ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sched. B, as amended;

AND IN THE MATTER OF an application by Toronto Hydro-Electric System Limited for an order or orders approving or fixing just and reasonable distribution rates and other charges, effective January 1, 2020 to December 31, 2024.

EB-2018-0165

CROSS-EXAMINATION COMPENDIUM

PANEL 2

DISTRIBUTED RESOURCE COALITION

July 4, 2019

EB-2018-0165

PANEL 2 COMPENDIUM

Table of Contents

Advisory Committee on Innovation

Report to the Chair of the Ontario Energy Board

Actions the OEB can take to advance innovation in Ontario's energy sector

November, 2018

Recommendations

1. Provide a Transparent and Level Playing Field

Consistent rules of engagement provide predictability and transparency to parties about their rights and responsibilities when engaging in various activities. To facilitate growth in new service arrangements that will deliver greatest value for consumers these concepts must be extended to and embrace new players in the marketplace. The OEB should further promote innovation through the following actions:

A. Improve the transparency and consistency of the distribution system connection process and clarify cost responsibilities to reduce uncertainty for DER proponents, utilities and consumers

B. Establish clear rules for DER integration into distribution systems, addressing technical matters including information, visibility, management and control to, among other things, protect the reliable and safe operation of the distribution system, and optimize the planning and management of resources and assets

C. Establish guidelines for commercial arrangements governing performance of non-traditional resources so utilities and others can rely upon them as alternatives to traditional system investment

D. Reexamine regulatory restrictions on utility business activities and review the separation of regulated and competitive services in light of new technologies and service expectations

Recommendations

2. Remove Disincentives to Innovative Solutions

Putting nontraditional alternatives on an equal footing with traditional utility solutions can support pursuit of least-cost solutions with greatest value for consumers. To achieve this, the OEB should:

A. Remunerate utilities to make them indifferent to conventional or alternative solutions, including when other parties own and provide the alternative solution. Considerations will include, among other things, meaningful incentives and moving away from traditional rate base regulation

B. Establish an empirical evaluation methodology for cost-benefit comparison so all proposals are evaluated on a fair and consistent basis. Elements such as the value of optionality (i.e., the benefit of having options down the road), flexibility, location, time, resiliency, optimizing existing assets, and externalities as appropriate should be considered

C. Establish a way to ensure DERs can be compensated for their services commensurate with their value while paying their appropriate share of system costs. The approach should recognize new revenue streams which may be aggregated and allow shared cost recovery

D. Consider timely funding mechanisms to encourage utility innovation that provides near term customer benefits

Recommendations

3. Encourage Market-Based Solutions and Customer Choice

Information transparency is key to developing and deploying new market-based solutions. It expands the options for utilities to consider in their service offerings and enables informed consumer choice. In order to facilitate better access to information, the OEB should:

A. Require utilities to publish information about the characteristics and capabilities of their systems to enhance transparency of distribution system needs and capabilities within the market

B. Encourage cost-effective investment by utilities in monitoring and control capabilities to the extent that these enabling investments will help them efficiently manage a more dynamic distribution system

Recommendations

4. Embrace Simplified Regulation

Regulatory processes serve an important purpose but their complexity and pace is not conducive to deployment of innovation. Consumers, utilities and innovators in the sector need a simple and timely way of trying things out and learning from their experience. Regulatory simplicity will result in better pathways for innovation. In order to embrace simplified regulation, the OEB should:

A. Provide a means by which both utilities and unregulated entities are encouraged to discuss specific regulatory obstacles with the OEB, in order to allow near-term deployment of innovations while longer-term regulatory reforms are implemented

B. Review the information the OEB collects to ensure it is used to evaluate performance in the sector – specifically whether utilities, other service providers and regulation itself are benefitting customers

C. Explore the use of self-executing processes that use transparent, pre-approved criteria to allow streamlined regulatory review

D. Further examine OEB decision timelines to determine whether they can be shortened without compromising the effectiveness of stakeholder participation

Ontario Energy Board

Report of the Board

Supplemental Report on Smart Grid

EB-2011-0004

February 11, 2013

distributed generation, the Board notes that it has made a number of amendments to the Distribution System Code to facilitate the connection of distributed generation.

Another example of relevant investments would be using intelligent devices on the system such that network maintenance is enhanced. This investment can be targeted to where and when it is needed and operational efficiencies can be achieved, including improved power quality and outage management to increase reliability of service to customers.

The Board notes that some distributors have already undertaken, with Board approval, pilot and demonstration projects related to power system flexibility, including systems that facilitate real time communications with distributed generators and software solutions that enhance network intelligence (e.g., outage responsiveness).

As distributors plan for the modernization of their systems they must consider cost and the expectations for service from their customers and invest accordingly. The Board does not intend to prescribe specific investments and technological choices to be implemented. The Board recognizes that there is a diversity of circumstances among distributors. For example, an investment considered standard practice for one distributor may represent a significant modernization activity for a different distributor because of differences in size, geography, or evolution of customer preferences.

3.3 Adaptive Infrastructure

The Minister's Directive sets out the adaptive infrastructure objectives as follows:

> "For the purpose of 'accommodating the use of emerging, innovative and energy saving technologies and system control applications,' in accordance with subsection 2(1.3)(c) of the Electricity Act."

As noted in Section 2, the adaptive infrastructure objectives in the Minister's Directive align with the outcomes of Operational Effectiveness and Public Policy Responsiveness. The Board's expectations for this area are based on the renewed regulatory framework's goals of promoting ongoing productivity improvements and encouraging innovation.

Regulated entities must demonstrate in their investment plans that they have investigated opportunities for operational efficiencies and improved asset management, enabled by more and better data provided by smart grid technology. Investments that support and advance network operation and evolution (e.g., energy storage, interoperability, forward compatibility, and electric vehicles) are expected to be pursued when and where appropriate. As stated with respect to power system flexibility in Section 3.2, the Board does not intend to prescribe specific investments and technological choices for regulated entities.

Following Board approval, some distributors have already undertaken pilot and demonstration projects related to adaptive infrastructure, including electric vehicle charging, home energy management applications, and electricity storage options. The Board expects that distributors will report on the outcomes and learning from these pilots for the benefit all regulated entities. This expectation is consistent with the Board's policies (e.g., Filing Requirements: Distribution System Plans), which emphasize the need to avoid duplication of efforts in testing out and learning about new technologies.

The adaptive infrastructure objective in the Minister's Directive includes the following parameters: "Encourage Innovation" and "Maintain Pulse On Innovation." **When applicable and appropriate, capital and investment planning by regulated entities must demonstrate the consideration and/or adoption of innovative processes, services, business models, and technologies as well as an awareness of innovation and best practices.** As the Board identified in the RRFE Report, additional guidance from the Board regarding innovation is forthcoming. The Board intends to explore further opportunities to embed in the rate-setting framework for distributors (and eventually all regulated entities) the facilitation and recognition of technological innovation. Smart grid development and implementation activities will be a central focus of that effort.

Investing in the Middle Class

BUDGET 2019

Tabled in the House of Commons
by the Honourable
William Francis Morneau, P.C., M.P.
Minister of Finance

March 19, 2019

For more information, please contact Service Canada at
1 800 O-Canada (1-800-622-6232)
TTY: 1-800-926-9105

Cat No.: F1-23/3E-PDF
ISSN: 1719-7740

This document is available on the Internet at www.fin.gc.ca

Cette publication est aussi disponible en français.

Part 2: Affordable Electricity Bills and a Clean Economy

For too many Canadians, the rising cost of electricity is a source of economic anxiety. No one should have to choose between heating their home in winter and being able to afford the other things that provide a good quality of life—things like healthy, nutritious food, or clothes for family members. Yet the fact remains that in many Canadian cities, the cost of electricity is rising much faster than growth in household disposable income—making it hard for many people to make ends meet.

Budget 2019 proposes a number of measures to help hard-working Canadians more easily afford this necessity.

Investing in the Future of Transportation

Transportation accounts for about one quarter of Canada's greenhouse gas emissions, mainly coming from gas- and diesel-powered cars and trucks. The future of transportation lies in the increased use of zero-emission vehicles—cars and trucks powered by rechargeable electric batteries or hydrogen fuel cells. While these vehicles are not yet common in communities across Canada, they can provide a cleaner, more efficient way to transport people and goods and, over the long run, help Canadians reduce the everyday cost of transportation.

That is why Canada has set a target to sell 100 per cent zero-emission vehicles by 2040, with sales goals of 10 per cent by 2025 and 30 per cent by 2030 along the way. By becoming an early adopter of this new technology, Canada will help the Canadian zero-emission vehicle market advance, making zero-emission vehicle options more readily available and affordable for more and more Canadians.

Making Zero-Emission Vehicles More Affordable

More and more Canadians are choosing to drive zero-emission vehicles as an increasing number of models become available and prices decline. Those who have already purchased these vehicles are realizing the financial savings from lower operating costs. The Government is taking action to help more Canadians choose zero-emission vehicles, which will allow Canada to transition to a low carbon economy and reduce transportation costs for the middle class. The Government also wants to encourage investment in Canada's domestic auto industry so that it can become a global leader in zero-emission transportation manufacturing.

Budget 2019 proposes strategic investments that will make it easier and more affordable for Canadians to choose zero-emission vehicles—helping people to get from place to place, improving air quality and cutting greenhouse gas emissions at the same time.

To expand the network of zero-emission vehicle charging and refuelling stations, Budget 2019 proposes to build on previous investments by providing Natural Resources Canada with $130 million over five years, starting in 2019–20, to deploy new recharging and refuelling stations in workplaces, public parking spots, commercial and multi-unit residential buildings, and remote locations.

Meeting the ambitious sales targets requires automakers to make sufficient models and numbers of zero-emission vehicles available for sale to meet Canadian needs. Budget 2019 proposes to provide $5 million over five years, starting in 2019–20 to Transport Canada to work with auto manufacturers to secure voluntary zero-emission vehicle sales targets to ensure that vehicle supply meets increased demand.

To encourage more Canadians to buy zero-emission vehicles, Budget 2019 proposes to provide $300 million over three years, starting in 2019–20, to Transport Canada to introduce a new federal purchase incentive of up to $5,000 for electric battery or hydrogen fuel cell vehicles with a manufacturer's suggested retail price of less than $45,000. Program details to follow.

To attract and support new high-quality, job-creating investments in zero-emission vehicle manufacturing in Canada, automotive manufacturers and parts suppliers can access funding through the Strategic Innovation Fund, which was recently provided $800 million in additional funding through the 2018 *Fall Economic Statement*.

Supporting Business Investment in Zero-Emission Vehicles

To further support businesses' adoption of zero-emission vehicles, Budget 2019 proposes that these vehicles be eligible for a full tax write-off in the year they are put in use. Qualifying vehicles will include electric battery, plug-in hybrid (with a battery capacity of at least 15 kWh) or hydrogen fuel cell vehicles, including light-, medium- and heavy-duty vehicles purchased by a business. This will encourage all businesses to convert to zero-emission fleets and leave more money to be invested in other productive ways. For example, a taxi company or a school bus operator will be able to recoup their investments in eligible zero-emission vehicles in a faster manner.

Immediate expensing will apply to eligible vehicles purchased on or after March 19, 2019 and before January 1, 2024. Capital costs for eligible zero-emission passenger vehicles will be deductible up to a limit of $55,000 plus sales tax. This is higher than the capital cost limit of $30,000 plus sales tax that currently applies to passenger vehicles. This new $55,000 capital cost limit reflects the comparably higher cost of zero-emission vehicles and will be reviewed annually to ensure that it remains appropriate as market prices evolve over time.

How Immediate Expensing Will Support Investment in Zero-Emission Vehicles

Anne is a travelling sales representative working as an independent contractor. She needs to replace the aging gasoline vehicle that she currently uses strictly for her business and is considering the advantages of buying an electric vehicle. Anne drives long distances every day and requires an electric vehicle with a long range. She found that a suitable electric vehicle has a cost of $48,000. With measures announced in this Budget, she could deduct the $48,000 purchase price of the electric vehicle in full in the year she starts using it. This is in addition to the fact that she would be refunded the GST or HST paid. The decision to purchase an electric vehicle would reduce Anne's federal/provincial income taxes and GST/HST in the year she acquires the vehicle by about $13,000. This significantly reduces the impact of the higher initial price of the electric vehicle. Given the electric car's lower operating costs, Anne concludes that opting for the electric vehicle would result in savings over time. This choice significantly reduces the carbon footprint of Anne's business, while freeing up resources for other purposes in the year she acquires the vehicle.

Happy Transport provides transportation services to schools in a rapidly growing community. The corporation would like to acquire $1 million worth of new electric school buses to expand its operations. Over time, Happy Transport expects that the lower operating costs of the electric school buses will improve profitability and allow it to further expand its business and the employment opportunity it provides. With immediate expensing for zero-emission vehicles, Happy Transport will be allowed to deduct from income the full $1 million acquisition cost in the year the buses are acquired. This is $550,000 more than previously permitted, resulting in savings of over $145,000 in current federal and provincial corporate income taxes. This improved cash-flow will help Happy Transport secure the bank loan it requires to pay for the increased upfront costs of electric school buses.

Toronto Hydro-Electric System Limited
EB-2018-0165
Exhibit 2B
Section E
Appendix E
ORIGINAL
(105 pages)

CENTRAL TORONTO AREA
INTEGRATED REGIONAL RESOURCE PLAN

Part of the Metro Toronto Planning Region | April 28, 2015

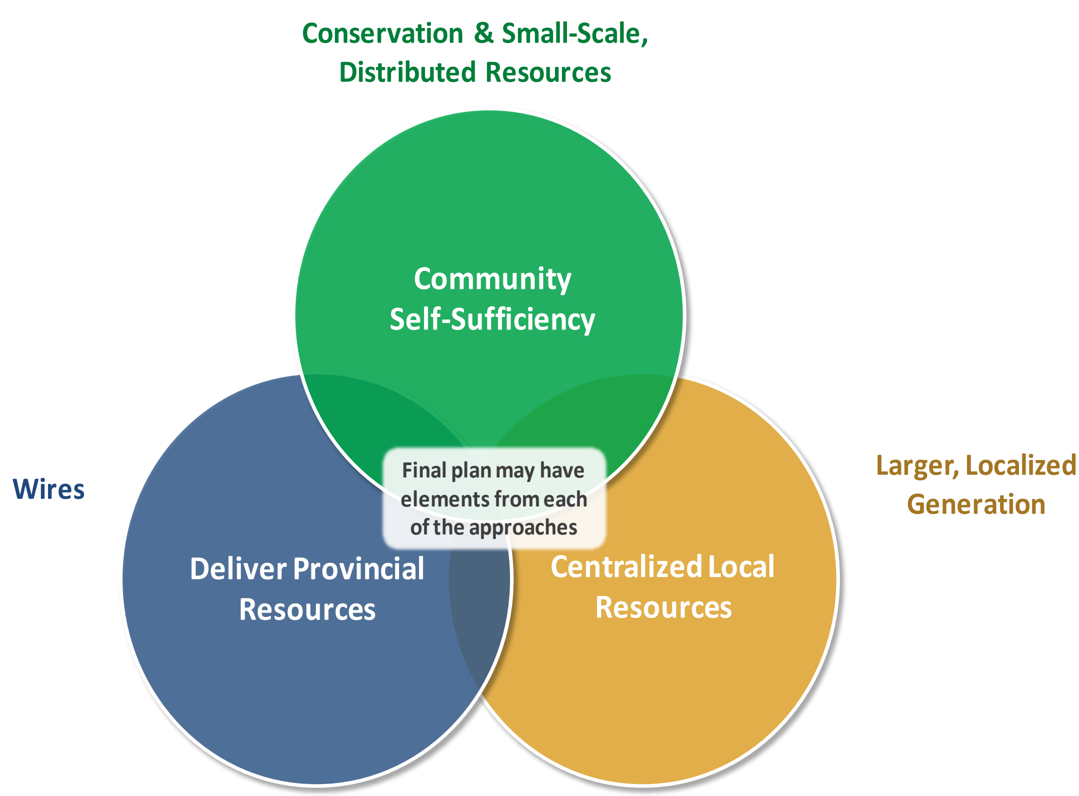
ieso
Independent Electricity System Operator

8.1 Approaches to Meeting Long-Term Needs

In recent years, a number of trends, including technology advances, policy changes supporting DG, greater emphasis on conservation as part of electricity system planning, and increased community interest in electricity planning and infrastructure siting, are changing the landscape for regional electricity planning. Traditional, "wires" based approaches to electricity planning may not be the best fit for all communities. New approaches that acknowledge and take advantage of these trends should also be considered.

To facilitate discussions about how a community might envision its future electricity supply, three conceptual approaches for meeting a region's long-term electricity needs provide a useful framework (Figure 8-3). Based on regional planning experience across the province over the last ten years, it is clear that different approaches are preferred in different regions, depending on local electricity needs and opportunities, and the desired level of involvement by customers and the community in planning and developing local energy systems.

Figure 8-3: Approaches to Meeting Long-Term Needs



The three approaches are as follows:

- **Delivering provincial resources**, or "wires" planning, is the traditional regional planning approach associated with the development of electric power systems over many decades. This approach involves using transmission and distribution infrastructure to supply a region's electricity needs, taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, with generation sources typically located remotely from the region. In this approach, utilities (transmitters and distributors) play a lead role in development.
- The **Centralized local resources** approach involves developing one or a few large, local generation resources to supply a community. While this approach shares the goal of providing supply locally with the community self-sufficiency approach below, the emphasis is on large central-plant facilities rather than smaller, distributed resources.
- The **Community self-sufficiency** approach entails an emphasis on meeting community needs largely with local, distributed resources, which can include: aggressive conservation beyond provincial targets, demand response, local renewable, DG and storage, smart grid technologies for managing distributed generation resources; integrated heat/power/process systems and electric vehicles ("EV"). While many of these applications are not currently in widespread use, for regions with long-term needs (i.e., 10-20 years in the future) there is an opportunity to develop and test these options before commitment to specific projects is required. The success of this approach depends on early action to explore potential and develop options; it also requires the local community to take a lead role. This could be through a Community Energy Planning process, or a LDC or other local entity taking the initiative to pursue and develop options.

The intent of this discussion, going forward, is to identify which approach should be emphasized in a particular region. In practice, certain elements of electricity plans will be common to all three approaches, and there will necessarily be some overlap between them. For example, provincially mandated conservation policies will be an element in all regional electricity plans, regardless of which planning approach is adopted for a region. As well, it is likely that all plans will contain some combination of conservation, local generation, transmission, and distribution elements. Once the preferences of the community are made clear, a plan can be developed around the approach that makes the most sense, which will affect the relative balance of conservation, generation, and wires in the plan. Details of how these three approaches could be developed to meet the specific long-term needs of Central Toronto are provided in the following sections.

The cost of the generation would depend on the size and technology of the units chosen, as well as the degree to which they can contribute to a provincial capacity or energy need.

8.1.3 Community Self-Sufficiency

Addressing the long-term needs of Toronto under an approach that favours community self-sufficiency requires leadership from the community itself to identify opportunities and deploy solutions. As this approach relies to a great degree on new and emerging technologies, there will be a need to develop and test solutions to establish their potential and cost-effectiveness, so that they can be appropriately assessed in future regional plans.

In Toronto, there is strong community interest in this approach, as evidenced by the municipality taking the lead in identifying and developing energy-based opportunities within the city. Some of these initiatives are described below.

Community Energy Plans

A Community Energy Plan[27] ("CEP") is a comprehensive long-term plan to improve energy efficiency, reduce energy consumption and greenhouse gas ("GHG") emissions. A number of municipalities across the province are undertaking Community Energy Plans to better understand their local energy needs, identify opportunities for energy efficiency and clean energy, and develop plans that better align energy, infrastructure and land use planning within the community.

The City of Toronto has completed a number of Community Energy Plans and others are in progress. While these plans may, more typically, be conducted at the level of the municipality, the size and character of the City of Toronto has resulted in a number of plans being done across the City. The CEPs completed and underway in the City of Toronto include:

- Etobicoke Centre (completed 2008)
- North York (completed 2010)
- Etobicoke – Mimico (completed 2012)
- Scarborough Centre (completed 2014)
- Downtown – Lower Yonge Precinct (in-progress)
- Etobicoke Centre – Six Points Interchange Reconfiguration (in-progress)
- North York – York University (in-progress)

[27] These plans are sometimes referred to as "Municipal Energy Plans."

Integrated energy planning at the community level provides an opportunity for broader consideration of land-use, development and growth, infrastructure requirements and technology solutions that include:

- Advanced fuel cell technologies
- Energy storage technologies
- Demand response programs – particularly residential and small commercial demand response programs enabled by aggregators
- Aggressive conservation programs targeted at residential consumers and enabled by next-generation home area networks
- Battery electric vehicle storage capabilities, especially for load intensification cluster applications
- Enhanced renewable generation opportunities enabled by next-generation storage technologies
- Micro-grid and micro-generation technologies coupled with next-generation storage technologies
- Combined Heat and Power and district energy opportunities
- Renewed consideration of the Load Serving Entity/aggregator market model

The Working Group recognizes that there are risks associated with the community self-sufficiency approach, with the most crucial being the ability to successfully meet the electricity demand growth needs with new and unproven load management and storage technologies. Other key challenges include demonstrating consumer value, cost recovery certainty for innovative technologies and the risk of asset stranding, risk/reward incentives and technological obsolescence as a factor for asset replacement.

E5.1 Customer Connections

E5.1.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 176.1	**2020-2024 Cost ($M):** 223.4
Segments: Load Connections; Generation Connections	
Trigger Driver: Customer Service Requests	
Outcomes: Customer Service, Public Policy, Safety, Reliability	

The Customer Connections program ("the Program") captures system investments that Toronto Hydro is required to make to provide customers with access to its distribution system. This includes enabling new or modified load and distributed generation ("DG") connections to the distribution system, in accordance with legal and regulatory obligations under various statutes and codes. This Program is a continuation of customer connection activities described in Toronto Hydro's 2015-2019 Distribution System Plan.[1]

Toronto Hydro's primary objective in this Program is to provide new and existing customers with timely, cost-efficient, reliable, and safe access to the distribution system. In pursuing this objective, the utility strives to meet, and where possible, exceed, all mandated service obligations. In 2017, Toronto Hydro completed 98.32 percent, and 98.41 percent, of low voltage (below 750 V) and high voltage (750 V or above) connections, respectively, as well as 92.41 percent of distributed generation connections on time.[2]

The Program is comprised of two segments:

- **Load Connections**: This segment involves completing new load connections and upgrades to existing load connections. Customers are connected to one of the various overhead or underground distribution systems in the City. The work also includes any expansion work necessary to address capacity constraints for the purpose of connecting customers.

