	18,333	21,986	1,330	2,334
03-Sep-17	20,508	23,043	1,370	2,590	03-Jun-18	19,082	21,502	1,292	2,416
10-Sep-17	18,922	22,219	680	2,437	10-Jun-18	19,744	24,008	1,055	2,561
17-Sep-17	19,328	21,001	781	2,501	17-Jun-18	20,625	24,098	835	2,576
24-Sep-17	18,088	20,105	420	2,469	24-Jun-18	22,314	24,304	754	2,641
01-Oct-17	17,373	18,629	554	2,411	01-Jul-18	22,162	23,995	1,016	2,680
08-Oct-17	17,633	17,667	786	2,448	08-Jul-18	22,211	24,709	814	2,662
15-Oct-17	17,451	17,591	507	2,429	15-Jul-18	22,381	23,640	838	2,750
22-Oct-17	17,677	18,114	392	2,466	22-Jul-18	21,731	23,629	1,035	2,647
29-Oct-17	17,837	18,358	318	2,507	29-Jul-18	21,764	24,448	841	2,730
05-Nov-17	17,985	18,711	416	2,519	05-Aug-18	22,225	24,418	958	2,751
12-Nov-17	19,108	19,678	601	2,625	12-Aug-18	21,843	24,500	985	2,710
19-Nov-17	19,398	20,189	342	2,643	19-Aug-18	20,983	24,281	1,362	2,687
26-Nov-17	19,839	20,625	607	2,716	26-Aug-18	21,215	23,234	1,413	2,687
03-Dec-17	20,248	21,329	409	2,765	02-Sep-18	20,355	22,900	1,370	2,575
10-Dec-17	20,408	21,607	555	2,792	09-Sep-18	18,805	22,097	680	2,421
17-Dec-17	20,909	21,832	690	2,836	16-Sep-18	19,193	20,869	781	2,485
24-Dec-17	20,671	21,749	362	2,805	23-Sep-18	17,924	19,961	420	2,454
31-Dec-17	20,422	21,566	528	2,711	30-Sep-18	17,255	18,513	554	2,399
07-Jan-18	21,154	22,056	570	2,844	07-Oct-18	17,479	17,520	786	2,431
14-Jan-18	21,727	22,884	547	2,912	14-Oct-18	17,309	17,344	507	2,412
21-Jan-18	21,297	21,939	483	2,900	21-Oct-18	17,526	17,961	392	2,450
28-Jan-18	21,136	22,113	404	2,905	28-Oct-18	17,692	18,206	318	2,490
04-Feb-18	21,133	22,284	734	2,911	04-Nov-18	17,940	18,609	416	2,505
11-Feb-18	20,351	21,820	635	2,847	11-Nov-18	18,918	19,484	601	2,605
18-Feb-18	20,076	21,475	581	2,797	18-Nov-18	19,214	20,008	342	2,621
25-Feb-18	19,717	21,489	501	2,745	25-Nov-18	19,664	20,450	607	2,696
04-Mar-18	20,306	21,533	531	2,774	02-Dec-18	20,068	21,158	409	2,741
11-Mar-18	19,770	20,598	649	2,730	09-Dec-18	20,224	21,428	555	2,771
18-Mar-18	18,702	19,397	611	2,653	16-Dec-18	20,756	21,682	690	2,819
25-Mar-18	18,255	19,009	569	2,564	23-Dec-18	20,541	21,621	362	2,806
01-Apr-18	18,145	19,113	567	2,509	30-Dec-18	20,112	20,911	528	2,649

Compared to the previous forecast, the weekly peaks and energy demand are generally lower throughout the forecast.

Figure 2.1: Weekly Energy Demand – History and Forecast

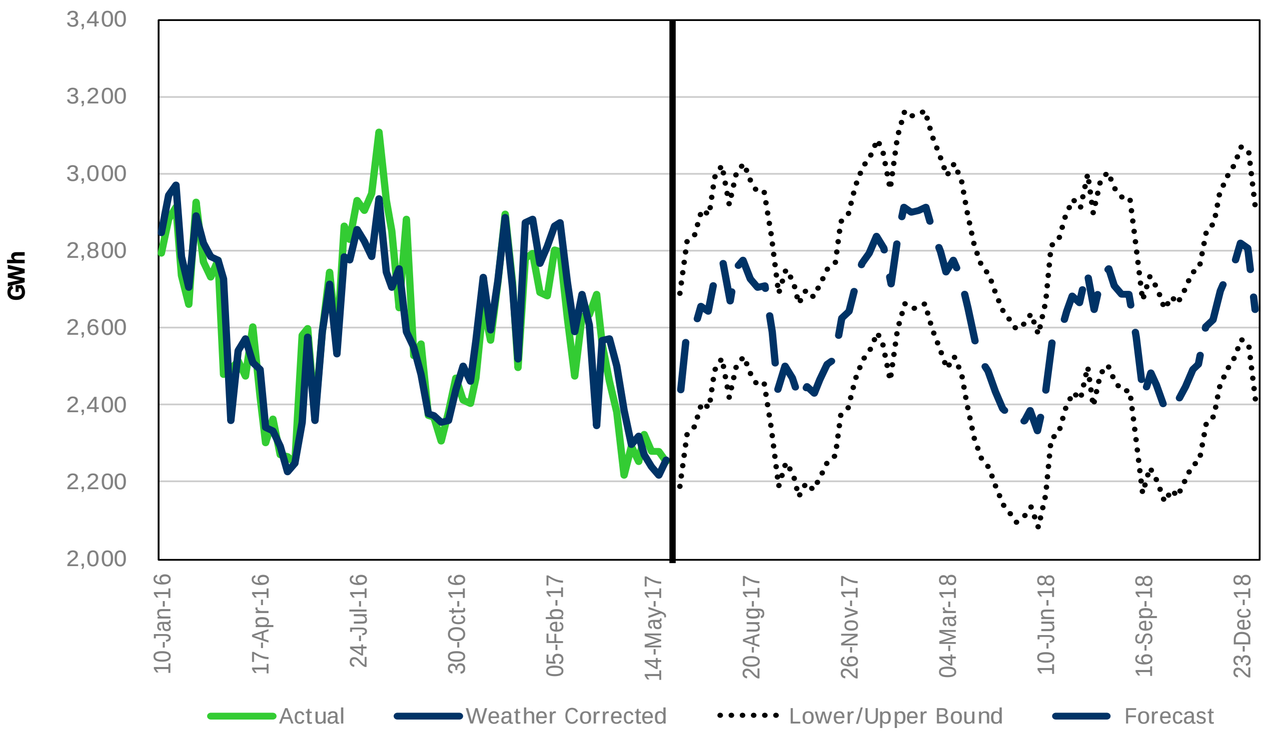
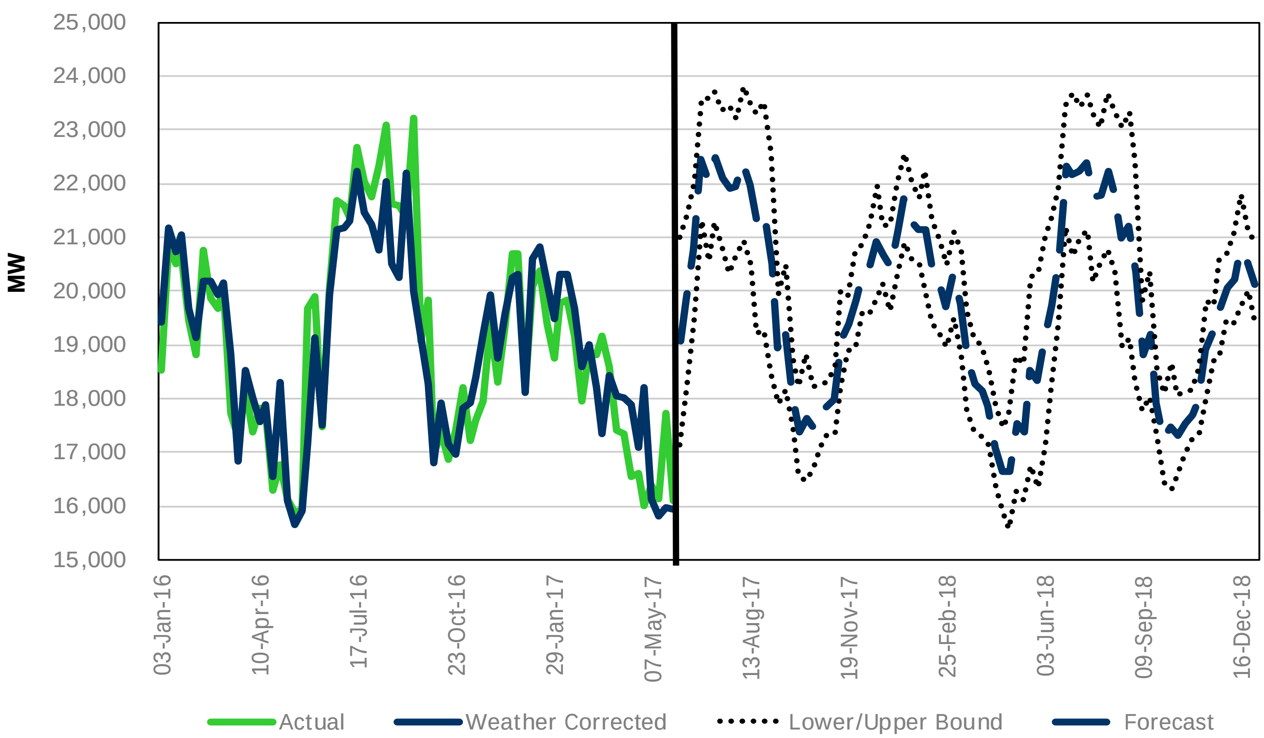


Figure 2.2: Weekly Peak Demand – History and Forecast



- End of Section -

3.0 Historical Review

This section discusses historical electricity demand. The weather-corrected numbers are generated based on Normal weather.

3.1 Six-Month Review – December to May

Since the last Ontario Demand document, actuals have been recorded for the period December to May. The winter of 2016-17 was milder than normal and the spring of 2017 was generally milder and wetter than normal.

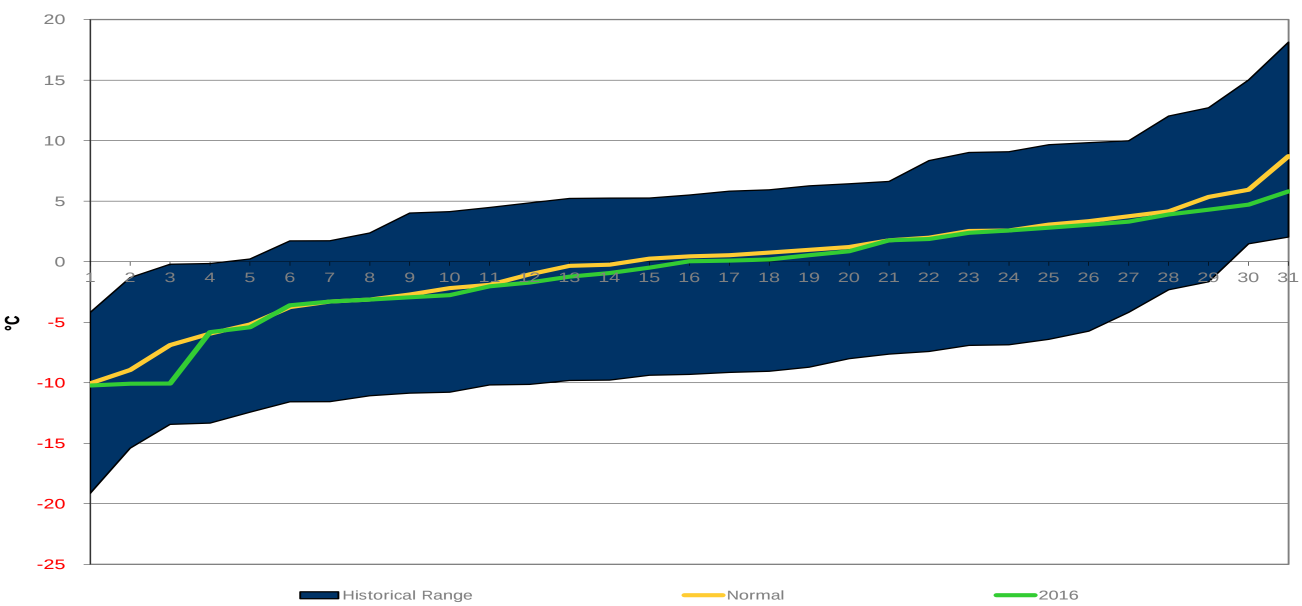
The winter peak came from December (20,688 MW) and the spring peak came from March (19,174 MW). Both were lower than the previous seasons.

Following is a month-by-month look at demand and weather.

<u>December</u>

December 2016 was very close to normal, both on average and peak. Figure 3.1 presents the ranked range of temperatures for the month, from coldest to warmest. The values for the month were consistently normal based on the history (1970 to present).

Figure 3.1: Daily Temperature - December



The peak demand occurred mid-month on December 15. At times, December peaks can be impacted by the holidays, but in this case the weather over the holidays was very mild. The peak occurred on the third coldest day of the month. The peak demand was 20,688 MW (20,299 MW weather-corrected) which is low by historical standards but consistent with the post-recession December values.

