Stantec

Hydro Ottawa Climate Change Adaptation Plan

FINAL REPORT

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Prepared for:

Hydro Ottawa
3025 Albion Road North
Ottawa ON K1V 9V9

Prepared by:

Stantec Consulting Ltd.
400-1331 Clyde Avenue
Ottawa ON K2C 3G4

Project No.: 122170294

Prepared by Nicole Flanagan Digitally signed by Nicole Flanagan Date: 2019.11.12 10:31:43 -05'00'
(signature)

Nicole Flanagan, M.A.Sc., P.Eng.

Reviewed and Approved by Daniel Hegg Digitally signed by Daniel Hegg Date: 2019.11.11 15:18:49 -08'00'
(signature)

Daniel Hegg, M.Sc., CEM

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Executive Summary

Hydro Ottawa Limited (Hydro Ottawa) provides electricity to over 330,000 residences and businesses in the City of Ottawa and the Village of Casselman, who depend on a continuous and reliable supply of energy. In recent years, particularly in 2018, Hydro Ottawa distribution infrastructure was subjected to notably extreme weather events that caused severe damages to their system. These events resulted in widespread outages and costly recoveries. In an effort to maintain reliable service in the coming years, Hydro Ottawa has retained Stantec Consulting Ltd. (Stantec) to conduct a Climate Change Adaptation Plan (the Plan) for their distribution system and supporting infrastructure to follow up on the risk and vulnerabilities identified in an earlier phase of work. This work is compiled in a standalone report prepared by Stantec, titled Distribution System Climate Risk and Vulnerability Assessment (CRVA).

This Climate Change Adaptation Plan considers the entire geographic extent of Hydro Ottawa's service territory which includes a vast portion of the City of Ottawa and the Village of Casselman and includes both overhead and underground electrical distribution assets. The purpose of this Plan is to identify and make recommendations for actions to reduce the risks identified in the CRVA as well as recommendations for integrating actions into the Hydro Ottawa planning systems and operation practices and procedures.

Both this assessment and the CRVA were completed in general conformance with the Canadian Electricity Association's (CEA) Guide On Adaptation To Climate Change, and the Engineers Canada Public Infrastructure Engineering Vulnerability Committee (PIEVC) Protocol. Furthermore, this methodology aligns with the principles, requirements and guidelines of the ISO 31000:2018 Risk Management Framework and ISO 14090:2019 Adaptation to Climate Change.

Climate changes in the Ottawa region include historical warming trends (approximately 1.7°C per century) which are projected to continue into the future. Seasonally, the most dramatic changes observed are associated with winter minimum temperatures, which constituted a 2.5°C increase between 1939 and 2010. Similarly, Ottawa has seen an increase in precipitation, where total precipitation has increased by 25.9mm over the past 30 years. Future projections indicate increases in total precipitation as well as an increase in the frequency of short duration, high intensity events. Furthermore, the climate modelling projections indicate that wind and other complex events (ex: freezing rain, lightning, etc.) are expected to increase as well.

The Climate Risks and Vulnerability Assessment identified impacts to Hydro Ottawa's infrastructure and operations which are expected to become more prominent in the future due to climate change. For this assessment, infrastructure systems identified in the CRVA have been grouped into four main asset categories: Pole Line Systems (PLS), Underground Line Systems (ULS), Substations (SUB), and Operations (OPS). Adaptation plans were created based on potential mitigation actions developed in a workshop with Hydro Ottawa. The timelines and prioritization of action plans were based on the current risk, future risk and the change in risk over time.

The Adaptation Plan includes recommendations based on possible measures developed in Hydro Ottawa workshops to mitigate the impact of climate related events. These prioritized recommendations are summarized in Table E-1.

Table E-1: Adaptation Plans

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
OPS-1	Refine and establish a policy on wind conditions when a lift bucket should not be used and when work should not be completed to mitigate the risk of injury related to wind.	Distribution Operations Health and Safety	1 year
PLS-1	Develop anti-cascading strategies and standards for hardening of pole line systems to protect against wind and ice accumulation events, including: • Introducing break or stress points into the distribution lines. • Anchoring. • Type of pole. Complete a cost-benefit review of the strategies at critical areas and/or strategic timelines (end of life).	Asset Planning	2 years
PLS-2	Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their potential to damage infrastructure or injure personnel during wind and ice events. Noting past program augmentations made in response to past storm events, evaluate feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate.	Forestry Asset Planning	2 years
PLS-3	Complete a technology review and feasibility study of technology that may use reduce ice build-up through pulsing or vibration of distribution lines to prevent ice build-up and galloping of lines.	Standards	2 years
PLS-4	Complete a study/analysis of potential methods to increase detection capabilities for downed lines to increase response time to repair damaged pole line system after damage from wind and/or ice accumulation.	Asset Planning	2 years
SUB-1	Review additional requirements for sanding and gritting prior to site access.	Facilities	2 years

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
OPS-2	Consider a review of policies surrounding heat stress on outdoor workers and revise to include projected climate changes to mitigate the impacts of heat stress. Policies to consider should including: • A policy on work redistribution (scheduling) to avoid outdoor work during peak heat hours. • Where feasible and risk assessment permits, consider a policy around the adoption and use of modified PPE to improve cooling / ventilation.	Distribution Operations Health and Safety	2 years
OPS-3	Work with Hydro One, and provincial regulators to ensure supply design and standards are aligned with climate risks.	Asset Planning System Operations	2 years
OPS-4	Consider the cost-benefit of the following measures to reduce the risk of employee injuries related to ice accumulation events: • Review, and consider revising policy for requiring installation of winter tires on Hydro-owned vehicles to prevent injuries to personnel rather than through a request/approval process. • Installation and use of additional automated devices to limit need to travel during inclement conditions. • Introducing policies to include heated steps or walkways on Hydro Ottawa properties versus continued salting/sanding.	Fleet & Facilities Asset Planning	2 years
PLS-5	While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life. Underground distribution lines and infrastructure would mitigate risk from wind, ice accumulation and fog.	Asset Planning	5 years
ULS-1	Complete an engineering review to identify if there are locations vulnerable to overheating (via a detailed assessment of locations that could be vulnerable to temperatures higher than 40°C) and complete a cost-benefit analysis for mitigation options, which may include: • Institute either operational constraints on how much power can be conveyed through cables to limit overheating of cables. • Cool ducts either actively or passively, for example, with thermal fill (a clay slurry).	Asset Planning Standards	5 years

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
ULS-2	Identify new technologies and processes through research and feasibility or pilot studies to reduce freeze thaw impacts. These may include: • Exploring the use of different materials for manholes instead of concrete that are less susceptible to freeze-thaw (e.g. fiber glass). • Redesign civil structure collars to move with the heading (e.g. telescopic collars).	Asset Planning Standards	5 years
SUB-2	Develop a policy to monitor and inspect substation building and structural components after an ice event to mitigate the risk of structural damage and loss of assets as a result of ice damage to substations.	Facilities Stations	5 years
SUB-3	Complete a cost-benefit analysis of installing protective covers on small exterior equipment, where feasible, to prevent damage/failure as a result of ice accumulation.	Facilities	5 years
SUB-4	In light of current design standards (40 mm of ice accumulations), assess the need for changes to technical specifications and policies for increased load break switch protection which may include: • Installation of alternative devices (i.e. breakers) to switch loads when load break switches are difficult to switch or inoperable. • Installation of switches without exposed contacts (replacement or protection). Update equipment specifications to require that switch operators break ice to allow for operability.	System Operations Asset Planning Standards	5 years
OPS-5	Develop a policy to monitor and inspect building and roofs after an ice event.	Facilities	5 years
OPS-6	Consider updating the work from home policy to eliminate or reduce commuting during extreme weather events and hazardous road conditions, particularly ice accumulation.	Human Resources	5 years
OPS-7	Consider future climate projections at end of life of current system when deciding to replace or rehabilitate building HVAC systems. Integrate requirement into Procurement Policy to size and design based on climate projections (heating and cooling requirements) in conjunction with critical needs (IT server requirements). By integrating future needs into procurement, the risk that cooling is not adequate during 40°C is minimized.	Facilities	5 years
PLS-6	Consider the feasibility of further increasing the frequency of pole washing and cost/benefit based on risk level (current/future) to prevent increase risk of fires related to an increase in anticipated fog days.	Asset Planning	5-10 years

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
PLS-7	Complete a cost/benefit analysis of expedited replacement of insulators and fused cut-outs with porcelain to prevent increase risk of fires related to an increase in anticipated fog days.	Asset Planning	5-10 years

These and other risk mitigation strategies are discussed in more detail in the main report along with a series of suggested best practices to help improve the resilience of Hydro Ottawa operations moving forward. Suggested best practices are summarized below.

- **Action 1:** Continue to invest in Smart Grid technology to increase resilience of the distribution system.
- **Action 2:** Continue to conduct post-disaster event analyses to identify lessons learned.
- **Action 3:** Continual improvement of emergency response planning, including communication protocols before, during and after extreme weather event.
- **Action 4:** Require that operating budgets account for climate risks and resiliency needs.
- **Action 5:** Continue to collaborate and plan with third-party service (e.g. City of Ottawa) providers to mitigate emerging risks and increase resilience of emergency planning procedures.
- **Action 6:** Consider wildfires as a potential risk that may emerge in the future and review the need for Wildfire Management Plans on an annual basis.
- **Action 7:** Collaborate with other utilities, regulators, and governments to develop guidance and protocols for climate resilience electrical infrastructure.
- **Action 8:** Build broad awareness and education among staff, such as incorporating extreme climate events and risks into health and safety communication and training materials.

Abbreviations

CRVA	Climate Risk and Vulnerability Assessment
GDP	Gross Domestic Product
GHG	Greenhouse Gas
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
OPS	Operations
PIEVC	Public Infrastructure Engineering Vulnerability Committee
PLS	Pole Line System
RCP	Representative Concentration Pathways
SUB	Substations
ULS	Underground Line Systems

1.0 INTRODUCTION

1.1 ABOUT HYDRO OTTAWA LIMITED

Hydro Ottawa Limited (Hydro Ottawa) provides electricity to over 330,000 residences and businesses in the City of Ottawa and the Village of Casselman, who depend on a continuous and reliable supply of energy. Its core business is electricity distribution and utility services with a service area of 1,116 km^2 which includes both the City of Ottawa and the Village of Casselman.

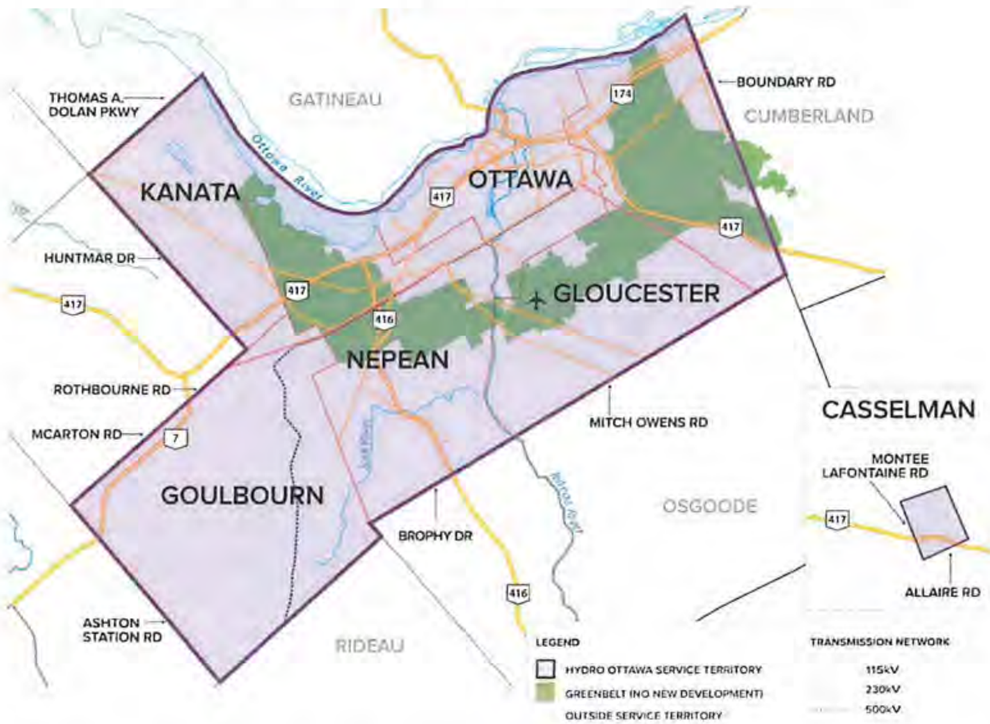

Figure 1: Map of Hydro Ottawa Service Territory[1]

[1] Hydro Ottawa. 2018. <https://hydroottawa.com/about/governance/overview>

1.2 FUTURE CLIMATE CHALLENGE

Hydro Ottawa is committed to creating long-term value for its shareholder, benefitting their customers and the communities it serves. However, climate change poses a serious threat to Hydro Ottawa's ability to deliver on that commitment. This was recently evidenced by the 2018 ice and windstorms of the spring, and the tornadoes that struck the service territory on September 21st, 2018. While these weather events had unavoidable impacts on the outage durations, Hydro Ottawa was able to moderate that impact due to past improvements to the physical infrastructure as well as to monitoring and remote response capabilities.

Hydro Ottawa has recognized the that changes in climate, as reflected in long-term trends and in increases in both frequency and intensity of extreme weather events, are expected to cause a greater range of potentially costly and disruptive impacts to the electrical distribution system, services, and operations. The inevitability of these climatic changes has prompted Hydro Ottawa to plan, monitor and adapt their systems and infrastructure to increase their resilience and limit the impact and damage that these extreme weather events can have on their services.

Hydro Ottawa has retained Stantec Consulting Ltd. (Stantec) to conduct a Climate Change Adaptation Plan (the Plan) for their distribution system and supporting infrastructure to follow up on the risk and vulnerabilities identified in an earlier phase of work. This work culminated in a standalone report prepared by Stantec, titled Distribution System Climate Risk and Vulnerability Assessment (CRVA). The risks identified in the CRVA are further detailed in Section 5 and available under separate cover. As a follow up to the CRVA, this Climate Change Adaptation Plan was developed.

1.3 PURPOSE OF THIS PLAN

This Climate Change Adaptation Plan (the Plan) considers the entire geographic extent of Hydro Ottawa's service territory which covers a vast portion of the City of Ottawa and the Village of Casselman, and includes both overhead and underground electrical distribution assets. The purpose of this Plan is to identify and make recommendations for actions to reduce the risks identified in the CRVA as well as recommendations for integrating actions into the Hydro Ottawa planning systems and operations.

The Plan, similar to the CRVA, was developed through a series of interviews and workshops with Hydro Ottawa staff.

2.0 CLIMATE CHANGE ADAPTATION

2.1 THE RISKS

In 2007, the Intergovernmental Panel on Climate Change (IPCC) concluded that "[the] warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global mean sea level."[2] The impacts of climate change are already being experienced, and the inertia in the atmosphere dictates that the planet is 'locked into' some level of temperature rise due to historic greenhouse gas (GHG) emissions. In fact, some changes are "effectively irreversible", e.g. major melting of the ice sheets[3], and can have abrupt and severe impacts to our global climate.

2.2 THE COSTS

While the costs of extreme weather events depend on multiple factors, climate change is already increasing the intensity of storms, floods, droughts and other severe weather events in Canada. Since the 1980's, catastrophic losses from weather-related events have been growing (Figure 2: Catastrophic Losses in Canada (1983-2018)

and are expected to grow from about $5 billion in 2020 to between $21 billion and $43 billion under a 2°C scenario.[4] The Canadian insurance industry defines a catastrophic event as one that exceeds a threshold of $25 million in insured losses.

[2] IPCC (2007) Climate Change 2007: Synthesis Report. Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, Paschauri, R.K. and Reisinger, A. (eds)], (Geneva, Switzerland: IPCC), p. 2.
[3] http://www.ipcc.ch/ipccreports/tar/vol4/011.htm
[4] Canada, National Round Table on the Environment and the Economy (2011) Paying the Price: The Economic Impacts of Climate Change for Canada (Ottawa: National Round Table on the Environment and the Economy), 162 p.

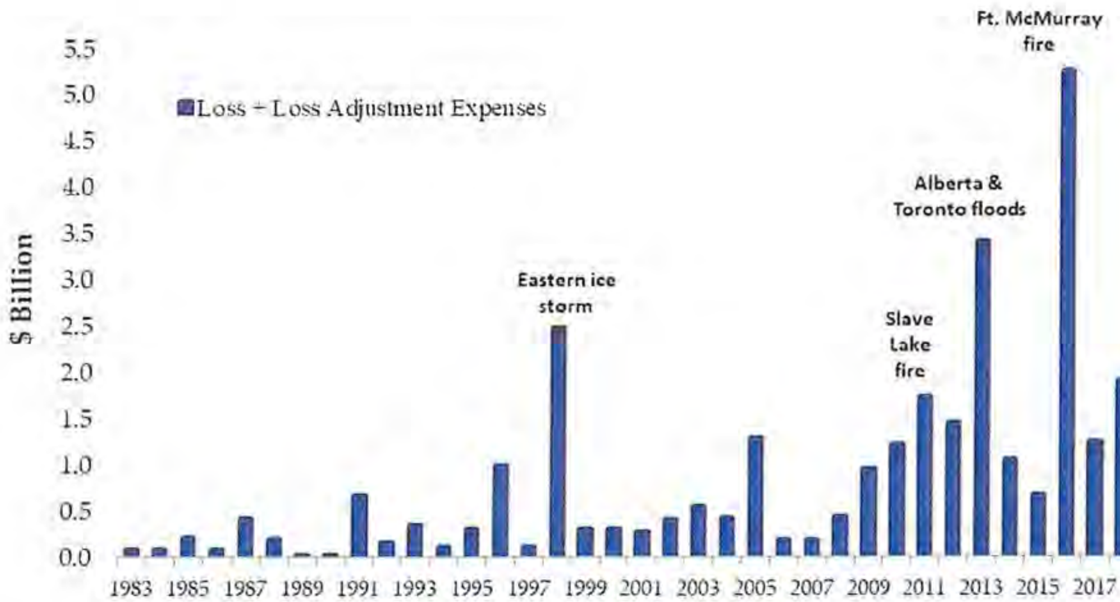

Figure 2: Catastrophic Losses in Canada (1983-2018)[5]

These costs have come close to, or exceeded, $1 billion in most years since 2009. They surpassed $1.5 billion in 2011 and 2017, $2.0 billion in 2018, $3 billion in 2013 and $5.0 billion in 2016. In the past decade, the sum of all severe weather-related catastrophic events has exceeded $20 billion. In 2018 alone, Hydro Ottawa's electrical distribution infrastructure was impacted by costly climate events including a freezing rain event in April, a heavy wind event in May, and a series of tornados that touched down in September in the Ottawa region. The impact of these events range in magnitude, but included service disruption to customers, damage to private property and distribution infrastructure and systems such as structural damage, reduced service life for asset components and for assets themselves, and increased stress to systems and operations. Increases in the frequency and intensity of these extreme events are likely to result in higher repair and maintenance costs, loss of asset value, and interruption of services or production if no risk mitigation and adaptation actions are taken.

With the IPCC concluding that the electricity sector is one of the sectors most at risk of disruption from climate change, and the occurrence of climate events already causing costly impacts, there is growing pressure from stakeholder for organizations to take responsibility to minimize the vulnerability of assets to a changing climate. Liabilities can often be attributed to the inadequate design or mismanagement of infrastructure that arise as a result of climate change and the impact can create public and environmental hazards that should have been mitigated or avoided entirely.

[5] https://globalnews.ca/news/5060791/commentary-climate-change-construction/

2.3 RESPONDING TO THE IMPACTS OF CLIMATE CHANGE

Addressing climate change requires efforts to prepare for changes that are irreversible and already underway, known as climate adaptation. Climate change adaptation involves making adjustments not only to infrastructure and operations but by integrating considerations for climate change into the decision-making process. Adaptation means enabling a sector or process to have a greater range of tolerance to extreme weather events (Figure 3). Most importantly, climate adaptation is now an essential aspect of managing infrastructure.

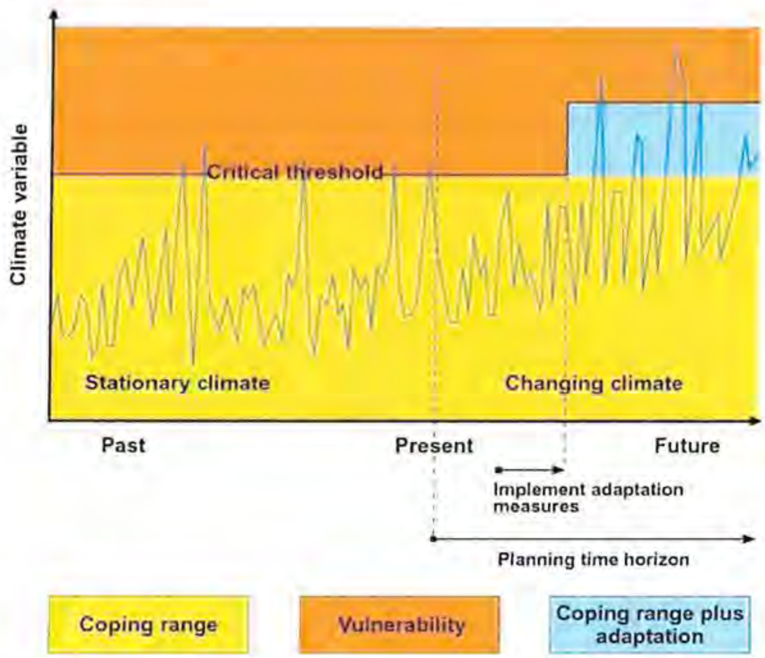

Figure 3: Adaptation Aims to Reduce Vulnerability by Increasing Coping Ranges[6]

Adaptation actions that are taken prior to experiencing specific climate change trends are called "anticipatory or proactive" and those taken after a trend or event has occurred are considered "reactive". Planned proactive adaptation actions typically incur lower long-term costs as the actions preserve assets, address issues of premature aging and increase overall resilience[7]. Successful adaptation does not necessarily mean that climate related impacts will no longer occur; rather, the impacts will still likely occur, but will be less severe in both harm and economic costs than if no adaptation measures been implemented.

[6] http://www.erm.com/en/insights/feature-articles/a-changing-climate-for-the-extractives-sector/

[7] Natural Resources Canada. (2009). What is adaptation? Retrieved from https://www.nrcan.gc.ca/environment/impacts-adaptation/adaptation-101/10025.

Although it is no longer possible to avoid the impacts of climate change, it is possible to reduce the cost and impacts of climate change to various extents. There is a business case for adaptation; this was clearly outlined in an economic report commissioned by the UK government called *The Stern Review*, which concluded, "the benefits of strong and early action far outweigh the economic costs of not acting." Using results from economic models, *The Stern Review* estimated that if society does not act, the overall costs and risks of climate change will be equivalent to losing at least 5% of global Gross Domestic Product (GDP) annually – potentially as much as 20% of GDP. In contrast, the estimated costs of implementing actions to reduce GHG emissions and avoid some of the worst impacts of climate change could be limited to around 1% of global GDP. Most recently, the National Round Table on the Environment and the Economy concluded that the for every dollar spent on climate change adaptation now, $9 to $38 of damages can be avoided in the future.[8]

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[8] http://nrt-trn.ca/wp-content/uploads/2011/09/paying-the-price.pdf

3.0 PREDICTING FUTURE CLIMATE CHANGE AND RISK

To understand anticipated future climate conditions in Hydro Ottawa's service territory, current and historical data from regional Environment Canada weather stations was analyzed in relation to projected global climate trends. Future climate conditions were projected based on Intergovernmental Panel on Climate Change (IPCC) global Representative Concentration Pathways (RCPs), while current and historical weather data was retrieved from Environment Canada records from local weather stations located at the Macdonald-Cartier International Airport and Russell, ON. From this data, localized climate projections were developed for the representative 30-year climate period centered on the 2050s (2041 – 2070) under the "business-as-usual" carbon emissions scenario, RCP8.5. These projections were then used estimate potential extreme weather events and general long-term patterns and trends by that could be expected to be experienced in the service territory during this future climate period.

The future climate conditions identified in the CRVA are based on a 'business as usual' greenhouse gas emissions scenario, which is referred by the IPCC as RCP 8.5 (Figure 4). Based on this scenario, it is assumed that global carbon emissions will continue to rise until 2100. Although some progress has been made in reducing global GHG emissions, current estimates of GHG emissions are still close to following the RCP 8.5 path and thus the CRVA and this Plan are based on risks identified from future climate projections estimated by the RCP 8.5 scenario.

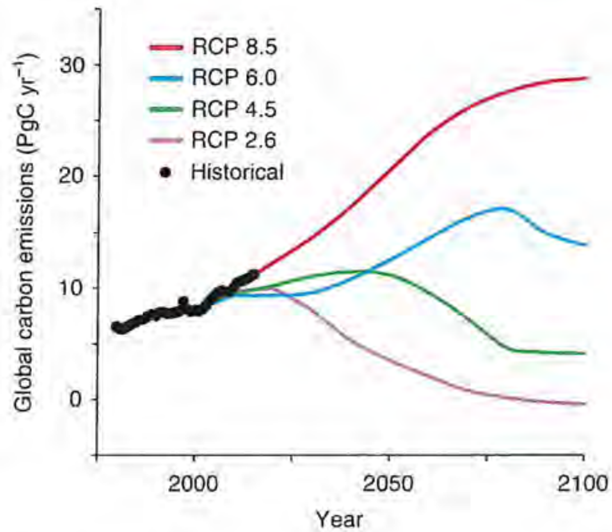

Figure 4: RCP Emissions Scenarios[9]

Climate modeling uses various GHG emissions scenarios, known as Representative Concentration Pathways (RCPs), to project future climate variables under different concentrations and rates of release of GHGs to the atmosphere, as well as different global energy balances. Various future trajectories of GHG emissions are possible depending on the global mitigation efforts in the coming years. RCPs are established by IPCC the international body for assessing the science related to climate change. The IPCC has set four GHG emissions scenarios through RCPs. RCP 8.5 is the internationally recognized the most pessimistic - "business as usual" GHG emissions scenario. Other GHG emissions scenarios represent more substantial and sustained reductions in GHG emissions: RCP 6, 4.5 and 2.6 (For example, the RCP 2.6 emissions scenario may be achievable with extensive adoption of biofuels/renewable energy and large-scale changes in global consumption habits, along with carbon capture and storage. RCP2.6 is representative of a scenario that aims to keep global warming likely below 2°C above pre-industrial temperatures. RCP 4.5 is considered the 'medium stabilization' scenario where global mitigation efforts result in intermediate levels of GHG emissions (IPCC, 2014).

A summary of potential climate changes centered around the 2050s identified in the CRVA for the Hydro Ottawa service area, is presented in Table 1.

[9] Source: https://www.nature.com/articles/s41558-018-0253-3

Table 1: Summary of Potential Climatic Changes by 2050

Climate Parameter	Projected Climatic Changes by Mid-Century
Temperature – Extreme Heat	• Increased frequency and intensity • Increased frequency and length of heat waves
Temperature – Extreme Cold	• Decreased frequency and intensity • Occurrence of extreme cold outbreaks ("Polar Vortex" winters) likely to continue
Rain (Short Duration – High Intensity)	• Increased intensity of events • Reduced return periods (e.g. 20-yr return period event becoming a 10-yr return period event in the future)
Freezing Rain & Ice Storms	• Increased frequency • Increased winter season (e.g. January) events
Snow	• Likely decrease in annual total accumulation • Continued occurrence and steady frequency of larger individual events
High Winds	• Slight increase in frequency of high wind events (e.g. 90 km/h; 120 km/h)
Lightning	• Increased frequency (by about 12% per degree Celsius of warming) • Increased length of the higher frequency lightning season
Tornadoes	• Increased frequency (25% increase by mid-century) • Increase (near 2x) in number of severe thunderstorm days by mid-century (capable of possibly producing tornadoes, hail, extreme winds, and extreme rainfall events)
Fog	• Likely increase
Frost (Freeze-Thaw Cycles)	• Decrease in annual total number of freeze-thaw days • Increase in monthly totals in the shoulder seasons (e.g. November and March)

4.0 APPROACH TO RISK AND ADAPTATION PLANNING

4.1 IDENTIFYING RISK AND ADAPTATION MEASURES

The CRVA was used to evaluate potential impacts and risks to the Hydro Ottawa electrical distribution system and supporting infrastructure as a result of changing climate and extreme weather events. This assessment process followed the Canadian Electricity Association's guide on adaptation to climate change, and Engineers Canada's Public Infrastructure Engineering Vulnerability Committee (PIEVC) Protocol. The process involved the systematic review of historical climate information and the projection of the nature, severity and probability of future climate changes and events. The assessment of climatic changes was used to establish the exposure of infrastructure systems to these climate events. The impact of a particular damaging or disruptive climate event was then quantified and used to calculate the risk for a particular climate-infrastructure interaction. This process was repeated for all applicable infrastructure elements to produce an electrical distribution infrastructure climate risk profile.

The CRVA followed the following methodology (details of the process are provided in the CRVA report):

1. Identification of climate events (e.g. temperature, precipitation, winds) and their threshold values above which infrastructure performance would be affected and projecting the probability of occurrence of the climate hazards in the future (i.e. 2050s).
2. Assignment of a probability score for each climate event based on the climate data. This involved converting the projected probability of occurrence of future climate parameters into the five-point rating scale used in Hydro Ottawa's Asset Management System Risk Procedures.
3. Assignment of a severity rating for the impact of climate events on each element of the distribution system considered in the assessment. Impacts on the infrastructure were assessed for various performance criteria. This part of the assessment was completed through a staff workshop.
4. Calculation of the risk for each infrastructure element was performed using the formula: Risk = Severity x Probability (Table 2).
5. Using Hydro Ottawa's Asset Management System Risk Table (Table 3), medium, high and very high risks to infrastructure and operations were identified.

The adaptive capacity – the ability of a system to respond which takes into consideration factors like, age, design setting, etc.– of the infrastructure elements were taken into account during the risk assessment stage.

Table 2: Sample Risk Scoring Visualization

		Severity				
		Insignificant	Minor	Moderate	Extreme	Significant
Likelihood	Rare	1	4	8	16	25
	Unlikely	2	8	16	32	50
	Possibly	3	12	24	48	75
	Likely	4	16	32	64	100
	Almost Certain	5	20	40	80	125

Table 3: Hydro Ottawa Risk Rating System

Risk Score	Risk Rating
Low	≤10
Medium	11-30
High	31-60
Very High	≥60

The development of the Adaptation Plan consisted of the following steps:

1. Validation of medium to very high risks to infrastructure and operations as well as the impacts in a workshop with Hydro Ottawa staff (See Appendix B for the list of the attendees).

2. Selection of risk mitigation or adaptation measures to reduce the impacts of medium to very high future climate risks; developed through the workshop with Hydro Ottawa.

3. Prioritization of actions based on the risk levels, change in risk (current to future) and Hydro Ottawa's Asset Management System Risk Procedures.

4. Assignment of responsibilities and the development of indicators to track and monitor progress in the Enterprise Risk Management System (ERMS).

5.0 IDENTIFIED RISK AND ADAPTATION MEASURES

5.1 INFRASTRUCTURE ELEMENTS AT RISK

The medium, high and very high future climate related risks developed in the CRVA are provided in Table 4 for a given climate parameter. For each climate parameter, the asset performance affected, impacts and consequences are identified as well as the current and future risk rating. The difference between the current risk and the future risk is generally attributed to the impact of a changing climate as well as the age of the infrastructure. Red risk ratings identify high and very high risks.

Table 4: Medium and Very High Climate Related Risks

Climate Parameter	System/Component Affected	Risk Rating		Asset Performance Affected	Impacts	Result / Consequence
		Current Climate	Future Climate			
Daily maximum temp. of 40°C and higher	Operators Powerline Maintenance Staff	26 26	65 65	Resource Efficiency Asset Value – Financial	• Potential heat stress impacts on personnel working outdoors. • Exacerbated by humidex.	• Health and safety concerns requiring precautionary measures such as more frequent resting periods, hydration, etc. • Delay in restoration. • Loss in productivity.
	Administrative and Operational Buildings	8	20	Asset Value – Financial	• Increased cooling demands for the building critical systems (e.g., communication and IT systems).	• Capacity of cooling system may not be adequate to maintain ambient temperature within the design range of equipment affected which can lead to loss of efficiency, functionality or failure.
	Underground Cables	10	25	Level of Service: Service Quality Asset Value – Financial	• Potentially reduced capacity due to increased daily electricity demand from end user (e.g., A/C units).	• Additional strain on, and limits to the underground electrical infrastructure capacity.
Annual wind speeds of 120 km/h or higher (30-year occurrence)	Operators Powerline Maintenance Staff	36 36	36 36	Level of Service: Service Quality Resource Efficiency Asset Value – Financial	• Instability of equipment (lift buckets), flying debris, or broken tree limbs hazards.	• Health and safety concern for personnel working outdoors.
	Power Distribution: East-West lines and poles	81	81	Level of Service: Service Quality Resource Efficiency Asset Value – Financial	• Damage to poles and lines from high wind events.	• Loss of assets. • Disruption of service. • Difficulty in restoring service due to health and safety concerns for staff. • Public safety concerns due to downed power lines. • Impact on scheduling/productivity/ resources.
					• Risk of damages from falling trees, broken tree limbs or flying debris.	• Loss of assets. • Disruption of service. • Difficulty in restoring service due to health and safety concerns for staff. • Public safety concerns due to downed power lines.
	Power Distribution: North-South lines and poles	108	108	Level of Service: System Accessibility Level of Service: Service Quality Resource Efficiency Asset Value – Financial	• Damage to poles and lines from high wind events.	• Loss of assets. • Disruption of service. • Difficulty in restoring service due to health and safety concerns for staff. • Public safety concerns due to downed power lines. • Impact on scheduling/productivity/ resources.
					• Risk of damages from falling trees, broken tree limbs or flying debris.	• Loss of assets. • Disruption of service. • Difficulty in restoring service due to health and safety concerns for staff. • Public safety concerns due to downed power lines.

Climate Parameter	System/Component Affected	Risk Rating		Asset Performance Affected	Impacts	Result / Consequence
		Current Climate	Future Climate			
Easterly winds of 80 km/h or higher (cool season [Oct.-March])	North-South lines and poles	32	32	Level of Service: System Accessibility Level of Service: Service Quality Resource Efficiency Asset Value – Financial	• Risk of damages from falling trees or broken tree limbs.	• Loss of assets. • Disruption of service. • Difficulty in restoring service due to health and safety concerns for staff. • Public safety concerns due to downed power lines.
	Operators Powerline Maintenance Staff	24	24	Level of Service: Service Quality Resource Efficiency Asset Value – Financial	• Instability of equipment (lift buckets), flying debris, or broken tree limbs hazards.	• Health and safety concern for personnel working outdoors.
	Power Distribution: East-West Lines and Poles	24	24	Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Damage to poles and lines from high wind events.	• Loss of assets. • Disruption of service. • Difficulty in restoring service due to health and safety concerns for staff. • Public safety concerns due to downed power lines. • Impact on scheduling/productivity/ resources.
					• Risk of damages from falling trees, broken tree limbs or flying debris.	• Loss of assets. • Disruption of service. • Difficulty in restoring service due to health and safety concerns for staff. • Public safety concerns due to downed power lines.
Ice accumulation of 40mm (30-year occurrence)	Third Party Services and Interactions: Hydro One	54	72	Level of Service: Service Quality Asset Value – Financial	• Loss of supply to Hydro Ottawa Damages to shared resources between Hydro One and Hydro Ottawa. • Loss of transmission. • Loss of redundancy. • Damage to equipment.	• Disruption of service. • Inability to restore service. • Loss of redundancy. • Loss of efficiency. • Potential damage to Hydro Ottawa and Hydro One shared resources • Damage to shared facilities.
	Administrative and Operational Buildings	24	32	Resource Efficiency Asset Value – Financial	• Access to the building is hindered due to heavy ice accumulation.	• Health and safety concerns for staff, contractors and/or public.
					• Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof.	• Potential structural and/or functional damage to roof elements (e.g., membrane on flat roofs). • May result in blocked roof drains. • Possible ice damming. • Potential loss of assets.
					• Ice accumulation on building mounted equipment (roof, exterior walls).	• Reduced efficiency and/or functionality, and failure of equipment affected.
	Substations - Buildings and Structural Components	24	32	Resource Efficiency Asset Value – Financial	• Access to the building is hindered due to heavy ice accumulation.	• Health and safety concerns for staff, contractors and/or public. • Delay in restoration.
					• Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof.	• Potential structural and/or functional damage to roof elements (e.g., membrane on flat roofs). • May result in block drains. • Possible ice damming. • Potential loss of assets. • Disruption of service.
					• Ice accumulation on building mounted equipment (roof, exterior walls).	• Reduced efficiency and/or functionality, and failure of equipment affected.

Climate Parameter	System/Component Affected	Risk Rating		Asset Performance Affected	Impacts	Result / Consequence
		Current Climate	Future Climate			
Ice accumulation of 40mm (30-year occurrence) (continued)	Operators Powerline Maintenance Staff	39 39	52 52	Resource Efficiency Asset Value – Financial	• Difficulty accessing areas needing repair due to icy conditions; e.g., ice on roadways and walkways, equipment.	• Potential delays in arriving to work site. • Potential delays in performing work due to ice accumulation on equipment. • Health and safety concerns.
	Power Distribution: East-West lines and poles	51	68	Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Damage from increased weight on overhead lines. • Ice falling off of lines.	• Loss of assets. • Disruption of service. • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work. • Public safety concerns due to downed power lines.
					• Ice accretion on lines in excess of 12.5 mm (0.5 inches) accompanied by a 90km/h wind could result in structural failure. • Uneven ice accretion could cause swinging or 'galloping' in the lines. • Damage to poles and attached equipment.	• Potential for flashovers. • Ice break-up from lines may cause public safety concerns. • Loss of assets. • Disruption of service. • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work. • Public safety concerns due to downed power lines.
					• Damages to lines from fallen trees or broken tree limbs.	• Loss of assets. • Disruption of service. • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work. • Public safety concerns due to downed power lines.
					• Damage to poles and other surface equipment from vehicles losing control on icy roads.	• Loss of assets. • Disruption of service. • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work. • Public safety concerns due to downed power lines.
	Power Distribution: North-South lines and poles	36	48	Level of Service: Service Quality Resource Efficiency Asset Value - Financial	• Damage from increased weight on overhead lines. • Ice falling off of lines.	• Loss of assets. • Disruption of service. • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work. • Public safety concerns due to downed power lines.
					• Ice accretion on lines in excess of 12.5 mm (0.5 inches) accompanied by a 90km/h wind could result in structural failure. • Uneven ice accretion could cause swinging or 'galloping' in the lines. • Damage to poles and attached equipment.	• Potential for flashovers. • Ice break-up from lines may cause public safety concerns. • Loss of assets. • Disruption of service. • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work. • Public safety concerns due to downed power lines.

Climate Parameter	System/Component Affected	Risk Rating		Asset Performance Affected	Impacts	Result / Consequence
		Current Climate	Future Climate			
Ice accumulation of 40mm (30-year occurrence) (continued)					• Damages to lines from fallen trees or broken tree limbs.	• Loss of assets. • Disruption of service. • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work. • Public safety concerns due to downed power lines.
					• Damage to poles and other surface equipment from vehicles losing control on icy roads.	• Loss of assets. • Disruption of service. • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work. • Public safety concerns due to downed power lines.
	Substations: Station Load Break Switch	18	24	Level of Service: Service Quality Resource Efficiency Asset Value – Financial	• Ice accretion on load break switches could result in difficulty transferring loads.	• Removal of ice required for the switch to be operable. • Delay in restoration.
Daily maximum temp. of 35°C and higher	Administrative and Operational Buildings	12	20	Asset Value – Financial	• Increased cooling demands for the building critical systems (e.g., communication and IT systems).	• Capacity of cooling system may not be adequate to maintain ambient temperature within the design range of equipment affected which can lead to loss of efficiency, functionality or failure.
Season with ≥ 50 fog days (Nov.-March)	Power Distribution: East-West Poles	18	24	Level of Service: Service Quality Resource Efficiency Asset Value – Financial	• Pole fires which are a result of contaminant build-up on the insulators and the fog reducing the dielectric strength of the air which increases the probability of a flashover.	• Risk of electrical arcs, flashovers and pole fires. • Loss of assets. • Disruption of service. • Public safety concerns.
	Power Distribution: North-South Poles	18	24	Level of Service: Service Quality Resource Efficiency Asset Value – Financial	• Pole fires which are a result of contaminant build-up on the insulators and the fog reducing the dielectric strength of the air which increases the probability of a flashover.	• Risk of electrical arcs, flashovers and pole fires. • Loss of assets. • Disruption of service. • Public safety concerns.
	Power Distribution: North-South - Fused Cut Out	12	16	Level of Service: System Accessibility Level of Service: Service Quality Resource Efficiency Asset Value – Financial	• Insulator breakdown on fused cut outs. • Pole fires which are a result of contaminant build-up on the insulators and the fog reducing the dielectric strength of the air which increases the probability of a flashover probability of a flashover.	• Risk of electrical arcs, flashovers and pole fires. • Loss of assets. • Disruption of service. • Public safety concerns.
Freeze-thaw cycles – Daily Tmax/Tmin temp. fluctuation of ±4°C around 0°C	Power Distribution: Underground - Civil Structures	16	24	Resource Efficiency Asset Value – Financial	• Water penetration into or around civil structures which freezes causing stress on material.	• Deterioration and damage (short- and long-term) to materials. • Uplift of near-surface infrastructure causing higher risks of damage during winter maintenance (e.g., snow removal) operations.

5.2 ADAPTATION MEASURES

5.2.1 Adaptation Workshop

A climate adaptation planning workshop was conducted on June 27, 2019 with Hydro Ottawa staff and Stantec's risk and adaptation planning team. The purpose of the workshop was to validate the risks identified in the CRVA and to identify adaptation measures.

The workshop split participants into two groups to review the medium, high and very high climate risks and develop a range of adaptation measures for each.

A list of participants who attended the risk assessment workshop is presented in **Appendix B**.

5.2.2 Prioritizing Actions

The adaptation measures from the workshop were assessed and prioritized based on the level of risk as well as the change in risk in the current climate and future climate. Actions were prioritized taking into consideration both current and future risk ratings prioritizing those in the very high and high category and an assessment of the change in risk as identified by the risk factor. The risk factor represents the change in risk in the future climate scenario and is calculated by dividing the future risk by the current risk rating. Timelines to implement were developed based on the same review with longer implementation times for lower risk rating that increase in the future scenario. The timelines for adaptation measures represent the schedule for completing any analysis (e.g. cost-benefit analysis, policy review and revisions, etc.) and incorporation into a business operation such as policy, or plan.

The sections below present the significant risks and potential adaptation measures for each of the major infrastructure categories evaluated. The four categories used are pole line systems, underground line systems, substations and operations.

5.3 POLE LINE SYSTEM

5.3.1 Risk and Potential Adaptation Actions

High winds (>120 km/h - 30-year occurrence) causing direct damage to the poles, pole mounted equipment, and distribution lines as well as damage from falling tree or tree limbs pose the highest climate risk to Hydro Ottawa's infrastructure in current and future climates.

Ice accumulation (>40 mm - 30-year occurrence) currently poses a medium and high risk to infrastructure elements with the risk escalating to very high for the East-West distribution lines. The risk rating increased in the future for all assets impacted by ice accumulation.

Risks to infrastructure elements from fog are projected to increase in the future but remained in the medium range.

Easterly winds (>80 km/h) currently pose a medium risk to North-South distribution lines; this is not expected to measurably change in the future.

The actions identified during the Hydro Ottawa workshop are identified in Table 5.

Table 5: Impacts to Pole Line System - Current and Future

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Annual wind speeds of 120 km/h or higher (30-year occurrence)	Power Distribution: East-West lines and poles	Damage to poles and lines from high wind events.	81	81	1.0	Use of higher strength structures (e.g. concrete, composite, metal poles) as anchoring in anti-cascading strategy. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Annual wind speeds of 120 km/h or higher (30-year occurrence)	Power Distribution: East-West lines and poles	Risk of damages from falling trees, broken tree limbs or flying debris.	81	81	1.0	Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their impacts on infrastructure and personnel. Recent revisions have been made to include more aggressive and frequent trimming, including wire to sky trimming. Consider the feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Annual wind speeds of 120 km/h or higher (30-year occurrence)	Power Distribution: North-South lines and poles	Damage to poles and lines from high wind events.	108	108	1.0	Use of higher strength structures (e.g. concrete, composite, metal poles) as anchoring in anti-cascading strategy. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Annual wind speeds of 120 km/h or higher (30-year occurrence)	Power Distribution: North-South lines and poles	Risk of damages from falling trees, broken tree limbs or flying debris.	108	108	1.0	Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their impacts on infrastructure and personnel. Recent revisions have been made to include more aggressive and frequent trimming, including wire to sky trimming. Consider the feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Easterly winds of 80 km/h or higher (cool season [Oct.-March])	Power Distribution: North-South Lines and Poles	Damage from falling trees, broken tree limbs or flying debris.	32	32	1.0	Develop anti-cascading strategies (e.g. introduce break or stress points in lines). Increase detection capabilities for downed lines. Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their impacts on infrastructure and personnel. Recent revisions have been made to include more aggressive and frequent trimming, including wire to sky trimming. Consider the feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Easterly winds of 80 km/h or higher (cool season [Oct.-March]) (continued)	Power Distribution: East-West Lines and Poles	Damage from falling trees, broken tree limbs or flying debris.	24	24	1.0	Develop anti-cascading strategies (e.g. introduce break or stress points in lines). Increase detection capabilities for downed lines. Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their impacts on infrastructure and personnel. Recent revisions have been made to include more aggressive and frequent trimming, including wire to sky trimming. Consider the feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Ice accumulation of 40mm (30-year occurrence)	Power Distribution: East-West lines and poles	Damage from increased weight on overhead lines. Ice accretion on lines in excess of 12.5 mm (0.5 inches) accompanied by a 90km/h wind could result in structural failure and uneven ice accretion could cause swinging or 'galloping' in the lines. Damages to lines from fallen trees or broken tree limbs. Damage to poles and other surface equipment from vehicles losing control on icy roads.	51	[illegible]	1.3	Develop anti-cascading strategies (e.g. introduce break or stress points in lines). Increase detection capabilities for downed lines. Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their impacts on infrastructure and personnel. Recent revisions have been made to include more aggressive and frequent trimming, including wire to sky trimming. Consider the feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life. Research technology and feasibility of pulsing or vibrating lines to reduce ice build-up.
Ice accumulation of 40mm (30-year occurrence)	Power Distribution: North-South lines and poles	Damage from increased weight on overhead lines. Ice accretion on lines in excess of 12.5 mm (0.5 inches) accompanied by a 90km/h wind could result in structural failure and uneven ice accretion could cause swinging or 'galloping' in the lines. Damages to lines from fallen trees or broken tree limbs. Damage to poles and other surface equipment from vehicles losing control on icy roads.	36	48	1.3	Develop anti-cascading strategies (e.g. introduce break or stress points in lines). Increase detection capabilities for downed lines. Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their impacts on infrastructure and personnel. Recent revisions have been made to include more aggressive and frequent trimming, including wire to sky trimming. Consider the feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life. Research technology and feasibility of pulsing or vibrating lines to reduce ice build-up.

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Ice accumulation of 40mm (30-year occurrence) (continued)	Power Distribution: North-South lines and poles	Damages to lines from fallen trees or broken tree limbs.	36	48	1.3	Consider updating the vegetation management plan to account for the impacts and risks of increased invasive species and their impacts on infrastructure and personnel. For example, modify the vegetation management plan to include the following actions: • Trimming trees more often/aggressively or include heritage tree. • Include trees in the fall zone if vulnerable through a condition assessment. • Work with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Season with ≥ 50 fog days (Nov.-March)	Power Distribution: All directions	Pole fires as a result of contaminants accumulating onto insulators and presence of fog.	18	24	1.3	Expedite the replacement of porcelain insulators with polymer insulators beyond replacement during maintenance. Consider the feasibility of further increasing the frequency of pole washing and cost/benefit based on risk level (current/future). While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.
Season with ≥ 50 fog days (Nov.-March)	Power Distribution: North-South - Fused Cut Out	Insulator breakdown on fused cut outs.	12	16	1.3	Replace porcelain fused cutouts with polymer fused cutouts on an expedited basis. While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life.

5.3.2 Pole Line System Recommended Actions

To address the future climate risks in the pole line system, the following recommendations are built on the actions identified by Hydro Ottawa in the Workshop.

Table 6: Recommendations for Pole Line System (PLS)

Priority Level	Initiative	Responsibility	Business Operation to Integrate Outcome	Climate Event Mitigated	Timeline to Complete and Integrate into Business Operations (if applicable)	Monitoring Strategy
PLS-1	Develop anti-cascading strategies and standards for hardening of pole line systems to protect against wind and ice accumulation events, including: • Introducing break or stress points into the distribution lines. • Anchoring. • type of pole. Complete a cost-benefit review of the strategies at critical areas and/or strategic timelines (end of life).	Asset Planning	Asset Management Plan Pole, Fixtures and Primary Overhead Conductor	Wind, ice accumulation	2 years	Monitor power outages from cascading events year over year and track by climate event.
PLS-2	Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their potential to damage infrastructure or injure personnel during wind and ice events. Noting past program augmentations made in response to past storm events, evaluate feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. • Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate.	Forestry Asset Planning	Vegetation Management Plan	Wind, ice accumulation	2 years	Review outage report as a result of tree damage on an annual basis and adjust Vegetation Management Plan as required.
PLS-3	Complete a technology review and feasibility study of technology that may use reduce ice build-up through pulsing or vibration of distribution lines to prevent ice build-up and galloping of lines.	Standards	Asset Management Plan Pole, Fixtures and Primary Overhead Conductor	Ice accumulation	2 years	Line and pole damage and ice accumulation.
PLS-4	Complete a study/analysis of potential methods to increase detection capabilities for downed lines to increase response time to repair damaged pole line system after damage from wind and/or ice accumulation.	Asset Planning	Asset Management Plan Pole, Fixtures and Primary Overhead Conductor	Wind, ice accumulation	2 years	Monitor power restoration response time to event.
PLS-5	While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life. Underground distribution lines and infrastructure would mitigate risk from wind, ice accumulation and fog.	Asset Planning	Asset Management Plan Pole, Fixtures and Primary Overhead Conductor	Wind, ice accumulation, fog	5 years	Outage reports for weather events and cost of damage estimates.
PLS-6	Consider the feasibility of further increasing the frequency of pole washing and cost/benefit based on risk level (current/future) to prevent increase risk of fires related to an increase in anticipated fog days.	Asset Planning	Asset Management Plan Pole, Fixtures and Primary Overhead Conductor	Fog	5-10 years	Monitor pole fires and fog days on a year over year basis
PLS-7	Complete a cost/benefit analysis of expedited replacement of insulators and fused cut-outs with porcelain to prevent increase risk of fires related to an increase in anticipated fog days.	Asset Planning	Asset Management Plan Pole, Fixtures and Primary Overhead Conductor	Fog	5-10 years	Monitor pole fires and fog days on a year over year basis.

5.4 UNDERGROUND LINES SYSTEM

5.4.1 Risk and Potential Adaptation Actions

The CRVA identified only one interaction that presented a medium or higher risk: impacts of freeze-thaw events on civil structures. This risk is currently medium and projected to remain medium in the future.

The actions identified during the Hydro Ottawa workshop are identified in Table 7.

Table 7: Impacts to Underground Lines System - Current and Future

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Daily maximum temp. of 40°C	Power Distribution: Underground – Underground Cables	Loss of asset life due High ambient temperatures in combination with the heating of cables resulting from increasing electrical loading.	10	25	2.5	Review to identify, if there are locations vulnerable to overheating (via a detailed assessment of locations that could be vulnerable to temperatures higher than 40°C) and: • Institute either operational constraints on how much power can be conveyed through cables to limit overheating of cables. • Cool ducts either actively or passively, for example, with thermal fill (a clay slurry).
Freeze-thaw cycles – Daily Tmax/Tmin temp. fluctuation of ±4°C around 0°C	Power Distribution: Underground - Civil Structures	Water penetration into or around civil structures which freezes causing stress on material.	16	24	1.5	Explore the use of different materials for manholes (fiber glass instead of concrete) that are less susceptible to freeze-thaw. Redesign civil structure collars to move with the heading (e.g. telescopic collars).

5.4.2 Underground Line Systems Recommended Actions

To address the future climate risks with underground line systems, the following recommendations are built on the actions identified by Hydro Ottawa in the Workshop.

Table 8: Recommendations for Underground Line Systems (ULS)

Priority Level	Initiative	Responsibility	Business Operation to Integrate Outcome	Climate Event Mitigated	Timeline to Complete and Integrate into Business Operations (if applicable)	Monitoring Strategy
ULS-1	Complete an engineering review to identify if there are locations vulnerable to overheating (via a detailed assessment of locations that could be vulnerable to temperatures higher than 40°C) and complete a cost-benefit analysis for mitigation options, which may include: • Institute either operational constraints on how much power can be conveyed through cables to limit overheating of cables. • Cool ducts either actively or passively, for example, with thermal fill (a clay slurry).	Asset Planning Standards	Asset Management Plan UG Cable R0	Maximum Temperatures	5 years	Temperature runs within prescribed levels. Premature cable failure events and occurrences of 40°C days.
ULS-2	Identify new technologies and processes through research and feasibility or pilot studies to reduce freeze thaw impacts. These may include: • Exploring the use of different materials for manholes instead of concrete that are less susceptible to freeze-thaw (e.g. fiber glass). • Redesign civil structure collars to move with the heading (e.g. telescopic collars).	Asset Planning Standards	Asset Management Plan - Civil Structures	Freeze-thaw events	5 years	Track freeze-thaw damage and annual freeze-thaw days.

5.5 SUBSTATIONS

5.5.1 Risk and Potential Adaptation Actions

All climate risks identified for substations and substation components are related to ice accumulation of 40mm (30-year occurrence), which has been found to impact building access, roof loading, exterior mounted equipment, and load break switches. All these risks were found to increase in the future. The risks related to substation buildings increased from medium to a high in the future. The actions identified during the Hydro Ottawa workshop are identified in Table 9.

Table 9: Substations - Current and Future

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Ice accumulation of 40mm (30-year occurrence)	Substations - Buildings and Structural Components	Access to the building is hindered due to heavy ice accumulation.	24	32	1.3	Increase spreading of gravel and grit before site access.
Ice accumulation of 40mm (30-year occurrence)	Substations - Buildings and Structural Components	Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof.	24	32	1.3	Develop a policy to monitor and inspect substation building and structural components after an ice event.
Ice accumulation of 40mm (30-year occurrence)	Substations - Buildings and Structural Components	Ice accumulation on building mounted equipment (exterior walls).	24	32	1.3	Install covers on vulnerable equipment attached to buildings (where feasible).
Ice accumulation of 40mm (30-year occurrence)	Substations: Station Load Break Switch	Ice accretion on load break switches could result in difficulty transferring loads.	18	24	1.3	Install switches without exposed contacts. Update equipment specifications to require that switch operators break ice to allow for operability. Consider alternative devices (i.e. breakers) to switch loads when load break switches are difficult to switch or inoperable.

5.5.2 Substations: Recommended Actions

To address the future climate risks to substations, the following recommendations are built on the actions identified by Hydro Ottawa in the Workshop.

Table 10: Recommendations for Substations (SUB)

Priority Level	Initiative	Responsibility	Business Operation to Integrate Outcome	Climate Event Mitigated	Timeline to Complete and Integrate into Business Operations (if applicable)	Monitoring Strategy
SUB-1	Review additional requirements for sanding and gritting prior to site access.	Facilities	Maintenance Procedures	Ice accumulation	2 years	Delays due to inaccessibility.
SUB-2	Develop a policy to monitor and inspect substation building and structural components after an ice event to mitigate the risk of structural damage and loss of assets as a result of ice damage to substations.	Facilities Stations	Maintenance Procedures	Ice accumulation	5 years	Number of leaks or damages. Track maintenance costs.
SUB-3	Complete a cost-benefit analysis of installing protective covers on small exterior equipment, where feasible, to prevent damage/failure as a result of ice accumulation.	Facilities	Asset Management Plans	Ice accumulation	5 years	Number of failures of attached equipment due to ice.
SUB-4	In light of current design standards (40 mm of ice accumulations), assess the need for changes to technical specifications and policies for increased load break switch protection which may include: • Installation of alternative devices (i.e. breakers) to switch loads when load break switches are difficult to switch or inoperable. • Installation of switches without exposed contacts (replacement or protection). • Update equipment specifications to require that switch operators break ice to allow for operability.	System Operations Asset Planning Standards	Asset Management Plan - Station Switchgear and Breakers	Ice accumulation	5 years	Number of operational failures due to ice.

5.6 OPERATIONS

5.6.1 Risk and Potential Adaptation Actions

Climate risks related to operations are associated with personnel, administrative buildings, and third-party interactions with Hydro One. These assets are impacted by daily maximum temperatures of 35°C and 40°C and higher, winds of 80 km/h and 120 km/h and higher, and ice accumulation of 40mm. The highest rated climate risks to Hydro Ottawa operations are heat stress on outdoor operators and maintenance personnel, and a loss of supply from Hydro One due to ice accumulation; these risks will increase in the future.

Risks associated with ice accumulation include impacts on administrative building roof loads and access; these risks have a medium risk rating in the current climate but will increase to high in the future. Ice accumulation was also identified as a high risk (current and future climates) to outdoor operators and maintenance staff.

Lastly, high maximum temperatures requiring higher cooling demands on administrative buildings produces a medium risk level in the current climate; this risk will remain medium in the future.

The actions identified during the Hydro Ottawa workshop are identified in Table 11.

Table 11: Impacts to Operations - Current and Future

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Daily maximum temp. of 40°C and higher	Operators	Potential heat stress impacts on personnel working outdoors. Exacerbated by humidex.	26	65	2.5	Work redistribution (scheduling) to avoid outdoor work during peak heat hours. Risk assessment to be completed to determine if potential for use of modified PPE that has improved cooling / ventilation and consideration for modifying worksite requirements where fire retardant may not be necessary.
Daily maximum temp. of 40°C and higher	Administrative and Operational Buildings	Increased cooling demands for the buildings, including critical systems (e.g., communication and IT systems).	8	20	2.5	Consider future climate projections at end of life of current system when deciding to replace or retrofit building HVAC systems.
Daily maximum temp. of 35°C and higher	Administrative and Operational Buildings	Increased cooling demands for the buildings, including critical systems (e.g., communication and IT systems).	12	20	1.7	Consider future climate projections at end of life of current system when deciding to replace or retrofit building HVAC systems.
Annual wind speeds of 120 km/h or higher (30-year occurrence)	Operators	Instability of equipment (lift buckets), flying debris, or broken tree limbs hazards.	36	36	1.0	This would result in a stop work authority; however, there is a need to refine and establish a wind condition policy establishing when a lift bucket should not be used and when work should not be completed.
Easterly winds of 80 km/h or higher (cool season [Oct.-March])	Operators/ Powerline Maintenance Staff	Instability of equipment (lift buckets), flying debris, or broken tree limbs hazards.	24	24	1.0	This would result in a stop work authority; however, there is a need to refine and establish a wind condition policy establishing when a lift bucket should not be used and when work should not be completed.
Ice accumulation of 40mm (30-year occurrence)	Third Party Services and Interactions: Hydro One	Loss of supply to Hydro Ottawa. Damages to Hydro One and Hydro Ottawa shared resources. Loss of transmission. Loss of redundancy. Damage to equipment.	54	72	1.3	Work with Hydro One, and provincial regulators to ensure supply design and standards are aligned with climate risks.
Ice accumulation of 40mm (30-year occurrence)	Administrative and Operational Buildings	Access to the building is hindered due to heavy ice accumulation.	24	32	1.3	Update the work from home plan to eliminate commuting during extreme weather events and hazardous road conditions.

Climate Parameter	System / Component Affected	Description of Impact	Current Risk Score	Future Risk Score	Risk Factor (Change)	Possible Actions to Mitigate Risk
Ice accumulation of 40mm (30-year occurrence)	Administrative and Operational Buildings	Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof may impact structural and assets.	24	32	1.3	Monitor, inspect and repair roof after climate event to prevent protect assets, equipment within the building.
Ice accumulation of 40mm (30-year occurrence)	Operators/Powerline Maintenance Staff	Injuries to operators and personnel.	39	52	1.3	Review, and consider revising policy for requiring installation of winter tires on Hydro-owned vehicles to prevent injuries to personnel rather than through a request/approval process. Installation and use of remotely operable switching devices to reduce travel requirements during inclement conditions. Introduce policies to include heated steps or walkways on Hydro Ottawa properties versus continued salting/sanding.

5.7 OPERATIONS: RECOMMENDED ACTIONS

To address the future climate risks to operations, the following recommendations are built on the actions identified by Hydro Ottawa in the Workshop.

Table 12: Recommendations for Operations (OPS)

Priority Level	Initiative	Responsibility	Business Operation to Integrate Outcome	Climate Event Mitigated	Timeline to Complete and Integrate into Business Operations (if applicable)	Monitoring Strategy
OPS-1	Refine and establish a policy on wind conditions when a lift bucket should not be used and when work should not be completed to mitigate the risk of injury related to wind.	Distribution Operations Health and Safety	Health and Safety Policy/Practice	Wind	1 year	Monitoring of the number of wind-related events and health and safety incidents associated with wind and lift buckets.
OPS-2	Consider a review of policies surrounding heat stress on outdoor workers and revise to include projected climate changes to mitigate the impacts of heat stress. Policies to consider should including: • A policy on work redistribution (scheduling) to avoid outdoor work during peak heat hours. • Where feasible and risk assessment permits, consider a policy around the adoption and use of modified PPE to improve cooling / ventilation.	Distribution Operations Health and Safety	Health and Safety Policy/Practice	Heat events	2 years	Monitor the number of heat-related incidents and daily max temperatures in excess of 35 °C and 40°C.
OPS-3	Work with Hydro One, and provincial regulators to ensure supply design and standards are aligned with climate risks.	Asset Planning System Operations	Various	Ice accumulation, wind	2 years	Track the frequency and scale of outages resulting from Hydro One service disruption.
OPS-4	Consider the cost-benefit of the following measures to reduce the risk of employee injuries related to ice accumulation events: • Review, and consider revising policy for requiring installation of winter tires on Hydro-owned vehicles to prevent injuries to personnel rather than through a request/approval process. • Installation and use of additional automated devices to limit need to travel during inclement conditions. • Introducing policies to include heated steps or walkways on Hydro Ottawa properties versus continued salting/sanding.	Fleet & Facilities Asset Planning	Health and Safety Policy/Practice	Ice accumulation	2 years	Monitor the number of ice-related incidents (near miss, incidents).
OPS-5	Develop a policy to monitor and inspect building and roofs after an ice event.	Facilities	Maintenance Procedures	Ice accumulation	5 years	Tracking of damage by weather event (if known). Track maintenance costs.
OPS-6	Consider updating the work from home policy to eliminate or reduce commuting during extreme weather events and hazardous road conditions, particularly ice accumulation.	Human Resources	Human Resources Policy	Ice accumulation	5 years	Safety bulletin for tracking number of slips, falls, and other ice-related incidents.
OPS-7	Consider future climate projections at end of life of current system when deciding to replace or rehabilitate building HVAC systems. Integrate requirement into Procurement Policy to size and design based on climate projections (heating and cooling requirements) in conjunction with critical needs (IT server requirements). By integrating future needs into procurement, the risk that cooling is not adequate during 40°C is minimized.	Facilities	Procurement Policy	Heat event	5 years	Monitor the efficiency and service requirements of the building's HVAC system and environmental controls.

5.8 BEST PRACTICES FOR A CHANGING CLIMATE

In addition to the recommendations for adaptation measures identified and prioritized in Section 5.3 to 5.6 that were developed in the Hydro Ottawa workshop, the Table 13 presents a number of best practices recommended to guide the organization in their on-going efforts to build resilience.