[1] EB-2014-0116, Exhibit 2B, Section E5.2
[2] These metrics will be published in Toronto Hydro's 2017 Scorecard.

Table 10: Basic Connection Fees

Customer Class		Basic Connection Fee
Class 1 to 5		$1,396
Unmetered (excluding street lighting)	*Overhead Supply*	$446 or $1,011
	Underground Supply	Collected directly from Customer

The contributions filed in the last application assumed a gross spend (and capital contribution ratio of 25 percent) identical to the 2014 historical, which was further adjusted as anticipated Metrolinx costs and contributions were added. However, the actual contributions received in 2015 and 2017 exceeded the forecast by $36 million. Therefore, to smooth any cyclical trends and better reflect actual contributions, the 2020-2024 forecast utilizes the average capital contribution of 46 percent experienced during the most recent 5-year period (i.e. 2013 to 2017).

Overall, for the 2015-2019 period, the load connection segment is forecasted to be within 5 percent of gross expenditures initially planned, however, recovered capital contributions were 90 percent higher than what was initially planned. This resulted in lower net expenditures.

The Customer Connections program is driven by customer service requests and as such, Toronto Hydro ranks and prioritizes jobs in this Program in accordance with the schedules and timelines of individual customers and service requests.

For customers requiring basic connections, prioritization is conducted on a first come, first served basis, taking into account the in-service date requested by the customer. This prioritization applies where Toronto Hydro has sufficient physical infrastructure, such as through overhead or underground lines, to enable the connection as well as adequate capacity on the relevant distribution feeder cable and station bus. Furthermore, customer timelines are considered to minimize disruptions or allow for efficiencies, whenever possible.

Wherever civil or electrical capacity is constrained or reliability is a concern, the connection is completed once the constraints are addressed by an expansion or system enhancement. For connections that cannot be completed without an expansion, prioritization of the work is determined in accordance with the timelines and requirements stated in the OTC.

E5.1.4.2 Generation Connections

Table 11: Historical & Forecast Program Costs ($ Millions)

		Actual			Bridge		Forecast				
		2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Generation Connection	*Gross*	0.9	0.6	0.8	3.4	2.8	2.9	3.5	3.2	4.1	4.5
	Customer Contribution†	(1.8)	(0.2)	(1.0)	(3.4)	(2.8)	(2.9)	(3.5)	(3.2)	(4.1)	(4.5)
	Net[24]	**(0.9)**	**0.4**	**(0.2)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

† Work and costs associated with additional modifications to the distribution system to incorporate renewable generation into the system are not paid for by the customer, and therefore, not covered under this Program. Such work and costs are discussed in the Generation Protection, Monitoring, and Control program see Exhibit 2B, Section E5.5.

The Generation Connection forecast has been compiled based on historical trends, completed assessments, and anticipated projects. A linear approximation was used to forecast the anticipated number of connections and total generation from 2018 through 2024. The forecast assumes the following:

1) The microFIT & FIT program will transition to a net metering program in 2018, as per the direction issued by the Minister of Energy on April 5, 2016;
   - no major changes will be introduced to the net metering program from 2020 to 2024;
2) A steady 3 percent increase year-over-year for renewable connections;
   - 90 micro and 60 small sized renewable connections in 2019 are used as the baseline;
3) Increased demand for energy storage connections due to reductions in lithium-ion battery prices;
   - 12 micro, 5 small and 3 medium sized energy storage connections in 2019 are used as the baseline, and a 20 percent increase year-over-year is used to forecast 2020-2024 connections;
4) Increased demand for CHP and diesel connections due to customers seeking site reliability and electricity charge reductions;

[24] All DG connections are 100 percent funded by capital contributions from the customer, and consequently, there should be zero net expenditure for DG connections. However, due to the pacing and timing of a DG installation, capital contributions may be collected from the customer in one year whereas the gross expenditures may span several years. As a result, the 2015- 2017 historical yearly total net expenditures do not equal zero.

- 15 small and 2 medium sized natural gas connections in 2019 are used as the baseline, and a 15 percent increase year-over-year is used to forecast 2020-2024 connections; and
- 1 small and 4 medium sized diesel connections in 2019 are used as the baseline, and an extra unit is forecasted to be added every two years.

Table 12 and Table 13 below provide a breakdown of work units and costs associated with the Generation Connection program based on generation type and size.

Table 12: 2015-2019 Volumes (Actual/Bridge)

Generation Type	Actual			Bridge		Total
	2015	2016	2017	2018	2019	
Micro (Renewable & Energy Storage)	122	124	155	247	102	**750**
Small Renewable	251	24	89	99	71	**534**
Small (Natural Gas, Diesel & Energy Storage)	2	2	3	22	23	**52**
Medium (Renewable, Natural Gas & Energy Storage)	1	2	2	6	2	**13**
Medium (Diesel)	3	2	-	8	8	**21**
Large (Natural Gas & Energy Storage)	-	-	-	-	3	**3**
Large Diesel	-	-	-	-	1	**1**

Table 13: 2020-2024 Volumes (Forecast)

Generation Type	Forecast					Total
	2020	2021	2022	2023	2024	
Micro (Renewable & Energy Storage)	108	114	121	129	139	**611**
Small Renewable	62	64	66	68	71	**331**
Small (Natural Gas, Diesel & Energy Storage)	25	30	36	43	51	**185**
Medium (Renewable, Natural Gas & Energy Storage)	4	4	4	5	5	**22**
Medium (Diesel)	9	10	11	13	14	**57**
Large (Natural Gas & Energy Storage)	1	2	-	1	1	**5**
Large Diesel	-	1	-	-	1	**2**

Toronto Hydro does not propose any net expenditure under this Program for the years 2020 to 2024 as all DG connections are 100 percent funded by capital contributions from the customer. Work and costs associated with additional modifications to the distribution system to incorporate renewable generation into the system are not paid for by the customer, and therefore, not covered under this Program but under the Generation Protection, Monitoring, and Control program.[25]

Toronto Hydro has a dedicated generation planning team that supports DG connections. The team works closely with customers to ensure the DG connection process is followed and timelines are met. Generation connections, like customer load connections, are processed and completed on a first come first serve basis. As such, the proposed investment pacing of this Program is based on historical trends, completed assessments, and anticipated projects.

E5.1.4.3 Cost Management

Toronto Hydro integrates the connection work with its planned construction activities to help ensure that the scope, nature and timing of the connection work does not adversely affect the utility's existing customers and planned work program.

If Toronto Hydro anticipates that load growth will require additional infrastructure upgrades beyond what is required under the expansion work set out in the OTC, the utility will include the additional distribution work, which can range from installing larger circuits to rebuilding cable chambers, as a part of the project. Project costs are allocated to the respective programs (e.g. Load Demand, Externally Initiated Plant, Overhead System Renewal, or Underground System Renewal). This coordinated approach is more cost-efficient than returning to the same area at a later date to perform additional upgrades.

An example of this approach can be found in work along Toronto's Waterfront, where the required civil work to connect new condominiums and developments was augmented to include the additional infrastructure necessary to meet future demands and system requirements that are imminently expected based on the City's Precinct Plans and progress for the revitalisation project.

Wherever possible, Toronto Hydro also coordinates its connection work with construction activities undertaken by other utilities or municipal or provincial government agencies. For example, Toronto

[25] Exhibit 2B, Section E5.5.

E8.1 Control Operations Reinforcement

E8.1.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): N/A	**2020-2024 Cost ($M):** 40.2
Segments: Control Operations Reinforcement	
Trigger Driver: Operational Resilience	
Outcomes: Reliability, Safety, Customer Service, Public Policy	

The Control Operations Reinforcement program (the "Program") will increase Toronto Hydro's operational resiliency and improve the utility's ability to safely operate the distribution grid by creating a fully functional dual Control Centre at its [redacted] work centre. The dual Control Centre at Toronto Hydro will be designed to withstand evolving hazards and threats, deliver reliable electricity, and support the capability to restore electricity as efficiently as possible.

Toronto Hydro's existing Control Centre is a critical infrastructure that acts as a control authority and real-time operator of the distribution system within the City of Toronto. Control Centre operations are hosted from Toronto Hydro's 500 Commissioners work centre and include the following two primary responsibilities:

1) maintain real-time control of Toronto Hydro's distribution plant through telemetry and remote operation of station breakers and field devices; and
2) coordinate all activities involving field crew workers within the "safe limits of approach" to Toronto Hydro plant that is energized above 750 Volts, as prescribed by the Ontario Electrical Safety Code and Electrical Utility Safety Rules.

Failure of Toronto Hydro's existing Control Centre can have substantial financial and economic consequences for Toronto, the largest city in Canada, the fourth largest in North America, and the economic and financial centre of the country.

The proposed dual Control Centre at [redacted] will replace the existing back-up Control Centre at Toronto Hydro's [redacted] location and will be used to operate and control Toronto Hydro's distribution grid in parallel with the primary Control Centre. [redacted]

[redacted]

The development of a dual Control Centre will allow Toronto Hydro to more effectively safeguard, manage, and operate its distribution system, minimize potential safety hazards to the public and employees, and minimize business interruption impacts on its customers, should the primary Control Centre be compromised.

As energy policy changes, bringing innovation and new technology, the evolution of the smart grid is changing the value proposition of Control Centres. Control Centres are becoming more integrated with the technology, not only from a monitoring and control of energy delivery perspective but also from an energy management perspective, elevating their role and importance. The growth of distributed generation has also given distributors some of the reliability responsibilities traditionally reserved for transmission utilities.[1] [redacted] As such, as part of the Program, Toronto Hydro intends to build its dual Control Centre with the technology required to manage this growing system requirement.

In addition, over the last five years, Toronto Hydro's operations have been disrupted by several large-scale environmental and other hazard events. These large scale environmental and hazard events are becoming increasingly more common within Toronto Hydro's service territory and across the industry.[2] For instance, in 2018 alone, Toronto Hydro has experienced four severe weather-related events that caused wide-spread damage and outages.[3] Further, in addition to more frequent and severe weather events, there continues to be an escalation of terrorist attacks on people and property, cyber terrorist attacks, as well as system attacks from increasingly sophisticated hackers. The impact of these events on the distribution system has already been experienced in Ukraine, as demonstrated by the 2015 cyber-attack on three separate distribution companies where continuity

[1] London Economics International LLC, Jurisdictional Review and Economic Case for a Dual Distribution Control Center in Toronto Hydro Territory (June 22, 2018), at p. 15.
[2] AECOM Environment, Toronto Hydro-Electrical Systems Limited Climate Change Vulnerability Assessment filed in EB-2014-0116, Toronto Hydro-Electric System Limited, Exhibit 2B, E8.8, Appendix A (Filed July 31, 2014, Updated February 6, 2015).
[3] See Table 6 for examples of recent severe weather events in Toronto.

of service was disrupted for up to 225,000 customers.[4] Canada is not immune to such threats. Public Safety Canada issued a report titled "The 2017 Public Report on The Terrorist Threat to Canada" indicating that since 2014, Canada's terrorism threat level is Medium, meaning that a violent act of terrorism could occur.[5]

Toronto Hydro has examined its existing operational capabilities in light of these emerging challenges and needs. The plans contained in this Program address the shortcomings of Toronto Hydro's current back-up Control Centre. To assess Toronto Hydro's investment in a dual Control Centre, the utility retained London Economics International ("LEI") to undertake a review of comparator utilities with fully functional dual control centres as well as an economic analysis determining whether this investment is justifiable, see Appendix A.[6] LEI found that utilities expressed similar rationales for requiring a dual control centre, including supporting resiliency, increasing reliability, and ensuring quick recovery from terrorist threats and natural disasters, for example earthquakes, storms, and floods.[7] LEI also found that the growth in distributed energy resources, as is the case in Toronto, has caused distribution utility operations to be more complex and take on some of the traditional responsibilities associated with the Bulk Electricity System, including managing interconnected generation and greater responsibility over bulk system reliability.[8] The review concludes that based on the estimated cost of an outage, the investment in a dual control centre can be economically justified if it can reduce the duration of such an outage.[9]

[4] Electricity Information Sharing and Analysis Center, White Analysis of the Cyber Attack on the Ukrainian Power Grid (March 18, 2016) at p. 1, found at <https://www.nerc.com>.
[5] 2017 Public Report on the Terrorist Threat to Canada (December 17, 2017), found at <https://www.publicsafety.gc.ca/cnt/rsrcs/pblctns/pblc-rprt-trrrst-thrt-cnd-2017/index-en.aspx>.
[6] Supra note 1.
[7] Ibid at pp. 5-14.
[8] Ibid at p.16.
[9] Ibid at pp. 24-26.

E8.1.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Reducing the likelihood of a complete or partial stand-down of field work and the likelihood of cascading outages resulting from interruption to visibility over the distribution system; and ○ Ensuring compliance with requirements relating to system restoration planning outlined in Chapter 5, Section 11 of the Market Rules.
Safety	• Contributes to Toronto Hydro's safety objectives as measured by Total Recordable Injury Frequency ("TRIF") by: ○ Providing seamless visibility over the distribution system, thereby reducing the likelihood of worker/public injury resulting from loading issues and inadvertent energizing of equipment; ○ Ensuring efficient administration and application of the Toronto Hydro Work Protection Code; and ○ Maintaining compliance with Ontario Regulation 22/04 (Electrical Distribution Safety) through timely reporting of serious electrical incidents involving Toronto Hydro plant.
Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Ensuring continued capability to receive and respond to trouble calls from customers and/or external stakeholders; ○ Maintaining the capability to effectively manage, prioritize and resolve multiple concurrent system issues impacting customers; and ○ Providing relevant and timely outage information to customers, such as estimated outage restoration times and other situational information relating to system outages.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by consistently meeting OEB-mandated service quality targets with respect to Emergency Response (Distribution System Code, s. 7.9).

E8.1.3 Drivers and Need

Table 3: Program Drivers

Trigger Drivers	Operational Resilience
Secondary Driver(s)	Reliability, Safety

E8.1.3.1 Program Drivers

The primary driver for the Program is Operational Resilience and the secondary drivers are Reliability and Safety. As discussed below, the Control Centre is the control authority for Toronto Hydro and is the real-time operator of Toronto Hydro's distribution system. The Control Centre executes most of the critical functions required to successfully operate the distribution system. [redacted]

[redacted]

Table 4: Minimum Space Requirements for a Control Centre – [redacted]

	500 Commissioners	[redacted]	Gap (%)
Control Room Space Requirements (ft²)	[redacted]	[redacted]	[redacted]

In November 2017, Toronto Hydro Power System Controllers executed a pilot whereby part of the distribution grid would be controlled entirely by the [redacted], as part of an effort to simulate the loss of the primary Control Centre. Within the scope of this pilot, key systems that are required to maintain full operational control of the system were identified as follows:

- [redacted]

[redacted]

[redacted]

Table 5: Summary of Technological Restrictions at [redacted] Facility

	500 Commissioners	[redacted]	Gap (%)
[redacted]			

[redacted] Orders to Operate ("OTO") are the final output of the system operation planning process to the field staff to receive step by step instructions on real time operation of equipment from Power System Controllers. These include orders which are executed in sequence to isolate, de-energize, and ground work areas to make them safe for work, change system state, test continuity, hipot test, and restore power. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] the primary Control Centre located at Toronto Hydro's 500 Commissioners site may be vulnerable to certain hazards, such as extreme weather events. Since the primary Control Centre is located within the flood plain, the most probable and consequential hazard or threat [redacted] The flooding is most likely to cause catastrophic damage to the building and various facilities that house the primary Control Centre, [redacted]

As discussed above, Canada's current terrorism threat level is "Medium," meaning that a violent act of terrorism could occur.[10] [redacted] Electrical hazards are, to a large extent, limited through constant system oversight via Control Centre operations.[11]

[redacted]

Moreover, with the introduction of renewable and other distributed energy resources, the nature of Control Centre operations continues to evolve. The growth of distributed energy resources has led to utilities being required to manage bi-directional flow of electricity, managing more complex operations and taking on increasing responsibility that has traditionally been reserved for transmission utilities.[12] This evolution changes the manner in which the power is managed and delivered throughout the grid. With the forecasted increase of distributed generation connections, which is expected to reach 800MW by the end of 2024, Toronto Hydro requires real-time monitoring and control in order to ensure distribution system safety and the adequate management of distributed energy connections.

Lastly, as part of its report, filed at Appendix A, LEI completed a review of various utilities in North America that have distribution operations with more than one Control Centre. These facilities were fully functional and were able to take over full operational functions from the primary Control Centre. The review confirms that utilities serving a critical load in North America invest in more than one fully functioning Control Centre to support resiliency, increase reliability, and ensure quick recovery

---

[10] Supra note 4.
[11] See Exhibit 4A, Tab 2, Schedule 7, for a discussion of the roles and responsibilities of Power System Controllers.
[12] Supra note 1 at p. 15.

from terrorist threats and natural disasters, for example earthquakes and floods. These same justifications are driving the need for Toronto Hydro's dual Control Centre.

E8.1.3.2 Control Centre Operations & Criticality

The Control Centre's Power System Controllers coordinate and monitor the safe distribution of electricity across Toronto Hydro's service territory and support most of its crtical functions. Power System Controllers maintain real-time control of Toronto Hydro's distribution plant and coordinate all activities involving field crew workers. This real-time control includes monitoring of grid operation, system loading, and response to system or asset failures.

[redacted]

Under normal operating conditions, Power System Controllers prepare and execute OTO (switching instructions), enabling planned capital, and operation and maintenance activities for Toronto Hydro's workforce. Control Centre personnel are involved in developing necessary OTO, dispatch of crews, and conducting isolation and switching functions for each capital construction project or maintenance task that is being performed in order to enable a safe work zone. Each OTO comprises a list of switching instructions which enable operations crews to safely transfer customer load and/or establish suitable work protection over a specified range of system devices, which, in turn, allows crews to work in accordance with applicable safety legislation and protects the security of supply to Toronto Hydro's customers. Work involved in the development of OTO is extremely detailed, drawing on multiple system records in conjunction with current system state/loading and is critical to crew and public safety. Where restoration is not possible, crews work directly with the Control Centre to switch equipment in order to restore power to the extent possible prior to continuing with the root cause.

During abnormal system conditions, which are typically caused by extreme weather events, defective equipment, or heat stress to distribution assets, Power System Controllers coordinate Toronto Hydro's response to these system contingencies. During the abnormal system conditions, the restoration efforts must be undertaken immediately as these conditions might pose a significant safety hazard. The emergency activities might include quick and safe restoration of the downed conductors, failed equipment, electrical/vault fires, environmental hazards and etc. Power System Controllers and Trouble Dispatchers direct the response efforts of Toronto Hydro's Grid Response (emergency maintenance) crews during system contingencies and abnormal conditions.

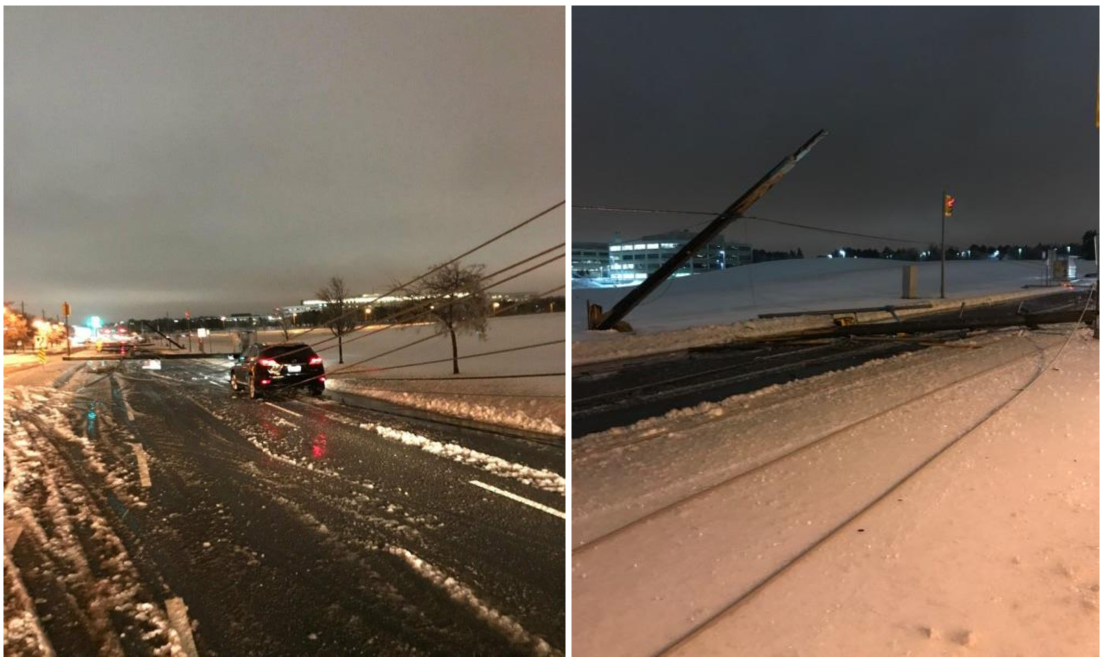


Figure 2: Damage from City of Toronto Ice Storm in April 2018

Toronto Hydro has defined a list of critical functions that are necessary for successful operation of the distribution system. A more detailed description of each these functions is provided in Appendix B. Notably, a number of these critical functions have a maximum tolerable downtime of zero hours.

The North American Electric Reliability Corporation ("NERC") have issued directives and rules concerning the "Loss of Control Room Functionality" which ensure continued reliable operation of the Bulk Electric System in the event that a Control Centre becomes inoperable.[13] NERC standards require the facility containing the Control Centre to be resilient enough to survive, to some extent, the hazards and threats it faces. With respect to criticality relative to their purpose or function, the assets that are subject to NERC requirements are similar in nature to Toronto Hydro's assets. Toronto Hydro serves the largest city in Canada and is also the Country's financial and business capital. As

[13] NERC, Reliability Standards for the Bulk Electric Systems of North America, Standard EOP-008-1 and EOP-008-2- Loss of Control Center Functionality (Updated February 15, 2018).

such, given the criticality of Toronto Hydro distribution system, NERC directives and rules are indicative of the measures that must be taken with respect to critical assets, such as the Control Centre.