Monthly energy demand was 11.9 terawatt-hours (TWh) and 11.9 TWh weather-corrected. The actual was an increase over the previous year which was historically mild. However, the weather-corrected value was the lowest since market opening.

Minimum demand for the month was 11,684 MW, occurring during the early hours of December 27. This is the product of mild weather and the holidays.

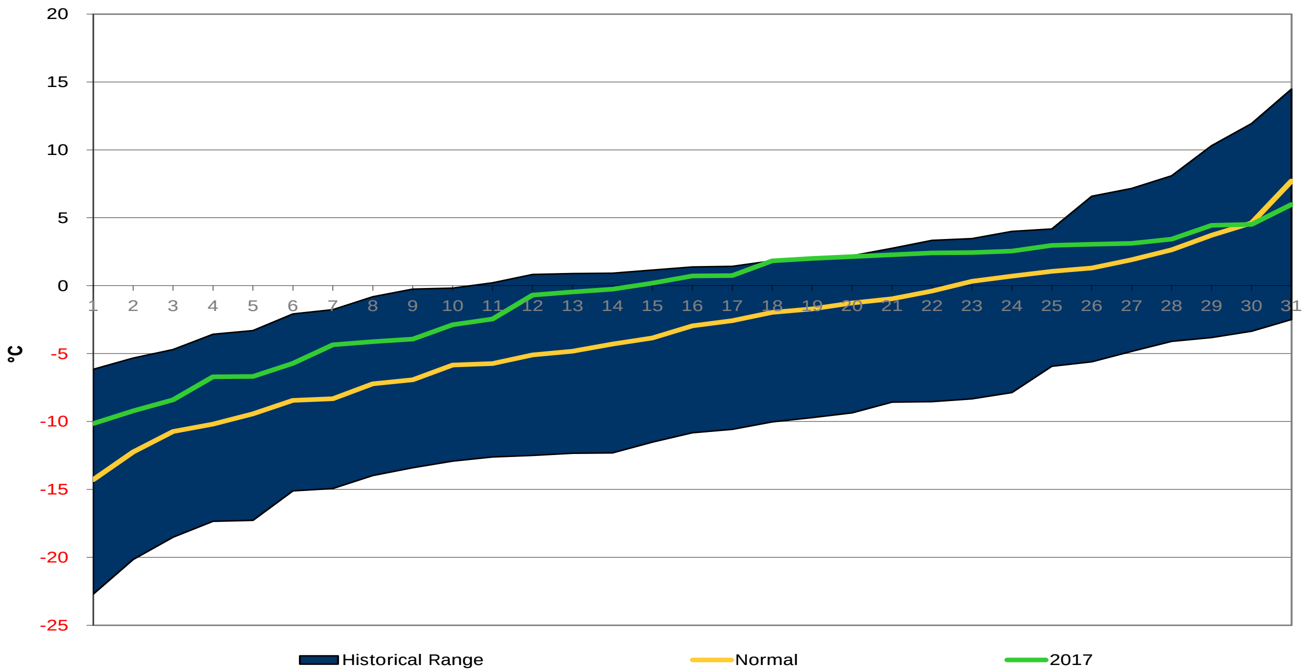
Embedded generation for the month was 446 GWh, a 0.8-percent increase over the previous December. Both solar and wind production was up with non-contracted generation falling compared to the previous year.

Wholesale customers' load showed year-over-year growth of 1.0 percent compared to the previous December.

January

The weather turned colder in January, but it still remained warmer than normal. Figure 3.2 shows how the temperature for January 2016 stacked up against history.

Figure 3.2: Daily Temperature - January



The peak occurred on January 9, which was the eighth coldest day of the month. It was a Monday and followed the coldest day of the month. The actual peak was 20,372 MW, and the weather-corrected peak was a higher 20,830 MW. Once again these values are low by historical standards and consistent with the post-recession period.

Energy demand for the month was 12.1 TWh (12.5 TWh weather-corrected). Both of these figures represent the lowest January energy demand since market opening.

Minimum demand for the month was 12,246 MW, which was higher than last year. The minimum occurred at 5 a.m. on a Sunday.

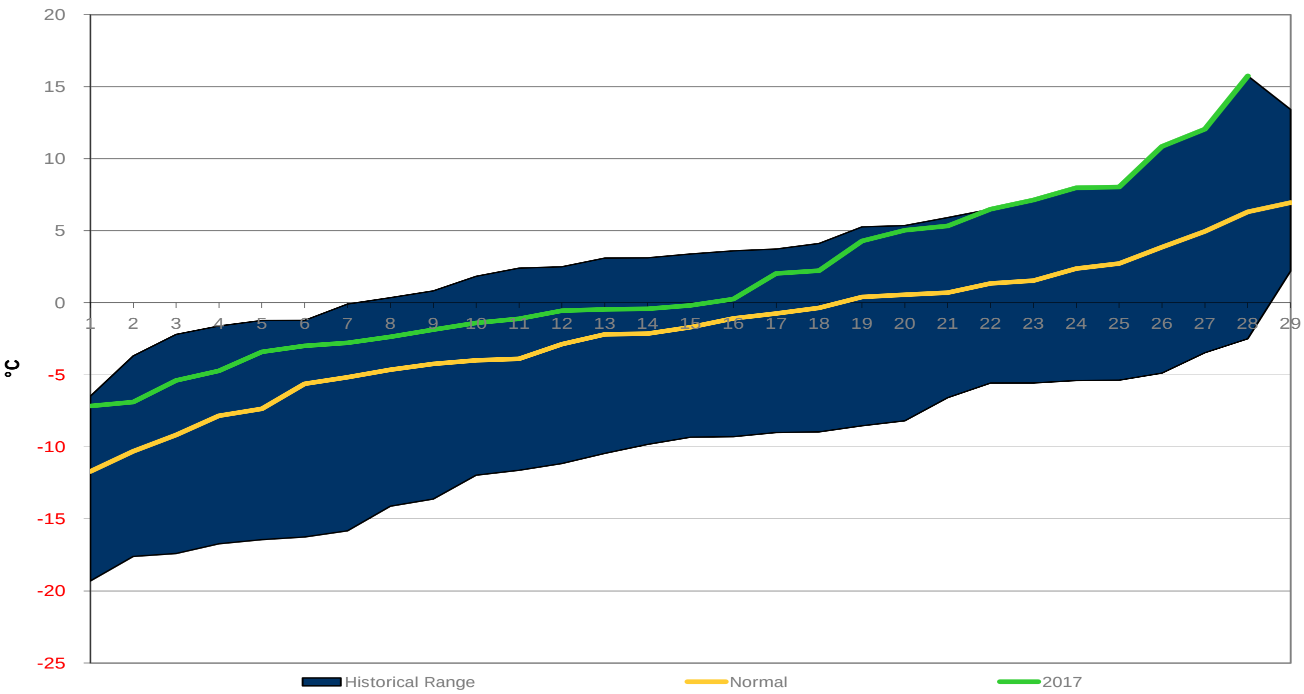
Embedded generation for the month was 472 gigawatt-hours (GWh), a 0.8-percent decrease over the previous January. Solar output fell dramatically (-14%), while wind output was up an even more dramatic 46%.

Wholesale customers' consumption decreased by a 1.0 percent compared to January 2015, reversing the trend of the positive growth for the previous two months.

February

February was significantly milder than normal. Figure 3.3 shows the February 2017 temperature relative to history.

Figure 3.3: Daily Temperature - February



The month's peak occurred on the seventh coldest day of the month, February 7. The peak was 20,766 MW and 20,195 MW weather-corrected. These numbers are consistent with the observations for February since the recession.

Energy demand for the month was 10.6 TWh (11.0 TWh weather-corrected). This is consistent with the downward trend since the recession and represents the lowest February values since market opening.

The minimum demand was 11,867 MW for the month. Last February was the first time that the minimum fell below 13,000 MW, so this represents a new low for the month by a significant margin. The minimum did occur on an extremely mild weekend with daily temperatures in excess of 10°C.

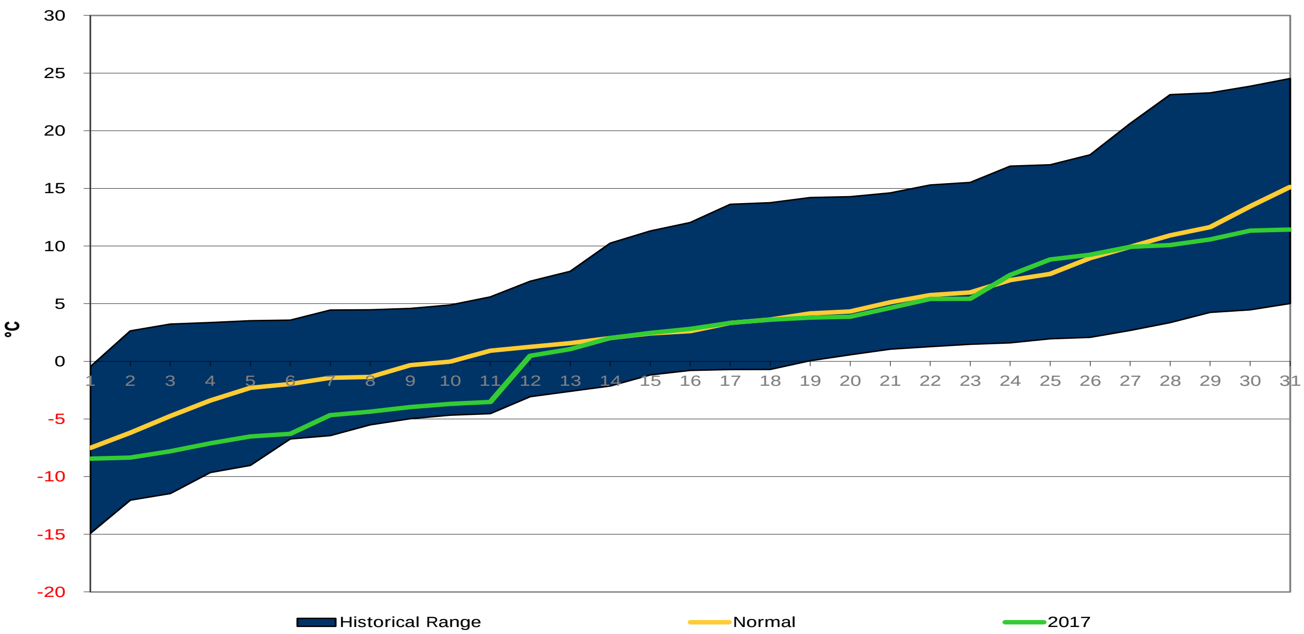
Embedded generation for the month was 493 GWh and represented a 2.1 percent increase over the previous February. The growth rate rises to 5.8% after adjusting for additional leap year day in 2016. Both solar and wind were down compared to the previous February.

Wholesale customers' consumption declined in February by 3.0% compared to February 2016. However all of this was due to the additional leap day in 2016. Adjusting for the day would translate into a 0.4% increase in wholesale customers' consumption.

March

The weather for March was colder than normal with the peak temperatures near normal. Figure 3.4 shows the March 2017 temperatures against the historical range.

Figure 3.4: Daily Temperature - March



The actual peak of 19,174 MW occurred on March 14, the third coldest day of the month. The two coldest days fell on the weekend. In fact, it was colder at the time of the March peak than it was for either the January or February peak. The weather-corrected peak was 18,742 MW. Both actual and weather-corrected peaks were historic lows for the month.

Energy demand for the month was 11.6 TWh and 11.4 TWh weather-corrected. The weather-corrected energy was the lowest for March since the market opened. The low values are being impacted by the increased conservation savings and the embedded generation output.

Minimum demand for the month was 12,158 MW, which was actually a reversal of recent experience, and is consistent with post-recession experience. The minimum occurred at 2 a.m. on a Sunday morning.

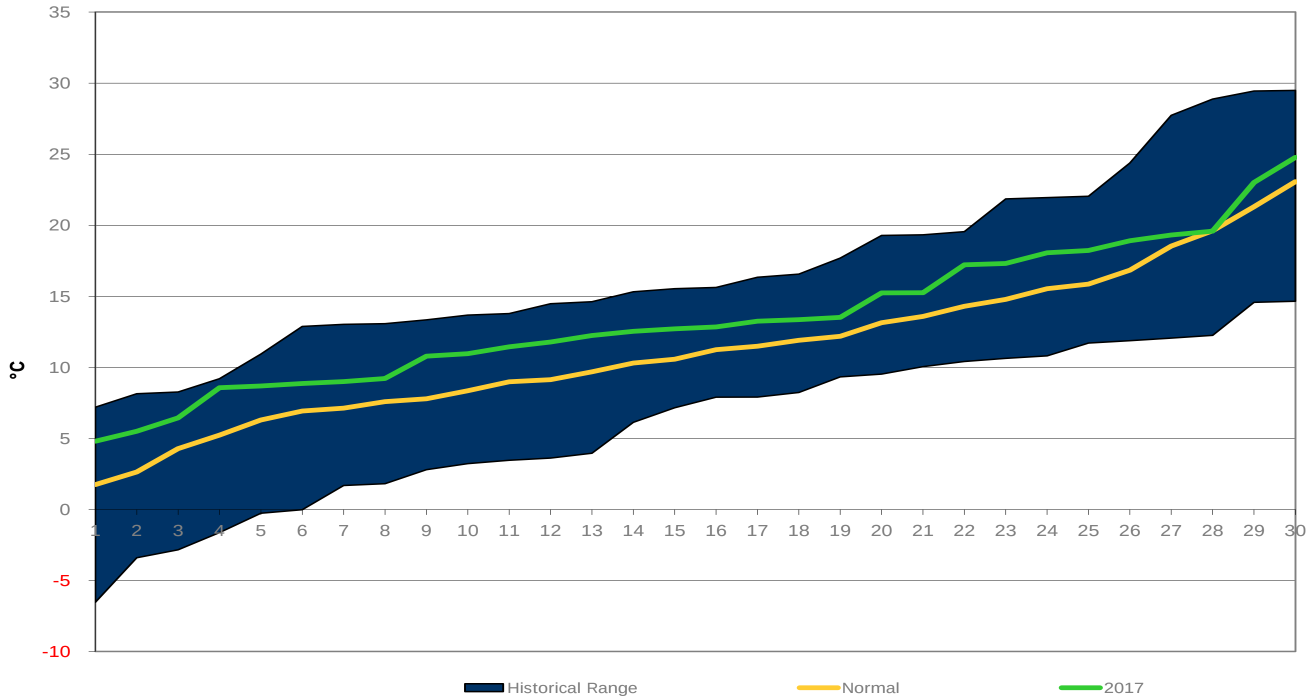
Embedded generation for the month was 568 GWh, an increase of 5.9 percent over the previous March. There was strong growth in both solar and wind output.