Table 13: Best Practices for Operations

Action	Action Description
Action 1: Continue to invest in Smart Grid technology to increase resilience of the distribution system.	Hydro Ottawa has invested and continues to invest in capital funding projects to build Smart Grid technology. As Smart Grid technology continues to evolve and mature, Hydro Ottawa should continue to seek opportunities to increase resilience of the system through enhanced Smart Grid technology and system transfer capacity.
Action 2: Continue to conduct post-disaster event analyses to identify lessons learned.	Continue to comprehensively review the outcomes of disaster and emergency events and their effect on Hydro Ottawa owned properties, staff, and service delivery. Continue to track and report data on damages experienced and identify recommended mitigation strategies and response protocols for future similar events. Consider whether events will warrant strategic decisions for Hydro Ottawa properties (e.g. hardening, replacement, relocation, etc.). Distribute findings to all relevant staff and leadership via standardized reports.
Action 3: Continual improvement of emergency response planning, including communication protocols before, during and after extreme weather events.	Continual improvement of Crisis Management Plan with lessons learned and post-disaster analyses and consider opportunities to: • Clarify protocols and staff education within Hydro Ottawa for staff to better understand their roles during an emergency. • Implementing an equipment sharing program or equipment rental agreements with local companies / contractors to avoid equipment limitations during an emergency • Contingency planning for fuel supply.
Action 4: Require that operating budgets account for climate risks mitigation and resiliency needs.	To successfully integrate climate change into an organization, it must be accounted for by management and operational decision-makers through budget planning, service planning, project management, enterprise risk management, asset management, energy management and procurement decisions.
Action 5: Continue to collaborate and plan with third-party service (e.g. City of Ottawa) providers to mitigate emerging risks and increase resilience of emergency planning procedures.	Other third-party risks to Hydro Ottawa's operations are related to their partnerships with the City of Ottawa (fuel supply, stormwater drainage and winter maintenance), partners for emergency response, and telecommunications. Engage and collaborate with third-parties to mitigate emerging risks, share lessons learned and build resilient emergency planning procedures.
Action 6: Consider wildfires as a potential risk that may emerge in the future and review the need for Wildfire Management Plans on an annual basis.	Wildfires are considered as a special case as they are generally related to a combination of weather events (i.e. temperature, rainfall). Wildfires currently pose a low risk to Hydro Ottawa; however, wildfire threat may escalate in the future. It is recommended that Hydro Ottawa monitor changes in fire threat days year over year and complete an assessment of the need to development a Wildfire Management Plan as part of the annual planning system.
Action 7: Collaborate with other utilities, regulators, and governments to develop guidance and protocols for climate resilience electrical infrastructure.	Work with partners to develop guidance and protocols for climate resilient electrical infrastructure. Review pilot projects conducted by peers to assess lessons learned. Adopt findings as necessary.
Action 8: Build broad awareness and education among staff, such as incorporating extreme climate events and risks into health and safety communication and training materials.	Share existing information and best practices with employees, contractors and the public to promote electrical system safety in extreme temperatures and weather.

5.9 IMPLEMENTATION

The Chief Electricity Distribution Officer will be primarily responsible for the implementation of Plan with individual actions falling to the responsibility of the relevant departments as deemed appropriate. Hydro Ottawa will need to dedicate staff time and annual funding for the Plan to be successful in its implementation. It will also be important for Hydro Ottawa to continually monitor, report and review progress on these activities so that they can be adjusted as necessary to improve the outcomes.

5.10 IMPLEMENTATION SCHEDULE

The Plan is intended to be a living document. Updates may be made to accommodate changes in policies, staff or financial resources, and unexpected extreme weather events. This flexibility will ensure that Hydro Ottawa is not constrained to certain parameters should new opportunities for implementation arise. The preliminary implementation schedule was developed to identify and allocate resources required to implement priority actions.

A summary of prioritize recommendations for Adaptation Planning is provided in Table 14.

Table 14: Prioritized Actions

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
OPS-1	Refine and establish a policy on wind conditions when a lift bucket should not be used and when work should not be completed to mitigate the risk of injury related to wind.	Distribution Operations Health and Safety	1 year
PLS-1	Develop anti-cascading strategies and standards for hardening of pole line systems to protect against wind and ice accumulation events, including: • Introducing break or stress points into the distribution lines. • Anchoring. • Type of pole. Complete a cost-benefit review of the strategies at critical areas and/or strategic timelines (end of life).	Asset Planning	2 years

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
PLS-2	Consider further updates to the vegetation management plan to account for the climate impacts and risks of increased invasive species and their potential to damage infrastructure or injure personnel during wind and ice events. Noting past program augmentations made in response to past storm events, evaluate feasibility of further augmentation with: • Trimming trees more often/aggressively or include heritage trees. • Include trees in the fall zone outside of Hydro Ottawa right away if condition assessment indicates vulnerability. Working with the City of Ottawa and the Village of Casselman to choose tree species that will be more resistant to future climate.	Forestry Asset Planning	2 years
PLS-3	Complete a technology review and feasibility study of technology that may use reduce ice build-up through pulsing or vibration of distribution lines to prevent ice build-up and galloping of lines.	Standards	2 years
PLS-4	Complete a study/analysis of potential methods to increase detection capabilities for downed lines to increase response time to repair damaged pole line system after damage from wind and/or ice accumulation.	Asset Planning	2 years
SUB-1	Review additional requirements for sanding and gritting prior to site access.	Facilities	2 years
OPS-2	Consider a review of policies surrounding heat stress on outdoor workers and revise to include projected climate changes to mitigate the impacts of heat stress. Policies to consider should including: • A policy on work redistribution (scheduling) to avoid outdoor work during peak heat hours. • Where feasible and risk assessment permits, consider a policy around the adoption and use of modified PPE to improve cooling / ventilation.	Distribution Operations Health and Safety	2 years
OPS-3	Work with Hydro One, and provincial regulators to ensure supply design and standards are aligned with climate risks.	Asset Planning System Operations	2 years

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
OPS-4	Consider the cost-benefit of the following measures to reduce the risk of employee injuries related to ice accumulation events: • Review, and consider revising policy for requiring installation of winter tires on Hydro-owned vehicles to prevent injuries to personnel rather than through a request/approval process. • Installation and use of additional automated devices to limit need to travel during inclement conditions • Introducing policies to include heated steps or walkways on Hydro Ottawa properties versus continued salting/sanding	Fleet & Facilities Asset Planning	2 years
PLS-5	While likely cost prohibitive, where it may be warranted, complete a cost/benefit analysis to converting overhead lines to underground infrastructure when major damage has occurred, or when the infrastructure is nearing its end of life. Underground distribution lines and infrastructure would mitigate risk from wind, ice accumulation and fog.	Asset Planning	5 years
ULS-1	Complete an engineering review to identify if there are locations vulnerable to overheating (via a detailed assessment of locations that could be vulnerable to temperatures higher than 40°C) and complete a cost-benefit analysis for mitigation options, which may include: • Institute either operational constraints on how much power can be conveyed through cables to limit overheating of cables. • Cool ducts either actively or passively, for example, with thermal fill (a clay slurry).	Asset Planning Standards	5 years
ULS-2	Identify new technologies and processes through research and feasibility or pilot studies to reduce freeze thaw impacts. These may include: • Exploring the use of different materials for manholes instead of concrete that are less susceptible to freeze-thaw (e.g. fiber glass). • Redesign civil structure collars to move with the heading (e.g. telescopic collars).	Asset Planning Standards	5 years
SUB-2	Develop a policy to monitor and inspect substation building and structural components after an ice event to mitigate the risk of structural damage and loss of assets as a result of ice damage to substations.	Facilities Stations	5 years
SUB-3	Complete a cost-benefit analysis of installing protective covers on small exterior equipment, where feasible, to prevent damage/failure as a result of ice accumulation.	Facilities	5 years

ID	Action	Accountability	Timeline to Complete and Integrate into Business Operations (if applicable)
SUB-4	In light of current design standards (40 mm of ice accumulations), assess the need for changes to technical specifications and policies for increased load break switch protection which may include: • Installation of alternative devices (i.e. breakers) to switch loads when load break switches are difficult to switch or inoperable. • Installation of switches without exposed contacts (replacement or protection). • Update equipment specifications to require that switch operators break ice to allow for operability.	System Operations Asset Planning Standards	5 years
OPS-5	Develop a policy to monitor and inspect building and roofs after an ice event.	Facilities	5 years
OPS-6	Consider updating the work from home policy to eliminate or reduce commuting during extreme weather events and hazardous road conditions, particularly ice accumulation.	Human Resources	5 years
OPS-7	Consider future climate projections at end of life of current system when deciding to replace or rehabilitate building HVAC systems. Integrate requirement into Procurement Policy to size and design based on climate projections (heating and cooling requirements) in conjunction with critical needs (IT server requirements). By integrating future needs into procurement, the risk that cooling is not adequate during 40oC is minimized.	Facilities	5 years
PLS-6	Consider the feasibility of further increasing the frequency of pole washing and cost/benefit based on risk level (current/future) to prevent increase risk of fires related to an increase in anticipated fog days.	Asset Planning	5-10 years
PLS-7	Complete a cost/benefit analysis of expedited replacement of insulators and fused cut-outs with porcelain to prevent increase risk of fires related to an increase in anticipated fog days.	Asset Planning	5-10 years

5.11 RESOURCE & BUDGET PLANNING

Many priority actions will be constrained by financial resources, available human resources and conflicting demands. By continuing to use a risk-based approach to action planning and considering climate resilience infrastructure and staffing needs in the budget planning process, Hydro Ottawa will be well-positioned to implement resilience strategies.

5.12 REPORTING & COMMUNICATION

Monitoring is an important part of the adaptation planning process. It provides an opportunity for Hydro Ottawa to examine performance of the adaptation actions and assess whether the estimated risks and vulnerabilities have changed. These learning outcomes can then be integrated into future strategies and actions. It is recommended that monitoring and reporting be undertaken on an annual basis. Designated lead managers should be responsible for providing updates on the status of action implementation, timelines, costs, indicators, and other details as required. The purpose of this reporting is to:

- Raise awareness and increase understanding of anticipated climate trends and their consequences for Hydro Ottawa and to provide context on specific risks, barriers and opportunities.
- Inform and consult with stakeholders on climate science, risk assessment methodologies used, findings, and recommendations to empower decision-making and collaboration around the actions recommended in this Plan.
- Take stock of both Hydro Ottawa and their partners efforts to share success stories and foster learning in the energy distribution sector.

At a minimum, the reporting should include:

- A description of the work that has been completed.
- Identification of any issues or challenges faced in advancing each action.
- List of new actions to address issues, barriers and challenges.
- An indication of progress toward achieving each initiative, using the following scale:
  - Not Started – The initiative has not been implemented.
  - On Track – The initiative has been implemented. For various initiatives, progress will be measured through metrics like maintenance costs, number of failures due to ice, damages due to trees, mitigation return on investment, etc. Other actions will either be noted as completed or not.
  - Outstanding – An issue, barrier and/or challenge is prohibiting the action from being implemented.
  - Delayed – The action has been delayed or placed on hold.
  - Completed – The action has been completed.

For initiatives that are at risk or delayed, the report should identify the barriers and challenges so that new initiatives can be implemented to address these aspects.

Formal updates to this Plan are recommended to occur on a five-year cycle and should focus on reviewing current climate science and its anticipated impacts to operations, staff, and infrastructure. This will also provide opportunity to take stock of progress made, share lessons learned, and to revisit the planning process to take advantage of any new technologies, or knowledge that could benefit operations.

APPENDICES

Appendix A WORKSHOP SUMMARY TABLES

ASSET ELEMENT: BUILDING & STRUCTURAL ELEMENTS

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
High	24	32	Administrative and Operational Buildings	Ice accumulation of 40mm (30-year occurrence)	• Access to the building is hindered due to heavy ice accumulation	• Health and safety concerns for staff, contractors and/or public	1. C/P – Salting entranceway, parking area, and walkways 2. P – Work at home policy	1. Low 2. Low	1. Low (issue remains off-property, i.e. challenge of getting to work still exists) 2. Medium: • Field staff: low • Office staff: high	1. Low 2. Medium	1. Availability of salt 1. Environmental concern 2. Doesn't work for everyone 2. Ability to respond to emergencies 2. Ability to track productivity	1. Facilitator 2. Human Resources	1. Maintenance contractor 2. IBEW (staff union)	1. Low 2. Medium	• Number of slips and falls • Develop a way to monitoring productivity remotely
High	24	32	Administrative and Operational Buildings	Ice accumulation of 40mm (30-year occurrence)	• Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof	• Potential structural and/or functional damage to roof elements (e.g., membrane on flat roofs) • May result in blocked roof drains • Possible ice damming • Potential loss of assets	• Monitor / inspections • Repair roof if damaged *Since Hydro Ottawa does not know how increased ice storms might affect their buildings, they suggest monitoring and acting reactively until the consequences are known. *In the past, Hydro Ottawa has sent someone up to rook to clear snow/ ice, however, this is an H&S issue	• Low	• Medium	• Low	• Access • Resources	• Facilities • Operations	• Facilities/Ops	• Low	• Number of leaks/damages • Maintenance cost

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: BUILDING & STRUCTURAL ELEMENTS

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
High	24	32	Administrative and Operational Buildings	Ice accumulation of 40mm (30-year occurrence)	• Ice accumulation on building mounted equipment (roof, exterior walls)	• Reduced efficiency and/or functionality, and failure of equipment affected	• Monitor and inspect • Install cover on smaller equipment. • *Since Hydro Ottawa does not know how increased ice storms might affect their buildings, they suggest monitoring and acting reactively until the consequences are known.	1. Low 2. Low	1. Medium 2. Medium	1. Low 2. Low	• Identifying problem area/devices • Access • Resources	• Stations • Grid technology	• Stations • Grid technology • System operation • Facilities	1. Low 2. Low	• Number of failures due to ice. • Monitor mitigation expenditures
Moderate	12	20	Administrative and Operational Buildings	Daily maximum temp. of 40°C and higher	• Increased cooling demands for the building critical systems (e.g., communication and IT systems)	• Capacity of cooling system may not be adequate to maintain ambient temperature within the design range of equipment affected which can lead to loss of efficiency, functionality or failure	• Building automation system could likely handle the change, however if overloaded, might sound an alert. *It was noted that the IT group has critical infrastructure within the building that is specially climate controlled.								

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: OPERATORS / POWERLINE MAINTENANCE STAFF

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Short, Medium, Long)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*
Very High	26	65	Operators / Powerline Maintenance Staff	Daily maximum temp. of 40°C and higher	• Potential heat stress impacts on personnel working outdoors. • Exacerbated by humidex.	• Health and safety concerns requiring precautionary measures such as more frequent resting periods, hydration, etc. • Delay in restoration • Loss in productivity	1. C – follow recommendations from H&S for work conditions related to heat stress 2. C – safety meetings / summer letdown with staff 3. P – possible work redistribution (scheduling) to avoid outdoor work during peak heat hours 4. P – modified PPE to improve cooling / ventilation 5. C – modify work site to not require full fire-retardant clothing – expand to other PPE requirements	3. Low – Cap 4. Medium – O&M 5. Low – Cap	3. Medium 4. Low 5. Low	3. Low 4. Low 5. Low	3. Other work to redistribute to 4. H&S approval technology exists safety requirement 5. Ability to modify	3. Operations/ scheduling 4. Health & Safety 5. Operations	3. Union 4. Vendors	3. Medium 4. Low 5. Low
High	39	52	Operators / Powerline Maintenance Staff	Ice accumulation of 40mm (30-year occurrence)	• Difficulty accessing areas needing repair due to icy conditions; e.g., ice on roadways and walkways, equipment.	• Potential delays in arriving to work site • Potential delays in performing work due to ice accumulation on equipment • Health and safety concerns	1. C – Boot ice spikes as needed 2. C – Safety driving training 3. P – Winter tires 4. C – Salt usage increased 5. P – automated devices 6. P – heated steps/ walkways policy (new)	3. Medium 5. High 6. Low	3. Medium 5. Low 6. Low	3. Low 5. High 6. Low	3. Cost, storage 5. Scada bond width, visual open 6. None	3. Fleet 5. Asset planning 6. Facilities	3. Tire shops 5. Vendors 6. Vendors	3. Low 5. Medium 6. Low
High	36	36	Operators / Powerline Maintenance Staff	Annual wind speeds of 120 km/hr or higher (30-year occurrence)	• Instability of equipment (lift buckets), flying debris, or broken tree limbs hazards	• Health and safety concern for personnel working outdoors, especially at heights	• C – Winds of this magnitude would result in a stop work authority • P – Need a more concrete policy on wind conditions where you would not use the lift bucket							

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: OPERATORS / POWERLINE MAINTENANCE STAFF

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Short, Medium, Long)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*
High	24	24	Operators / Powerline Maintenance Staff	Easterly winds of 80 km/hr or higher (cool season [Oct.-March])	• Instability of equipment (lift buckets), flying debris, or broken tree limbs hazards	• Health and safety concern for personnel working outdoors, especially at heights	• C – Winds of this magnitude may result in a stop work authority • P – Need a more concrete policy on wind conditions where you would not use the lift bucket							

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: POWER DISTRIBUTION: SUBSTATIONS

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
High	24	32	Buildings and Structural Components	Ice accumulation of 40mm (30-year occurrence)	• Access to the building is hindered due to heavy ice accumulation	• Health and safety concerns for staff, contractors and/or public • Delay in restoration	• Plow and spread gravel / grit before site access. *This takes place regularly under contract, but additional 'as needed' calls to the snow removal contractor are needed from time to time. *Hydro Ottawa avoids using salt where possible for environmental reasons.	• Low	• Medium	• Low	• Availability of contractors to spread grit	• Field operators/ managers (facilities)	• Contractor • Hydro One	• Low	• Safety bulletin for tracking • H&S, number of slips & falls / incidents
High	24	32	Buildings and Structural Components	Ice accumulation of 40mm (30-year occurrence)	• Increase in load on building due to ice accumulation, particularly if event occurs at a time where abundant snow on the roof	• Potential structural and/or functional damage to roof elements (e.g., membrane on flat roofs) • May result in block drains • Possible ice damming • Potential loss of assets • Disruption of service	• Monitor / inspections • Repair roof if damaged *Since Hydro Ottawa does not know how increased ice storms might affect their buildings, they suggest monitoring and acting reactively until the consequences are known. *In the past, Hydro Ottawa has sent someone up to roof to clear snow/ ice, however, this is an H&S issue.	• Low	• Medium	• Low	• Access • Resources	• Facilities • Operations	• Facilities/Ops	• Low	• Number of leaks/damages • Maintenance cost

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: POWER DISTRIBUTION: SUBSTATIONS

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
High	24	32	Buildings and Structural Components	Ice accumulation of 40mm (30-year occurrence)	• Ice accumulation on building mounted equipment (roof, exterior walls)	• Reduced efficiency and/or functionality, and failure of equipment affected	1. Monitor and inspect 2. Install cover on smaller equipment. *Since Hydro Ottawa does not know how increased ice storms might affect their buildings, they suggest monitoring and acting reactively until the consequences are known.	1. Low 2. Low	1. Medium 2. Medium	1. Low 2. Low	• Identifying problem area/devices • Access • Resources	• Stations • Grid technology	• Stations • Grid technology • System operation • Facilities	1. Low 2. Low	• Number of failures due to ice • Monitor mitigation expenditures
Moderate	18	24	Station Load Break Switch	Ice accumulation of 40mm (30-year occurrence)	• Ice accretion on load break switches could result in difficulty transferring loads.	• Removal of ice required for the switch to be operable • Delay in restoration	1. Operators to break ice to allow for operability 2. Use alternative devices to switch loads 3. Install switches without exposed contacts	1. Low 2. Low 3. High	1. Medium 2. Medium 3. High	1. Low 2. Low 3. High	1. Limitations of safe practices 1. Availability of qualified operators 3. Cost of devices 3. Space limitation 3. Risk assessment	1. Operations 3. Engineering and operations	1. Health & Safety 3. Health & Safety 3. Standards 3. Operations 3. Vendors	1. Low 2. Medium 3. Medium -high	• Number of operation failures to ice

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: POWER DISTRIBUTION: NORTH-SOUTH

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Very High	108	108	Lines & Poles	Annual wind speeds of 120 km/hr or higher (30-year occurrence)	• Damage to poles and lines from high wind events.	• Loss of assets • Disruption of service • Difficulty in restoring service due to health and safety concerns for staff • Public safety concerns due to downed power lines • Impact on scheduling/ productivity/ resources	1. P – Convert to underground lines 2. C/P – Increased storm guying, possibly to every pole 3. P – Break/stress point to limit cascading failure 4. C – increase pole class (new installs) 5. C – Design for 90km/hr winds 6. C – Partnering agreements with contractors/ utilities for resourcing when needed 7. P – Increased detection capabilities for downed lines 8. C – Public safety lines on grounds 9. C – review of N-S arterial lines and guying	1. High – Cap 2. Medium – O&M 3. Medium – Cap 7. Medium – Cap	1. High 2. Medium 3. Low 7. Low	1. High 2. Medium 3. Medium 7. High	1. Cost casements, equipment, location, resources, customer acceptance 2. Easements, study 3. Study 7. Study	1. Asset planning 2. Standards 3. Standards 7. Asset planning	1. Utility coordination 2. City of Ottawa consultant 3. Consultant 7. CEA/CEATZ	1. Hight 2. Medium 3. Medium 7. High	• Monitor weather activity in comparison to damaged equipment. • Did the investment mitigate the expected outcome?

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Very High	108	108	Lines & Poles	Annual wind speeds of 120 km/hr or higher (30-year occurrence)	• Risk of damages from falling trees, broken tree limbs or flying debris.	• Loss of assets • Disruption of service • Difficulty in restoring service due to health and safety concerns for staff • Public safety concerns due to downed power lines	1. P – Convert to underground lines 2. P – Break/stress point to limit cascading failure 3. P – increased detection capabilities for downed lines 4. C – Public safety lines on grounds 5. C – 2/3-year cycle per policy, line to sky smart review of cust. Trees 6. P – Trim trees more often/aggressively or heritage trees 7. C – tree planting advice brochure/ standards *Hydro Ottawa to explain to the city and other groups where and how to plant trees such that they do not affect Hydro infrastructure/ equipment 8. P – include trees in fall zone/condition assessment	1. High 2. Medium 3. Medium 6. High 8. Medium	1. High 2. Low 3. Low 6. Medium 8. Medium	1. High 2. Medium 3. High 6. Medium 8. Medium	1. Cost casements, equipment, location, resources, customer acceptance 2. Study 3. Study 6. Budget, customer, city acceptance 8. Customer and city acceptance	1. Asset planning 2. Standards 3. Asset planning 6. Forestry 8. Standards	1. Utility coordination 2. Consultant 3. CEA/CEATZ	1. High 2. Medium 3. High 6. High 8. High	• SAIDI/SAIFI Due to tree damage. • Potentially annual contacts

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
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	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
High	36	48	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Damage from increased weight on overhead lines • Ice falling off of lines	• Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines	1. P – Convert to underground lines 2. C/P – Increased storm guying, possibly to every pole 3. C – increase pole class (new installs) 4. Install hardened equipment (strength of insulators) expedite vs. normal replacement *current action is just to implement based on design practices 5. Pulse/vibrate lines	1. High 2. Medium 3. Medium 4. High - Cap 5. High - O&M	1. High 2. Low 3. Low 4. Medium 5. High	1. High 2. Medium 3. Medium 4. Medium 5. High	1. Cost casements, equipment, location, resources, customer acceptance 2. Easements, study 4. Study to ensure no unwanted consequences ex. Now poles fail vs insulators 5. Study needed, resources, cost, public safety	1. Asset planning 2. Standards 4. Asset planning 5. System office	1. Utility coordination 2. City of Ottawa consultant 4. Vendors 5. Other utilities CEATZ	1. High 2. Medium 4. Medium 5. High	• Monitor weather activity in comparison to damaged equipment. • Did the investment mitigate the expected outcome?
High	36	48	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Ice accretion on lines of 12.5 mm (0.5 inches) and more accompanied by a 90km/h wind could result in swinging or 'galloping' in the lines • Damage to poles and attached equipment	• Potential for flashovers • Ice break-up from lines may cause public safety concerns • Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines	***Covered in previous***								

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
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	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
High	36	48	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Damages to lines from fallen trees or broken tree limbs.	• Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines	1. P – Convert to underground lines 2. P – Break/stress point to limit cascading failure 3. P – increased detection capabilities for downed lines 4. C – Public safety lines on grounds 5. C – 2/3-year cycle per policy, line to sky smart review of cust. Trees 6. P – Trim trees more often/aggressively or heritage trees 7. C – tree planting advice brochure/ standards *Hydro Ottawa to explain to the city and other groups where and how to plant trees such that they do not affect Hydro infrastructure/ equipment	1. High 2. Medium 3. Medium 7. High	1. High 2. Low 3. Low 7. Medium	1. High 2. Medium 3. High 7. Medium	1. Cost casements, equipment, location, resources, customer acceptance 2. Study 3. Study 7. Budget, customer, city acceptance	1. Asset planning 2. Standards 3. Asset planning 7. Forestry	1. Utility coordination 2. Consultant CEA/CEATZ	1. High 2. Medium 3. High 7. High	• SAIDI/SAIFI Due to tree damage. • Potentially annual contacts
High	36	48	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Damage to poles and other surface equipment from vehicles losing control on icy roads	• Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines	1. C – Install pole laterals for risers 2. C – Install bollards for pad-mounted equipment in vehicle areas 3. P – Install pole laterals on all poles 4. P – Change pole standard to a higher strength material 5. P – Underground pad-mounted equipment (submersible)	3. Medium 4. High (+) 3. High (+)							

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
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ASSET ELEMENT: POWER DISTRIBUTION: NORTH-SOUTH

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
High	32	32	Lines & Poles	Easterly winds of 80 km/hr or higher (cool season [Oct.-March])	• Guy wires in north-south lines are installed to support against prevailing westerly winds; poles and lines are therefore damaged from to high easterly winds	• Loss of assets • Disruption of service • Difficulty in restoring service due to health and safety concerns for staff • Public safety concerns due to downed power lines • Public safety concern is falling branches	1. P – Convert to underground lines 2. C/P – Increased storm guying, possibly to every pole 3. P – Break/stress point to limit cascading failure 4. C – increase pole class (new installs) 5. C – Design for 90km/hr winds 6. C – Partnering agreements with contractors/ utilities for resourcing 7. P – increased detection for downed lines 8. C – Public safety lines on grounds C – reviewed N-S arterial lines and guying	1. High - Cap 2. Medium - O&M 3. Medium - Cap 7. Medium - Cap	1. High 2. Medium 3. Low 7. Low	1. High 2. Medium 3. Medium 7. High	1. Cost casements, equipment, location, resources, customer acceptance 2. Easements , study 3. Study 7. Study	1. Asset planning 2. Standards 3. Standards 7. Asset planning	1. Utility coordination 2. City of Ottawa consultant 3. Consultant 7. CEA/CEATZ	1. High 2. Medium 3. Medium 7. High	• Monitor weather activity in comparison to damaged equipment. • Did the investment mitigate the expected outcome?

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
High	32	32	Lines & Poles	Easterly winds of 80 km/hr or higher (cool season [Oct.-March])	• Risk of damages from falling trees or broken tree limbs.	• Loss of assets • Disruption of service • Difficulty in restoring service due to health and safety concerns for staff • Public safety concerns due to downed power lines	1. P – Convert to underground lines 2. P – Break/stress point to limit cascading failure 3. P – increased detection capabilities for downed lines 4. C – Public safety lines on grounds 5. C – 2/3-year cycle per policy, line to sky smart review of cust. Trees 6. P – more often/aggressively or heritage trees 7. C – tree planting advice brochure/standards *Hydro Ottawa to explain to the city and other groups where and how to plant trees such that they do not affect Hydro 8. P – include trees in fall zone/condition assessment	1. High 2. Medium 3. Medium 6. High 8. Medium	1. High 2. Low 3. Low 6. Medium 8. Medium	1. High 2. Medium 3. High 6. Medium 8. Medium	1. Cost easements, equipment, location, resources, customer acceptance 2. Study 3. Study 6. Budget, customer, city acceptance 8. Customer and city acceptance	1. Asset planning 2. Standards 3. Asset planning 6. Forestry 8. Standards	1. Utility coordination 2. Consultant 3. CEA/CEATZ	1. High 2. Medium 3. High 6. High 8. High	• SAIDI/SAIFI Due to tree damage. • Potentially annual contacts
Moderate	18	24	Poles	Season with ≥ 50 fog days (Nov.-March)	• Pole fires as a result of salt and other conductive contaminants accumulating onto insulators.	• Risk of electrical arcs, flashovers and pole fires. • Loss of assets • Disruption of service • Public safety concerns	1. C – replace porcelain insulators with polymer when doing work on pole 2. C- insulator water washing (twice/year in high travelled roads) 3. P – proactive/ expedited replacement of porcelain insulators with polymer 4. P – increase pole washing program	3. High - Cap 4. Medium - O&M	3. High 4. Medium	3. Medium 4. Low	3. Budget 4. Ongoing O&M expenses	3. Asset planning 4. Asset planning	4. Contractor	3. Low 4. Low	• Number of pole fires • SAIDI/SAIFI

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
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	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Moderate	12	16	Fused Cut Out	Season with ≥ 50 fog days (Nov.-March)	• Insulator breakdown on fused cut outs. • Pole fires as a result of salt and other conductive contaminants accumulating onto insulators.	• Risk of electrical arcs, flashovers and pole fires. • Loss of assets • Disruption of service • Public safety concerns	1. C – replace porcelain with polymer fused cutouts when doing work on pole 2. P – proactive/ expedited replacement of porcelain with polymer	1. High 2. Medium	1. High 2. High	1. Medium 2. Medium	1. Budget 2. Budget	1. Asset Planning 2. Asset Planning		1. Low 2. Low	• Number of pole fires • SAIDI/SAIFI

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: POWER DISTRIBUTION: EAST-WEST

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Very High	108	108	Lines & Poles	Annual wind speeds of 120 km/hr or higher (30-year occurrence)	• Damage to poles and lines from high wind events.	• Loss of assets • Disruption of service • Difficulty in restoring service due to health and safety concerns for staff • Public safety concerns due to downed power lines • Impact on scheduling/productivity/ resources	1. P – Convert to underground lines 2. C/P – Increased storm guying, possibly to every pole 3. P – Break/stress point to limit cascading failure 4. C – increase pole class (new installs) 5. C – Design for 90km/hr winds 6. C – Partnering agreements with contractors/ utilities for resourcing when needed 7. P – increased detection capabilities for downed lines 8. C – Public safety lines on grounds 9. C – review of N-S arterial lines and guying	1. High – Cap 2. Medium – O&M 3. Medium – Cap 7. Medium – Cap	1. High 2. Medium 3. Low 7. Low	1. High 2. Medium 3. Medium 7. High	1. Cost casements, equipment, location, resources, customer acceptance 2. Easements, study 3. Study 7. Study	1. Asset planning 2. Standards 3. Standards 7. Asset planning	1. Utility coordination 2. City of Ottawa consultant 3. Consultant 7. CEA/CEATZ	1. Hight 2. Medium 3. Medium 7. High	• Monitor weather activity in comparison to damaged equipment. • Did the investment mitigate the expected outcome?

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
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ASSET ELEMENT: POWER DISTRIBUTION: EAST-WEST

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Very High	108	108	Lines & Poles	Annual wind speeds of 120 km/hr or higher (30-year occurrence)	• Risk of damages from falling trees, broken tree limbs or flying debris.	• Loss of assets • Disruption of service • Difficulty in restoring service due to health and safety concerns for staff • Public safety concerns due to downed power lines	1. P – Convert to underground lines 2. P – Break/stress point to limit cascading failure 3. P – increased detection capabilities for downed lines 4. C – Public safety lines on grounds 5. C – 2/3-year cycle per policy, line to sky smart review of cust. Trees 6. P – Trim trees more often/aggressively or heritage trees 7. C – tree planting advice brochure/ standards *Hydro Ottawa to explain to the city and other groups where and how to plant trees such that they do not affect Hydro infrastructure/ equipment 8. P – include trees in fall zone/condition assessment	1. High 2. Medium 3. Medium 6. High 8. Medium	1. High 2. Low 3. Low 6. Medium 8. Medium	1. High 2. Medium 3. High 6. Medium 8. Medium	1. Cost casements, equipment, location, resources, customer acceptance 2. Study 3. Study 6. Budget, customer, city acceptance 8. Customer and city acceptance	1. Asset planning 2. Standards 3. Asset planning 6. Forestry 8. Standards	1. Utility coordination 2. Consultant 3. CEA/CEATZ	1. High 2. Medium 3. High 6. High 8. High	• SAIDI/SAIFI Due to tree damage. • Potentially annual contacts.

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
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Very High	36	68	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Damage from increased weight on overhead lines • Ice falling off of lines	• Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines	1. P – Convert to underground lines 2. C/P – Increased storm guying, possibly to every pole 3. C – increase pole class (new installs) 4. Install hardened equipment (strength of insulators) expedite vs. normal replacement *current action is just to implement based on design practices 5. Pulse/vibrate lines	1. High 2. Medium 3. Medium 4. High – Cap 5. High - O&M	1. High 2. Low 3. Low 4. Medium 5. High	1. High 2. Medium 3. Medium 4. Medium 5. High	1. Cost casements, equipment, location, resources, customer acceptance 2. Easements, study 4. Study to ensure no unwanted consequences ex. Now poles fail vs insulators 5. Study needed, resources, cost, public safety	1. Asset planning 2. Standards 4. Asset planning 5. System office	1. Utility coordination 2. City of Ottawa consultant 4. Vendors 5. Other utilities CEATZ	1. High 2. Medium 4. Medium 5. High	• Monitor weather activity in comparison to damaged equipment. • Did the investment mitigate the expected outcome?
Very High	36	68	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Ice accretion on lines of 12.5 mm (0.5 inches) and more accompanied by a 90km/h wind could result in swinging or 'galloping' in the lines. • Damage to poles and attached equipment	• Potential for flashovers • Ice break-up from lines may cause public safety concerns • Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines	***Covered in previous***								

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
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	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Very High	36	68	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Damages to lines from fallen trees or broken tree limbs.	• Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines	1. P – Convert to underground lines 2. P – Break/stress point to limit cascading failure 3. P – increased detection capabilities for downed lines 4. C – Public safety lines on grounds 5. C – 2/3-year cycle per policy, line to sky smart review of cust. Trees 6. P – Trim trees more often/aggressively or heritage trees 7. C – tree planting advice brochure/ standards *Hydro Ottawa to explain to the city and other groups where and how to plant trees such that they do not affect Hydro infrastructure/ equipment	1. High 2. Medium 3. Medium 7. High	1. High 2. Low 3. Low 7. Medium	1. High 2. Medium 3. High 7. Medium	1. Cost casements, equipment, location, resources, customer acceptance 2. Study 3. Study 7. Budget, customer, city acceptance	1. Asset planning 2. Standards 3. Asset planning 7. Forestry	1. Utility coordination 2. Consultant 3. CEA/CEATZ	1. High 2. Medium 3. High 7. High	• SAIDI/SAIFI Due to tree damage. • Potentially annual contacts

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
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Very High	36	68	Lines & Poles	Ice accumulation of 40mm (30-year occurrence)	• Damage to poles and other surface equipment from vehicles losing control on icy roads	• Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines	1. C – Install pole laterals for risers 2. C – Install bollards for pad-mounted equipment in vehicle areas 3. P – Install pole laterals on all poles 4. P – Change pole standard to higher strength material 5. P – Underground pad-mounted equipment (submersible)	3. Medium 4. High (+) 5. High (+)							
Moderate	18	24	Poles	Season with ≥ 50 fog days (Nov.-March)	• Pole fires as a result of salt and other conductive contaminants accumulating onto insulators.	• Risk of electrical arcs, flashovers and pole fires. • Loss of assets • Disruption of service • Public safety concerns	1. C – replace porcelain insulators with polymer when doing work on pole 2. C- insulator water washing (twice/year in high travelled roads) 3. P – proactive/ expedited replacement of porcelain insulators with polymer 4. P – increase pole washing program	3. High – Cap 4. Medium - O&M	3. High 4. Medium	3. Medium 4. Low	3. Budget 4. Ongoing O&M expenses	3. Asset planning 4. Asset planning	4. Contractor	3. Low 4. Low	• Number of pole fires • SAIDI/SAIFI

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
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ASSET ELEMENT: POWER DISTRIBUTION: EAST-WEST

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Moderate	32	32	Lines & Poles	Easterly winds of 80 km/hr or higher (cool season [Oct.-March])	• Risk of pole damage from strong winds	• Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines	1. P – Convert to underground lines 2. C/P – Increased storm guying, possibly to every pole 3. P – Break/stress point to limit cascading failure 4. C – increase pole class (new installs) 5. C – Design for 90km/hr winds 6. C – Partnering agreements with contractors/ utilities for resourcing 7. P – increased detection for downed lines 8. C – Public safety lines on grounds 9. C – reviewed N-S arterial lines and guying	1. High - Cap 2. Medium - O&M 3. Medium - Cap 7. Medium - Cap	1. High 2. Medium 3. Low 7. Low	1. High 2. Medium 3. Medium 7. High	1. Cost casements, equipment, location, resources, customer acceptance 2. Easements, study 3. Study 7. Study	1. Asset planning 2. Standards 3. Standards 7. Asset planning	1. Utility coordination 2. City of Ottawa consultant 3. Consultant 7. CEA/CEATZ	1. High 2. Medium 3. Medium 7. High	• Monitor weather activity in comparison to damaged equipment. • Did the investment mitigate the expected outcome?

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: POWER DISTRIBUTION: EAST-WEST

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	Monitoring and Evaluation
Moderate	32	32	Lines & Poles	Easterly winds of 80 km/hr or higher (cool season [Oct.-March])	• Risk of damages from falling trees or broken tree limbs.	• Loss of assets • Disruption of service • Difficulty or delays in restoring service due to health and safety concerns for staff, delays in accessing sites, or performing restoration work • Public safety concerns due to downed power lines	1. P – Convert to underground lines 2. P – Break/stress point to limit cascading failure 3. P – increased detection capabilities for downed lines 4. C – Public safety lines on grounds 5. C – 2/3-year cycle per policy, line to sky smart review of cust. Trees 6. P – more often/aggressively or heritage trees 7. C – tree planting advice brochure/standards *Hydro Ottawa to explain to the city and other groups where and how to plant trees such that they do not affect Hydro 8. P – include trees in fall zone/condition assessment	1. High 2. Medium 3. Medium 6. High 8. Medium	1. High 2. Low 3. Low 6. Medium 8. Medium	1. High 2. Medium 3. High 6. Medium 8. Medium	1. Cost casements, equipment, location, resources, customer acceptance 2. Study 3. Study 6. Budget, customer, city acceptance 8. Customer and city acceptance	1. Asset planning 2. Standards 3. Asset planning 6. Forestry 8. Standards	1. Utility coordination 2. Consultant 3. CEA/CEATZ	1. High 2. Medium 3. High 6. High 8. High	• SAIDI/SAIFI Due to tree damage. • Potentially annual contacts

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
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Moderate	18	24	Poles	Season with ≥ 50 fog days (Nov.-March)	• Pole fires as a result of salt and other conductive contaminants accumulating onto insulators.	• Risk of electrical arcs, flashovers and pole fires. • Loss of assets • Disruption of service • Public safety concerns	1. C – replace porcelain insulators with polymer when doing work on pole 2. C- insulator water washing (twice/year in high travelled roads) 3. P – proactive/ expedited replacement of porcelain insulators with polymer 9. P – increase pole washing program	3. High - Cap 4. Medium - O&M	3. High 4. Medium	3. Medium 4. Low	3. Budget 4. Ongoing O&M expenses	3. Asset planning 4. Asset planning	4. Contractor	3. Low 4. Low	• Number of pole fires • SAIDI/SAIFI
Moderate	12	16	Fuse / Cut Out	Season with ≥ 50 fog days (Nov.-March)	• Insulator breakdown on fused cut outs. • Pole fires as a result of salt and other conductive contaminants accumulating onto insulators.	• Risk of electrical arcs, flashovers and pole fires. • Loss of assets • Disruption of service • Public safety concerns	1. C – replace porcelain with polymer fused cutouts when doing work on pole 2. P – proactive/ expedited replacement of porcelain with polymer	1. High 2. Medium	1. High 2. High	1. Medium 2. Medium	1. Budget 2. Budget	1. Asset Planning 2. Asset Planning		1. Low 2. Low	• Number of pole fires • SAIDI/SAIFI

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

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ASSET ELEMENT: POWER DISTRIBUTION: UNDERGROUND

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	
Moderate	10	25	Underground Cables	Daily maximum temp. of 40°C and higher	• Potentially reduced capacity due to increased daily electricity demand from end user (e.g., A/C units)	• Additional strain on, and limits to the underground electrical infrastructure capacity.	Identifying vulnerable locations (via a detailed assessment of locations that could be vulnerable to temperatures higher than -40°C) and; 1. institute either operational constraints on how much power can be conveyed through cables to limit overheating of cables 2. replacing cable material to one that will not overheat as readily 3. Cool ducts either actively or passively with thermal fill (a clay slurry) 4. Deploy community level energy storage to reduce peaks	1. Low 2. High 3. High 4. High	1. High 2. High 3. Medium 4. Medium	1. Low 2. Medium 3. High 4. High	1. Insufficient alternative (low system cap) 3. Cost 3. Room for cooling equipment 3. Increased O&M 4. Coordinating with community 4. Customer implications	1. Assets 2. Assets 3. Assets 4. Assets	1. Operation finances 2. Operation finances 3. Operation finances 4. Operation finances & community	1. Low 2. Low 3. Medium 4. High	Monitor cables for premature failure Trending within SCATA, data monitoring Temps run within the prescribed levels

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
High	> $2,000,000	> $200,000	> 3 years	> 75%

ASSET ELEMENT: POWER DISTRIBUTION: UNDERGROUND

	Current Climate Risk Score	Future Climate Risk Score	Asset / Element	Climate Parameter	Impacts	Result / Consequence	Actions Available *Current + Potential*	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action	Difficulty of Implementation *(High, Medium, Low)*	
Moderate	16	24	Civil Structures	Freeze-thaw cycles – Daily Tmax Tmin temp. fluctuation of ±4°C around 0°C	• Water penetration into or around civil structures which freezes causing stress on material	• Deterioration and damage (short- and long-term) to materials. • Uplift of near-surface infrastructure causing higher risks of damage during winter maintenance (e.g., snow removal) operations	1. Explore different materials for manholes instead of concrete that are less susceptible to freeze-thaw (e.g. fibre glass) 2. Explore continuous pipe rather than sectional pieces to eliminate joints were shifting can occur 3. Exploration of redesign collars to move with the heading (e.g. telescopic heading) 4. Explore moving utility to under sidewalk from under roadway where the temperature is more consistent	1. Low 2. Low 3. Low 4. Low	1. Low 2. Low 3. Low 4. Low	1. Low 2. Low 3. Low 4. Low	Resourcing	Assets Standards	Asset/standards	1. Low 2. Low 3. Low 4. Low	Viable solutions came out of exploratory work

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
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EXTERNAL THIRD PARTIES

Element	External Third Party(ies) Affected	Impacts	Result / Consequence	Actions Available *Current + Potential*	Resource Requirements (Cost, Staff Time, Etc.)	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action
Power supply, shared infrastructure, attached equipment	Hydro-One	• Loss of supply to Hydro Ottawa (this happens to some extent approximately once per month) • Damages to poles shared between Hydro One and Hydro Ottawa • Loss of transmission • Loss of redundancy • Damage to equipment due to Hydro One-related issues	• Disruption of service • Inability to restore service • Loss of redundancy • Loss of efficiency • Potential damage to Hydro Ottawa equipment (attached to Hydro One poles) • Damage to shared facilities	1. C – System distribution / contingency planning (need to install distribution ties to remedy, doing so continues building the resilience of the system as well) 2. P – Coordination of construction standards between Hydro Ottawa and Hydro One	1. Resources/financial 2. Resources/financial	1. Medium	1. Medium	1. Medium	1. Cost 1. Availability of physically redundant system (since all power is channeled to Ottawa through one corridor)	1. Asset planning / system operations 2. Asset planning / system operations	1. Hydro One 1. IESO 2. Hydro One
Telecommunications	Phone Service & Fibre lines	• Potential for Hydro Ottawa equipment damage if support by damaged communication poles • Loss of communication services	• Health and Safety • Communication to field personnel and field equipment • Loss of communication to customers • SCATA system	• C – Any vendor that runs a critical service to Hydro Ottawa, an agreement is in place. • C – Highly redundant communications services plan. For example, the operations center has landline phones, cell phones, and satellite phones			• High • High				

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
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Emergency Response (Capability & Capacity)	Partners & Internal	• Inability to get resources for response both external and holiday staff
		• Logistically complex
		• Staff potentially not fit for duty
			• Stress on staff
			• Delayed services restoration
				• C – For large-scale events, difficult to acquire additional resources as most geographically close resources are also affected. For small-scale events, Hydro Ottawa calls external aid when internal resources are exhausted. Logistics for external aid includes:
				  • 12-hour on/off scheduling
				  • Food services provided to aid workers
				  • Hydro Ottawa headquarters building open to aid workers and provides critical services
				  • Lodging provided
				HO noted the difficulties of how to determine when to call for aid. Sometimes there is political pressure to call for aid prematurely.
				• C – Have increased stand-by capacity
				• P – Formalize emergency response plan and clarify protocols and staff education within Hydro Ottawa for staff to better understand their roles during an emergency.
				• P – Equipment sharing program or equipment rental agreements with local companies / contractors if limited by equipment during an emergency							

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
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Stormwater drainage, winter maintenance	City Ottawa	• Surface flooding • Snow removal • Debris removal • Plows hitting U/G equipment and poles • Flooded areas and overland flow flooding vaults and transformers due to plugged storm drains *For example, blocked rear-yard storm drains are a regular culprit for overland flooding and impacting pad-mounted transformers. • Manholes full of water • Snowplows hitting/damaging response vehicle • City of Ottawa plan hitting roadside transformers • Snow piling and storage on or around pad-mounting transformers • Salting damages to Hydro Ottawa equipment	• Potential impacts on equipment if City does not maintain stormwater system • Damages and delays due to winter maintenance activities • Delays in service or in response capacity	1. Identify location where there are particular issues related to stormwater / flooding and winter road maintenance issues to Hydro Ottawa equipment and work with the City of Ottawa to mitigate 2. Install snow marker flags to highlight the location of equipment during winter months Note: Hydro Ottawa calls the City of Ottawa to provided extra snow removal if needed when HO requires access to snowed-in areas		• Low • Low	• High • Medium	• Medium • Low	• City of Ottawa budgets • Public push back	• Asset planning • Standards • Operations • Communications	• Public works department • Community communication

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
Medium	$100,000 - $2,000,000	$10,000 - $200,000	1 – 3 years	25 – 75%
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Element	External Third Party(ies) Affected	Impacts	Result / Consequence	Actions Available *Current + Potential*	Resource Requirements (Cost, Staff Time, Etc.)	Costs (Low, Medium, High)	Effectiveness of Adaptation Low, Medium, High)	Time to Implement (Low, Medium, High)	Barriers to Action *(e.g. cost, timing, lack of information available, existing controls, existing policies, etc.)*	Staff / Department Responsible for Action	Partners / Stakeholders That May Support Action
Fuel Supply	City Ottawa	• Hydro Ottawa vehicles not able to travel • Lack of fuel supply for backup generators • Partner and contractors' inability to support while stranded at work/home	• Delays in service • People stranded at work/site/home • Lack of emergency backup power	1. P – Store fuel 2. P – Modify work to manage fuel 3. P – EV fleet 4. C – Contract with fuel suppliers for generators 5. P – City of Ottawa / Hydro Ottawa emergency fuel strategy. Understand City's risk	1. Cost, staff, space, training 2. N/A 3. Cost, tech, Power 5. Staff time	1. Medium 2. N/A 3. High 5. Low	1. Medium 2. N/A 3. High 5. High	1. Medium 2. N/A 3. Low 5. Medium	1. Historical practice 2. Policies, union 3. Chargers, purchasing, existing fleet 5. Relationships	1. Facilities/fleet 2. OPS 3. Fleet 5. Fleet	1. City, field partners 2. City, union 3. Vendors 5. City
	Hydro Ottawa Subsidiaries	*No real impacts from subsidiaries*									

	Capital Costs	O&M Costs	Time to Implement	Effectiveness of Implementation
Low	< $100,000	< $10,000	< 1 year	< 25%
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Appendix B ADAPTION PLANNING WORKSHOP ATTENDEES

Participant	Role
Nicole Flanagan	Stantec, Project Manager
Guy Félio	Stantec, Climate Change Resilience Advisor
Riley Morris	Stantec, Environmental Engineer
Eric Lafleur	Stantec, Electrical Engineer, Subject Matter Expert
Matthew McGrath	Hydro Ottawa, Project Manager, Supervisor, Distribution Layouts
Greg Bell	Hydro Ottawa, Manager, Distribution Operations (Underground)
Margret Flores	Hydro Ottawa, Supervisor, Asset Planning
Ben Hazlett	Hydro Ottawa, Manager, Distribution Policies and Standards
Ed Donkersteeg	Hydro Ottawa, Supervisor, Standards
Doug Boldock	Hydro Ottawa, System Operations
Chris Murphy	Hydro Ottawa, Supervisor, Distribution Design
Kyle Smith	Hydro Ottawa, Supervisor, Standards

ISO 55000 Gap Analysis

Private and confidential

Prepared for: Hydro Ottawa

Project No: 131850
Document Version: 1
Date: 27th March 2019

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Version History

Date	Version	Author(s)	Notes
26/03/2019	Issue 1	A J McHarrie	

Final Approval

Date	Version	Approval	Notes
28/03/2019	Issue 1	David Roberts	

EA Technology Limited, Capenhurst Technology Park, Capenhurst, Chester, CH1 6ES;
Tel: 0151 339 4181 Fax: 0151 347 2404

http://www.eatechnology.com

Registered in England number 2566313

Executive summary

EA Technology was invited to provide Hydro Ottawa with a gap analysis assessment for their Asset Management System (AMS) in-line with the requirements of ISO 55001. Hydro Ottawa have already carried out a previous gap analysis assessment, which identified a number of gaps which have already been addressed. Hydro Ottawa requested that EA Technology should carry out an ISO55000 gap analysis assessment of their AMS to provide an independent and objective view of their level of conformance to the ISO 55000 standard and the maturity of their AMS. This gap analysis was carried out at Hydro Ottawa's Merivale Road offices on the 25th to the 28th February 2019.

This document details the findings of the audit and provides a list of conclusions and recommendations that will assist Hydro Ottawa with their ambition of obtaining ISO55000 accreditation.

The radar chart below (Figure 1) illustrates the maturity scoring for the gap analysis assessment, carried out on the Hydro Ottawa's AMS. It can be seen that for a such a new system it has demonstrated what could be judged as conformance (green line) for twenty one of the twenty-seven assessed sections of ISO 55001.

For clarity the red line indicates the results of the previous gap analysis audit, the green line indicates what would be considered as conformance, and the blue line indicates the results of the gap analysis detailed within this document.

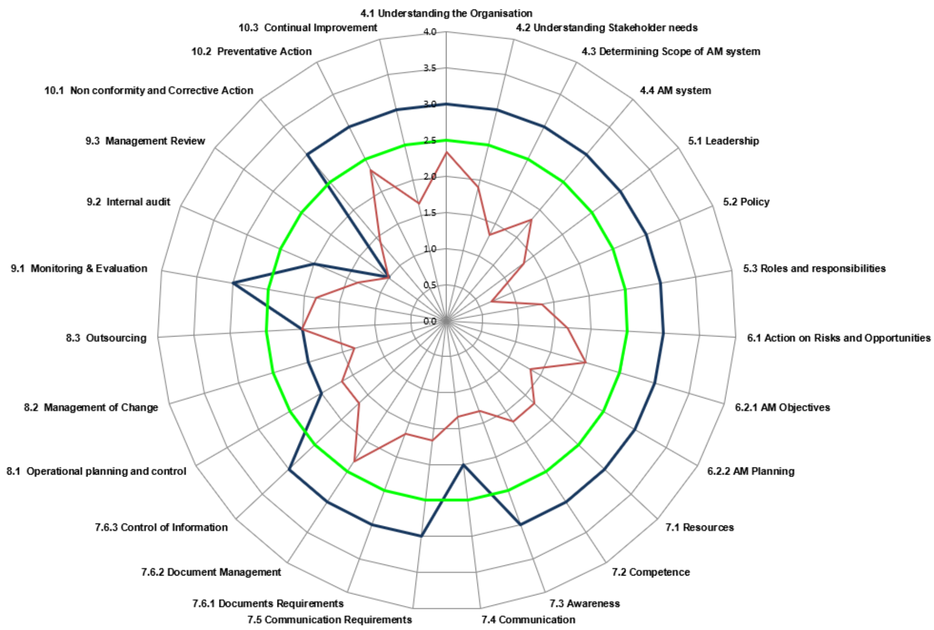

Figure 1 – Hydro Ottawa AMS Maturity Scoring

The gap analysis assessment carried out on the AMS was very encouraging as Hydro Ottawa were able to demonstrate that a large majority of the requisite processes were in place. The gaps identified in this document are typically due to the maturity of the AMS, and therefore the lack of a full management review and Internal Audit cycle.

As the most difficult and time-consuming activities are usually the creation and implementation of processes, it can be seen that Hydro Ottawa have already done a large majority of the work required to implement an effective AMS through creating new or adopting existing Hydro Ottawa processes.

Contents

1. Background

EA Technology was invited to provide Hydro Ottawa Limited (Hydro Ottawa or HOL) with a gap analysis assessment of their Asset Management System (AMS) against the requirements of ISO55001. The work carried out under this gap analysis assessment was exclusively for Hydro Ottawa, who are a regulated electricity distribution company, operating in the City of Ottawa and the Village of Casselman. Hydro Ottawa's electricity distribution system serves over 324,000 residential and commercial customers across a service area of 1,100 square kilometres.

The gap analysis described in this document is the second gap analysis carried out on Hydro Ottawa's AMS, and was requested to identify conformance against the ISO55001 requirements in view of recent work carried out on the AMS. The results from the previous gap analysis (Figure 1 Executive Summary) are illustrated in this document to show progress; however, it should be noted that EA Technology's audit team carrying out the gap analysis assessment were unaware of these results until after the gap analysis assessment was finalized.

2. Scope of the Document.

EA Technology carried out an ISO55000 gap analysis assessment at Hydro Ottawa's Merivale Road offices on the 25th to the 28th February 2019. The scope of the project was to assess the size of any gaps that exist between Hydro Ottawa's AMS and the requirements detailed in ISO55001. This document provides a list of conclusions and recommendations that will assist Hydro Ottawa with their ambition of obtaining ISO55000 accreditation.

3. Gap Analysis

3.1 Schedule

EA Technology carried out an ISO55000 gap analysis assessment on Hydro Ottawa's AMS from the 25th to the 28th February 2019. The gap analysis assessment was carried out to provide Hydro Ottawa with an independent objective view of the conformance of Hydro Ottawa's AMS against the requirements of ISO55001.

Figure 1illustrates a high-level view of the gap analysis schedule carried out between the 25th and the 28th of February. A more detailed schedule is provided in Appendix I, which details individual audit sessions and attendees.

	AM	PM
Day 1 – Monday, 25th February 2019	Introduction / Context	Leadership
Day 2 – Tuesday, 26th February 2019	Site Visit	Planning
Day 3 – Wednesday, 27th February 2019	Performance / Support	Support
Day 4 – Thursday, 28th February 2019	Operation / Planning	Improvement / Presentation

Figure 1 – Gap analysis schedule

3.2 Audit Team

Lead Auditor: Andrew McHarrie

Andrew is a Principal Consultant who currently holds the position of Head of Asset Management and Power System Studies. He has over 40 years' experience in the electrical utility sector, since he started work as an apprentice electrician in the late seventies. Andrew is a chartered engineer and a Fellow of the IET, and an active member of the Institute of Asset Management. Andrew is a member of a number of Asset Management working groups and has recently contributed to the review of the new ISO55002 standard.

Support Auditor: Tim Erwin

Tim Erwin holds the position of National Sales Manager for EA Technology USA. He has over 20 years as a protection and control engineer for medium and high voltage applications with 9 year at ABB. He graduated with a BS in electrical engineering from The New Jersey Institute of Technology. He is a member of IEEE.

3.3 Findings

During the gap analysis the audit team assessed the conformance of all seven sections of the ISO55001 standard (Sections 4 to 10), which implements 27 clauses. The gap analysis assessment was carried out with the assistance of EA Technology's bespoke gap analysis tool that is based on the IAM's SAM tool. During the assessment the audit team were looking for appropriate answers to specific questions plus where appropriate some form of evidence to prove validity and maturity. The following sections detail the findings of the gap analysis, which illustrates the score, the summary of any discussions and evidence provided for each clause.

Section 4. Context of the Organisation

Clause 4.1: Understanding the organisation and its context

The aim of clause 4.1 is to provide context and structure in which an organisation can manage its assets efficiently and effectively. To do this the context of the organisation implementing the AMS must be identified, as an AMS must support, and be driven by the organisation's objectives.

In understanding the context of the organisation, implementing the AMS will ensure that:

- the alignment of all internal and external stakeholders and their issues will be considered
- the AM policy, objectives and plans are developed so as to obtain maximum benefit from its assets in support of the organisation's objectives, and/or business plan

Maturity Score: 3

Discussion
HOL's overall strategy for the organisation is refreshed every 5 years, which is in line with their regulatory submission. The current 5-year strategy provides an overview of Hydro Ottawa's business strategy and financial projections for 2016 to 2020. The strategy document informs HOL's relevant stakeholders about issues that shape HOL's business environment and how HOL intends to respond to such issues. HOL hold an annual board retreat, which verifies the alignment with HOL's strategic plan and carries out a SWOT analysis based on HOL's business environment (regulations, customer input, environmental challenges) and determines any issues and their potential impacts. HOL hold monthly/bi weekly executive management meetings Enterprise risk management team tracks "business risks" and meet on a monthly basis and report to the board on a quarterly basis. HOL tracks issues concerning the development of distributed generation, energy storage and sectionalisation through their Smart Energy Executive Steering Committee. HOL have an internal website that communicates issues to all HOL staff (HydroBuzz) HOL produced the Strategic Direction Document 2016 – 2020 as evidence, This document is currently being reviewed in line with HOL's rate submission, which is due for late 2019 for the 2021 - 2026 period.

Conclusions	
C4.1	Hydro Ottawa have demonstrated that they fully understand the context of their organization by considering issues that can affect its business environment.

Clause 4.2: Understanding the needs and expectations of Stakeholders

The organisation should identify and review the stakeholders that are relevant to the asset management System. The needs and expectations of these stakeholders should be identified and how they impact on Asset Management decision making and reporting.

Following engagement with relevant stakeholders, mandatory requirements and expectations should be documented and communicated. Levels of service should then be reviewed at regular intervals so that stakeholder needs are concurrent with those listed.

Maturity Score: 3

Discussion

HOL demonstrated a broad set of interactions with stakeholders and stakeholder engagement process.

HOL have a Customer Service Experience Committee that assess new customer needs as well as assessing the performance of the customer experience. Inputs into the committee meeting will be customer complaints, customer enquiries (customer call centres)

Call centre staff are trained to respond to customer needs e.g. Key accounts, Vulnerable customers.

HOL demonstrated that they proactively ask customers their needs

HOL provided evidence of HOL's:

- Customer Service Experience Committee Meetings;
- Customer Satisfaction 2018 process;
- Customer engagement overview;
- Low - Volume Focus Group Report illustrates stakeholder requirements (Innovative)
    - The 'Innovate - Low Volume Focus Group Report Draft' document illustrated the Identified priorities of HOL customers (price, Reliability, Efficiency and cost reductions etc
- The Customer Satisfaction Results 2018 CEA National CSAT presentation (x3) was presented to demonstrate stakeholder engagement. The presentation demonstrated engagement and benchmarked against the province of Ontario and nationally.
    - 1st presentation was the annual CEA (Canadian Electricity Association) customer satisfaction survey
    - 2nd was Residential and small business customers
    - 3rd was Large Customers

HOL have a Customer Experience committee that assesses how HOL engage with its customers plus they also report any significant stakeholder requirements. This committee is made up of cross business personnel.

The 'Customer Engagement Program Overview' document was submitted to illustrate how HOL demonstrate stakeholder engagement to the regulator, which is part of the rate submission.

Conclusions	
C4.2	HOL demonstrated that they engage with stakeholders that are relevant to its Asset Management System and their needs and requirements are considered.

Clause 4.3: Determining the scope of the asset management system

Based upon the outcomes of reviews of its context and stakeholder requirements and expectations, the organisation should define (or review) the boundaries of its AMS, establishing its scope in the process.

Maturity Score: 3

Discussion
HOL's Asset Management System is documented in HOL's 'IAS0002 Asset Management System Manual' document. HOL have a sentence in the Asset Management System Manual that excludes facilities, fleet and information technology, this should be reinforced in the SAMP so that the table displays the major asset groups and a statement below, which states what is explicitly outside the AMS scope. The AMS manual makes a reference to 'other management systems'. It is suggested that HOL's current management systems should be detailed (ISO9001, ISO14001). The network area is mapped out in the SAMP document. The stakeholders and the roles and responsibilities are also detailed in the SAMP.

Conclusions	
C4.3	HOL document the scope of the AMS through its AMS and SAMP documents.

Recommendation	
R4.3a	It is recommended that HOL should document in the SAMP document which Assets are explicitly excluded from the AMS.
R4.3b	It is recommended that HOL should make reference to HOL's current management systems (ISO9001, ISO14001) in the AMS Manual.

Clause 4.4: Asset management system

The AMS is the framework in which all asset documents are written, reviewed and used.

The SAMP shows alignment of how corporate objectives are met through AM objectives and AM plans.

The AMS and the SAMP should be reviewed on an annual basis to:

- determine if the corporate objectives or business needs are meet through the SAMP
- Determine if the AMS provides an effective and efficient framework to support the organisation in meeting its business needs and corporate objectives

Maturity Score: 3

Discussion
HOL have a documented AMS manual document, which specifies each of the requirements of ISO55001. The AMS Manual is the responsibility of the Asset Manager who reviews and updates it. HOL have an Asset Management System Key Elements flowchart (ISO55000) with the addition of the documents that constitute the AMS. The AMS manual aligns to the requirements of ISO55001 and it references other documents that constitute the AMS. HOL have continual improvement document 'Asset Management System continual improvement' document that specifies the process for continually improving the AMS. The document specifies the setting of KPIs, HOL have created an Asset Management Council (AMC), which sits to provide information and offer insight and feedback into the creation and development of the AMS. The AMC sits once a month (progress meetings) and every quarter, when it reviews the KPIs. HOL have a SAMP document that has a diagram that aligns the Corporate Strategic Direction, the Corporate Strategic Objectives, Asset Management Objectives, Asset Management Measures. The Asset Management Plans align to the Asset Management Objectives through the template layout. The AMPs detail the AS-IS and the To-Be situations and the SAMP details the strategy to accomplish these.

Conclusions	
C4.4	HOL have demonstrated that they document the AMS through the AMS Manual document and the SAMP.

Section 5. Leadership

Overview

Every organisation needs leadership to provide direction and drive the AMS. It is also important that the roles and responsibilities in implementing and managing the AMS are established implemented and reviewed.

ISO 55002 (2018) states that '*top management should ensure that it demonstrates leadership and commitment by taking an active role in engaging, promoting, directing and supporting, communicating and monitoring the performance, effectiveness and continual improvement of the assets, asset management and the asset management system…*'

Clause 5.1: Leadership and commitment

Top management is responsible for creating the vision and values that guide policies within the organisation. They should also have responsibility for developing the AM policy and AM objectives and ensuring that these align with the organisational objectives. Managers (or designated leaders) at all levels of the organisation should be involved in the planning, implementation and operation of the AMS.

The commitment of top management to the AMS is important to its success, as top management should not only provide direction in the form of organisational objectives, but ensure sufficient resource is assigned to successfully implement the AMS.

Top management should ensure that the AMS is compatible with the organisational objectives and promotes continual improvement, cross functional collaboration and risk management. Top management also defines the responsibilities, accountabilities and AM objectives and AM strategies, which create the environment for the AMS.

Maturity Score: 3

Discussion

HOL demonstrate leadership through:
 	
• The Chief Electricity Distribution Officer and the President are signatories on the Asset Management Policy;
• The direction for implementing HOL's Asset Management System is top down;
    ○ An example of this was illustrated by the presentation of a Corporate Performance Goals and Priorities - 'Complete Asset Management ISO55000 standards project' which is reported to the HOL Board Holding Board;
• All members on the AMC committee are sponsored by Top Management. Risks are escalated through the sponsors who would raise it with the Board;
    ○ The AMC participation graphic illustrates how the AMC is made up of different parts of the organisation;
• The Chief Electricity Distribution Officer sponsors and signs off the AMC terms of reference;
• Top management supports the stakeholder engagement process through engagement of a third party to obtain stakeholder requirements;
• The existence of the Asset Management Objectives & Performance Measures document, which illustrates a number of activities that demonstrate top management approval and resources;
• An example of top management communications was provided that illustrated the importance of Asset Management to HOL;
    ○ HOL have employee emails that link to news stories on the Intranet;

- The Risk Management approach used in the AMS is aligned to the ERM process at corporate level, the AMS document aligns the risk management approaches and references the Risk Register and its scoring criteria; - The 2018 Performance scorecard was submitted as evidence that the Chief Distribution Officer has ownership of implementing the AMS within the ISO55000 project that he has to deliver to the Board. - This presentation was given to the HOHI (Hydro Ottawa Holdings Inc) and HOL (Hydro Ottawa Limited) Board of Directors - The 2019 CFO Divisional Scorecard was provided as evidence that the CFO is responsible for the Rate application to the regulator, the rate application is processed through the regulatory director supported by the Distribution business (Asset Management)	
Conclusions	
C5.1	HOL have demonstrated that top management at all levels of the organisation are involved in the planning, implementation and operation of the AMS

Clause 5.2: Asset Management Policy

The AM policy should set out the commitment of the AMS and provide a framework for the setting of AM objectives that are appropriate to the purpose of the organisation.