E8.1.3.3 Continuity of Operations Capabilities

Control Centers_have become increasingly more sophisticated over the past 30 years from simple analogue tone-based telemetry and control based on electromechanical devices to digital electronic monitoring, data acquisition and control. Paper-based records have been replaced with geo-referenced graphical information systems and outage management systems and crew dispatch and coordination can be accomplished through tablets and crew resource management systems. Control Centers have always been considered critical infrastructure for the management of the distribution system mainly for monitoring and control of substations, transformers, and feeders. However, their purpose continues to evolve to support the new smart grid ecosystem, comprising renewable and other distributed energy resources, micro-grids, electric vehicles, and growing interest in energy storage on the system for power quality, off-peak storage, and grid resilience. As this new paradigm comes into focus, the manner in which power is managed and delivered evolves. Smart grid development requires a completely new concept of a smart grid Control Center, one which is not only critical to distribution system management, but also critical to energy management within the City, and ultimately the Bulk Electric System.

LEI, in its review, concludes that as distribution utilities evolve towards more complex operations and greater responsibility for reliability within the bulk electricity system, fully functioning dual Control Centres will become increasingly necessary.[14] See Figure 3, below, for LEI's depiction of industry trends such as distributed energy resources, smart grids, and electric vehicles that will inevitably challenge the traditional role of the distributor. The fundamental shift to managing bi-directional flow of electricity adds a layer of complexity to Control Centre operations necessitating more active involvement in forecasting intermittent generation, energy scheduling or dispatching generation to manage outages.[15]

14 Supra note 1 at p. 15.
15 Supra note 1 at p. 16.

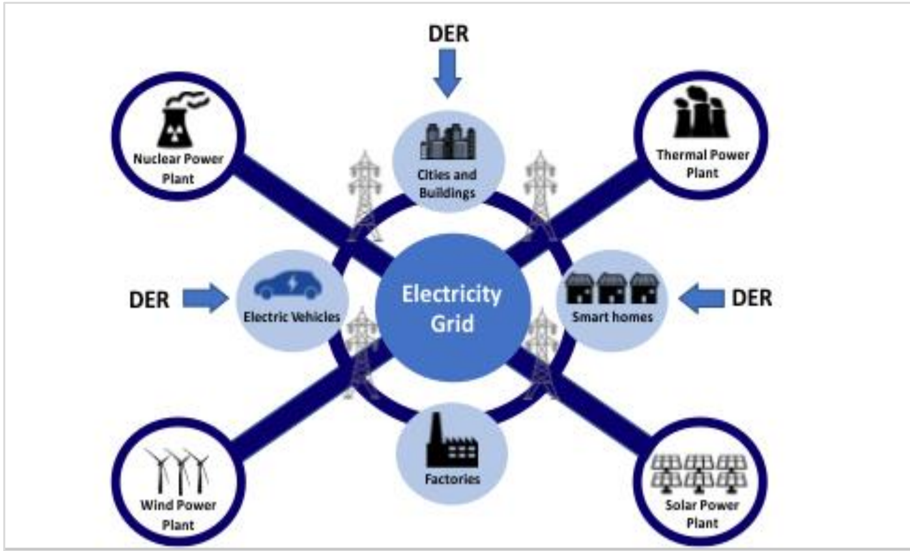


Figure 3: Distributed Energy Resources Interacting with the Electricity Grid[16]

In 2017, Toronto Hydro responded to over 8,000 inquiries from customers and developers seeking to connect generation under various programs. A wide range of proponents have submitted project applications, including many schools, housing managers, large grocery stores, condominium corporations, and department stores. As of the end of 2017, Toronto Hydro has connected over 1,780 Distributed Generators of various sizes representing approximately 225MW. Based on internal forecasts, Distributed Generation connections in Toronto are expected to increase and to reach 800 MW by the end of 2024.[17]

[redacted] As such, as part of the Program, Toronto Hydro intends to build its dual Control Centre with the technology required to manage this growing system requirement. The dual Control Centre will have the capability to monitor and control distributed energy resources. In the event that primary control is lost, it is critical to understand which sources on the system have tripped off, and which have not, both for work protection, but also for power restoration efforts. In accordance with Rule 149 of the Electrical Utility Safety Rules, Toronto Hydro must identify backfeed hazards and eliminate where possible, or control using approved temporary grounding procedures. Although modern inverters

16 Supra note 1 at p. 15.
17 See Exhibit 2B, Section E5.1.

have anti-islanding capabilities, it has been known to fail, and, therefore, do not completely eliminate the back feed hazard, as required by the Electrical Utility Safety Rules.

E8.1.3.4 Risk Exposures

1. Extreme Weather Events

Toronto Hydro evaluates its state of operational preparedness for managing large-scale events on a periodic basis. As part of the evaluation, significant weather events are reviewed along with system resilience, system and customer impacts, and organizational response. Over the last five years, Toronto Hydro experienced several incidents, and some of the more extreme examples include:

- Hurricane Sandy (2012);
- Ice Storm (2013);
- City of Toronto Flooding Event (2013);
- Manby Station Flooding (2013);
- Freezing Rain Event (2017);
- City of Toronto High-water/flooding event (2017);
- Ice Storm (2018); and
- Wind Storm (2018).

Figure 4: Damage from City of Toronto Wind Storm in May 2018

Table 6, below, provides examples of extreme weather events occurring in the first half of 2018 in the City that exceeded Toronto Hydro's standard response practices and triggered the deployment of additional planning and response resources under the utility's Disaster Preparedness Management program.[18]

Table 6: Examples of Recent Severe Weather Events in the City of Toronto

Event	Description
Wind storm (April 2018)	• Sustained 65km/h winds, with gusts approaching 90km/h. • Estimated 24,000 customers out at peak; all customers restored within 48 hours of the end of the event.
Ice storm (April 2018)	• Approximately 10-20mm of freezing rain, 20-25mm rain, sustained winds of 70km/h with gusts up to 110km/h. • Estimated 51,000 customers out at peak. • 99 percent of customers restored within first two days of response; all impacted customers restored within 5 days of the start of the event.
Wind storm (May 2018)	• High winds reported throughout service territory with gusts reaching approximately 120km/h. • Estimated 68,000 customers out at peak. • 96 percent of customers restored within 48 hours of the start of the event
Flash storm (June 2018)	• High winds reported throughout service territory with gusts reaching approximately 90-100km/h. • Estimated 16,500 customers out at peak. • 86 percent of customers restored within the first 12 hours and 97 percent of customers restored within the first 24 hours of the event's occurrence

These events, some of which had significant impacts on Toronto Hydro operations, have highlighted a need for increased emergency preparedness and operational resilience of Toronto Hydro's distribution system. Toronto Hydro's distribution system and facilities continue to be exposed to ever-increasing hazards due to the increase in severe environmental events introduced as a result of

18 See Exhibit 4A, Tab 2, Schedule 6.

climate change.[19] It has been identified that global and regional climate has changed and will continue to change within the City of Toronto, including continued increases in average and extreme maximum temperatures, increases in total annual rainfall, and increases in the intensity of rainfall events.[20]

As illustrated in Figures 5 and 6 below, the 500 Commissioners work centre, which houses the primary Control Centre, is situated along the path of the Don flood plain and is adjacent to Lake Ontario. The last known major flooding disaster – brought on by Hurricane Hazel – occurred in 1953, affecting an extensive portion of Toronto and the Greater Toronto Area ("GTA"), and in particular introducing widespread flooding at the location where the 500 Commissioners facility currently exists. In recent years, including 2013 and 2017, there have been additional flooding events within the City of Toronto, brought on by ongoing climate changes. Global climate change is expected to continue to introduce observable impacts to the environment, including changes in precipitation patterns.[21] [redacted]

19 AECOM Environment, Toronto Hydro-Electrical Systems Limited Climate Change Vulnerability Assessment filed in EB-2014-0116, Toronto Hydro-Electric System Limited, Exhibit 2B, E8.8, Appendix A (Filed July 31, 2014, Updated February 6, 2015).
20 Ibid.
21 This is a consequences of climate change, see National Aeronautics and Space Administration (NASA), URL: https://climate.nasa.gov/effects/, 2018.

Jurisdictional review and economic case for a dual distribution control center in Toronto Hydro territory

prepared by London Economics International LLC

June 22nd, 2018

Distribution control centers ("DCC") support reliability, resiliency, and the ability to recover quickly from deliberate attacks and natural disasters. LEI has found that there is a precedent for utilities across North America to build fully functional backup control centers, at similar costs to those proposed by Toronto Hydro. Justifications included increasing reliability and resiliency, with certain utilities citing specific situations such as natural disasters or terrorism threats. Growth in distributed energy resources has also caused distribution utility operations to be more complex and take on some of the responsibilities traditionally required in the Bulk Electricity System, including dealing with interconnected generation and taking greater responsibility for bulk system reliability. LEI believes that the evolution of these responsibilities also support the need for Toronto Hydro's proposed dual DCC. Finally, LEI's analysis indicates that the proposed costs can be justified economically, given the significant costs of outages in the city of Toronto, and the potential for the dual control center to reduce the duration of high-impact outages.

Table of contents

London Economics International LLC
390 Bay Street, Suite 1702
Toronto, ON M5H 2Y2
www.londoneconomics.com

contact:
Ian Chow/Adam Hariri
416-643-6627
ian@londoneconomics.com

1 Executive Summary

1.1 Scope of services

LEI was engaged by Toronto Hydro to undertake an independent study of comparator utilities with fully functional backup control centers ("BUCCs") in other jurisdictions. The utilities were reviewed and analyzed in terms of their functionality as well as cost. LEI also considered the proposed dual control center from an economic perspective by estimating economic costs of a high-impact outage on Toronto Hydro's service territory.

1.2 Summary of findings

LEI has identified five utilities that have built fully functional BUCCs— Hydro One, Consolidated Edison, Pacific Gas & Electric, Florida Light & Power, and San Diego Gas & Electric. These utilities identify various justifications for their investment, including supporting resiliency, increasing reliability, and ensuring quick recovery from terrorist threats and natural disasters, for example earthquakes and floods. Integration of Distributed Energy Resources ("DERs") was also cited.

All reviewed BUCCs were fully functional and were able to take over operations from the primary control center. However, different utilities varied in terms of their mode of operation: the number of backups, whether they were manned or unmanned, and whether they ran in parallel or not. Toronto Hydro's current BUCC has only [redacted] of the functionalities of the primary control center; the proposed dual control center is to be fully functional and run in parallel with the primary control center.

In its study of comparator utilities, LEI found that the cost of BUCCs built in the past 5 years are aligned with the cost of Toronto Hydro's proposed dual control center. Moreover, the justifications of costs, and challenges faced by comparator utilities are comparable. Compared to the utilities reviewed, Toronto Hydro serves a uniquely important load in terms of political and economic significance, as well as a large base of customers with significant population density.

LEI also reviewed the impact of DERs on the role of the distribution utility. The growth of distributed generation has given distributors some of the reliability responsibilities traditionally reserved for transmission utilities, such as forecasting and dispatching generation. In California, Texas and Hawaii, as well as Ontario, utilities, regulators and reliability authorities have recognized the threat of high DER penetration to the reliability of the bulk transmission system. Bulk system utilities are governed by NERC safety requirements, including the requirement for backup functionality of its control center. LEI believes as distribution utilities evolve towards more complex operations with greater responsibility for reliability, fully functional backup distribution control centers will become increasingly necessary.

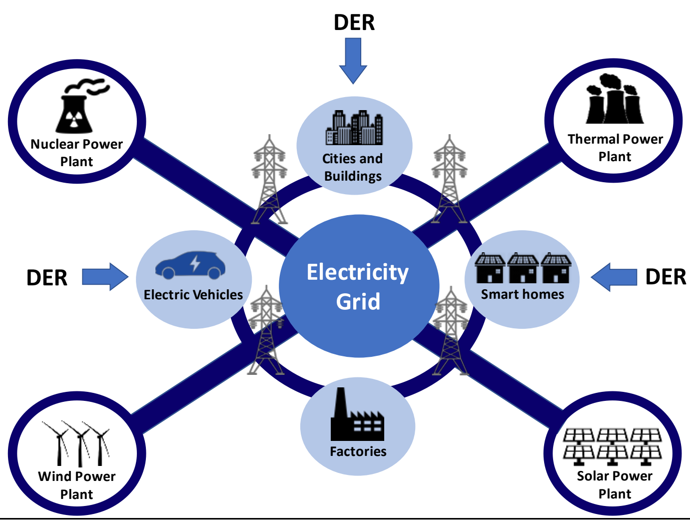
Finally, LEI conducted a high-level review of the economic cost of a high-impact outage on Toronto Hydro's service territory, which covers the financial and economic capital of Canada. Extraordinary events such as natural disasters or terrorist attacks could cause the inability to operate Toronto Hydro's primary control center, resulting in delayed service recovery time following an outage. LEI's analysis shows that the proposed costs for the dual control center can be justified economically, given the significant costs of outages in the city of Toronto, and the dual control center's potential to reduce the duration of these outages.

4 Impact of distributed energy resources on the role of distribution utilities

The following section discusses how the growth of DER has led distribution utilities to manage more complex operations. Ontario has seen significant DER growth, which has impacted distributor operations across the province in terms of monitoring and control of energy delivery as well as energy management. The growth of distributed generation has also given distributors some of the reliability responsibilities traditionally reserved for transmission utilities. Transmission utilities are part of the bulk electricity system and thus governed by NERC safety requirements, including the requirement for backup functionality of its control center. LEI believes as distribution utilities evolve towards more complex operations and greater responsibility for reliability, fully functional BUCCs will become increasingly necessary.

4.1 Changing role of the distribution utility

Figure 7. Distributed Energy Resource interaction with the electricity grid



Electricity distribution grids are undergoing fundamental changes with the advancement of industry trends such as DERs, smart grids, and integration of electric vehicles. These trends are challenging the traditional role of the distributor and the DCCs. The traditional power grid delivered power from large scale, centralized generation, through the transmission system and the distribution system to consumers. Therefore, DCCs only handled flows of electricity in a single direction: to electricity consumers. However, small scale generation and other DERs can now be found in the distribution side of the grid, as illustrated in Figure 7. Their growth means that distributors at times need to manage bi-directional flow of electricity between the utility and consumers. This fundamental change in utility operations adds a layer of complexity to control center operations, as they try to integrate, interpret, and act on this new information.[33] This evolution has caused DCCs to take on more operations which are more typically associated with TCCs, such as forecasting intermittent generation, energy scheduling, or dispatching generation to manage outages.

4.2 Growth of Distributed Energy Resources in Ontario

The definition for DERs can vary across jurisdictions, but generally they are decentralized, often modular, distribution grid-connected power supplying devices with smaller installed capacity. They often include power generation, storage, and demand response. In certain jurisdictions they may also have specific renewable, interconnection voltage or capacity requirements. The IESO definition of DERs is introduced in the textbox below.

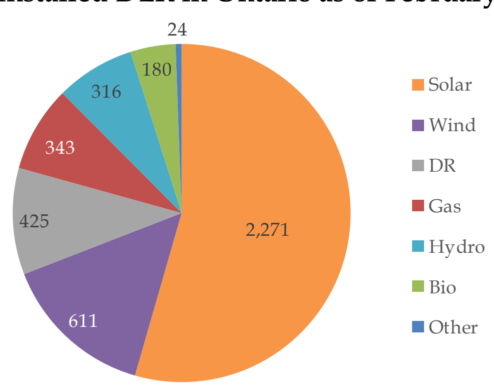
IESO definition of DERs

Distributed Energy Resources (DERs) are any electricity producing resources or controllable (dispatchable) loads connected to a distribution system that can serve electricity demand.

- DERs include, but are not limited to, generation, storage, and controllable load resources, but exclude persistent load reduction
- DERs may operate individually or be aggregated into virtual units
- DERs may connect directly to the distribution system or be integrated into a load

Source: IESO. *Grid-LDC Coordination and Interoperability Initiatives*. September 26, 2017. <http://www.ieso.ca/-/media/files/ieso/document-library/tp/2017/iesotp-20170926-6-grid-ldc-distributed-energy-resources-presentation.pdf?la=en&hash=50850B963ECB5B17141A7BB7F740444DE777F3EF>

Figure 8. Contracted and Installed DER in Ontario as of February 2017 (MW)



Source: IESO. Grid-LDC Coordination and Interoperability Initiatives. September 26, 2017.

[33] Stevens-Adams, Susan Marie, Cole, Kerstan Suzanne, Haass, Michael Joseph, Jeffers, Robert Fredric, Warrender, Christina E., Burnham, Laurie, and Forsythe, James C. *Situation awareness and automation in the electric grid control room*. United States: N. p., 2015. Web.

In Ontario, the growth of DER has been significant – as of 2017, there is 4,169 MW of contracted and installed DER capacity,[34] which is broken down in Figure 8. This includes over 2,000 MW of solar and 600 MW of wind connected to the distribution system. Solar and wind DER capacity is expected to grow to a total of over 3,000 MW by the early 2020s, and 34 MW of storage is also expected.[35] Between 2009 and 2016, Toronto Hydro has enabled approximately 81.9 MW of renewable generation, or over 1,572 interconnections.[36] Toronto's 2009 Sustainable Energy Strategy calls for an increase of 550 MW of renewable generation,[37] which is estimated to result in an additional 9,000 interconnections.[38] In the 2017 Long Term Energy Plan ("LTEP"), the Government of Ontario also refers to the future growth of DERs, including energy storage, microgrids, electric vehicles, in addition to renewable generation.[39] Although the 2017 LTEP does not explicitly state procurement targets, it has led to the development of the IESO's Renewable Distributed Generation Integration ("RDGI") Fund which will fund DER and smart-grid integration demonstration projects.[40]

The IESO has recognized impacts of DER to distributors and the broader bulk electric system. In 2017 it convened the Grid-LDC Inter-Operability Standing Committee, with the objectives of discussing issues and opportunities to coordinate management of the system.[41] Parties have discussed DER integration challenges, issues in forecasting, and data availability and sharing, with the goal of initiating pilot projects enabling greater coordination between LDCs and the IESO.[42]

---

[34] IESO. *Grid-LDC Coordination and Interoperability Initiatives*. September 26, 2017. <http://www.ieso.ca/-/media/files/ieso/document-library/tp/2017/iesotp-20170926-6-grid-ldc-distributed-energy-resources-presentation.pdf?la=en&hash=50850B963ECB5B17141A7BB7F740444DE777F3EF>

[35] Ibid.

[36] Toronto Hydro. *2016 Toronto Hydro Environmental Performance Report*. 3/3/2017. <https://www.torontohydro.com/sites/electricsystem/corporateresponsibility/Documents/2016%20Toronto%20Hydro%20Environmental%20Report%20-%202017-03-09.pdf>

[37] City of Toronto. *The Power to Live Green: Toronto's Sustainable Energy Strategy*. October 19, 2009 <https://www.toronto.ca/legdocs/mmis/2009/ex/bgrd/backgroundfile-24583.pdf>

[38] Assuming 2009-2016 average rate of 52 kW per interconnection.

[39] Government of Ontario. *2017 Long-Term Energy Plan: Delivering fairness and choice*. <https://www.ontario.ca/document/2017-long-term-energy-plan>

[40] IESO. *Renewable Distributed Generation Integration (RDGI) Fund*. March 29, 2018. http://www.ieso.ca/-/media/files/ieso/document-library/engage/rdgif/rdgif-20180329-presentation.pdf?la=en

[41] IESO. *Grid-LDC Inter-Operability Standing Committee Terms of Reference*. March 2017. <http://www.ieso.ca/-/media/files/ieso/document-library/standing-committee/gli/gldc-20170327-terms-of-reference.pdf?la=en>

[42] IESO. *Where Do We Go From Here*. Feb 8, 2018. <http://www.ieso.ca/-/media/files/ieso/document-library/standing-committee/gli/gldc-20180208-planning-discussion.pdf?la=en>

4.3 Role of the Distribution System in Reliability

Potential DER impact to bulk system reliability

The bulk electricity system (including the transmission system) in the Continental US and Canada is under the regulatory authority of NERC, which develops and enforces reliability standards. NERC has studied the potential impacts to the bulk system from high levels of DER. NERC noted the operations at wholesale and retail, and transmission and distribution "may be increasingly blurred" and that additional communication and controls infrastructure will be required to handle the operational challenges associated with coordinating distribution and bulk data. Bulk system reliability impacts identified include:

- Non-dispatchable ramping/variability of certain DER
- Response to faults: lack of low voltage ride through, lack of frequency ride-through and coordination with the IEEE 1547 interconnection standards for distributed generation
- Potential system protection considerations
- Under Frequency Load Shedding (UFLS) and Under Voltage Load Shedding (UVLS) disconnecting generation and further reducing frequency and voltage support
- Visibility/controllability of DER
- Coordination of system restoration
- Scheduling/forecasting impacts on base load/cycling generation mix
- Reactive power and voltage control
- Impacts on forecast of apparent load seen by the transmission system

Source: NERC. *Potential Bulk System Reliability Impacts of Distributed Resources*. August 2011. https://www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf

The growth of DERs has not only shifted the role and responsibilities of distributors and their DCCs, but the distribution system has also taken on greater importance from a bulk system reliability perspective. Traditionally, DCCs and TCCs have been managed separately and there has been minimal coordination between them. This is because the impact of the distribution system on the transmission system was previously assumed to be trivial.[43] This is generally true at lower DER penetration rates, as any impacts can be managed by bulk power system

[43] Li, Zhengshuo. *Distributed Transmission-Distribution Coordinated Energy Management Based on Generalized Master-Slave Splitting Theory*. January 24, 2018. P. 1.

E8.3 Fleet and Equipment Services

E8.3.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 19.1	**2020-2024 Cost ($M):** 42.5
Segments: Fleet and Equipment Services	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Reliability, Environment, Safety, Financial	

The Fleet and Equipment Services program (the "Program") is responsible for the procurement, maintenance, and disposal of vehicles and equipment that are needed to support Toronto Hydro's functional and operational needs. The Program's primary objective is to manage the Program's assets to the lowest overall lifecycle cost, while ensuring asset reliability and employee and public safety. Capital investments within the Program are grouped into two categories: (1) vehicles: which includes, (a) heavy duty vehicles, used as a primary tool to perform distribution work, and to transport operators and equipment; and (b) light duty vehicles, which are fully equipped for employees to inform, manage and monitor distribution work; and (2) vehicle and employee equipment (e.g. forklifts, trailers, telematics systems, boom lifts, protective gear, etc.). The Program and its constituent segments are a continuation of the activities described in the Fleet and Equipment Services program in Toronto Hydro's 2015-2019 Rate Application.[1]

Toronto Hydro relies on its fleet of vehicles to support functional needs and performance requirements associated with executing a complex and dynamic capital and maintenance program. An insufficient or unreliable fleet can negatively impact utility performance, such as reliability and employee productivity. In addition, as vehicle fleets age, they incur higher operating expenses due to increasing levels of reactive repairs. Therefore, the Program ensures that capital investments are made at a level and pace that allow asset maintenance, repair and capital costs to be minimized. An optimally timed vehicle replacement strategy also ensures that the appropriate level of vehicles are available to support system maintenance and capital investment plans.