Wholesale customers' consumption was up 1.7% over the previous March. This is overstating the level of activity as March 2016 included Easter whereas March 2017 did not and would have had an extra work day.

April

April was warmer than normal and also very wet. It was the wettest April for many locations across the province. As well, Ontario received as much snow in April as it did in March. Figure 3.5 illustrates the temperatures of April 2016 against the historical range.

Figure 3.5: Daily Temperature - April



The month's peak demand occurred on April 6, which was the second coldest day of the month. By historical standards the temperature was warm for April. The actual peak was 17,349 MW which was the lowest April peak since market opening being slightly lower than April 2010. The weather-corrected value was higher at 18,217 MW. Both values are consistent with the post-recession time period.

Actual energy demand for the month was 9.8 TWh and represents the first time any month has been less than 10 TWh. The weather corrected value was 10.1 TWh. Both actual and weather-corrected were all-time lows.

The minimum demand of 10,167 MW occurred at 4 a.m. on a Sunday April 16. This was the perfect conditions for a minimum value as it was Easter Sunday and significantly warmer than normal.

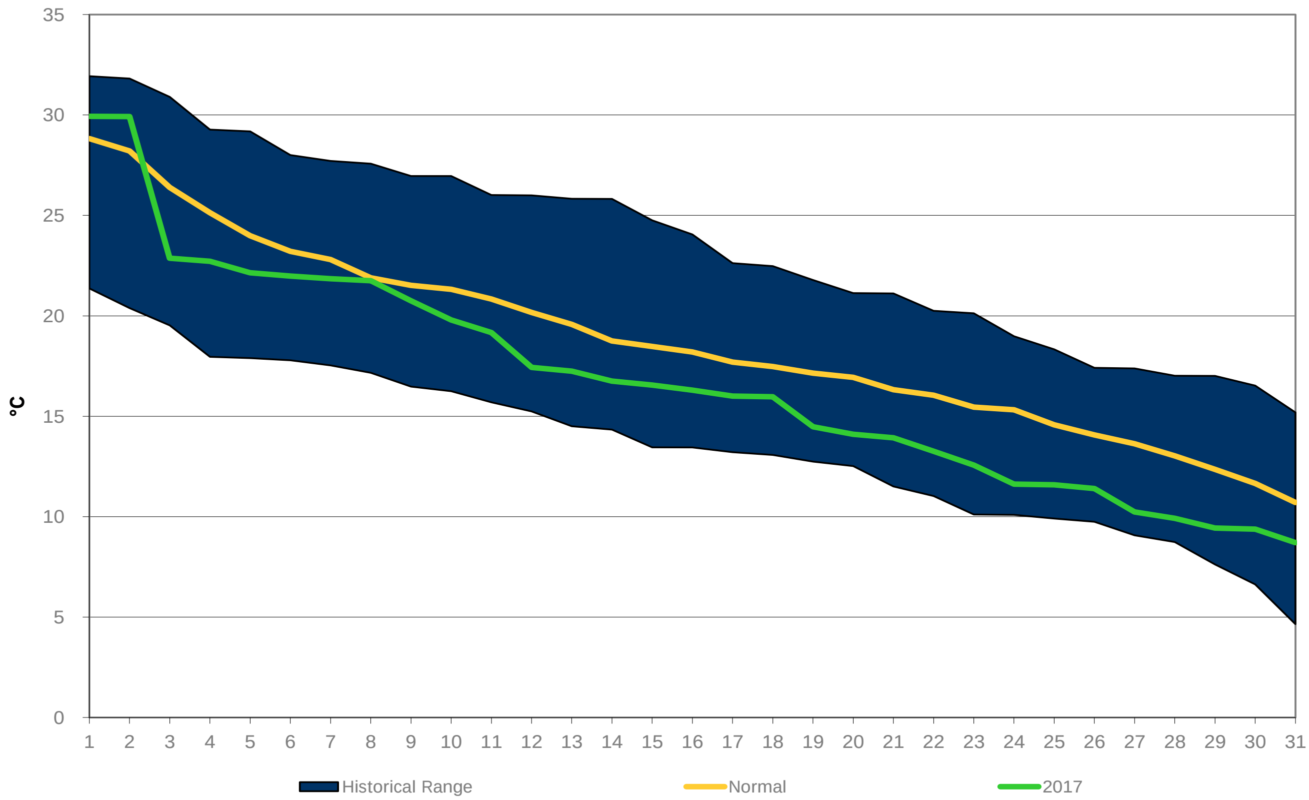
Embedded generation for the month was 604 GWh. This represents a slight 9.6-percent decrease over the previous April. Despite all the rain, solar output was actually up over the previous April. Likewise wind production also increased year over year. The decline stemmed from a drop in non-contract generation and hydroelectric output.

Wholesale customers' consumption dropped 5.1 percent over the previous April. As a converse to March, April 2017 included the Easter weekend whereas April 2016 did not. The additional holiday weekend would impact the level of activity this April.

May

May was cooler than normal and much wetter normal. Many cities had more rain than any time in the past 50 years.

Figure 3.6: Daily Temperature - May



The actual peak for May was 17,738 MW occurring on Thursday, May 18. It was the second warmest day of the month. The weather-corrected value was virtually the same at 17,764 MW. The actual peak was the lowest since the recession.

The impacts of conservation and embedded generation mean that the energy demand for the month has been fairly flat since the recession but trending downward. Actual demand for the month was 10.2 TWh and weather-corrected energy demand was slightly lower at 10.1 TWh. Both are historical lows for May.

Minimum demand of 10,249 MW occurred Sunday, May 21 at 3 a.m. This is the lowest May minimum since market opening.

Embedded generation topped 632 GWh for the month, which represents a decrease of 6.8 percent compared to the previous May. Increases in wind, hydro and biofuel output were offset by solar and non-contracted embedded generation.

The wholesale customers' consumption fell 0.6 percent compared to the previous May. Motor vehicle manufacturing was up but most other major sectors had shown a decline.

Table 3.3.2 of the 18-Month Outlook Tables spreadsheet contains monthly demand information going back to market opening.

Table 3.1 contains a summary of the weather and demand for the past six months.

Table 3.1: Historical 2016-2017 Weather and Demand Summary

Historical Analysis		December	January	February	March	April	May
Actual Weather	Average Temperature (°C)	0.3	0.2	2.6	2.8	13.4	16.2
	Minimum Temperature (°C)	-8.1	-9.3	-5.0	-8.1	4.4	6.9
	Maximum Temperature (°C)	5.7	6.2	17.4	15.3	25.3	29.6
Normal Weather	Normal Average Temperature (°C)	0.2	-3.3	-1.5	3.6	10.7	17.1
	Normal Minimum Temperature (°C)	-8.4	-13.5	-13.5	-5.5	2.8	8.7
	Normal Maximum Temperature (°C)	10.0	6.7	8.2	16.7	25.0	27.2
Actual Demand	Peak Demand (MW)	20,688	20,372	19,838	19,174	17,349	17,738
	Average Hour (MW)	16,060	16,274	15,785	15,579	13,595	13,839
	Minimum Hour (MW)	11,684	12,246	11,867	12,158	10,167	10,745
	90th Percentile (MW)	18,666	18,425	18,065	17,608	15,576	15,675
	Percent above 20,000 (MW)	1.4%	0.3%	0.0%	0.0%	0.0%	0.0%
	# of Hours Above 20,000 (MW)	10	2	0	0	0	0
	Energy Demand (GWh)	11,948	12,108	10,608	11,591	9,789	5,979
Weather Corrected Demand	Peak Demand (MW)	20,299	20,830	20,306	18,986	18,217	17,764
	Energy Demand (GWh)	11,923	12,537	10,970	11,324	10,171	10,064
Forecast Demand	Peak Demand (MW)	20,888	21,914	20,966	20,137	17,970	19,193
	Energy Demand (GWh)	12,431	12,819	11,295	11,824	10,367	10,577

Notes for Table 3.1 – Weather is for Toronto. Temperature is the daily high. Forecast is the most recent for that period.

3.2 Historical Energy Demand

The six-month period can be broken down into its two main components, winter (December, January and February) and spring (March, April and May).

The weather over the winter was milder than normal. Compared to the previous winter energy demand was down 1.5%. If you adjust for the weather and the additional leap year day the decline was a 1.3% or 0.5 TWh.

Distributors' loads have declined by 1.7 percent over the winter compared to last winter. After making the weather and leap year adjustments, the decline remains 1.7%. This reduction is a result of growth in embedded generation output, conservation savings and economic structural change. Over the course of the winter, embedded generation was 1.4 TWh, an increase of 0.9 percent over the previous year.

For the winter months, wholesale loads showed a decrease of 1.0 percent compared to the previous winter. However, that becomes a virtually flat once adjusted for the additional leap day.

For the spring, demand was 2.0 percent lower than the previous year and a nearly identical -1.9% decline after adjusting for weather. The distributor loads showed an actual decline of 2.0-percent and a 1.9-percent decline after correcting for weather.

Wholesale customers' loads decreased by 1.3 percent compared to the previous spring. The declines stem from decreases in the pulp and paper sector.

Figure 3.7 shows weather-corrected distributor load and embedded generation output. Though embedded generation shows seasonal volatility, the underlying upward trend is quite evident in the graph. Annual embedded generation output was 6.3 TWh in 2016 an increase of 4.6% over 2015. The growth rate has slowed in concert with the growth in capacity.

For the six months from December to May, distributors' loads declined by 1.9 percent compared to the same six-month period a year earlier. Embedded generation declined by a same 1.9 percent for the same period.

Figure 3.7: Monthly Weather-Corrected Distributor Load and Embedded Generation Output

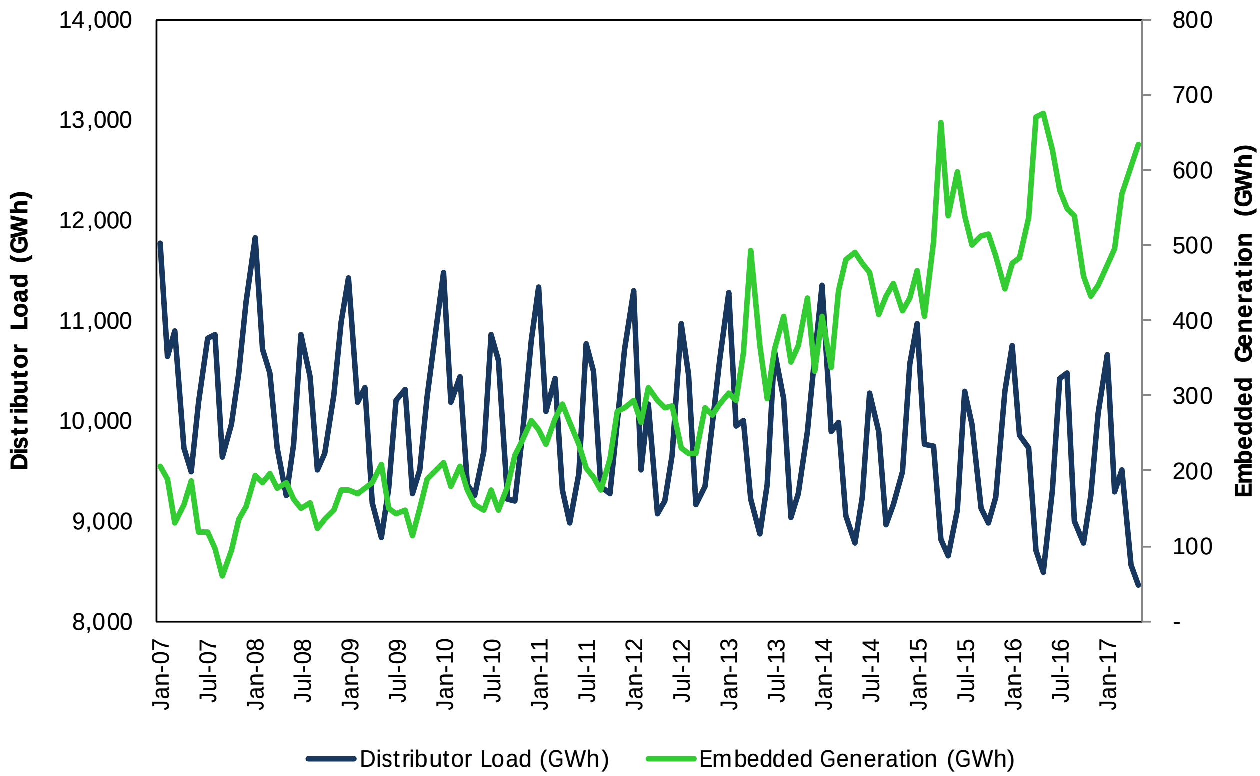


Figure 3.8 shows the year-over-year change in wholesale customers' average hourly consumption. The graph traces the impact of the recession, the short and modest recovery in 2010 and the up and down nature since.