The AM policy is a commitment from the top management that the organisation will adopt Asset Management throughout its business.

The AM policy should be communicated to all stakeholders (internal and external) including any outsourced contractors working on Hydro Ottawa's assets or AMS.

The AM policy should be created in a consistent way with other company policies and should be reviewed periodically and updated where required.

Maturity Score: 3

Discussion	
The HOL Asset Management Policy is signed by the Chief Electricity Distribution Officer and the President. The Asset Management Policy is communicated to all staff through HOL's HydroBuzz, staff emails and physical copies are posted in HO's Head Office Currently HOL do not communicate the Asset Management Policy to their contractors.	
Conclusions	
C5.2	Currently HOL do not communicate the Asset Management Policy to their contractors.
Recommendation	
R5.2	It is recommended that the Asset Management Policy is included in the contractor on-boarding process and maybe the Contractor intranet.

Clause 5.3: Organisational roles, responsibilities and authorities

The organisation should define the responsibilities and authorities of each AM key function (internal and outsourced). Typically, this will take the form of job descriptions or similar and be reflected by way of an organisational chart.

Top management shall assign responsibly and authority for the following:

- establishing and controlling the SAMP
- ensuring the AMS supports delivery of the SAMP
- ensuring the SAMP conforms to the requirements of ISO 55000
- ensuring the suitability, adequacy and effectiveness of the AMS
- ensuring and updating the AM plans
- reporting on the performance of the AMS to top management and stakeholders alike

Maturity Score: 3

Discussion	
HOL have a part in the SAMP document that specifies the high level AMS roles and responsibilities Other responsibilities are mapped to roles throughout the SAMP and AMS documents. For example, the 'Review of the SAMP' illustrates that the SAMP is updated as required by the Asset Manager and Approved by the Asset Owner	
Conclusions	
C5.3	HOL document roles and responsibilities within the AMS Manual and SAMP documents.
Recommendation	
R5.3	It is recommended that HOL ensure that the responsibilities documented in the SAMP and AMS Manual documents are reflected in personal job descriptions.

Section 6. Planning

Section 6.1: Actions to address risks and opportunities for the asset management system

In planning the AMS, the organisation shall consider external and internal issues that are relevant to its purpose and that affect its ability to achieve its intended outcomes. Associated risks and opportunities should be considered and addressed so as to:

- provide assurance that the AMS can achieve its intended objectives
- mitigate risk by implementing suitable controls
- achieve continual improvement

Maturity Score: 3

Discussion
Projects are prioritized on the value to the organization – the risk is monetized and replacement would reduce that risk therefore representing value. Once a project has been identified it is risk scored in HOL's C55 application - Worst performing circuits, load lost, customers affected etc. The value score prioritizes projects on their value to the organization. HOL's 'IAP0022 Schedule 1 Risk Register R0' was supplied as evidence of HOL's risk register, which illustrates how HOL record and assess risks, plus how they assess the effects of any control actions required to mitigate against these risks. Figure 2 illustrates that HOL consider the risks associated with the planning of their Asset Management Plans.

*Figure 2 – Asset Management * Expenditure Process*

Conclusions	
C6.1	HOL have demonstrated that they consider external and internal issues that affect its ability to achieve its intended outcomes.

6.2: Asset management objectives and planning to achieve them

Clause 6.2.1: Asset management objectives

A fundamental of the AM system is to ensure alignment between the organizational objectives and the technical and financial decisions, plans and activities.

Defined AM objectives form the link between the organisation's AM policy, strategy, corporate objectives and individual plans. The organisation should develop its AM plans in-line with its time horizons which in turn meet the organisation's needs and take account of periods of responsibility and life of assets.

AM objectives are created through the AM policy therefore enabling organisation's corporate objectives to be met using the AMS.

Maturity Score: 3

Discussion	
HOL have a set of generic Asset Management Objectives in the SAMP document, which are aligned to HOL's Organizational Objectives These generic Asset Management Objectives are further defined in each of the individual Asset Management Plan documents. The alignment of the Asset Management objectives and the Organisational objectives in the SAMP document and the further defining of the asset management objectives in the individual Asset Management Plans illustrates a clear line of sight between the business plans and the planning function.	
Conclusions	
C6.2.1	HOL have demonstrated that Asset Management Objectives are created and linked to HOL's Organizational Objectives.

Clause 6.2.2: Planning to achieve Asset management objectives

In order for an organisation to achieve its objectives, plans need to create, document and maintain asset management plans that consider, and are compatible with other business functions. Asset Management Plans need to consider risks and opportunities across the asset's life cycles, and provide details of objectives, the organisation shall determine how and when the plans will be carried out/completed.

Maturity Score: 3

Discussion

HO have a number of AMPs that illustrate how a number of asset groups will be managed over their lifecycles.

There are currently 11 AMPs with another 2 under development. The AMPs have been defined through legacy management and regulatory reporting of assets.

The 'IAP0005 Asset Management Plan Pole, Fixtures and Primary Overhead Conductor R0' was provided as evidence and demonstrated that each Asset Management Plan provided:

- Asset Management Objectives – The following bullets in **Bold** text are the Asset Management Objectives that are aligned to the Organizational Objectives in the SAMP document, and their sub bullets are the further defining of these objectives.
  - **Levels of Service**
    - Impact on system reliability through electrical interruptions which may be localized, affecting customers connected to that specific pole or overhead conductor, or a wider outage, affecting a large number of customers supplied by the connecting conductors
    - Achieve quicker reliability restoration as failed poles, fixtures or overhead conductors are easier to locate compared to underground equipment
  - **Health, Safety & Environmental Stewardship**
    - Impact employee and public safety due to fallen poles and downed overhead conductors
    - Achieve clearances for public safety from roads, walk ways, rail lines, buildings, etc.
    - Impact environmental stewardship by failing to support oil filled equipment
  - **Asset Value**
    - Achieve reduced costs due to economic effectiveness of overhead vs. underground distribution
    - Impact asset lifecycle cost as an emergency replacement is more costly than planned replacement
  - **Resource Efficiency**
    - Impact resource optimization as a single emergency replacement is less efficient than planned replacement which usually has multiple poles in a row
- Asset Performance
- Asset Lifecycle Management
- Future Demand
- Resource Plan
- Continuous Improvement
- Implementation

Conclusions

C6.2.2	HOL have clearly demonstrated that they create, document and maintain asset management plans that consider, risks and opportunities across the asset's life cycles, and provide details of objectives.

Section 7. Support

Clause 7.1: Resources

The organisation shall determine and provide adequate resource for the establishment, implementation, maintenance and continual improvement of its AMS. In doing so the organisation shall ensure compliance with its AM objectives and for implementing activities specified in its AM plans.

Resource should be considered as part of the organisation's planning stage and communicated with the relevant stakeholders to ensure effective collaboration and to determine the required resources to deliver the AM objectives and AM plans.

Maturity Score: 3

Discussion
HOL have a strategic workforce plan that determines the resources on an hour per $ basis. The Asset Management Plans are rolled up to the corporate Rate application which is used to inform the '2021-2025 Resource Hours v1 Feb 7 2019' which illustrated how HOL evaluate resources at a program level. More specific assessments are carried out, and the 'power Line Technicians WFP Summary October 2018' document was shown as evidence HOL review the planned against actual headcount which is reported to the board on an annual basis. A slide that demonstrated actual resource hiring against planned was shown as evidence. The '2021-20125 Resource Hours v1 Feb 7 2019' illustrated the resource hours for the constrained version of the roll up of all of the Asset Management Plans"

Conclusions	
C7.1	HOL have demonstrated that they link resource requirements to their plans and their regulatory submission

Clause 7.2: Competence

To ensure all AM activities are effectively carried out, the organisation shall identify the correct level of competency required for each individual AM role. Therefore, each individual competence must be evaluated and documented.

The organisation should carry out a periodic review of its competence requirements to ensure continued credibility and effectiveness. Training or mentoring may be employed for situations where competencies are known to be deficient.

For outsourced resource, the organisation’s training department or similar should maintain a list of approved contractors and their relevant competency levels.

Maturity Score: 3

Discussion
HOL have a 'Workday' system that notifies staff and their managers when training (refresher training) needs to be carried out. Each manager has a report on each of their direct reports that detail their competence needs and training requirements; Each member of staff has their own transcript that details their training requirements; Everyone is notified about their upcoming training requirements and anyone that does not enrol within the required timescale is logged and requested to enrol; HOL provided a Job description to illustrate that competence needs are documented, and a training record was provided as evidence to demonstrate how HOL ensure competence is achieved and maintained; The 'Power Line Technicians WFP Summary - October 2018' document was provided as evidence that the resource is considered over a 3- year period, and the ’PLT Training Profile’ spreadsheet demonstrated the training required to achieve competence.

Conclusions	
C7.2	HOL have demonstrated that they consider, evaluate and track staff competence

Clause 7.3: Awareness

To ensure AM Activities are correctly carried out, individuals working under the control of the organisation must have appropriate awareness of the AMS, and their impact on its effectiveness. Individuals should be made aware of the AM policy, how their work activities may impact the AMS (including risk and mitigation) and any non-conformances. This should be extended to appropriate external stakeholders such as contractors working on the organisation's assets and should be recognized in an individual's defined roles and responsibilities.

Maturity Score: 3

Discussion

All HOL asset management documentation is made available to HOL employees

Posters that illustrate and communicate ISO55000 and AM activities"

Hydro Ottawa make their staff aware of their AMS through "Hydro Buzz" (Figure 3)

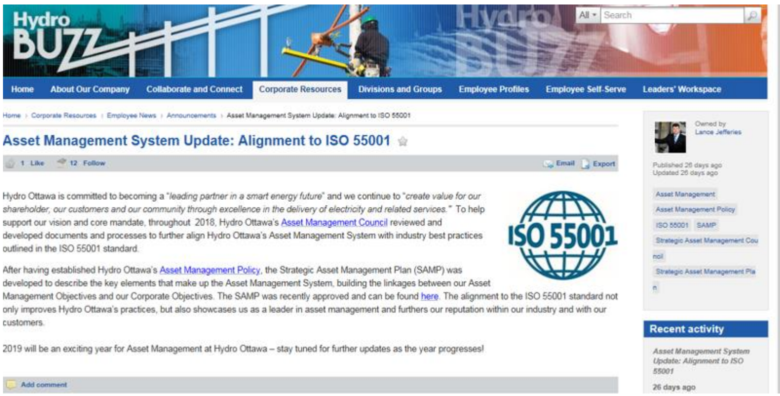

Figure 3 – HydroBuzz

The audit team attended a substation inspection during the gap analysis, and staff questioned were fully aware of their obligations under the AMS plus they were also fully conversant with the data they collect and the importance of this data in informing Asset Management decisions.

Conclusions

C7.3	During the audit Hydro Ottawa demonstrated a good level of awareness.

Recommendation

R7.3	It is recommended that Hydro Ottawa continue to make their staff as aware as possible regarding the AMS, as the awareness process conducted during the audit was minimal compared to a certification audit.

Clause 7.4: Communication

AM activities should be communicated at different levels to different stakeholders so as to inform the relevant participants exactly who could impact the AM plans and the achievement of the AM objectives. Good communication of the AMS will promote engagement with stakeholders, whilst enhancing transparency and accountability of the AMS.

Maturity Score: 2

Discussion

HOL have a communication plan that illustrates:

- Internal and external communication processes;
- How Hydro Ottawa communicate with certain customers;
- Roles and responsibilities in-line with communication requirements;
- How Hydro Ottawa continually improves its communications

Hydro Ottawa use ‘All User’ emails to communicate Asset Management information and awareness of the AMS with their staff. The following email was provided as evidence (Figure 4).

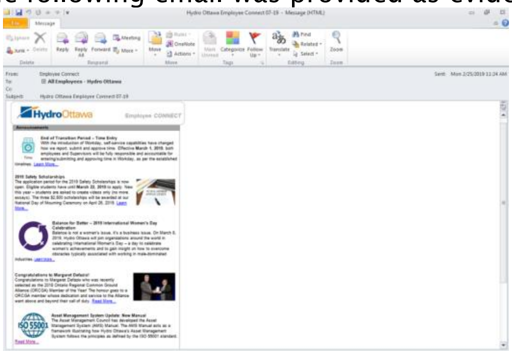

Figure 4 – Staff Communication

HOL’s Asset Management Council (AMC) determines:

- What stakeholders are relevant to the AMS;
- The requirements and expectations of these stakeholders with respect to asset management;
- The stakeholder requirements for recording financial and non-financial information relevant to asset management.

HOL communicate with their stakeholders through a broad set of interactions.

Call centre staff are trained to communicate effectively with customers, and to identify their needs e.g. Key accounts, Vulnerable customers.

HOL have a Customer Experience committee that assesses how HOL engage with its customers plus they also report any significant stakeholder requirements. This committee is made up of cross business personnel.

The 'Customer Engagement Program Overview' document was submitted to illustrate how HOL communicate with their customers. This document is part of HOL’s rate submission.

HOL need to expand the major known communication tasks

Conclusions

C7.4	HOL have demonstrated that they effectively communicate with their relevant stakeholders; however, it was felt that the major known communication tasks need expanding within HOL’s Asset Management documentation.

Recommendation

R7.4	It is recommended that HOL document major known communication tasks in the AMS or SAMP document.

Clause 7.5: Information requirements

To ensure the efficient operation of the AMS and the achievement of the organisation's objectives, pertinent information should be determined and collected. Information should be sourced using a systematic approach and stored in assigned repositories. Security, copying and archiving should be considered.

Maturity Score: 3

Discussion
HOL have determined what information requirements are needed to determine the health condition of its assets. This was formulated from the employment of a contractor HOL have a KPI dashboard that illustrates the KPIs for different parts of the AMS. Some are mandated regulatory requirements however most are tracking the AMS. A number of criteria were TBC such as the 'Asset Value - Value Optimization'. Evidence was produced in the 'IA0025 - Asset Management System Continual Improvement Plan R0' document that illustrated how HOL determine what information is required to populate this KPI. 'The average normalized capital value of projects to the budget of the projects presently planned by Hydro Ottawa. This index is meant to demonstrate the expected value for money obtained from the project portfolio for system renewal and system service projects.' The AMC was used to decide on the KPIs and the information requirements that support them. one of the Asset Management Council minutes were shown as evidence as well as a couple of presentations that were delivered to the AMC to prompt discussion on KPIs. HOL have a risk register which identifies deficiencies in information which would result in a risk. The SAMP details the requirements of Data quality Electrical Distribution CAD & GIS Construction Drawing Standard illustrates the information requirements plus the 'Placing construction proposals in GIS' was produced to illustrate how HOL quality assures data input. HOL are looking at creating a KPI and audit process for the data in its information systems. It is recommended that HOL create this (level of confidence in its data)"

Conclusions	
C7.5a	HOL have demonstrated that they have identified the required information to ensure that they can make effective Asset Management decisions.
C7.5b	HOL use a systematic approach to acquiring and storing information in designated repositories.

Recommendation	
R7.5	It is recommended that HOL create a KPI(s) that provides a level of confidence in their asset information.

7.6: Documented Information

Clause 7.6.1: General

To ensure the efficient operation of the AMS and the achievement of the organisation's objectives the organisation shall make sure that sufficient documented information is available to satisfy the requirements of ISO55001 and all applicable legal and regulatory requirements. Sufficient documented Information shall also be provided to ensure the effectiveness of the Asset Management System.

Maturity Score: 3

Discussion
HOL have an AMS document that specifies the documented information required for its AMS In addition to this the AMS Manual references a number of supporting documents that are deemed relevant, such as: • Hydro Ottawa – Strategic Direction • Hydro Ottawa – IAS-0001 – Asset Management Policy • Hydro Ottawa – Asset Management Plans • Hydro Ottawa – IAP0022 – Asset Management System Risk Procedure • Hydro Ottawa – IAP0021 – AMS Communication Plan • Hydro Ottawa – IAP0025 – Continual Improvement Plan • Hydro Ottawa – ESS0008 – Equipment Approval Process • Hydro Ottawa – POL-En-006.01 – Approval Authority for Procurements and Distributions • Hydro Ottawa – POL-Fi-003.01 – Procurement Policy • Hydro Ottawa – PRO-Fi-013.00 – Contract Procurement Process • Hydro Ottawa – POL-Fi-009.00 – Internal Controls over Financial Reporting • Hydro Ottawa – POL-Fi-013.00 – Capitalization Policy • Hydro Ottawa – DFS0007 – Control and Retention of Tech Based Docs and SWM • Hydro Ottawa – POL-IM-001.00 – Information Management Policy • Hydro Ottawa – PRO-MS-002.09 – Document and Data Management • Hydro Ottawa – Records Classification and Retention V9.1 • Ontario Energy Board – Distribution System Code • British Standards Institution – ISO55001 – Asset Management – Management System • British Standards Institution – ISO14001 – Environmental Management System • British Standards Institution – 18001 – Occupational Health and Safety Assessment Series • Institute of Asset Management – an Anatomy

Conclusions	
C7.6.1	HOL have demonstrated that they have sufficient documentation to satisfy the requirements of ISO55001

Clause 7.6.2: Creating and Updating

To ensure the effectiveness of documented information the organisation shall ensure that when the documents are created or reviewed, that they are constantly described, identified, formatted and documented in the correct media type. All documents that have been created or reviewed shall also be approved by a suitable authority for their suitability and adequacy.

Maturity Score: 3

Discussion
HOL have a document that specifies how HOL write documents 'Technical "Text Based" Document' was shown as evidence of how HOL control the formatting of documents. Hydro Ottawa Brand Guide Jan 2016 illustrates how Presentations can be created. All brand templates are kept in HydroBuzz Technical Standards are also kept in the Technical Standards Portal."

Conclusions	
C7.6.2	HOL demonstrated that they effectively create and manage their documented information.

Clause 7.6.3: Control of documented information

For the effective implementation of the AMS the organisation should ensure that the documented information deemed as relevant to its assets and Asset Management System is adequately controlled and available to use as appropriate to organisation. All documented information should be adequately protected, and be controlled to ensure the correct distribution, access, retrieval and use. The documented information should also be correctly stored and preserved including the control of any changes.

Maturity Score: 3

Discussion
The 'Control and Retention of Technical Based Documents and Standard Work Methods' details the control of HOLS documents, A flowchart illustrates the control process. All documentation has been readily available throughout the audit. HOL have a database that details the revision dates on all HOL documents, HOL also use this database to generate document numbers. HOL have a document identification number format that within the 'Technical Based Document & Standard Work Method Number Format' document 3 letters identify the document type and the remaining 4 numbers are just sequential.

Conclusions	
C7.6.3	HOL have demonstrated that they effectively control their documented information.

Section 8. Operation

Clause 8.1: Operational planning and control

The organisation should establish operational planning and control processes in order to support the effective delivery of the activities contained within the asset management plan. The processes should identify who is responsible for the planning and how the defined activities will be executed, including how risks arising during the planning and execution will be managed and controlled.

Maturity Score: 2

Discussion	
Sustainment is HOL's capital program projects HOL have a C55 (Copperleaf) (project tracker system) that records changes to projects. A project was identified on the 'Capital Program Tracking' spreadsheet as being deleted and the changes were linked in C55 (the example was new, so all changes were not in the C55 system) HOL map out project progress for different crews in a Gant chart style, the WhiteBoard' spreadsheet estimates the project dependent upon the labour hours and % completes. A project was identified on the white board and checked in the Capital Program Tracking spreadsheet and it checked out. The whiteboard spreadsheet is reviewed at bi monthly (twice a month) meetings which have a good cross functional attendance. This is a recurring invite on outlook for each of the HOL areas. A budgetary forecast review is carried out on a monthly basis. There is no direct link from all of these processes and the risk register.	
Conclusions	
C8.1	HOL have demonstrated that they have operational planning and control processes that support the effective delivery of the activities contained within the asset management plans; however, these processes are not linked to HOL’s risk register.
Recommendation	
R8.1	It is recommended that HOL should link their operational planning and control processes to HOL’s risk register.

Clause 8.2: Management of change

Planned changes within the organisation could have an impact on achieving the corporate objectives and associated delivery of the AM plans, therefore such changes should be assessed to identify any risks and impact these changes may have. Risks identified, controls should be implemented to mitigate possible adverse effects on the AM plans, AM objectives and corporate objectives.

It is the responsibility of the person making change to assess if this change has any impact on the AM objectives and ultimately the organisation's corporate goals.

All change should be documented and clearly express what change has occurred, the impact of this change and the mitigating controls that are required.

It is important to note that any change to the AM plans should be adequately assessed for its impact on the existing AM objectives.

Maturity Score: 2

Discussion

Changes to any technical standards need to be in-line with the 'Signing authority for technical based documents'

Project changes need to be as per the Change Request template which is documented in C55

A Change in the direction of a project will be in-line with the Planning Directive.

It is unclear how management of change is carried out for changes to the AMS and how Management of Change requests are monitored and recorded.

As a management of change process identifies and determines any potential risks associated with a change, any significant risks should therefore be reflected in HOL's Risk Register. There is currently no documented link to the risk register from the management of change processes.

The flowchart below (Figure 5) illustrates a management of change process that identifies risks of any change request

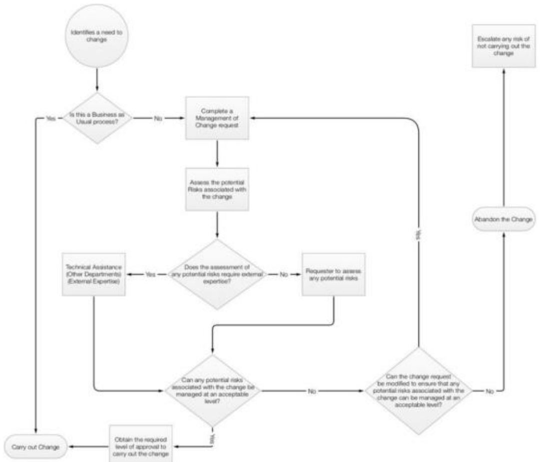

Figure 5 – Generic Management of Change flowchart

Conclusions

C8.2a	Management of change is controlled within HOL for technical standards/documents and projects; however, it is unclear how management of change is carried out for changes to the AMS and how Management of Change requests are monitored and assessed.

C8.2b	There is currently no link between the management of change processes and HOL's Risk Register.
Recommendation	
R8.2a	It is recommended that HOL should document how it will consider and manage changes to its AMS.
R8.2b	It is recommended that HOL should consider how Management of Change requests are monitored and recorded.
R8.2c	It is recommended that HOL should link any significant risks identified from a management of change process to HOL's risk register
R8.2d	It is recommended that HOL create a process that identifies the requisite parts of a management of change request (see diagram above).

Clause 8.3: Outsourcing

Outsourcing is a common method for an organisation that prefers to perform certain AM activities using an external service provider. When these activities influence the achievement of the AM objectives, these should be part of the AMS and should be documented.

For outsourced activities, the organisation should implement controls so as to provide assurance that actual performance is as planned. The performance of outsourced activities should be subject to regular management reviews.

When outsourcing any life cycle activities and AM activities, the organisation should consider the associated risk and impact on its assets and AMS.

Maturity Score: 2

Discussion	
HOL's RFSO (Request for standing offer) sets out a set of parameters that the outsourced company needs to adhere to. Each contractor is approved on their ISN Grade (IS Network) Each contractor goes through an onboarding process. Outsourced contractors do not currently receive HOL's Asset Management Policy or Asset Management Awareness training. This should be added to the contractor on-boarding process."	
Conclusions	
C8.3	HOL do consider the technical requirements and competence of their outsourced contractors; however, currently outsourced contractors do not receive a copy of HOL's Asset Management Policy or awareness training.
Recommendation	
R8.3a	It is recommended that HOL ensure that all outsourced contractors are aware of HOL's Asset Management Policy.
R8.3b	It is recommended that HOL provide all outsourced contractors with Asset Management Awareness training, possibly through the on-boarding process.

Section 9. Performance and Evaluation

Clause 9.1: Monitoring, measurement, analysis and evaluation

The organisation should develop processes to provide for the systematic measurement, monitoring, analysis and evaluation of the organisation's assets, AMS and AM activity on a regular basis.

Maturity Score: 3

Discussion
HOL have a corporate scorecard that measures the organizational objectives. Each division then has KPIs that they need to achieve. The Scorecard for Q4 2018 was shown as evidence which illustrated many different metrics under the following areas: ● Financial Strength ● Customer Value ● Organizational Effectiveness ● Productivity ● Corporate Citizenship Each time HOL have a reported unplanned outage the operator will categorize the failure mode, such as Tree contact, Lightning etc. (Regulatory Cause Codes). The operational staff will then amend the identified cause if it is different to the one reported. Failures are monitored to determine whether HOL should carry out a full failure investigation. CEA Association (Service continuity committee) benchmarks the failures of all Canadian Utilities. The taxonomy of the System Interruption Database (HOL database) allows HOL to assess common failures and failure types.

Conclusions	
C9.1	HOL have demonstrated that they developed processes to provide for the systematic measurement, monitoring, analysis and evaluation of the organisation's assets, AMS and AM activity.

Clause 9.2: Internal audit

The organisation shall conduct internal audits at regular intervals to ensure the suitability and efficiency of its AMS.

The organisation should establish an audit process to direct the planning and conduct of audits, and to determine the audits needed to meet its objectives. The process should be based on the organisation's activities, its risk assessments, the results of past audits, and other relevant factors.

Maturity Score: 2

Discussion	
HOL have an independent Audit group that has an annual audit plan that is risk based. Parts of the Asset Management System that are consistent with HOL's quality management system have undergone some internal auditing. HOL have not currently carried out an internal audit upon its Asset Management System, due to its maturity.	
Conclusions	
C9.2	HOL have all of the requisite processes and audit expertise to carry out internal auditing of the AMS.
Recommendation	
R9.2	It is recommended that HOL's internal audit team carry out an internal audit upon HOL's AMS.

Clause 9.3: Management review

Top management should review the organisation's assets, AMS and AM activity, as well as the operation of its policy, objectives and plans, at planned intervals, to ensure their suitability, adequacy and effectiveness.

Maturity Score: 1

Discussion	
The AMC is due to start holding quarterly meetings that review the AMS and its performance. HOL are to use the AMC quarterly meetings to carry out the Management Review of the AMS; however, it is felt that the quarterly meetings are not the correct forum to carry out an in-depth management review of the AMS. The tracking of KPIs in the AMC quarterly meetings is good practice and will contribute to the Management Review process.	
Conclusions	
C9.3a	Due to the maturity of HOL's AMS, HOL have not yet carried out a full management review.
C9.3b	The tracking of KPIs in the AMC quarterly meetings is good practice and will contribute to the Management Review process
Recommendation	
R9.3a	It is recommended that HOL carry out a management review of the AMS separately to the AMC quarterly meetings.
R9.3b	It is recommended that HOL determine and document the minimum content of the management review process

Section 10. Improvement

Clause 10.1: Nonconformity and corrective action

The organisation should establish plans and processes to control nonconformities and their associated consequences, so as to minimize any adverse effects on the organisation and on stakeholder needs and expectations. This can be accomplished by documenting and reviewing past non-conformities, evaluating how the consequences were dealt with and by determining methodologies to prevent future nonconformity.

Nonconformities can occur in two ways:
- Nonconformity of the AMS
- Nonconformity of assets

Maturity Score: 3

Discussion
HOL receive non-conformance information through the OMS (Outage Management System), Call centres, Dispatch, Inspection, staff observation. I Net Dispatcher holds the incident/failures these are then sent electronically to the field staff or via a 'General Construction Order & CVP Certificate The details of any asset changes are recorded and the GIS is changed. The 'General Construction Order & CVP Certificate' green is indicative of daily work whereas a Pink certificate indicates further work required. An audit is carried out on HOL every March to determine HOL's compliance with their Technical Standards. The auditor checks a number of projects against the current applicable technical standards. If HOL need to deviate from a standard they need to complete a Deviation Form that identifies the deviation. These forms are held in the project folders and in a central folder. The central folder is then interrogated by the Policy and standards section to determine whether the standards need changing. The AMS is monitored through the AMC

Conclusions	
C10.1a	HOL have demonstrated that they have established plans and processes to control nonconformities and their associated consequences.

Clause 10.2: Preventive Action

Preventive actions, which may include predictive actions, are those taken to address the root causes of potential failures or incidents, as a proactive measure, before such incidents occur. The organisation should establish, implement and maintain processes for initiating preventive or predictive actions. Asset inspections will be carried out by the relevant operations and maintenance departments.

Maturity Score: 3

Discussion	
HOL determine preventative actions through Standards committees, or the Reliability council. The Standards committee are asset types and spread across a wide range of staff - an example was given about the change from Cedar to Red Pine poles. The reliability council looks at trends in outages.	
Conclusions	
C10.2	HOL demonstrated that they consider predictive actions to address the root causes of potential failures or incidents, as a proactive measure, before such incidents occur.

Clause 10.3: Continual Improvement

Opportunities for improvement should be identified, assessed and implemented across the organisation as appropriate, through a combination of monitoring and corrective actions for the assets, asset management, or asset management system. Continual improvement should be regarded as an ongoing iterative activity, with the ultimate aim of delivering the organisational objectives.

Maturity Score: 3

Discussion	
HOL participate in several working groups, councils and agencies. HOL participate in conferences. HOL are members of CEATI HOL identify areas for continuous improvement in each of the Asset Management Plans.	
Conclusions	
C10.3	HOL have demonstrated that they consider and actively pursue continuous improvement of their AMS and Asset Management activities.

4. Discussion

Figure 6 illustrates the maturity scoring for the gap analysis assessment carried out on Hydro Ottawa's Asset Management System. It can be seen that for a such a new system it has demonstrated conformance for twenty-one of the twenty-seven assessed sections of ISO55001. The scoring of each of the ISO55001 clauses, is in-line with the scoring methodology in Appendix II.

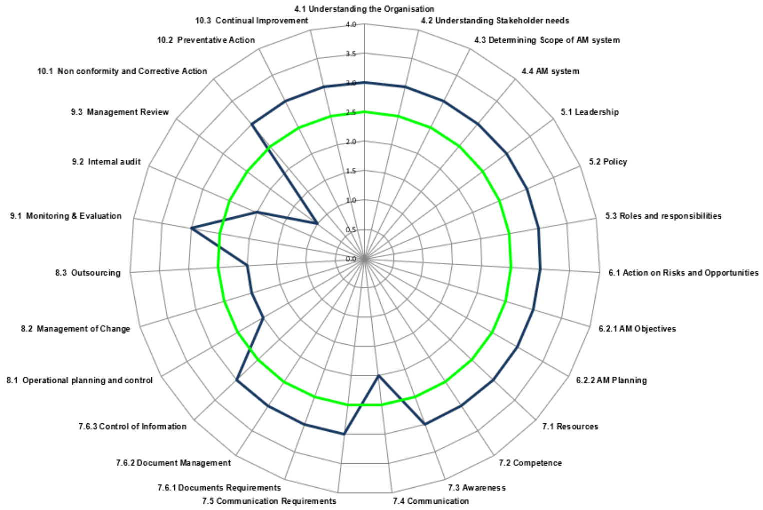

Figure 6- Maturity Assessment

Figure 7 illustrates the average gap across each of the seven ISO55001sections, which highlights the areas that have the largest gaps. It should be noted that the green line indicates what would be seen as conformance of the requirements of ISO55001.

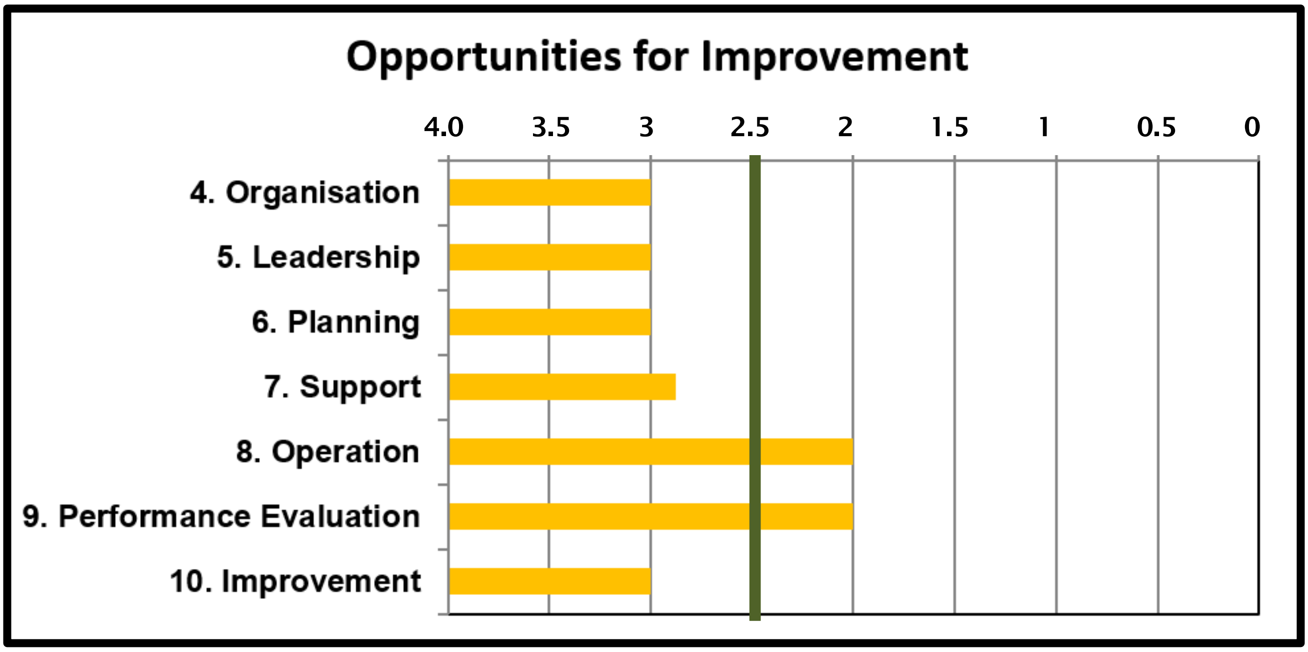

Figure 7 – Improvement Opportunities

It can be seen that section 8 (Operation) and section 9 (Performance Evaluation) have the largest gaps. The cause of the gap in section 8 is that all of the three clauses that make up section 8 have scored a maturity score of 2. Within Section 9, clause 9.2 (Internal Audit) scored a 2 and clause 9.3 (Management Review) scored a 1.

The low scoring of these clauses is commonly caused by the audited organisation not having the requisite processes in place; however, for Hydro Ottawa it is due to the immaturity of its Asset Management System.

As the most difficult and time-consuming activities are usually the creation and implementation of processes, it can be seen that Hydro Ottawa simply need to execute an Internal Audit on its Asset Management System and define and carry out its annual Management Review to close these identified gaps.

There are seventeen recommendations in this document, which EA Technology recommends that Hydro Ottawa carry out in order to comply with the requirements of ISO55001.

.

5. Conclusions

Note the Conclusions are numbered in line with the relevant parts of ISO 55001.

C4.1	Hydro Ottawa have demonstrated that they fully understand the context of their organization by considering issues that can affect its business environment.
C4.2	HOL demonstrated that they engage with stakeholders that are relevant to its Asset Management System and their needs and requirements are considered.
C4.3	HOL document the scope of the AMS through its AMS and SAMP documents.
C4.4	HOL have demonstrated that they document the AMS through the AMS Manual document and the SAMP.
C5.1	HOL have demonstrated that top management at all levels of the organisation are involved in the planning, implementation and operation of the AMS.
C5.2	Currently HOL do not communicate the Asset Management Policy to their contractors.
C5.3	HOL document roles and responsibilities within the AMS Manual and SAMP documents.
C6.1	HOL have demonstrated that they consider external and internal issues that affect its ability to achieve its intended outcomes.
C6.2.1	HOL have demonstrated that Asset Management Objectives are created and linked to HOL's Organizational Objectives.
C6.2.2	HOL have clearly demonstrated that they create, document and maintain asset management plans that consider, risks and opportunities across the asset's life cycles, and provide details of objectives.
C7.1	HOL have demonstrated that they link resource requirements to their plans and their regulatory submission.
C7.2	HOL have demonstrated that they consider, evaluate and track staff competence.
C7.3	During the audit Hydro Ottawa demonstrated a good level of awareness.
C7.4	HOL have demonstrated that they effectively communicate with their relevant stakeholders; however, it was felt that the major known communication tasks need expanding within HOL's Asset Management documentation.
C7.5a	HOL have demonstrated that they have identified the required information to ensure that they can make effective Asset Management decisions.
C7.5b	HOL use a systematic approach to acquiring and storing information in designated repositories.

C7.6.1	HOL have demonstrated that they have sufficient documentation to satisfy the requirements of ISO55001.
C7.6.2	HOL demonstrated that they effectively create and manage their documented information.
C7.6.3	HOL have demonstrated that they effectively control their documented information.
C8.1	HOL have demonstrated that they have operational planning and control processes that support the effective delivery of the activities contained within the asset management plans; however, these processes are not linked to HOL's risk register.
C8.2a	Management of change is controlled within HOL for technical standards/documents and projects; however, it is unclear how management of change is carried out for changes to the AMS and how Management of Change requests are monitored and assessed.
C8.2b	There is currently no link between the management of change processes and HOL's Risk Register.
C8.3	HOL do consider the technical requirements and competence of their outsourced contractors; however, currently outsourced contractors do not receive a copy of HOL's Asset Management Policy or awareness training.
C9.1	HOL have demonstrated that they developed processes to provide for the systematic measurement, monitoring, analysis and evaluation of the organisation's assets, AMS and AM activity.
C9.2	HOL have all of the requisite processes and audit expertise to carry out internal auditing of the AMS.
C9.3a	Due to the maturity of HOL's AMS, HOL have not yet carried out a full management review.
C9.3b	The tracking of KPIs in the AMC quarterly meetings is good practice and will contribute to the Management Review process.
C10.1a	HOL have demonstrated that they have established plans and processes to control nonconformities and their associated consequences.
C10.2	HOL demonstrated that they consider predictive actions to address the root causes of potential failures or incidents, as a proactive measure, before such incidents occur.
C10.3	HOL have demonstrated that they consider and actively pursue continuous improvement of their AMS and Asset Management activities.

6. Recommendations

Note the Recommendations are numbered in line with the relevant parts of ISO 55001.

R4.3a	It is recommended that HOL should document in the SAMP document which Assets are explicitly excluded from the AMS.
R4.3b	It is recommended that HOL should make reference to HOL's current management systems (ISO9001, ISO14001) in the AMS Manual.
R5.2	It is recommended that the Asset Management Policy is included in the contractor on-boarding process and maybe the Contractor intranet.
R5.3	It is recommended that HOL ensure that the responsibilities documented in the SAMP and AMS Manual documents are reflected in personal job descriptions.
R7.3	It is recommended that Hydro Ottawa continue to make their staff as aware as possible regarding the AMS, as the awareness process conducted during the audit was minimal compared to a certification audit.
R7.4	It is recommended that HOL document major known communication tasks in the AMS or SAMP document.
R7.5	It is recommended that HOL create a KPI(s) that provides a level of confidence in their asset information.
R8.1	It is recommended that HOL should link their operational planning and control processes to HOL's risk register.
R8.2a	It is recommended that HOL should document how it will consider and manage changes to its AMS.
R8.2b	It is recommended that HOL should consider how Management of Change requests are monitored and recorded.
R8.2c	It is recommended that HOL should link any significant risks identified from a management of change process to HOL's risk register
R8.2d	It is recommended that HOL create a process that identifies the requisite parts of a management of change request (see diagram above).
R8.3a	It is recommended that HOL ensure that all outsourced contractors are aware of HOL's Asset Management Policy.
R8.3b	It is recommended that HOL provide all outsourced contractors with Asset Management Awareness training, possibly through the on-boarding process.
R9.2	It is recommended that HOL's internal audit team carry out an internal audit upon HOL's AMS.
R9.3a	It is recommended that HOL carry out a management review of the AMS separately to the AMC quarterly meetings.
R9.3b	It is recommended that HOL determine and document the minimum content of the management review process.

Appendix I Audit Schedule

ISO55000 Gap Analysis Schedule
Monday 25th February 2019 to Thursday 28th February 2019

	AM	PM
Day 1	Introduction / Context	Leadership
Day 2	Site Visit	Planning
Day 3	Planning / Support	Support
Day 4	Operation / Performance Evaluation	Improvement / Presentation

Audit Steering Committee
Jenna Matt Margaret Ben Steve

Name	Position
Lance Jefferies	Chief Electricity Distribution Officer
Guillaume Paradis	Director, Distribution Engineering & Asset Management
Joseph Muglia	Director, Distribution Operations
Jenna Gillis	Manager, Asset Planning
Ben Hazlett	Manager, Distribution Policies and Standards
Matthew McGrath	Supervisor, Maintenance and Reliability
Margaret Flores	Supervisor, Asset Planning
Doug Baldock	Manager, System Operations
Greg Van Dusen	Director, Regulatory Affairs
Kirk Thomson	Management Accountant
Brent Fletcher	Manager, Program Management and Business Performance
Tony Stinziano	Manager, Distribution Design
Kristy Biddle	Manager, Talent Performance and Development
Ed Donkersteeg	Supervisor, Standards
Shannon Fowler	Engineering Intern - Smart Grid
David Ayer	Manager, Supply Chain
Greg Bell	Manager, Distribution Operations
Brian Kuhn	Manager, Distribution Operations

Day 1: Monday 25th February 2019

Time	Title	Activity	Areas covered	Suggested Attendees by EA Technology	Suggested Attendees from HOL
09:00 to 09:30	Introduction	Presentation	Introduction Review of project Overview of Audit Aims and outputs	Project Team Senior Management	Lance Guillaume Joseph Audit Steering Committee
09:30 to 10:30	Context of the Organisation	Meeting	Understanding the organization and its context Understanding the needs and expectations of stakeholders	Senior Management Persons that deal with stakeholder engagement and use this information to determine the organisation's objectives	Lance Guillaume Joseph Audit Steering Committee
10:30 to 10:45	Comfort Break				
10:45 to 12:30	Context of the Organisation	Meeting	Scope of the asset management system Strategic Asset Management Plan	Asset Manager(s)	Guillaume Joseph Jenna
12:30 to 13:30	Lunch				
13:30 to 15:30	Leadership	Meeting	Leadership and commitment Policy Organisational Roles, Responsibilities and Authorities	Senior Management Asset Manager(s)	Lance Guillaume Joseph Jenna
15:30 to 15:45	Comfort Break				
15:45 to 16:30	Collate Results/Contingency				

Day 2: Tuesday 26th February 2019

Time	Title	Activity	Areas covered	Suggested Attendees by EA Technology	Suggested Attendees from HOL
08:45 to 09:00	Review	Meeting	Review of day 1	Key project team members	Audit Steering Committee
09:00 to 12:00	Site Visit	Assessment of a field operation	Data Collection Awareness		Organized by Steve Hawthorne
12:00 to 13:00	Lunch				
13:30 to 15:30	Planning	Meeting	Asset Management Objectives Risks and opportunities Planning to achieve Asset Management Objectives	Planning Engineers Asset Manager(s)	Jenna Margaret Matt Planners + Maint Eng
15:30 to 15:45	Comfort Break				
15:45 to 16:30	Collate Results/Contingency				

Day 3: Wednesday 27th February 2019

Time	Title	Activity	Areas covered	Suggested Attendees by EA Technology	Suggested Attendees from HOL
08:45 to 09:00	Review	Meeting	Review of days 1 & 2	Key project team members	Audit Steering Committee
09:00 to 10:30	Performance Evaluation	Meeting	Monitoring, measurement, analysis and evaluation Internal audit Management review	Asset Manager(s) Operations Auditor	Jenna Doug Greg Van Dusen Kirk
10:30 to 10:45	Comfort Break				
10:45 to 12:30	Support	Meeting	Resources Competence Awareness	Human Resources Asset Manager(s)	Brent HR - Kristy Biddle Tony Jenna
12:30 to 13:30	Lunch				
13:30 to 15:30	Support	Meeting	Communication Information Requirements Documented Information	Asset Manager(s) Standards and Policy Engineers IT	Jenna Ben Ed Shannon
15:30 to 15:45	Comfort Break				
15:45 to 16:30	Collate Results				

Day 4: Thursday 28th February 2019

Time	Title	Activity	Areas covered	Suggested Attendees by EA Technology	Suggested Attendees from HOL
08:45 to 09:00	Review	Meeting	Review of days 1 & 2	Key project team members	Audit Steering Committee
09:00 to 10:30	Operation	Meeting	Operational planning and control Management of Change Outsourcing	Asset Manager(s) Operations Managers Human Resources	Doug Brent HR - Kristy Biddle David Ayer Jenna
10:30 to 10:45	Comfort Break				
10:45 to 12:30	Planning	Meeting	Asset Management Objectives Risks and opportunities Planning to achieve Asset Management Objectives	Planning Engineers Asset Manager(s)	Jenna Margaret Matt Planners + Maint Eng
12:30 to 13:30	Lunch				
13:30 to 15:3	Improvement	Meeting	Nonconformity and corrective action Preventive action Continual improvement	Asset Manager(s) Operations	Jenna Greg Bell Brian
15:30 to 15:45	Comfort Break				
15:45 to 16:30	Results	Presentation	Initial Findings	Project Team Senior Management	Lance Guillaume Joseph Audit Steering Committee

Appendix II ISO 55001 Maturity Assessment

EA Technology will apply the IAM's scoring criteria to all of the ISO 55001 sections assessed during a gap analysis and Stage 1 and Stage 2 certification audits. The scoring criteria represents five "levels" of asset management maturity (Level 0 to Level 4). The maturity levels as defined by the IAM are summarized as follows:

- Maturity Level 0 (Learning)
  - The elements required are not in place. The organisation is in the process of developing an understanding of ISO 55000.
- Maturity Level 1 (Applying)
  - The organisation has a basic understanding of the requirements It is in the process of deciding how the elements will be applied and has started to apply them.
- Maturity Level 2 (Embedding)
  - The organisation has a good understanding of ISO 55000. It has decided how the elements of ISO 55000 will be applied and work is progressing on implementation.
- Maturity Level 3 (Optimising and Integrating)
  - All elements of ISO 55000 are in place and are being applied and are integrated. Only minor inconsistencies may exist.
- Maturity Level 4 (Beyond ISO 55000)
  - Using processes and approaches that go beyond the requirements of ISO 55000. Pushing the boundaries of asset management development to implement new concepts and ideas.

Global Footprint

We provide products, services and support for customers in 90 countries, through our offices in Australia, China, Europe, Singapore, UAE and USA, together with more than 40 distribution partners.

Our Expertise

We provide world-leading asset management solutions for power plant and networks.

Our customers include electricity generation, transmission and distribution companies, together with major power plant operators in the private and public sectors.

- Our products, services, management systems and knowledge enable customers to:
- Prevent outages
- Assess the condition of assets
- Understand why assets fail
- Optimize network operations
- Make smarter investment decisions
- Build smarter grids
- Achieve the latest standards
- Develop their power skills

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PEOPLE. DRIVE. RESULTS.

Hydro Ottawa Local Achievable Potential Study

Final Report
Hydro Ottawa Limited

October 30, 2019

02	Final Report	30-Oct-2019	AS	TA	TA
01	Draft Report	21-Oct-2019	AS	TA	TA
00	Draft Report	01-Oct-2019	AS	TA	TA
REV.	DESCRIPTION	DATE	PRPD	CHKD	APPRD
			SNC-Lavalin		

LICENSED PROFESSIONAL ENGINEER
T. ABDELGALIL
100143354
PROVINCE OF ONTARIO

Tarek Abd
Oct 30, 2019

Contents

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List of acronyms

APS	Achievable Potential Study
BES	Battery Energy Storage
CDM	Conservation and Demand Management
DB	Dun & Bradstreet Database
DER	Distributed Energy Resources
EUF	End-Use Forecasting
EUI	Energy Use Intensity
HOL	Hydro Ottawa Ltd
HR	High Rise
IESO	Independent Electricity System Operator
kWh	Kilo Watt hour
LAP	Local Achievable Potential
LR	Low Rise
MAL	IESO's Measure and Assumption lists
MPAC	Municipal Property Assessment Corporation
MURB	Multi-Unit Residential Building
NRCAN	Natural Resources Canada
OEB	Ontario Energy Board
SCIEU	Survey of Commercial and Institutional Energy Use
SHEU	Survey of Household Energy Use
sq. ft.	Square feet

1. Executive Summary

This is the final report for the study entitled "Hydro Ottawa Local Achievable Potential (LAP) Study," which commenced on Dec. 7, 2018. This study, undertaken at the request of Hydro Ottawa Ltd, Ontario, is conducted by SNC-Lavalin Inc. Toronto, Canada, as the Consultant.

The objective of this study is to evaluate non-wires options potential to offset load growth in the Kanata North area to defer or eliminate the need for new infrastructure. The non-wire options considered in this study include Conservation and Demand Side Management (CDM) Programs, distributed generation, and energy storage.

The study included the following tasks

- Determining the local load characterization for Kanata North area served by Kanata and Marchwood MTS
- Identifying the technically feasible measures for addressing the local area needs
- Evaluating market analysis of feasible measures and developing adoption and cost curves
- Developing an Excel tool to Assess the impact of incentives on the achievable potential and determining the combinations of CDM and DERs measures that provide maximum savings for a given avoided cost and incentive levels

a) Local Load Characterization

The Kanata North area serves prominently residential and commercial sectors. Table 1-1 and Table 1-2 show the total estimated electrical consumptions for Kanata and Marchwood, respectively.

Table 1-1 Estimated consumptions (kWh) for Kanata MTS

Kanata	624F1	624F2	624F3	624F5	624F6	Total
Residential	21,957,355	6,777,998	3,546,205	705,710	12,049,252	45,036,520
Commercial	35,437,231	52,884,403	7,694,143	75,889,460	28,808,356	200,713,593
Industrial	0	3,339,425	0	0	0	3,339,425
Total	57,394,587	63,001,826	11,240,347	76,595,170	40,857,608	249,089,538

Table 1-2 Estimated consumptions for Marchwood MTS

Marchwood	MWDF1	MWDF2	MWDF3	MWDF4	Total
Residential	16,556,027	13,659,061	19,679,985	13,625,418	63,520,491
Commercial	31,584,597	20,260,960	10,979,980	27,307,879	90,133,415
Industrial	0	0	0	0	0
Total	48,140,624	33,920,021	30,659,965	40,933,296	153,653,906

Figure 1-1 and Figure 1-2 show the end-use segmentation for the residential and commercial sectors of Kanata North area.

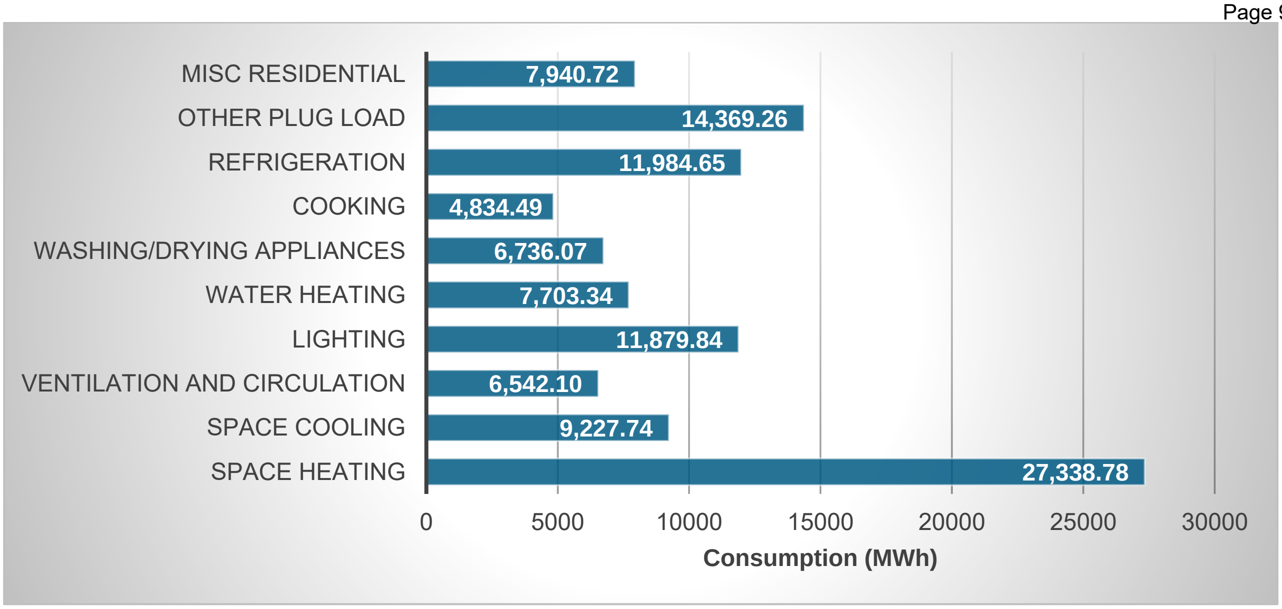

Figure 1-1 End-use Segmentation for Residential Sector, Kanata North Area

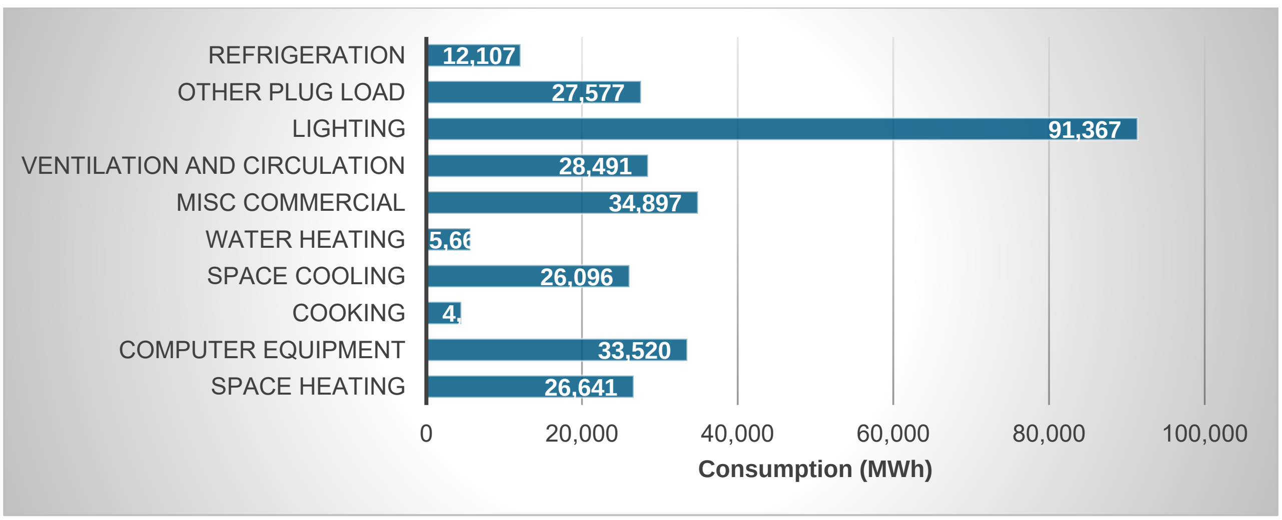

Figure 1-2 End-use Segmentation for Commercial Sector, Kanata North Area

The aggregated commercial and residential forecast of the Kanata North area is illustrated in Figure 1-3. A total increase in electricity consumption of 4% from 402,743 MWh in 2018 to 418,971 MWh is forecasted by 2040. The commercial section is expected to provide the largest increase in electricity use, rising from 290,847 MWh in 2018 to 319,038 MWh (9.7 % increase). The residential sector electricity consumption is expected to show a decrease from 108,557 MWh in 2018 to 99,309 MWh in 2040 (8.51 % decrease).

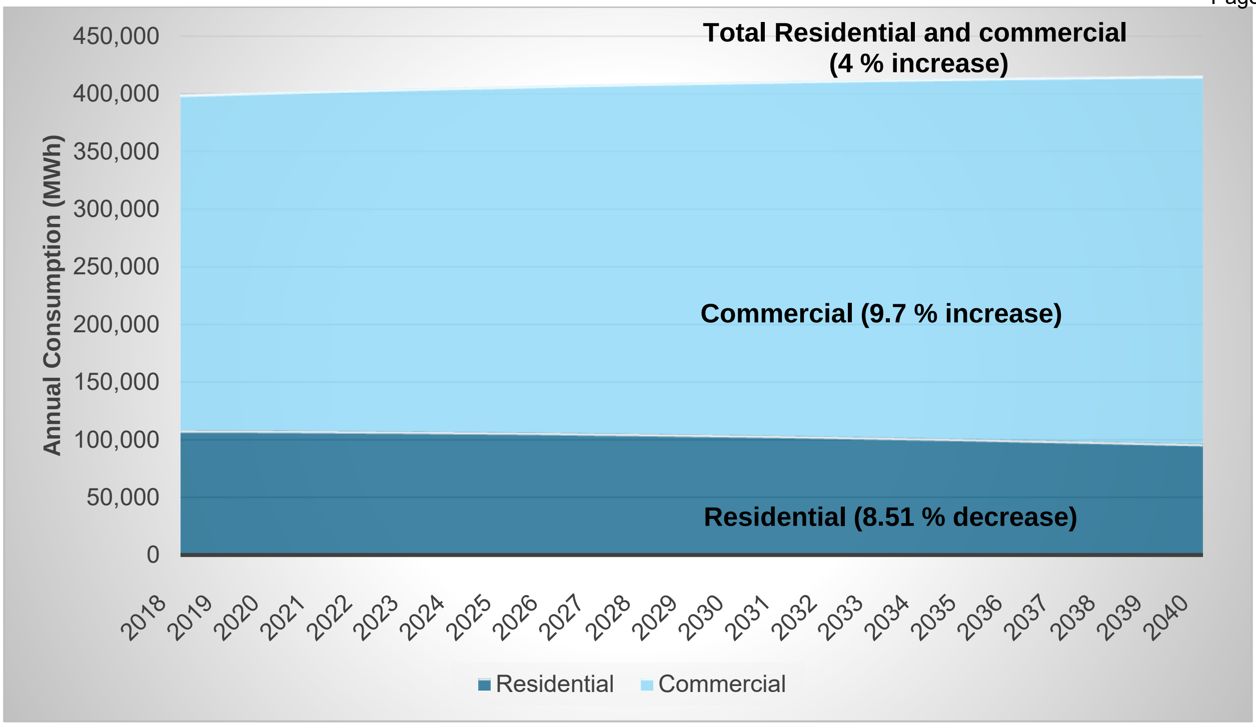

Figure 1-3 Kanata-Marchwood forecast (2018-2040) by sector

b) Technical Potential of Non-Wire Alternatives for Peak Reduction

The conservation and demand management (CDM) measures were developed with input from IESO and other CDM measures from North American jurisdictions, that could be rolled into the market quickly, are added to the CDM list of measures. The annual energy consumption saving, as well as the peak demand savings, were estimated for each measure then shortlisted based on their effectiveness addressing the summer peak demand at the Kanata North area.

The maximum potential for peak demand reduction for each measure was evaluated based on the local area load segmentation, the number of equipment per subsector, the consumption of the total equipment as a percentage of the end-use consumption, and the fraction of equipment that is energy efficient.

Finally, the aggregated technical potential for peak reduction for all the CDM measures was evaluated. The total residential summer peak reduction in 2023 was estimated to be 4.713 MW, while the total commercial summer peak reduction in 2023 was estimated to be 13.691 MW. Figure 1-4 shows the technical potential Summer peak reduction for each subsector; the largest technical potential was estimated for the single-family subsector, which accounts for 62.725 % of the total peak reduction in 2023. Figure 1-5 shows the technical potential Summer peak reduction for each subsector; the largest technical potential was estimated for the office subsector, which accounts for 61.19 % of the total peak reduction in 2023.

In addition to the CDM measures, the impact of the Distributed Energy Resources (DER) on Kanata-Marchwood summer peak was considered, the analysis is categorized into load shifting using battery energy storage system and renewable-based distributed generation. The technical potential for peak reduction of the battery energy storage is calculated on the utility-scale and on the large customers-scale. Moreover, the technical potential of photovoltaic roof-top distributed generation mounted on the residential and commercial buildings is calculated. The results, presented in Figure 1-6, show that the maximum technical potential of the battery storage is 5.87 MW, and the technical potential of the photovoltaic PV Distributed generators DG is 7.03 MW, in addition to the technical potential of the CDM measures (i.e., 18.4 MW).

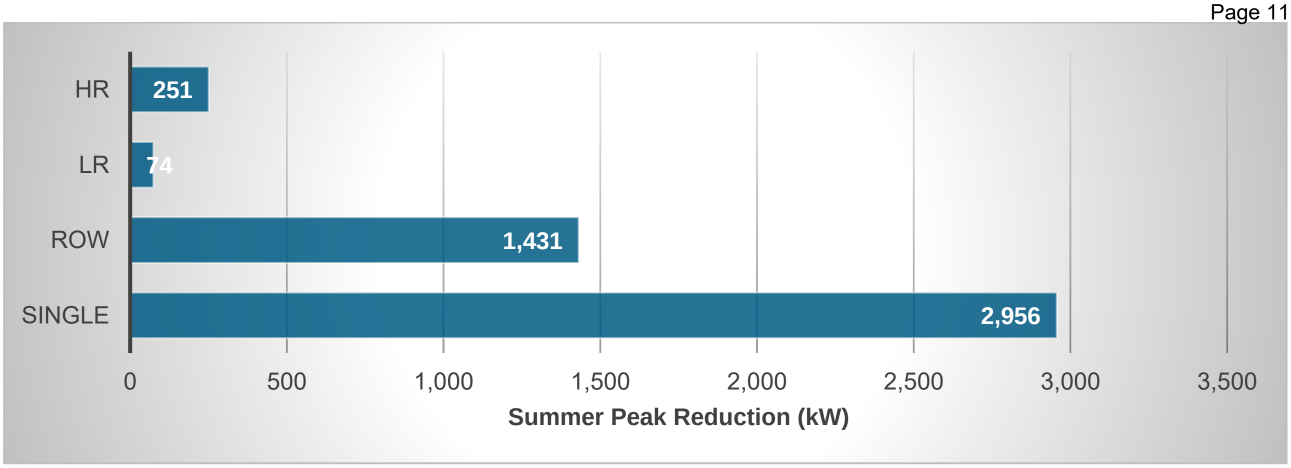

Figure 1-4 Technical Potential Peak Reduction by Residential Subsector in 2023

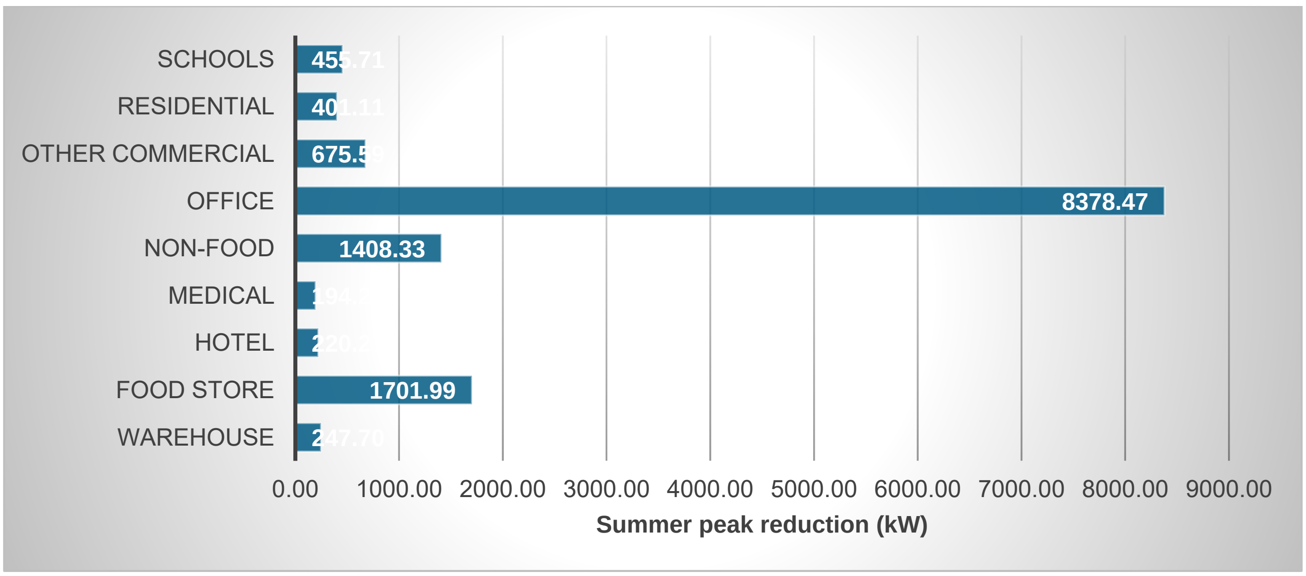

Figure 1-5 Technical Potential Peak Reduction by Commercial Subsectors in 2023

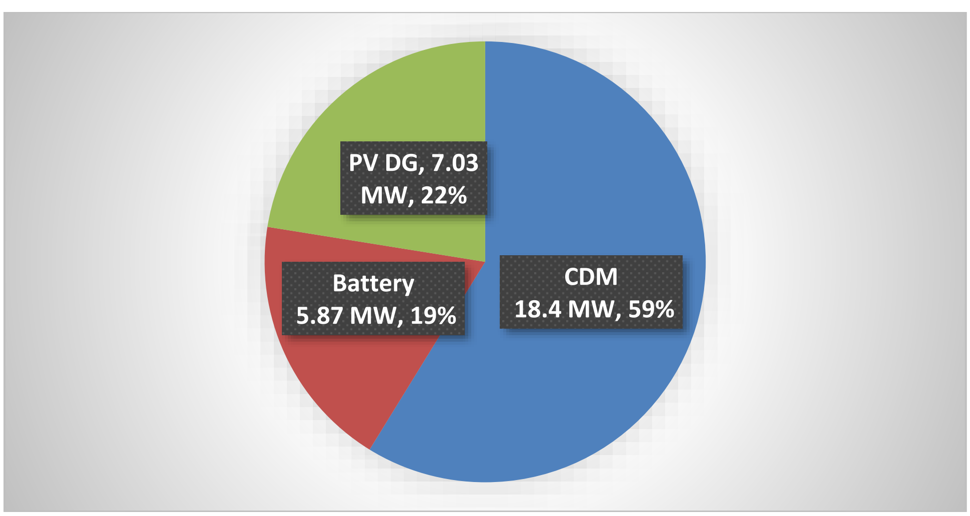

Figure 1-6 Percentage contribution of each of the technical potential on peak reduction

c) Market Analysis

Historical participation in CDM was analyzed and used to develop the adoption curve for each measure. Using the developed adoption curves the aggregated achievable potential for peak reduction for all the CDM measures was estimated. The total achievable potential for residential sector in 2023 was estimated to be 481.31 kW. The total achievable potential for commercial sector in 2023 was estimated to be 5972.96 kW. The total achievable potential for the peak reduction of the CDM measures is estimated at 6454.915 kW. Figures 1-7 and 1-8 show the estimated values for the achievable potential vs. technical potential of the CDM measures for the residential and commercial sectors respectively.