[1] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected February 6, 2015), Exhibit 2B, Schedule 8.1.

To ensure that the vehicles are replaced in a cost-effective manner, Toronto Hydro utilizes the Life Cycle Analysis ("LCA") approach to identify the capital investment candidates for future replacements and bases its decision to replace or dispose of the vehicle on the actual asset condition assessment. The LCA provides empirical justification to identify the best time to replace vehicles in terms of age, mileage or other pertinent factors. As the age of a vehicle increases, ownership costs decline and operating costs increase. As such, the optimal time to replace a vehicle is before the point where the operating costs begin to outweigh the decline in ownership costs. To assist with determining the LCA, Toronto Hydro retained a third party consultant to undertake a comprehensive study of Toronto Hydro on-road vehicle fleet and to provide recommendations regarding the optimal replacement age of the fleet vehicles. Toronto Hydro leverages the analysis to plan its future capital replacements during the 2020-2024 plan period.

Figure 1: Toronto Hydro Fleet

Although the LCA identifies the optimal age for vehicle replacements for the purposes of expenditure planning, Toronto Hydro replaces vehicles according to the results of vehicle condition assessments. Because a replacement cycle varies depending on the vehicle make, model year, equipment design, operating environment or even by how the operator uses the vehicle, some vehicles that are in poor condition or unsafe may require replacement before the criteria is met, and alternatively, some vehicles that exceed the criteria may be in good condition and not warrant replacement. As such, the vehicles forecasted for replacement in accordance with the LCA, also undergo condition assessments performed as part of the regular vehicle inspections. This forms the basis of Toronto Hydro's vehicle replacement and disposal decision-making.

Prioritization within the Program reflects the importance of the vehicle class to performing core distribution work, the lead time required to procure the asset, cost, and the level of customization required. As such, capital plans are created by first scheduling the heavy duty vehicle replacements in their recommended replacement year, followed by light duty vehicles. Equipment is scheduled on a more ad-hoc basis. It is more economical and efficient to procure vehicles in batches of approximately five to ten units, therefore asset replacements are shuffled between years within a five year plan to assist with balanced spending during the years.

Over the 2020-2024 plan period, Toronto Hydro will focus primarily on the replacement of heavy duty vehicles that are or will be due for replacement. Owing primarily to the fact that heavy duty vehicles are eight to ten times more expensive than light duty vehicles and due to the increase in foreign exchange rates that has led to an escalation in asset price, the requested Program funding over the 2020-2024 plan period is higher than the 2015-2019 period. Nevertheless, Toronto Hydro continues to implement various mitigation measures to minimize the impact of these costs. For instance, Toronto Hydro has taken steps to reduce its overall fleet size from 660 units[2] down to 588, thereby, reducing the operating costs of running a larger fleet.

In addition, the investments in Toronto Hydro vehicle fleet can produce the following benefits:

- Minimization of total vehicle costs;
- Minimization of fleet downtime due to repairs, and a corresponding increase in fleet reliability;
- Increase in vehicle efficiency, i.e. lower fuel consumption and idle reduction;
- Improvements in shop efficiency as less labour will be required to maintain new vehicles and focus can be on older vehicles;
- Reduction in environmental impacts such as reduction in greenhouse gases emitted as well as a reduction in the maintenance fluids used; and
- Increased employee and field safety as newer vehicles are equipped with new safety technology.

[2] I in EB-2014-0116, Toronto Hydro reported a fleet size of 660 units, including cars, pickups, bucket trucks, and other vehicles. See EB-2014-0116 Exhibit 2B, Section E8.1 at page 5.

E8.3.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Ensuring work crews have the necessary vehicles and equipment to perform distribution work when required; and ○ Ensuring that the fleet is in good running order and the assets are replaced before critical equipment failures arise that necessitate lengthy and costly offsite repairs.
Environment	• Contributes to Toronto Hydro's environmental objectives by aiming to reduce GHG emissions associated with fleet fuel consumption by: ○ Utilizing hybrid and electric vehicles and biofuels where possible; and ○ Implementing anti-idling technology, GPS reporting used to drive changes in driver behaviour, and the use of biofuels.[3]
Safety	• Contributes to Toronto Hydro's safety objectives, measured through metrics such as the Total Recordable Injury Frequency ("TRIF") by helping to ensure employees are working safely with minimal exposure to hazards.
Financial	• Contributes to Toronto Hydro's financial objectives as measured by the total cost and efficiency measures by: ○ Managing fleet and equipment assets to the lowest overall lifecycle cost; and ○ Mitigating fuel expense by aiming to reduce fuel consumption through a combination of utilizing hybrid and electric vehicles; idle-reduction technologies; and adhering to recommended vehicle lifespans.

[3] The use of technology to drive these results is limited by funding and classes of vehicles where the Return on Investment is justifiable.

E8.3.3 Drivers and Need

Table 3: Program Drivers

Trigger Driver	System Maintenance and Capital Investment Support
Secondary Driver(s)	Safety, Reliability, Business Operations Efficiency

E8.3.3.1 System Maintenance and Capital Investment Support

The trigger driver for this Program is the need to ensure that Toronto Hydro continues to have access to vehicles that support system maintenance and capital investment activities during the 2020-2024 plan period and beyond. Toronto Hydro requires access to vehicles and equipment that meet current and future functional requirements to transport employees and materials to and from job sites, to perform work onsite, and provide onsite working area and shelter. Toronto Hydro's fleet consists of many types of vehicles that are designed for multiple purposes. On the job-site vehicle uses include, but are not limited to, lifting and positioning material, storing material, preparing material for installation, acting as a planning station and serving as shelter. Fleet vehicles must be available to support these functions in a safe, reliable, and operationally efficient manner.

Heavy duty vehicles are a primary means of transporting equipment for distribution work. Light duty vehicles facilitate the engineering and management functions of distribution work. Associated equipment assets are used to perform lifting and towing, and include operator safety implements, such as network protection relays, rubber gloves, and gas monitors. Over time, these units are subject to wear and tear that impact vehicle safety, reliability, and operational efficiency. In addition, operational needs and requirements change over time in a manner that necessitates certain vehicle and equipment types, technologies and configurations that are not found in the utility's existing fleet.

If the age profile of the fleet surpasses the target age identified in the LCA, reliability of these assets may become compromised, posing risks to the timeliness and reliability of distribution work. When the average age of the fleet exceeds the target age, the vehicle-related parts and services operating costs also begin to increase significantly. It is expected that the vehicle-related operating costs will also continue to escalate as the average age of the fleet increases.

E8.3.3.2 Safety

As vehicles age, there is an increased risk of safety issues such as structural and component failure, and electrical faults, caused by a number of factors, including corrosion. Toronto Hydro vehicles are continuously used throughout the year and spend the majority of the time outdoors in direct exposure to the weather and external elements. In addition to high levels of humidity throughout the year which can cause corrosion, road salt used on city streets and highways is of particular concern as it can lead to corrosion that damages and weakens the frame of the unit over time. The frame is the main structure of a vehicle to which all running gears are fastened, and supports the entire weight of the vehicle excluding the wheels, suspension, and some steering components. Severe rust to the frame can lead to breaks while under load, e.g. during a lift operation, cable pull, or material loading. Frame weakness can also decrease the ability of the vehicle to withstand crashes, thus jeopardizing the safety of the operators and the general public.

As shown in Figure 2 and Figure 3 below, corrosion can also appear on vehicle body panels, causing them to be weak and brittle. Brittle panels are subject to breaking, leaving sharp edges or presenting a potential fall hazard if the rusting occurs on a step, handle, or vehicle floor.

Figure 2: Corrosion on Cube Van Steps

Corrosion may also occur on components that are critical to the operation of the vehicle, such as transmission and brake lines, that are often not observable between vehicle services. Rust on these components results in weak spots that have the potential to rupture and leak, and/or cause failures while in use. For example, a transmission line rupture could result in a seized transmission. If this occurs while in motion, the operator is at risk of losing control of the vehicle. Further, brake line leaks can result in brake failure, possibly leading to a loss of control.

Costly transmission replacements are a determining factor in taking a vehicle out of service as the repair costs can exceed the netbook value and market value of the vehicle.

Figure 3: Underbody Corrosion on Bucket Truck

As mentioned above, regular use of the fleet over time can lead to the failure of critical components that are not readily serviceable or observable by maintenance staff. Components such as the hydraulic hoses running through an aerial cannot be directly inspected at service intervals. As the hoses age, they become less flexible and more brittle. Hose failure results in hydraulic fluid leaks to the environment, and could also result in an inability to lower an employee operating a bucket to the ground. Rescuing an employee from an aerial bucket presents a potential risk to the employee in the bucket, other field employees who are assisting with the operation and the public.

Lastly, components designed to protect electrical circuitry can become compromised as a vehicle ages and wear down with regular use, leading to potential electrical failures. The longer a vehicle is in service, the more inevitable this failure becomes. Electrical failures could lead to the disabling of auxiliary safety lighting systems and onboard equipment which are required as field staff perform their distribution functions.

E8.3.3.3 Reliability

Unreliable or unavailable vehicles adversely impact Toronto Hydro's ability to provide acceptable levels of reliable service, and could also result in lost productivity or a disruption to construction and/or maintenance plans. As is discussed elsewhere in this Program, Toronto Hydro vehicles generally require increasing maintenance as they age. In addition, even with regular maintenance, as part of regular wear and tear activities, vehicles are more likely to fail while in use or will need to be held out of service for repairs following an inspection. Furthermore, parts availability decreases over time, and there is a risk of make and model obsolescence. As a result, there is an increased probability that the vehicle will be taken out of service for longer periods of time, while Toronto Hydro procures the requisite parts.

E8.3.3.4 Business Operations Efficiency

Toronto Hydro's utilization of a vehicle's LCA is intended to minimize the operating costs of the fleet relative to the cost of ownership. As vehicles age, ownership costs (such as purchase costs and cost of capital) decrease as operating costs (such as fuel, maintenance costs, downtime) increase. At some point in the asset's life cycle, the operating costs begin to outweigh ownership costs. The total life cycle vehicle costs are at their lowest at a point in time just before operating costs exceed ownership costs. Vehicle replacement at that point in time minimizes total vehicle costs. As vehicles age, performance such as fuel economy and lifting efficiency tend to decline while emission tends to increase. New vehicles generally entail lower maintenance costs in early years, as they tend to experience less failures requiring repairs.

E8.3.4 Expenditure Plan

Table 4: Historical & Forecast Program Costs ($ Millions)

	Actual			Bridge		Forecast				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Heavy Duty Vehicles	2.2	2.9	3.3	1.7	1.7	5.8	6.6	7.2	7.4	6.5
Light Duty Vehicles	1.3	0.8	0.3	1.5	1.5	2.7	2.2	1.2	1.2	1.1
Equipment	0.6	0.1	1.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1
Total	**4.1**	**3.7**	**4.7**	**3.3**	**3.3**	**8.6**	**8.9**	**8.5**	**8.7**	**7.8**

Toronto Hydro's expenditure and asset replacement planning begins several years in advance, primarily due to the lead time required to procure vehicles. To identify the candidates for future replacements, Toronto Hydro utilizes LCA and asset condition assessments collected during vehicles inspections. As mentioned previously, a LCA enables determination of the optimal time to replace vehicles and equipment based on age, mileage or other pertinent factors.

As vehicles age, ownership costs decrease, and operating costs increase. In this context, operating costs includes maintenance, loss in driver productivity from reduced vehicle reliability and the impact of increased fuel consumption by older vehicles. As the summation of all ownership and operating costs, life cycle costs are determined by modeling actual and anticipated ownership and operating cash flows for a particular vehicle over the life of a vehicle. The projected costs are then used to determine the replacement cycle that results in the lowest overall life cycle costs. The time window in the cycle in which this occurs is the optimal point at which to replace a vehicle. This optimal replacement point is given primarily in terms of age in years.

Figure 4: Toronto Hydro Heavy Duty Vehicles

To assist with the LCA, Toronto Hydro retained a third party consultant to undertake a review of Toronto Hydro's on-road vehicle fleet and to provide recommendations regarding the optimal replacement age of the fleet vehicles. The review identified: (i) the age at which a vehicle should be replaced; and (ii) when replacement should occur (i.e. ideally before costs rise and reliability/safety is reduced and before major capital investment is required).

Using Toronto Hydro's historical costs from 2013 to 2016, the review provided its life cycle analysis recommendations for Toronto Hydro's vehicle fleet, which are summarized in Table 6, below. The conclusions reached in the review include an increase in the lifespans of many light duty vehicles, and a decrease in the lifespans of some heavy duty vehicles.

Table 5: Life Cycle Analysis Replacement Criteria

Priority	Segment	Vehicle Type	2013 LCA (Years)	2017 LCA (Years)	Net	Considerations
1	*Heavy Duty (HD)*	Cube Van	12	12-15	↑	Heavy duty vehicle replacements are routinely evaluated on an individual basis.
1	*Heavy Duty (HD)*	Single Bucket	14	12-16	→	
1	*Heavy Duty (HD)*	Single Bucket -Van Mount	8	11	↑	
1	*Heavy Duty (HD)*	Cable Truck	16	11-14	↓	
1	*Heavy Duty (HD)*	Crane Truck	14	10-14	↓	
1	*Heavy Duty (HD)*	Dump Truck	14	8-12	↓	
1	*Heavy Duty (HD)*	Line Truck	13	13	→	
1	*Heavy Duty (HD)*	Double Bucket Truck	14	14	→	
1	*Heavy Duty (HD)*	Digger-Derrick	13	13	→	
2	*Light Duty (LD)*	Car	6	9	↑	Exceptions: Above average maintenance costs, obsolescence, and usability for the task, poor reliability, excessive downtime, and lack of parts.
2	*Light Duty (LD)*	Cargo Minivan	7	7	→	
2	*Light Duty (LD)*	Passenger Minivan	6	9	↑	
2	*Light Duty (LD)*	Full-size Van	9	10	↑	
2	*Light Duty (LD)*	Pick-Up Truck	9	9	→	
2	*Light Duty (LD)*	SUV	6	8	↑	
3	*Equipment (Eq)*	Trailers	20	20	→	Equipment replacement is on a run-to-failure and/or ad-hoc request basis.

Total life cycle costs and the optimal time for replacement will differ from vehicle to vehicle due to variability in factors such as the vehicle's make, model year, equipment design, initial cost, maintenance costs, and operator usage. Due to this variability, the optimal period is an estimation of the optimal replacement time for most units within the class. Nevertheless, an asset's condition is the final determinative factor in deciding whether or not it will be replaced.

Further, exceptions to the above recommended lifespans may arise depending on specific considerations that may necessitate vehicle replacement ahead of schedule. These considerations include, but are not limited to, average maintenance costs, obsolescence, and unsuitability for the task, poor reliability, excessive downtime and non-availability of parts or accident damage beyond repair. In addition, specialized heavy vehicle replacements are routinely evaluated on an individual basis, irrespective of the schedule. This is primarily due to the critical role heavy duty vehicles play, their costs and the longer lead times required for their procurement.

Expenditure planning for capital replacements begin several years in advance due to the lead time required to procure vehicles. The lead time for heavy duty vehicles, which are of the highest priority and costliest type, is the longest at 1.5-2 years. This is due to the high degree of complexity and specialization required to be responsive to utility functions, as well as the involvement of multiple vendors.

E8.3.4.1 Heavy and Light Duty Vehicles

The number of light and heavy duty vehicles Toronto Hydro is proposing to replace in the current plan period is virtually identical to what was proposed in the 2015-2019 plan period (260 vehicles versus 261 vehicles, respectively).[4] However, in the 2015-2019 period, Toronto Hydro required funding for 62 heavy duty and 199 light duty vehicles. In the current 2020-2024 plan period, Toronto Hydro requires funding for 101 heavy duty and 159 light duty vehicles. In other words, in the 2020-2024 period, Toronto Hydro requires 63 percent more heavy duty vehicles.

For the 2015-2019 period, Toronto Hydro requested funding of $16.9 million for fleet vehicles, $11 million on heavy duty and $5.9 million on light duty vehicles. In the current plan period, Toronto Hydro plans to invest $32.8 million on heavy duty, and $8.2 million on light duty vehicles. Heavy duty vehicles are typically five to ten times more costly than light duty vehicles. As can be seen in Tables 6 and 7, below, an average bucket truck (a heavy duty vehicle) costs $350,000-$450,000, whereas a pick-up or SUV (a light duty vehicle) will cost $35,000-$45,000. In addition, heavy duty vehicles have

[4] EB-2014-0116, Toronto Hydro-Electric System Limited Application (Filed July 31, 2014), Exhibit 2B, Section E8.1, p. 9.

been more significantly impacted by exchange rate fluctuations given that some of the customization requirements are sourced from the U.S.

Table 6: Replacement Costs[5] For Heavy Duty Vehicles for the 2020 to 2024 Period ($ Millions)

Description	2020		2021		2022		2023		2024		Total Cost
	No.	Cost	No.	Cost	No.	Cost	No.	Cost	No.	Cost	
Cube Van	4	0.5	2	0.3	5	0.7	0	0	7	1.0	**2.5**
Van With Aerial Device	3	0.3	0	0	3	0.4	0	0	0	0	**0.7**
Line Truck	2	0.3	0	0	0	0	1	0.1	0	0	**0.4**
Single Bucket Truck	7	2.6	10	3.8	6	2.4	5	1.9	4	1.6	**12.3**
Double Bucket Truck	3	1.3	2	0.9	7	3.1	5	2.3	6	2.7	**10.2**
Cable Truck	0	0	2	1.0	0	0	0	0	0	0	**1.0**
Small Crane Truck	0	0	1	0.3	1	0.3	2	0.5	0	0	**1.0**
Large Crane Truck	0	0	0	0	0	0	1	0.5	0	0	**0.5**
Small Derrick Truck	1	0.4	1	0.4	1	0.4	1	0.4	0	0	**1.6**
Large Derrick Truck	1	0.4	0	0	0	0	2	0.9	1	0.4	**1.7**
Dump Truck	0	0	0	0	0	0	3	0.7	3	0.8	**1.5**
Total	**21**	**5.8**	**18**	**6.6**	**23**	**7.2**	**20**	**7.4**	**21**	**6.5**	**33.5**

Table 7: Replacement Costs[6] For Light Duty Vehicles for the 2020 to 2024 Period ($ Millions)

Description	2020		2021		2022		2023		2024		Total Cost
	No.	Cost	No.	Cost	No.	Cost	No.	Cost	No.	Cost	
Sports Utility Vehicle	25	1.1	0	0	0	0	0	0	0	0	**1.1**
Pick-Up Truck	15	0.8	15	0.7	15	0.9	15	0.9	13	0.8	**4.1**
Minivan - Passenger	3	0.1	0	0	0	0	0	0	0	0	**0.1**
Minivan - Cargo	3	0.1	17	0.8	0	0	0	0	0	0	**1.0**
Full Size Van - Cargo	10	0.5	12	0.6	5	0.3	5	0.3	6	0.3	**2.0**
Total	**56**	**2.7**	**44**	**2.2**	**20**	**1.2**	**20**	**1.2**	**19**	**1.1**	**8.3**

[5] These costs are inclusive of all up-fitting necessary for the job, such as storage bins, partitions, racking, lighting, additional power supply; and any other aftermarket additions required in a particular light duty vehicle.
[6] Ibid.

As vehicles age, they incur higher operating expenses due to increasing levels of reactive repairs. Therefore, if the recommended replacements are not completed during the 2020-2024 period, operating costs for repairs will increase with the escalating average age of the fleet.

E8.3.4.2 Equipment

On-vehicle equipment includes anti-idling technology, GPS units, and laptop mounts installed in vehicles and equipment such as trailers and lifts (scissor lift, forklift, boom lift, vehicle lift). Toronto Hydro currently has 52 trailers and 45 lifts, ranging in age from one to 30 years (average age for both is 12 years). Replacement of this equipment is done on a reactive, or 'run-to-fail' model for the following reasons:

- Equipment generally has long lifespans;
- The variability in frequency of use makes it difficult to forecast replacement based on age or usage;
- Equipment procurement requires short lead times;
- There is little to no customization of equipment required so procurement is prompt;
- There is low safety risk of critical equipment failure; and
- There are similar units available for immediate use if a unit fails critically.

Table 8, below, shows the forecasted costs associated with replacement of equipment on a reactive basis. Equipment is assessed at every preventative maintenance review within a six month period and respective replacement is determined based on unit condition and performance.

Table 8: Equipment Replacement Costs For 2020 To 2024 Period ($ Millions)

	2020	2021	2022	2023	2024	Total
Equipment	0.1	0.1	0.2	0.1	0.1	0.6
Total	**0.1**	**0.1**	**0.2**	**0.1**	**0.1**	**0.6**

Telematics and anti-idling systems helps the Program monitor and continuously improve idling, utilization, driver safety, and diagnostic maintenance. The anti-idle system manages, monitors and provides real-time data to the user on battery voltage, coolant, temperature, idling, anti-theft mode, and engine start/stop. It also provides exceptions reporting on driver behaviour that helps reduce speeding and harsh braking. The use of telematics GPS hardware and software provides benefits in a number of areas, including: real-time tracking of vehicle locations and maintenance indicators[7]; customer complaints investigations and claims (by enabling access to historical tracking of the entire fleet and history of vehicle location); speed profile (notification of speeding based on local speed limit and set data); zone management (home zones based on location of vehicles parked when not in use); and zone creation based on work centre locations to track and optimize arrival and departure of vehicles. Most newly purchased heavy duty diesel vehicles are now equipped with GRIP anti-idling technology to aid in the reduction of idling which will increase lifespan (as it is directly related to the wear and tear of the engines) and decrease GHG emissions. These systems are included in the specifications which the vendors must comply with for purposes of the purchase contract.