Figure 3.9 shows the wholesale customers' highest monthly average hourly load by industry segment for each of 2008, 2015, 2016 and 2017 year to date.

Mining is the only sector that is higher than its pre-recession value. Pulp and paper has shown the greatest decline. The other sectors show a similar pattern of having fallen from the pre-recession values and appear to have found a new equilibrium that has been more or less stable over the past four years.

The changing industrial structure is due to a variety of causes. Some changes are sector specific – the impact of the decline in demand for newsprints on pulp and paper – while other changes are broad-based – such as the appreciation of the Canadian dollar from 2004 through to 2014. Wholesale loads declined by 24 percent in 2009. Since then loads have shown a very slight increase.

Figure 3.8: Wholesale Customers' Year-over-Year Change in Consumption

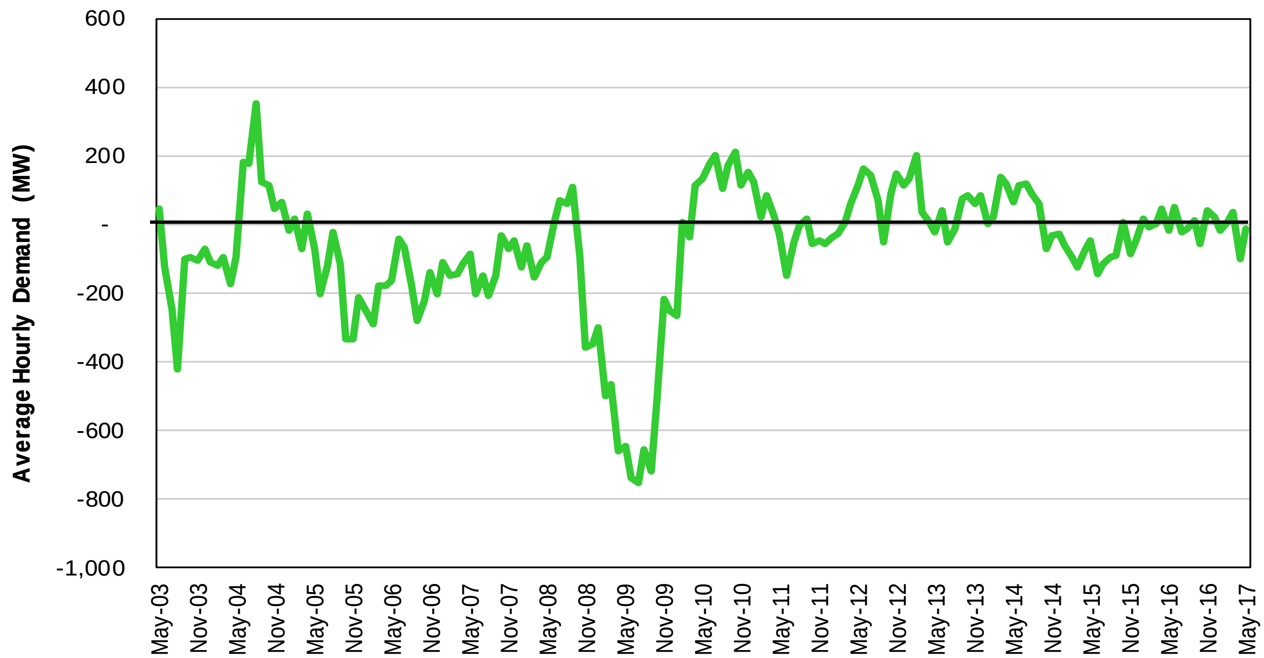


Figure 3.9: Wholesale Customers' Average Hourly Consumption by Industry Segment

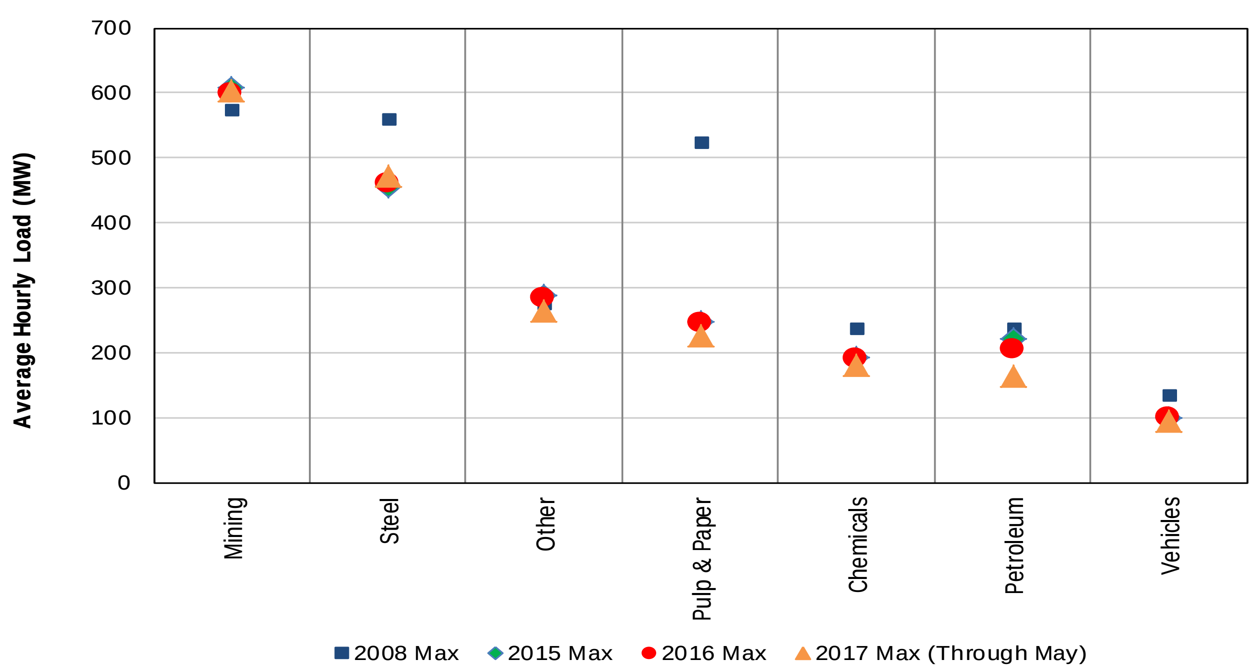


Table 3.2 contains the weekly energy demand for the past six months. The table has the actual and weather-corrected demand for each week and notes any item of significance for the week. If the weather-corrected

demand is greater than the actual demand, it means that the actual weather was milder than normal. Additional history is available in the 18-Month Outlook Tables spreadsheet in Table 3.3.1.

Table 3.2: Historical Weekly Energy Demand

Week Number	Week Ending	Peak Day	Actual Energy (GWh)	Corrected Energy (GWh)	Notes
48	04-Dec-16	28-Nov-16	2,567	2,592	
49	11-Dec-16	09-Dec-16	2,720	2,724	
50	18-Dec-16	15-Dec-16	2,896	2,886	
51	25-Dec-16	19-Dec-16	2,718	2,703	Christmas Day
52	01-Jan-17	28-Dec-16	2,496	2,517	Boxing Day & New Years Day
1	08-Jan-17	05-Jan-17	2,778	2,873	
2	15-Jan-17	09-Jan-17	2,795	2,884	
3	22-Jan-17	17-Jan-17	2,690	2,768	
4	29-Jan-17	24-Jan-17	2,684	2,811	
5	05-Feb-17	30-Jan-17	2,804	2,865	
6	12-Feb-17	07-Feb-17	2,795	2,875	
7	19-Feb-17	16-Feb-17	2,626	2,719	
8	26-Feb-17	21-Feb-17	2,474	2,591	Family Day
9	05-Mar-17	02-Mar-17	2,629	2,689	
10	12-Mar-17	10-Mar-17	2,633	2,606	
11	19-Mar-17	14-Mar-17	2,686	2,346	
12	26-Mar-17	22-Mar-17	2,559	2,566	
13	02-Apr-17	30-Mar-17	2,461	2,570	
14	09-Apr-17	06-Apr-17	2,383	2,500	
15	16-Apr-17	12-Apr-17	2,217	2,384	Good Friday
16	23-Apr-17	20-Apr-17	2,294	2,297	Easter Monday
17	30-Apr-17	25-Apr-17	2,254	2,321	
18	07-May-17	04-May-17	2,324	2,268	
19	14-May-17	08-May-17	2,280	2,238	
20	21-May-17	18-May-17	2,277	2,218	
21	28-May-17	25-May-17	2,253	2,255	Victoria Day

3.3 Historical Peak Demand

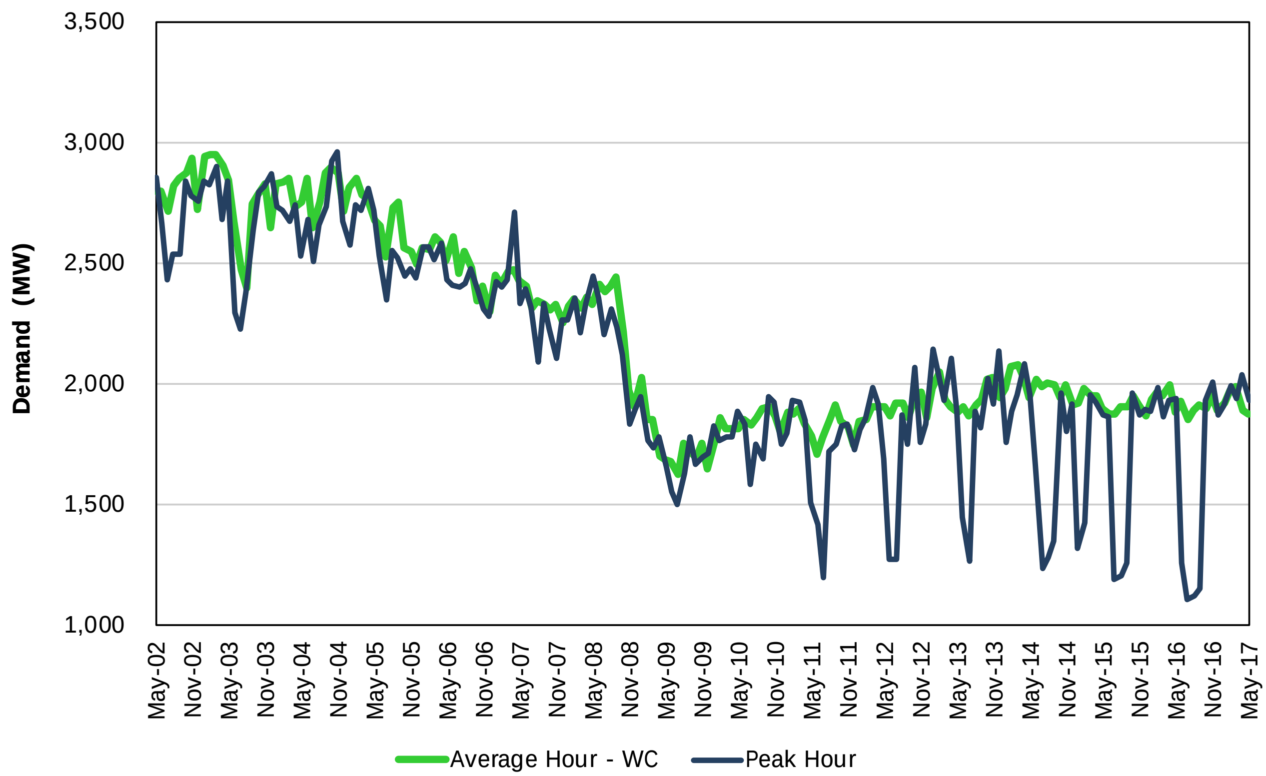
Peak demands are weather-driven, weekday events. Peak demands have been facing downward pressure due to a number of factors. Conservation, time-of-use rates, embedded generation, demand response, the Industrial Conservation Initiative (ICI) and economic restructuring have all contributed to lower peak demands.

The winter peak was 20,688 MW, which is lower than last winter's peak (20,836 MW). The peak weather was warmer than the previous winter. As well, the weather-corrected winter peak was lower than the previous one. The spring peak was 19,174 MW, which was also lower than the previous spring peak (20,063 MW). Even after adjusting for weather the spring 2017 peak was lower than the previous spring.

Figure 3.10 shows the wholesale customers' average hourly monthly demand and their consumption at the time coincident with the system peak. It is evident that prior to the ICI program, the average and coincident peak tracked quite closely as many operations operated 24/7. With the introduction of the program in 2010, wholesale customers have responded by reducing their load during the five peak days. The graph shows a portion of the response as the program applies to Class A customers -- that includes wholesale customers and a number of customers served by distributors.