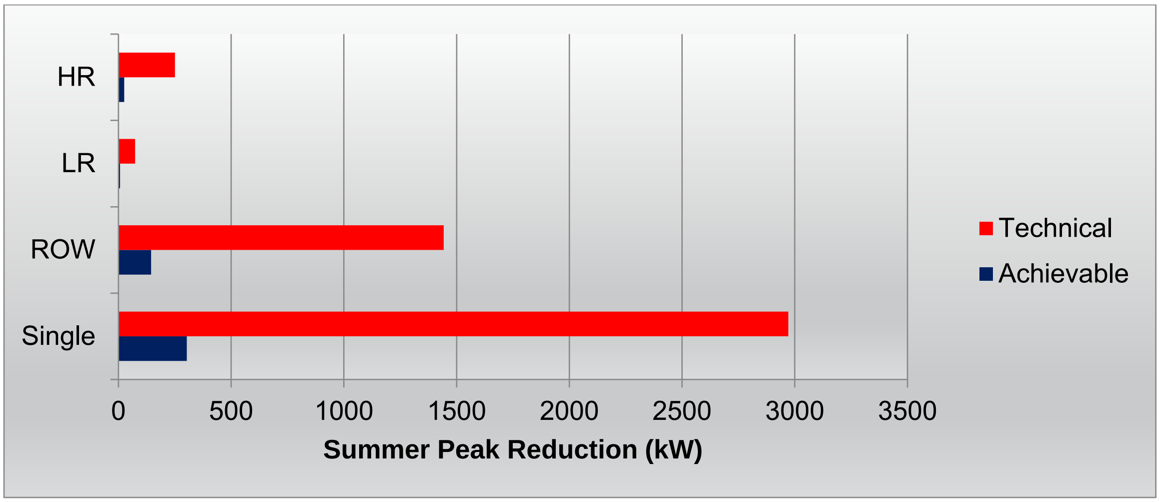

Figure 1-7 Technical Vs. Achievable Potential, Residential Subsector

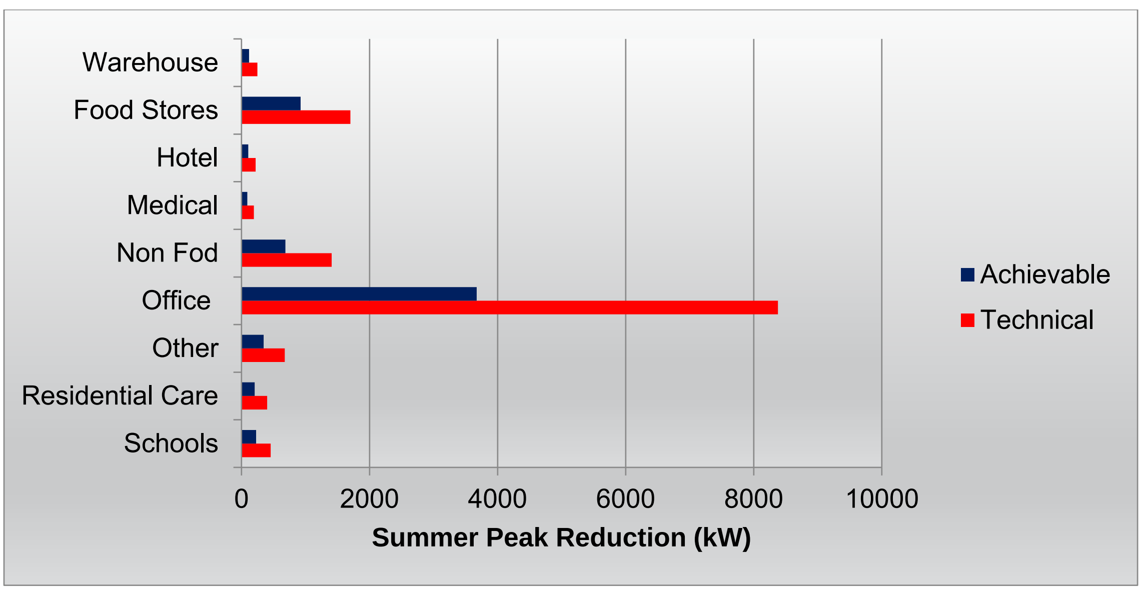

Figure 1-8 Technical Vs. Achievable Potential, Commercial Subsector

d) Assessment of the Impact of Incentive on Achievable Potential

Economic analysis was conducted to determine the required level of incentive for the DER project investment (Battery Energy Storage (BES) and PV DGs) to be profitable. The economic analysis shows that the required incentives for the customer-scale battery project are in a range of $ 5,570-6,930 per kW peak reduction. This incentive level is significantly high relative to the corresponding savings and is not economically viable. As a result, the customer-scale BES was excluded from the achievable potential analysis, as discussed with HOL and IESO. For a profitable PV DG project investment, the incentives per installed kW were estimated to be 1140.76 and 2,200 $/kW for the residential and commercial PV roof-top, respectively. The achievable potential for peak reduction for the PV DGs (DER measures) was estimated to be 0.36 MW based on the information provided by HOL.

An Excel tool was developed to evaluate the impact of incentives on the achievable potential and to determine the combination of CDM and DERs measures that provide maximum peak reduction for a given avoided costs and incentive levels. Input to the tool includes the incentive level per each measure, peak demand reduction per unit, and the achievable potential of each measure.

The tool was used to evaluate the impact of incentives variations on the achievable potential. The price elasticity values were used to establish the adjustment factor to be applied to the base case modelled savings estimates, where the price elasticity is a basic measure of demand or supply sensitivity to changes in price. An elasticity value of 1.0 would indicate a product that is perfectly elastic, while a value of 0 would indicate that the product is inelastic (changes in prices have no effect on demand or supply)

The incentive cost curve is constructed based on the peak demand reduction cost of all the CDM and DER measures. The curve, presented in Figure 1-9, shows each measure as a step in the curve, with the horizontal length of each step indicating the achievable potential of the measure, and its height above the horizontal axis indicates the incentive costs per kW ($/kW) of reduction.

The achievable potential and the corresponding budget are estimated for various incentive levels including current incentive levels, 5 % increase, 10 % increase, 20 % increase, and 40 % increase, as given in Figure 1-9, where the horizontal axis represents the total estimated achievable potential in kW up to the year 2023, while, the vertical axis represents the total budget provided in the form of incentives for participants up to year 2023. The curve, presented in Figure 1-9, shows each measure as a step in the curve, with the horizontal length of each step indicating the achievable potential of the measure, and its height above the horizontal axis indicates the corresponding incentive costs ($).

The avoided costs (avoided energy costs and avoided capacity costs) are estimated for different scenarios to determine the savings the utility would have if it deferred building the plant.

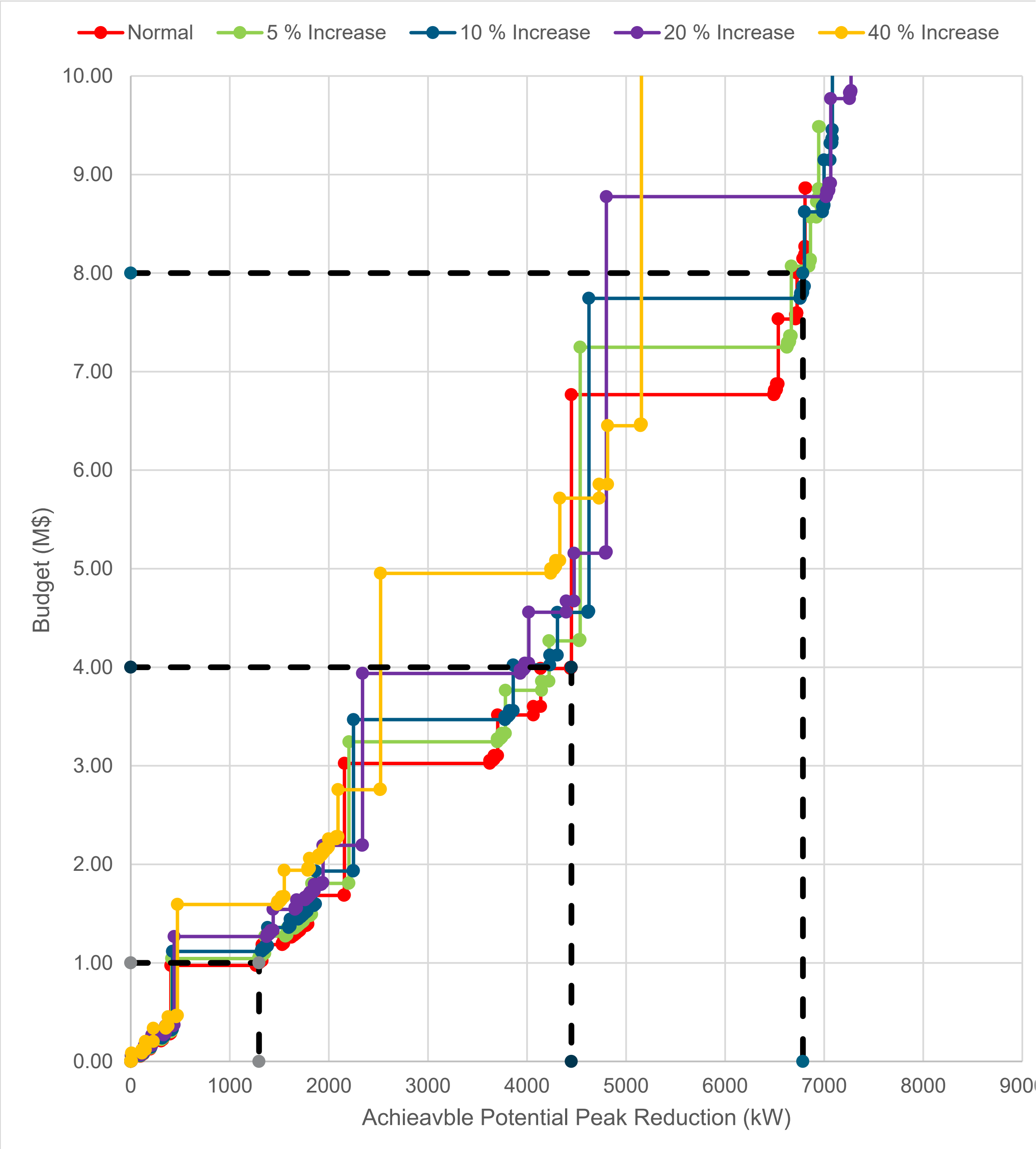

Figure 1-9 Achievable potential up to the year 2023 versus budget for various incentive levels

1.1. Conclusions and Recommendations

The analysis reveals the following:

- For the residential sector, the achievable potential at the current incentive levels provided by IESO is estimated at 481.95 kW. Increasing the incentive levels by 40 % is estimated to increase the peak reduction between 529.86 – 539.88 kW.
- For the commercial sector, the achievable potential at the current incentive levels is estimated at 5972.96 kW. Increasing the incentive levels by 40 % is estimated to increase the peak reduction between 6990.75 – 7071.98 kW.
- For DERs, the achievable potential at the incentive levels recommended in this study is estimated at 360.3 kW. Increasing the incentive levels by 40 % is estimated to increase the peak reduction between 396.33– 403.82 kW.
- For commercial-scale battery storage, the required incentive levels are estimated between $ 4432-5791 per kW of peak reduction.
- For utility-scale energy storage, the budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW.
- For residential and commercial PV rooftop, the incentives per installed kW are 1140.76 $/kW and 2200 $/kW. This incentive level would provide the minimum attractive rate of return of 7%.
- The maximum achievable peak demand reduction is estimated at 6,814.95 kW (6.81 MW) for an incremental budget of C$ 8,862,912 (excluding program administrative cost). It is worth noting that higher achievable potential is reachable with the consideration of utility-scale energy storage. The budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW.
- The desired peak demand reduction, which represents the gap between the existing summer peak and 2023 forecasted peak is 18.5 MW and 26.5 MW for median and extreme weather conditions forecast, which cannot be achievable from the CDM program.
- The certainty of some load growth, such as (Broccolini Business Park) and (550 Innovation (Ciena)) should be checked annually due to their high required demand, and their exclusion would reduce the gap significantly.
- In addition to serving load growth in the Kanata area, the newly planned transformer station will improve system reliability and availability by providing backup service for other stations in the area such as Terry Fox TMS station.
- The higher achievable potential is reachable with the consideration of utility-scale energy storage. The budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW.
- The avoided costs for budget scenario 3 (C$ 8,000,000) is estimated at C$ 5,075,557.41, in addition to C$ 1,144,000 (transmission capacity cost) for each deferral year and C$ 160,000 (distribution capacity cost) for each deferral year.

1.2. Lessons Learned

The lessons learned from this study are summarized as follows:

- Data collection took a substantial amount of time and effort. In the future, it is recommended to allocate more time in the schedule for the same as part of Milestone 1. A dedicated point of contact for data collection in the Hydro Ottawa aided greatly in the data collection effort.
- The addition of a few more stations would be beneficial (as data collection time and effort would not increase substantially). As such, more detailed study could be performed in a cost-effective manner.
- It would be preferable to cast a wider net and spend more time on understanding the different CDM measures that could pave a path to understand new technologies. Additional time in the schedule of future studies should be allocated for this activity.
- A future APS study, may entail analysis of sensitivity scenarios that would evaluate the impact of EV and electrification, multiple penetration levels of EV & electrifications could be considered in the analysis (business as usual, moderate, and aggressive (green) scenario)
- Development of a load research focus group within the HOL would help collect and analyze data related to end use behaviour within each sector and sub-sector served by HOL. This is particularly important as the energy use pattern may change significantly over the next decade. The group can collect data via surveys, interviews, market research, and direct load measurements for selected representative samples.

2. Introduction

The achievable potential study is required through a direction from Ontario's Minister of Energy. The IESO is required to coordinate, support, and fund the delivery of conservation and demand management (CDM) programs by HOL to determine the possible potential solutions to lower the summer peak demand in the Kanata-Marchwood area.

The achievable potential of peak load reduction would allow for more efficient use of existing facilities and infrastructure and differ or eliminate the need for a new transformer station. Based on the HOL plan, the new station (new Kanata North) is planned to be in service in 2028. Therefore, the presented study focuses on the short-term technical potential scenarios that may differ or eliminate the need for the new station.

The required local achievable potential study (L-APS) focuses on the non-wires options for load growth reduction at the Kanata North area. The Kanata North area includes a combination of the residential and commercial load with a large business park area supplied from Kanata MTS and Marchwood MTS. The methodology of the L-APS develops unique energy use profiles to reflect the composition of the Kanata North area load. The objective of this study is conducted through the following milestones:

a) Milestone 1: the aim of this stage is to determine the local load characterization for Kanata and Marchwood
b) Milestone 2: the main target of this milestone is to identify the technically feasible measures for addressing local area needs
c) Milestone 3: this milestone provides a market analysis of feasible measure through the development of adoption and cost curves
d) Milestone 4: this milestone is covering the development of updateable Excel model to assess CDM and DER options for addressing local needs

This remainder of this report is organized as follows: Section 3 describes the determination of the local load characterization for the Kanata North area served by Kanata and Marchwood MTS. Based on the load characterization, the technically feasible measures are developed in Section 4. The market analysis and achievable potential of the identified technically feasible measures are determined in Section 5. Finally, a comprehensive evaluation is conducted in Section 6 to assess the impact of incentives on the achievable potential and to determine the combinations of CDM and DERs measures providing maximum savings for a given avoided costs and incentive levels.

3. Local Load Characterization

The local load characterization for the Kanata North area served by Kanata and Marchwood MTS is presented in this section.

The sector and subsector energy load profiles for the Kanata North area, which serves prominently residential and commercial/ sectors, were evaluated. For each sector, the energy share distributions were estimated, and then each sector was segmented by subsectors (i.e., building type). Also, the end-use profiles for each sector were calculated. The end-use profiles from the IESO's recent achievable potential studies, as well as NRCAN residential and commercial end-use surveys, were used to develop the end-use profiles.

The total actual annual consumptions for Kanata and Marchwood MTS was compared to the total consumptions determined from the bottom-up analysis to calculate the calibration factor. After performing the calibration, the annual consumption for each feeder was obtained by calibrating the feeder's consumption obtained from the analysis.

3.1. Methodology

The segmentation of Kanata North area customers by sector, by subsector, and by end-use were carried out following the method presented in [1], [2]. Then, the calibration of the obtained profile to changes in sales and customer forecasts is performed.

The energy share distributions for the residential and commercial/institutional sectors are determined, and then each sector is segmented by subsectors (i.e., building type). This classification is aligned with the IESO's End-Use Forecasting (EUF) model for planning purposes.

End-use profiles are developed for each sector, End-use profiles from the IESO's recent achievable potential studies [2] as well as NRCAN residential and commercial end-use surveys are used to develop the end-use profiles for this study.

The total reported (actual) annual consumptions for Kanata and Marchwood MTS are compared with the total consumptions determined from the bottom-up analysis to determine the gap and to calculate the calibration factor. After performing the calibration, the annual consumption for each feeder is obtained by calibrating the feeder's consumption obtained from the analysis.

HOL declared that no fuel switching or change in load profile is anticipated or forecasted. The findings of the Hemson study [3], the official community plan for Kanata North [4], and NRCAN surveys were used to develop the load forecast over the study period.

For Distributed Energy Resources, HOL and IESO provided the complete list of existing DERs, the total contract capacity of the DERs at Kanata-Marchwood area, and the forecasted effective capacities of the DERs and the CDM.

3.2. Load Segmentation for Base Year and Reference Case Forecast

3.2.1. Kanata MTS Load Segmentation for Base Year (2018) by Sector/ Subsector

The methodology presented in section 3.1 is applied to Kanata premises that consist of five feeders named 624F1, 624F2, 624F3, 624F5, 624F6. This section shows the analysis performed for the five feeders shown in Figure 3-1. These feeders' service areas are covering residential and commercial loads, as well as one large industrial load located at feeder 624F2.

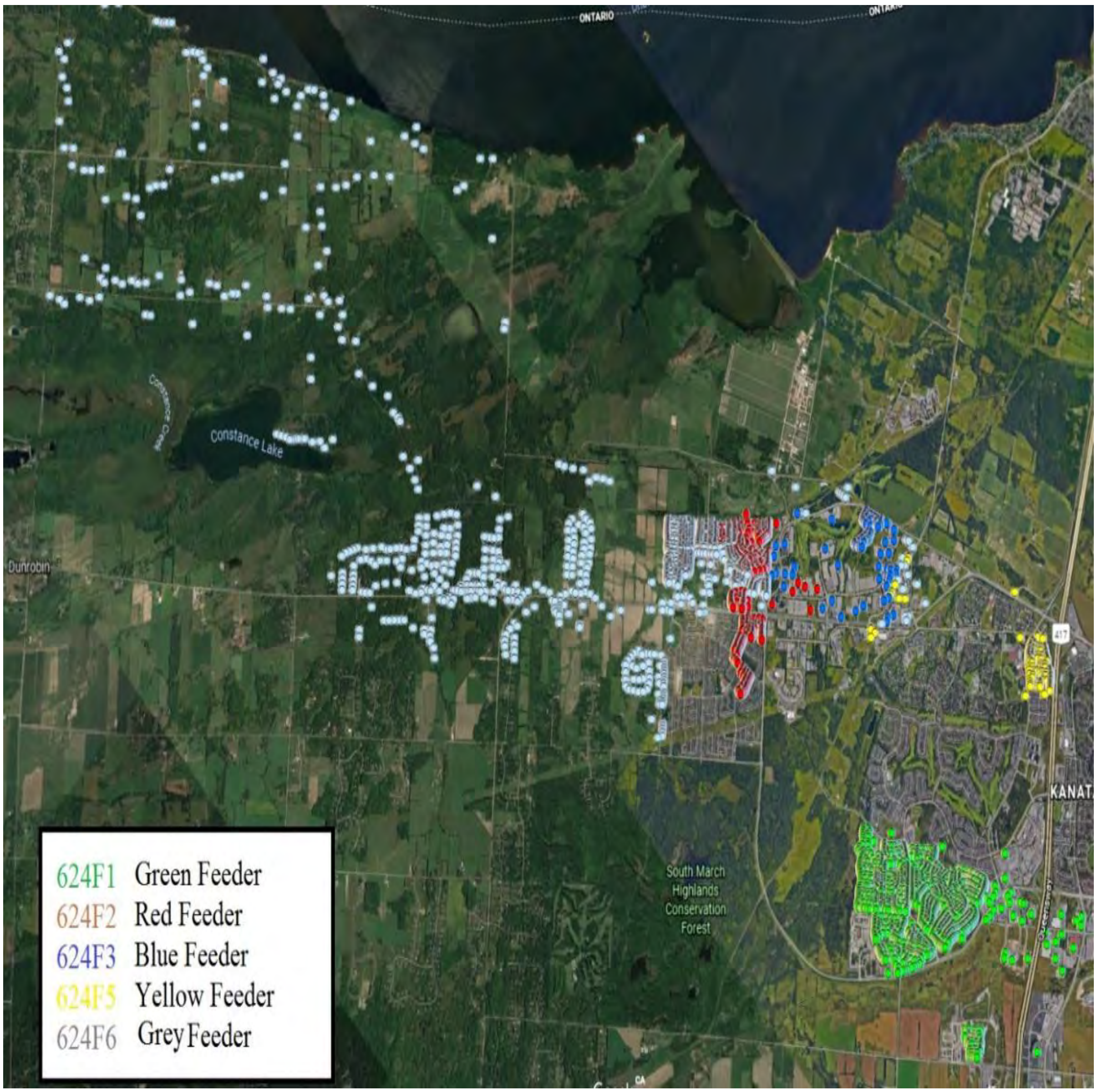

Figure 3-1 Kanata MTS service area

3.2.1.1. Kanata MTS Residential Load Segmentation

The residential sector buildings are subdivided to four subsectors based on the definition presented in Table A-1 in Appendix A, the number of residential buildings in each subsector is counted using Google Earth [5] files provided by HOL and adjusted using the total residential building number provided by HOL; Table 3-1 summarizes the number of buildings in each subsector for each of the five feeders.

Table 3-1 Residential Subsectors Premises, Kanata MTS

Residential building type	Single-family	ROW	Low rise	High rise	Total
Number of units / Subsector for feeder 624F1	1596	924	192	0	2712
Number of units / Subsector for feeder 624F2	458	387	0	0	845
Number of units / Subsector for feeder 624F3	111	169	94	194	568
Number of units / Subsector for feeder 624F5	22	81	0	0	103
Number of units / Subsector for feeder 624F6	652	945	0	0	1597
Number of units / Subsector for Kanata MTS	2839	2506	286	194	5825

The NRCAN residential building (SHEU) database [6] is used to determine the energy intensity per premise; Table 3-2 summarises the energy intensities for all residential subsectors in Ontario. The methodology discussed in section 3.1 is applied, and the total annual energy, annual electricity consumption, and the annual Natural gas consumption for each subsector are obtained. Then, the average estimated kWh per residential customer is calculated using the total residential consumption and the total number of residential buildings; the average estimated kWh per customer for Kanata MTS is 7,732 kWh which is close to the actual kWh per residential customer reported in the OEB yearbook [7] (i.e., 7,537 kWh). Thus, no calibration is needed. A summary of the total residential consumption for the Kanata MTS service area is presented in Table 3-3.

Table 3-2 Residential Subsectors Energy Intensity [6]

Residential building type	Single-family	ROW	Low rise	High rise
Annual Total Energy intensity (eMWh/household)	38.75	26.55	8.18	9.58
Annual Electricity intensity (MWH/household)	9.65	6.09	4.81	5.12

Table 3-3 Total Residential Subsectors Energy Consumptions for Kanata MTS

Residential building type	Single Family	ROW	Low Rise	High Rise	Total
Annual Electricity consumptions (MWh)	27,404	15,264	1,376	993	45,037
Total Annual Energy consumptions (eMWh)	109,999	66,546	2,338	1,858	180,741

3.2.1.2. Kanata MTS Commercial Load Segmentation

The commercial sector buildings are subdivided to subsectors based on the definition presented in Table A-2 in Appendix A. Dun & Bradstreet database [8], MPAC database [9], and Google Earth files are used to determine the number, area, and activity of all commercial buildings located at each of the five feeders of Kanata MTS. The energy intensities for all commercial subsectors are obtained using the NRCAN commercial building SCIEU database [10]. The methodology discussed in section 3.1 is applied, and the total annual energy, annual electricity consumption, and the annual Natural gas consumption for each commercial subsector are obtained; a summary of the total commercial consumption for Kanata MTS service area is presented in Table 3-4.

Table 3-4 Commercial Subsectors Energy Consumption, Kanata MTS

Commercial Subsector	Annual Electricity Consumption (MWh)
Office buildings (non-medical)	90,018
Medical office buildings	3,135
Elementary and/or secondary schools	1,416
Assisted daily/residential care facilities	1,197
Warehouses Wholesale	5,106
Hotels, motels or lodges	3,003
Hospitals	0
Food and beverage stores	13,653
Non-food retail stores	11,414
Other activity or function	5,282

3.2.2. Marchwood MTS Load Segmentation for Base Year (2018) by Sector/ Subsector

The methodology discussed in section 3.1 is applied to Marchwood premises that consist of four feeders named MWDF1, MWDF2, MWDF3, and MWDF4. This section presents the analysis performed for the four feeders shown in Figure 3-2. These feeders' service areas are covering different residential and commercial loads.

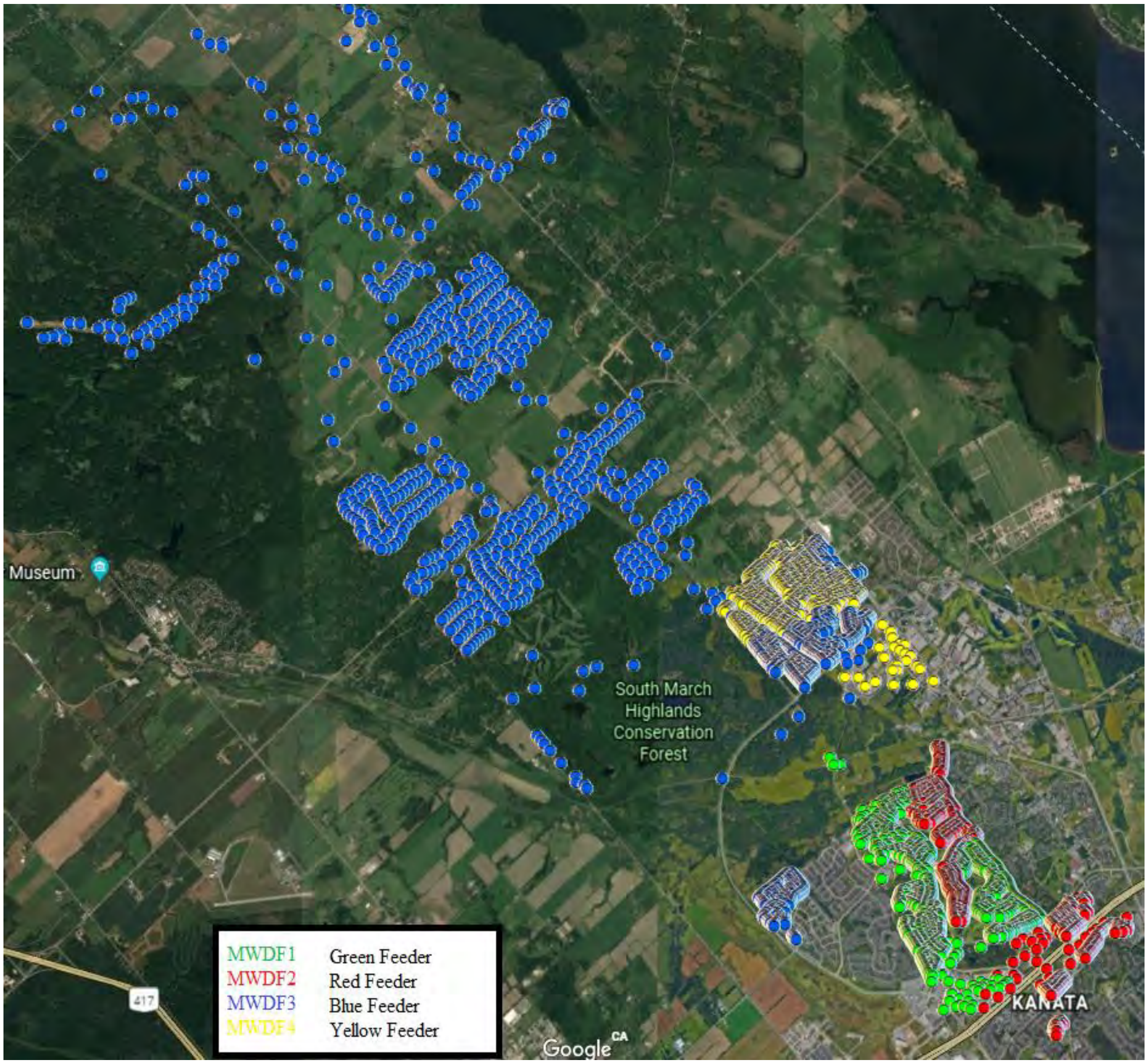

Figure 3-2 Marchwood MTS service area

3.2.2.1. Marchwood MTS Residential Load Segmentation

The residential sector buildings are subdivided into four subsectors, and the number of residential buildings in each subsector is counted using Google Earth files provided by HOL; Table 3-5 summarizes the number of buildings in each subsector for each of the four feeders.

Table 3-5 Residential Subsectors Premises, Marchwood MTS

Residential Building Type	Single-Family	ROW	Low Rise	High Rise	Total
Number of premises / subsector for feeder MWDF1	1076	649	62	0	1787
Number of premises / subsector for feeder MWDF 2	584	696	0	739	2019
Number of premises / subsector for feeder MWDF3	1435	889	86	0	2410
Number of premises / subsector for feeder MWDF4	1192	348	0	0	1540
Number of premises / subsector for Marchwood MTS	4287	2582	148	739	7756

The NRCAN residential building (SCEU) database is used to determine the energy intensity per premise, as summarized in Table 3-2. The total annual energy, annual electricity consumption, and the annual Natural gas consumption for each subsector are obtained. Then, the average estimated kWh per residential customer is calculated using the total residential consumption and the total number of residential buildings; the average estimated kWh per customer for Kanata MTS is 7,802 kWh which is very close to the actual kWh per residential customer reported in the OEB yearbook (i.e., 7,537 kWh). Thus, no adjustment for the used EUIs needed. A summary of the total residential consumption for the Marchwood MTS service area is presented in Table 3-6.

Table 3-6 Total Residential Subsectors Energy Consumptions for Marchwood MTS

Residential Building Type	Single-Family	ROW	Low Rise	High Rise	Total
Annual electricity consumptions (MWh)	41,381	15,726	712	3,783	41,381
Total annual energy consumptions (eMWh)	166,103	68,564	1,210	7,076	166,103

3.2.2.2. Marchwood MTS Commercial Load Segmentation

Dun & Bradstreet database, MPAC database, and Google Earth files are used to determine the number, area, and activity of all commercial buildings located at each of the four feeders of Marchwood MTS. The energy intensities for all commercial subsectors are obtained using the NRCAN commercial building SCIEU database. The methodology described in section 3.1 is applied, and the total annual energy, annual electricity consumption, and the annual Natural gas consumption for each commercial subsector are obtained; a summary of the total commercial consumption for the Marchwood MTS service area is presented in Table 3-7.

Table 3-7 Commercial Subsectors Energy Consumption, Marchwood MTS

Commercial Subsector	Annual Electricity Consumption (MWh)
Office buildings (non-medical)	31,555
Medical office buildings	2,475
Elementary and/or secondary schools	3,477
Assisted daily/residential care facilities	3,818
Warehouses Wholesale	1,498
Hotels, motels or lodges	3,205
Hospitals	0
Food and beverage stores	12,607
Non-food retail stores	13,690
Other activity or function	3,766

3.2.3. Calibrated Load Segmentation for Base Year

The calibration methodology described in section 3.1.3 is applied to determine the calibration factor for each sector. The actual annual consumption for Kanata and Marchwood MTS is obtained using the data provided by HOL; this consumption is reduced by a factor of 17 % to represent the share of street lighting and a factor of 3 % to account for the system losses (obtained from 2017 OEB Yearbook [5]) as shown in Tables 3-8 and 3-9.

Table 3-8 Actual and estimated consumptions for Kanata MTS

Kanata		Consumptions (kWh)
Actual consumptions	with street lighting	321,700,199
	without street lighting	267,011,165
	without street lighting & losses	259,000,830
Estimated consumptions	Residential	45,036,520
	Commercial	189,328,355
	Industrial	3,150,000
	Total	237,514,875
Gap		-21,485,955

Table 3-9 Actual and estimated consumptions for Marchwood MTS

Marchwood		Consumptions (kWh)
Actual consumptions	with street lighting	178,540,075
	without street lighting	148,188,262
	without street lighting & losses	143,742,614
Estimated consumptions	Residential	63,520,491
	Commercial	85,020,705
	Industrial	0
	Total	148,541,196
Gap		4,798,582

The reported metered KWh for residential customers is compared to the bottom-up estimation, and the results are closely matched. Thus, the estimated annual consumption for the residential sector is kept without calibration. Then, the calibration factor is calculated for the commercial and industrial sectors, as the ratio between the total actual annual consumption for commercial and industrial sectors divided by the total bottom-up estimated annual consumption for commercial and industrial sectors (Table 3-10).

Table 3-10 Calibration Factor Calculation

	Kanata	Marchwood	Sum	Sum of commercial and Industrial
Total actual (kWh)	259,000,830	143,742,614	402,743,445	294,186,433
Total estimated (kWh)	237,514,875	148,541,196	386,056,071	277,499,060
Calibration Factor	= (294,186,433 / 277,499,060) =1.06			

3.2.3.1. Calibrated Load Segmentation by Sector/Sub-sector

The obtained calibration factor is used to modify the estimated consumption for each feeder; i.e., the calibration factor is multiplied times the bottom-up estimation of each feeder to determine a bottom-up estimation that is matching the actual annual consumptions. Tables 3-11 and 3-12 show the total estimated electrical consumptions (after calibration) for Kanata and Marchwood, respectively.

Table 3-11 Estimated consumptions (kWh) for Kanata MTS after calibration

Kanata	624F1	624F2	624F3	624F5	624F6	Total
Residential	21,957,355	6,777,998	3,546,205	705,710	12,049,252	45,036,520
Commercial	35,437,231	52,884,403	7,694,143	75,889,460	28,808,356	200,713,593
Industrial	0	3,339,425	0	0	0	3,339,425
Total	57,394,587	63,001,826	11,240,347	76,595,170	40,857,608	249,089,538

Table 3-12 Estimated consumptions (kWh) for Marchwood MTS after calibration

Marchwood	MWDF1	MWDF2	MWDF3	MWDF4	Total
Residential	16,556,027	13,659,061	19,679,985	13,625,418	63,520,491
Commercial	31,584,597	20,260,960	10,979,980	27,307,879	90,133,415
Industrial	0	0	0	0	0
Total	48,140,624	33,920,021	30,659,965	40,933,296	153,653,906

3.2.4. End-Use Load Segmentation for Base Year

3.2.4.1. Kanata End-Use Segmentation

Based on the end-uses profiles provided by IESO for the residential and commercial sectors, the end-use load segmentation was developed. The end-use classification was performed using the calibrated annual consumption of the loads.

The end-use segmentations for Kanata MTS are developed for the residential sector and subsectors. Kanata residential and commercial end-use segmentation for the residential sector is presented in Figure 3-3 and Figure 3-4, respectively.

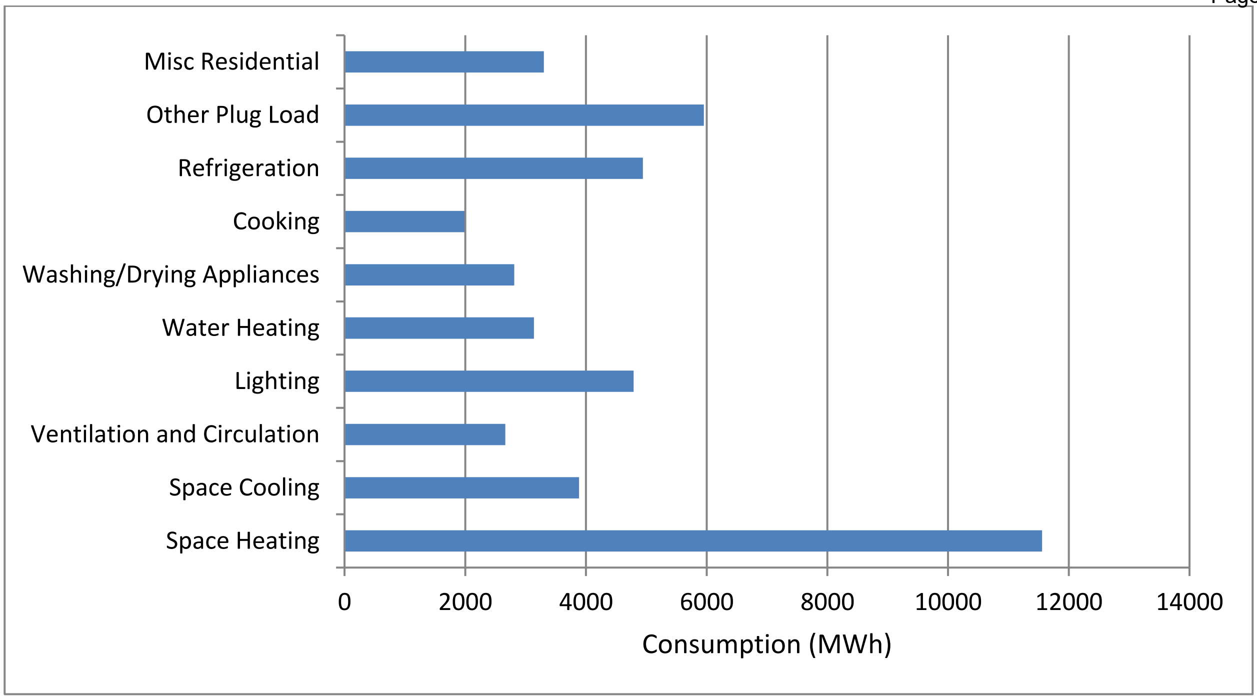

Figure 3-3 End-use Segmentation for Residential Sector, Kanata MTS

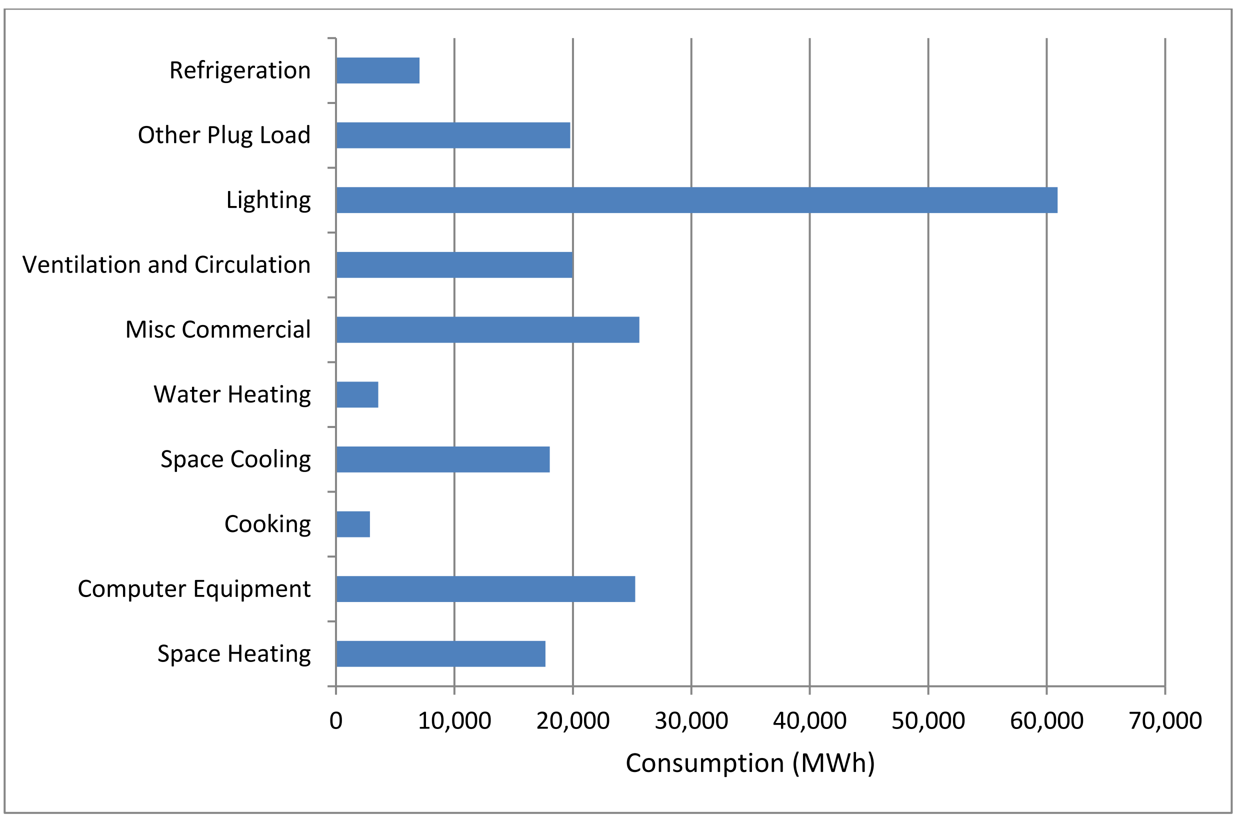

Figure 3-4 End-use Segmentation for Commercial Sector, Kanata MTS

3.2.4.2. Marchwood MTS End-Use Load Segmentation

The end-use segmentations for Marchwood MTS are developed for the residential and commercial sector and subsectors. The residential and commercial end-use segmentation is presented in Figure 3-5 and Figure 3-6.

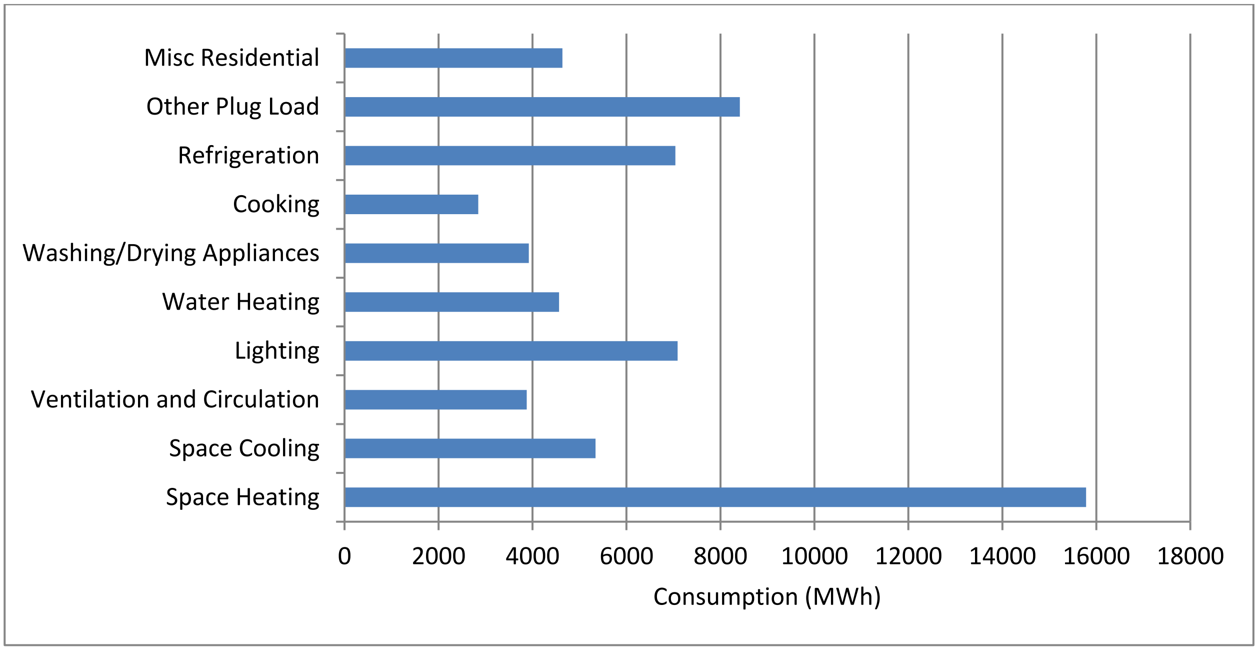

Figure 3-5 End-use Segmentation for Residential Sector, Marchwood MTS

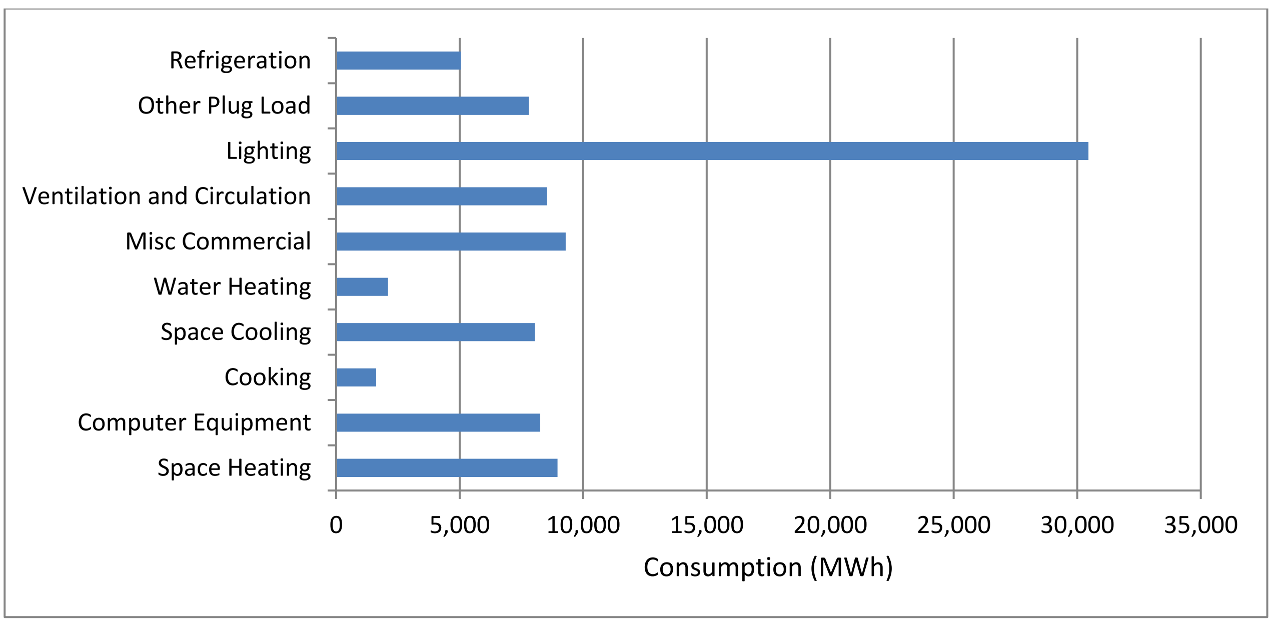

Figure 3-6 End-use Segmentation for Commercial Sector, Marchwood MTS

3.2.5. Reference Case Forecast: 2019- 2040

3.2.5.1. Residential Forecast

The NRCAN historical data for the number of residential buildings and energy intensity was used to develop a residential load forecast. The official community plan for Kanata North shows that the potential distribution for residential units over the planning period (i.e., 2018 to 20131) is as shown in Table 3-13. The official residential building plan for Kanata North was used to calibrate the residential building forecast.

Table 3-13 Potential Unit Distribution for Kanata North [4]

Unit Type	Potential Unit Distribution
Single Detached	960 Units
Apartments	527 Units
Street Townhouses and other ground-oriented multiple dwelling	1477 Units

Based on the base year residential demand, the calibrated forecasts of residential buildings number, and the forecasted energy intensities, the residential forecast for Kanata and Marchwood MTS are obtained. Moreover, the residential subsectors consumptions for the base year are compared to the short-term forecasted consumptions (i.e., 2023) and the long-term forecasted consumptions (i.e., 2040). The comparison results are presented in Figures 3-7 and 3-8 for Kanata and Marchwood MTS, respectively. Furthermore, the end-use residential forecasts for Kanata and Marchwood MTS are developed, as shown in Figures 3-9 and 3-10, respectively.

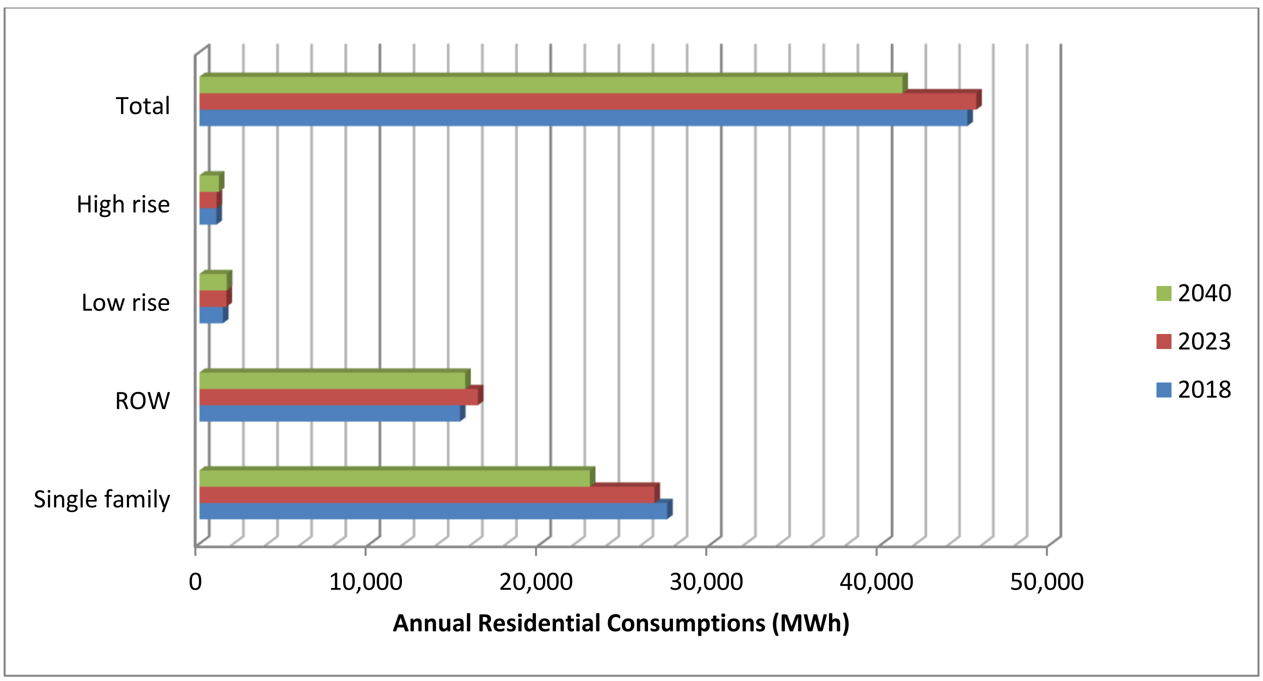

Figure 3-7 Residential sector load forecast, Kanata MTS

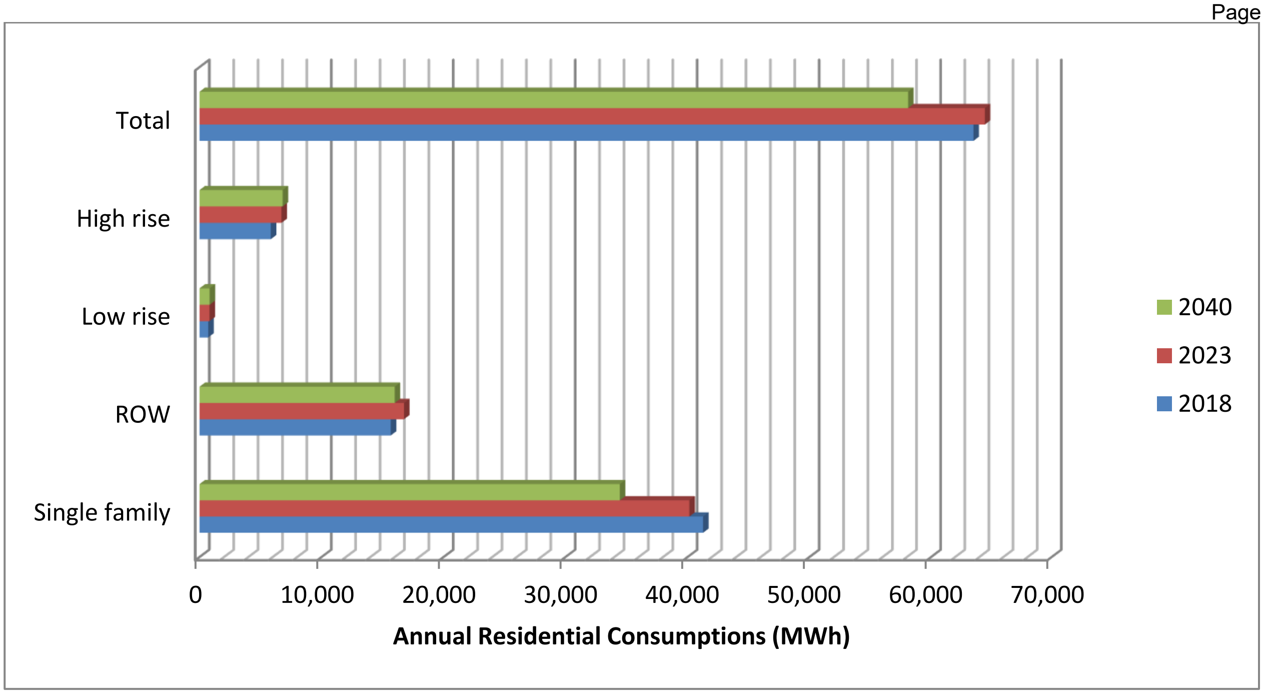

Figure 3-8 Residential sector load forecast, Marchwood MTS

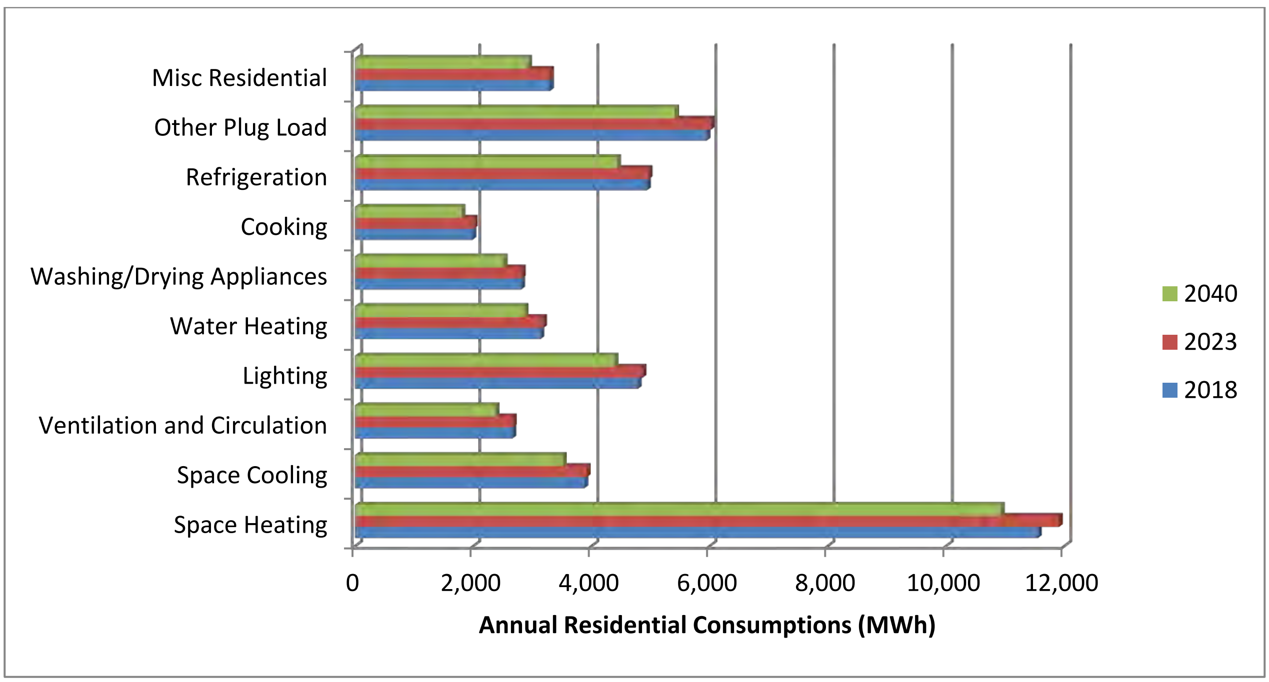

Figure 3-9 Residential load forecast by end-use, Kanata MTS

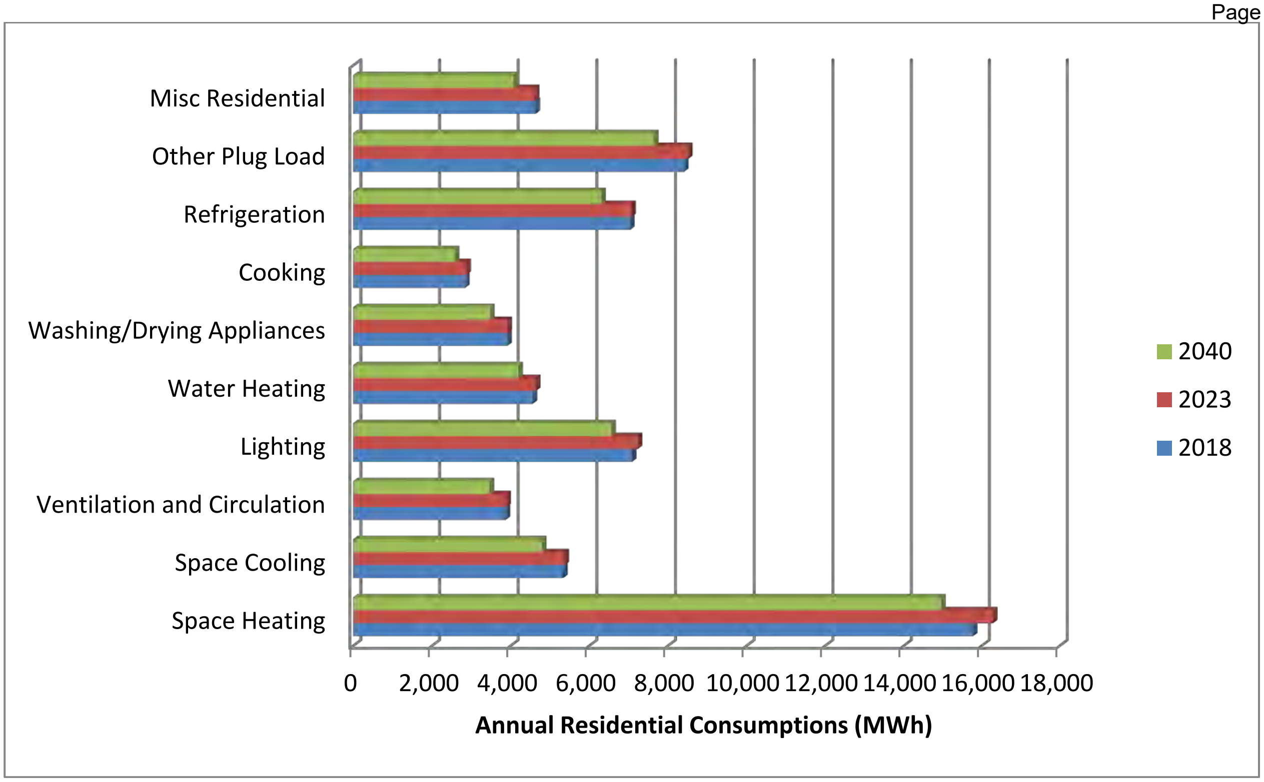

Figure 3-10 Residential load forecast by end-use, Marchwood MTS

3.2.5.2. Commercial Forecast

The forecast of the square footage of the commercial subsectors at Kanata and Marchwood MTS was developed using the base-year commercial sector estimation as well as the Hemson study provided by IESO. The forecast for the energy intensity for each commercial subsector was constructed based on NRCAN historical energy intensities for commercial subsectors.

The commercial forecast for Kanata and Marchwood MTS was carried out based on the base year commercial load consumption, the area forecast of commercial subsectors, and the forecasted energy intensities for commercial subsectors. Moreover, the commercial subsectors consumptions for the base year are compared to the short-term forecasted consumptions (i.e., 2023) and the long-term forecasted consumptions (i.e., 2040). The comparison results are presented in Figures 3-11 and 3-12 for Kanata and Marchwood MTS, respectively. Furthermore, the end-use residential forecasts for Kanata and Marchwood MTS were developed and shown in Figures 3-13 and 3-14, respectively.