Other onboard equipment includes laptop mount kits, for ruggedized laptops used in the field, equipped with pedestal, docking station and wiring needed to power laptops. These mounts are installed in most vehicles (light and heavy duty) to facilitate ergonomically safe use of laptops for onsite crew inspections, site visits and other situations without the need to drive back to the work centre and file paperwork. Ergonomic features (such as dock tilt, spring loaded, telescopic and adjustable base) along with a risk assessment help enhance user safety and performance over time.

Figure 5, below, shows views of a steel lap mount installed in an underground cube van which include a pedestal bolted to the base of the cab along with a docking station, battery protector, and antenna.

Figure 5: Lap Top Mount Installed In Cube Van

[7] For example, engine light on, fuel tank, battery voltage, tire air, GPS not reporting/working, unplugged devices, idling, zoning, trip history, PTO (power off take-off) used for CVOR units (commercial vehicle operation registration).

Prioritization within the Program reflects the importance of the vehicle class to performing core distribution work, the lead time required to procure the asset, the level of customization and/or specialization required, and the cost. Capital plans are created by first scheduling the heavy duty vehicle replacements in their recommended replacement year, followed by light duty vehicles. Asset condition assessment is used to prioritize the replacement of vehicles. Equipment is scheduled on a more ad-hoc basis.

It is more economical and efficient to procure vehicles in batches of approximately five to ten vehicles, therefore asset replacements are shuffled between years within a five-year plan to assist with balanced spending during the year. Replacing in batches and leveling spending in a given year makes it easier for the administration and maintenance teams to ensure work is balanced throughout the lifecycle of the vehicle. The parameters or factors affecting prioritization in long-term capital planning are shown in Table 9, below, by vehicle class.

Table 9: Factors Influencing Capital Planning By Asset Class

	Functional Criticality	Procurement Time	Average Cost/Unit ($M)	Degree of Customization
Heavy Duty Vehicles	High	18-24 months	$0.26	High
Light Duty Vehicles	Medium	6-12 months	$0.04	Medium
Equipment	Low	3-6 months	$0.01	Low

E8.3.5 Options Analysis / Business Case Evaluation ("BCE")

Toronto Hydro considered three options for investments in the Program over the current plan period: (i) run to failure; (ii) managed fleet replacement (the proposed approach); and (iii) replacement of all assets as per the results of the LCA.

E8.3.5.1 Option 1: Run-to-Fail Approach

In the run-to-fail approach, a vehicle would only be replaced once it has completely failed and can no longer perform its intended function. To provide an estimate of the cost impact of this option, Toronto Hydro assumes the average age of the fleet continues to increase by one year for each calendar year. In other words, all fleet assets that are currently owned are assumed to remain in the fleet without turnover. Using Toronto Hydro's current data from 2012-2017, which connects the average age of the fleet with the total vehicle-related parts and services costs, a projection of future vehicle-related costs is forecasted. As shown in Figure 6, below, by year 2024 the average fleet age would be approximately 13.2 years and the corresponding vehicle operating costs would be approximately $11.8 million. This represents a 121 percent increase in operating costs compared to 2017 ($11.8 million versus $5.3 million) – this is more than double the current vehicle related maintenance and repair costs. These cost increases over and above 2017 levels include fuel, parts, labour for maintenance that could have been mitigated with a newer vehicle.

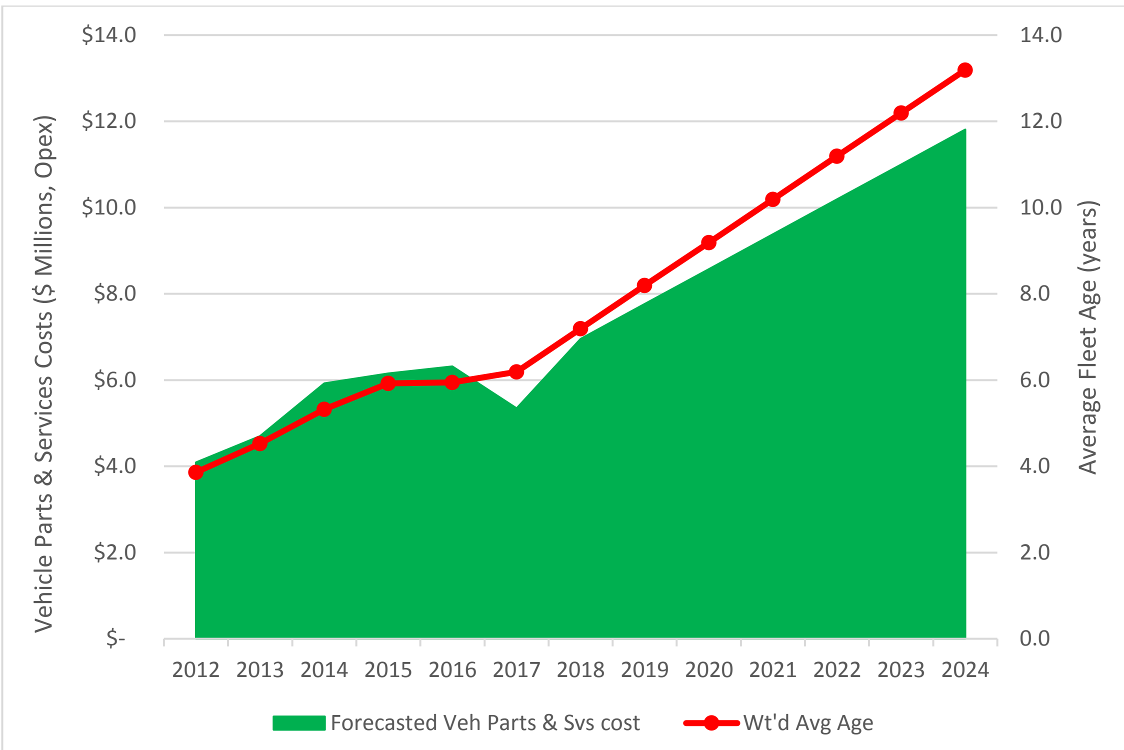


Figure 6: Run-to-Fail Approach - Vehicle OPEX Costs

This option would have the following consequences:

- Unit field failures will likely increase as vehicles age – these field failures will adversely affect field crew productivity and, in some cases, result in Toronto Hydro's inability to conduct system maintenance and capital investment as planned. This will lead to higher labour and support costs (such as permits, penalties for late work completion, additional fuel on account of more frequent trips to and from a work location, etc.).
- The severity of failures is likely to increase, and these failures could potentially become more catastrophic, leading to safety risks, injuries, damage to property or equipment and

environmental spills. For example, hydraulic hoses are more prone to failure over time. A catastrophic hydraulic line failure could, at minimum, result in an employee becoming trapped in a bucket, as well as result in a significant hydraulic fluid spill on to a roadway.

- Running a vehicle to failure would mean that the replacement date is somewhat unpredictable. This would mean being without a specific type of critical fleet vehicle for several months before a replacement is available, given the lead time of a vehicle is between three and 24 months. Distribution work would not be able to be carried out reliably if vehicles are not readily available and in a state of good repair.
- Toronto Hydro operating costs for repairs are likely to increase as parts fail and are replaced. As a vehicle ages, parts will likely become less available, resulting in increasing costs with respect to their purchase. Furthermore, to keep pace with increasing failures, it may be necessary for Toronto Hydro to increase the frequency of preventative maintenance tasks, as well as the number of mechanics it employs and/or the additional external resources it relies on.
- Toronto Hydro may have to increase its vehicle count to maintain similar vehicle availability levels to deliver equivalent service levels to customers. This is because as vehicles age, out of service time will likely also increase due to increasing repair challenges that result from an aging fleet (such as rusted bolts and more significant repairs). To ensure that vehicles are available for use, Toronto Hydro would likely require the use of 'spare' vehicles should the main service vehicles become unavailable on account of maintenance or repairs. In addition, Toronto Hydro may have to rent new equipment for vehicles at a significant cost.
- Replacement for vehicles that have reached total failure require a lead times of up to 24 months for purchase and delivery of specialized vehicles. During this time, Toronto Hydro's ability to perform system maintenance and capital investment may be impaired and/or delayed if alternate vehicles cannot be sourced internally, or via a temporary path such as renting or leasing.

E8.3.5.2 Option 2 (Selected Option): Managed Fleet Replacement

The managed fleet replacement is the proposed approach under the Program. Under this option, Toronto Hydro would undertake a like-for-like replacement of vehicles in line with the fleet replacement considerations outlined in the Expenditure Plan. Utilizing this option, Toronto Hydro is able to bring the average fleet age within +/- 0.5 years of the target average age of five years during the 2020 to 2024 period. By using this approach, Toronto Hydro is able to ensure vehicle-related operating costs do not escalate as a result of equipment failure and other more costly repairs while also having greater assurance that vehicles operate predictably and safely.

This approach will have the following consequences:

- By utilizing this option, Toronto Hydro ensures that replacement of vehicles according to the applicable criteria will optimize the total cost of vehicle ownership on average over time, which translates into savings for ratepayers.
- The managed approach will improve overall vehicle reliability, translating to less downtime, fewer vehicle failures, and resulting in improved field crew productivity;
- Increase in fleet vehicle and equipment performance;
- Improved overall safety of fleet vehicles due to new/improved safety systems; and
- Improved fuel efficiency leading to reduced GHG emissions and fuel costs.

E8.3.5.3 Option 3: Replacement of all Assets According to the Life Cycle Analysis

This option entails replacing all vehicle types according to the exact replacement ages provided for in the LCA review and replacing all trailers over 20 years of age, without taking into account asset condition assessments gathered during routine inspections. Trailers are usually replaced reactively once failure or breakdown occurs. This option would require $56.5 million in funding over the 2020-2024 period.

This option will have the following consequences:

- Pre-emptive mitigation of age-related safety risks and corresponding escalation of repair costs;
- Ensuring adequate availability of similar vehicles to maintain reliability during weather and other emergency events;
- Ensuring adequate availability of vehicles due to an increase in the use of external repair services, which causes vehicles to be out of service for longer durations;
- The overall funding required to implement this option is $14 million more than needed under the managed fleet approach, Option 2, above;
- The number of vehicles to be replaced would also vary greatly year to year, creating logistical challenges with in-servicing and disposing of decommissioned vehicles. In contrast, in Toronto Hydro's proposed approach, the LCA is used as a tool to forecast which assets will

become due for replacement and condition assessments determine exactly which vehicles need to be replaced; and

- Less reliance on condition based assessments. As explained above, there could be an instance when a vehicle that has not met its replacement criteria will need to be replaced due to its poor or unsafe condition. Alternatively, there could be a vehicle that has exceeded its replacement criteria but may be in good condition and, as such may not warrant replacement.

E8.3.5.4 Evaluation of Options

Toronto Hydro has opted to proceed with Option 2, the managed fleet replacement approach, as it is the most cost-effective solution to manage Toronto Hydro's vehicle fleet to the lowest overall lifecycle cost, while ensuring asset reliability and employee and public safety.

Replacing vehicle fleet on a run to failure basis (Option 1) will not only adversely affect field crew productivity and inability to conduct planned system maintenance and capital investment, but it will also more than double the current vehicle related maintenance and repair costs. In addition, Toronto Hydro could have chosen to replace its vehicle fleet according to the exact replacement ages provided for in the LCA review, as per Option 3, without taking into consideration the asset condition. Option 3 would increase vehicle reliability and provide assurance of vehicle availability more so than the other two options. However, Option 3, among other things, would require more capital funding over the 2020-2024 plan period and would not be the most cost-effective solution.

The managed fleet replacement approach ensures that capital investments are made at a level and pace that minimizes asset maintenance, repair, and capital costs. An optimally timed vehicle replacement strategy also ensures that the appropriate level of vehicles are available to support system maintenance and capital investment plans. As such, Option 2 provides maximum value for ratepayers.

E8.3.6 Execution Risks & Mitigation

There are two primary execution risks inherent in the Program. The first is the fluctuating exchange rate between Canadian and American currency. Most heavy duty and specialized vehicle manufacturers are located in the United States. The weakening of the Canadian dollar in recent years increased the cost of cab and chassis for bucket trucks, line trucks and other specialized trucks, as well as lift equipment and parts. The value of the Canadian dollar has dropped since 2012. As a mitigation strategy, Toronto Hydro has secured multi-year tenders with limitations on cost increases per year (1.8 percent maximum). In addition, where possible, Canadian supplies are chosen since total costs per unit are approximately 10-15 percent less when compared to vendors based in the United States.

Vehicle lead time is another critical execution risk. Once the vehicle specifications have been drafted, and the procurement process has been completed, vendors must be awarded the bid and a purchase order must be issued with sufficient time for the vehicle to be delivered in the current plan year. While unit order size and relationship with the vendor can sometimes reduce product lead time, many variables such as the manufacturer's inventory of the requested vehicle, vendor time availability to perform up-fits/customizations, and specification complexity, are not controlled by the successful bidder. For instance, the successful bidder may only perform the up-fit portion of the delivery in-house, and may order all other parts of the unit specified in the tender from another vendor. The lead-time risk can be mitigated by awarding plan submissions well in advance of the calendar year of purchase. In order to do so, Toronto Hydro will need to ensure that vehicle reviews, specifications, and request for proposal/quotation are largely completed in the first half of the prior calendar year. Multi-year contracts for bucket truck tenders is another strategy utilized to lock in pricing of a completed unit and guarantee truck deliveries and forecasted in-servicing of new bucket trucks.

E8.4 Information Technology and Operational Technology Systems

E8.4.1 Overview

Table 1: Program Summary

2015-2019 Cost ($M): 231.2	**2020-2024 Cost ($M):** 281.4
Segments: IT Hardware, IT Software, and Communication Infrastructure	
Trigger Driver: System Maintenance and Capital Investment Support	
Outcomes: Customer Service, Public Policy, and Financial	

The Information Technology and Operational Technology[1] Systems ("IT/OT") program (the "Program") proposes to invest in hardware, software, and communication assets that provide critical support to Toronto Hydro's customer and business-facing services. Toronto Hydro relies on IT/OT systems to execute capital and operational programs, including customer-facing and operationally-critical functions. The investments proposed in this Program were developed in accordance with Toronto Hydro's IT Asset Management Strategy,[2] which mitigates risks to reliability, cybersecurity, and the utility's business operations.

The Program's objective is to provide reliable technology solutions and services to support Toronto Hydro's business functions, including effective and reliable service to customers, safe and efficient management, and operation of the distribution system, compliance with legal and regulatory requirements, and sustainment of the utility's long-term financial viability.

The Program consists of the following three segments:

- **IT Hardware**: includes the core back end infrastructure assets (e.g. servers, local area networks and data storage/centres) and endpoint assets (e.g. desktop computers, laptops, printers, smart phones, and tablets) that support Toronto Hydro's day-to-day operations and core systems;
- **IT Software**: includes software applications that provide process improvements to a range of customer-facing and business functions; and,

[1] Operational Technology refers to hardware and software that detect or cause a change through the direct monitoring and/or control of physical devices, processes, and events in the enterprise (https://www.gartner.com/it-glossary/operational-technology-ot/).
[2] Provided at Exhibit 2B, Section D5.

- **Communication Infrastructure**: includes assets that enable the monitoring and control of distribution communication infrastructure, including fibre-optic assets and wireless Supervisory Control and Data Acquisition ("SCADA") infrastructure.

E8.4.2 Outcomes and Measures

Table 2: Outcomes and Measures Summary

Customer Service	• Contributes to Toronto Hydro's customer service objectives by: ○ Improving the customer experience of interacting with the utility through digital platform; and ○ Supporting accurate and timely communication with customers during prolonged power outages.
Reliability	• Contributes to Toronto Hydro's system reliability objectives (e.g. SAIDI, SAIFI, FESI-7) by: ○ Maintaining the availability of modern, reliable and secure enterprise-wide IT/OT systems that support efficient distribution system management; ○ Supporting outage restoration efforts by ensuring that system operators have the necessary IT/OT tools to promptly identify incidents, develop effective resolution plans and communicate with operational teams; and ○ Enhancing IT/OT systems to enable remote equipment monitoring and operations capabilities.
Public Policy	• Contributes to Toronto Hydro's public policy objectives by: ○ Providing the technological infrastructure framework required to achieve conservation and demand management targets, enable grid-modernization, and support energy storage and distributed energy resources; and ○ Ensuring the effectiveness and availability of IT/OT systems that are required to support the utility's implementation of new policy initiatives and compliance with regulatory requirements, including those arising out of the OEB's Cyber Security Framework.

DISASTER PREPAREDNESS MANAGEMENT

1. OVERVIEW

Table 1: Disaster Preparedness Management Program Summary

2015-2017 Average Cost ($M): 2.3	**2020 Cost ($M):** 2.7
Segments: Disaster Preparedness Management Program	
Outcomes: Customer Service, Reliability, and Safety	

The Disaster Preparedness Management program (the "Program") is responsible for the implementation of Toronto Hydro's robust and comprehensive disaster preparedness framework. The Program is comprised of activities to prepare for, respond to, and recover from disasters or large-scale emergencies (e.g. severe storms, major system/facility disruptions) at both a system and corporate level. It delivers the governance, planning, and training that enable Toronto Hydro to mobilize, and deploy its resources rapidly and effectively during and following disasters in order to mitigate the public safety, reliability, and financial-related risks that can materialize at those critical times.

Toronto is home to approximately 2.9 million residents and 106,000 businesses.[1] It is Canada's largest city and includes the Country's largest financial institutions, leading medical and research facilities, educational institutions, major transportation hubs, and federal, provincial, and municipal government offices. In addition, the City is a frequent host to events of regional, national, and international significance. Extended power disruptions can have significant impacts on these important organizations and events, causing far-reaching social and economic consequences. Accordingly, it is essential that

[1] City of Toronto, Toronto at a Glance, available at <https://www.toronto.ca/city-government/data-research-maps/toronto-at-a-glance/>.

triggered the deployment of additional planning and response resources under the Program.

Table 3: Examples of Recent Severe Weather Events in the City of Toronto

Event	Description
Freezing Rain (February 2017)	• Approximately 2-6 mm of freezing rain followed by additional heavy rain. • Estimated 9,200 customers out at peak; all customers restored within 24 hours of the start of the freezing rain event.
High-water/flooding (May - June 2017)	• Heavy rainfall in southern Ontario exceeded the yearly average for an entire summer. • Numerous incidents of high-water/flooding reported across Toronto. • No customers were directly impacted during this 55-day incident due to the utility's proactive damage assessment and DPM mitigation measures, including flood mitigation efforts.
Wind Storm (October 2017)	• Strong wind gusts approaching 100 km/h in some areas and lasting approximately 3 hours. • Estimated 43,000 customers out at peak. • 90 percent of customers restored within 11 hours of event; all customers restored within 48 hours of the end of the event.
Wind storm (April 2018)	• Sustained 65km/h winds, with gusts approaching 90km/h. • Estimated 24,000 customers out at peak; all customers restored within 48 hours of the end of the event.
Ice Storm (April 2018)	• Approximately 10-20 mm of freezing rain, 20-25 mm rain, sustained winds of 70 km/h with gusts up to 110 km/h. • Estimated 51,000 customers out at peak. • 99 percent of customers restored within first two days of response; all impacted customers restored within 5 days of the start of the event.
Wind Storm (May 2018)	• High winds reported throughout service territory with gusts reaching approximately 120 km/h. • Estimated 68,000 customers out at peak. • 96 percent of customers restored within 48 hours of the start of the event.
Flash Storm (June 2018)	• High winds reported throughout service territory with gusts reaching approximately 90-100/h. • Estimated 16,500 customers out at peak. • 86 percent of customers restored within the first 12 hours and 97 percent of customers restored within the first 24 hours of the event.

CUSTOMER CARE

1. OVERVIEW

Table 1: Customer Care Program Summary

2015-2017 Average Cost ($M): 39.5	**2020 Cost ($M):** 49.4
Segments: • Billing, Remittance, and Meter Data Management • Collections • Customer Relationship Management • Communications and Public Affairs	
Outcomes: Customer Service, Public Policy, and Financial	

The Customer Care program (the "Program") addresses the direct interactions between the utility and its approximately 768,000 customers, and the work required to support these interactions, including customer communications, relationship management, billing, metering and collections functions. Providing excellent customer service is at the core of Toronto Hydro's corporate priorities, and the utility is consistently seeking new ways to foster meaningful two-way communication, expand the range of service offerings to meet evolving customer needs, improve service convenience, and integrate new technological advancements to drive improvement and productivity.

The Program is comprised of the following four segments: (i) Billing, Remittance, and Meter Data Management, which handles the reading of customer meters, upkeep associated with infrastructure and metering data management, preparation of customer bills and payments; (ii) Collections, which handles all activities associated with unpaid accounts; (iii) Customer Relationship Management, which involves activities related to customer interactions; and (iv) Communications and Public Affairs, which involves community outreach, media relations, municipal government interactions and other consumption and cost alerts, disaggregation charts, home assessments, and customized tips and recommendations to reduce consumption. The portal is available online or via mobile devices, further enhancing the customer experience. The adoption of this service continues to be driven through marketing campaigns and the Contact Centre since it supports Toronto Hydro's customer service and financial stability outcomes.

Additional offerings will continue to be incorporated based on customer research and feedback to identify opportunities to bolster usage of the self-service portal. This includes offering MyTorontoHydro account management services to commercial customers, as well as expanding capabilities on PowerLens for electric vehicle usage.

Customer communication efforts continue to expand due to the ongoing changes in public policy affecting Ontario's electricity environment including the introduction of monthly billing and low income programs.

7.1.5 Quality Assurance

The Quality Assurance function manages the development and distribution of training materials for internal and external resources. It is also engaged in knowledge and service quality management, analyzing staff performance, escalation trends, and post-call customer surveys, to identify training gaps as well as process technology improvement opportunities. The function is responsible for maintaining tools that provide staff with information on current policies, procedures, and regulatory changes to better serve customers.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 7:

Reference(s): Exhibit 2B, Section D, Appendix D

a) Please identify any and all instances in which electrification, electric mobility, EVs, and electrified transportation charging were included or considered as mitigating or aggravating factors in THESL's Climate Change Vulnerability Assessment.