In 2017, the program was expanded to include customers with a peak load of 0.5 MW or higher. Additionally, for those with an average peak load in excess of 1 MW, the NAIC code restrictions were lifted. Previously, participants were restricted to manufacturing sectors. This change will enable large commercial facilities access to the program. Those between 0.5 MW and 1 MW are still restricted to specific sectors: manufacturing, greenhouses and floriculture.

Figure 3.10: Wholesale Customers' Coincident Peak and Average Hourly Consumption



For most years, the province has been summer peaking, but the summer peaks face more downward pressure than the winter peaks. In particular, conservation and embedded solar generation do not impact the seasonal peaks to the same degree. The summer peak is primarily driven by air conditioning load, whereas the winter peak is a result of a mix of end uses. As such, conservation programs that increase air conditioner efficiency and improve the building envelope will have a direct impact on summer peak. The winter peak is mostly impacted through conservation initiatives that improve lighting efficiency, and the resulting impact on the winter peak is smaller. The second factor is embedded solar generation. Since the winter peak occurs after sunset, the output of embedded solar will be zero and have no impact on the winter peak. The summer peak occurs during daylight hours when embedded solar output is significant. This is reducing the summer peaks but is also having an impact of pushing the summer peaks later in the day.

Traditionally, the summer peak occurred in the late afternoon as air conditioners worked to dispel the accumulated heat. Now the embedded solar is "carving out" demand in the middle of the day and having the effect of pushing the peak later in the day when solar output is declining more rapidly than demand.

Figure 3.11 shows the winter weekday peaks levels in MW and the hour in which they occurred for the winter of 2005 and the winter of 2016. The graph clearly shows how peaks are lower today – a result of conservation and lower industrial load – but that the peaks occur in the same timeframe from hours 18-20. Figure 3.12 shows the weekday peaks in MW and the hour in which they occurred for the summer of 2005 and 2016. Here the peaks are once again lower but in the case of the summer, the hours at which those peaks are occurring have changed. Generally, the peaks have shifted to later in the day. The contrast between the summer and winter distribution of peak hours shows the impact that embedded solar in having on the summer peaks. Embedded solar is making the summer peaks lower and later in the day.

Figure 3.11: Seasonal Weekday Peak Hour Distribution - Winter

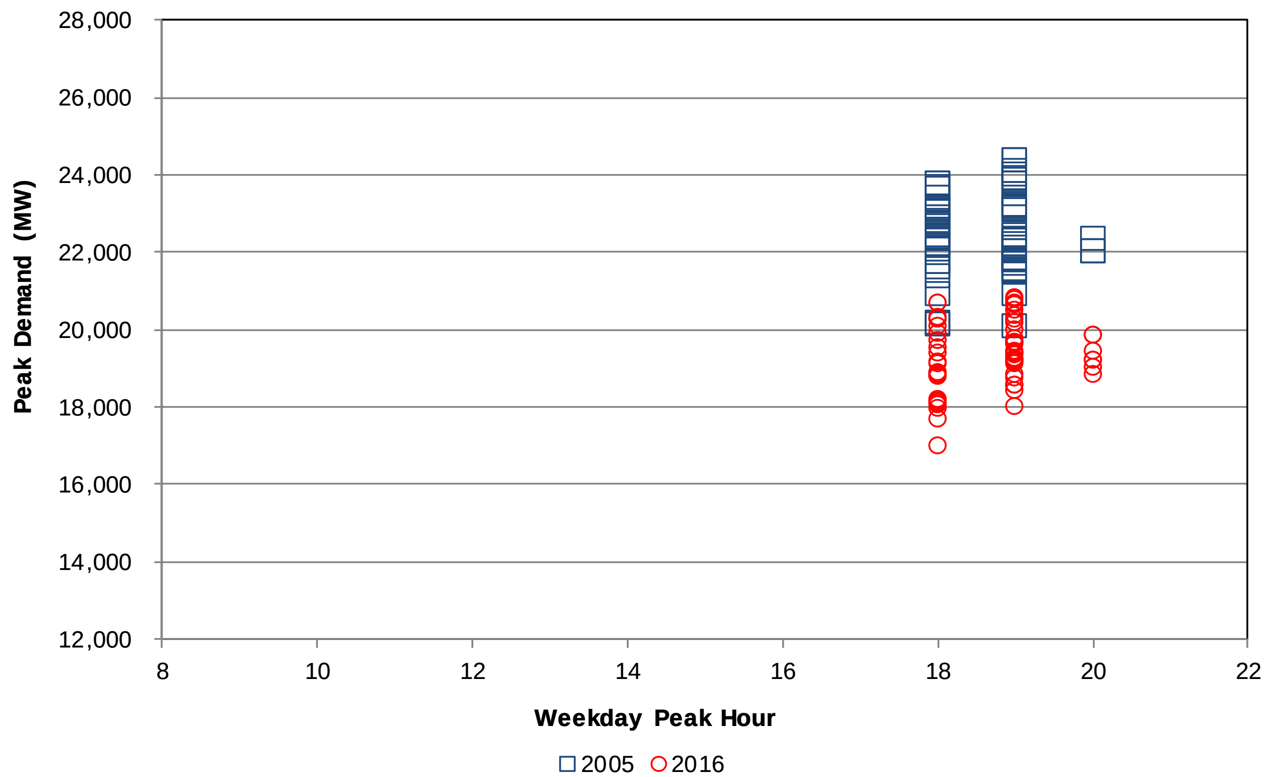
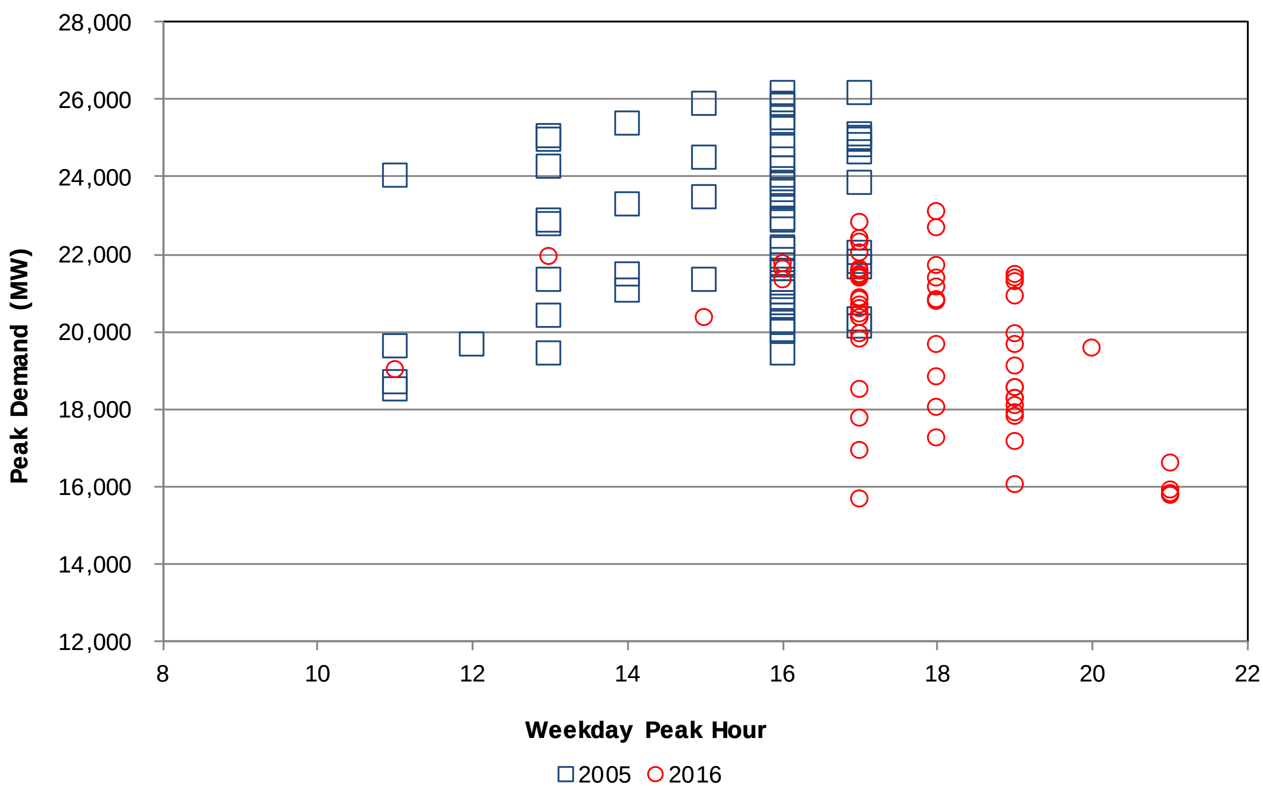


Figure 3.12: Seasonal Weekday Peak Hour Distribution – Summer



The interesting aspect of the seasonal peaks is that the winter peak has less underlying growth, but fewer factors are acting to mitigate that growth, while the summer peak has greater underlying growth but more factors working to reduce them.

Figure 3.13 shows the break-down for the past two summer and winter peaks. For the past two winters ICI has not been a factor. As well, for all of the seasonal peaks depicted there was no demand response activated. Generally, the embedded generation is higher during the summer peak as the significantly larger solar capacity doesn't impact the winter peak which occurs after dark. However, the 2016-17 winter peak had a very high level of embedded generation output as it was extremely windy on the peak day.

Figure 3.13: Anatomy of Seasonal Peaks

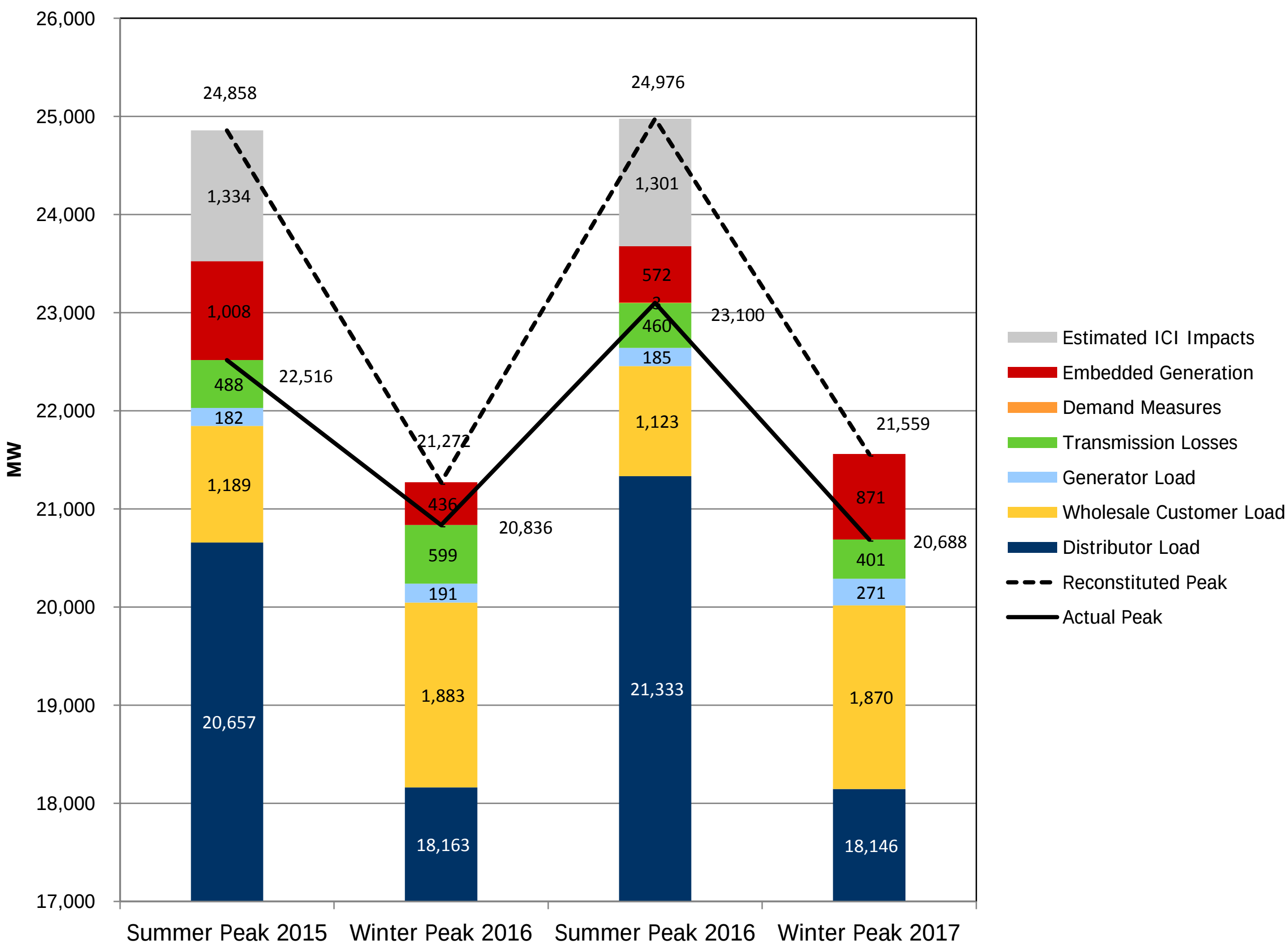


Table 3.3 shows the actual and weather-corrected weekly peak demand for the past six months.