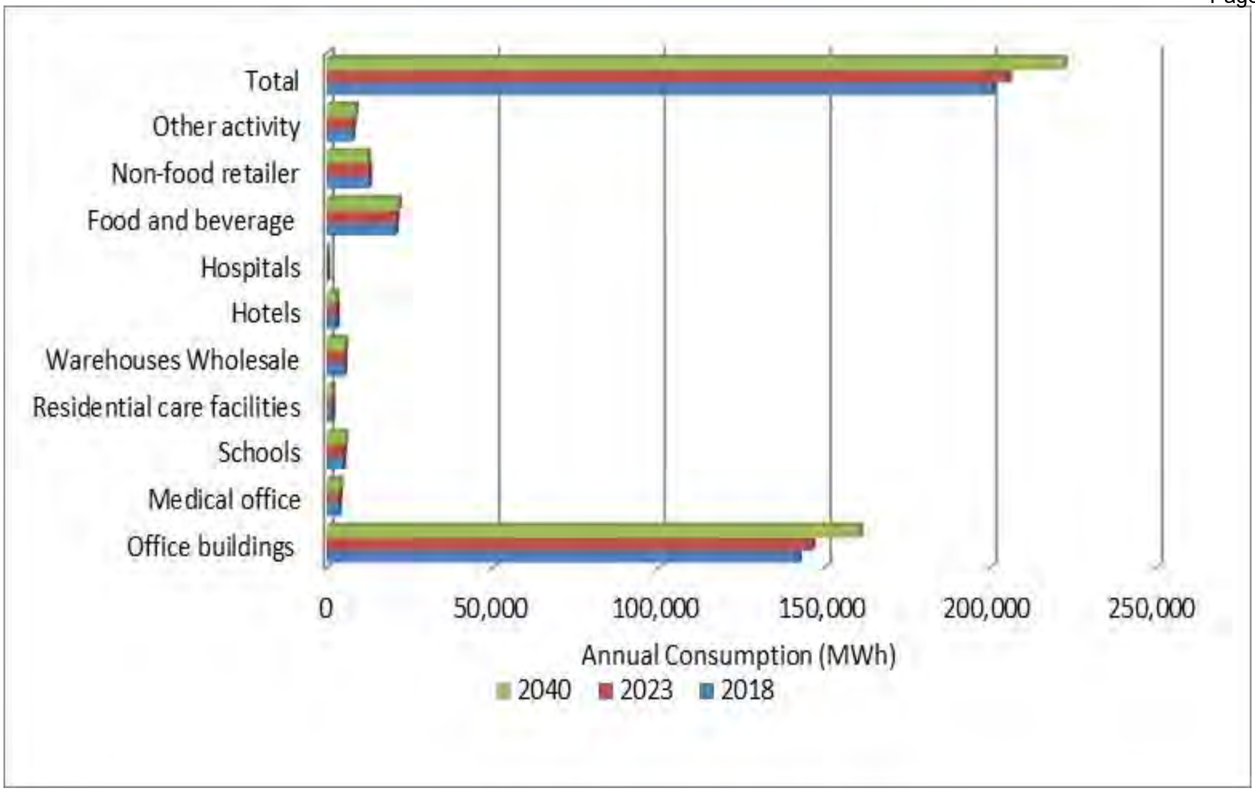

Figure 3-11 Commercial sector load forecast, Kanata MTS

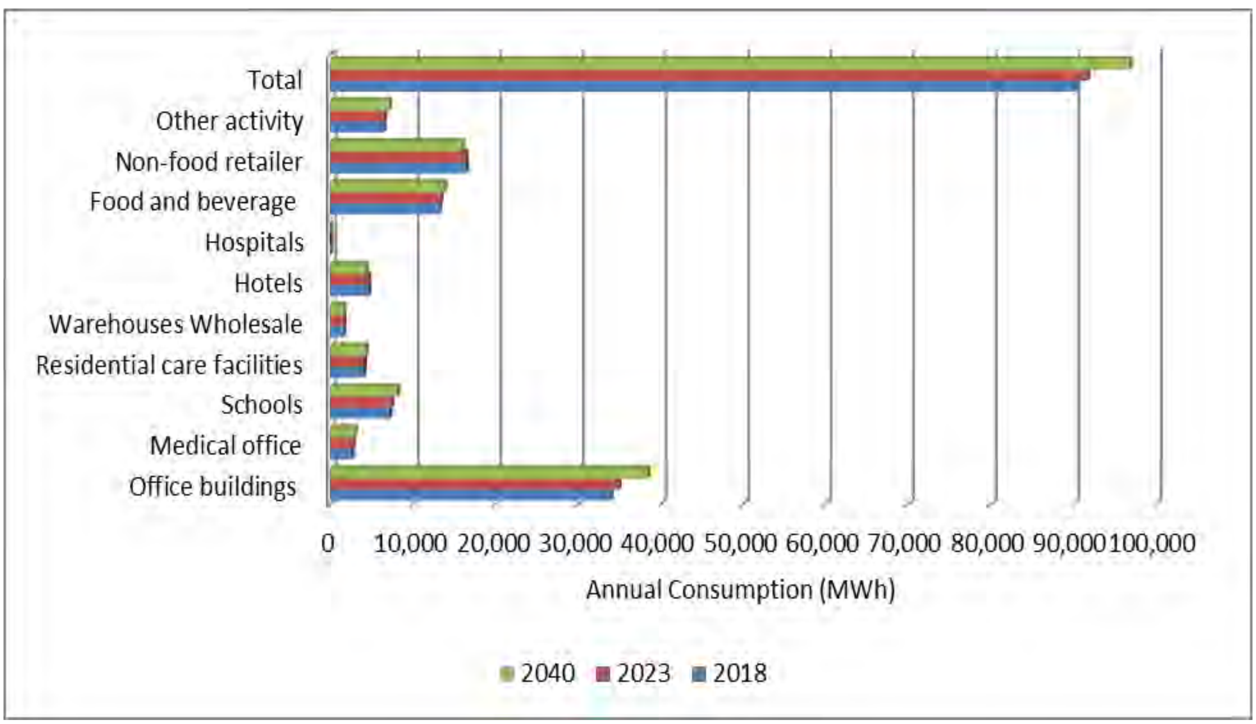

Figure 3-12 Commercial sector load forecast, Marchwood MTS

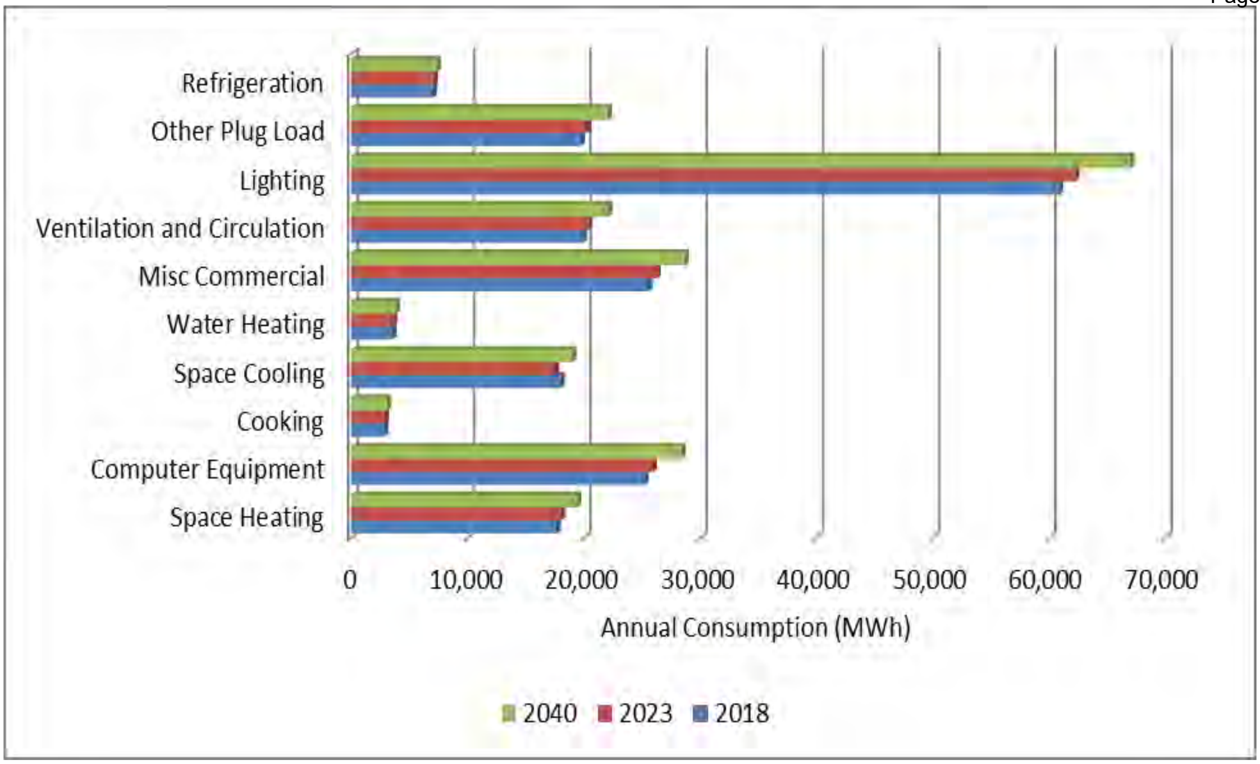

Figure 3-13 Commercial sector load forecast by end-use, Kanata MTS

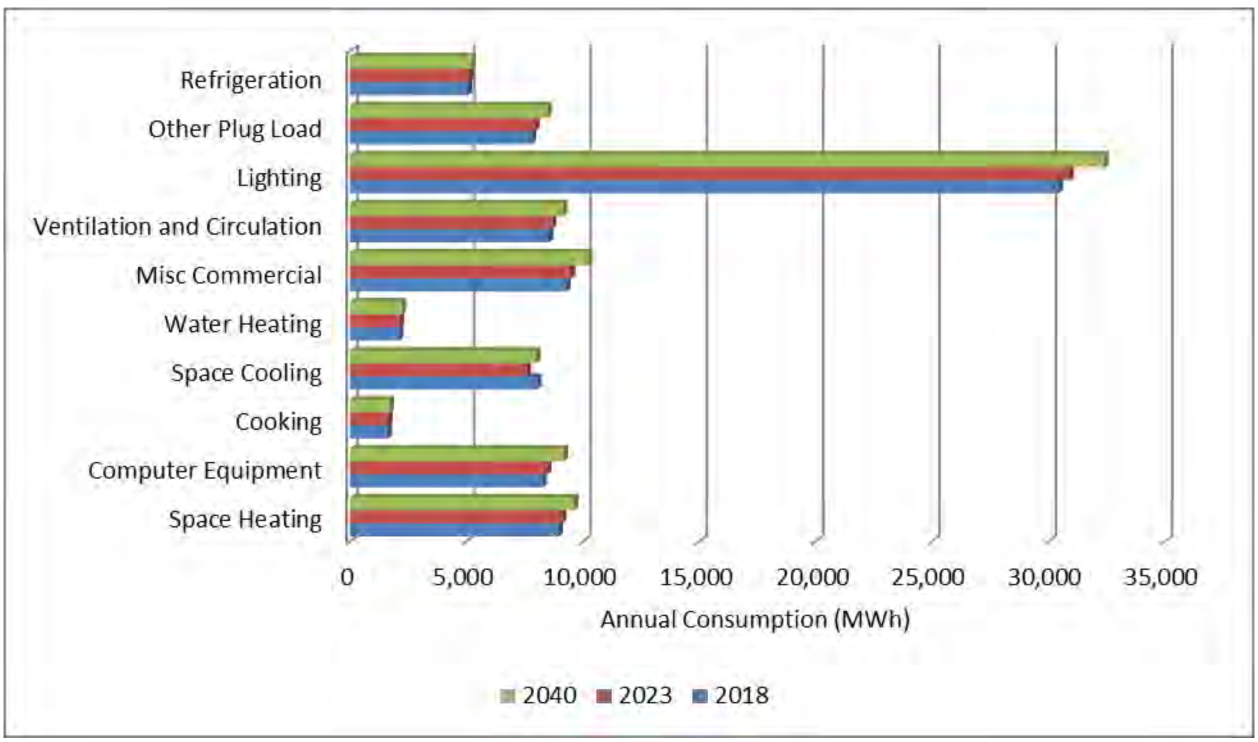

Figure 3-14 Commercial load forecast by end-use, Marchwood MTS

3.2.5.3. Aggregated Forecast

The aggregated commercial and residential forecast of the Kanata-Marchwood area is calculated and illustrated in Figure 3-15. When compared to the base year of 2018, the total aggregated load forecast for 2040 estimates an overall increase in electricity consumption of 4% from 402,743 MWh in 2018 to 418,971 MWh in 2040. The commercial section is expected to provide the most significant increase in electricity use, rising from 290,847 MWh in 2018 to 319,038 MWh (9.7 % increase). The residential sector electricity consumption is expected to show a decrease from 108,557 MWh in 2018 to 99,309 MWh in 2040 (8.51 % decrease). The industrial forecast is assumed to be constant over the forecasting period as one industrial building only exists at Kanata-Marchwood area.

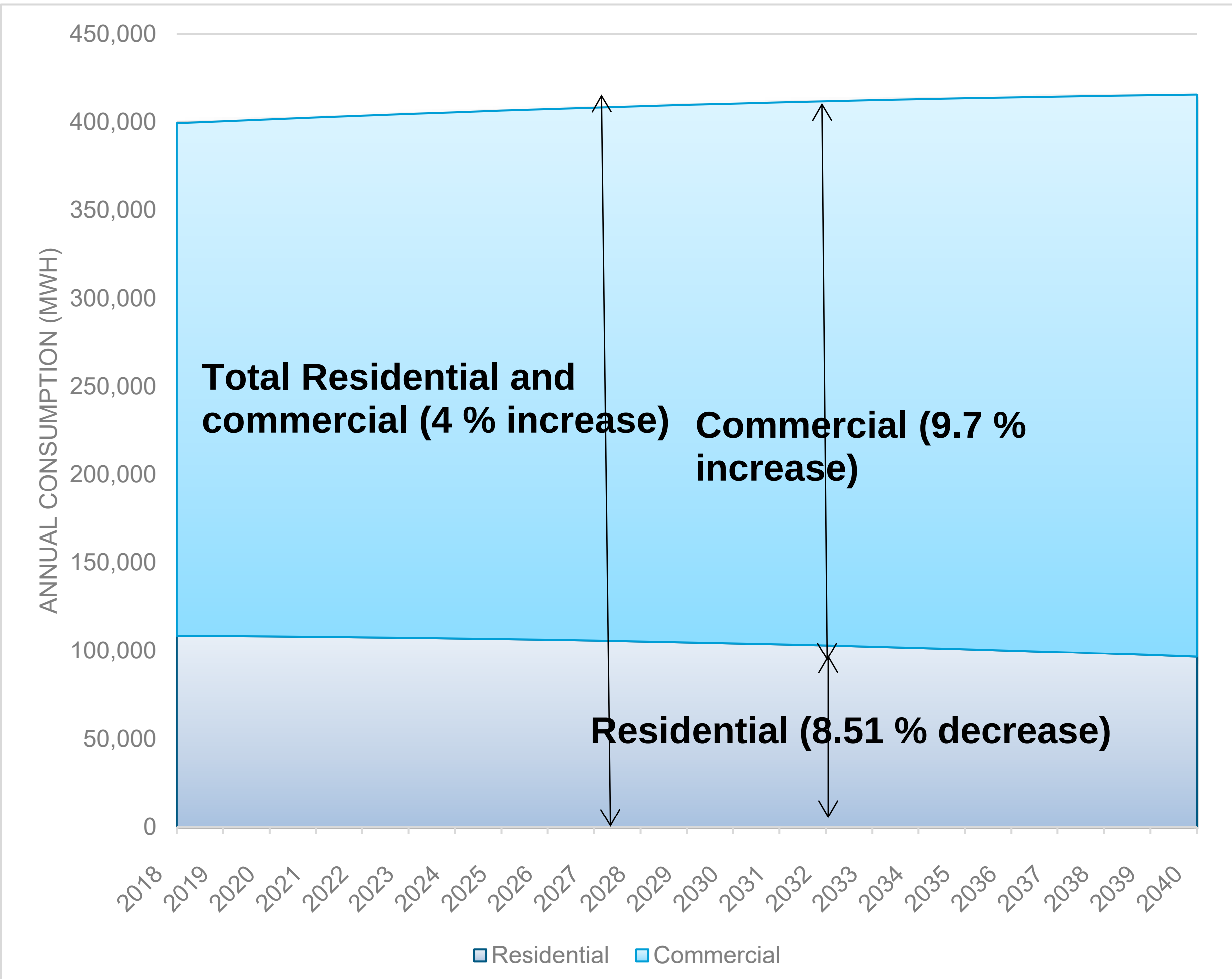

Figure 3-15 Kanata-Marchwood forecast (2018-2040) by sector

3.2.6. Participation in CDM and DER Programs

The historical participation of the loads in the CDM programs and the existing DERs, as well as the potential for expansion, were provided by HOL. The complete list of existing DERs at the Kanata-Marchwood area is presented in Table 3-14. Moreover, the total contract capacity of the DERs at Kanata-Marchwood area is presented in Table 3-15. The forecasted effective capacities of the DERs and the CDM are presented in Tables 3-16 and 3-17, respectively.

Table 3-14 Existing Energy Resources Facilities at Kanata-Marchwood

Station	Feeder	Capacity (KW)	Fuel Type
Kanata MTS	624F1	400	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	2.5	Solar PV
Kanata MTS	624F1	500	Solar PV
Kanata MTS	624F1	8	Solar PV
Kanata MTS	624F5	250	Solar PV
Kanata MTS	624F1	40	Solar PV
Kanata MTS	624F2	5120	Battery
Marchwood MTS	MWDF1	10	Solar PV
Marchwood MTS	MWDF2	250	Solar PV
Marchwood MTS	MWDF3	65	Solar PV
Marchwood MTS	MWDF1	250	Solar PV
Marchwood MTS	MWDF1	150	Solar PV
Marchwood MTS	MWDF3	297	Solar PV
Marchwood MTS	MWDF2	150	Solar PV
Marchwood MTS	MWDF3	10	Solar PV
Marchwood MTS	MWDF3	100	Solar
Marchwood MTS	MWDF4	990	Battery

Table 3-15 DERs Contract Capacity at Kanata-Marchwood

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capacity connected to Marchwood MTS (MW)	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Capacity connected to Kanata MTS (MW)	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94

Table 3-16 DERs Effective Capacity at Kanata-Marchwood

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capacity connected to Marchwood MTS (MW)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Capacity connected to Kanata MTS (MW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3

Table 3-17 CDM Effective Capacity at Kanata-Marchwood

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
CDM Effective Capacity Reduction Marchwood MTS (MW)	1.8	2.3	2.6	2.3	2.4	2.6	2.9	3.4	3.8	4.3
CDM Effective Capacity Reduction Kanata MTS	2.3	2.7	3.1	3.2	3.2	3.4	3.9	4.2	4.8	5.4

3.3. Findings and Observations

- The largest decrease in electricity consumption in the residential sector is expected to occur in the single-family subsector (16.25% decrease from 2018 to 2040).
- The electricity consumption of the ROW subsector is expected to increase up to the year 2026 (7 % increase from 2018 to 2026), and then the ROW consumption will fall for the remaining forecasted years (4.67% decrease from 2018 to 2040).
- The electricity consumption of low-rise and high-rise subsectors is expected to increase over the forecasted period (16.67% increase for low-rise and high-rise)
- At the end-use level, all residential end-use items are expected to decrease in electricity use.
- Increased electricity usage is expected for all commercial subsectors, except for non-food retailers and hotels that are expected to decrease in electricity use (3.28 decrease for non-food retailers and 6.36 decrease for hotels).
- At the end-use level, all commercial end-use items are expected to increase in electricity use. Lighting shows the most significant increase, while cooking, space cooling, water heating, and refrigeration show the lowest growth.

4. Identification of Technically Feasible Measures

The objective of this task is to identify the technically feasible measures for addressing local area needs. Data from different sources were collected on the conservation and demand management (CDM) measures, where the 2018 and 2019 IESO's Measure and Assumption lists (MAL) represented the basis for the measure research. In addition, the list of measures of the 2016's APS provided by the IESO for Ottawa was also included [1]. Moreover, other CDM measures from North American Jurisdictions (outside existing MAL), that could be rolled into the market quickly were added to the CDM list of measures used. For each measure, the annual energy consumption saving, as well as the peak demand savings were calculated and screened to determine the shortlisted measures that can impact the summer peak demand at the Kanata North area.

The maximum potential for peak demand reduction for each measure was calculated based on the local area load segmentation discussed in Section 3, the number of equipment per subsector, the consumption of the total equipment as a percentage of the end-use consumption, and the fraction of equipment that is energy efficient. Finally, the technical potential for peak reduction for all the CDM measures was obtained by aggregating the decrease associated with each measure.

In addition to the CDM measures, the impact of the DER on Kanata-Marchwood summer peak was assessed; the analysis is categorized into load shifting using battery energy storage system and renewable-based distributed generation. The technical potential for peak reduction of the battery energy storage is calculated on the utility-scale and on the large customers-scale. Moreover, the technical potential of photovoltaic roof-top distributed generation mounted on the residential and commercial buildings is calculated. Based on the calculated technical potentials for the CDM and DER measures, the total technical potential for the peak reduction of the Kanata North area is calculated.

4.1. Peak Load Analysis for Kanata North Area

4.1.1. Historical Peak Load Analysis

Based on the data received from HOL, the historical peak loading was analyzed, Figure 4-1 shows the coincidental combined peak load for the years 2012 to 2016 for Kanata MTS and Marchwood MTS. Kanata MTS contains 2 X 41.7 MVA transformers, and Marchwood MTS has 2 X 33 MVA transformers. Thus, the combined N-1 ratings for the two stations is 74.7 MVA. The limited-time ratings (LTR) for Kanata MTS is 54.5 MVA, and for Marchwood, MTS is 34 MVA; thus, the combined LTR for the two stations is 88.5 MVA. It worth noting that all the maximum peak loading occurred at the Summer Season for all these years. The highest historical coincidental loading occurred in 2016 with a summer peak of 105.2 MW, while the winter coincidental peak load for this year was 77 MW. This historical data analysis shows that the Summer peak is always more significant than the Winter peak for all available historical data. In addition, the Summer peak exceeded the combined LTR for the two stations over the past years.

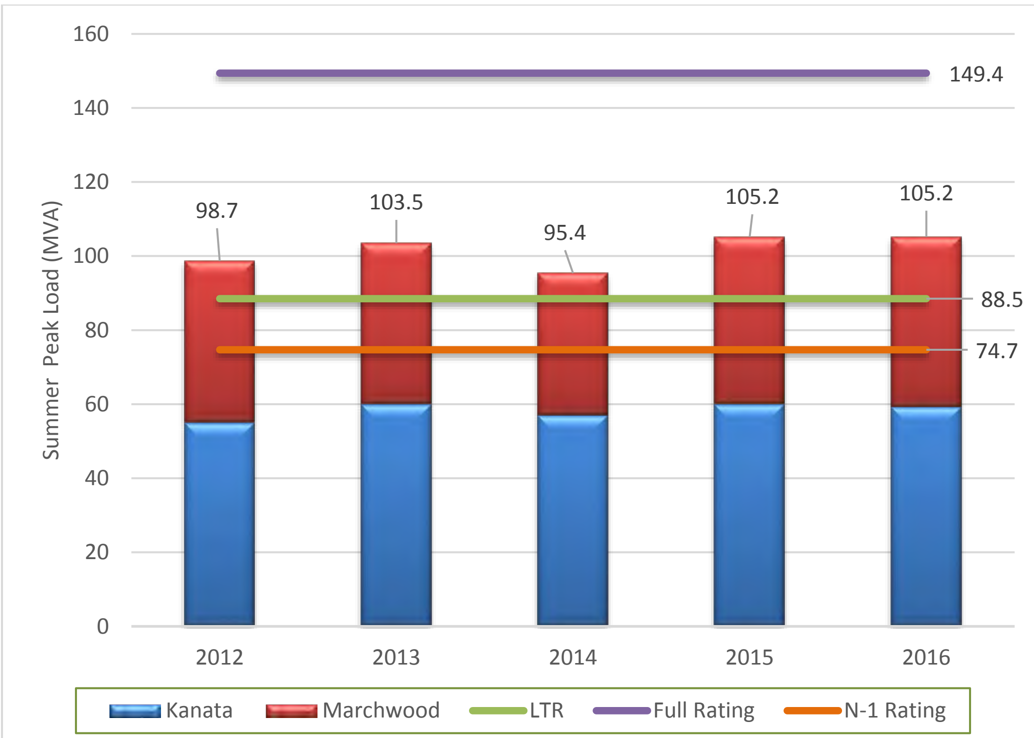

Figure 4-1 Historical Peak Loading for Kanata-Marchwood

4.1.2. Base Year Peak Load

The chronological loading curves for the peak day for the Winter and Summer seasons are determined based on the feeder hourly loading profiles for years 2017 and 2018. Figure 4-2 shows the chronological loading curve for the summer peak. The highest peak loading during the summer was reached on July 5th, while for the Winter Season the highest peak was reached on January 5th. The winter peak is 14.7% less compared to Summer, and the total number of days for the Winter season where the peak loading exceeded the planning ratings is ten days, while this number increased to 52 days in the Summer Season. Based on this analysis, the Winter Peak will not be analyzed given the available data and the large difference between winter and summer peak. Therefore, non-wire solutions should be addressing the Summer peak to lower this peak below the planning ratings of the two stations.

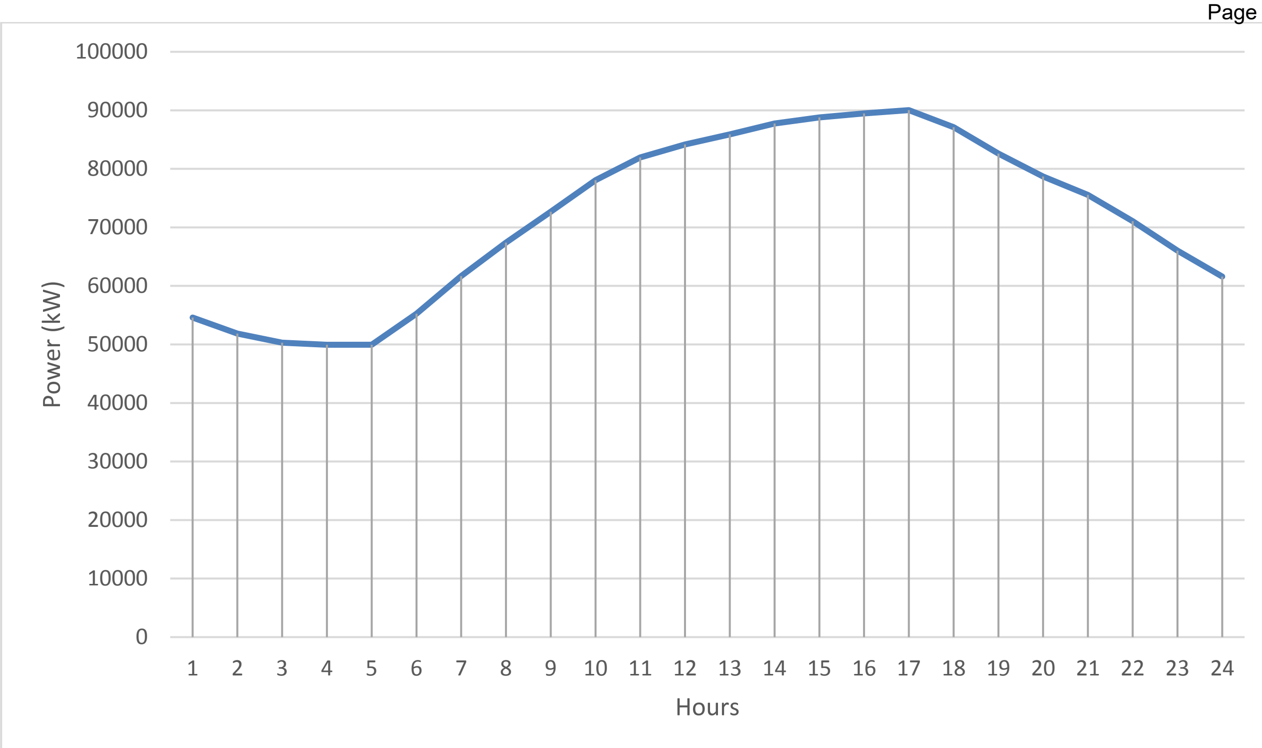

Figure 4-2 Peak Coincident Loading Day for the Base Year for Kanata-Marchwood, Summer Season Year 2018

4.1.3. Peak Load Forecast

The coincident peak forecast for the Summer season is developed using the IESO peak load at the base-year (2018) and by considering the median weather conditions, as shown in Figure 4-3, and by using extreme weather conditions as shown in Figure 4-4. The Summer peak is expected to exceed the combined LTR rating of the two stations (i.e., 88.5 MVA). It should be mentioned that the certainty of some load growth, such as (Broccolini Business Park) and (550 Innovation (Ciena)), should be checked annually due to the high required demand.

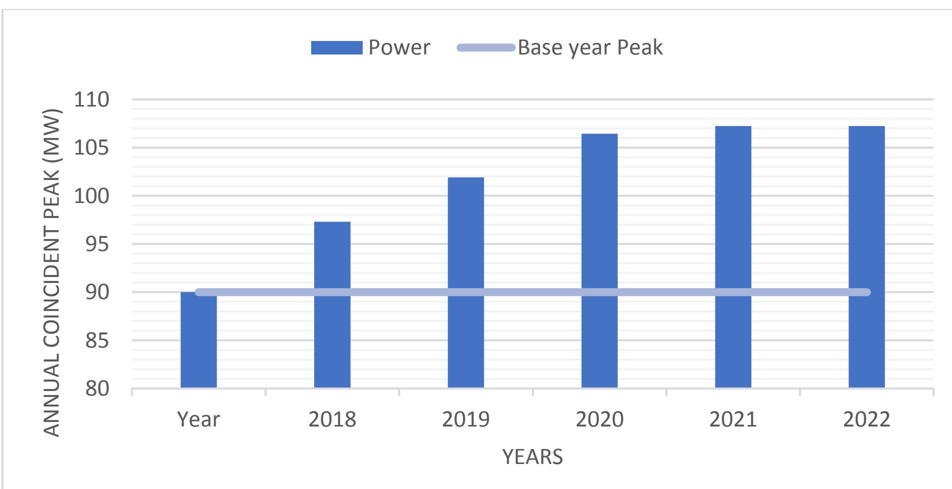

Figure 4-3 Forecasted Coincident Peak Loading for Kanata-Marchwood, Median Weather

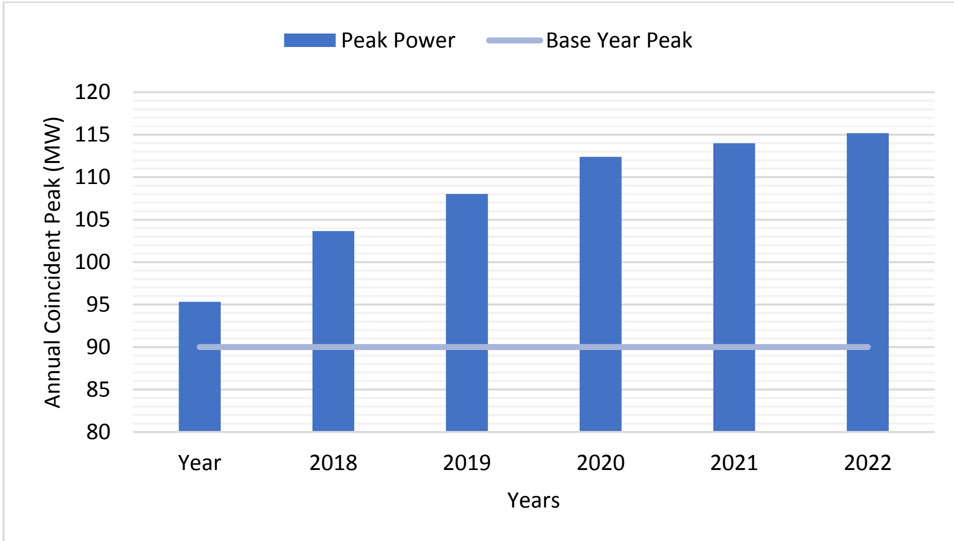

Figure 4-4 Forecasted Coincident Peak Loading for Kanata-Marchwood, Extreme Weather

4.2. Technical Potential of CDM Measures

The technical potential scenario estimates the saving potential when all technically feasible non-wire solutions are implemented at their full technical potential. This saving potential is the maximum potential that is not considering the economics of the measures nor customer adoption. This section presents the methodology followed for shortlisting the available CDM measures in Ontario and for calculating the technical potential of these measures.

4.2.1. Methodology

The primary project rationale is to determine the possible potential solutions to lower the summer peak demand in the Kanata-Marchwood area. The achievable potential of Summer peak load reduction would allow for more efficient use of existing facilities and infrastructure and differ or eliminate the need for a new station. Based on the HOL plan, the new station (New Kanata North) is planned to be in service in 2028. Therefore, the presented study focuses on the short-term technical potential scenarios that may differ or eliminate the need for the new station.

The relevant data on the available conservation measures were collected from IESO's MAL, the 2016's APS, and from other North American Jurisdictions [11] - [15]. Then, the measures were screened to determine the effective ones that can address the summer peak demand at Kanata North area; three screening stages are followed to exclude the measures that are not suitable for addressing the local area needs; i.e., measures of subsectors/end uses not available in Kanata area, measures that are no longer offered in 2018 and 2019 IESO list of measures, and measures that have no impact on summer peak demand.

For each measure, compared to the base case equipment, the consumption, annual energy saving, and peak demand reduction are determined. For each measure in each competition group, the following data were collected: the fraction of equipment that is energy efficient and the number of equipment per subsector, and the consumption of the total equipment as a percentage of end-use consumption. Then, the maximum potential for peak demand reduction for each measure is calculated.

4.2.2. Mapping of CDM Measures

The measure competition groups were developed for each subsector/end-use separately. Each competition group consolidates similar measures that could be an alternative to each other. For example, the competition groups for the space cooling end-use are a thermal envelope, space cooling control, room/window air conditions, and central AC. The measures in each competition group are alternatives to each other, while a measure from the room AC group cannot compete with measures of the central AC group. The aggregated measure savings potential for each competitive group is determined; double-count of potential savings is avoided by limiting the total adoption to 100% within each measure competition group.

The complete list of competition groups mapped to subsectors, and end-use are presented in Table 4-1 and 4-2 for residential and commercial sectors, respectively. The subsectors mentioned in Table 4-2 are office, medical office, hotels, residential care, non-food retailers, food retailers, schools, warehouse wholesale, and other commercials.

Table 4-1 Residential Sector Competition Groups

End-use	Competition Groups
Indoor Lighting	Screw-in lamps, light control
Outdoor Lighting	Screw-in lamps, light control
Common Area Lighting	Screw-in lamps, light control
Cooking	Wall Oven
Refrigeration	Refrigerators, Freezers
Space Cooling	Control, Thermal Envelope, Room AC, Central AC, Other Cooling
Water Heating	Pipe Insulation, Showerhead, Water heater, Aerator
Plug Loads	Televisions, Water cooler
Washer Dryer	Washing Machines, Dryers, Dishwashers
Ventilation	Dehumidifiers

Table 4-2 Commercial Sector Competition Groups

End-use	Competition Groups
Subsector Lighting	Screw-in lamps, light control
Subsector space cooling	Packaged AC units, Chillers, Room AC
Subsector refrigeration	Residential size refrigerators, Walk-in refrigerators, Cabinet, pipes insulation, strip curtain, Gasket.
Subsector plug loads	Ice machine, Vending machine
Subsector computers	Computers
Subsector Domestic Hot Water	Water heater
Subsector cooking	Dishwasher, cooking
Subsector Miscellaneous commercial	Visc commercial
Subsector ventilation and circulation	Ventilation and circulation

4.2.3. Results and Discussions

The methodology described in section 4.2.1 is applied to the Kanata-Marchwood load profile, for the year 2023 forecasted load, forecasted number of residential units and forecasted commercial areas were used to determine the technical potential, due to CDM measures, for this year. The factors required for calculating the technical potential; (i.e., the measure share, the energy efficient factor, and the total number of equipment per household or square footage) are obtained from the residential survey provided by IESO and the commercial CDM data provided by HOL. The missing information is completed using NRCAN residential and commercial surveys [10], [16], and EIA's Commercial Buildings Energy Consumption Survey (CBECS) [17].

4.2.3.1. Residential Sector

The technical potential peak reduction is calculated for each competition group of the residential subsector/ end-use, and the total technical potential peak reduction is calculated for each subsector and end-use. The overall residential summer peak reduction in 2023 was estimated to be 4.713 MW. Figure 4-5 shows the technical potential Summer peak reduction for each subsector; the most significant technical potential was determined for the single-family subsector, which accounts for 62.725 % of the total peak reduction in 2023. Figures 4-6 to 4-9 show the reductions per residential end-use for each subsector.

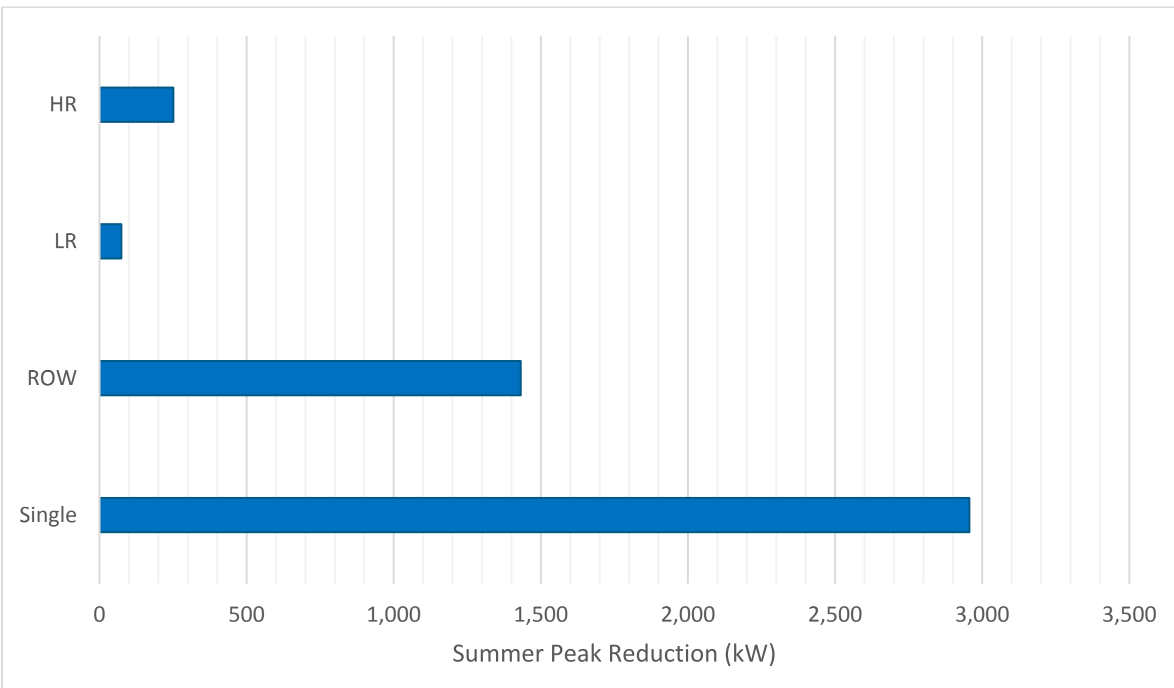

Figure 4-5 Technical Potential Peak Reduction by Residential Subsector in 2023

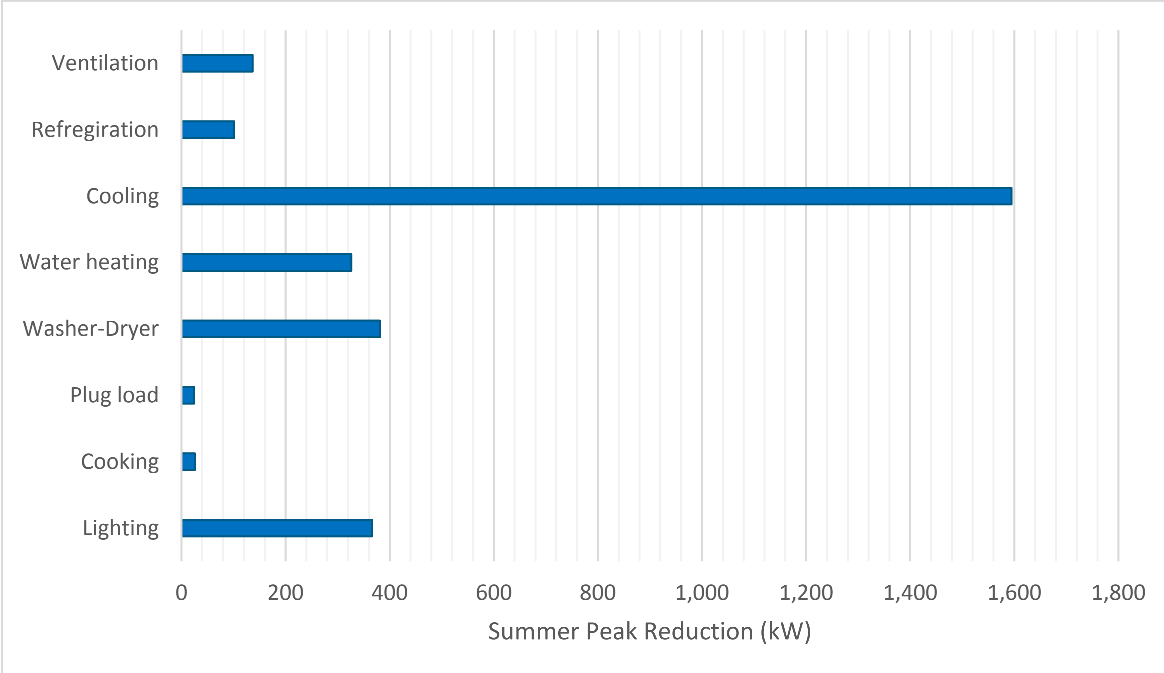

Figure 4-6 Technical Potential Peak Reduction by End-use in 2023, Single-family

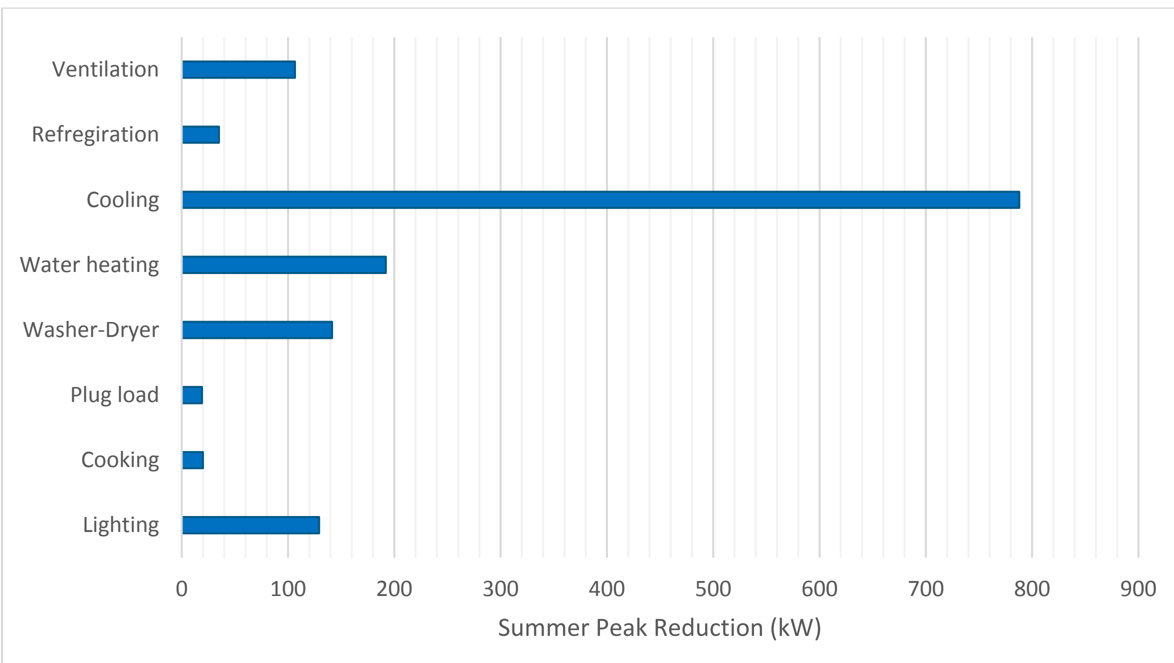

Figure 4-7 Technical Potential Peak Reduction by End-use in 2023, ROW

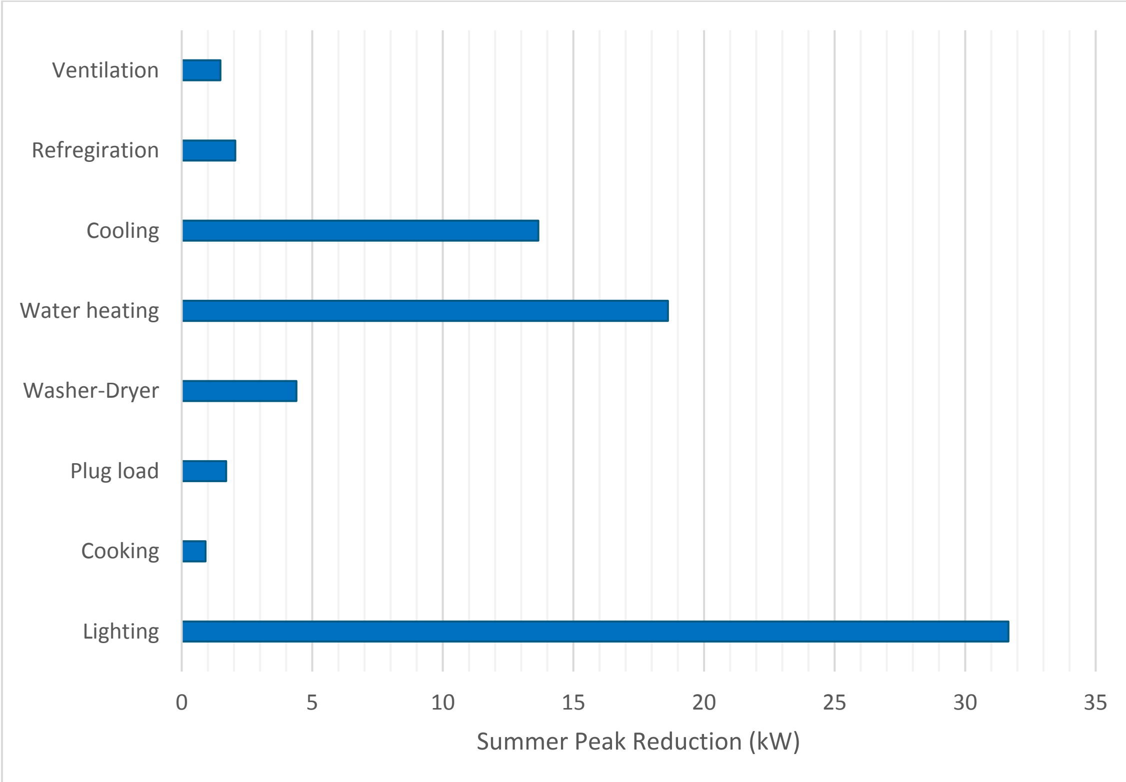

Figure 4-8 Technical Potential Peak Reduction by End-use in 2023, Low Rise

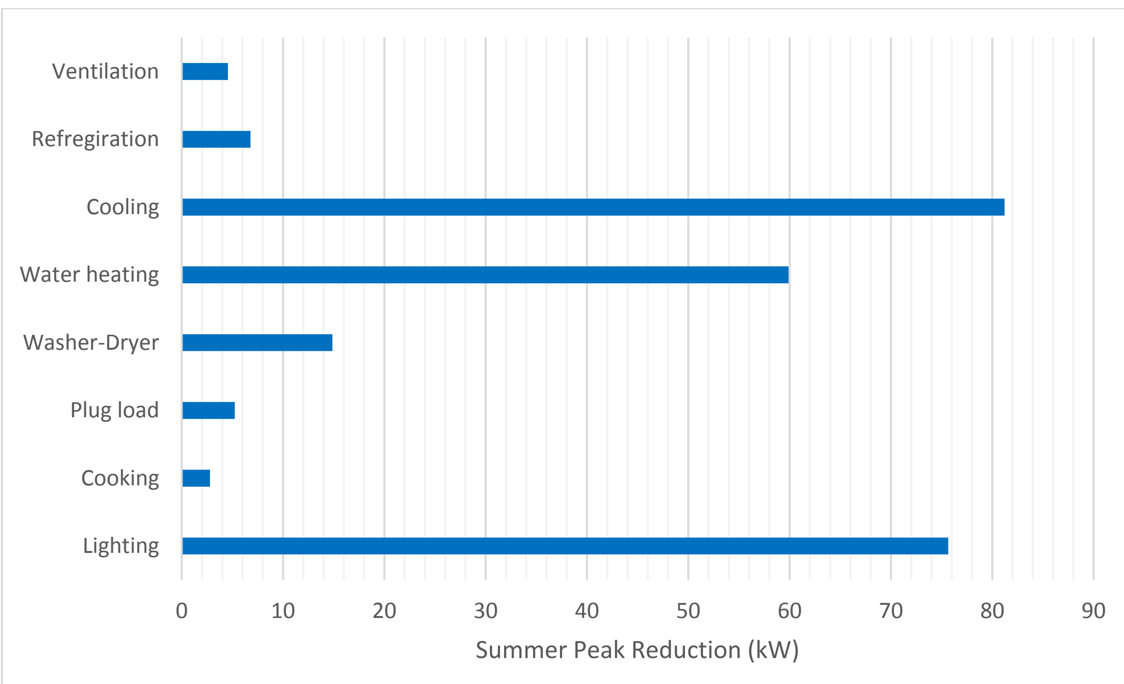

Figure 4-9 Technical Potential Peak Reduction by End-use in 2023, High Rise

4.2.3.2. Commercial Sector

The technical potential peak reduction is calculated for each competition group of the commercial subsector/ end-use, and the total technical potential peak reduction is calculated for each subsector and end-use. The overall commercial summer peak reduction in 2023 was estimated to be 13.691 MW. Figure 4-10 shows the technical potential Summer peak reduction for each subsector; the most significant technical potential was determined for the office subsector, which accounts for 61.19 % of the total peak reduction in 2023 followed by the food stores subsector that accounts for 12.43%. Figure 4-11 shows the overall reductions per commercial end-use. The lighting end-use accounts for the most significant peak reductions of 58.17% of the overall reductions.

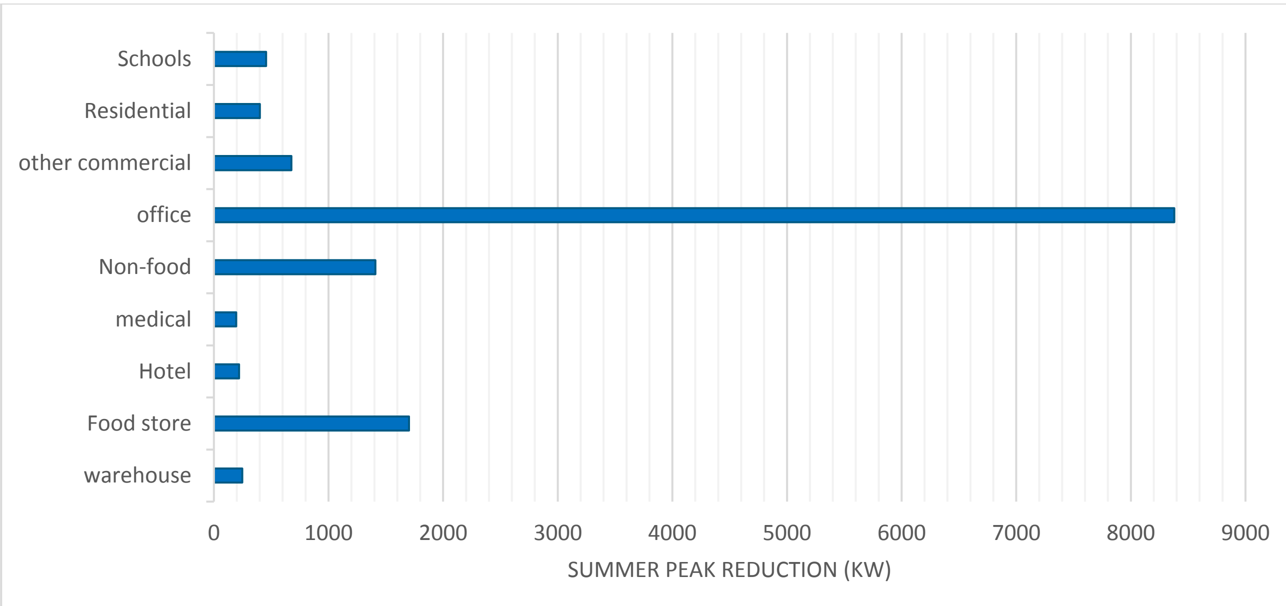

Figure 4-10 Technical Potential Peak Reduction by Commercial Subsectors in 2023

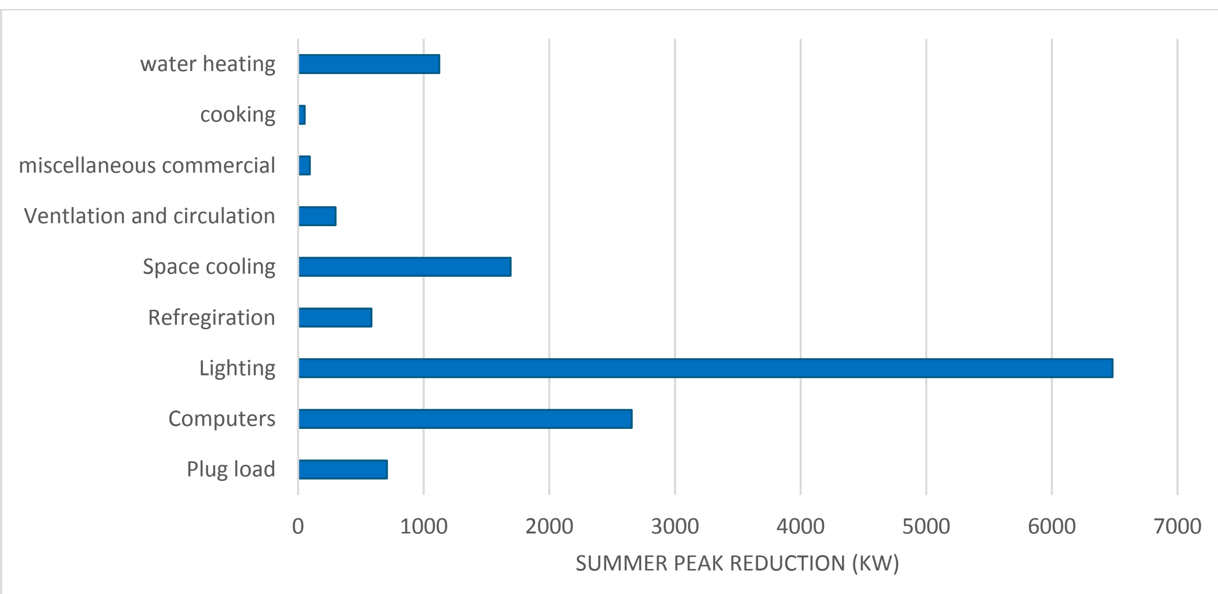

Figure 4-11 Technical Potential Peak Reduction by End-use, Commercial Sector

4.2.4. CDM Peak Reduction Portfolio

The total technical potential reduction in 2023 was calculated to be 18,396 MW, and the residential sector accounts for 26%, while the commercial sector accounts for 74 %, as shown in Figure 4-12. As only one industrial building is located at Kanata-Marchwood and there is no plan for expansion, the industrial sector CDM measures were not included in the shortlisted measures. In addition, the street lighting does not contribute to the Summer Peak reduction as the peak hour coincides with the daytime.

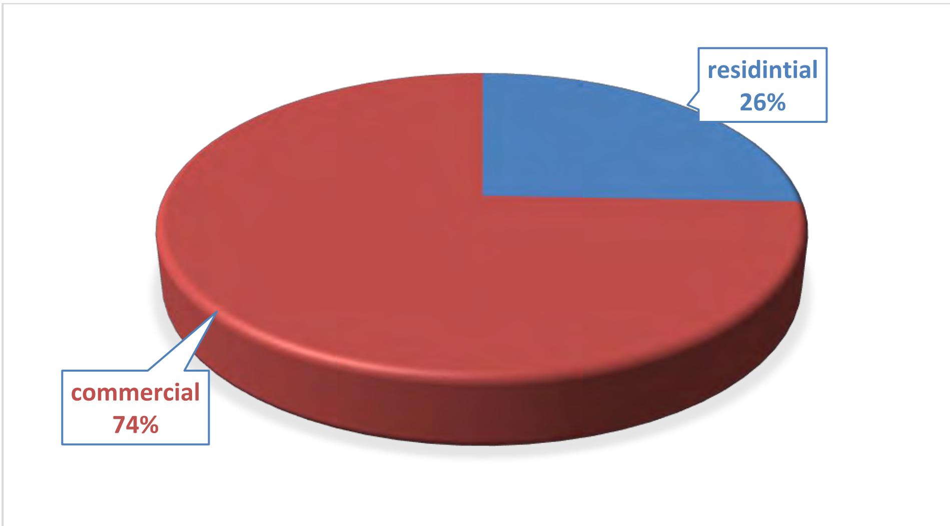

Figure 4-12 Total Technical Potential of CDM measures

4.3. Technical Potential of Load Shifting Measures

This objective of this task is to analyse the impact of load shifting measures that includes Time of Use (TOU) and Battery Energy Storage (BES) on Kanata-Marchwood summer peak.

HOL already adopted the TOU pricing for the Regulated Price Plan (RPP) customers. Most of the residential customers and the small commercial customers (i.e., 50kW to 1000 kW) are RPP customers. The larger commercial customers (i.e. Wholesale Market Participants (WMP)) purchase electricity through the IESO directly. Therefore, the TOU pricing is implicitly included in the wholesale energy prices. Thus, for the TOU, it was concluded that the TOU pricing measure is already applied in the Kanata North area, and no additional load shifting could be achieved using it.

The possibility of load shifting using the battery energy storage system was performed for two scenarios, i.e., utility-scale and large customers-scale. The load shifting analysis determined the technical potential of using a battery owned by HOL and installed at the substation. Moreover, the technical potential for installing batteries owned by large customers greater than 1000 KW was also determined.

4.3.1. Utility-Scale Battery Energy Storage

The total system peak is analyzed, as shown in Figure 4-13, and the potential for peak reduction using substation scale battery storage is determined. Two scenarios are studied, i.e., batteries that are capable of discharging for 4 or 6 hours. The adequate battery size for the 4 hours scenario is 7,60 kWh, and this battery can reduce the system peak by 2.92 MW (shaving the peak from 90.05 MW to 87.11 MW). For the 6 hours scenario, the battery size is 24,125 kWh, and this battery can reduce the system peak by 5.87 MW.

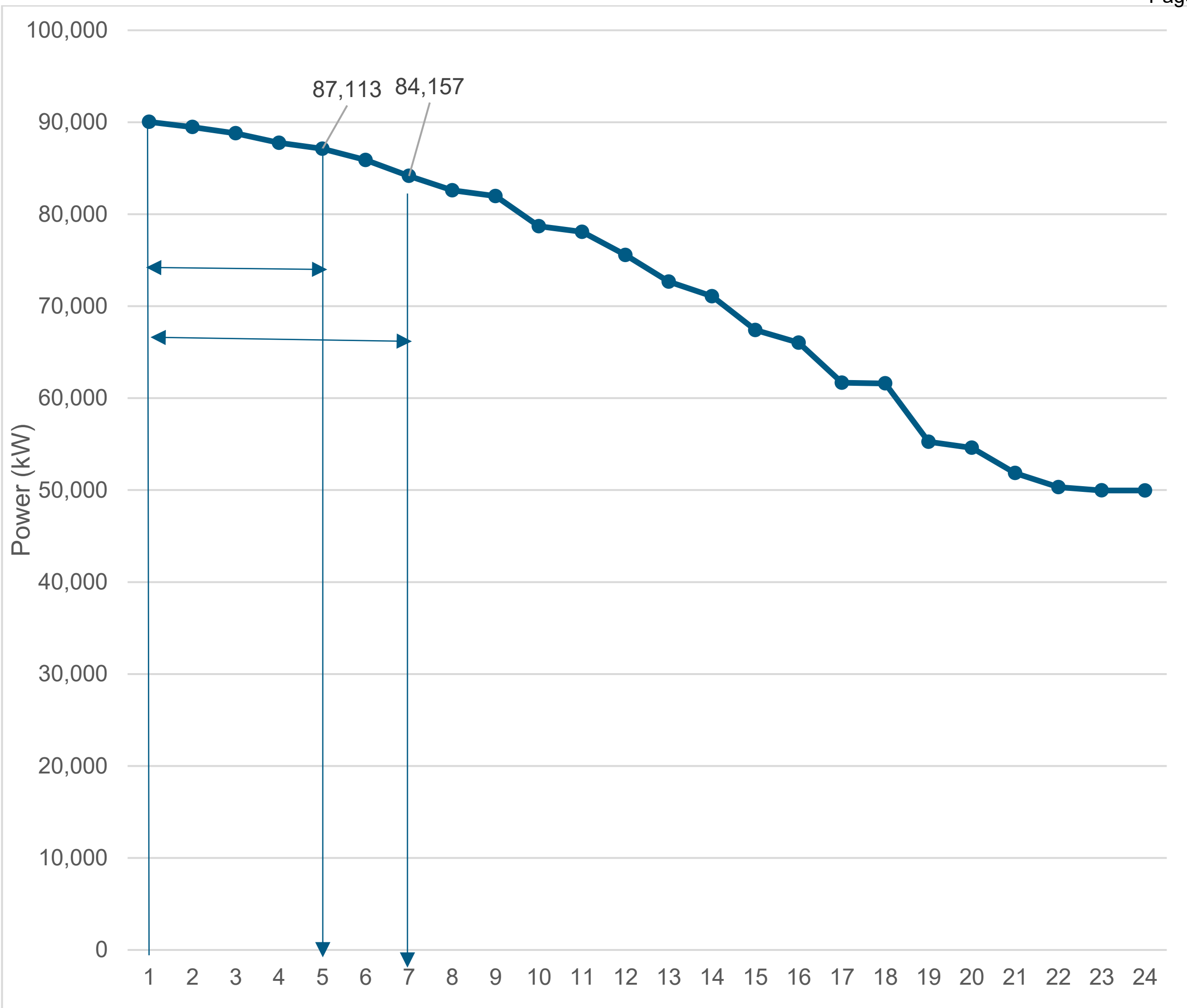

Figure 4-13 Load Duration Curve of the Summer Peak Day

4.3.2. Customer-Scale Battery Energy Storage

The potential for peak reduction using customer scale battery storage is determined. Two scenarios are studied, i.e. batteries that are capable of discharging for 4 or 6 hours. The adequate battery size for the 4 hours and 6 hours scenarios are determined for the large customers greater than 1000kW. The corresponding technical potentials of peak reduction for these batteries are obtained. Table 4-3 shows the customer meter reference number and the adequate battery sizes for both scenarios as well as the technical potential of these batteries. The total technical potential peak reduction for the 4-hour battery is 746 kW, while for the 6-hour battery, the reduction is 1,186 kW.

Table 4-3 Technical Potential of Large Customer Batteries

Meter Data Reference Number	Customer Maximum Load (kW)	Four Hours Scenario		Six Hours Scenario	
		Battery Capacity (kWh)	Technical Potential for Peak Reduction (kW)	Battery Capacity (kWh)	Technical Potential for Peak Reduction (kW)
1064575000	2,077	52.92	21.6	78.48	25.92
1323516000	1,013	129.6	72.9	181.08	82.08
2261516000	1,655	35.46	13.86	194.22	44.28
2313175000	2,173	166.88	69.44	327.6	100.24
2589675000	1,597	142.56	52.2	467.64	106.38
3948590255	2,278	62.04	19.92	141.36	34.32
5430710301	1,230	33.72	17.52	77.88	25.32
5649575000	1,479	75.24	29.76	263.52	65.04
6445807039	1,050	102.24	32.94	171	45.18
7489675000	1,055	68.13	27.45	121.5	36.99
8079416000	1,967	57.60	21.96	242.82	54.18
9046027318	2,098	15.48	6.3	55.08	12.96
9098675000	3,396	400.76	173.88	689.13	245.97
9771025037	1,097	31.32	17.16	34.8	17.76
9858616000	1,105	198.96	60.48	368.28	93.96
9866575000	3,594	40.08	25.32	97.68	36.54
9951516000	1,053	26.46	10.26	42.3	12.96
9982475000	8,273	227.67	91.41	545.73	145.95

4.4. Technical Potential of DG Measures

The impact of roof-top small-scale PV DGs located at residential and commercial buildings on the system peak was assessed. Helioscope software was used to determine the optimal distribution of the PV panels. The software utilized the actual solar irradiances at the Kanata North area to develop the daily profile of the PV DG output power and the DG capacity. The minimum daily power profile for the Summer season was used to determine the technical potential for the Summer peak reduction using the PV DGs.