RESPONSE:

a) There were no such instances.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 8:

Reference(s): **Exhibit 2B, Section B**

Exhibit 2B, Section B, Appendix E

Preamble:

The Central Toronto Area Integrated Regional Resource Plan (the **IRRP**) prepared by the IESO on behalf of the Central Toronto Area Working Group (which includes THESL) identifies the following key considerations related to planning for long-term needs:

- Recent trends (including policy changes supporting distributed generation) are changing the landscape for regional electricity planning. "Traditional", wire-based approaches to electricity planning may not be the best fit for all communities (page 85).
- The "community self-sufficiency" approach to regional electricity planning places emphasis on meeting community needs largely with local, distributed resources, which include, *inter alia*, demand response, distributed generation and storage, smart grid technologies, and EVs (page 86).
- Integrated energy planning at the community level provides an opportunity for broader consideration of land-use, development and growth, infrastructure requirements, and technology solutions that include, *inter alia*, energy storage technologies, battery EV storage capabilities (especially for load intensification cluster applications), micro-grid and micro-generation capabilities (page 90).
- There is a strong community interest in the "community self-sufficiency" approach to planning (page 89).

THESL notes that its DSP has been informed by the results of the completed regional plans and continues to coordinate with the IESO and Hydro One Networks Inc. with respect to plans that are under development.

a) Please explain how THESL's DSP has been informed by the "community self-sufficiency" approach to regional electricity planning, as discussed in the IRRP, including the extent to which THESL has considered the capacity of EVs, "prosumers", and other DERs to meet integrated energy planning needs.

b) Please describe all measures that THESL is undertaking to facilitate the integration of EVs, "prosumers", and other DERs in its energy planning and business planning processes.

RESPONSE:

a) Toronto Hydro's DSP includes a number of investments which are aligned with the "community sufficiency approach" discussed in the IRRP, and which support the Conservation First Framework, the connection of renewable energy generation (REG), and the use of distributed generation (DG) to meet long-term energy planning needs. These investments are summarized below. For more information, please refer to the evidence cited:

- The Energy Storage program (Exhibit 2B, Section E7.2) includes plans to use energy storage systems (ESS), which are non-wires solutions, to enhance grid performance, remediate power quality problems (e.g. voltage sags), improve reliability in problem areas, increase the capacity of feeders at peak periods, and enable the connection of renewables.

- The investment in the Customer Connection (Exhibit 2B, Section E5.1) and Generation, Protection, Monitoring and Control (Exhibit 2B, Section E5.5) programs support the safe, timely and cost-efficient connection of distributed generation customers to the grid, including REG projects, in accordance with generation connection forecasts which show that Toronto Hydro expects over 581 MW of incremental DG by 2024.
- The Stations Expansion Program, in particular the Local Demand Response segment (Exhibit 2B, Section E7.4.3) includes non-wires alternatives to defer capacity-related upgrades at two stations in Central Toronto. The investments involve installing battery storage, and offering demand response incentives to reduce peak demand by 10 MW, allowing the utility to defer an estimated $135 million of expansion investments at Cecil TS and Basin TS.
- The Control Operations Reinforcement program (Exhibit 2B, Section 8.1) includes plans to invest in technology required to manage the growing system requirements to support the evolution of the smart grid (e.g. distributed energy resources), not only from a monitoring and control of energy delivery perspective but also from an energy management perspective.

b) Please refer to the response provided above, as well as Toronto Hydro's responses to interrogatories 1B-DRC-2(b) and 1C-DRC-6 which address the use of EVs and DERs in enhancing reliability and managing asset integrity risk, respectively.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 9:

Reference(s): Exhibit 2B, Section E7.2

<u>Preamble:</u>

THESL's proposed Energy Storage Systems (**ESS**) Program includes "renewable enabling" ESS investments, which are distribution investments that support the growth of distributed renewable generation on the system that in turn offset generation and transmission investments. THESL acknowledges that ESS can cost-effectively enable EVs to connect to the distribution system by addressing localized system constraints. However, THESL does not propose any EV ESS projects at this time.

a) Please indicate whether EV batteries are expressly and/or implicitly, included in THESL's definition of "Energy Storage Systems" and, if so, how?

b) Please explain how THESL proposes to optimize efficiencies from the many EV batteries and charging infrastructure in its systems?

c) Please itemize all of the benefits that an EV ESS may have and provide THESL's rationale for not pursuing any EV ESS projects at this time given the stated benefits.

RESPONSE:

a) EV batteries are not included in Toronto Hydro's definition of Energy Storage Systems.

b) Toronto Hydro does not currently have such a proposal. Toronto Hydro continues to monitor the development of EV technology and its effect on the safety and reliability of the distribution system.

c) Please see the response to part (b) above.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 10:

Reference(s): **Exhibit 2B, Section E7.4**
Exhibit 3, Tab 1, Schedule 1, p. 10

<u>Preamble:</u>

THESL notes that impacts of EVs and distributed generation on overall loads and demands on the system have not been determined to be material. THESL states that it does not have enough information about these markets to be able to confidently include any impacts on loads or demands and there has been no explicit incorporation of the potential load impacts in\to the load forecast, other than trends that would be part of measured loads to date, and would be captured in the multivariate regression models.

THESL's Stations Expansion program addresses medium- to long-term system capacity needs. One of the segments of the program will expand the capacity of the Copeland TS located in Toronto's financial district, providing additional capacity of 144 MVA. The importance of the Copeland TS expansion is framed in the context of THESL's load forecasting for the area. However, THESL notes that the impact of EV deployment has not been accounted for in its forecast.

Further, THESL states that, following the release of the LTEP in the fall of 2017, THESL is working with regional planning stakeholders to develop a 25 year load forecast that includes an assessment of different EV deployment scenarios. Large-scale EV deployment may increase the peak load demand at certain stations, thus triggering the need for additional capacity.

a) Please provide the 25 year load forecast that includes an assessment of different EV deployment scenarios referenced at Exhibit 2B, Section E7.4, page 10. Please provide any and all EV-related data that THESL relied upon in support of the conclusions above and the load forecast. If the load forecast is not available, please provide an update as to its status and its expected date of completion.

b) Please provide, in the chart format below, an assessment of the impacts on loads and demands — including the load forecast for the 2020-2024 period — of your estimate of EVs and distributed generation in each of the years of the CIR and any supporting references.

	2020	**2021**	**2022**	**2023**	**2024**
EVs (number, kWh)					
EV infrastructure (number, kWh)					
DERs (number, type, kWh)					
etc.					

c) In the recently released *Made-in-Ontario Environment Plan* (the **Environment Plan**; see Attachment 1), the Ministry of Environment, Conservation and Parks estimates that 16% of targeted greenhouse gas emissions reductions will come from low carbon vehicles (i.e., primarily EV adoption. Please indicate:

i) whether THESL's assumptions regarding EVs are consistent with this;

ii) if not, what were THESL's assumptions;

iii) whether THESL has reconsidered the impact of EV adoption on load forecasts in light of the Environment Plan;

iv) whether THESL will update its EV assumptions in light of the Environment Plan;

v) what are the estimated total capital expenditures and operating expenditures regarding EV charging infrastructure that THESL has included in the application and for each year;

vi) what capital expenditure and operating expenditure funding (federal, provincial, or otherwise) is available to THESL specific to EVs and DERs.

d) Please explain whether THESL's load forecasts are consistent with and take into account EV adoption rates expected under the Environment Plan.

RESPONSE:

a) As set out in Exhibit 2B, Section B2.1, the planning process that produces the load forecast referred to in Exhibit 2B, Section E7.4 is ongoing and expected to conclude in the fall of 2019.

b) The forecasted generation connections in number and capacity for the period 2020-2024 can be found in Table 6 and Table 7 in Exhibit 2B, Section E5.1.

With respect to EVs, please refer to Toronto Hydro's response to interrogatory 1C-DRC-6.

c)

i) The Government's Environment Plan does not include an EV adoption forecast for the City of Toronto.

ii) Please see Toronto Hydro's response to part (a) with respect to regional planning. Please refer to Toronto Hydro's response to interrogatory 1C-DRC-6 with respect to more localized planning.

iii) Please see Toronto Hydro's response to part (c)(i).

iv) Please see Toronto Hydro's response to part (c)(i).

v) Please refer to Toronto Hydro's response to interrogatory 1C-EP-16 (c).

vi) As a distributor, Toronto Hydro is eligible to apply for a host of different federal, provincial, and other funding programs related to EVs. For example, Toronto Hydro received funding through the Workplace Electric Vehicle Charging Incentive Program through the Ministry of Transportation. With respect to DERs, Toronto Hydro is able to recover costs in accordance with O.Reg. 330/09 – Provincial Rate Protection.

d) Please see Toronto Hydro's response to part (c)(i).

Preserving and Protecting our Environment for Future Generations

A Made-in-Ontario Environment Plan

Ministry of the Environment,
Conservation and Parks

Ontario

We will work to unlock private capital to give Ontario businesses and residents new and more affordable ways to invest in energy efficiency, save money and reduce greenhouse gas emissions. One of the most effective ways we can combat climate change is encouraging innovation and reducing regulatory barriers to climate solutions. Through this plan, our government will focus on smart regulatory and policy approaches to facilitate and enable innovation rather than hindering it.

The following chapter of our environment plan acts as Ontario's climate change plan, which fulfills our commitment under the *Cap and Trade Cancellation Act, 2018*.

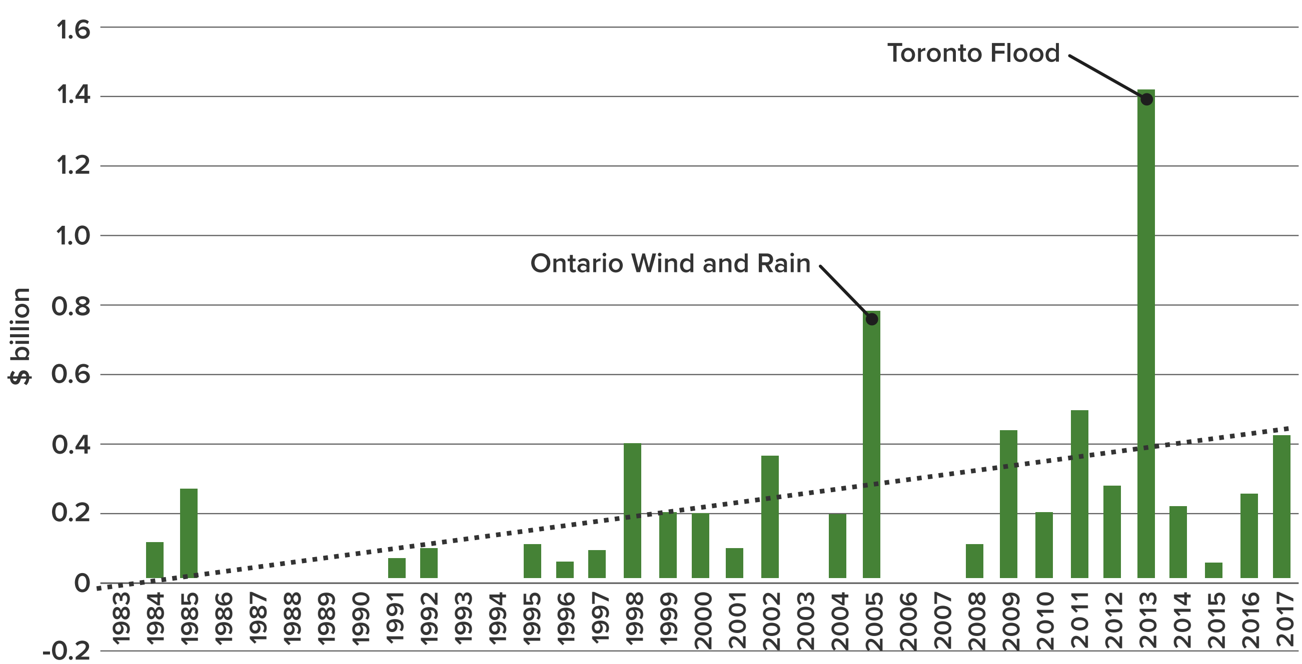
BUILDING RESILIENCE:
Helping Families and Communities Prepare

We are committed to preparing families and communities for the costs and impacts of climate change, and to protecting our natural environment, communities, businesses and municipalities.

While our actions are important in the global fight to reduce emissions, we all understand the need to strengthen our resilience to the impacts of climate change such as more frequent extreme weather events.

The following graph shows the rising costs of insured property damage in Ontario between 1983 and 2017, providing an indication of the costs of climate change. The financial costs associated with extreme weather events in Ontario have increased over this period. Chief among factors affecting the increasing costs to Ontarians is the phenomenon of flooding, and more specifically, residential basement flooding.

Costs of Insured Property Damage in Ontario Between 1983 and 2017



Source: Insurance Bureau of Canada.

Building resilience is about having the right information, tools and resources to adapt and respond to our changing climate. We will access the best science and information to better understand where the province is vulnerable and know which regions and economic sectors are most likely to be impacted. Through this enhanced understanding, the province, local communities, businesses, Indigenous communities and the public will be more prepared for the impacts of a changing climate.

Case study:
Climate change impact assessments

Ontario has never completed a provincial-level climate change impact assessment. Since 2008, the United Kingdom has conducted two assessments using best available data and an up-to-date understanding of climate science and future climate impacts. Each assessment provides detailed analysis of the risks, vulnerabilities and impacts of climate change on key economic sectors, infrastructure, the environment and societal health and well-being.

Each assessment gives the government a roadmap to "high" and "low" climate change risks now and in future years.

Actions

Improve our understanding of how climate change will impact Ontario

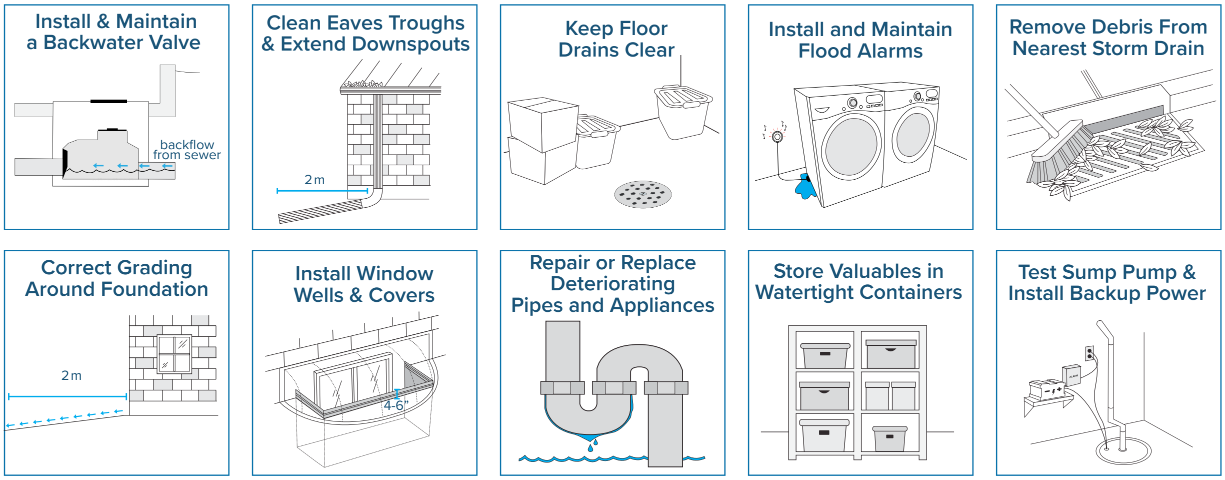
- Undertake a provincial impact assessment to identify where and how climate change is likely to impact Ontario's communities, critical infrastructure, economies and natural environment. The assessment would provide risk-based evidence to government, municipalities, businesses, Indigenous communities and Ontarians and guide future decision making.
- Undertake impact and vulnerability assessments for key sectors, such as transportation, water, agriculture and energy distribution.

Help Ontarians understand the impacts of climate change

- Develop a user-friendly online tool that makes practical climate change impact information available for the public and private sectors. This tool will help developers, planners, educators, homeowners and others understand the potential impacts of climate change in their communities.
- Work closely with climate science modelling experts, researchers, Indigenous communities, and existing climate service providers to identify and create adaptation solutions.
- Support communities by demonstrating how climate science can be applied in decision making to improve resilience.

The graphics below illustrate practical actions that homeowners can take – simply and affordably – to lower their risk of basement flooding. Home flood protection can include property level initiatives such as disconnecting downspouts from weeping tile systems, placing plastic covers over window wells, outfitting sump pumps with battery back-up supply, and installing back water valves on drain lines.

10 Ways to Prevent Home Basement Floods



Source: Home Flood Protection Program, Intact Centre on Climate Adaptation, University of Waterloo

Ontario will work with the real estate and insurance industries to raise awareness among homeowners about the increasing risk of flooding as we experience more frequent extreme weather events. Flooding damage is the leading cause of insured property damage in Ontario. The risk of home flooding is also increasingly the reason why homeowners are unable to adequately insure their homes.

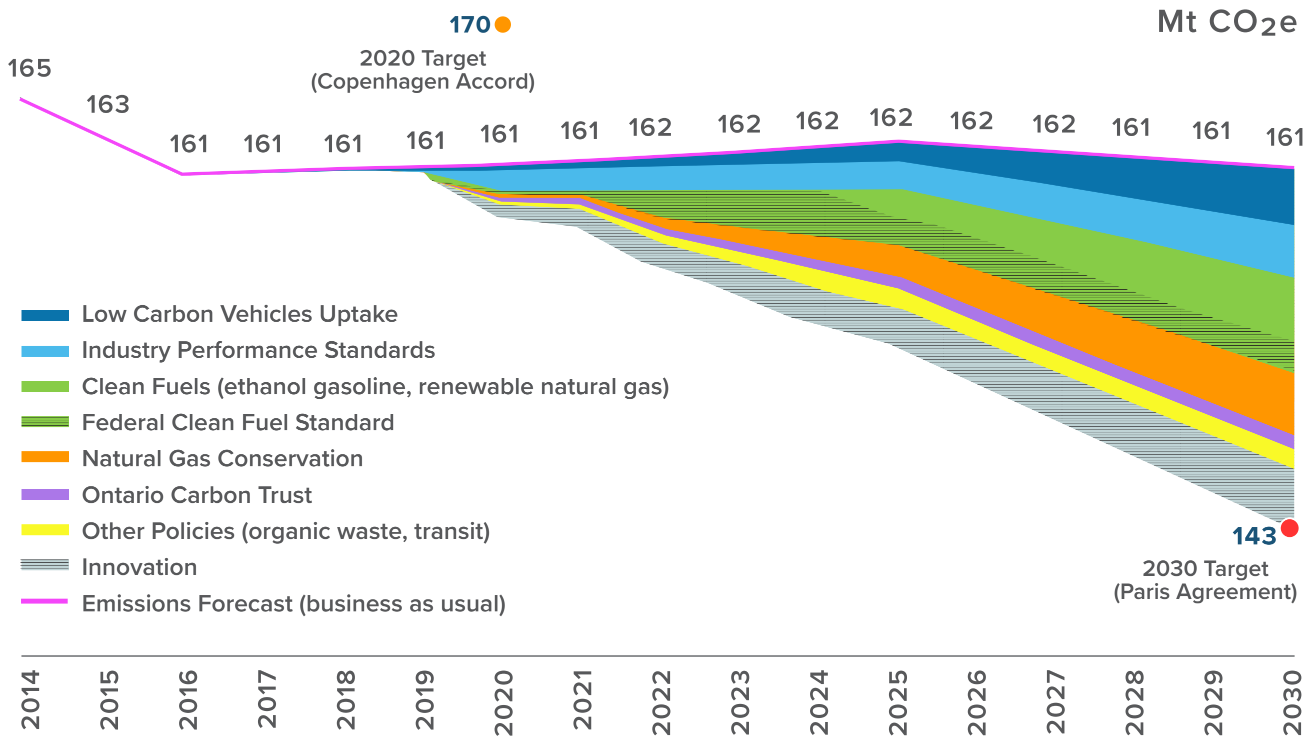
Flood damages can cost homeowners tens of thousands of dollars to repair. According to the National Flood Insurance Program in the U.S., a 15-centimetre flood in a 2,000-square-foot home is likely to cause about USD $40,000 in flood damage. Once flooding occurs, securing insurance will become more difficult and may become unaffordable for individual homeowners.

However, simple steps, such as removing debris from nearby storm drains, ensuring correct grading around home foundations, clearing eaves troughs, and installing extended downspouts and window well covers can significantly mitigate basement flood risks.

Update government policies and build partnerships to improve local climate resilience

- Modernize the Building Code to better equip homes and buildings to be better able to withstand extreme weather events. This could include affordable adaptation measures such as requiring backwater valves in new homes that are at risk of backflow, which would significantly reduce the impacts of basement flooding.
- Review the Municipal Disaster Recovery Assistance program to encourage municipalities to incorporate climate resilience improvements when repairing or replacing damaged infrastructure after a natural disaster. Since the Municipal Disaster Recovery Assistance program was launched in 2016, over $2.6 million has been provided to 11 municipalities.
- Consult on tax policy options to support homeowners in adopting measures to protect their homes against extreme weather events, such as ice and wind storms and home flooding.

Path to Meeting Ontario's 2030 Emission Reduction Target



The chart above shows where we expect Ontario's emissions to be if we take no action (161 megatonnes) compared to where we expect our emissions to go if we take actions in specific sectors. Our target is equivalent to 143 megatonnes in 2030 and we will need reductions in key sectors identified in the graph to get there.

The coloured portions of the chart above refer to emissions reductions we expect to see from actions in this plan and the shaded portions represent the potential we have to enhance some of those actions.

The actual reductions achieved will depend on how actions identified in our plan are finalized based on feedback we get from businesses and communities. The estimated reductions are explained in more detail below.

The **Low Carbon Vehicles** uptake portion refers primarily to electric vehicle adoption in Ontario and in small part to the expansion of compressed natural gas in trucking.

Industry Performance Standards refer to our proposed approach to regulate large emitters of greenhouse gas emissions, as described later in this plan. The final impact of this approach will depend on consultation with industry partners.

Clean Fuels refer to increasing the ethanol content of gasoline to 15% as early as 2025, and encouraging uptake of renewable natural gas and the use of lower carbon fuels.

The Federal **Clean Fuel Standard** is an estimate of the additional impact of the proposed federal standards, which could expand the use of a broad range of low-carbon fuels, energy sources and technologies, such as ethanol, renewable natural gas, greener diesel, electricity, and renewable hydrogen.

The Natural Gas Conservation action reflects programs that are well established in Ontario to conserve energy and save people money. This case assumes a gradual expansion of programs delivered by utilities, which would be subject to discussions with the Ontario Energy Board.