Table 3.3: Historic Weekly Peak Demand

Week Number	Week Ending	Peak Day	Actual Peak (MW)	Weather Corrected Peak (MW)	Peak Day Temperature
49	06-Dec-15	01-Dec-15	19,161	20,155	6.8
50	13-Dec-15	07-Dec-15	19,064	19,998	5.4
51	20-Dec-15	15-Dec-15	18,909	19,820	8.6
52	27-Dec-15	21-Dec-15	18,527	19,321	6.6
53	03-Jan-16	03-Jan-16	18,512	19,423	1.6
1	10-Jan-16	04-Jan-16	20,836	21,158	-11.8
2	17-Jan-16	11-Jan-16	20,494	20,727	-6.6
3	24-Jan-16	19-Jan-16	20,660	21,056	-4.3
4	31-Jan-16	29-Jan-16	19,439	19,666	-5.1
5	07-Feb-16	04-Feb-16	18,818	19,112	2.9
6	14-Feb-16	11-Feb-16	20,766	20,166	-10.0
7	21-Feb-16	17-Feb-16	19,863	20,195	-1.4
8	28-Feb-16	24-Feb-16	19,675	19,930	1.7
9	06-Mar-16	01-Mar-16	20,063	20,153	-7.9
10	13-Mar-16	10-Mar-16	17,715	18,817	10.2
11	20-Mar-16	15-Mar-16	17,267	16,816	9.3
12	27-Mar-16	21-Mar-16	18,168	18,517	3.5
13	03-Apr-16	29-Mar-16	17,381	18,005	7.2
14	10-Apr-16	05-Apr-16	17,821	17,557	0.6
15	17-Apr-16	12-Apr-16	17,743	17,879	6.7
16	24-Apr-16	19-Apr-16	16,283	16,549	15.8
17	01-May-16	25-Apr-16	16,774	18,292	7.4
18	08-May-16	02-May-16	16,116	16,101	12.0
19	15-May-16	12-May-16	15,884	15,658	20.5
20	22-May-16	19-May-16	15,949	15,892	19.7
21	29-May-16	27-May-16	19,681	17,141	28.9

3.4 Load Duration Curves

The following load duration curves display load for the four seasons. The seasons are defined as: spring (March, April and May), winter (December, January and February), fall (September, October and November) and summer (June, July and August).

The figures are not weather-corrected so the weather will influence the shape of each of the graphs. The spring and fall load duration curves are more heavily influenced by the level of economic activity than by the weather. Those load duration curves show that demand remains low by historical standards.

Figure 3.14: Spring Load Duration Curve

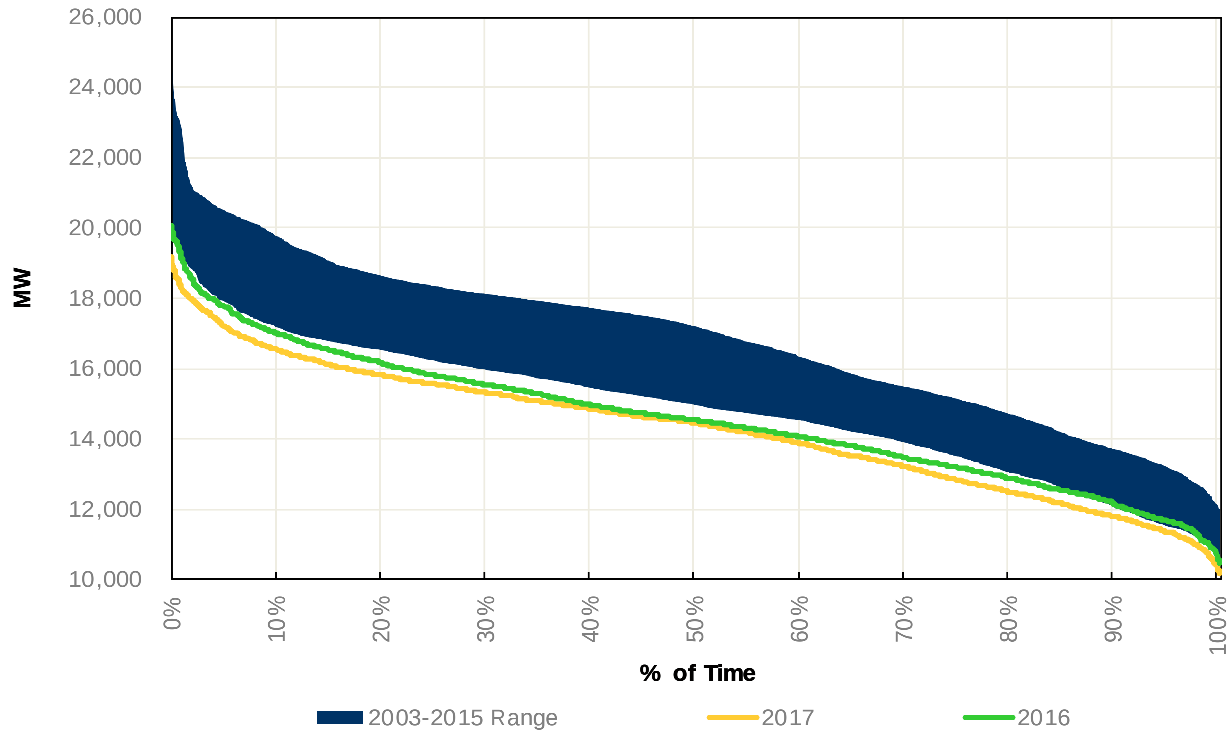


Figure 3.15: Winter Load Duration Curve

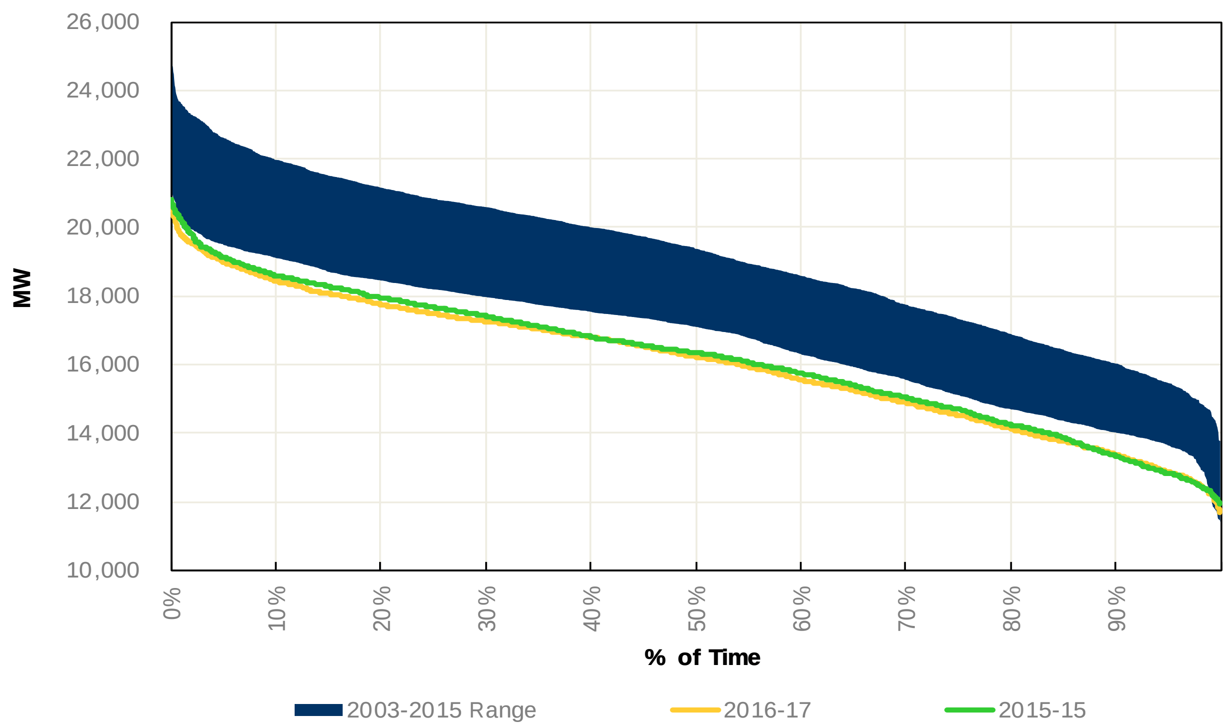


Figure 3.16: Fall Load Duration Curve

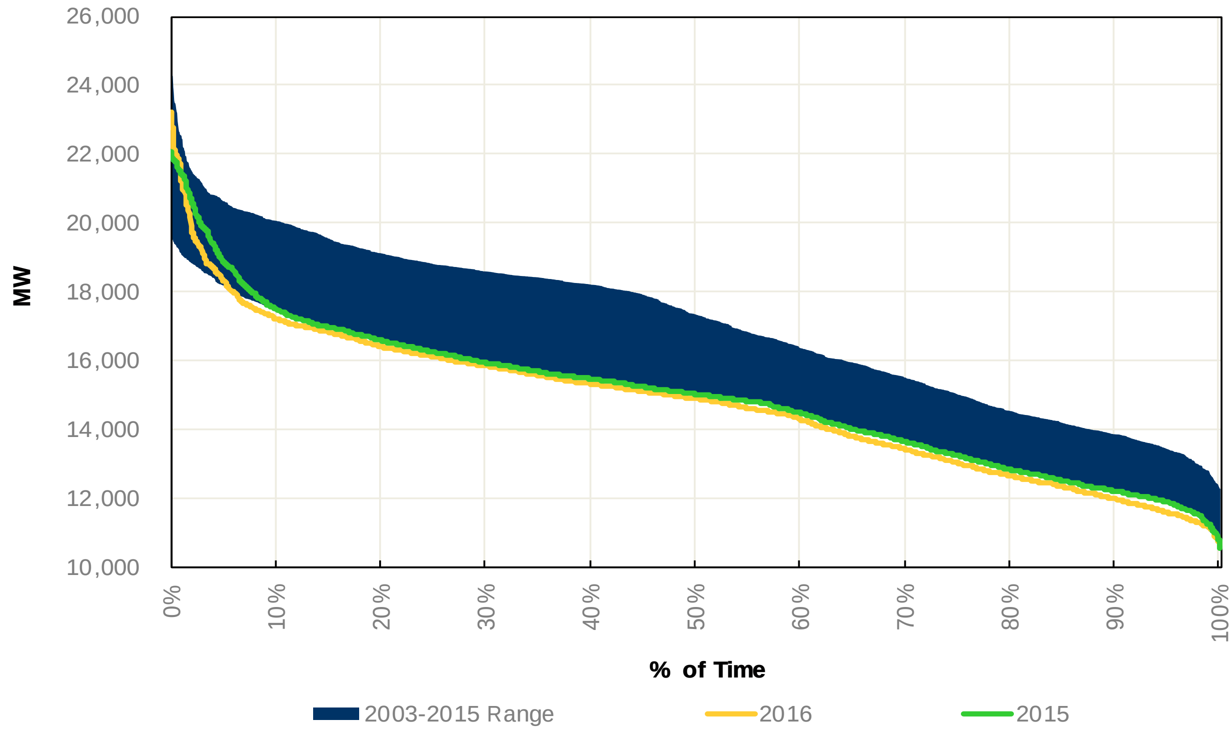
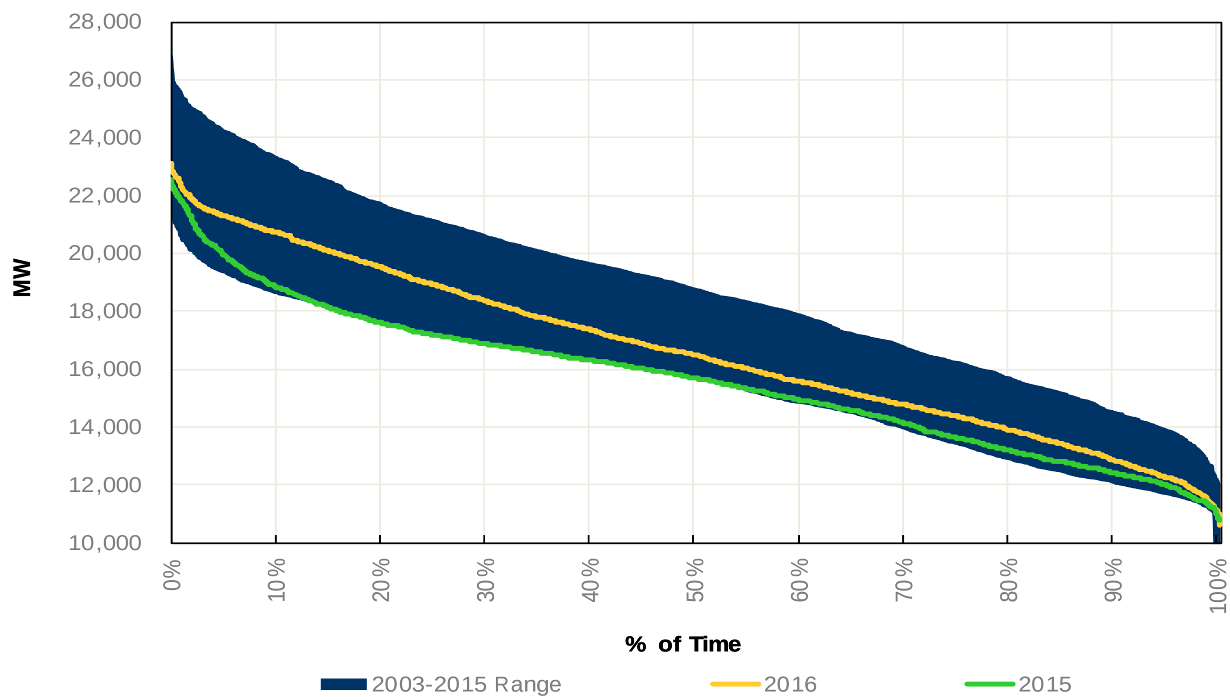