4.4.1. Technical Potential of Commercial DGs

One large commercial building located at Terry Fox Dr. is selected (shown in Figure 4-14) to determine the technical potential per square footage. The optimal PV module distribution is developed, as shown in Figure 4-15, and the minimum Summer day output powers are obtained as presented in Fig 4-16. The results show that this PV DG can reduce the summer peak by 12.2 kW.

Figure 4-14 Location of the Selected Commercial Building

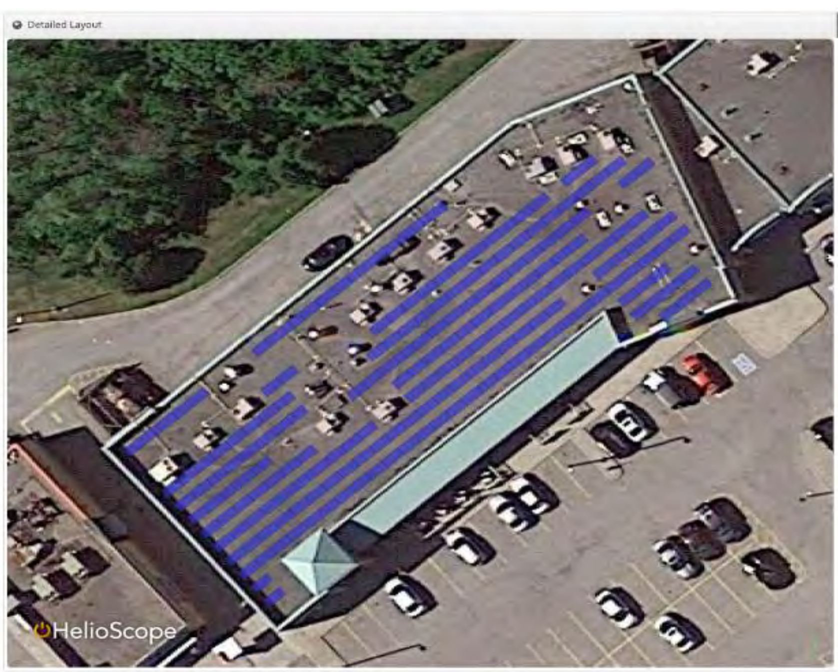

Figure 4-15 Layout of the PV arrays, Commercial Building

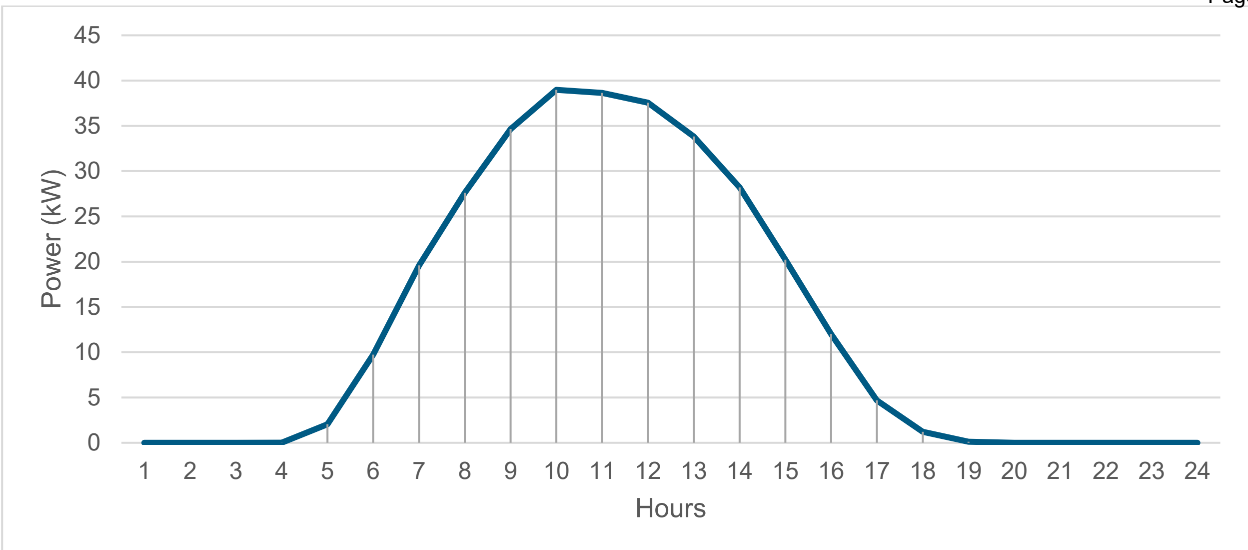

Figure 4-16 Minimum Hourly Output Power for a Summer Day, Commercial Building

The square area of the roof of the selected building is 13,788 square feet. The total square area of the roofs at Kanata North is obtained using MPAC data and adjusted using the square footage forecast developed in milestone #1. The total square footage forecasted in the year 2023 is found to be 7,945,730 square feet. Therefore, the total technical potential for peak reduction using roof-top PV DGs, mounted on commercial buildings, is 7.03 MW.

4.4.2. Technical Potential of Residential DGs

The same procedure is applied for the residential buildings; two houses were selected; one single-family house and one ROW house. Helioscope was used to determine the optimal PV module distribution. Figures 4-17 shows the optimal PV module distribution for the selected single-family house.

Figure 4-17 Layout of the PV arrays, Single-Family House

The minimum Summer day output powers are obtained as presented in Figure 4-18 and 4-19 for the single family and the ROW house, respectively. The results show that the PV DG mounted on the single-family house reduced the Summer peak by 2.732 kW, and that of the ROW house reduced the Summer peak by 1.793 kW.

To calculate the total technical potential for peak reduction for all residential buildings, the residential building forecast developed in Section 3 was used. The total forecasted single-family houses in 2023 are 7,468 houses, and the forecasted RO housed in 2023 are 5,826 houses. Therefore, the total technical potential for peak reduction using roof-top PV DGs is 20.4 MW for the single-family and 10.446 MW for the ROW. Therefore, the total technical potential of peak reduction for the residential sector is 30.84 MW and the total technical potential of the DER is 37.87 MW.

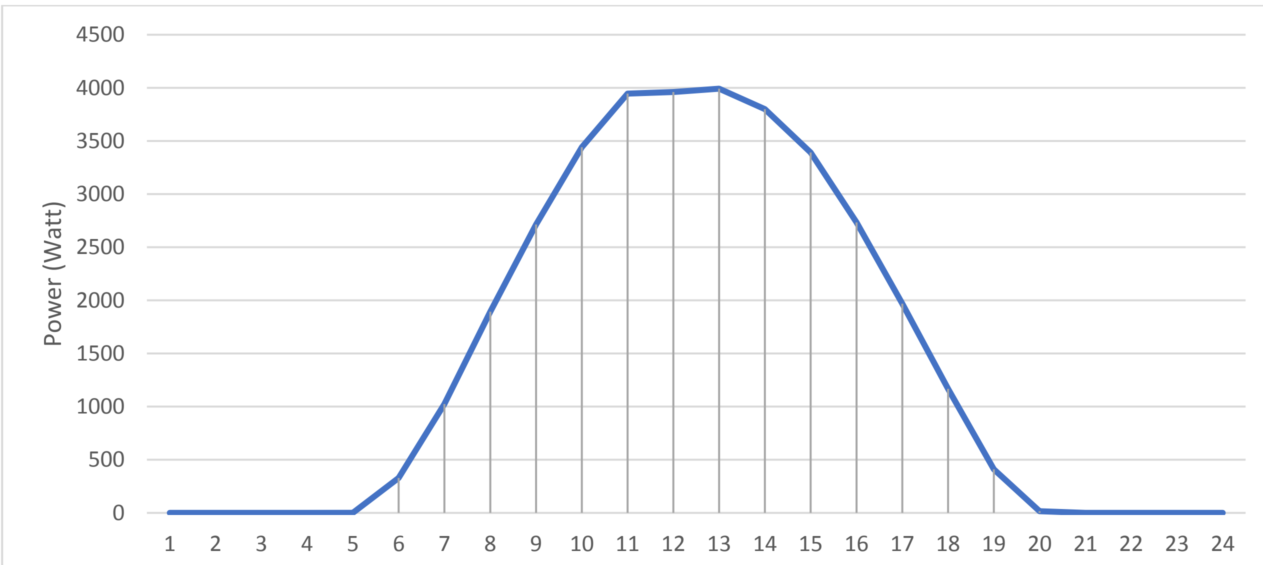

Figure 4-18 Minimum Hourly Output Power for a Summer Day, Single-Family House

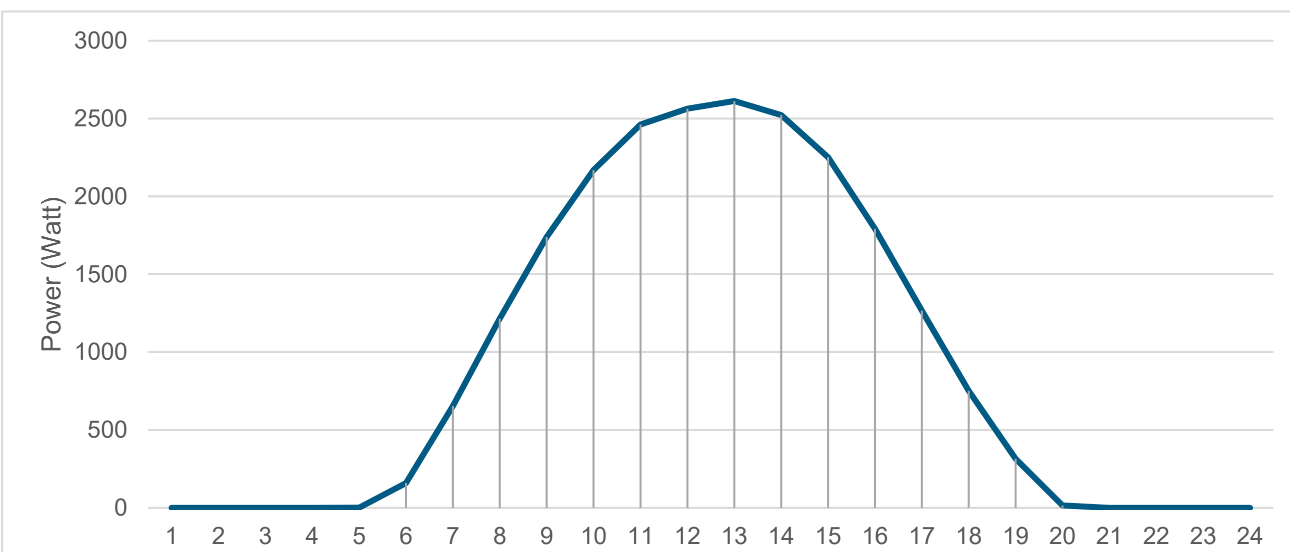

Figure 4-19 Minimum Hourly Output Power for a Summer Day, ROW House

5. Market Analysis of the Feasible Measures

Market analysis of all feasible CDM and DER are discussed in this section.

Adoption curves were developed to estimate the achievable potential of the CDM measures, which are curves estimating the participation of eligible customers in a program, based on their willingness to accept new technology or an idea, at a particular year as a percentage of the total population as shown in Figure 5-1 [18]. The adoption curve for each of the CDM measures was developed based on the historical participation in CDM programs and the values of the bass diffusion equation.

In addition, the impact of the Distributed Energy Resources (DER) on Kanata-Marchwood summer peak reduction is evaluated; the impact analysis is categorized into load shifting using a battery energy storage (BES) system and renewable-based distributed generation.

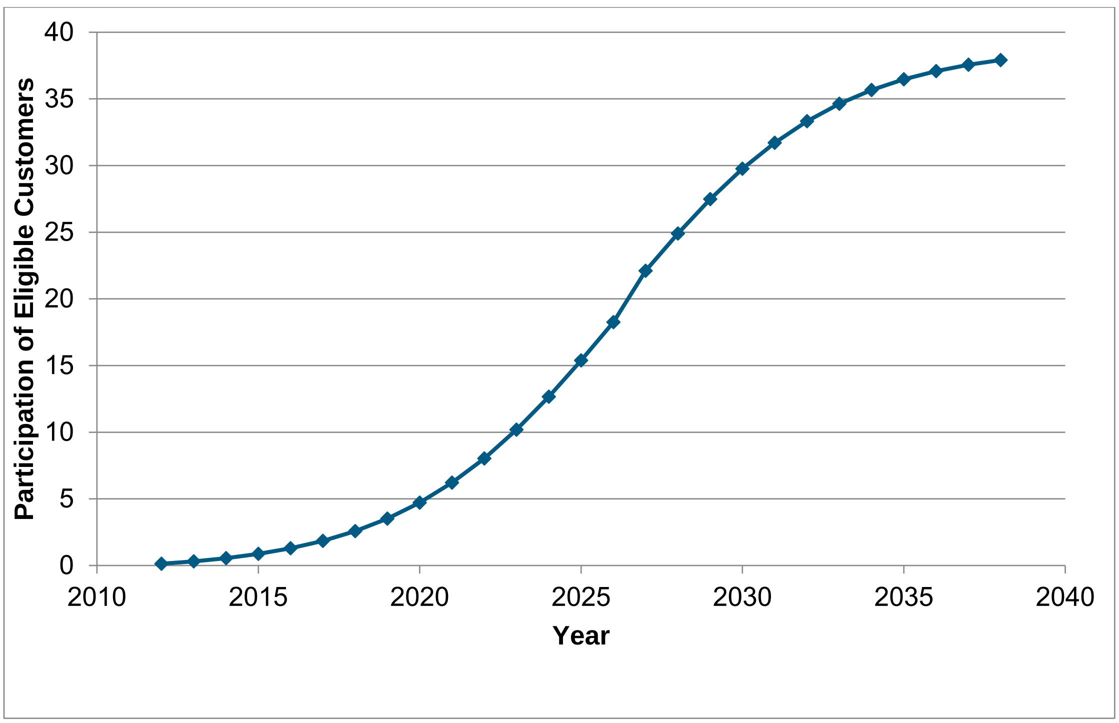

Figure 5-1 Adoption Curve

5.1. Achievable Potential of CDM Measures

The achievable potential is estimated using the technical potential determined in Section 3 after considering the customer adoption.

Based on the HOL plan, the new station (new Kanata North) is planned to be in service in 2028. Therefore, the presented study focuses on short-term achievable potential scenarios. This section shows the methodology followed for calculating the achievable potential of the CDM measures.

5.1.1. Methodology

Assessing achievable potential requires: calculating the technical potential of the CDM measures (identified in Section 3) and estimating the rate at which cost-effective measures could be adopted over time. The following key items were considered and addressed in developing the methodology:

- Historical performance of programs in HOL
- Development of adoption curves
- Mapping of measures to the adoption curves

The steps implemented in developing the adoption curves are:

- Measures categorization by sectors and subsectors first, and then further classification by end-use was done.
- For each end-use, the competition groups were developed. The obtained measures were mapped to the competition groups/ end-use/ subsector/ sector.
- The values of p, q, and m parameters in the bass diffusion equation were developed using statistical analysis of Ontario historic program participation data as provided by HOL [19]. These values were used to establish the adoption curves.
- Measures were then mapped to the adoption curves.
- The achievable potential for peak demand reduction for each measure was calculated as follows:

$$Achievable\ potential\ of\ measure = \frac{Technical\ potential\ of\ measure\ \times \text{number of}\ adopters}{eligible\ population}$$

5.1.2. Results and Discussions

The methodology described in section 5.1.1 is applied to the Kanata-Marchwood technically feasible measures developed in section #4.

5.1.2.1. Residential Sector

The achievable potential peak reduction is calculated for each competition group of the residential subsector/ end-use, and the total achievable potential peak reduction is calculated for each subsector and end-use. Figure 5-2 shows the technical and achievable potential summer peak reduction for each subsector; the most significant achievable potential was estimated for the single-family subsector, which accounts for 63.13% of the total peak reduction in 2023. Figures 5-3 to 5-6 show the reductions per residential end-use for each subsector. The overall achievable residential summer peak reduction in 2023 was estimated to be 481.31 kW, which accounts for 10.22% compared with the technical potential of the residential measures that had a value of 4.7 MW.

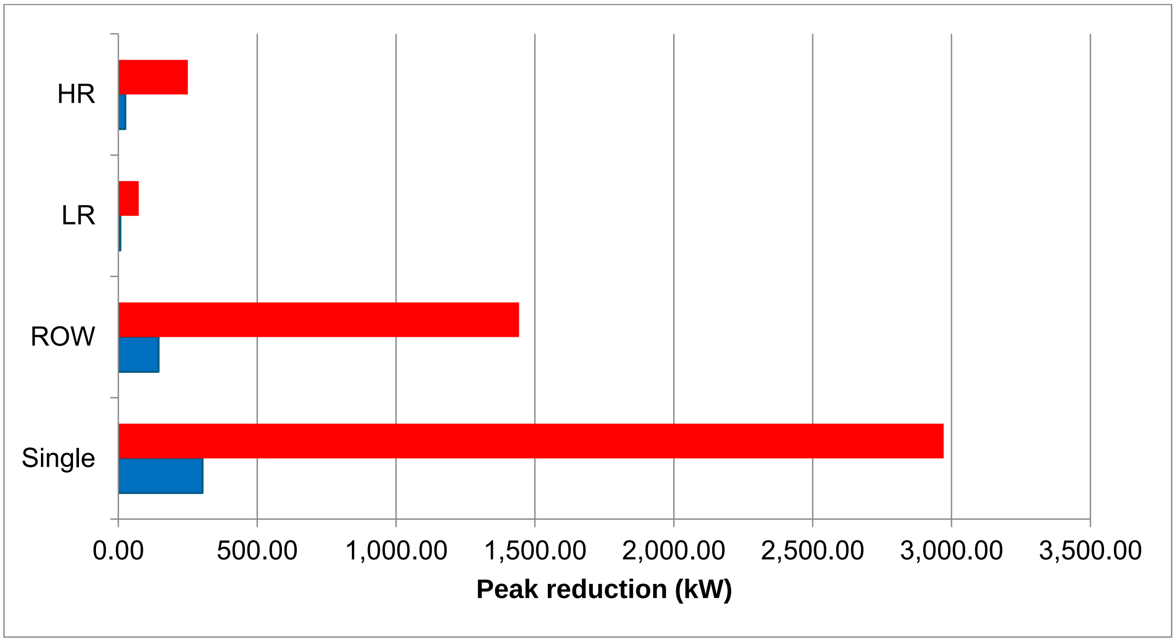

Figure 5-2 Technical and Achievable Potential Peak Reduction by Residential Subsector in 2023

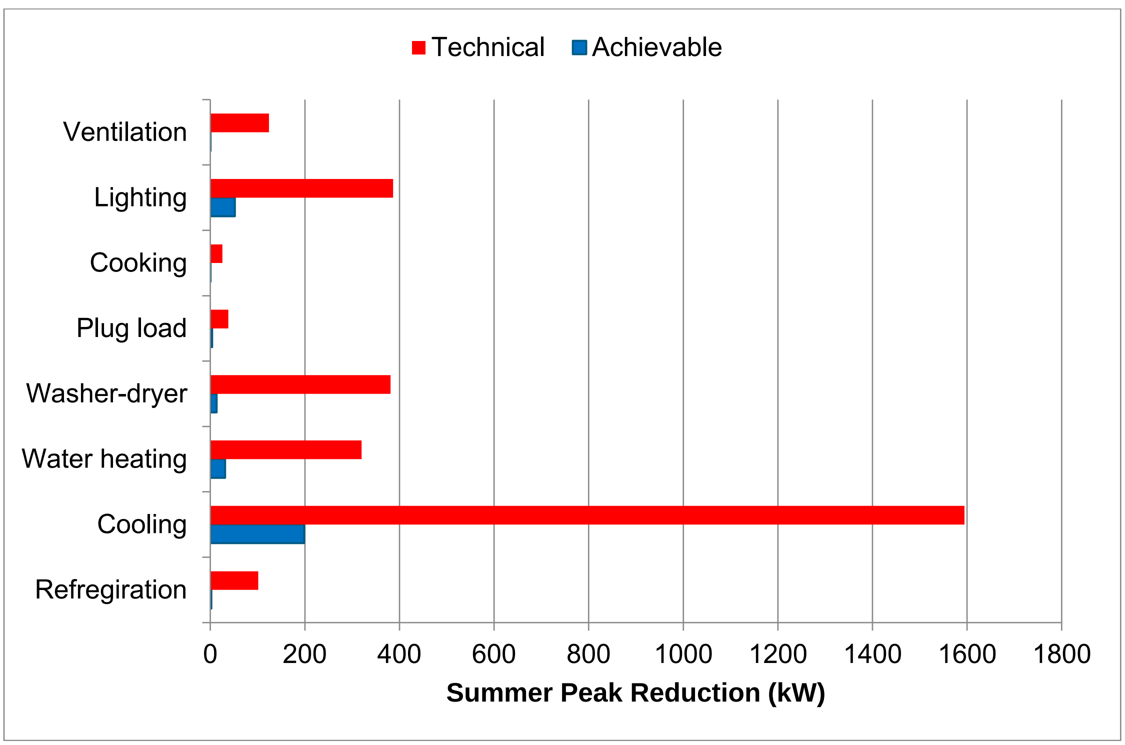

Figure 5-3 Technical and Achievable Potential Peak Reduction by End-use in 2023, Single-family

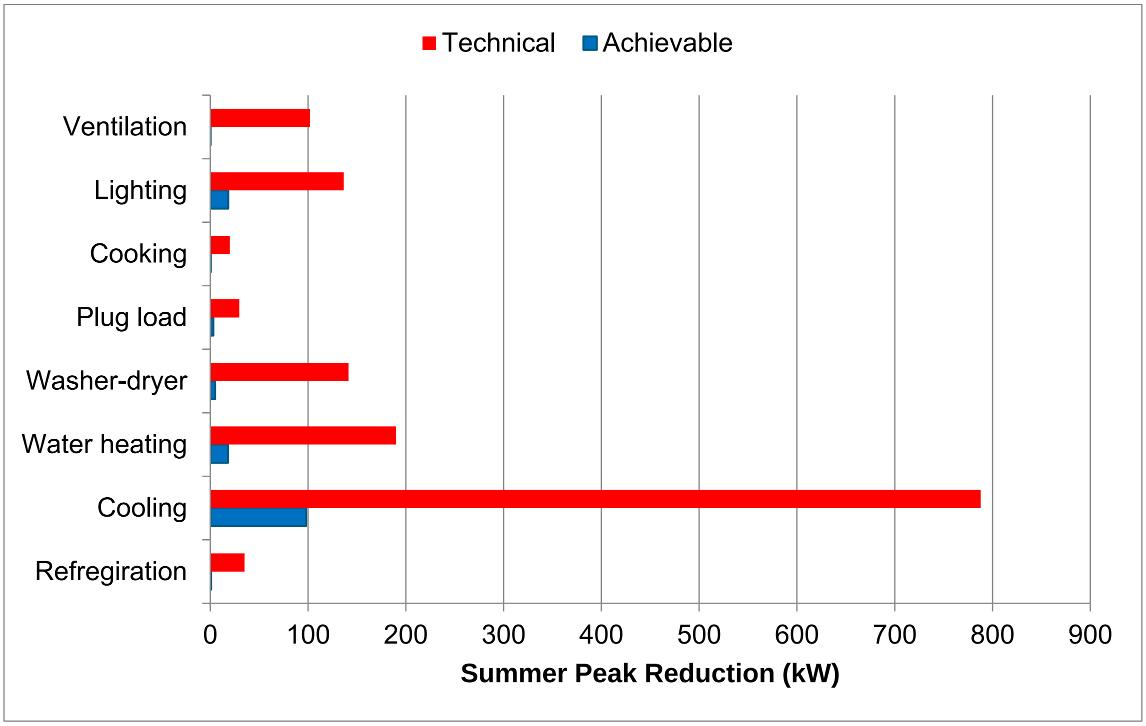

Figure 5-4 Technical and Achievable Potential Peak Reduction by End-use in 2023, Row

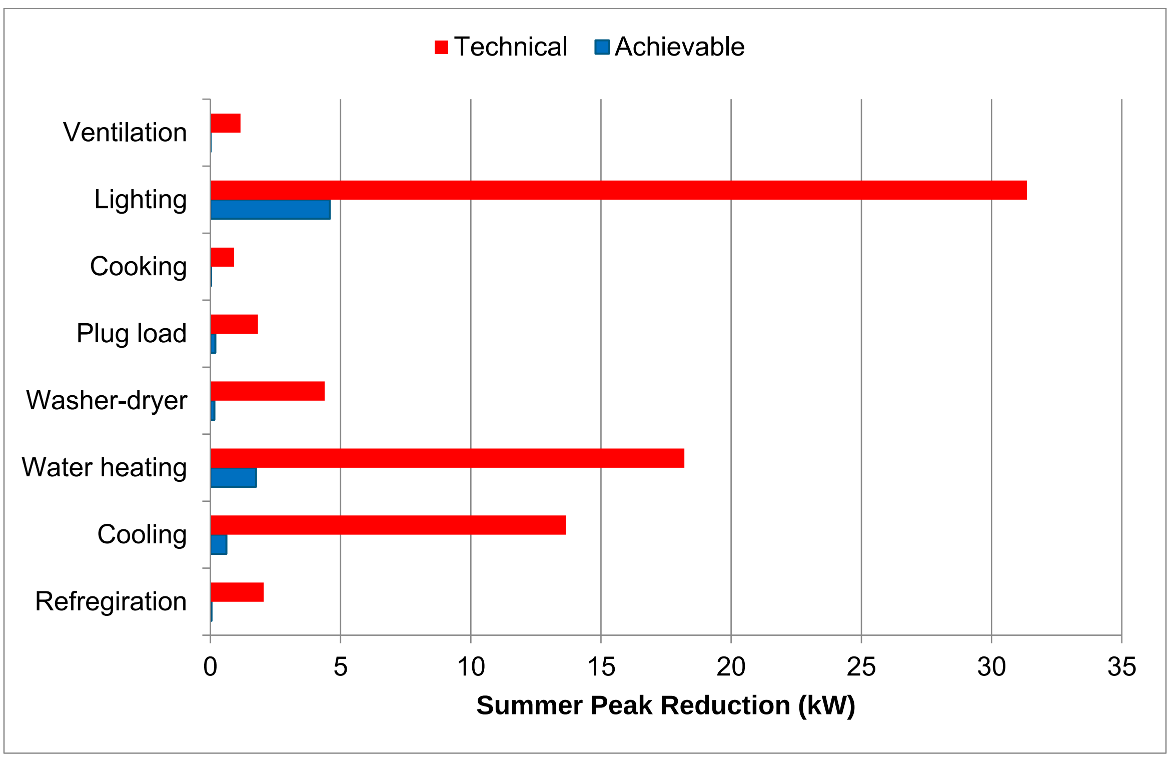

Figure 5-5 Achievable Potential Peak Reduction by End-use in 2023, Low Rise

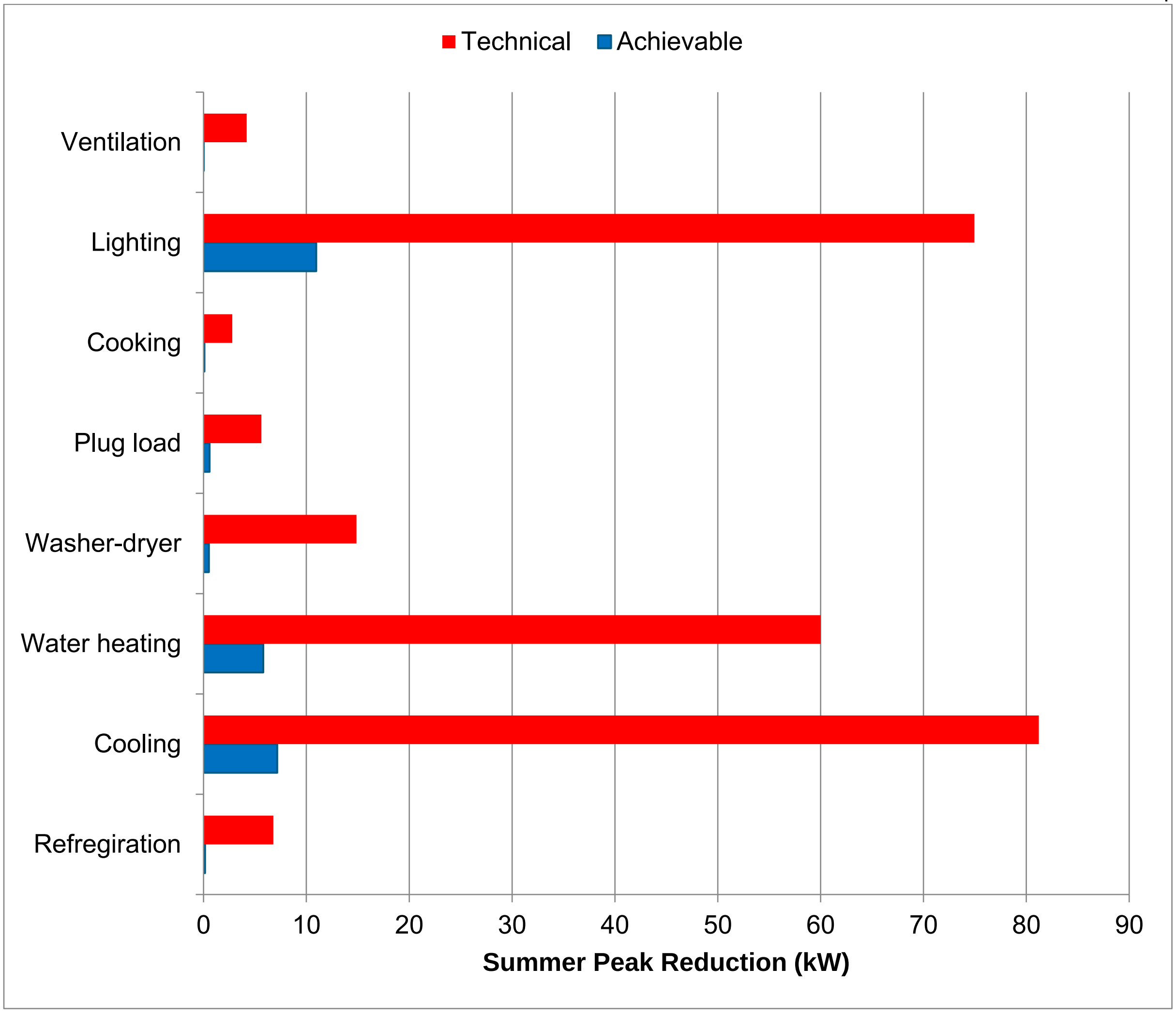

Figure 5-6 Achievable Potential Peak Reduction by End-use in 2023, High Rise

5.1.2.2. Commercial Sector

The achievable potential peak reduction is calculated for each competition group of the commercial subsector/ end-use, and the total achievable potential peak reduction is calculated for each subsector and end-use. Figure 5-7 shows the technical and achievable potential summer peak reduction for each subsector; the most significant achievable potential was estimated for the office subsector, which accounts for 57.58 % of the total peak reduction in 2023 followed by the food stores subsector that accounts for 14.48%. Figure 5-8 shows the overall reductions per commercial end-use; the lighting end-use represents the largest peak reductions of 60.51% of the overall reductions. The overall achievable commercial summer peak reduction in 2023 was estimated to be 5972.96 kW.

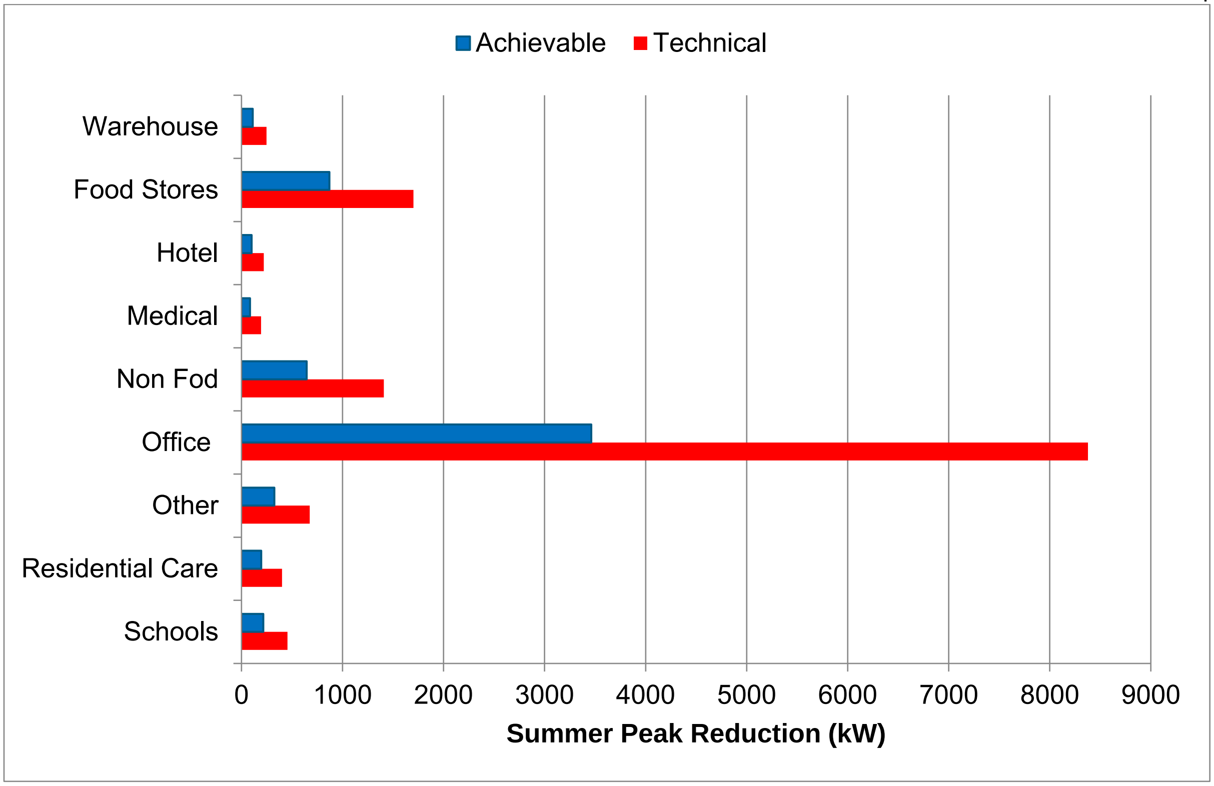

Figure 5-7 Technical and Achievable Potential Peak Reduction by Commercial Subsectors in 2023

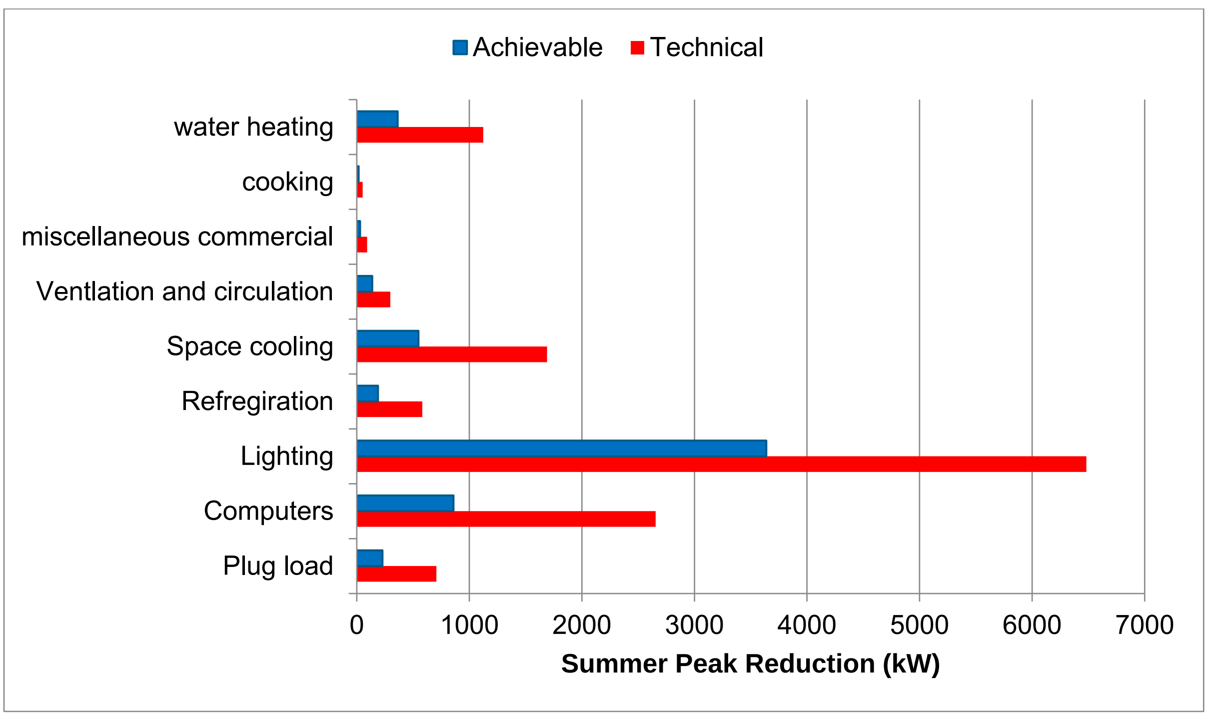

Figure 5-8 Technical and Achievable Potential Peak Reduction by End-use, Commercial Sector

5.2. Cost Analysis of Load Shifting Measures

The possibility of load shifting using the Battery Energy Storage (BES) system was performed for two scenarios, i.e., utility-scale and large customers-scale. In Section 4, the technical potential for using a battery owned by HOL and installed at the substation was determined. Moreover, the technical potential for installing batteries owned by large customers greater than 1000 kW was also determined. For each scenario, two cases were studied, i.e., batteries that are capable of discharging for 4 or 6 hours. In this section, the cost analysis for the BES is analyzed, as will be illustrated in the next subsections.

5.2.1. Utility-Scale Battery Energy Storage

The total system peak for the year 2023 was analyzed in Section 4, and the potential for peak reduction using substation-scale battery storage was determined for the 4-hour and 6-hour batteries. For utility-scale BES, no incentives will be provided since the BES is owned by HOL, and hence, only the economic analysis will be analyzed for this scenario.

The adequate battery size for the 4-hour scenario was 9,846 kWh, which can reduce the system peak by 3.782 MW. For the 6 hour scenario, the battery size was 31,216 kWh, which can reduce the system peak by 7.607 MW.

An example indicative order of magnitude capital costs for implementing distribution scale lithium-ion batteries to meet the requirements is summarized in Table 5-1. The budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 for the 4-hour and 6-hour scenarios, respectively. The estimate is built based on recent budgetary quotes received for a project of similar nature, and the average cost of $/kW and $/kWh are within the ranges published in [20]. It is to be noted the price is very sensitive for the battery cost, and in this example, the cost is estimated at C$ 390/kWH for Li batteries. Estimates published by various resources suggested decline prices for the LI batteries as the market for storage increases.

Table 5-1 Distribution Scale Battery Installation Cost

Scenario	4-Hour Scenario	6-Hour Scenario
Proposed Capacity Rating	3.75 MW	7.5 MW
Proposed Duration	4 Hrs	6 Hrs
MWH	15	45
Total Energy Storage System Cost		
DC Modules & BMS Equipment (excl. PCS)*	5850000	17550000
General conditions, EPC & Commissioning	2,000,000	2,000,000
Power Conversion System Equipment	750,000	1,500,000
Electric BoS	125,000	250,000
General conditions, EPC & Commissioning	750,000	1,250,000
Misc.	100,000	100,000
Total Cost	9,575,000	22,650,000
Avg. Cost $/KWh	638	503
Avg. Cost $/KW	2553	3020

5.2.2. Customer-Scale Battery Energy Storage

The presented methodology, in this section, aims to determine the level of incentive required for the BES project investment to be profitable, for the customer-scale BES. The concept of a minimum attractive rate of return (MARR) is selected for achieving the objective. If the internal rate of return (IRR), i.e., the rate of return that yields zero present worth value of cash flow, of the project is equal to or higher than the MARR, the project is considered profitable. The income of the BES investment is calculated at different levels of incentives, and the minimum level of incentives is determined. This minimum incentive level is the value that makes the IRR equal to MARR. For accurate economic assessment of the BES project, cash flow is performed. The following procedure is used to calculate the minimum incentives of the BES:

1) Calculate the battery capital cost (Cap) using (1)

$$Cap = [Capitalcost] - [(\frac{Incentives}{kWh}) \times battery\ capacity] \tag{1}$$

2) Calculate the income per year for the project lifetime using (2), considering the BES rated capacity as base power.

$$Inc\ (y) = \sum_{m=1}^{12} \Delta Peak\ of\ month \times demand\ peak\ rate] \tag{2}$$

3) Calculate the inflation-adjusted cash flow (C(y)) for each year using (3)

$$C(y) = \frac{Inc\ (y)}{(1 + inflation\ index)^y} \tag{3}$$

4) Calculate the minimum incentives/kW of the BES project capacity using (4); the net present value is equalized to zero, and the project IRR is replaced by the MARR.

$$NPV = Cap - \sum_{y=1}^{N} \frac{C(y)}{(1 + MARR)^y} = 0 \tag{4}$$

5.2.1.1 Case Study

For the customer-scale BES, presented in Section #4, the customer with reference number (1323516000) was selected. The maximum load of this customer was 1,013 kW with BES of capacity 129.6kW and 181kW for the 4-hour and 6-hour case, respectively. The technical peak reduction was found to be 72.9 and 82 kW for the 4-hour and 6-hour case, respectively.

The economic analysis presented in the previous procedure is executed based on an average capital cost of $410,391 and $573,155 for the 4-hour and 6-hour case, respectively [21]. The MARR is set to 7%. The income is calculated based on the average regulated price plan for small business in HOL [20]. The inflation rate is set to 2.4% [22], the cash flow is calculated as presented in Table 5-2 and the required incentives to achieve the 7% MARR for the 4-hour and 6-hour cases are $323,065 and $474,928 which means the incentive range between $ 4432-5791 per kW peak reduction. These incentives are significantly high relative to the corresponding savings and are not economically viable. As a result, the customer-scale BES will be excluded from the achievable potential analysis.

Table 5-2 Cash Flow for Customer-Scale BES

	4-Hour Case				6-Hour Case			
Year	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)
0	410391				573155			
1		7873.2	7718.82	7213.85		8856	8682.35	8114.35
2		8138.95	7822.90	6832.83		9154.92	8799.42	7685.76
3		8404.69	7919.93	6465.02		9453.84	8908.56	7272.04
4		8670.44	8010.15	6110.90		9752.77	9010.04	6873.72
5		8936.19	8093.78	5770.75		10051.68	9104.11	6491.11
6		9201.93	8171.05	5444.72		10350.60	9191.03	6124.37
7		9467.68	8242.18	5132.82		10649.51	9271.04	5773.54
8		9733.43	8307.38	4834.97		10948.43	9344.38	5438.52
9		9999.17	8366.86	4551.02		11247.35	9411.28	5119.11
10		10264.92	8420.81	4280.71		11546.27	9471.97	4815.07
11		10530.66	8469.42	4023.76		11845.19	9526.65	4526.04
12		10796.41	8512.90	3779.83		12144.11	59575.54	4251.66
13		11062.16	8551.41	3548.53		12443.03	9618.86	3991.49
14		11327.9	8585.13	3329.46		12741.95	9656.80	3745.08
15		11593.65	8614.25	3122.20		13040.87	9689.56	3511.94
16		11859.4	8638.93	2926.30		13339.79	9717.31	3291.59
17		12125.14	8659.32	2741.32		13638.71	9740.25	3083.51
18		12390.89	8675.60	2566.80		13937.63	9758.56	2887.21
19		12656.64	8687.90	2402.28		14236.54	9772.40	2702.15
20		12922.38	8696.39	2247.31		14535.46	9781.95	2527.84
PV of Adjusted Income Considering MARR (A)				87325.39	PV of Adjusted Income Considering MARR (A)			98226.09
Capital Cost (B)				410391	Capital Cost (B)			573155
Incentive (B)-(A)				323065	Incentive (B)-(A)			474928
Peak Reduction kW				72.9	Peak Reduction kW			82
Incentive $/KW of peak reduction				4432	Incentive $/KW of peak reduction			5791

5.3. Cost Analysis of DG Measures

The presented methodology, in this section, aims to determine the level of incentive required for the DG project investment to be profitable and to calculate the achievable potential for the DG measures.

The concept of MARR is selected for determining the level of incentives. The income of the DG investment is calculated, and the minimum level of incentives is determined. For accurate economic assessment of the PV DG project, cash flow is performed. The proposed algorithm for the minimum incentive level determination is discussed as detailed below in section 5.3.1 and 5.3.2, while the achievable potential calculation is discussed in section 5.3.3.

5.3.1. PV DGs Installed on Residential Rooftops

The following procedure is used to calculate the minimum incentives of the residential scale PV DGs:

1) Calculate the DG capital cost (Cap) using Equation (5)

$$\mathrm{Cap} = [\mathrm{Capital\ cost/\ kW} \times \ \mathrm{DG\ Capacity}] - [\mathrm{Incentives\ /\ kW} \times \mathrm{DG\ Capacity}] \quad (5)$$

2) Calculate the income per year for the project lifetime using (6), considering the DG rated capacity as base power.

$$\mathrm{Inc}\ (\mathrm{y}) = \sum_{\mathrm{m}=1}^{12} \sum_{\mathrm{hr}=1}^{24} [\mathrm{E_g}(\mathrm{y}, \mathrm{m}, \mathrm{hr}) \times \mathrm{P_r}(\mathrm{m}, \mathrm{hr})] \ \times \ \mathrm{N_d}(\mathrm{m}) \quad (6)$$

Where Inc (y) is the DG project income for certain year (y), Eg (y,m,hr) is the DG generated energy at certain hour (hr) at certain month (m) for a certain year, Pr (m, hr) is the time of use (TOU) electricity rates at certain hour at certain month and Nd (m) represents the number of days per month (m).

3) Calculate the inflation-adjusted cash flow (C(y)) for each year using (7)

$$\mathrm{C}(\mathrm{y}) = \frac{\mathrm{Inc}\ (\mathrm{y})}{(1 + \mathrm{inflation\ index})^{\mathrm{y}}} \quad (7)$$

4) Calculate the minimum incentives/kW of the DG project capacity using (8); the net present value is equalized to zero, and the project IRR is replaced by the MARR.

$$\mathrm{NPV} = \mathrm{Cap} \ - \sum_{\mathrm{y}=1}^{\mathrm{N}} \frac{\mathrm{C}(\mathrm{y})}{(1 + \mathrm{MARR})^{\mathrm{y}}} = 0 \quad (8)$$

Where NPV is the net present value, and N is the project lifetime.

5.3.1.1. Case Study

For the PV DGs installed on the single-family house presented in Section 4, the PV DG installed capacity is 8.68 kW with annual generated energy of 9.231 MWh. This generated energy is still lower than the average annual electricity consumption for a single house (9652 MWh; obtained from Milestone #1 load segmentation report). This means according to the net energy metering, the PV DG will not inject any energy into the grid, and all the generated energy will be used to lower the electricity bill. Based on the average capital cost of 2.53 $/W [23], the economic analysis presented in the previous procedure is executed with a MARR of 7%. The income is calculated based on the generated energy/hr, residential electricity price as per [24], and an inflation rate of 2.4%. The cash flow is calculated as presented in Table 5-3, and the required incentives to achieve the 7% MARR is 9,867$, which means the incentives per installed kW is 1140.76 $/kW.

Table 5-3 Cash Flow for PV Installed on Residential Rooftop

Year	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)
0	21960.4			
1		1039.20	1018.83	952.17
2		1084.36	1042.26	910.35
3		1131.49	1066.23	870.36
4		1180.66	1090.75	832.13
5		1231.97	1115.83	795.57
6		1285.51	1141.49	760.62
7		1341.37	1167.74	727.21
8		1399.66	1194.60	695.27
9		1460.49	1222.07	664.73
10		1523.96	1250.18	635.53
11		1590.19	1278.93	607.61
12		1659.29	1308.34	580.92
13		1567.98	1212.10	502.98
14		1659.29	1257.54	487.69
15		1659.29	1232.88	446.85
16		1576.23	1148.20	388.94
17		1559.73	1113.90	352.63
18		1551.48	1086.28	321.39
19		1543.22	1059.32	292.91
20		1534.97	1032.99	266.94

5.3.2. PV DGs Installed on Commercial Rooftops

The following procedure is used to calculate the minimum incentives of the commercial-scale PV DGs:

1) Calculate the DG capital cost using (9)

$$Cap = [Capitalcost/\ kW \times DGCapacity] - [Incentives\ /\ kW \times DGCapacity] \tag{9}$$

2) Calculate the income per year for the project lifetime using (10), considering the DG rated capacity as base power.

$$Inc\ (y) = \sum_{m=1}^{12} [E_g(m) \times [A_{WPR}(m)] \tag{10}$$

E_G (m) is the DG generated energy for certain month (m) for a certain year, A_{WPR}(m) is the averaged weight hourly price at certain month m.

3) Calculate the inflation-adjusted cash flow (C(y)) for each year using (11)

$$C(y) = \frac{Inc\ (y)}{(1 + inflationindex)^y} \tag{11}$$

4) Calculate the minimum incentives/kW of the DG project capacity using (12); the net present value is equalized to zero, and the project IRR is replaced by the MARR.

$$NPV = Capcost - \sum_{y=1}^{N} \frac{C(y)}{(1 + MARR)^y} = 0 \tag{12}$$

5.3.2.1. Case Study

For the PV DGs installed on commercial buildings presented in Section 4, the PV DG installed capacity is 58.5 kW with an annual generated energy of 73.79 MWh. This generated energy is still lower than the average annual electricity consumption for a single commercial building. This means according to the net energy metering, the PV DG will not inject any energy into the grid, and all the generated energy will be used to lower the electricity bill. Based on the average capital cost of 2.53 $/W, the economic analysis presented in the previous procedure is executed. The MARR is set to 7%. The income is calculated based on the energy price in Ontario [25], and on the inflation rate of 2.4%, the cash flow is calculated as presented in Table 5-4, and the required incentives to achieve the 7% MARR is $ 129,442 which means the incentives per installed kW is 2200 $/kW.

Table 5-4 Cash Flow for PV Installed on Commercial Building

Year	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)
0	21960.4			
1		1742.01	1707.85	1596.12
2		1800.81	1730.88	1511.82
3		1859.60	1752.35	1430.44
4		1918.40	1772.31	1352.08
5		1977.20	1790.81	1276.82
6		2036.00	1807.91	1204.69
7		2094.80	1823.65	1135.68
8		2153.60	1838.07	1069.78
9		2212.40	1851.23	1006.95
10		2271.19	1863.17	947.14
11		2329.99	1873.93	890.29
12		2388.79	1883.54	836.32
13		2447.59	1892.07	785.14
14		2506.39	1899.53	736.67
15		2565.19	1905.97	690.81
16		2623.98	1911.43	647.47
17		2682.78	1915.94	606.54
18		2741.58	1919.54	567.92
19		2800.38	1922.27	531.52
20		2859.18	1924.14	497.24

5.3.3. Achievable Potential of PV DGs

The DERs contract capacity, as well as the potential for expansion based on the input data received from the HOL and IESO, is presented in Section 3. The installed DER capacity at Kanata-Marchwood was given as 1.1498 MW, and it is forecasted to be at the same level in 2023 based on the current DERs programs and incentives offered in Ontario. Given the capital cost of the DERs as 2.53 \$/W, the total cost of the installed capacity is \$ 2,908,994. The installed capacity (1.1498 MW) would reduce the summer peak demand by 0.3603 MW as illustrated in Section 3, and hence the unit cost of peak reduction associated with the PV DGs is estimated as follows:

$$\text{Unit cost}\left(\frac{\$}{\text{kW}}\right) = \frac{\text{Incremental life cost}}{\text{Summer peak demand savings per unit (kW)}} = \frac{2{,}908{,}994}{360.3059} = 8073.67\ \$/\text{kW} \qquad (13)$$

5.4. Findings and Observations

The following can be observed from the achievable potential and cost analysis by sector, subsectors, and end use:

- The total achievable potential reduction for CDM was estimated at 6,454.91 kW, the residential sector accounts for 481.31 kW, while the commercial sector accounts for 5972.96 kW.
- For the residential sector, the largest achievable potential was estimated for the single-family subsector.
- For the commercial sector, the largest achievable potential was estimated for office subsector.
- At the residential sector end-use level, lighting items showed the largest achievable potential, while cooking, refrigeration, and ventilation showed the lowest achievable potential.
- At the commercial sector end-use level, lighting items represented the largest achievable potential, while cooking and miscellaneous commercial showed the lowest achievable potential.
- For commercial-scale BES, the required incentive levels were estimated between $ 4432-5791 per kW of peak reduction, which are significantly high relative to the corresponding savings. Accordingly, the customer-scale BES was excluded from the achievable potential analysis.
- For utility-scale BES, the budgetary cost for implementing this project was estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW.
- In addition to the peak reduction considered in this study, the utility-scale BES can provide flexibility and operational benefits by providing ancillary services such as providing back up power, voltage, and frequency support. The economic benefits of ancillary services were not considered in this study due to the lack of market regulation that can be used to generate revenues corresponding to these ancillary services.
- For residential and commercial PV rooftop, the incentives per installed kW were estimated at 1140.76 $/kW and 2200 $/kW.

6. Scenario Analysis

This section presents the analysis of the impact of incentives variations on the achievable potential identified in section 5 in order to estimate the new achievable potential and determine the combinations of technical feasible CDM and DER measures that can meet the technical requirement for given incentive levels and avoided costs.

The incentive level of each measure was determined based on the IESO libraries. The obtained incentive levels and the sources of these values were referenced in the workbook submitted to IESO. Then, incentive cost ($/kW) for each measure was determined as described in (1).

$$Incentives\ cost\ (\frac{\$}{kW}) = \frac{Incentives\ provided\ by\ IESO}{Summer\ peak\ demand\ savings\ per\ unit\ (kW)} \quad (1)$$

A cost curve is constructed based on the peak demand reduction cost of all the CDM measures, under the achievable potential scenario in this section. The curve shows each measure as a step in the curve, with the horizontal length of each step indicating the peak demand reduction of the measure and its height above the horizontal axis shows how much it costs per kW ($/kW) of reduction. Measures are sorted according to their incentive cost ($/kW), where the measures with low incentive cost come first in the curve. The advantage of developing a cost curve is that the overall cost-effective potential can be estimated using one graph, as illustrated in Figure 6-1 for the CDM and DER measures.

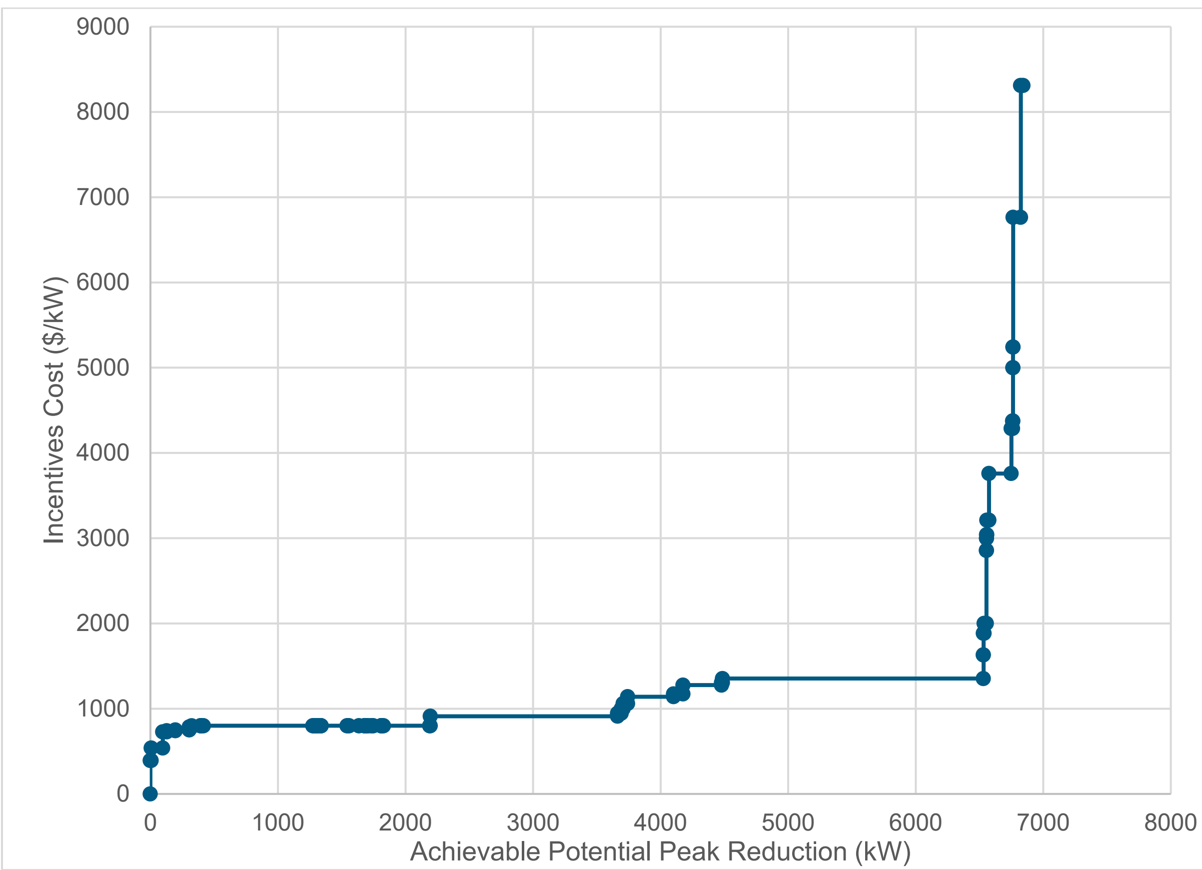

Figure 6-1 Cost Curve of CDM and DER Measures

6.1. Impact of Incentives Variation on Achievable Potential

The sensitivity analysis was conducted to study the impact of incentives variations on the achievable potential based on the price elasticity technique. Where the price elasticity is a primary measure of demand or supply sensitivity to changes in price. The price elasticity values were used to establish the adjustment factor to be applied to the base case modelled savings estimates.

The following methodology was used to access the impact on the achievable potential due to variation in incentives rates:

1- Incentive rates were changed by a certain percentage (+/-) for each measure category (e.g., lighting control products, advanced power bars, etc.).
2- The value of the incentive cost is then calculated based on (2).

$$Incentives\ cost\ (\frac{\$}{kW}) = \frac{Incentives\ provided\ by\ IESO}{Summer\ peak\ demand\ savings\ per\ unit\ (kW)} \quad (2)$$

3- The savings factor adjustment was determined based on the price elasticity values for the residential and commercial sectors. This factor was applied to the base case modelled savings estimates using the formula described in (3).

$$Savings\ Factor\ Adjustment = 1 + Price\ Elasticity\ Value\ \times Incentive\ Change\ \% \quad (3)$$

Where the price elasticity is a primary measure of demand or supply sensitivity to changes in price, an elasticity value of 1.0 would indicate a product that is perfectly elastic, while a value of 0 would mean that the product is inelastic and hence changes in prices have no effect on demand or supply [19] and [26].

4- The project team considered ranges from 0.426-0.46 and from 0.25-0.302 for the price elasticity in the commercial and residential sectors, respectively [19], [26]. The price elasticity of the DERs is assumed to be in the range of 0.25-0.302.
The price elasticity values were based on methodology on a collection of EIA [27] Form 861 data for individual utilities and on panel regression analysis of utility customer supply of demand response capacity as a function of utility incentive payments.
5- The achievable potential estimations were revised based on the incentive level and price elasticity value.

6.1.1. Results and Discussions

The methodology described in the previous section is applied to the Kanata-Marchwood technically feasible measures. The factors required for estimating the achievable potential corresponding to variations in the incentive rates; (i.e., the incentive cost of each measure and the achievable potential of each measure) are determined, as illustrated in the previous section. It should be noted that the incentive levels of all measures are assumed to be equally increased. However, the IESO has the capability to provide the incentive level of each measure independently in the updatable excel sheet.

6.1.1.1. Residential Sector

The impact of incentive rate variations on the achievable potential peak reduction is estimated for each competition group of the residential subsector/ end-use, and the total achievable potential peak reduction is determined for each subsector and end-use. Figure 6-2 presents the increase in the achievable potential summer peak reduction, assuming incentive increases of 5%, 10%, 20%, and 40%. For residential sector, the elasticity estimates suggest that increasing the amount of each product's incentive by 5%, 10%, 20%, and 40%, would increase the total achievable potential by 1.24-1.49 %, 2.44-2.93 %, 4.76-5.69 %, and 9.09-10.78 %, for price elasticity ranging from 0.25-0.302. In other words, increasing the incentive rates by 5%, 10%, 20%, and 40% resulted in an increase in the achievable potential to a value ranging from 487.71 kW- 488.96 kW, 493.73-496.24 kW, 505.77-501.78 kW, and 528.86-539.88 kW, respectively, for price elasticity ranging from 0.25-0.302.

Figure 6-3 to 6-6 present the achievable potential summer peak reduction per end-use for price elasticity of 0.25 and 0.302, assuming incentive increases of 5%, 10%, 20%, and 40, respectively.