Quick Fact: About 60% of Ontario's food and organic waste is sent to landfills which emits methane – a potent greenhouse gas – when it decomposes. Efficient diversion of household waste from landfills is an important tool in the fight against climate change. To read more about our plan to fight litter and waste, see page 40.

Actions

Conserve energy in homes and buildings to cut costs and reduce emissions

- Increase the availability and accessibility of information on energy and water consumption so that households, businesses and governments understand their energy use (e.g. collection of data related to electric vehicles, household-level energy and water consumption data). For example, provide customers with access to their energy data by working with electricity and natural gas utilities to implement the Green Button data standard. We will support water utilities to implement Green Button on a voluntary basis.
- Work with the Ontario Real Estate Association to encourage the voluntary display of home energy efficiency information on real estate listings to better inform buyers and encourage energy-efficiency measures.
- Review the Building Code and support the adoption of cost effective energy efficiency measures that can lower the cost of electricity and natural gas needed to operate buildings. Ontario is currently a leading jurisdiction in Canada when it comes to energy efficiency standards in its Building Code. Today, Ontario's Building Code ensures new homes built after 2017 use 50% less energy to heat and cool than houses built before 2005, resulting in a much lower carbon footprint than older homes.
- Work with the Ontario Energy Board and natural gas utilities to increase the cost-effective conservation of natural gas to simultaneously reduce emissions and lower energy bills.
- Ensure Ontario's energy-efficiency standards for appliances and equipment continue to be among the highest in North America.

Quick Fact: Enbridge Gas Distribution and Union Gas offer gas conservation programs that offer incentives for homeowners to complete upgrades that make their homes more energy efficient. Each dollar spent results in up to $2.67 in reduced energy bills for program participants.

Increase access to clean and affordable energy for families

- Continue to support connecting Indigenous communities in Northern Ontario to Ontario's clean electricity grid, to replace local diesel and other types of electricity generation.
- Increase the renewable content requirement (e.g. ethanol) in gasoline to 15% as early as 2025 through the Greener Gasoline regulation, and reduce emissions without increasing the price at the pump, based on current ethanol and gasoline prices.
- Encourage the use of heat pumps for space and water heating where it makes sense, as well as innovative community-based systems like district energy.
- Require natural gas utilities to implement a voluntary renewable natural gas option for customers. We will also consult on the appropriateness of clean content requirements in this space.
- Consult on tax policy options to make it easier for homeowners to increase energy efficiency and save money.
- Streamline and prioritize environmental approvals for businesses that use low-carbon technology, while maintaining high standards for environmental protection.
- Support the integration of emerging smart grid technologies and distributed resources – including energy storage – to harness and make best use of Ontario's clean electricity.
- Improve rules and remove regulatory barriers that block private investors from deploying low-carbon refueling infrastructure that will help increase the uptake of electric, hydrogen, propane, autonomous and other low-carbon vehicles without government subsidies.
- Collaborate with the private sector to remove barriers to expanding 24/7 compressed natural gas refueling stations for trucks along the 400-series highways, and maintain the existing tax exemption (gasoline and fuel tax) on natural gas as a transportation fuel. This will provide heavy-duty vehicles (such as transport trucks) with a cost-effective path to lower on-road transportation emissions.

Quick Fact: Natural gas is exempt from the fuel tax in Ontario, and natural gas trucks have a smaller carbon footprint compared to diesel trucks.

Success story:
Niagara Falls pump generating station produces zero-emissions power

Ontario Power Generation's Sir Adam Beck Pump Generating Station is an important source of flexible zero-emissions power for Ontarians. The station fills a 750-acre reservoir when demand for power is low, storing the equivalent amount of energy as 100,000 electric car batteries. The filled reservoir can then be used to generate hydroelectric power when needed, displacing 600 megawatts of fossil fuel generation for up to eight hours.

Success story:
Partnering to fuel lower-carbon heavy-duty transportation

In April 2018, Union Energy Solutions Limited Partnership, an unregulated affiliate of Union Gas Limited (an Enbridge Company), announced a partnership with Clean Energy to build three compressed natural gas fueling stations along Ontario's Highway 401. The initiative will enable heavy-duty vehicles (such as transport trucks) that use natural gas as a transportation fuel to travel and refuel along the 401, leading to lower on-road transportation emissions.

Case study:
Electrify Canada building an electric vehicle charging network

Electrify Canada is a new company that will build ultra-fast charging networks for electric vehicles across Canada, which are anticipated to be operational starting in 2019. This includes the installation of 32 electric vehicle charging sites near major highways and in major metro areas in British Columbia, Alberta, Ontario and Quebec.

Improve public transportation to expand commuter choices and support communities

Commit $5 billion more for subways and relief lines. Ontario will also invest in a two-way GO transit service to Niagara Falls, as part of the existing plan to build a regional transportation system.

- Establish a public education and awareness program to make people more aware of the environmental, financial and health impacts of their transportation choices.
- Develop a plan to upload the responsibility for Toronto Transit Commission (TTC) subway infrastructure from the City of Toronto to Ontario. An upload would enable the province to implement a more efficient regional transit system, and build transit faster. Moreover, this would allow the province to fund and deliver new transit projects sooner.

Support green infrastructure projects

We're also greening the government's fleet of vehicles. The Ontario Public Service currently has 1,632 hybrid, plug-in hybrid and full battery electric vehicles, which represent 70% of its entire passenger vehicle fleet.

Work with federal and municipal governments through the green stream of the Investing in Canada Infrastructure Program to invest up to $7 billion in federal, provincial and municipal funding over the next 10 years. Funding could be for projects that lower greenhouse gas emissions, reduce pollution, and help make community infrastructure more resilient. Example investments could include improvements to transit and transportation infrastructure and improved local water, wastewater and stormwater systems.

Early actions: GO Train Service Increase

This government is expanding GO service and making it easier for commuters and members of the community to move around the GTHA. More riders in seats relieves congestion on the roads. We're providing more reliable, predictable journeys across the region – greatly improving the daily transit experience. These improvements bring us a step closer to our vision to deliver two-way, all-day GO service.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 11:

Reference(s): **Exhibit 2B, E8.1**
Exhibit 2B, E8.1, Appendix A
Exhibit 4A, Tab 2, Schedule 7

Preamble:

THESL states that control centres support the new smart grid ecosystem, comprising renewable and other DERs, micro-grids, EVs, and growing interest in energy storage on the system for power quality, off-peak storage, and grid resilience.

THESL also acknowledges that there are externally driven factors that will likely increase the volume or complexity of control centre activities, including increased market penetration of distributed generation, EVs and charging stations, and energy storage.

a) Please provide, directionally if there is no supporting data, THESL's assessment of how each of these factors will impact the volume or complexity of control centre actions:
   i) increased market penetration of distributed generation;
   ii) EVs;
   iii) EV charging stations;
   iv) energy storage (and please indicate if EV batteries are included in your assessment of energy storage).

RESPONSE:

a) The fundamental change in Control Centre operations as a result of the new smart grid ecosystem is a shift towards the management of bi-directional power flow and the resulting practices and procedures required to safeguard the public, field crews, the grid, and grid-connected equipment (e.g. customer equipment). A directional summary of some specific anticipated impacts follows in Table 1.

Table 1: General Impact to Complexity/Volume of Control Centre Actions

Factor	General Impact to Complexity / Volume of Control Centre Actions
Increased market penetration of distributed generation	• With the forecasted increase of distributed generation connections of 800MW by the end of 2024, there is a need for detailed monitoring and control capabilities within Control Centre operational systems in order to ensure that operators are able to safeguard, manage and control the distribution system in a manner that maximizes operational resilience. • Ensure the safety of workers through adequate work practices, proper application of the work protection code and field procedures, etc. Isolating sections of the distribution system for planned work will become more complex as they need to account for an increase of the number of energy sources. • Additional energy sources increases the number of options for outage restoration, particularly if islanding certain areas is a technically acceptable option in certain circumstances. • Evolving customer service needs as customers that supply energy to the grid have unique expectations. As it relates to planned and unplanned outages, they may be losing out on potential revenue and/or require direct coordination with the utility Control Centre in order to safely synchronize to the grid. Local protection and control schemes may need to be continually monitored and addressed on a case by case basis. This currently exists with many distributed generation sites connected to the Toronto Hydro grid. • Short circuit levels are more dynamic and require active monitoring to ensure that the overall circuit is operated within short circuit limits. • Providing stable load during restoration of bulk system outages.

Factor	General Impact to Complexity / Volume of Control Centre Actions
	• If output of the distributed generation resources is not monitored individually and at an aggregate level, long term planning assumptions will be not be accurate as distributed generation supply will mask overall load consumption.
Electric vehicles (including electric vehicle batteries and electric vehicle charging stations)	• Similar impacts as stated for distributed generation resources (see above). • Electric vehicles can feed excess power back to the grid. • Mobility of electric vehicles can result in more volatility in local electricity demand (vehicles will be connected to different circuits depending on what charging stations they're using at a given point in time).
Energy storage	• Similar impacts as stated for distributed generation resources (see above). • Management of microgrids may require active management particularly following a loss of utility supply. • Increased coordination with microgrid owners and/or operators. For example, charging, discharging and dispatch scheduling. • Optimized operation of an energy storage system will require knowledge of the current and forecasted operating conditions at the utility level, and/or may require direct coordination with the utility operators.

RESPONSES TO DISTRIBUTED RESOURCE COALITION INTERROGATORIES

INTERROGATORY 12:

Reference(s): Exhibit 4A, Tab 2, Schedule 14, p. 26

Preamble:

THESL notes that an increasingly popular method of customer engagement continues to be its customized self-service portal (known as "MyTorontoHydro"). THESL states that additional offerings will be incorporated into MyTorontoHydro based on customer research and feedback, including expanding capabilities on PowerLens for EV usage.

a) Please provide any written documentation of research and feedback on MyTorontoHydro or otherwise pertaining to EVs, batteries, EV charging, energy storage, and DERs generally. Please redact customer names or personal information (e.g., address, account numbers) accordingly, if any information is subject to privacy concerns.

b) Please explain how and when THESL will expand the capabilities of PowerLens for EV usage and how it intends to facilitate awareness and outreach concerning PowerLens to the EV community.

RESPONSE:

a) Toronto Hydro has not conducted research on, or gathered feedback from, MyTorontoHydro as it pertains to EVs, batteries, EV charging, energy storage, and DERs.

b) The residential PowerLens portal was modified late 2018 to enable residential customers to better understand electricity consumption associated with electric vehicle charging. This modification, funded by the Independent Electricity System Operator's conservation program, is solely focused on electricity conservation. The functionality will allow users to flag that they charge an electric vehicle during the home assessment process and PowerLens will then consider this in the usage breakdown and disaggregation charts provided. This provides better categorization of consumption to users to enable customers to make better usage decisions. The Conservation and Demand Management program will continue to raise awareness of PowerLens across all customers to support the achievement of conservation objectives.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 78:

Reference(s): Exhibit 2B, Section E5.1, pp. 12-13, 16-17

a) Please provide the forecast from Toronto Hydro's last rebasing proceeding for generation connections and capacity for the 2015-2019 period. Please provide a comparison to the amount of connections and capacity that has been actually placed in-service or is expected to be placed in service in those years (Exhibit 2B / Section E5.1 / pp. 12-13).

b) Please show the calculation supporting the 46% average capital contribution that has been applied to determine the net customer connection capital expenditures for the 2020-2024 period (Exhibit 2B / Section E5.1 / p. 16).

c) Please explain why the capital contributions for generation connections were higher in some years than the costs (Exhibit 2B / Section E5.1 / p. 17).

RESPONSE:

a) Please see Table 1 and Table 2 below. Please note that Toronto Hydro does not currently have this data finalized for 2018.

Table 1: 2015-2019 Generation Connection Breakdown

Type		2015	2016	2017	2018	2019
Renewable / FIT	Forecast	424	300	296	300	312
	Actual	326	250	201	N/A	N/A

Type		2015	2016	2017	2018	2019
Natural Gas / CHP	Forecast	6	13	10	9	9
	Actual	2	0	4	N/A	N/A
Diesel / Other	Forecast	8	9	8	9	8
	Actual	2	3	2	N/A	N/A
Energy Storage	Forecast	0	0	0	0	0
	Actual	2	3	0	N/A	N/A

Note: All figures based on date of electrical connection.

Table 2: 2015-2019 Generation Capacity (MW) Breakdown

Type		2015	2016	2017	2018	2019
Renewable / FIT	Forecast	41.9	23.9	25.8	27.7	29.7
	Actual	27.5	14.7	10.0	N/A	N/A
Natural Gas / CHP	Forecast	35.5	28.2	27.3	24.0	104.0
	Actual	9.8	0	5.0	N/A	N/A
Diesel / Other	Forecast	32.9	18.0	8.0	15.0	8.0
	Actual	10.1	6.5	11.0	N/A	N/A
Energy Storage	Forecast	0	0	0	0	0
	Actual	0.7	0	0	N/A	N/A

b) Toronto Hydro applied a 5-year (i.e. 2013-2017) weighted average calculation to arrive at the capital contribution percentage.

First, actual expenditures and contributions for the most recent five historic years (i.e. 2013-2017) were escalated to 2020 dollars using an inflation rate of 2%. Please see the escalation equation, historic figures (Table 3), and escalated figures in 2020 dollars (Table 4).

$$Future\ Value = Present\ Value \times (1+i)^n$$

Table 3: Spend ($ Millions)

	2013	2014	2015	2016	2017
Gross	77.1	65.6	68.3	67.1	58.7
Customer Contributions	(23.6)	(13.5)	(35.7)	(27.4)	(36.6)

Table 4: Escalated Spend ($ Millions in 2020 amounts)

	2013 (1)	2014 (2)	2015 (3)	2016 (4)	2017 (5)
Gross (G_i)	88.5	73.9	75.4	72.6	62.2
Customer Contributions (CC_i)	(27.1)	(15.2)	(39.4)	(29.7)	(38.8)

Second, weights were assigned to each year as shown in Table 5 below. The weights are linear in nature, cumulatively add up to 100% over the 5-year period, and are designed to place more emphasis on recent years.

Table 5: Weights (w_i)

Year	2013 (1)	2014 (2)	2015 (3)	2016 (4)	2017 (5)
Weight (w)	6.7%	13.3%	20.0%	26.7%	33.3%

Third, the capital contribution ratio was calculated using the formula below.

$$Capital\ Contribution\ Ratio = \frac{w_1 \times CC_1 + w_2 \times CC_2 + w_3 \times CC_3 + w_4 \times CC_4 + w_5 \times CC_5}{w_1 \times G_1 + w_2 \times G_2 + w_3 \times G_3 + w_4 \times G_4 + w_5 \times G_5}$$

Please note that for the 2020-2024 forecast amounts, Toronto Hydro applied other allocations to the gross customer connections forecast.

c) Please refer to footnote 24 on page 17 of Exhibit 2B, Section E5.1.

RESPONSES TO OEB STAFF INTERROGATORIES

INTERROGATORY 87:

Reference(s): **Exhibit 2B, Section E7.2, p. 1**
Exhibit 2A, Tab 6, Schedule 5

<u>Preamble:</u>

For the energy storage systems (ESS) program, Toronto Hydro provides forecast (2020-2024) rate base of $5.8 million, net costs of $10.5 million, and gross costs of $52.8 million (Exhibit 2B / Section E7.2 / p. 1).

a) Please advise whether the difference between gross costs and net costs is the forecast capital contributions. If not, please explain.

b) Please advise whether the difference between net costs and rate base is the amount that will be recovered through the provincial benefit program. If not, please explain.

c) Please provide the capital expenditures related to each of the three sub-categories of the energy storage system program (grid performance ESS, renewable enabling ESS, and customer-specific ESS) in terms of their contribution towards each of rate base, net costs, and gross costs.

d) Please advise whether there are any OM&A costs (both upfront and ongoing) related to any of the three categories of ESS. If not, please explain. If yes, please provide the amount by category and for each category explain how the OM&A costs are proposed to be recovered (e.g. through the proposed OM&A budget, directly from customers, etc.). Specifically, please explain why there do not seem to be any OM&A costs proposed to be recovered through the provincial benefit program.

RESPONSE:

a) Yes it is.

b) Yes it is.

c) Please see Table 1 below.

Table 1: Capital Expenditure ($ Millions)

ESS Segment	Rate Base (A)	Provincial Benefit (B)	Net Costs (C = A + B)	Capital Contribution (D)	Gross Costs (D + C)
Grid Performance	$5.5	$0	$5.5	$0	**$5.5**
Renewable Enabling	$0.3	$4.7	$5.0	$0	**$5.0**
Customer Specific	$0	$0	$0	$42.3	**$42.3**
Total	**$5.8**	**$4.7**	**$10.8**	**$42.3**	**$52.8**

d) For Customer Driven ESS, OM&A costs are recovered from the customer through the capital contribution. For Grid Performance ESS and Renewable Enabling ESS, no OM&A costs have been explicitly included in the application because these ESS are relatively small in size and the associated OM&A costs are not expected to be material (and will be covered by existing OM&A programs).

As part of the Energy Storage program, Toronto Hydro intends to conduct a detailed benefits analysis. Please refer to Toronto Hydro's response to interrogatory 2B-Staff-89 (d).

Ontario

ONTARIO ENERGY BOARD

FILE NO.: **EB-2018-0165** **Toronto Hydro Electric System Limited**

VOLUME: **Technical Conference**

DATE: **February 22, 2019**

position, you are not seeking approval of the specific measures?

MR. HIGGINS: Yes, it is.

MS. GRICE: Okay, thank you. Those are my questions, thank you.

MR. MILLAR: Thank you, Ms. Grice. Mr. McGillivray, are you prepared to go?

EXAMINATION BY MR. MCGILLIVRAY:

MR. McGILLIVRAY: Thank you, Mr. Millar. Good afternoon, panel. If I could take you to interrogatory 2B DRC 10, and maybe we can skip down to the question under part B.

And then this will probably lead us to somewhere in the evidence, but in part B you make reference, I think, to Exhibit 2B, section E8.1. So we may have to go there, and then there will be a few references here, which hopefully will become clear in a second.

So on page 8, line 20 there's reference made to the 800 megawatts by end of 2024. Do you see that?

MR. SEAL: I do.

MR. McGILLIVRAY: So it says:

> "The forecasted increase of distributed generation connections is expected to reach 800 megawatts by the end of 2024."

And then if we go down to page 12, roughly lines 5 through 8, that figure is repeated. And the evidence also states that Toronto Hydro has connected over 1,780 distributed generators of various sizes representing approximately 225 megawatts; do you see that?

MR. SEAL: Yes, I do.

MR. McGILLIVRAY: And then if I can take you to Exhibit 2B, section E5.5, page 10, line 13. It says that there's forecasted 581 megawatts of additional distributed generation capacity anticipated by the year 2024. And I think that additional could also read incremental, but do you see that?

MR. SEAL: I see the reference.

MR. McGILLIVRAY: And then the actual forecasts are provided in section E5.1. We don't have to go there. My question basically is I am wondering if you can explain how this works a little bit, where are we now and where are we going, basically, and whether or not you can do the math for me between the 800 megawatt number and the 225 megawatt number.

MR. SEAL: I won't be able to help you with this particular exhibit, because I am not familiar with this particular piece of evidence, so I can't lead you between those.

MR. McGILLIVRAY: Okay. Could that be accomplished by way of undertaking? Because I think I have exhausted my panels at this point. And this interrogatory was under panel 3.

MR. SEAL: I can certainly speak to my load forecast, but not these particular numbers in this particular evidence.

MR. STERNBERG: We can respond by way of undertaking.

MR. McGILLIVRAY: Okay. I appreciate that. Thanks. And maybe we could -- well, you can see if you want to include these in the undertaking as well. My follow-up question was in relation to whether I would be right to say that the distributed generation forecast pertains to generation only and doesn't have any bearing on load or load forecasting, or maybe that could be answered by this panel?

MR. SEAL: Well, that would certainly be one of my considerations in doing my load forecast which I am doing for rate purposes, for billing purposes, as to whether any of this distributed generation would actually impact that load that I am using to set rates on or not. I would need to consider that exactly.

MR. McGILLIVRAY: Okay. And you haven't considered it to date, but you would?

MR. SEAL: To the extent that there was something, I had some information that led me to believe that there might be an impact on our load forecast I would. And I think in our evidence, in my evidence, and I will turn you to it, Exhibit 3, tab 1, schedule 1, page 10, so section 3.2 talks about electric vehicles and distributed generation and indicates it in my load forecast we haven't explicitly included any impacts other than trends that would have been part of historical data that we use in our multi-variant regression models.

MR. McGILLIVRAY: That's great, and I was actually going to go there next, so we can go there now. I think my question on that point that you just made was could you help me understand what potential load impacts from electric vehicles and distributed generation might already be reflected because of that multi-variant regression model, what kinds of things relating to distributed generation or -- and/or electric vehicles get captured in that model?

MR. SEAL: So our regression models use historical measured consumption as the basis for modelling against our various variables that drive that measured load. And so to the extent that there are any electric vehicles in our historical data or distributed energy that are impacting the measured loads, that would be captured within those models.

MR. McGILLIVRAY: Just like any other aspect of load, I guess?

MR. SEAL: Correct.

MR. McGILLIVRAY: Okay.

MR. MILLAR: Mr. McGillivray, I am sorry to interrupt. There had been an offer of an undertaking which we didn't mark, but I don't know if the question has been otherwise answered, so do you still require the undertaking?

MR. McGILLIVRAY: I think the first part would still be helpful to do by way of undertaking, so --

MR. MILLAR: And could you just repeat what that is so it's clear for the record?

MR. McGILLIVRAY: It's basically to explain the relationship between the 800 megawatt number, the 225 megawatt number, and the 581 megawatt number, all of which are in Exhibit 2B at various places, and I think the transcript will reflect where they are.

MR. McGILLIVRAY: Thank you.

MR. MILLAR: JTC4.23.

UNDERTAKING NO. JTC4.23: TO EXPLAIN THE RELATIONSHIP BETWEEN THE 800 MEGAWATT NUMBER, THE 225 MEGAWATT NUMBER, AND THE 581 MEGAWATT NUMBER, ALL OF WHICH ARE IN EXHIBIT 2B AT VARIOUS PLACES.

MR. McGILLIVRAY: Thank you. So in that reference that you just referred me to in section 3.2 around page 10 or 11, you indicated in a few places, I think, that the impacts are -- of electric vehicles and distributed generation may not be material or have determined not to be material and that you don't have enough information about those markets to be able to confidently include any impacts. And my question would be, would you be able to elaborate on what additional data or information you believe you might need in order to be able to confidently include those kinds of impacts on loads and demands?