Figure 3.17: Summer Load Duration Curve



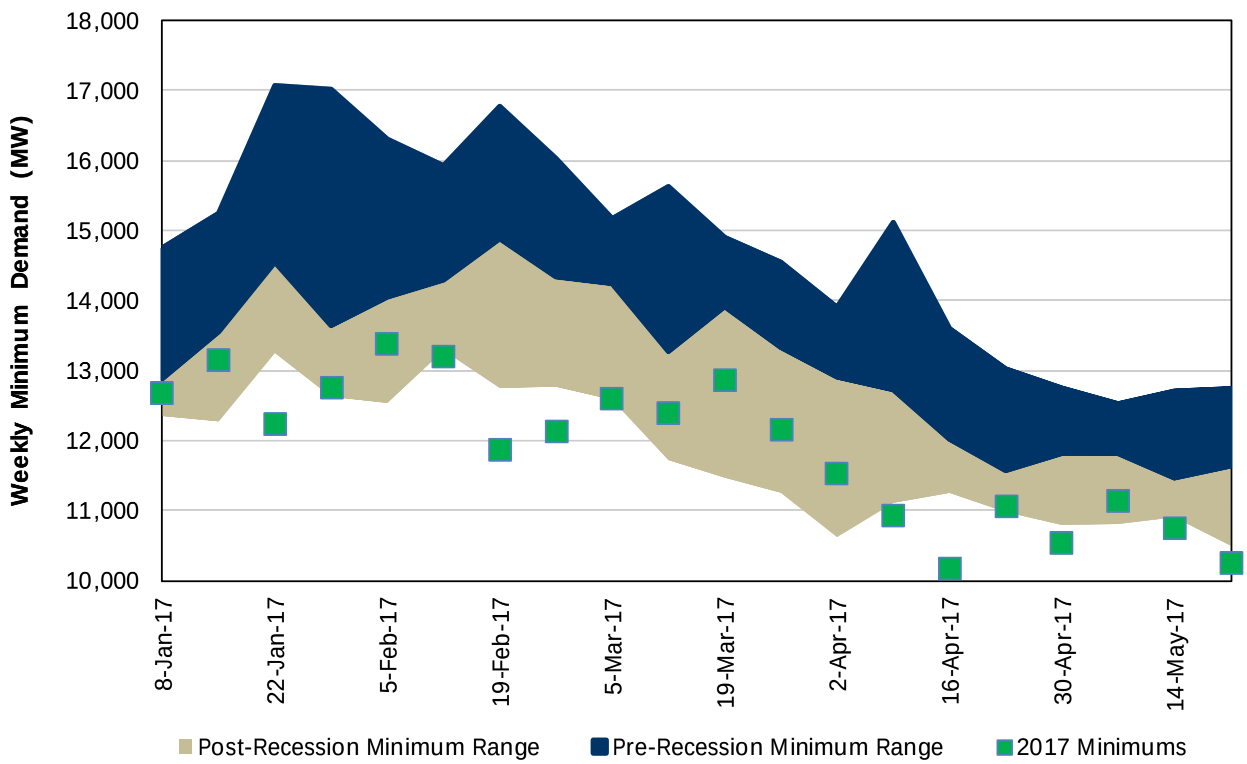
3.5 Historical Minimum Demand

Like peak demands, the minimums are driven by weather, calendar and economic effects, which, of the drivers, is most important varies throughout the seasons. The winter, spring and fall have the potential for heating load, whereas the summer period has the potential for cooling loads. Minimums continue to establish new lows in the post-recession era due to lower industrial loads, conservation and increased embedded generation. In the case of minimums that occur during the early predawn hours, it is embedded wind that is further reducing the need for grid-supplied electricity. In fact, some load points with high quantities of embedded wind actually push power back onto the grid overnight when embedded wind output is high.

Figure 3.18 shows the minimum weekly demands for the period January to May since market opening. The dark band represents the range of values for the years 2002 – 2008 while the lighter band shows the post-recession minimums for the 2009 to 2016 time frame. The squares represent the weekly minimums for the past six months.

The minimums of the past six months reflect the generally mild weather. Numerous times in 2017 the weekly minimums were reaching new lows. This is due to the aforementioned combination of impacts – embedded generation, conservation, mild weather and the level of overnight economic activity. The weekly minimums occur during the early morning hours of the weekend, when the level of economic activity is lowest.

Figure 3.18: Weekly Minimum Demands



- End of Section -

4.0 Forecasting Process and Assumptions

A detailed description of the forecasting methodology can be found in the document entitled "Methodology to Perform Long-Term Assessments" found on the IESO web site at http://www.ieso.ca/-/media/files/ieso/document-library/planning-forecasts/18-month-outlook/methodology_rtaa_2017jun.pdf.

The form and structure of the model have been modified to enhance and strengthen the explanatory powers of the economic drivers, conservation and embedded generation. The most recent demand, weather and economic data were incorporated into the model, which was re-estimated based on this information.

The forecast of demand requires inputs, and this section covers each class of drivers.

4.1 Calendar Drivers for Forecast

Calendar variables are addressed in the Methodology document. Essentially, forecasting demand for electricity according to the calendar – days of the week, holidays, sunrise and sunset – is pretty straightforward.

4.2 Economic Drivers for Forecast

To produce an energy and peak demand forecast, an economic forecast of various drivers is required. The IESO uses both a consensus of publicly available provincial forecasts and purchases forecasts of economic data in order to generate economic drivers for the demand forecast and to provide additional insight and analysis.

Canada has had strong economic fundamentals since the recession – low interest rates, a strong financial sector and a rich resource base – despite this, Canada has not experienced strong growth in the post-recession recovery period. Much of that is a reflection of the overall global situation as Canada is a trade dependent nation. Strong fundamentals at home cannot outweigh the declining demand from our trading partners who were experiencing sluggish growth.

The economic climate bodes well for central Canada's export-oriented manufacturing sector. Strong U.S. growth means there is a market for Canada's goods. Lower commodity prices mean the cost of inputs has declined. Finally, a lower dollar means exports will be more competitively priced. All this lays the ground work for improved economic activity in Ontario. Recent economic data suggests that Ontario's economy and its manufacturing base are showing increased strength.

There are a significant number of downside risks to the economic outlook. In particular, trade-based disputes surrounding the renegotiation of NAFTA could derail Ontario's economic trajectory. With the CETA and TPP, Canada is diversifying its export markets as to not be so U.S. dependent. However, those expanded markets will not shield the Ontario economy of any US/Canada trade issues in the near term.

Table 4.1 summarizes the key economic drivers for the demand forecast. The Ontario growth index is a weighting of the economic drivers as they relate to demand.

Table 4.1: Forecast of Ontario Economic Drivers

Year	Ontario Employment		Ontario Housing Starts		Ontario Growth Index	
	Thousands	Annual Growth (%)	Thousands	Annual Growth (%)	Index	Annual Growth (%)
2001	5,921	2.1	70.3	4.2	1.150	1.88
2002	6,034	1.5	79.6	13.3	1.169	1.65
2003	6,213	3.1	80.9	1.7	1.198	2.49
2004	6,314	1.7	79.9	-1.3	1.219	1.81
2005	6,381	1.3	73.2	-8.4	1.236	1.39
2006	6,452	1.5	67.8	-7.4	1.253	1.35
2007	6,545	1.6	62.8	-7.4	1.271	1.41
2008	6,610	1.5	71.9	14.6	1.287	1.23
2009	6,433	-2.7	47.9	-33.3	1.276	-0.85
2010	6,538	1.6	57.1	19.1	1.294	1.41
2011	6,658	1.8	65.2	14.3	1.314	1.60
2012	6,703	0.7	74.4	14.1	1.329	1.09
2013	6,823	1.8	58.6	-21.2	1.348	1.49
2014	6,878	0.8	56.2	-4.2	1.361	0.96
2015	6,923	0.7	68.3	21.6	1.375	1.00
2016	6,999	1.1	74.4	8.9	1.392	1.27
2017 (f)	7,094	1.4	77.5	4.2	1.412	1.42
2018 (f)	7,172	1.1	70.8	-8.6	1.429	1.22

The IESO has highlighted the shifting patterns in Ontario's employment as a measuring stick for sustained growth. Since the recession, growth has been sector- or region-specific and not broad-based. To generalize, much of the growth was centered in the service sector and in the GTA.

Figure 4.1 shows the year-over-year change in employment for Ontario, the Toronto zone and all other zones combined. Broad-based growth would mean that both Toronto and the other zones would be enjoying similar job creation. For the period following the recession, Ontario's economy experienced fairly broad-based growth over the 2010-2011 timeframe. Since then, however, growth has been an "either/or" experience with either the GTA or the rest of the province dominating. The last twelve months have shown a more balanced job growth between the two sub-provincial areas.

Figure 4.2 shows the year-over-year changes in employment broken down into services, manufacturing and other goods (mining, construction, agriculture, forestry, etc.). As with the zonal growth, a more broad-based and sustainable growth pattern would have growth across all of the sub-sectors. Since the start of 2016, employment growth is showing signs of being across all sectors.

Both these graphs point to a more broad based employment pattern, across regions and sectors. This is indicative of a more sustained economic expansion. Together with strong underlying economic fundamentals of low inflation, low interest rates and a competitive dollar will help the Ontario economy to growth over the forecast horizon.

Figure 4.1: Zonal Employment Growth

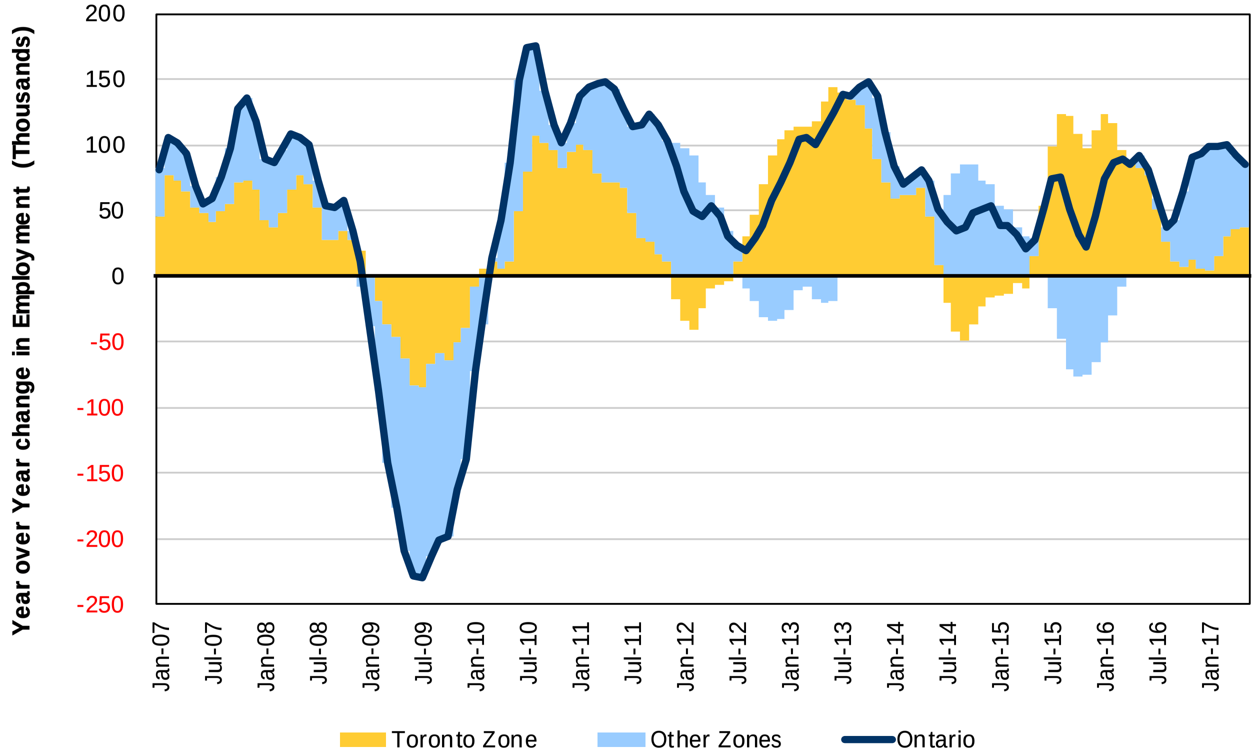
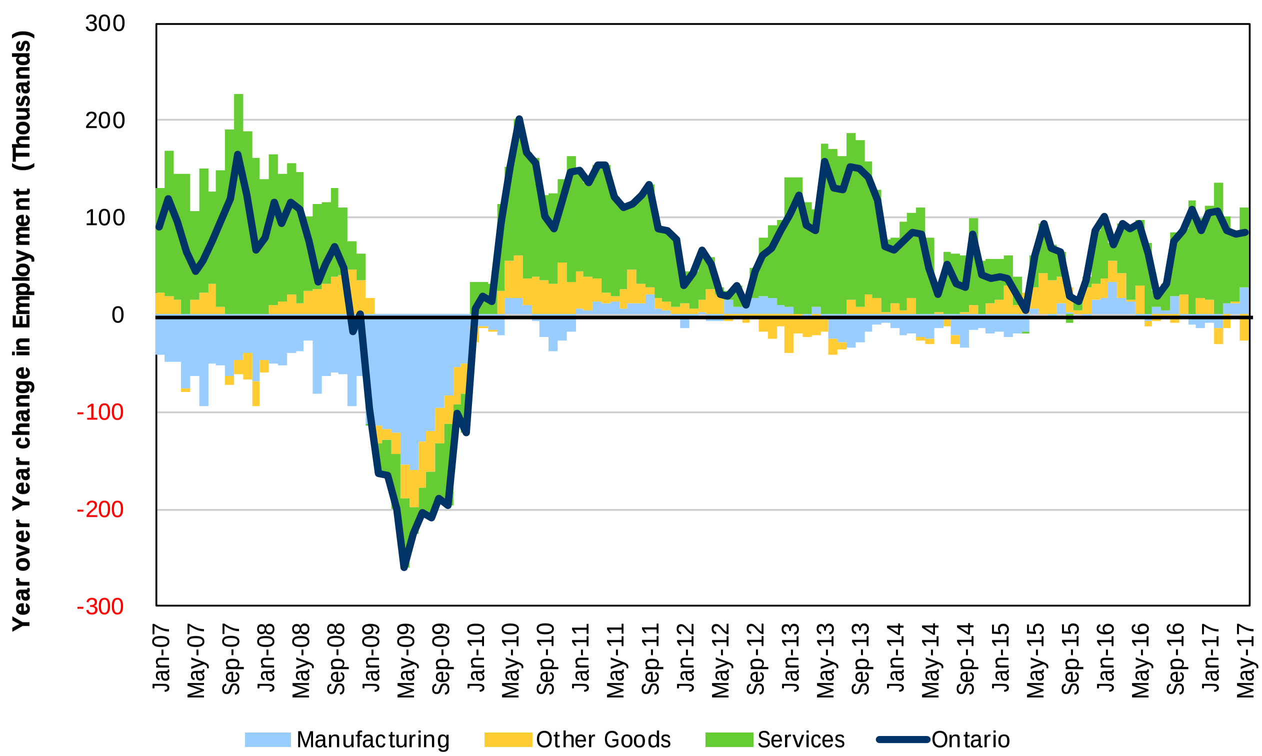