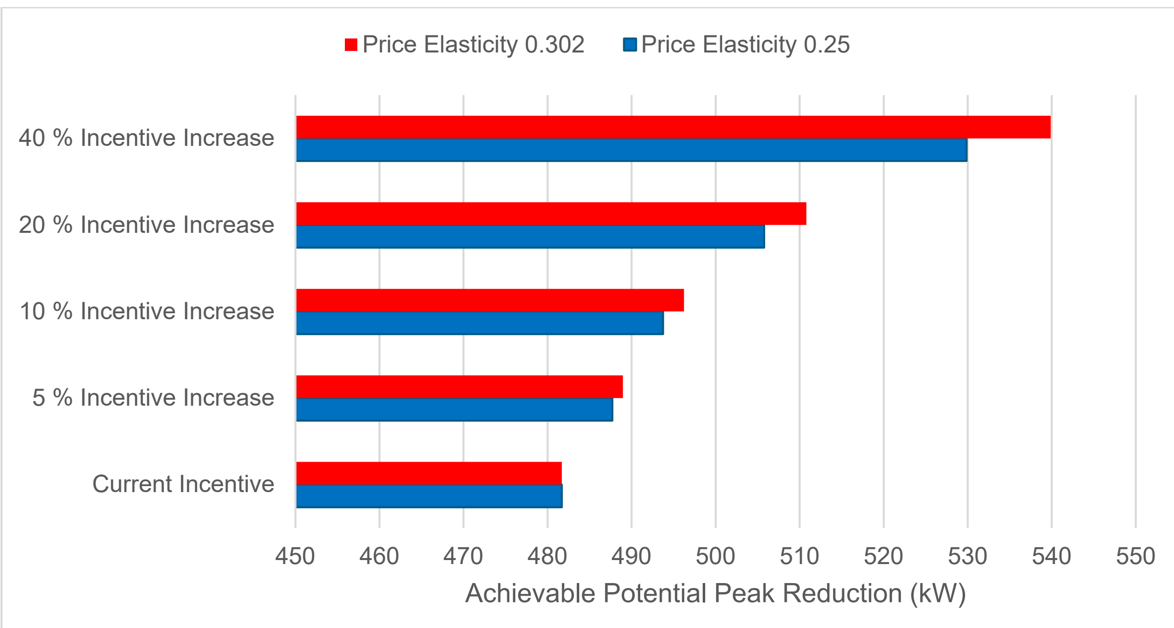

Figure 6-2 Impact of Incentives Variations on Residential Sector Achievable Potential

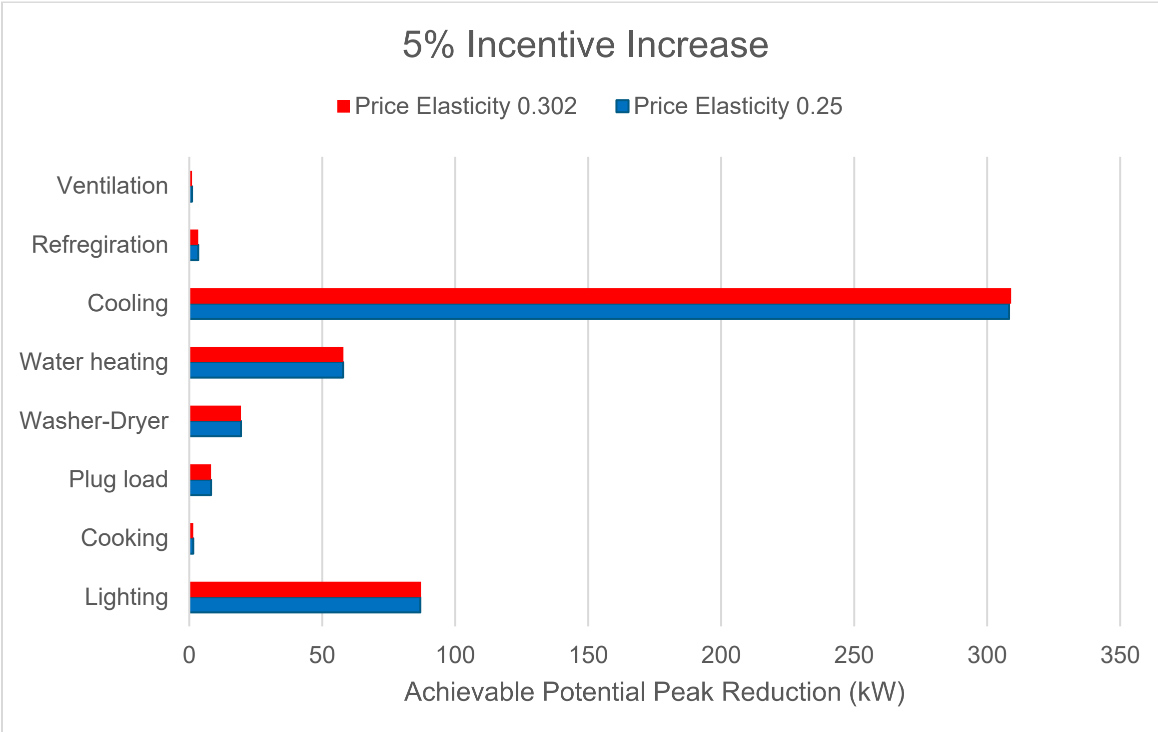

Figure 6-3 Impact of 5% Incentives Increase on Achievable Potential Per End-Use

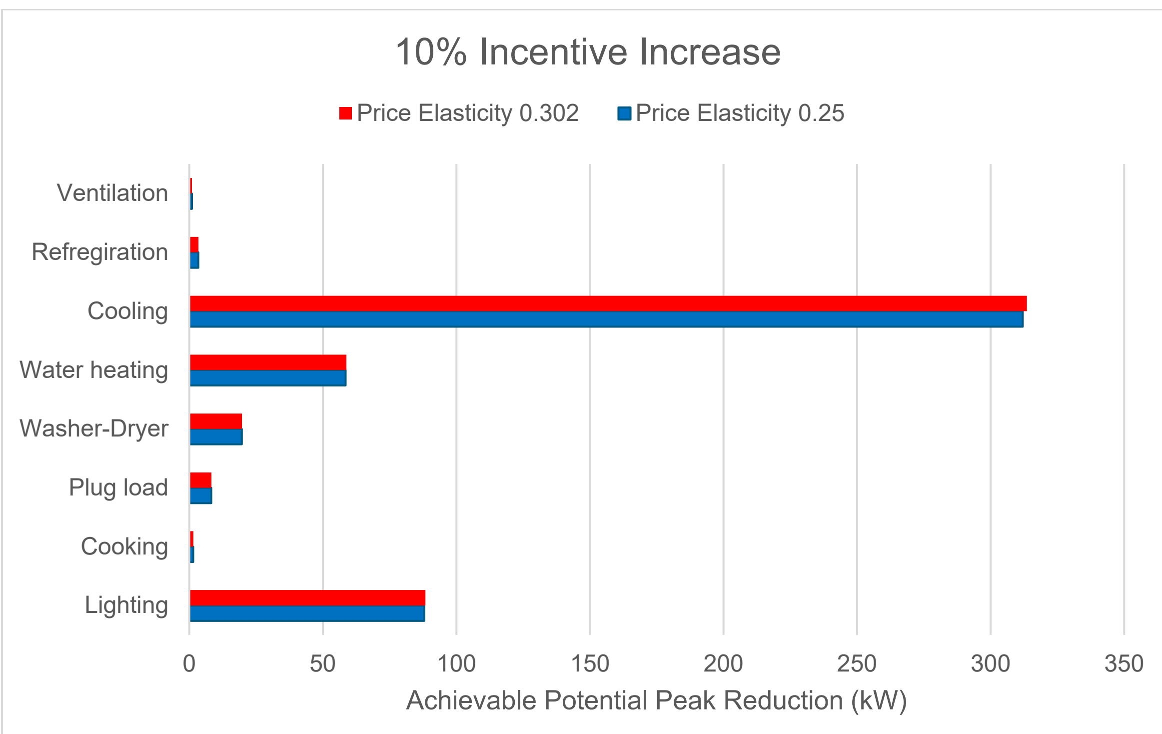

Figure 6-4 Impact of 10% Incentives Increase on Achievable Potential Per End-Use

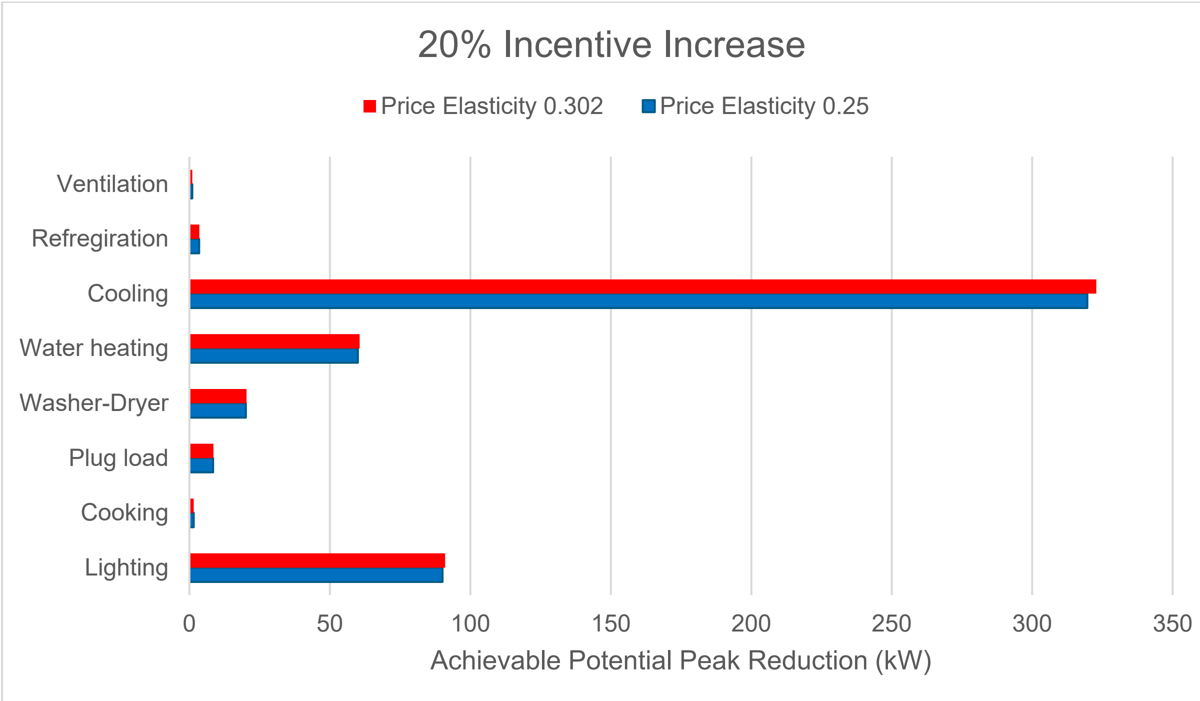

Figure 6-5 Impact of 20% Incentives Increase on Achievable Potential Per End-Use

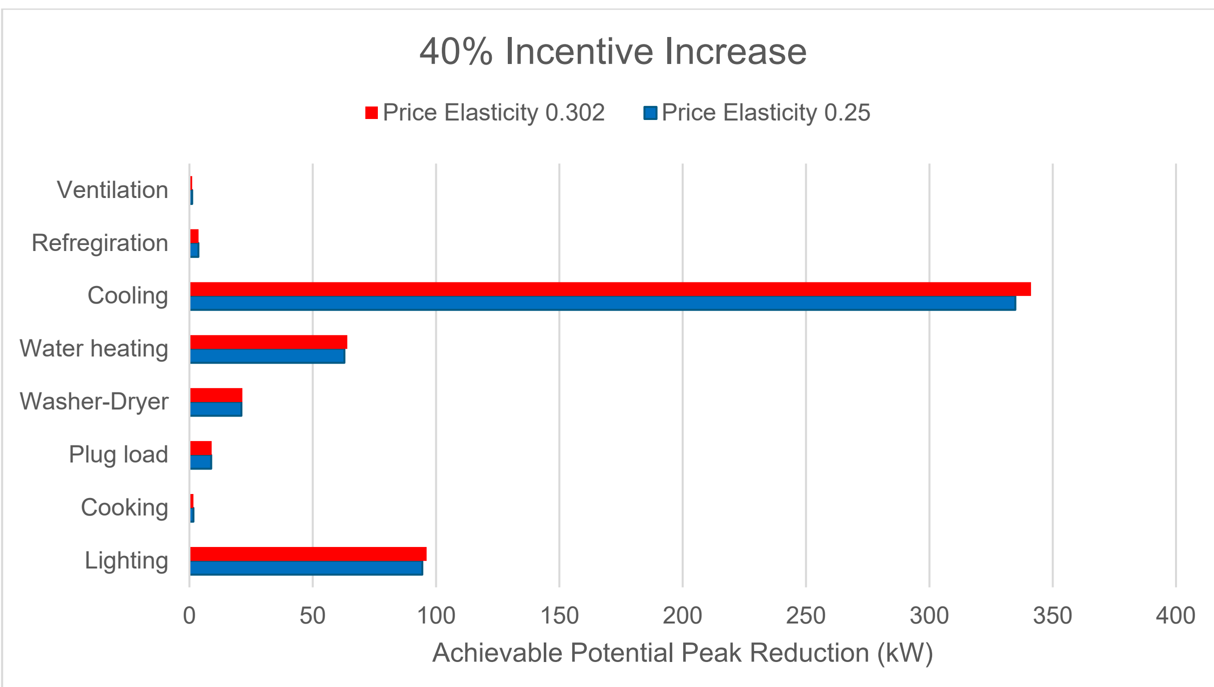

Figure 6-6 Impact of 40% Incentives Increase on Achievable Potential Per End-Use

6.1.1.2. Commercial Sector

The impact of incentive rate variations on the achievable potential peak reduction is estimated for each competition group of the commercial subsector/ end-use, and the total achievable potential peak reduction is estimated for each subsector and end-use. Figure 6-7 presents the increase in the achievable potential summer peak reduction, assuming incentive increases of 5%, 10%, 20%, and 40%. For commercial sector, the elasticity estimates suggest that increasing the amount of each product's incentive by 5%, 10%, 20%, and 40%, would increase the total achievable potential by 2.09-2.25 %, 4.09-4.40 %, 7.85-8.43 %, and 14.56-15.54 %, for price elasticity ranging from 0.426-0.46. In other words, increasing the incentive rates by 5%, 10%, 20%, and 40% resulted in an increase in the achievable potential to a value ranging from 6100.18 kW- 6100.33 kW, 6227.41-6247.72 kW, 6481.86-6522.47 kW, and 6990.75-7071.98 kW, respectively, for price elasticity ranging from 0.426-0.46.

Figures 6-8 to 6-11 present the achievable potential summer peak reduction per end-use for price elasticity of 0.426 and 0.46, assuming incentive increases of 5%, 10%, 20%, and 40, respectively

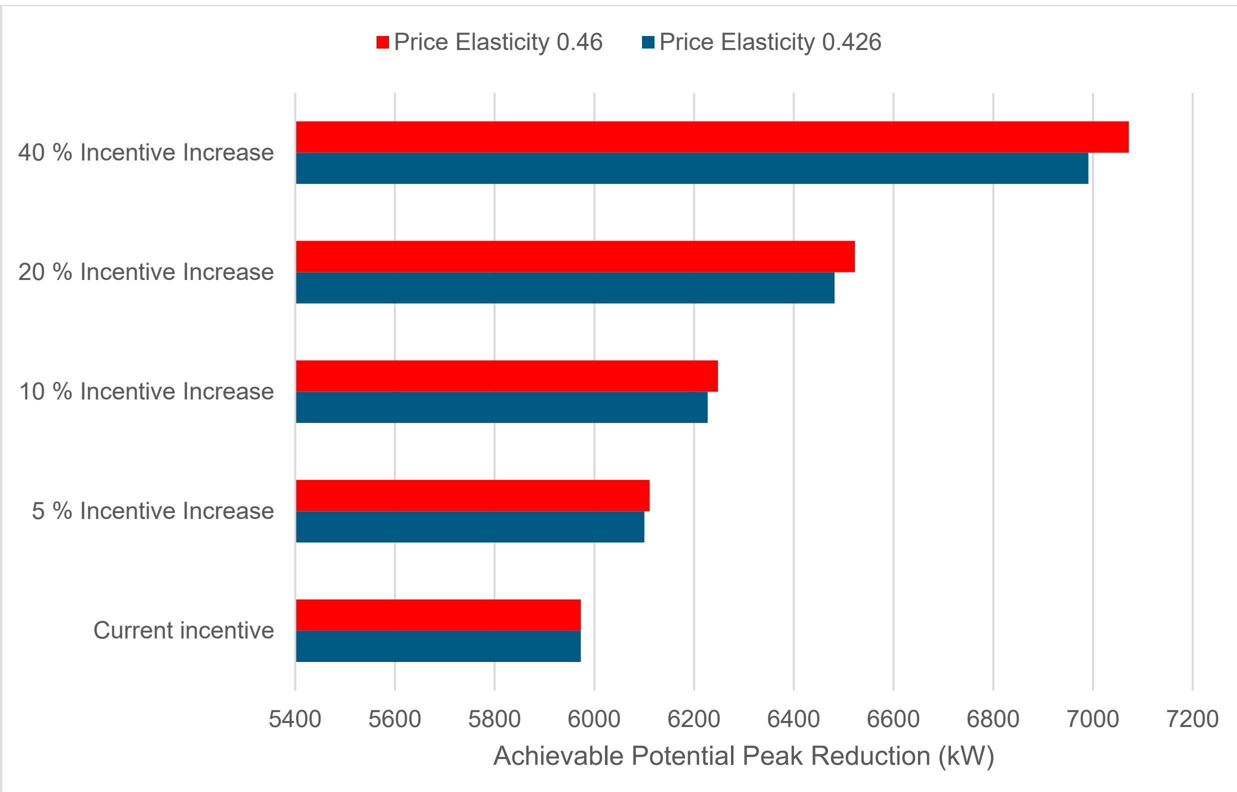

Figure 6-7 Impact of Incentives Variations on Commercial Sector Achievable Potential

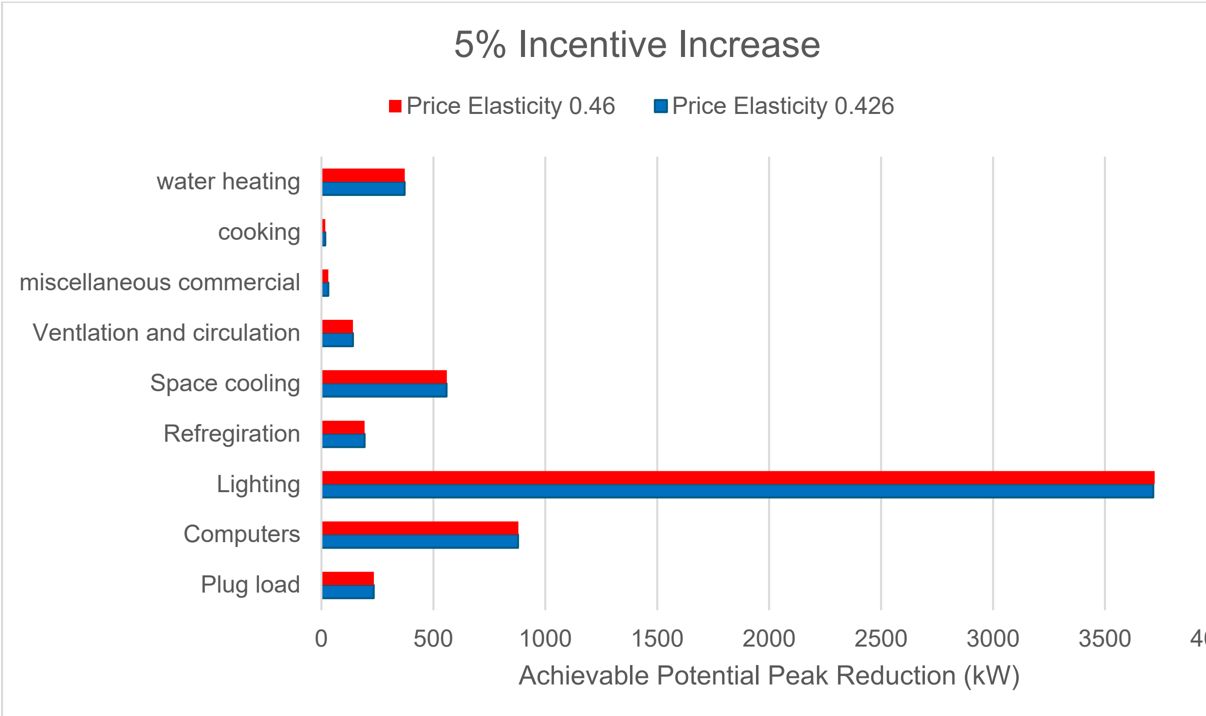

Figure 6-8 Impact of 5% Incentives Increase on Achievable Potential Per End-Use

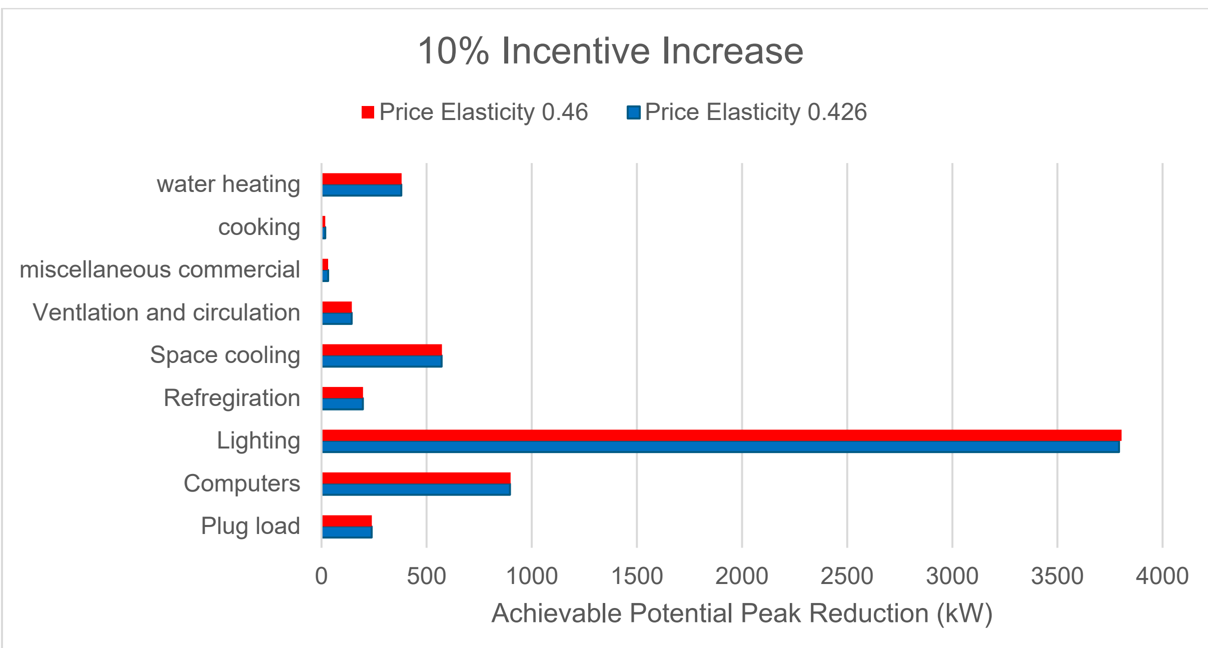

Figure 6-9 Impact of 10% Incentives Increase on Achievable Potential Per End-Use

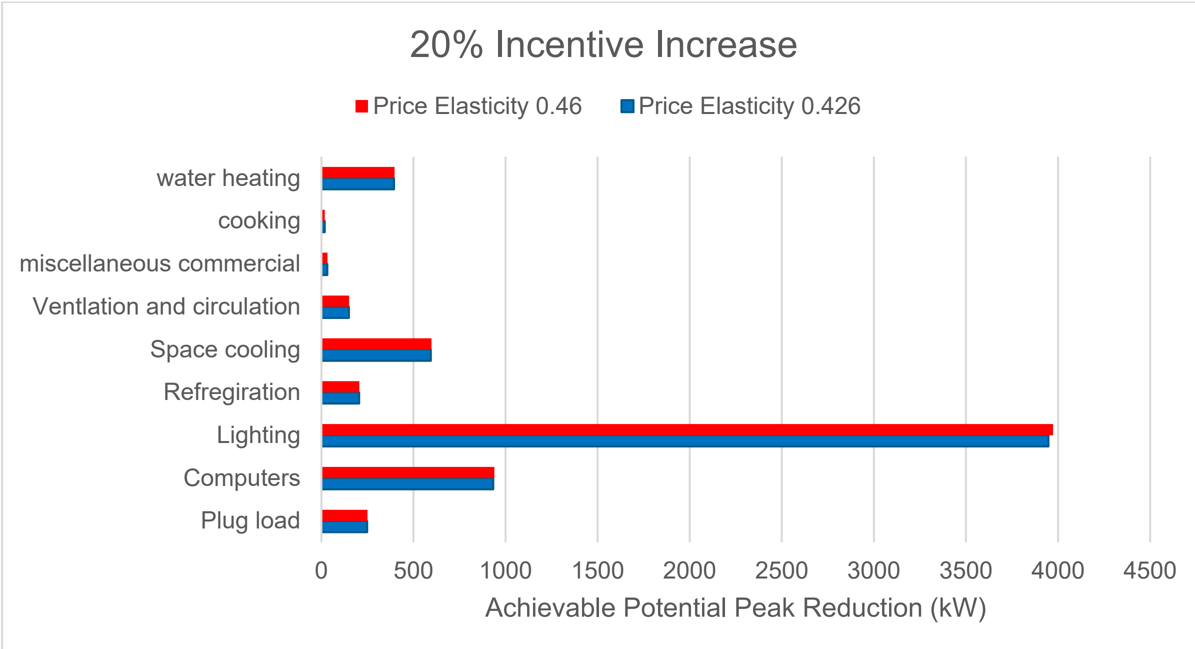

Figure 6-10 Impact of 20% Incentives Increase on Achievable Potential Per End-Use

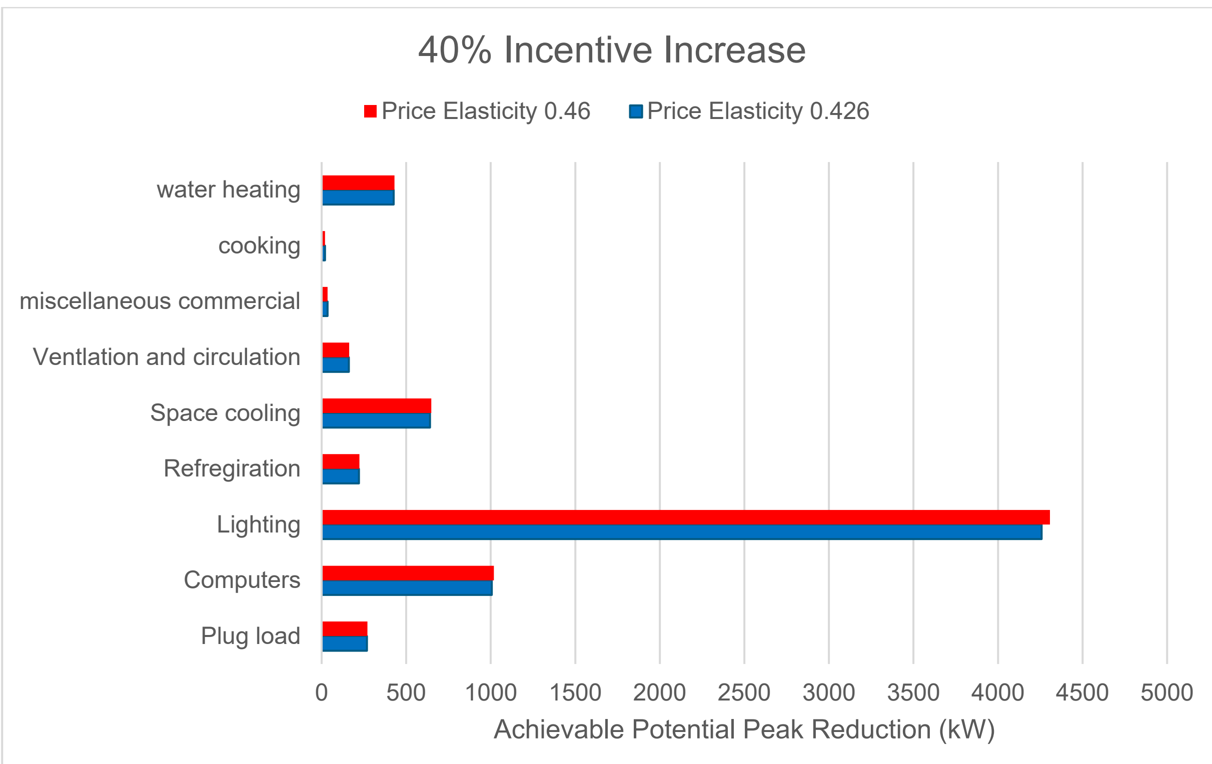

Figure 6-11 Impact of 40% Incentives Increase on Achievable Potential Per End-Use

6.1.1.3. DER

The impact of incentive rate variations on the achievable potential peak reduction is estimated for the DERs contract capacity based on the input data received from HOL in milestone #1. The installed capacity would reduce the summer peak demand (achievable potential) by 360.3 kW, as illustrated in Milestone # 3 report. Figure 6-12 presents the increase in the achievable potential summer peak reduction, assuming incentive increases of 5%, 10%, 20%, and 40%. For DERs, the elasticity estimates suggest that increasing the amount of each product's incentive by 5%, 10%, 20%, and 40%, would increase the total achievable potential by 1.24-1.49 %, 2.44-2.93 %, 4.76-5.69 %, and 9.09-10.78 %. In other words, increasing the incentive rates by 5%, 10%, 20%, and 40% resulted in an increase in the achievable potential to a value ranging from 364.804 kW- 365.741 kW, 369.308-371.181 kW, 378.315-382.32 kW, and 396.33-403.824 kW, respectively.

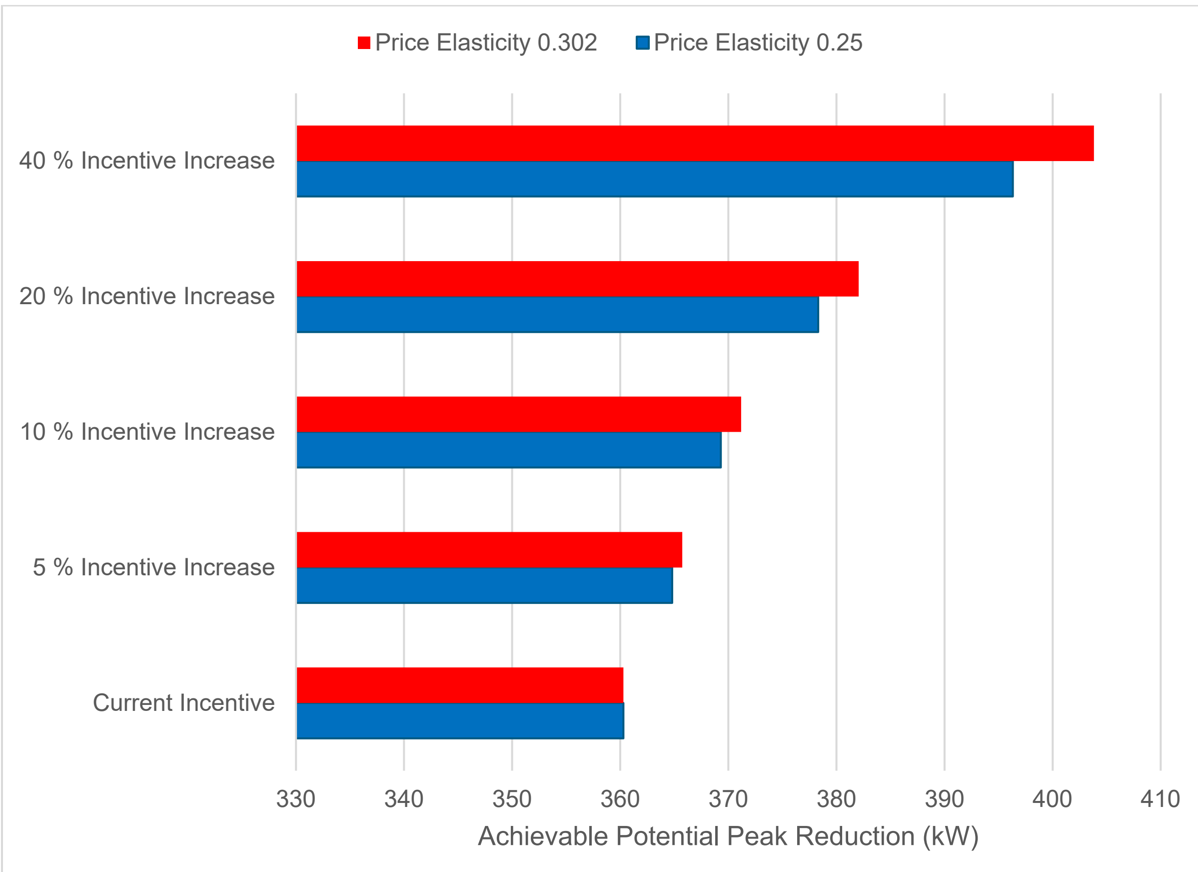

Figure 6-12 Impact of Incentives Variations on DERs Achievable Potential

6.2. Budget

Based on the analysis conducted in section 6.1, the achievable potential and the corresponding budget are estimated for various incentive levels, including current incentive levels, 5 % increase, 10 % increase, 20 % increase, and 40 % increase, as given in Figure 6-13. Where the horizontal axis represents the total estimated achievable potential in kW up to year 2023, while the vertical axis represents the total budget provided in the form of incentives (excluding program administrative costs) for participants up to year 2023.

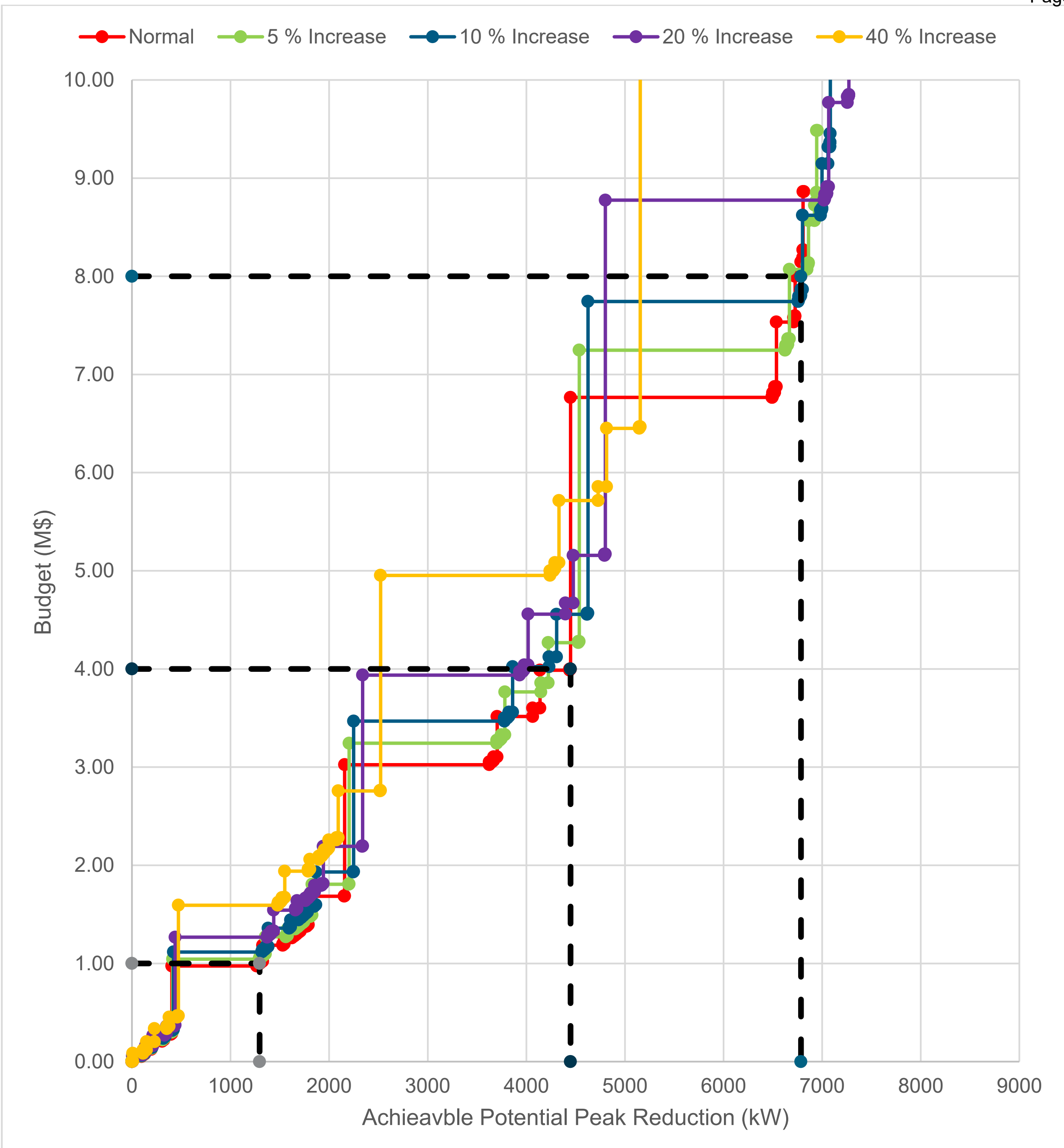

Figure 6-13 Achievable potential up to the year 2023 versus budget for various incentive levels

Three possible budget scenarios, up to the year 2023, are then considered (1 M$, 4 M$, and 8 M$). For each budget scenario, the achievable potential is estimated at the various incentive levels provided in Figure 6-13, and the incentive level providing the maximum achievable potential is considered.

The achievable potential and best incentive level for each of the three scenarios are summarized in table 6-1.

Table 6-1 Achievable Potential for different budget scenarios

Scenario	Incentive	Selected Incentive level	Achievable Potential up to the year 2023 (kW)
1	1 M$	Current	1294.95
2	4 M$		4448.27
3	8 M$		6785.48

According to Table 6-1, the current incentive levels provided by IESO yields the maximum peak reduction for most of the studied scenarios. Therefore the IESO current incentive levels are appropriate.

The total achievable potential for the three budget scenarios at different years is estimated in table 6-2, and the list of measures corresponding to each of the three scenarios is given in Appendix B.

It is worth noting that higher achievable potential is reachable with the consideration of utility-scale energy storage. The budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW.

Table 6-2 Achievable Potential for different budget scenarios

Budget Scenario	Achievable Potential (kW) up to year :			
	2020	2021	2022	2023
1	605.78	846.10	1090.53	1294.95
2	2871.13	3483.41	3994.14	4448.27
3	3882.80	4955.56	5937.02	6785.48

6.3. Avoided Costs

Avoided costs are the “anticipated marginal cost” of energy or capacity or both that the utility would have had to pay if it built a plant to generate that much power. In this study, the avoided costs are avoided energy costs and avoided capacity costs.

6.3.1. Avoided Energy Costs

Avoided energy costs account for variable generation costs, including the cost of fuel and variable Operation and maintenance (O&M) for power plants.

The avoided energy costs are calculated according to the following steps:

Step 1: Calculate the net energy savings at the generator level

Step 2: Energy saving is multiplied by the on-peak, off-peak, and shoulder pricing as per IESO reference [28]. The average energy costs for each year are given in table 6-3 [28].

Table 6-3 Avoided Cost of Energy Production

Year	Avoided Cost of Energy Production ($/MWh)					
	Winter			Summer		
	On-Peak	Mid-Peak	Off-Peak	On-Peak	Mid-Peak	Off-Peak
2020	27	26	24	24	23	22
2021	30	30	32	23	23	27
2022	28	26	24	25	25	23
2023	32	31	33	26	28	27

Table 6-4 Avoided energy cost (including line losses)

Budget Scenario	Avoided energy cost ($)				
	2020	2021	2022	2023	Total
1	123,311.78	145,316.53	161,403.79	190,935.57	620,967.67
2	423,586.15	499,174.27	554,435.34	655,879.43	2,133,075.18
3	646,146.80	761,450.44	845,746.78	1,000,491.63	3,253,835.65

6.3.2. Avoided Capacity Costs

Avoided capacity costs account for the reduction in coincident peak demand capacity, including avoided generation capacity (i.e., capital and fixed O&M required to build new generation), transmission, and distribution capacity costs.

The avoided capacity costs are calculated according to the following steps:

Step 1: Calculate the net annual peak demand reduction at the generator level

Step 2: Multiply the peak demand savings by the generation capacity cost to estimate the generation capacity cost. The generation capacity cost at each year is given in table 6-5 [28]

Table 6-5 Generation Capacity Costs

Year	Generation Capacity Cost ($/kW-year)
2020	62
2021	0
2022	104
2023	142

The avoided generation capacity cost is given in table 6-6.

Table 6-6 Avoided Generation capacity cost

Budget Scenario	Avoided Generation Capacity Cost ($)				
	2020	2021	2022	2023	Total
1	37,558.32	0	113,415.57	183,883.23	334,857.12
2	178,010.19	0	415,390.07	631,654.09	1,225,054.34
3	240,733.59	0	617,450.36	963,537.81	1,821,721.76

The avoided distribution capacity cost is assumed to be 160,000 $ per deferral year.

According to the coincident peak forecast for the Summer season developed in section 4.1.3 by considering the median and extreme weather conditions, the summer peak is estimated to reach 107 MW and 115 MW for the median and extreme weather conditions, respectively. The combined LTR rating of the two stations is 88.5 MW, which leads to a gap of 18.5 MW and 26.5 MW. Accordingly, the maximum achievable potential that can be obtained from the three budget scenarios (i.e. provided in table 6-1) represents only 25 % - 30 % of the MW gap. In conclusion, the CDM programs will not be able to meet reduce the peak demand to the desired level and the deferral of the substation cannot be justified. In this case, the avoided transmission capacity cost is zero.

On the other hand, the certainty of some load growth, such as (Broccolini Business Park) and (550 Innovation (Ciena)) should be checked annually due to the high required demand. If these projects were not implemented, the MW gap would reduce significantly, and the achievable potential associated with the CDM programs would be able to reduce the peak demand to the desired level. Based on the data provided by HOL, the cost of building the station is estimated at 36,000,000 $, while the distribution upgrades cost 4,000,000 $. Consequently, the avoided transmission capacity and distribution capacity is estimated based on 4 % interest rate which is equal to 1,144,000 and 160,000, respectively, per deferral year.

The avoided capacity costs for the three budget scenarios are summarized in table 6-7.

Table 6-7 Avoided capacity cost

Budget Scenario	Avoided Generation Capacity Cost up to the year 2023 ($)	Avoided Distribution Capacity Cost ($)	Avoided Transmission Capacity Cost ($)
1	334,857.12	160,000 per deferral year	1,144,000 per deferral year
2	1,225,054.34		
3	1,821,721.76		

6.4. Findings and Observations

The following can be observed from the load forecasts, avoided cost calculation, and achievable potential:

- The maximum achievable peak demand reduction up to 2023 is estimated at 6,785.48 kW (6.78 MW) for an incremental budget of C$ 8,000,000 (excluding program administrative cost).
- The desired peak demand reduction, which represents the gap between the existing summer peak and 2023 forecasted peak is 18.5 MW and 26.5 MW for median and extreme weather conditions forecast, which cannot be achievable from the CDM program.
- The certainty of some load growth, such as (Broccolini Business Park) and (550 Innovation (Ciena)) should be checked annually due to their high required demand, and their exclusion would reduce the gap significantly.
- It is worth noting that higher achievable potential is reachable with the consideration of utility-scale energy storage. The budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW.
- The avoided costs for budget scenario 3 (C$ 8,000,000) are estimated at C$ 5,075,557.41, in addition to C$ 1,144,000 (transmission capacity cost) for each deferral year, and 160,000 (distribution capacity cost) for each deferral year.

Table 6-8 Budget Scenarios and Avoided Costs Summary – up to 2023

<table>
<tr><th colspan="2"></th><th>Scenario 1</th><th>Scenario 2</th><th>Scenario 3</th></tr>
<tr><td colspan="2">Incentives (Budget)</td><td>1 M$</td><td>4 M$</td><td>8 M$</td></tr>
<tr><td colspan="2">Achievable Potential up to year 2023 (kW)</td><td>1294.95</td><td>4448.27</td><td>6785.48</td></tr>
<tr><td rowspan="4">Avoided Costs</td><td>Avoided Generation Capacity Cost up to the year 2023 ($)</td><td>334,857.12</td><td>1,225,054.34</td><td>1,821,721.76</td></tr>
<tr><td>Avoided Distribution Capacity Cost ($)</td><td colspan="3">160,000 for each deferral year</td></tr>
<tr><td>Avoided Transmission Capacity Cost ($)</td><td colspan="3">1,144,000 for each deferral year</td></tr>
<tr><td>Avoided Energy Cost up to the Year 2023 ($)</td><td>620,967.67</td><td>2,133,075.18</td><td>3,253,835.65</td></tr>
</table>

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Appendix A

Definitions and Extracted Data from the Input Database

Table A-9 Residential Subsector Definition

Subsector	Definition
Single family	Single-family, detached and semi-detached households
Row house	Single-family, attached households (e.g., townhouses)
Multi-Unit Residential Building (MURB) low rise	Individually metered units in multi-unit residential buildings less than five stories
Multi-Unit Residential Building (MURB) high rise	Individually metered units in multi-unit residential buildings greater than or equal five stories

Table A-10 Residential Subsector Definition

Subsector	Definition
Office buildings (non-medical)	Office buildings including governmental offices
Medical office buildings	Buildings whose primary business operations include healthcare services (e.g., labs and dialysis centers)
Elementary and/or secondary schools	Elementary and secondary education, apprenticeship, training, and daycare facilities.
Assisted daily/residential care facilities	Home health care facilities and homes for the elderly.
Warehouses Wholesale	Warehouse and wholesale distribution facilities
Hotels, motels or lodges	Overnight accommodation buildings
Hospitals	Inpatient and outpatient health facilities.
Food and beverage stores	Full-service restaurants, caterers, cafeterias, and retail buildings whose primary business operation includes the sale of food.
Non-food retail stores	All retail buildings whose primary business operation does not include the sale of food
Other activity or function	All other activities not specified above (e.g., theaters, sports arena, libraries, etc.)

Appendix B

Table B-11 List of CDM Measures for a Corresponding Budget (Incentives)

Sector	End-Use	Competition group	Measure	Cumlative Budget (Incentives) in $
Residential	Water heating	Hot Water-Insulation	PIPE WRAP : Per 3' Pipe Wrap (different ratings)	2,902.89
Commercial	Refrigeration	Walk-in	ECM MOTORS FOR EVAPORATOR FANS (REFRIGERATOR WALK-IN)	51,379.97
Residential	Water heating	Water heater	(Water, solar and natural gas) water Heater	74,401.20
Commercial	Plug Load	Vending M/C	BEVERAGE VENDING MACHINE CONTROLS	125,067.88
Commercial	Lighting	lighting	Refrigerated display case LED	206,208.56
Commercial	Refrigeration	Cabinet	ENERGY STAR® REFRIGERATOR: Glass Door (≥ 15 cu.ft. to < 30 cu.ft.)	221,506.77
Commercial	Plug Load	Other plug loads	Smart Strip Plug outlets	277,841.95
Commercial	Plug Load	Washer-plug load	electric hot water heater, electric and gas dryers	286,008.84
Commercial	Computers	Computers	NETWORK PC POWER MANAGEMENT SOFTWARE	973,966.74
Commercial	Refrigeration	Pipes	installation of insulation on bare Cooler suction pipes	978,320.33
Commercial	Refrigeration	strip curtain	Strip curtains for walk-in coolers or Freezers	991,961.20
Commercial	Refrigeration	Gasket	DOOR GASKETS FOR WALK-IN AND REACH-IN Coolers	994,389.45
Commercial	Refrigeration	Control	Anti-sweat heat (ASH) and temprature adjustment controls - Cooler/Freezer	997,502.39
Commercial	Refrigeration	Night covers	Vertical Night Covers	1,004,819.67
Commercial	Refrigeration	Refrigeration	Refrigeration Optimization	1,020,848.06
Commercial	Refrigeration	Insulation	Suction Pipe Insulation Freezer/Refrigerator	1,022,600.78
Commercial	Space Cooling	Chillers	Energy efficient Air-cooled chiller: different ratings	1,185,519.89
Commercial	Space Cooling	Room AC	Energy efficient RAC (with louvered sides): different ratings	1,197,657.85
Commercial	Space Cooling	Space Cooling	Chilled Water Optimization	1,259,227.74
Commercial	Space Cooling	Economizer	HVAC Optimization&outside air economizer	1,278,858.39
Commercial	Space Cooling	Space Cooling	air curtains	1,279,214.24
Commercial	Space Cooling	Insulation	Duct Insulation, R8	1,286,090.33
Commercial	Space Cooling	Roof treatment	Adding reflective (White) roof treatment or a green roof	1,297,850.64

Commercial	Ventilation and Circulation	Ventilation and circulation	Air Handler with Dedicated Outdoor Air Systems	1,318,154.92
Commercial	Ventilation and Circulation	Ventilation and circulation	CO Sensors for parking garage exhaust fans	1,328,987.86
Commercial	Ventilation and Circulation	Ventilation and circulation	Demand Control Kitchen Ventilation	1,379,783.23
Commercial	Miscellaneous Commercial	Visc commercial	CEE Tier 2/Energy Star Clothes Washers	1,379,893.20
Commercial	Miscellaneous Commercial	VSD	VSD Air Compressor	1,379,908.08
Commercial	Cooking	Dishwasher	ENERGY STAR Dishwasher	1,382,190.69
Commercial	Cooking	Cooking	High Efficiency Induction Cooking	1,393,437.95
Commercial	Water Heating	water heater	Efficient electric resistance water heater- Different Ratings & heat pump water heater	1,684,570.33
Commercial	Space Cooling	Space Cooling	ECM MOTORS FOR HVAC APPLICATION (FAN-POWERED VAV BOX)	1,687,387.05
Commercial	Lighting	indoor screw in	LED RECESSED DOWNLIGHTS- Different Ratings	3,024,412.18
Commercial	Miscellaneous Commercial	VFD	VFD on Pumps	3,052,572.40
Residential	Water heating	Showerhead	different showerhead	3,066,893.21
Commercial	Ventilation and Circulation	Ventilation and circulation	Variable Frequency Drive (VFD)	3,104,272.86
DERs	Solar PV Rooftop	Solar PV Rooftop	Solar PV Rooftop	3,515,288.69
Commercial	Plug Load	Ice M/C	ENERGY STAR® ICE MACHINES- Different Ratings	3,601,651.24
Residential	Cooling	Central AC	SEER 18 CAC	3,987,323.60
Residential	Lighting	light control	DIMMER SWITCH, light timer and Motion sensor	3,997,785.17
Commercial	Lighting	control	OCCUPANCY SENSORS: Switch Plate and fixture Mounted	6,766,000.63
Residential	Cooling	Space cooling control	Smart Thermostat	6,766,434.58
Residential	Water heating	Aerator	EFFICIENT AERATORS: Kitchen - (different ratings)	6,776,280.52
Residential	Lighting	Screw-in lamps	ENERGY STAR® QUALIFIED INDOOR LIGHT FIXTURE - Hard wired- Different Ratings	6,812,268.93
Residential	Cooking	Wall Oven	SmartBurner Intelligent Cooking System	6,816,417.54
Residential	Cooling	Thermal Envelope	Weather tripping door frame	6,816,909.47

Residential	Cooling	Room AC	ENERGY STAR® ROOM AIR CONDITIONER- Different Ratings	6,822,570.94
Residential	Washer Dryer	Dryer	ENERGY STAR Clothes Dryers, drying rack and gas clothes dryer	6,874,910.64
Commercial	Space Cooling	Packaged AC	UNITARY AIR-CONDITIONING UNIT- Different Ratings	7,533,610.56
Commercial	Refrigeration	Residential	Multi-Residential In Suite Appliance	7,579,540.37
Residential	Washer Dryer	Washer	ENERGY STAR Clothes Washers- Different Ratings	7,589,933.74
Residential	Ventilation	Screw-in lamps	ENERGY STAR® CEILING FAN	7,590,680.80
Residential	Ventilation	Dehumidifier	ENERGY STAR® DEHUMIDIFIER	7,596,185.35
Residential	Lighting	Screw-in lamps	ENERGY STAR® LED BULBS - (Different ratings)	7,999,713.07
Commercial	Lighting	outdoor screw in	LED EXTERIOR AREA LIGHTS: LED fixture different ratings	8,147,586.89
Residential	Washer Dryer	Dishwasher	Energy star dishwasher	8,152,880.33
Residential	Refrigeration	Refrigerator	ENERGY STAR® Refrigerator- Different Ratings	8,189,061.66
Residential	Cooling	Other Cooling	Ducted ASHP w/baseline having Cooling	8,189,540.18
Residential	Refrigeration	Freezers	ENERGY STAR® FREEZER- Different Ratings	8,269,073.80
Residential	Plug Load	Television	ENERGY STAR® Most Efficient TV (Different ratings)	8,862,912.48

Appendix C

SNC-Lavalin has submitted the following reports as part of the deliverables.

Description	Report Name	Revision Number
Milestone 1	660803_LAPS_Hydro Ottawa_Final Report_Milestone_1.pdf	00
Milestone 2	660803_LAPS_Hydro Ottawa_Final Report_Milestone_2.pdf	03
Milestone 3	660803_LAPS_Hydro Ottawa_Final Report_Milestone_3.pdf	00
Milestone 4	UPDATABLE_EXCEL_Model_R1.xlsm	NA

Hydro Ottawa Local Achievable Potential (LAP) Study

Local Load Characterization

Milestone #1 Report

SLI PROJECT NO.: 660803

				Tarek Abdelaziz	Tarek Abdelaziz
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SUMMARY

This is the first milestone report of the study entitled “Hydro Ottawa Local Achievable Potential (LAP) Study” which commenced on Dec. 7, 2018. This study, undertaken at the request of Hydro Ottawa Ltd, Ontario, is conducted by SNC-Lavalin Inc. Toronto, Canada, as the Consultant.

The objective of Milestone #1 of this study is to determine the local load characterization for Kanata North area served by Kanata and Marchwood MTS.

The project team developed the sector and subsector energy load profiles for the Kanata North area which serves prominently residential and commercial/ sectors. For each sector, the energy share distributions were estimated, and then each sector was segmented by subsectors (i.e., building type). Also, the team developed the end-use profiles for each sector. The end-use profiles from the IESO’s recent achievable potential studies as well as NRCAN residential and commercial end-use surveys were used to develop the end-use profiles for this study.

The project team compared the total reported (actual) annual consumptions for Kanata and Marchwood MTS both with the total consumptions determined from the bottom-up analysis to determine the gap and to calculate the calibration factor. After performing the calibration, the annual consumption for each feeder was obtained by calibrating the feeder’s consumption obtained from the analysis.

Based on the base year residential demand, the forecasted number of residential buildings, and the forecasted energy intensities, the team determined the residential forecast for Kanata and Marchwood MTS. Also, the team carried out the commercial forecast for Kanata and Marchwood MTS using the base year load consumption, the area forecast of commercial subsectors, and the forecasted energy intensities for commercial subsectors. Furthermore, the project team developed the end-use residential and commercial forecasts for Kanata and Marchwood MTS.

Based on the input data received from HOL and the IESO, the project team identified the historical participation of the loads in the Conservation and Demand Side Management (CDM) programs and the existing Distributed Energy Resources (DERs) as well as the potential for expansion. HOL and IESO provided the complete list of existing DERs, the total contract capacity of the DERs at Kanata-Marchwood area, and the forecasted effective capacities of the DERs and the CDM.

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List of acronyms

APS	Achievable Potential Study
CDM	Conservation and Demand Management
DB	Dun & Bradstreet Database
DER	Distributed Energy Resources
EUF	End-Use Forecasting
EUI	Energy Use Intensity
HOL	Hydro Ottawa Ltd
IESO	Independent Electricity System Operator
kWh	Kilo Watt hour
LAP	Local Achievable Potential
MPAC	Municipal Property Assessment Corporation
MURB	Multi-Unit Residential Building
NRCAN	Natural Resources Canada
OEB	Ontario Energy Board
SCIEU	Survey of Commercial and Institutional Energy Use
SHEU	Survey of Household Energy Use
sq. ft.	Square feet

1 Introduction

This report provides the methodology and the complete analyses of milestone #1 that aims to determine the local load characterization for the Kanata North area served by Kanata and Marchwood MTS. This progress report is summarizing the following:

- Market segmentation of the load of Kanata and Marchwood MTS,
- End-use segmentation of the residential and commercial sectors,
- Reference case forecast: 2018-2040 of Kanata and Marchwood MTS load segmented to sectors, subsectors, and end-use,
- Survey of existing area DERs, and
- Summary of local historical participation in CDM programs.

2 Methodology

The project team followed the approach presented in [1-2] to develop a unique profile by conducting the following tasks:

- Segmentation of Kanata North area customers by sector, by subsector and by end use,
- Calibration of the obtained profile to changes in sales and customer forecasts, and
- Determine the existing DERs in the area and the local historical participation in CDM programs.

2.1 Segmentation by sector and by subsectors

The energy share distributions for the residential and commercial/institutional sectors are determined, and then each sector is segmented by subsectors (i.e., building type). Table 2-1 summarizes the sectors and subsectors used in the study. This classification is aligned with the IESO's End-Use Forecasting (EUF) model for planning purposes.

Table 2-1 Sectors and Subsectors

Sector	Residential	Commercial
Subsector	• Single family • Row house • Multi-unit Residential Building - low rise • Multi-unit Residential Building - high rise	• Office buildings (non-medical) • Medical office buildings • Elementary and/or secondary schools • Assisted daily/residential care facilities • Warehouses wholesale • Hotels, motels or lodges • Hospitals • Food and beverage stores • Non-food retail stores • Other activity or function

2.1.1 Residential buildings

The residential sector buildings are subdivided to four categories based on the definition presented in Table A-1. Kanata-Marchwood area residential buildings characteristics are used to develop the local area residential load segmentation as follows;

- The number of residential units by subsector is determined based on the google earth files [3] provided by HOL.
- The counted number of a residential building is calibrated to the number given by HOL for each feeder.
- The energy use intensity (annual kWh consumption/ unit) is derived from the NRCAN residential building SHEU database [4] and adjusted to the average EUI reported in the OEB yearbook [5].
- The total residential estimated annual consumption is compared and calibrated to the actual residential consumption provided by HOL.

2.1.2 Commercial Sector

The commercial sector buildings are subdivided to ten categories based on the definition presented in Table A-2. Kanata-Marchwood area commercial buildings characteristics are used to develop the local area commercial load segmentation as follows;

- The square footage area of commercial buildings by subsector is determined based on Dun & Bradstreet database [6], MPAC database [7], Hemson Data [8], and google earth files [3] provided by IESO and HOL.
- The energy use intensity (annual kWh consumption/ unit) is derived from commercial building SCIEU database [9].
- The total annual electricity consumption (kWh) for public sector facilities is determined by the Public Sector database [10]
- The total commercial estimated annual consumption is compared and calibrated to the actual commercial annual consumption provided by HOL to determine the commercial load segmentation that represents the actual load segmentation for Kanata-Marchwood local area.

2.2 Segmentation by end use

End-use profiles are to be developed for each sector, and Table 2-2 provides a summary of the end uses for the residential and commercial sectors. End-use profiles from the IESO's recent achievable potential studies [2] as well as NRCAN residential and commercial end-use surveys are used to develop the end-use profiles for this study.

Table 2-2 End Uses per Sector

Sector	Residential	Commercial
End uses	Lighting Plug Load Space Heating Space Cooling Ventilation and Circulation Domestic Hot Water Refrigeration Washer/ Dryer/ Dishwashers Cooking Dehumidifiers Miscellaneous	Lighting Space Cooling Ventilation Space Heating Domestic Hot Water Cooking Refrigeration Computer Equipment Other Plug Loads Miscellaneous

2.3 Calibration Methodology

The total reported (actual) annual consumptions for Kanata and Marchwood MTS are compared with the total consumptions determined from the bottom-up analysis to determine the gap and to calculate the calibration factor. After performing the calibration, the annual consumption for each feeder is obtained by calibrating the feeder's consumption obtained from the analysis.

The methodology used for calibration is discussed as follows;

1- The actual annual consumption for each feeder is obtained using the feeders' hourly consumption data provided by HOL.
2- The total actual consumptions should be reduced by a factor of 17 % to represent the share of street lighting and a factor of 3 % to represent the system losses
3- Based on the bottom-up methodology, the annual consumptions for all subsectors and sectors are estimated. Then, the estimated annual consumption for each station is determined as the total sum for all sectors consumptions per station.
4- The reported metered annual consumptions for residential, commercial, and industrial customers are compared to the estimated consumptions.
5- The calibration factor, for each sector, is calculated as the ratio between the total actual annual consumption for the sector divided by the total bottom-up estimated annual consumption for the sector.

6- The calibration factor is then used to modify the bottom-up estimated consumption; i.e., the calibration factor is multiplied times the bottom-up estimation to determine an estimation that is matching the actual annual consumptions.

2.4 Adjust Kanata North load Profile to Changes in Sales and Customer Forecasts

SNC requested all the anticipated changes on load trend from HOL, and HOL declared that no fuel switching is anticipated. Thus, the project team use the findings of the Hemson study, the official community plan for Kanata North [11], and NRCAN surveys to develop the load forecast over the study period.

2.5 Participation in CDM and DER program

From the input data from HOL and IESO, the existing DERs, and the potential for expansion, the participation of DER in Kanata North area identified. Moreover, the historical participation of the loads in the CDM programs are assessed.

3 Load Segmentation for Base Year and Reference Case Forecast

3.1 Kanata MTS load segmentation for Base Year (2018) by Sector/ Subsector

The methodology presented in section 2 is applied to Kanata premises that consist of five feeders named 624F1, 624F2, 624F3, 624F5, 624F6. This section presents the analysis performed for the five feeders presented in Figure 3-1. These feeders' service areas are covering residential and commercial loads as well as one large industrial load located at feeder 624F2.

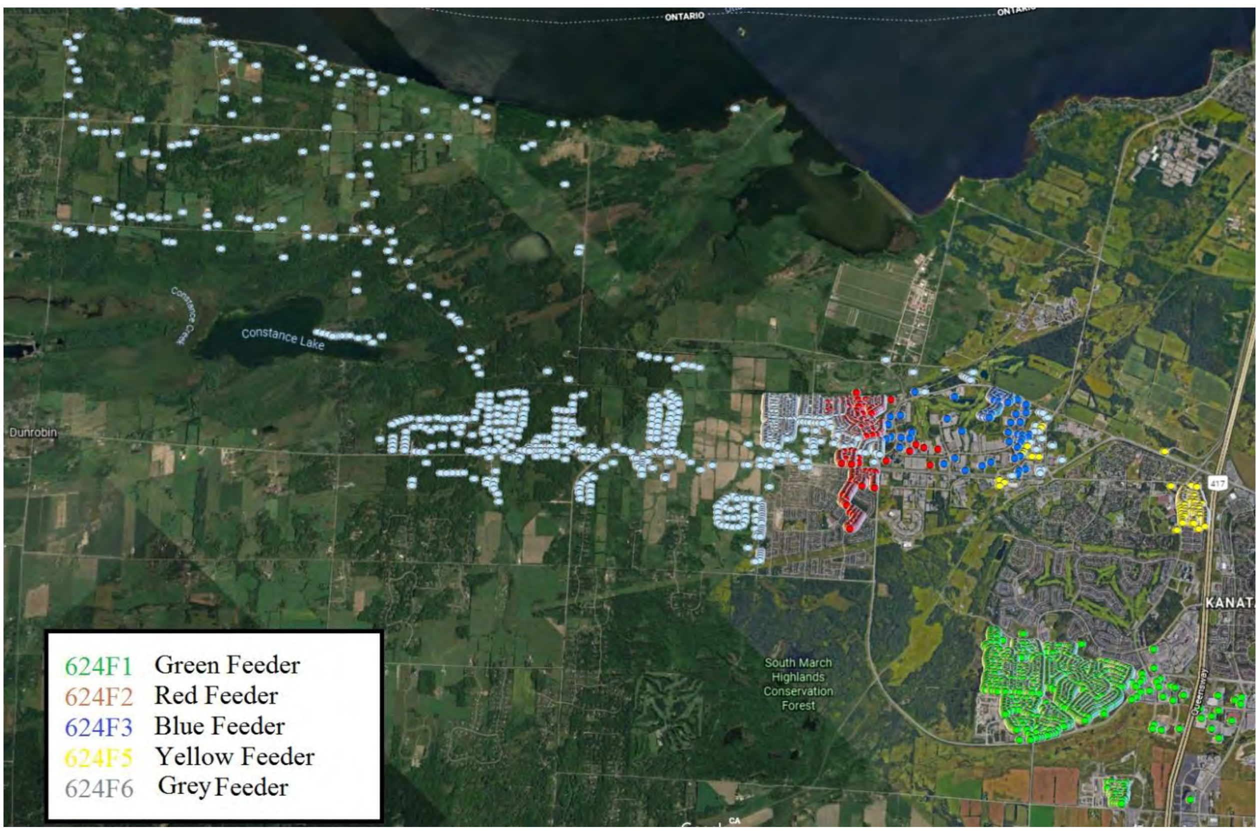


Figure 3-1 Kanata MTS service area

3.1.1 Kanata MTS Residential load segmentation

The residential sector buildings are subdivided to four subsectors based on the definition presented in Table A-1, the number of residential buildings in each subsector is counted using Google Earth files provided by HOL and adjusted using the total residential building number provided by HOL; Table 3-1 summarizes the number of buildings in each subsector for each of the five feeders.

Table 3-1 Residential Subsectors Premises, Kanata MTS

Residential building type	Single family	ROW	Low rise	High rise	Total
Number of units / Subsector for feeder 624F1	1596	924	192	0	2712
Number of units / Subsector for feeder 624F2	458	387	0	0	845
Number of units / Subsector for feeder 624F3	111	169	94	194	568
Number of units / Subsector for feeder 624F5	22	81	0	0	103
Number of units / Subsector for feeder 624F6	652	945	0	0	1597
Number of units / Subsector for Kanata MTS	2839	2506	286	194	5825

The NRCAN residential building (SHEU) database is used to determine the energy intensity per premise; Table 3-2 summarises the energy intensities for all residential subsectors in Ontario. The methodology discussed in section 2 is applied, and the total annual energy, annual electricity consumption, and the annual Natural gas consumption for each subsector are obtained. Then, the average estimated kWh per residential customer is calculated using the total residential consumption and the total number of residential buildings; the average estimated kWh per customer for Kanata MTS is 7,732 kWh which is close to the actual kWh per residential customer reported in the OEB yearbook (i.e., 7,537 kWh). Thus, no calibration is needed. A summary of the total residential consumption for Kanata MTS service area is presented in Table 3-3.

Table 3-2 Residential Subsectors Energy Intensity [9]

Residential building type	Single family	ROW	Low rise	High rise
Annual Total Energy intensity (eMWh/household)	38.74571	26.5547 3	8.17610 8	9.575353
Annual Electricity intensity (MWH/household)	9.652535	6.09079 2	4.81258 6	5.118794
Natural Gas intensity (eMWh/household)	24.56966	20.3224 7	3.31705 8	4.36854
Other Energy intensity (eMWh/household)	4.52353	0.14147 3	0.04646 8	0.088023

Table 3-3 Total Residential Subsectors Energy Consumptions for Kanata MTS

Residential building type	Single Family	ROW	Low Rise	High Rise	Total
Annual Electricity consumptions (MWh)	27,404	15,264	1,376	993	45,037
Annual Natural gas consumptions (eMWh)	69,753	50,928	949	848	122,478
Annual Other energy consumptions (eMWh)	12,842	354	13	17	13,227
Total Annual Energy consumptions (eMWh)	109,999	66,546	2,338	1,858	180,741

3.1.2 Kanata MTS Commercial load segmentation

Dun & Bradstreet database, MPAC database, and Google Earth files are used to determine the number, area, and activity of all commercial buildings located at each of the five feeders of Kanata MTS. The energy intensities for all commercial subsectors are obtained using the NRCAN commercial building SCIEU database and summarized in Table A-3. The methodology discussed in section 2 is applied, and the total annual energy, annual electricity consumption, and the annual Natural gas consumption for each commercial subsector are obtained; a summary of the total commercial consumption for Kanata MTS service area is presented in Table 3-4.