MR. SEAL: So generally, in developing our load forecasts, as I said, we rely on our regression modelling to determine the forecasts. The regression modelling takes into account various economic drivers, various climate drivers, various other drivers of what would be explaining loads, and then uses forecasts of those to predict the consumption of the various -- of the different rate classes. So to the extent that -- generally, those models have a degree of variants within them, so they are a best estimate is what they are, but we recognize they are not going to be perfect.

To the extent that I would consider adjusting those models, I would -- I would need some confident forecasts that -- of loads that would be outside of what those models would be.

So I would want to have -- and especially for the purpose of developing the load forecast for rate-making treatment, which is what this is, I would want to have a high degree of confidence in the forecasts of those particular components, preferably with some kind of knowledge about where they have been historically.

Maybe one of the best examples of where I might make an adjustment to what my model forecast load would be, if I knew a particular large customer was going to be closing down business, I would probably reflect that in my load forecast for the large user class because I knew it was coming and I knew what kinds of loads were involved in it.

Those are the kinds of certainty and confidence that I would want before I would include anything in my load forecast beyond what my models are predicting.

MR. McGILLIVRAY: Thank you. So for, let's say electric vehicles, would that be things like the number of them out there, the type, the kilowatt hours, that sort of thing, or does it go beyond that?

MR. SEAL: I think it would go beyond that. It's not just numbers and kilowatts, it's somebody takes a usage by vehicle, but some confidence that the forecasted number of vehicles has some basis -- sound basis for it. And as I said, when we put together our forecast we didn't have that information to be able to include anything.

MR. McGILLIVRAY: Do you believe that information's out there but not collected or is it simply not available yet?

MR. SEAL: In my view, the electric vehicle industry is still in its infancy, and as I am sure you're aware, the climate is changing around some of those electric vehicle policies in Ontario. So, you know, I think that there's not enough information out there right now to confidently include anything in my load forecast.

MR. McGILLIVRAY: Okay, thank you. If I could take you to interrogatory 2B DRC 10; we have may have been there. I am now going to look at part A of that, the response to part A where it says Toronto Hydro is working -- oh, sorry. Could you scroll up to the questions?

Yes, I think part A is the right reference. Toronto Hydro is working with regional planning stakeholders to develop a 25-year load forecast that includes an assessment of different EV deployment scenarios. And this might be an in an exhibit that you can't speak to, but it's in, I think, Exhibit 2B, section E 7.4. And we don't have to go there, but there it says large scale EV deployment may increase the peak load demand at certain stations, thus triggering the need for additional capacity.

So I think maybe you can discuss the relationship between this sort of forecast, which I recognize is ongoing, and the ultimate load forecast for rate purposes that is developed and whether there is connection between this specific regional planning sort of level of 25-year load forecast and the load forecast for rates.

MR. SEAL: So I think you alluded to it in your question. I think the this particular exhibit, and the regional planning tends to be about peak demand -- peak demands on the system, peak demands on stations, peak demands on delivery points -- which is different than the load forecast that I am producing, which is all about billing units.

You know, one good example might be the difference -- the impact of electric vehicles on electric usage for the residential class. The residential class, starting in 2020, the distribution rates are fully fixed. So any electric vehicle usage behind the residential meter doesn't matter for the purposes of setting distribution rates. So there can be very different for different purposes.

MR. McGILLIVRAY: Okay, and just to confirm on this, this large scale peak load demand, I guess forecasting exercise going out 25 years, can you confirm that there are no interim reports or working papers in relation to this process?

MR. SEAL: I am not familiar -- I am not aware of what's going on with this regional plan.

MR. McGILLIVRAY: Could you undertake to provide an update on the status of it? I understand it's ongoing until fall 2019.

MR. STERNBERG: Yes, I'm pausing for a couple reasons, trying to understand what the specific request is first.

I am not sure what's being requested by way of update. Perhaps you can clarify that, and we might be able to take that away.

MR. McGILLIVRAY: Sure. I think there is an effort that's ongoing in respect of this 25-year load forecast including -- which includes an assessment of different EV deployment scenarios, and that goes back to the Exhibit 2B section E7.4 reference, page 10, lines 9 to 10. And I think in part A to interrogatory response 2B-DRC-10, Toronto Hydro indicated that the process is ongoing and expected to conclude in fall 2019, I think it says.

So my question would be what is the status of that and if there are any interim reports or working papers in relation to it, could they be produced.

MR. STERNBERG: We can certainly undertake to provide an update on the status of where that's at. I don't know whether there are documents or not. So in respect of the document request part, we will make an inquiry if there are any such documents and if so, consider them and whether they are probative. But we can certainly provide an update on the status.

MR. McGILLIVRAY: Great.

MR. MILLAR: JTC4.24.

UNDERTAKING NO. JTC4.24: TO PROVIDE A STATUS UPDATE TO THE 25-YEAR LOAD FORECAST INCLUDING ASSESSMENT OF

EV DEPLOYMENT SCNEARIOS; TO PROVIDE ANY RELATED REPORTS OR WORKING PAPERS, IF RELEVANT

MR. McGILLIVRAY: Thank you, those are my questions.

MR. MILLAR: Thank you, Mr. McGillivray. Dwayne, was that you just joining us?

MR. QUINN: Yes, it is, Michael.

MR. MILLAR: Very good timing on your behalf. You're up. Just to let you know, I think Bill may have actually asked some of your questions. But I think you were in another engagement so you didn't hear. So it's possible some of the responses you get may be to see what they said to Bill. But why don't you ask your questions, and we will see where we get.

EXAMINATION BY MR. QUINN:

MR. QUINN: Okay, thank you. I don't want to take people's time, so will just do this quickly. Was there an undertaking taken for Bill's inquiry?

MR. MILLAR: Yeah. Bill doesn't actually have your questions, and my notes on the undertakings are little more than the numbers, so I am not sure. You can review the transcript. But I suggest you just ask your questions and if they say they've already answered it, you'll know.

MR. QUINN: Okay, I will be quick then. So if I could ask Exhibit B -- sorry 1B, tab 5, schedule 1, page 5; if you can turn that up and let me know when you have it.

MR. SEAL: We see that.

MR. QUINN: Okay. So I am reading from that page, and it says:

TECHNICAL CONFERENCE UNDERTAKING RESPONSES TO DISTRIBUTED RESOURCE COALITION

UNDERTAKING NO. JTC3.25:
Reference(s): **2B-DRC-12(b)**

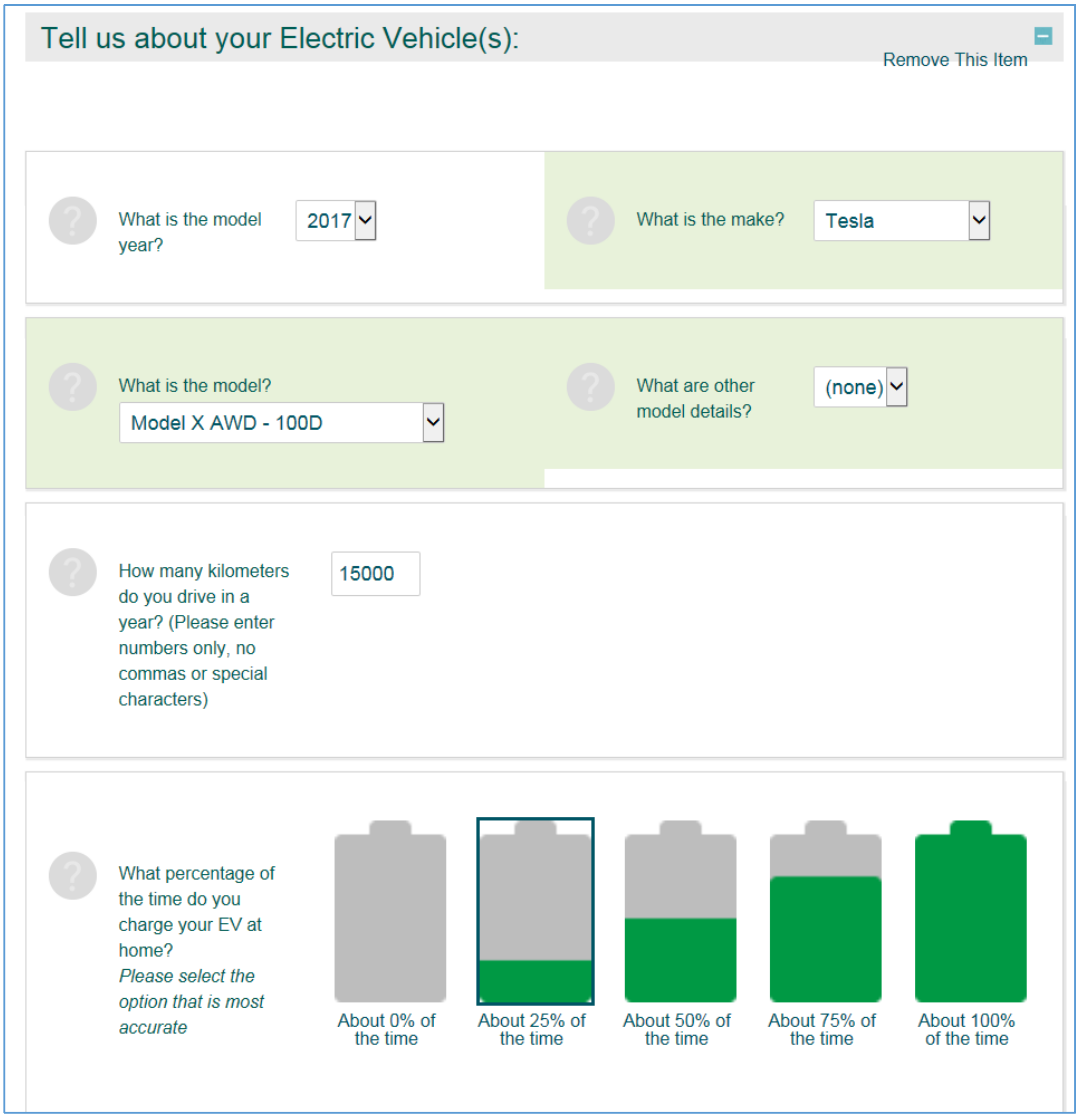
To provide screenshots of what aspects of PowerLens looks like.

RESPONSE:
PowerLens provides residential customers with information about their consumption and incents them through various methods to reduce their overall consumption. The tool is funded by the Independent Electricity System Operator's conservation program.

The PowerLens dashboard includes a pie chart that provides a high level disaggregation of consumption within the household based on an online customer self-assessment, during which the customer provides information such as the size of their house, the direction it faces, the type of heating, number of people living in the house, and other factors which may influence electricity consumption. If a customer indicates during this assessment that they have an electric vehicle ("EV") being charged at the property, this consumption will be included in the disaggregation calculation and displayed in the pie chart section of the dashboard as shown in Figure 1 below. Figure 2 shows the information the customer is asked to provide about their electric vehicle, driving habits, and charging patterns.

PowerLens provides all users with Time-of-Use ("TOU") data and charts to enable them to compare and manage consumption patterns across On-Peak, Mid-Peak, and Off-Peak periods. Samples can be seen in Figures 3, 4, and 5. This information enables EV users to understand and manage their charging patterns.

Figure 1: PowerLens Dashboard



1 **Figure 2: Electric Vehicle Information Collection**

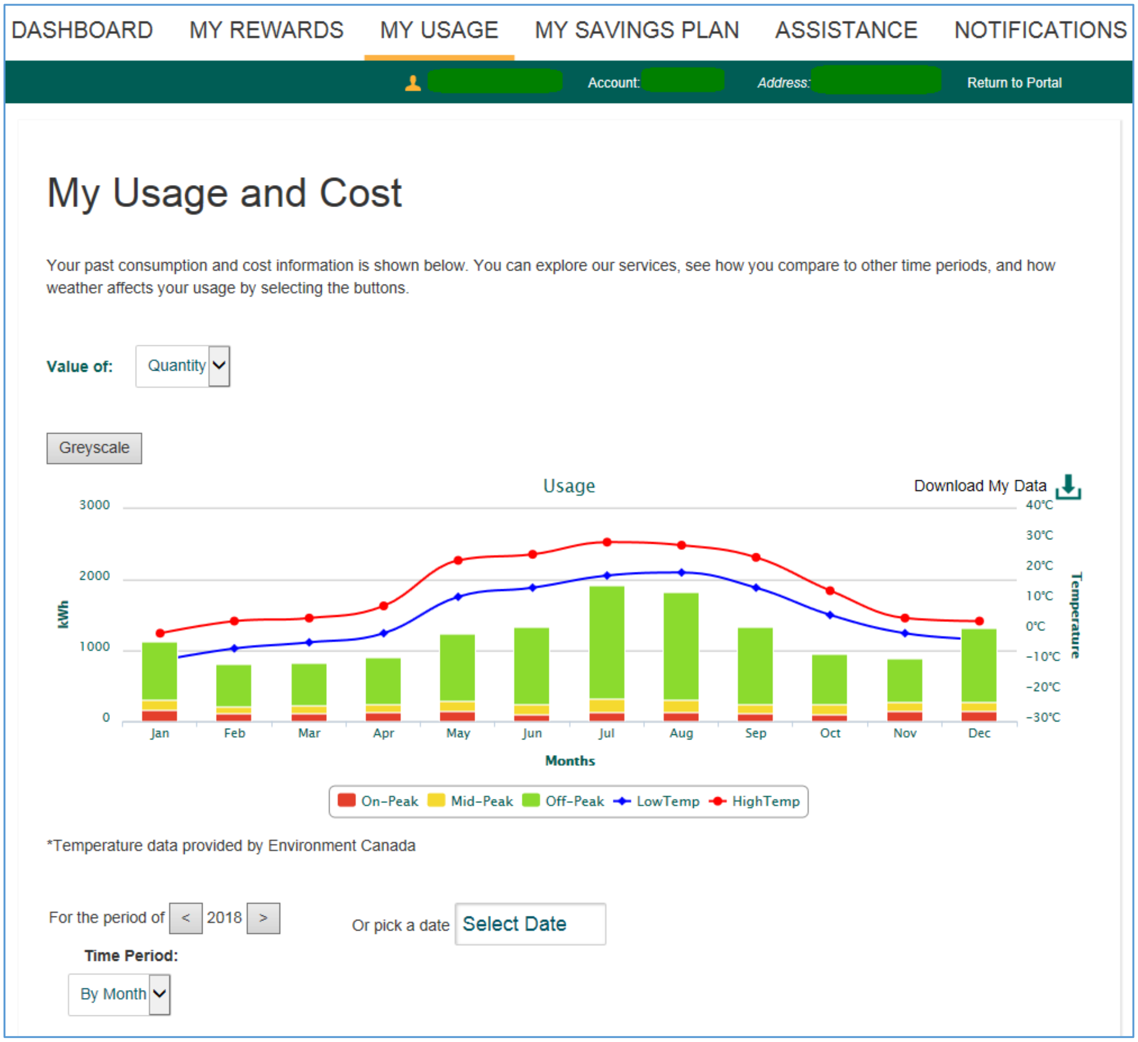


Figure 3: Monthly Time-of-Use Consumption Pattern

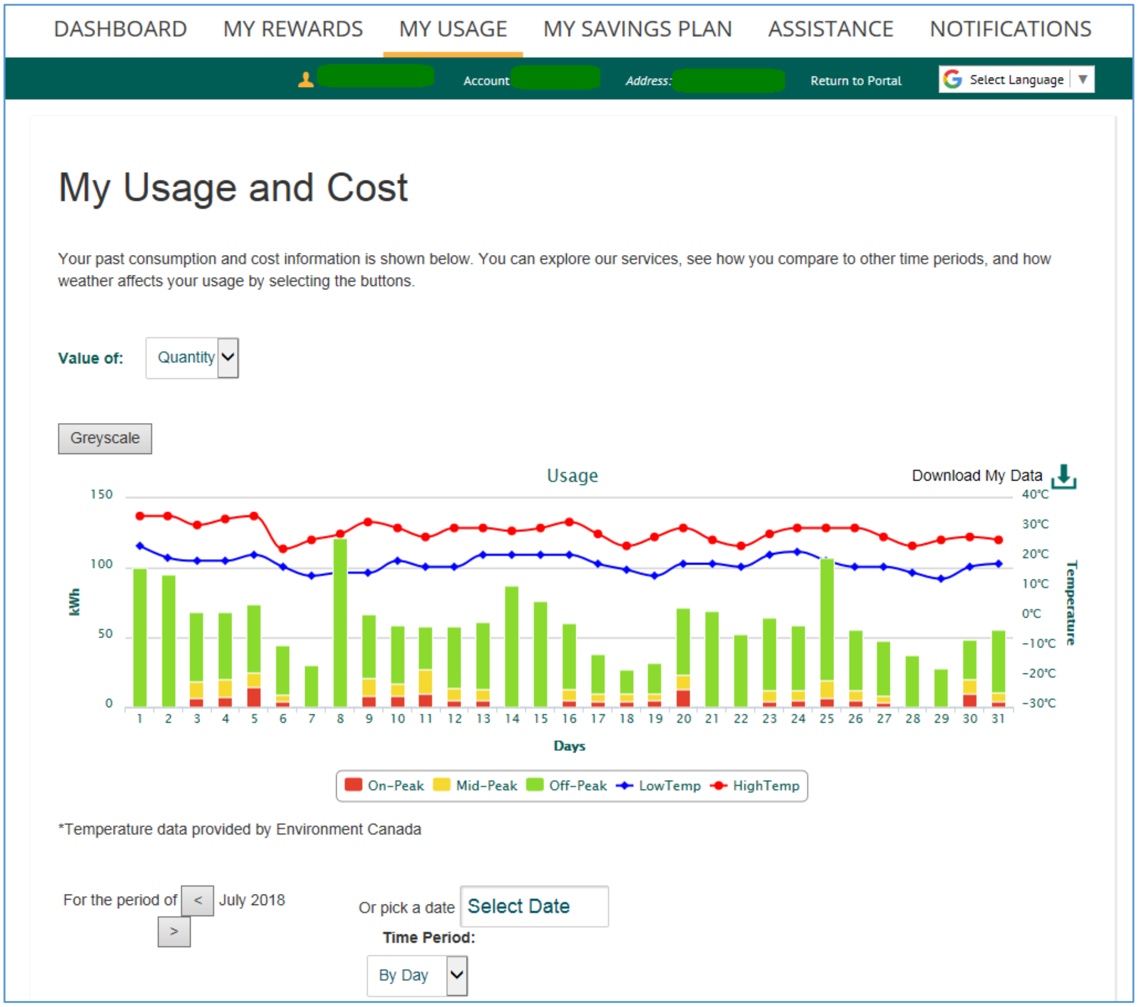


Figure 4: Daily Time-of-Use Consumption Pattern

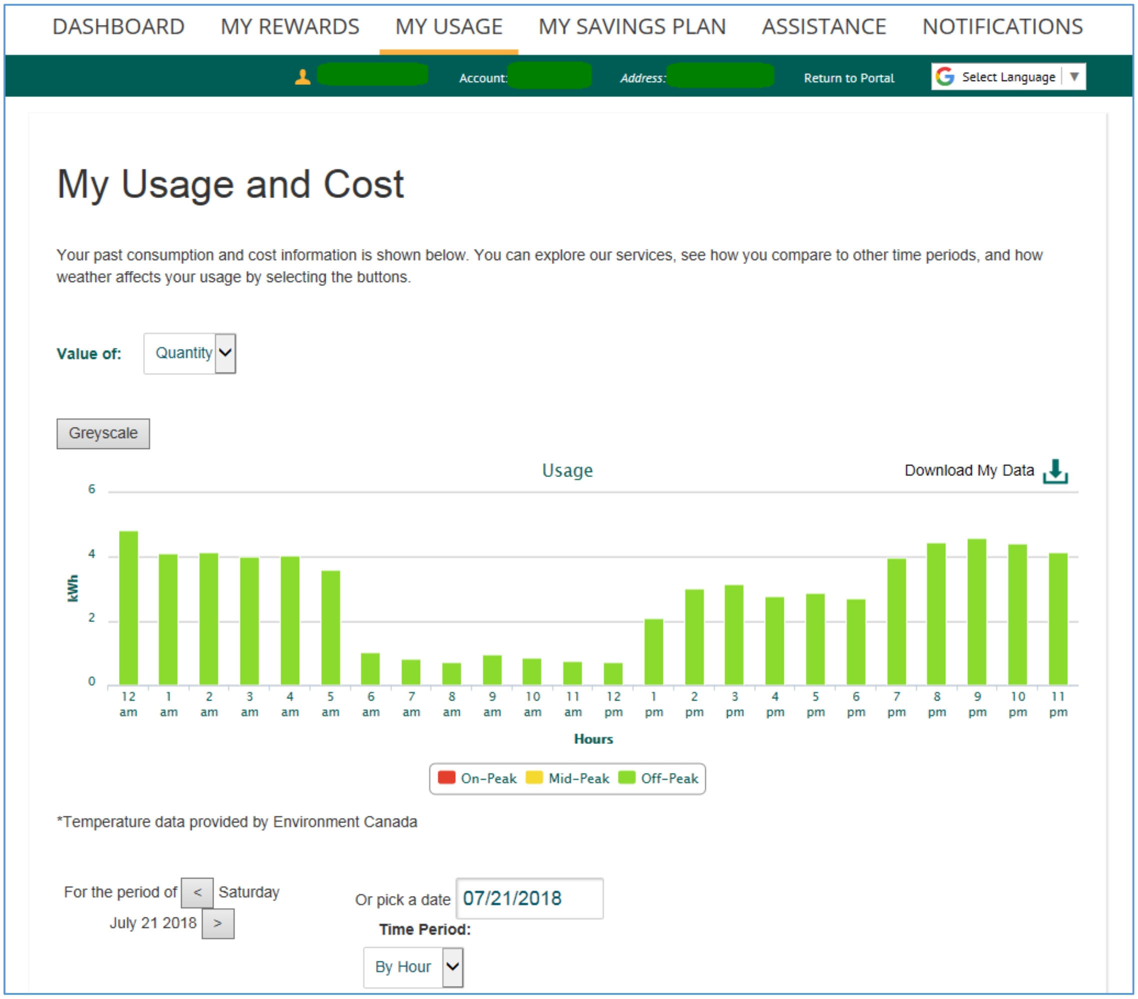


Figure 5: Hourly Time-of-Use Consumption Pattern