Figure 4.2: Composition of Ontario's Employment Growth



4.3 Weather Drivers for Forecast

Since forecasting long-term weather is not possible, weather scenarios are generated using historical data. The analytical studies that the IESO produces serve a variety of purposes and needs. As such, a variety of inputs are required. Therefore, the IESO produces demand forecasts based on a number of different weather scenarios. The most commonly utilized scenarios are Normal and Extreme.

The weather scenarios are generated using the following steps:

For each day over the past 31 years, a "weather factor" is calculated based on the weather conditions of that day (temperature, wind speed, cloud cover and humidity). This weather factor represents the MW impact on demand if those weather conditions were observed in the forecast horizon.

The daily weather factors are sorted from highest to lowest for each month.

Normal weather is based on the median value of the sorted weather factors across the 31 years of history. For example, the median value of the maximum weather factor from each January from 1980 to 2010 would be the first value for the normal January. The median value of the second highest weather factor from each January from 1980 to 2010 would be the second day in the normal January. This is repeated until all days in the month are generated. Once the normal months are created, they are mapped to the calendar based on the weekly average distribution of weather. The weekly peak-eliciting weather is always mapped to Wednesday to ensure that peaks do not occur on weekends or holidays.

Extreme weather is generated in a similar manner except that the maximum, rather than the median, value from the sorted 31-year history is used.

Load forecast uncertainty (LFU) -- a measure of demand fluctuations due to weather variability -- is a critical part of the analysis. In conjunction with the normal weather forecast, LFU is valuable in determining a distribution of potential outcomes under various weather conditions. The resource adequacy assessments use the Normal weather forecast in combination with LFU to consider a full range of peak demands that can occur under various weather conditions with varying probability of occurrence.

The Extreme weather scenario is valuable for studying situations where the system is under duress. Although the Extreme weather scenario is useful when examining peak conditions, it is unrealistic from an energy demand standpoint, as severe weather conditions do not persist over a long time period.

The 18-Month Outlook Tables spreadsheet includes Table 3.3.5, which has the Normal and Extreme weather scenarios. For each week, the table shows the historical weather used for the peak day of that week. The table shows the daily high (temperature) and wind speed. Not shown but used in forecasting demand are humidity and cloud cover. The IESO uses six weather stations in the demand models – the data in the table is for Toronto. The weather scenarios were updated for data through the end of December 2012.

4.4 Demand Measures and Load Modifiers

There are a number of initiatives and policies that have an impact on electricity demand. They can be grouped into two categories: demand measures and load modifiers. The rationale for the two categories is how they are treated with respect to the demand forecast. Demand measures are not incorporated into the demand forecast whereas the load modifiers are. In essence, demand measures are controllable while load modifiers are not. Demand measures include dispatchable loads, demand response programs and the peaksaver PLUS program. Load modifiers include conservation, prices and embedded generation.

Demand Measures

Demand measures are dispatched like a generation resource. Whether you dispatch a gas plant to meet a level of demand or dispatch a load off to reduce that level of demand, the system is indifferent as supply equals demand. For the correct accounting of demand measures, they must be treated equitably on both sides of the ledger. Therefore, since demand measures are included in the supply mix to be dispatched off, demand must be forecasted at the higher level prior to demand measures. The historical demand is reconstituted to include load that was shed through the various demand response programs. Demand measures have no impact on the demand forecast.

Load Modifiers -- Conservation

Conservation includes energy-efficiency programs, codes and standards and fuel switching. Projected conservation numbers are based on existing and future programs.

The impacts of conservation vary according to the program mix. For example, programs that promote increasing the efficiency of air conditioners will reduce the demand for electricity in summer but have no impact in the winter. Programs aimed at improving the insulation of building envelopes will impact electricity consumption year round.

Projected conservation impacts are incorporated into the demand forecast with the result of reducing forecasted demand.

Load Modifiers -- Prices

Prices include the impact of time-of-use (TOU) rates and the Industrial Conservation Initiative (ICI). Both are factored into the demand forecast. As both are relatively new, information continues to be gathered and analyzed. The impact of these programs continues to evolve as market participants and consumers gain more experience and adjust their consumption.

TOU impacts will vary as rates are set. The overall impact will be to shift load within the day or week. Overall, peaks will be impacted more than energy in the short term. However, an increased awareness of electricity pricing will lead consumers to make equipment and usage decisions that can impact total electricity consumption in the future.

The ICI offers a financial incentive to participants who reduce their consumption at the time of the peak for the five highest peak days. The program runs from May to April. The ICI was expanded this year to allow customers with an average monthly peak demand greater than 500 kW and less than 1 MW who are in the manufacturing and greenhouse sectors. As well, those sector restrictions were lifted for customers with a peak greater than 1 MW. This will allow large commercial customers such as hospitals, universities and hotels to participate. Peak reductions have grown as both the number of participants have increased and the participants have improved their ability to identify and react to the peaks. First-year (2010) reductions were estimated at 200 MW, growing to an estimated 1,300 MW for the five peak days in 2016.

Both TOU and ICI impacts are incorporated into the demand forecast.

Load Modifiers -- Embedded Generation

Embedded generation refers to load-displacing generation that is located on the market participants' side of the meter. This would include all generation under the Renewable Energy Standard Offer Program (RESOP), all generation under the microFIT program and some generation under the Green Energy Act's Feed-in Tariff (FIT). It also includes generators that are not contracted through the above programs. All output provided by embedded generation is an offset to grid-supplied electricity. Therefore, the impact of embedded generation is factored into the 18-month demand forecast as a reduction to demand.

For the forecast, embedded generation is split into groups according to fuel type: solar, wind, biomass, hydro and gas-fired generation. Figure 4.3 shows the installed and projected capacity of embedded generation by fuel type. As the graph shows, the vast majority of the embedded generation is solar. Due to its large share, solar output is treated differently than the other fuel types. The impact of solar generation is generated by using engineering models that use location, cloud cover and temperature to estimate solar production. The remaining embedded generation fuel types' output is produced using average production profiles based on history. The total embedded generation output is then incorporated into the demand forecast. Table 4.2 has a summary of the estimated embedded capacity by fuel type as of June for the history and the forecast period. A more detailed table is included in the 18-Month Outlook Tables.

Figure 4.3: Projected Embedded Generation Capacity

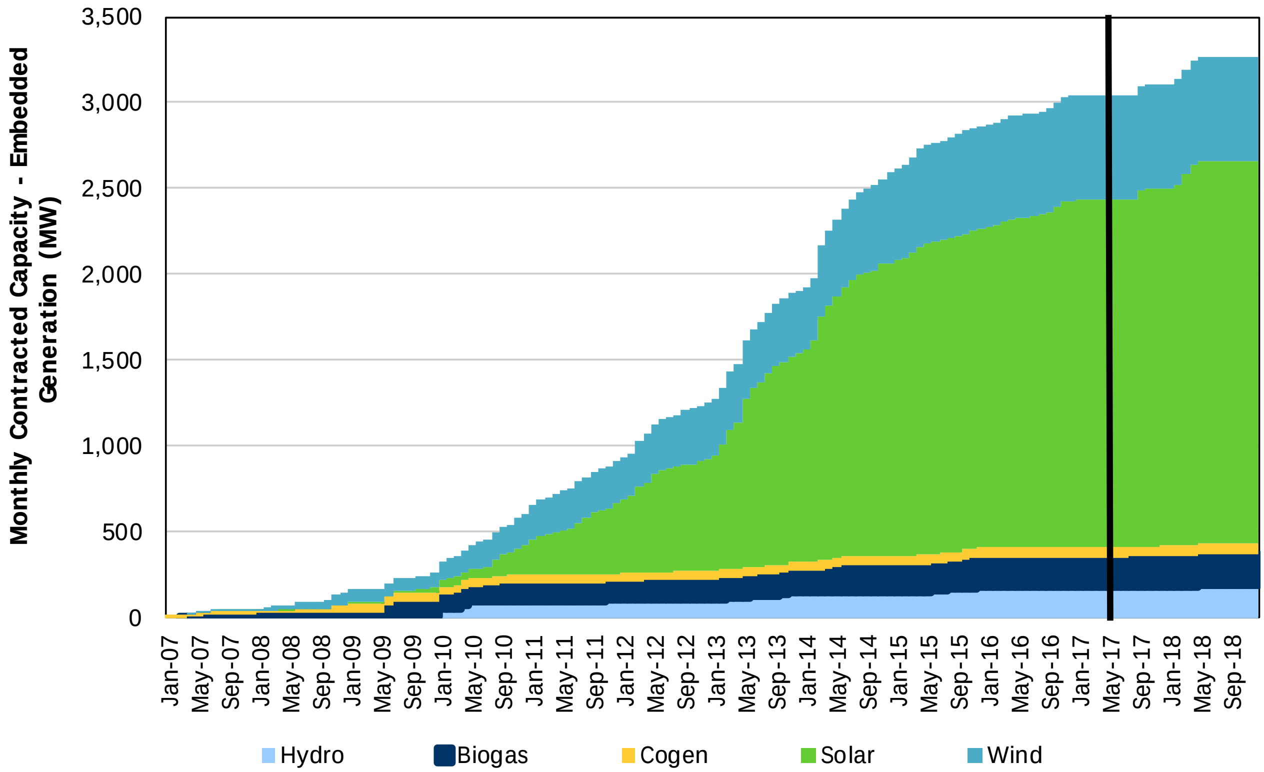


Table 4.2: Embedded Capacity

Month	Estimate of Contracted Embedded Generation Capacity (MW)					
	Biogas	Cogeneration	Solar	Hydro	Wind	Total
Jun-07	14	18	0	5	7	43
Jun-08	20	25	0	7	38	91
Jun-09	61	49	10	12	74	207
Jun-10	94	49	53	92	160	448
Jun-11	108	49	262	99	241	759
Jun-12	114	49	595	106	298	1,162
Jun-13	125	49	1,042	123	345	1,684
Jun-14	156	55	1,567	148	461	2,386
Jun-15	161	55	1,816	158	575	2,765
Jun-16	176	60	1,921	176	598	2,931
Jun-17	179	60	2,017	177	608	3,041
Jun-18	182	63	2,228	187	608	3,269

Over the course of the 18-month forecast, the amount of embedded solar installed capacity will range from over 1,900 MW to just over 2,200 MW. The impact of embedded solar on demand will vary over the course of the year and the time of day, due to the amount of sunlight available. Table 4.3 shows the monthly average forecasted capacity factor (%) of embedded solar at the time of the weekday peak hour. Since winter peaks occur after sunset, the average contribution is zero for the winter months. Note that, as discussed in section 3.3, embedded solar is having the impact of pushing summer peaks later in the day. As peaks move later in the day, the result is a reduction in the solar capacity contribution. Therefore solar capacity contribution during peak demand has decreased and will continue to decline. This has not been updated since the last Ontario Demand Outlook.

Table 4.3: Forecasted Embedded Solar Capacity for the Weekday Peak Hour

Monthly Average	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Forecasted Embedded Solar Capacity Factor (%) at Weekday Peak Hour	0.0%	0.0%	0.0%	0.0%	5.7%	20.0%	22.5%	17.3%	0.0%	0.0%	0.0%	0.0%

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