Table 3-4 Commercial Subsectors Energy Consumption, Kanata MTS

Commercial Subsector	Annual Electricity Consumption (MWh)	Annual Natural gas Consumption (eMWh)
Office buildings (non-medical)	90,018	52,672
Medical office buildings	3,135	2,270
Elementary and/or secondary schools	1,416	2,124
Assisted daily/residential care facilities	1,197	1,246
Warehouses Wholesale	5,106	6,768
Hotels, motels or lodges	3,003	3,386
Hospitals	0	0
Food and beverage stores	13,653	5,407
Non-food retail stores	11,414	9,983
Other activity or function	5,282	6,200

3.1.3 Kanata MTS Industrial Load segmentation

Dun & Bradstreet database, MPAC database, and Google Earth files are used to determine the number, area, number of employees, and primary activity of all industrial buildings located at Kanata MTS service area. One industrial building is found at feeder 624F2 as shown in Table 3-5. The total annual energy, annual electricity consumption, and the annual Natural gas consumption for the industrial building are obtained based on the methodology described in section 2.1.3; the obtained results are presented in Table 3-6.

Table 3-5 Industrial Facilities located at Kanata MTS

Feeder	Company Name	Address	Activity	Square Footage	Employees
624F2	ASTENJOHNSON, INC	1243 TERON RD	Fibre, Yarn and Thread Mills	120, 181	37

Table 3-6 Industrial Subsectors Total Energy Consumption for Kanata MTS

Subsector	Electricity Consumption (MWh)
Miscellaneous industrial	3,150

3.2 Marchwood MTS load segmentation for Base Year (2018) by Sector/ Subsector

The methodology discussed in section 2 is applied to Marchwood premises that consist of four feeders named MWDF1, MWDF2, MWDF3, and MWDF4. This section presents the analysis performed for the four feeders presented in Figure 3-2. These feeders' service areas are covering different residential, commercial, and industrial loads.

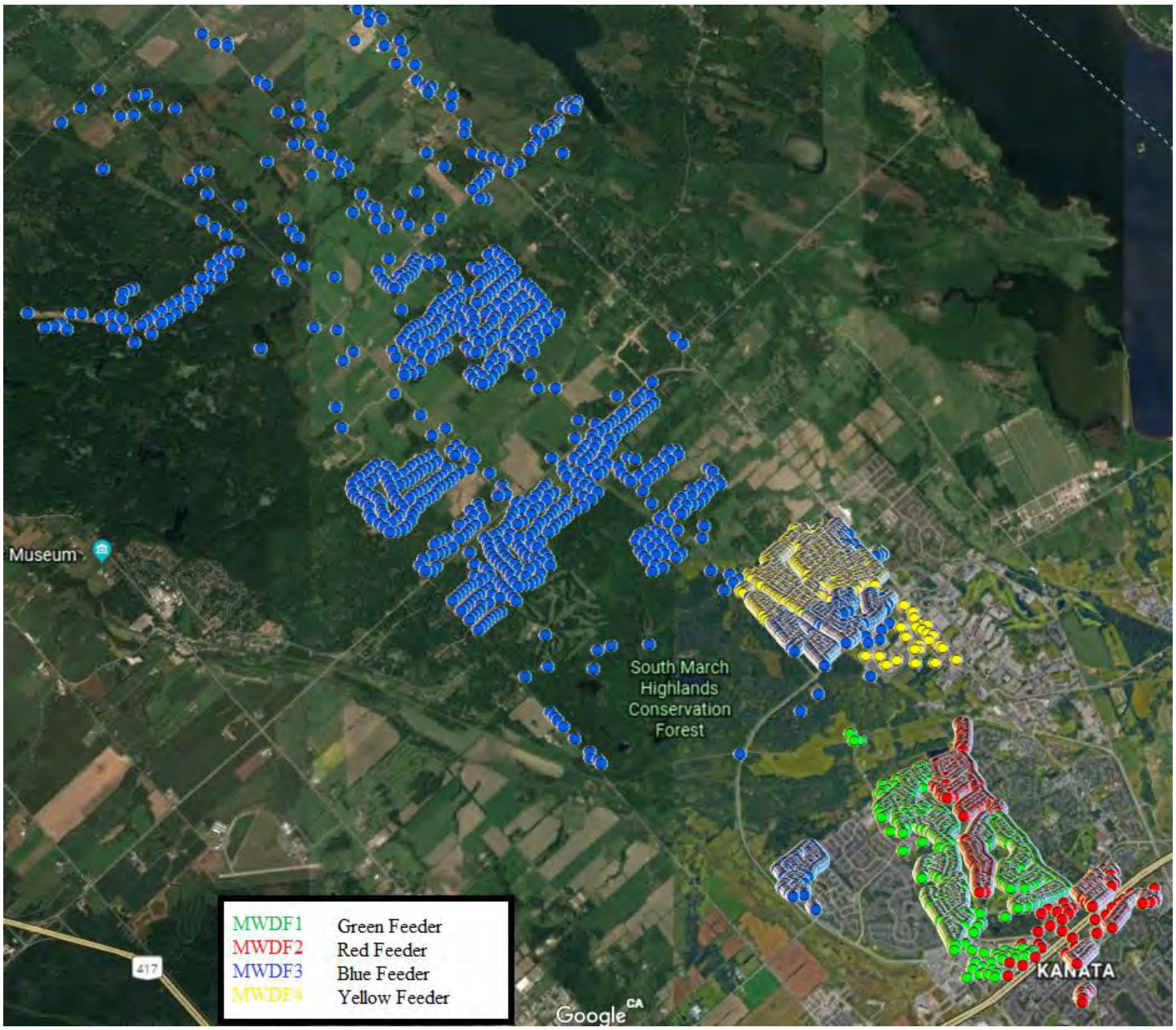


Figure 3-2 Marchwood MTS service area

3.2.1 Marchwood MTS Residential load segmentation

The residential sector buildings are subdivided to four subsectors based on the definition presented in Table 2-1, the number of residential buildings in each subsector is counted using Google Earth files provided by HOL; Table 3-7 summarizes the number of buildings in each subsector for each of the four feeders.

Table 3-7 Residential Subsectors Premises, Marchwood MTS

Residential Building Type	Single Family	ROW	Low Rise	High Rise	Total
Number of premises / subsector for feeder MWDF1	1076	649	62	0	1787
Number of premises / subsector for feeder MWDF 2	584	696	0	739	2019
Number of premises / subsector for feeder MWDF3	1435	889	86	0	2410
Number of premises / subsector for feeder MWDF4	1192	348	0	0	1540
Number of premises / subsector for Marchwood MTS	4287	2582	148	739	7756

The NRCAN residential building (SCEU) database is used to determine the energy intensity per premise as summarized in Table 3-2. The total annual energy, annual electricity consumption, and the annual Natural gas consumption for each subsector are obtained. Then, the average estimated kWh per residential customer is calculated using the total residential consumption and the total number of residential buildings; the average estimated kWh per customer for Kanata MTS is 7,802 kWh which is very close to the actual kWh per residential customer reported in the OEB yearbook (i.e., 7,537 kWh). Thus, no adjustment for the used EUIs needed. A summary of the total residential consumption for Marchwood MTS service area is presented in Table 3-8.

Table 3-8 Total Residential Subsectors Energy Consumptions for Marchwood MTS

Residential Building Type	Single Family	ROW	Low Rise	High Rise	Total
Annual electricity consumptions (MWh)	41,381	15,726	712	3,783	41,381
Annual natural gas consumptions (eMWh)	105,330	52,473	491	3,228	105,330
Annual other energy consumptions (eMWh)	19,393	365	7	65	19,393
Total annual energy consumptions (eMWh)	166,103	68,564	1,210	7,076	166,103

3.2.2 Marchwood MTS Commercial load segmentation

Dun & Bradstreet database, MPAC database, and Google Earth files are used to determine the number, area, and activity of all commercial buildings located at each of the four feeders of Marchwood MTS. The energy intensities for all commercial subsectors are obtained using the NRCAN commercial building SCIEU database. The methodology described in section 2 is applied, and the total annual energy, annual electricity consumption, and the annual Natural gas consumption for each commercial subsector are obtained; a summary of the total commercial consumption for Marchwood MTS service area is presented in Table 3-9.

Table 3-9 Commercial Subsectors Energy Consumption, Marchwood MTS

Commercial Subsector	Annual Electricity Consumption (MWh)	Annual Natural Gas Consumption (eMWh)
Office buildings (non-medical)	31,555	18,532
Medical office buildings	2,475	1,792
Elementary and/or secondary schools	3,477	5,215
Assisted daily/residential care facilities	3,818	3,973
Warehouses Wholesale	1,498	1,986
Hotels, motels or lodges	3,205	3,614
Hospitals	0	0
Food and beverage stores	12,607	4,903
Non-food retail stores	13,690	11,662
Other activity or function	3,766	4,421

3.2.3 Marchwood MTS Industrial Load segmentation

Dun & Bradstreet database, MPAC database, and Google Earth files are used to determine the number, area, number of employees, and primary activity of all industrial buildings located at Marchwood MTS service area. The data search shows that no industrial buildings are located at Marchwood service area.

3.3 Calibrated Load Segmentation for Base Year

The calibration methodology described in section 2.3 is applied to determine the calibration factor for each sector. The actual annual consumption for Kanata and Marchwood MTS is obtained using the data provided by HOL; this consumption is reduced by a factor of 17 % to represent the share of street lighting and a factor of 3 % to represent the system losses (obtained from 2017 OEB Yearbook [5]) as shown in Tables 3-10 and 3-11.

Table 3-10 Actual and estimated consumptions for Kanata MTS

Kanata		Consumptions (kWh)
Actual consumptions	with street lighting	321,700,199
	without street lighting	267,011,165
	without street lighting & losses	259,000,830
Estimated consumptions	Residential	45,036,520
	Commercial	189,328,355
	Industrial	3,150,000
	Total	237,514,875
Gap		-21,485,955

Table 3-11 Actual and estimated consumptions for Marchwood MTS

Marchwood		Consumptions (kWh)
Actual consumptions	with street lighting	178,540,075
	without street lighting	148,188,262
	without street lighting & losses	143,742,614
Estimated consumptions	Residential	63,520,491
	Commercial	85,020,705
	Industrial	0
	Total	148,541,196
Gap		4,798,582

The reported metered KWh for residential customers is compared to the bottom-up estimation, and the results are closely matched. Thus, the estimated annual consumption for residential sector is kept without calibration. Then, the calibration factor is calculated, for the commercial and industrial sectors, as the ratio between the total actual annual consumption for commercial and industrial sectors divided by the total bottom-up estimated annual consumption for commercial and industrial sectors (Table 3-12).

Table 3-12 Calibration Factor Calculation

	Kanata	Marchwood	Sum	Sum of commercial and Industrial
Total actual (kWh)	259,000,830	143,742,614	402,743,445	294,186,433
Total estimated (kWh)	237,514,875	148,541,196	386,056,071	277,499,060
Calibration Factor	= (294,186,433 / 277,499,060) =1.06013			

3.3.1 Calibrated Load Segmentation by sector/sub-sector

The obtained calibration factor is used to modify the estimated consumption for each feeder; i.e., the calibration factor is multiplied times the bottom-up estimation of each feeder to determine a bottom-up estimation that is matching the actual annual consumptions. Table 3-13 and Table 3-14 show the total estimated electrical consumptions (after calibration) for Kanata and Marchwood respectively. Moreover, Tables B-1 to B-13 shows the detailed estimated electrical consumption for each feeder for each sector/ subsector.

Table 3-13 Estimated consumptions (kWh) for Kanata MTS after calibration

Kanata	624F1	624F2	624F3	624F5	624F6	Total
Residential	21,957,355	6,777,998	3,546,205	705,710	12,049,252	45,036,520
Commercial	35,437,231	52,884,403	7,694,143	75,889,460	28,808,356	200,713,593
Industrial	0	3,339,425	0	0	0	3,339,425
Total	57,394,587	63,001,826	11,240,347	76,595,170	40,857,608	249,089,538

Table 3-14 Estimated consumptions for Marchwood MTS after calibration

Marchwood	MWDF1	MWDF2	MWDF3	MWDF4	Total
Residential	16,556,027	13,659,061	19,679,985	13,625,418	63,520,491
Commercial	31,584,597	20,260,960	10,979,980	27,307,879	90,133,415
Industrial	0	0	0	0	0
Total	48,140,624	33,920,021	30,659,965	40,933,296	153,653,906

3.4 End-Use Load segmentation for Base Year

3.4.1 Kanata End-Use segmentation

Based on the end-uses profiles provided by IESO for the residential and commercial sectors, the project team developed the end-use load segmentation for As per discussion with HOL, only one industrial building is located at Kanata- Marchwood area; thus, the project team performs the load segmentation for the residential and commercial buildings. The Kanata area. The end-use classification was performed using the calibrated annual consumption of the loads.

A. Kanata Residential End-Use segmentation

The end-use segmentations for Kanata MTS are developed for the residential sector and subsectors. Kanata residential end-use segmentation for the residential sector is presented in Figure 3-3, while Kanata residential end-use segmentations for the single house, Row, Low-rise, and High-rise subsectors are presented in Figures B-1, B-2, B-3, and B-4 respectively.

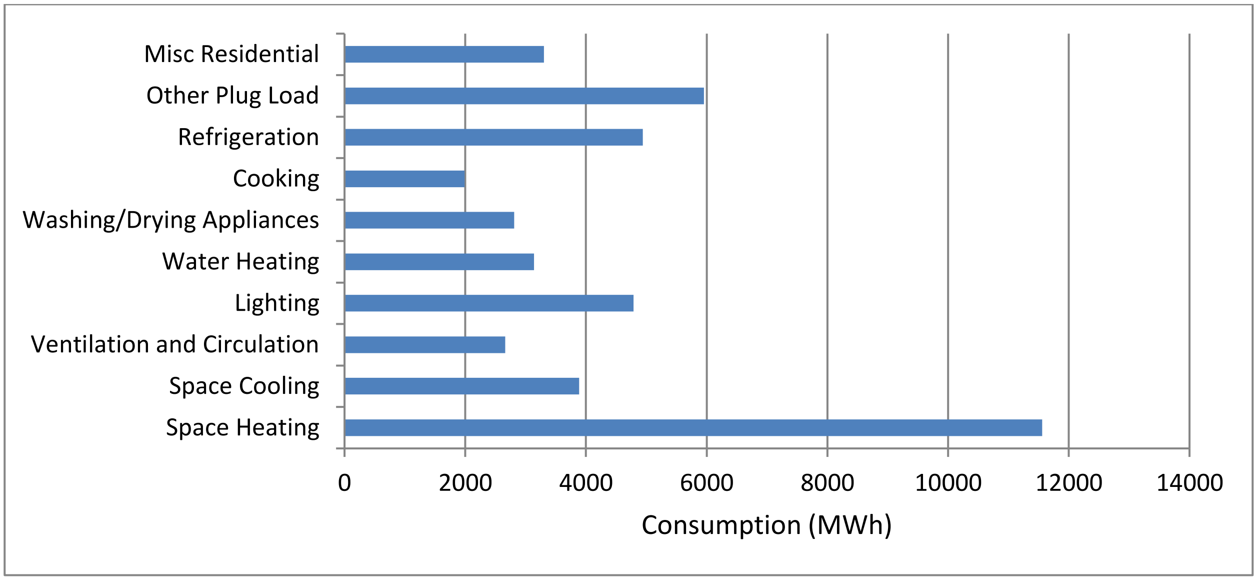


Figure 3-3 End-use Segmentation for Residential Sector, Kanata MTS

B. Kanata Commercial End-Use segmentation

Based on the end-uses profiles provided by IESO for the commercial sectors, the project team developed the end-use load segmentation for Kanata. The end-use segmentation for the commercial sector is presented in Figures 3-4. Moreover, the end-use segmentations for all commercial subsectors are presented in Figures B-5 to B-13.

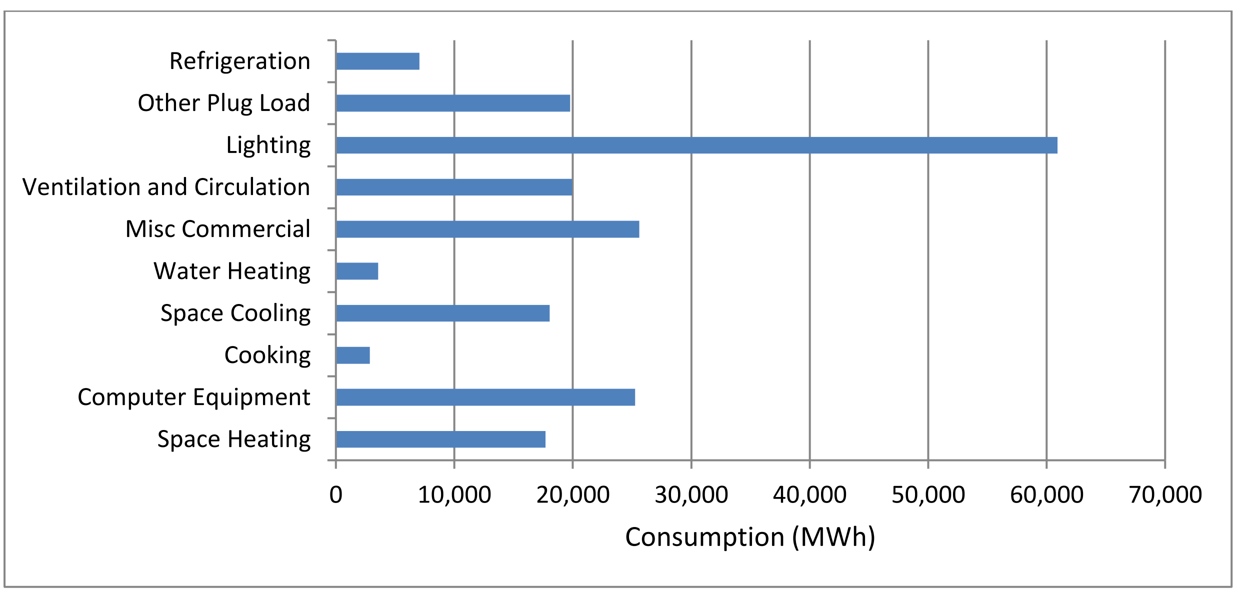


Figure 3-4 End-use Segmentation for Commercial Sector, Kanata MTS

3.4.2 Marchwood MTS End-Use Load segmentation

A. Marchwood Residential End-Use segmentation

The end-use segmentations for Marchwood MTS are developed for the residential sector and subsectors. The residential end-use segmentation is presented in Figure 3-5, while subsector residential end-use segmentations for the single house, Row, Low-rise, and High-rise are presented in Figures B-14, B-15, B-16, and B-17 respectively.

B. Marchwood Commercial End-Use segmentation

Based on the end-uses profiles provided by IESO for the commercial sectors, the project team developed the end-use load segmentation for Marchwood. The end-use segmentation for the commercial sector is presented in Figures 3-6. Moreover, the end-use segmentations for all commercial subsectors are presented in Figures B-17 to B-25.

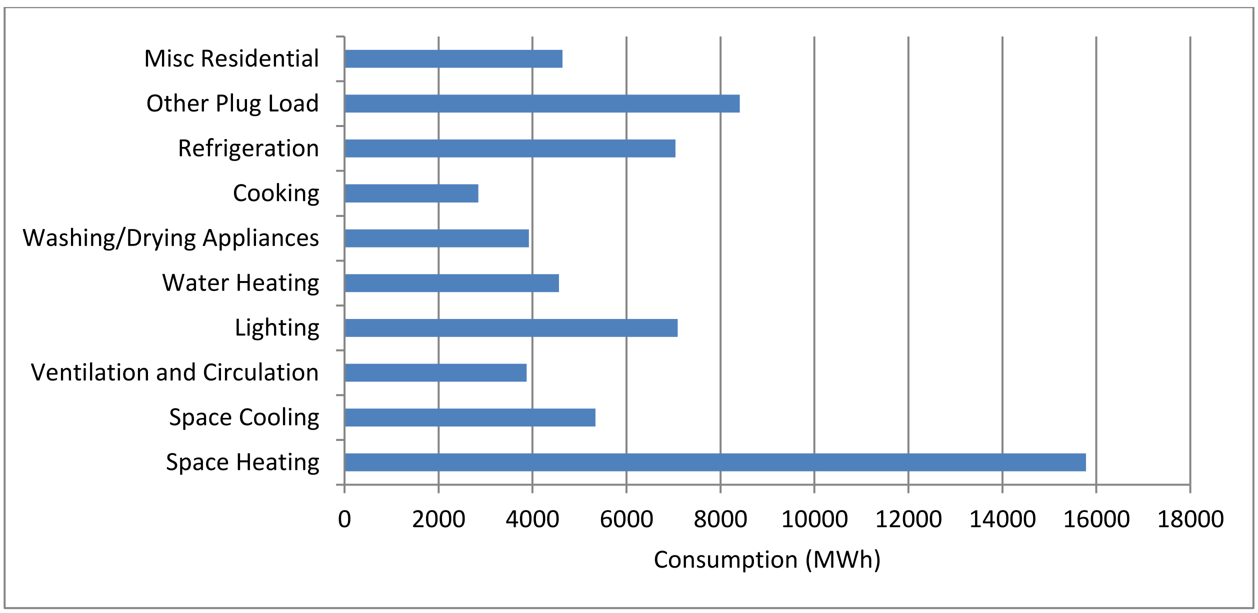


Figure 3-5 End-use Segmentation for Residential Sector, Marchwood MTS

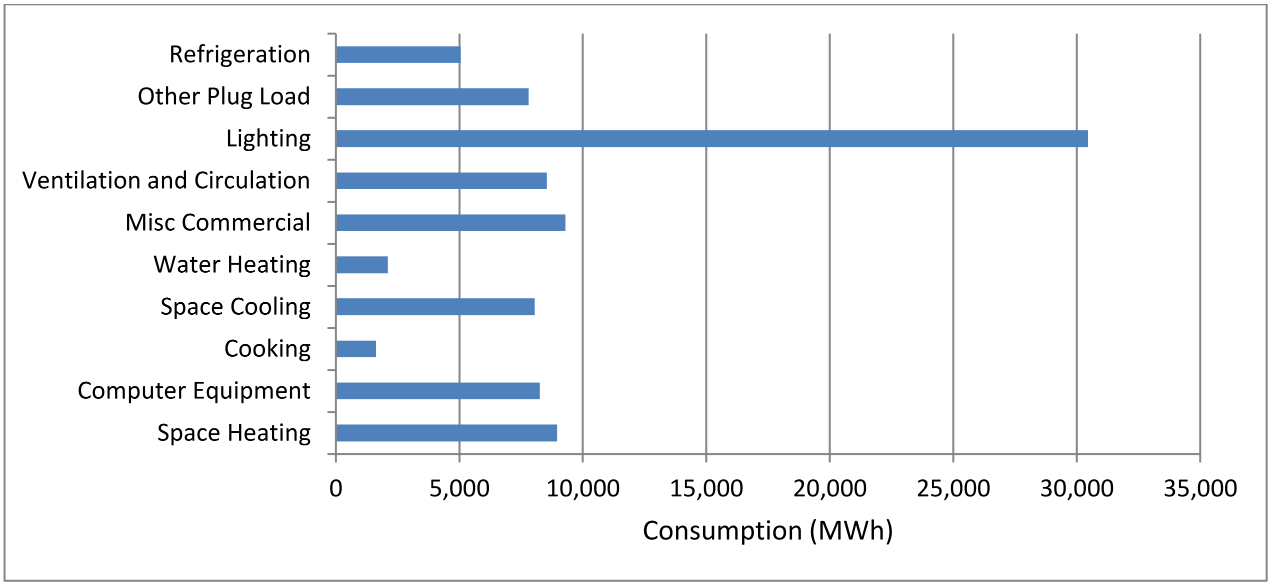


Figure 3-6 End-use Segmentation for Commercial Sector, Marchwood MTS

3.5 Reference Case Forecast: 2019-2040

3.5.1 Residential Forecast

The project team carried out a forecast for the expected number of residential buildings and energy intensity over the forecast period with respect to the base year. The NRCAN historical data for the number of residential buildings and energy intensity presented in Tables A-4 and A-5 were used to develop the forecast. The official community plan for Kanata North [11] show that the potential distribution for residential units over the planning period (i.e., 2018 to 20131) is as shown in Tables 3-15. The official residential building plan for Kanata North is used to calibrate the residential building forecast. The calibrated residential building forecasts for the four residential subsectors are presented in Table B-14, and the residential energy intensity forecasts are presented in Table B-15.

Table 3-15 Potential Unit Distribution for Kanata North [11]

UNIT TYPE	Potential Unit Distribution
Single Detached	960 Units
Apartments	527 Units
Street Townhouses and other ground oriented multiple dwelling	1477 Units

Based on the base year residential demand, the calibrated forecasts of residential buildings number, and the forecasted energy intensities, the residential forecast for Kanata and Marchwood MTS are obtained. Complete results for the residential forecast for Kanata MTS and Marchwood MTS are introduced in Tables B- 16 and B-17 respectively. Moreover, the residential subsectors consumptions for the base year are compared to the short-term forecasted consumptions (i.e., 2023) and the long-term forecasted consumptions (i.e., 2040). The comparison results are presented in Figures 3-7 and 3-8 for Kanata and Marchwood MTS respectively. Furthermore, the project team developed the end-use residential forecasts for Kanata and Marchwood MTS as shown in Figures 3-9 and 3-10 respectively.

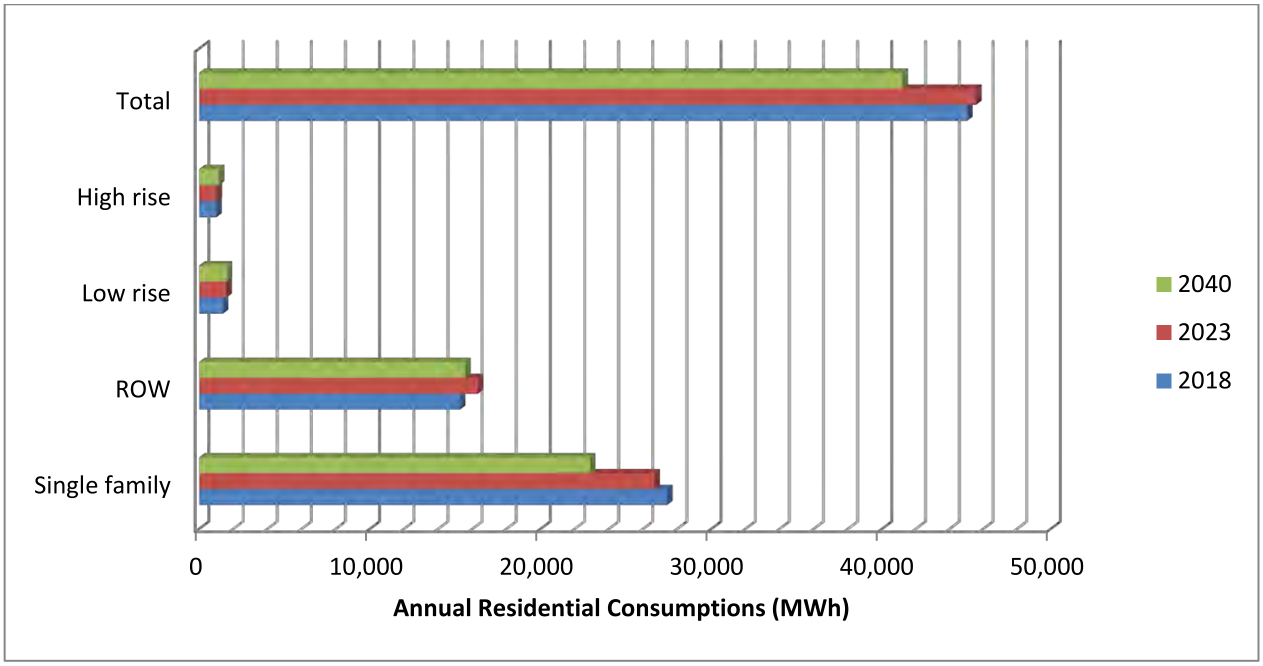


Figure 3-7 Residential sector load forecast, Kanata MTS

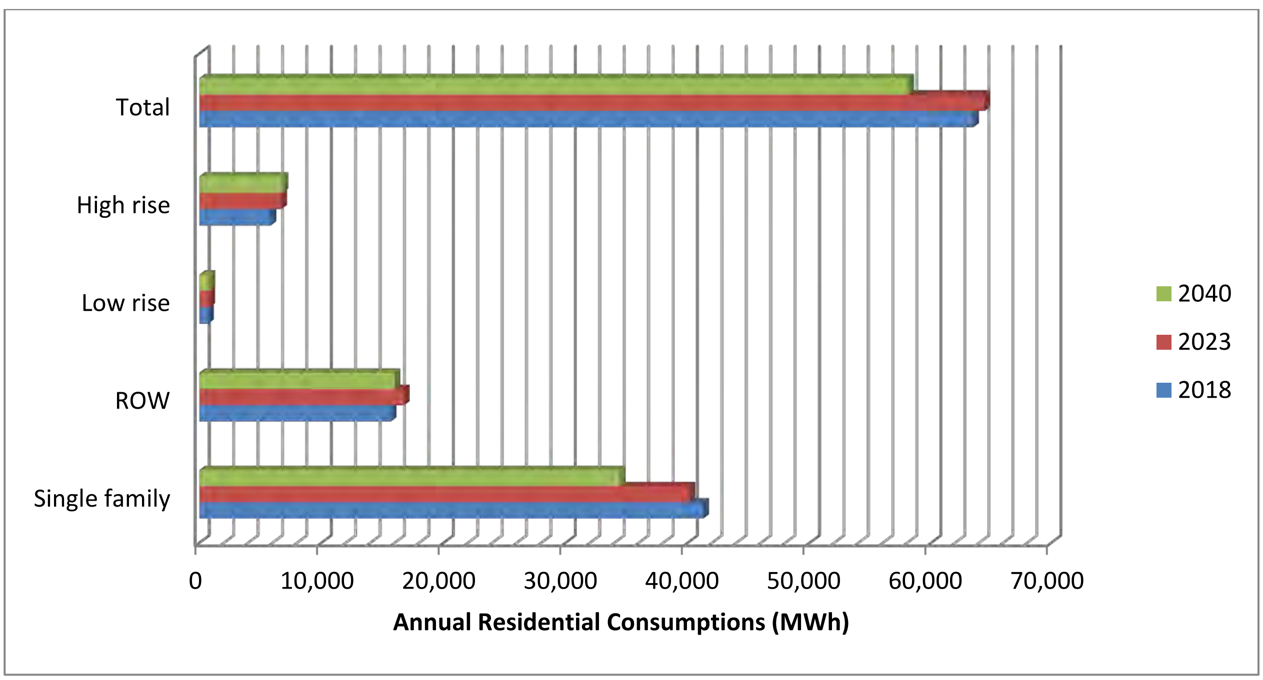


Figure 3-8 Residential sector load forecast, Marchwood MTS

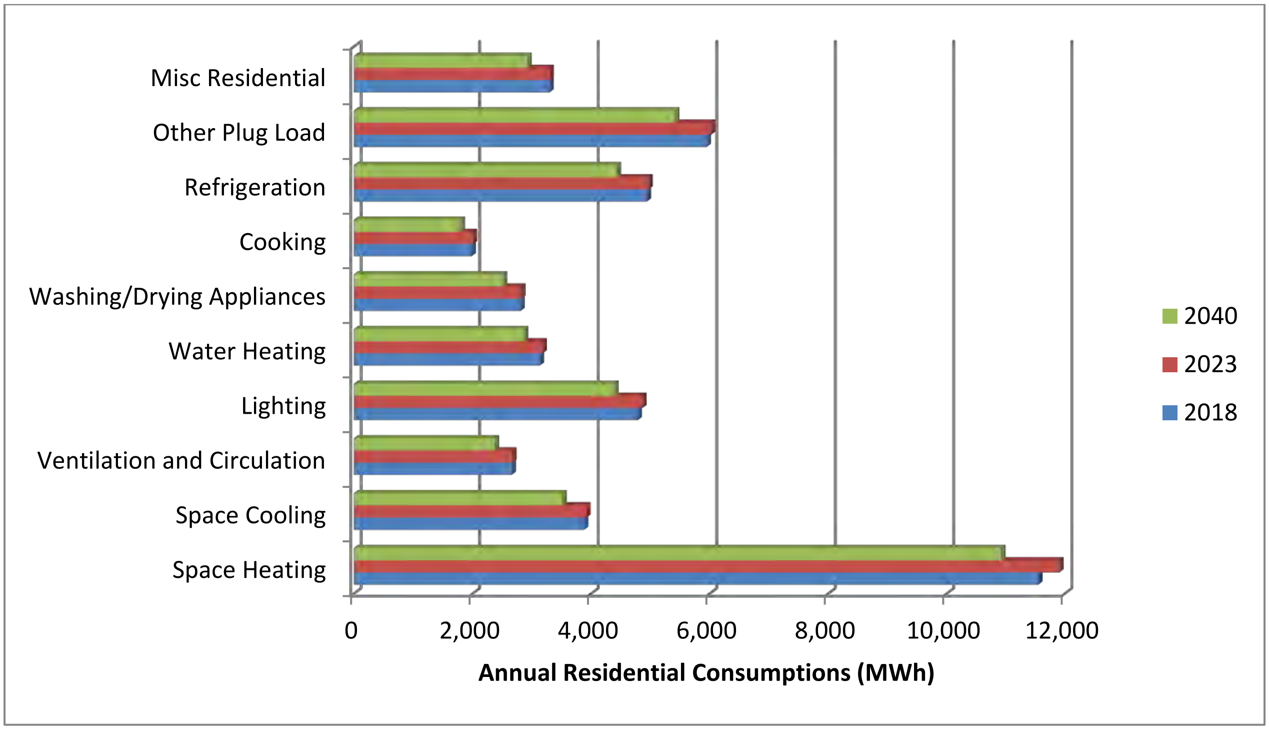


Figure 3-9 Residential load forecast by end-use, Kanata MTS

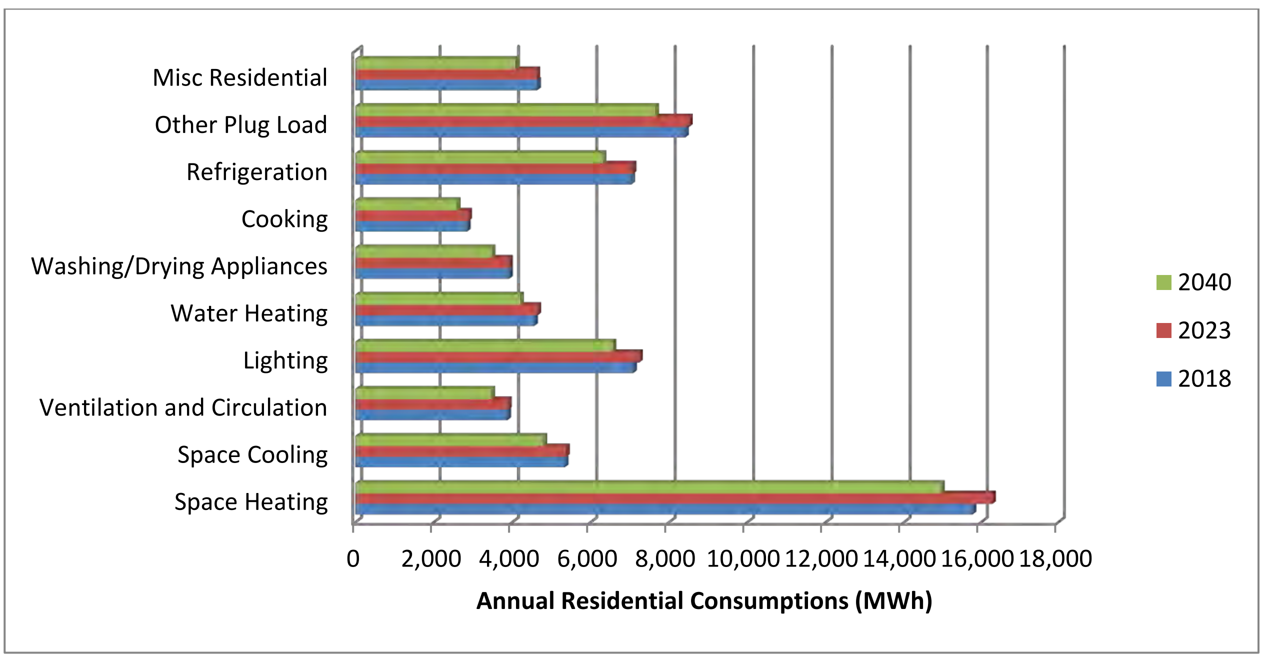


Figure 3-10 Residential load forecast by end-use, Marchwood MTS

3.5.2 Commercial Forecast

The project team developed the forecast of the square footage of the commercial subsectors at Kanata and Marchwood MTS using the base-year commercial sector estimation as well as Hemson study provided by IESO. Also, the project team developed a forecast for the energy intensity for each commercial subsector based on NRCAN historical energy intensities for commercial subsectors.

The project team carried out the commercial forecast for Kanata and Marchwood MTS based on the base year commercial load consumption, the area forecast of commercial subsectors, and the forecasted energy intensities for commercial subsectors. The complete results for the residential forecast for Kanata MTS and Marchwood MTS are introduced in Tables B- 18 and B-19 respectively. Moreover, the commercial subsectors consumptions for the base year are compared to the short-term forecasted consumptions (i.e., 2023) and the long-term forecasted consumptions (i.e., 2040). The comparison results are presented in Figures 3-11 and 3-12 for Kanata and Marchwood MTS respectively. Furthermore, the project team developed the end-use residential forecasts for Kanata and Marchwood MTS as shown in Figures 3-13 and 3-14 respectively.

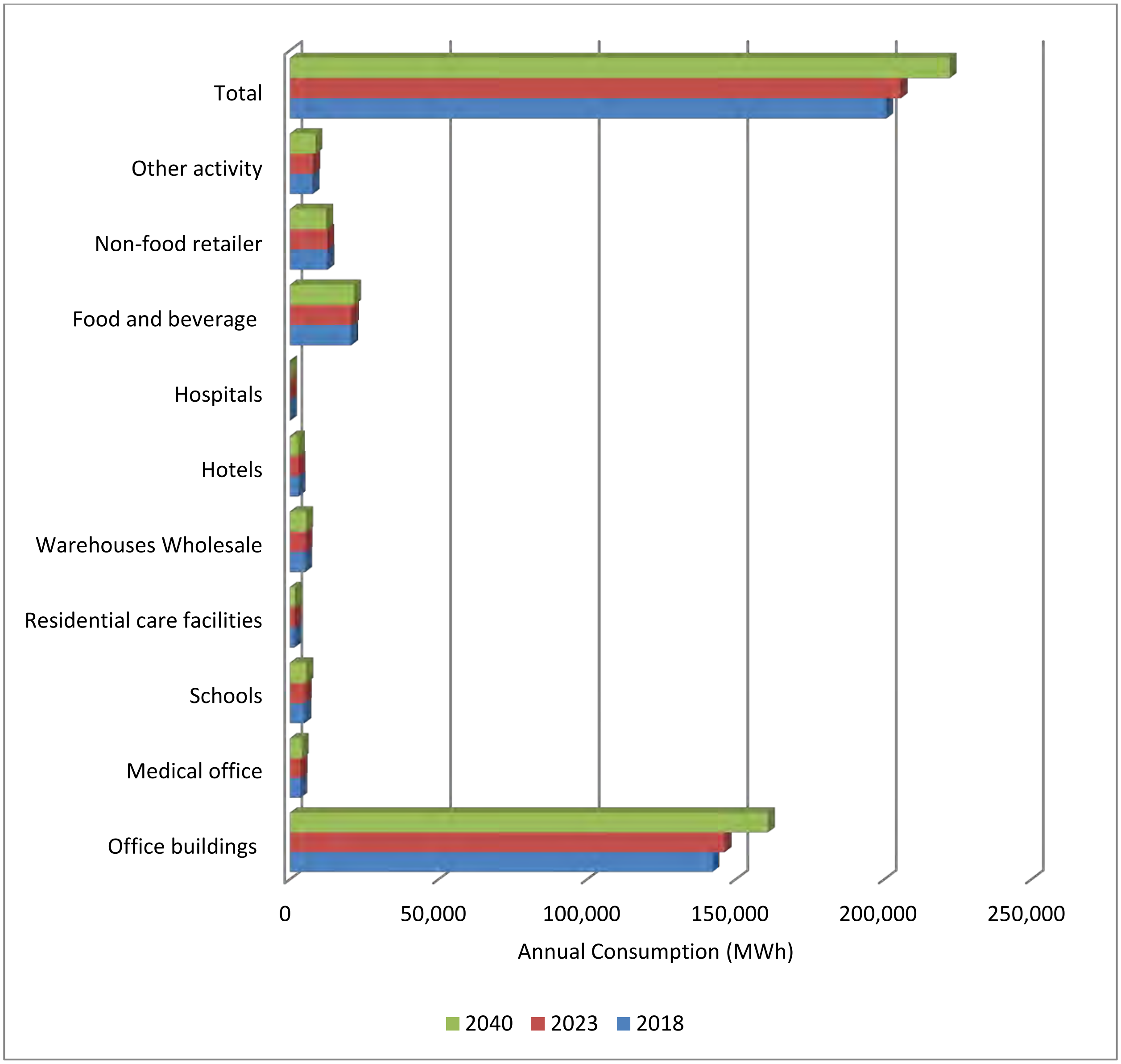


Figure 3-11 Commercial sector load forecast, Kanata MTS

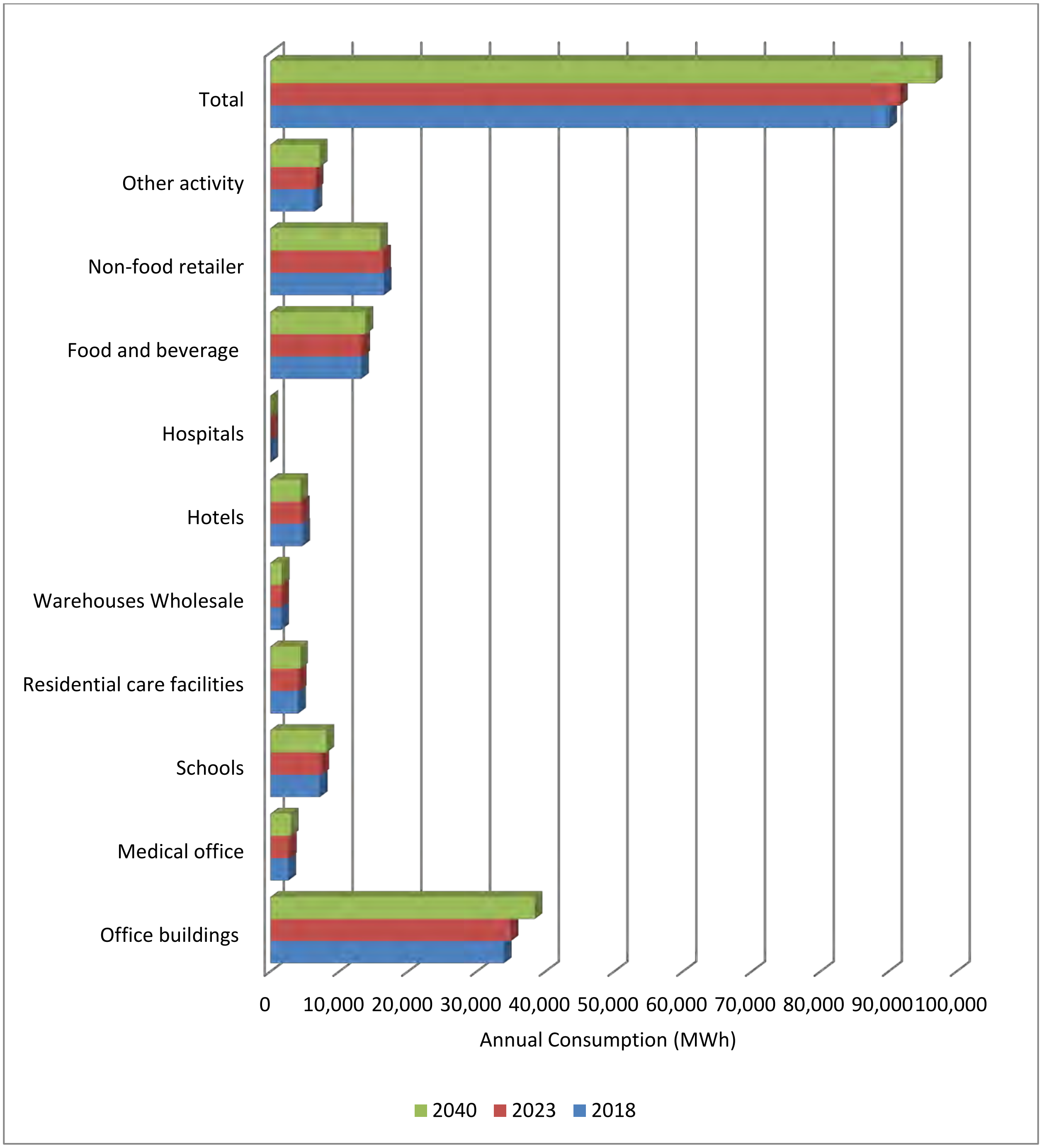


Figure 3-12 Commercial sector load forecast, Marchwood MTS

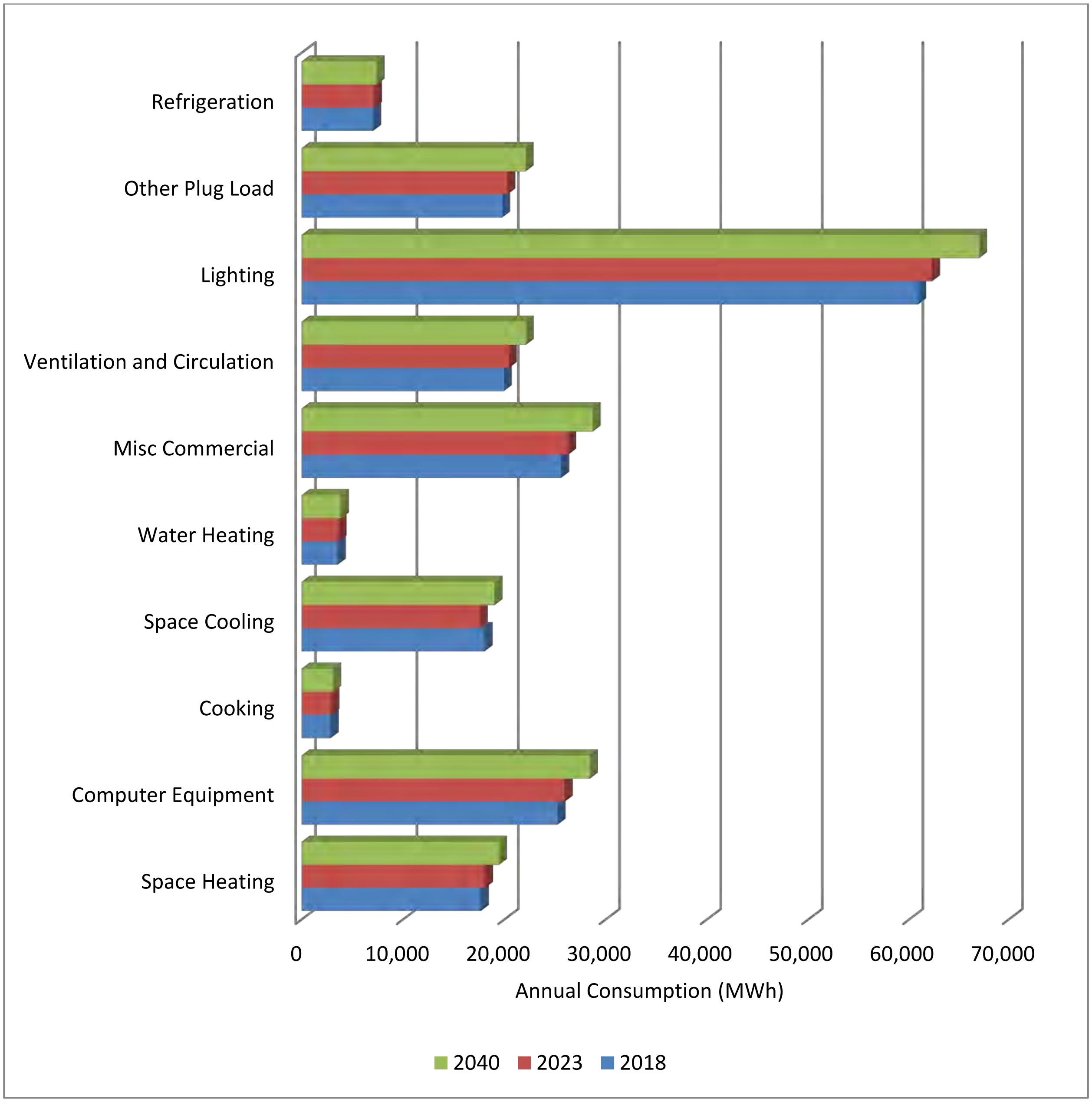


Figure 3-13 Commercial load forecast by end-use, Kanata MTS

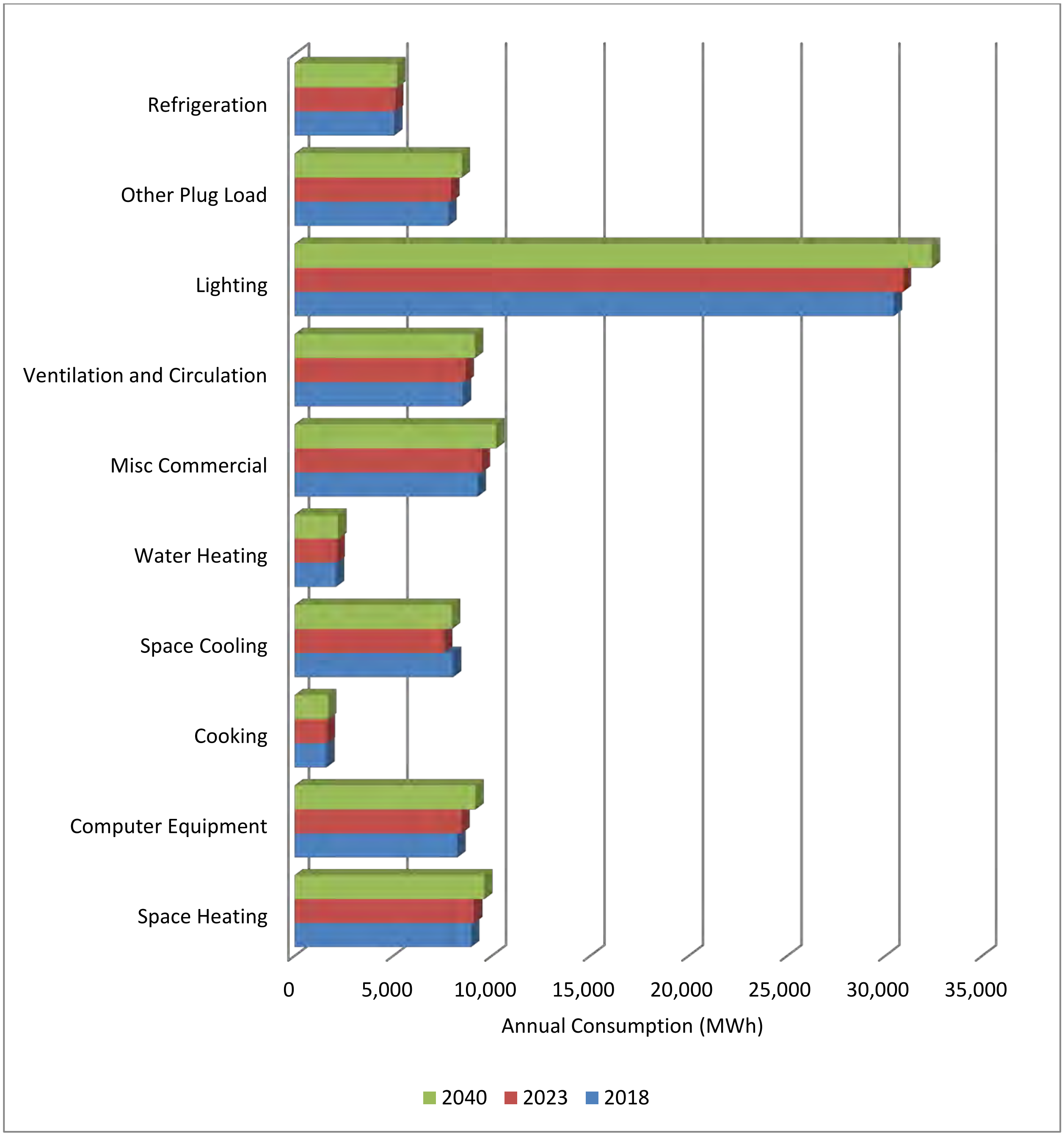


Figure 3-14 Commercial load forecast by end-use, Marchwood TS

3.5.3 Aggregated Forecast

The project team determined the aggregated commercial and residential forecast of Kanata-Marchwood area; illustrated in Figure 3-15. When compared to the base year of 2018, the total aggregated load forecast for 2040 estimates a total increase in electricity consumption of 4% from 402,743 MWh in 2018 to 418,971 MWh in 2040. The commercial section is expected to provide the largest increase in electricity use, rising from 290,847 MWh in 2018 to 319,038 MWh (9.7 % increase). The residential sector electricity consumption is expected to show a decrease from 108,557 MWh in 2018 to 99,309 MWh in 2040 (8.51 % decrease). The industrial forecast is assumed to be constant over the forecasting period as one industrial building only exists at Kanata-Marchwood area.

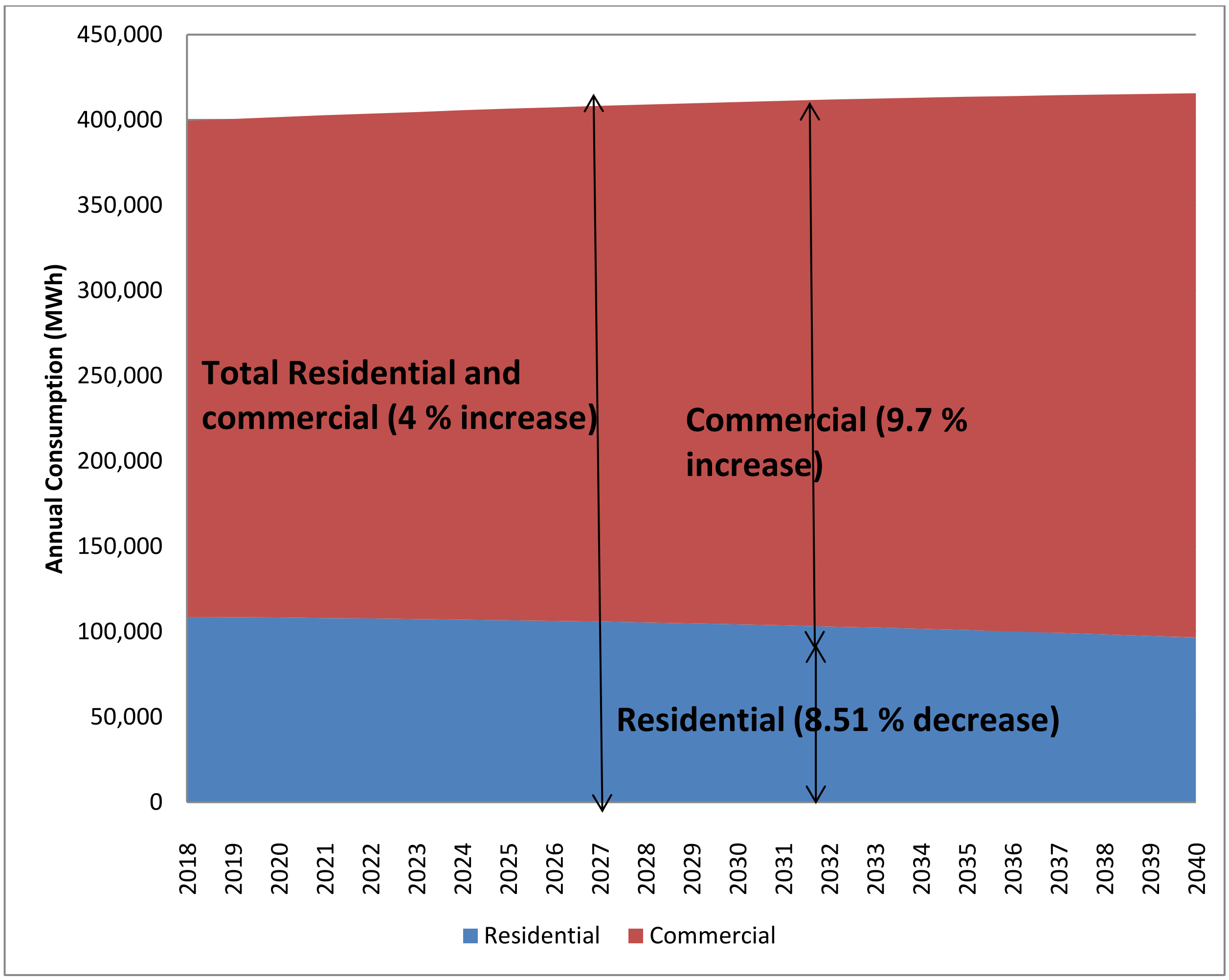


Figure 3-15 Kanata-Marchwood forecast (2018-2040) by sector

3.5.4 Observations

The following can be observed from the 2018-2040 load forecasts by sector, subsectors, and end use:

- The largest decrease in electricity consumption in the residential sector is expected to occur in the single-family subsector (16.25% decrease from 2018 to 2040).
- The electricity consumption of ROW subsector is expected to increase up to the year 2026 (7 % increase from 2018 to 2026), and then the ROW consumption will fall for the remaining forecasted years (4.67% decrease from 2018 to 2040).
- The electricity consumption of low-rise and high-rise subsectors is expected to increase over the forecasted period (16.67% increase for low-rise and high-rise)
- At the end-use level, all residential end-use items are expected to decrease in electricity use.
- Increased electricity usage is expected for all commercial subsectors, except for non-food retailers and hotels that are expected to decrease in electricity use (3.28 decrease for non-food retailers and 6.36 decrease for hotels).
- At the end-use level, all commercial end-use items are expected to increase in electricity use. Lighting shows the largest increase, while cooking, space cooling, water heating, and refrigeration show the lowest increase.

3.6 Participation in CDM and DER program

Based on the input data received from the HOL and IESO, the project team identified the historical participation of the loads in the CDM programs and the existing DERs as well as the potential for expansion. The complete list of existing DERs at Kanata-Marchwood area is presented in Table 3-15. Moreover, the total contract capacity of the DERs at Kanata-Marchwood area is presented in Table 3-16. The forecasted effective capacities of the DERs and the CDM are presented in Table 3-17.

Table 3-16 Existing Energy Resources Facilities at Kanata-Marchwood

Station	Feeder	Capacity (KW)	Fuel Type
Kanata MTS	624F1	400	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	8.2	Solar PV
Kanata MTS	624F1	2.5	Solar PV
Kanata MTS	624F1	500	Solar PV
Kanata MTS	624F1	8	Solar PV
Kanata MTS	624F5	250	Solar PV
Kanata MTS	624F1	40	Solar PV
Kanata MTS	624F2	5120	Battery
Marchwood MTS	MWDF1	10	Solar PV
Marchwood MTS	MWDF2	250	Solar PV
Marchwood MTS	MWDF3	65	Solar PV
Marchwood MTS	MWDF1	250	Solar PV
Marchwood MTS	MWDF1	150	Solar PV
Marchwood MTS	MWDF3	297	Solar PV
Marchwood MTS	MWDF2	150	Solar PV
Marchwood MTS	MWDF3	10	Solar PV
Marchwood MTS	MWDF3	100	Solar
Marchwood MTS	MWDF4	990	Battery

Table 3-17 DERs Contract Capacity at Kanata-Marchwood

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capacity connected to Marchwood MTS (MW)	0.2098	0.2098	0.2098	0.2098	0.2098	0.2098	0.2098	0.2098	0.2098	0.2098	0.2098
Capacity connected to Kanata MTS (MW)	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94	0.94
Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Capacity connected to Marchwood MTS (MW)	0.2098	0.2098	0.2098	0	0	0	0	0	0	0	0
Capacity connected to Kanata MTS (MW)	0.94	0.94	0.94	0.04	0.04	0.04	0.04	0	0	0	0

Table 3-18 DERs Effective Capacity at Kanata-Marchwood

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capacity connected to Marchwood MTS (MW)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Capacity connected to Kanata MTS (MW)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Capacity connected to Marchwood MTS (MW)	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0
Capacity connected to Kanata MTS (MW)	0.3	0.3	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0

Table 3-19 CDM Effective Capacity at Kanata-Marchwood

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capacity connected to Marchwood MTS (MW)	1.8	2.3	2.6	2.3	2.4	2.6	2.9	3.4	3.8	4.3
Capacity connected to Kanata MTS (MW)	2.3	2.7	3.1	3.2	3.2	3.4	3.9	4.2	4.8	5.4
Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Capacity connected to Marchwood MTS (MW)	4.7	5.2	5.5	5.8	6.1	6.3	6.3	6.3	6.3	6.2
Capacity connected to Kanata MTS (MW)	6.0	6.6	7.1	7.5	7.9	8.0	8.0	8.0	8.0	8.0

List of References

[1] Achievable Potentials Study: Project Plan for Long Term Analysis; http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Completed/Achievable-Potential-Study-LDC-Working-Group

[2] Achievable Potentials Study: Project Plan for Short Term Analysis; http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Completed/Achievable-Potential-Study-LDC-Working-Group

[3] Google Earth Files for Kanata and Marchwood MTS service area; received from HOL.

[4] Survey of Household Energy Use; Detailed Statistical Report http://oee.nrcan.gc.ca/publications/statistics/sheu/2011/pdf/sheu2011.pdf

[5] Ontario Electricity Board 2017 Yearbook of Electricity Distributors: https://www.oeb.ca/oeb/_Documents/RRR/2017_Yearbook_of_Electricity_Distributors.pdf

[6] Dun & Bradstreet database: database on Kanata and Marchwood commercial and industrial building; received from IESO.

[7] MPAC database: database on Kanata and Marchwood commercial and industrial building; received from IESO.

[8] Hemson Data: database on Ottawa city commercial building forecast; received from IESO.

[9] Survey of Commercial and Institutional Energy Use (SCIEU) - https://www.nrcan.gc.ca/energy/efficiency/17137

[10] Public Sector database: database on an annual consumption of schools, universities, and hospitals https://www.ontario.ca/data/energy-use-and-greenhouse-gas-emissions-broader-public-sector

[11] https://documents.ottawa.ca/sites/default/files/kanata_north_cdp_en.pdf

Appendix A

Definitions and Extracted Data from the Input Database

Table A-1 Residential Subsector Definition

Subsector	Definition
Single family	Single-family, detached and semi-detached households
Row house	Single-family, attached households (e.g., townhouses)
Multi-Unit Residential Building (MURB) low rise	Individually metered units in multi-unit residential buildings less than five stories
Multi-Unit Residential Building (MURB) high rise	Individually metered units in multi-unit residential buildings greater than or equal five stories

Table A-2 Commercial Subsector Definition

Subsector	Definition
Office buildings (non-medical)	Office buildings including governmental offices
Medical office buildings	Buildings whose primary business operations include healthcare services (e.g., labs and dialysis centers)
Elementary and/or secondary schools	Elementary and secondary education, apprenticeship, training, and daycare facilities.
Assisted daily/residential care facilities	Home health care facilities and homes for the elderly.
Warehouses Wholesale	Warehouse and wholesale distribution facilities
Hotels, motels or lodges	Overnight accommodation buildings
Hospitals	Inpatient and outpatient health facilities.
Food and beverage stores	Full-service restaurants, caterers, cafeterias, and retail buildings whose primary business operation includes the sale of food.
Non-food retail stores	All retail buildings whose primary business operation does not include the sale of food
Other activity or function	All other activities not specified above (e.g., theaters, sports arena, libraries, etc.)

Table A-3 Energy Intensity for Commercial Buildings

Primary activity	Building size	Energy intensity GJ/m^2	Electricity/natural gas split (%)
Office buildings (non-medical)	**Total**	**1.12**	**63/37**
	5,000 square feet or less (465 square metres or less)	1.57	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.28	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	1.08	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	1.16	
	Over 200,000 square feet (Over 18,580 square metres)	1.09	
Medical office buildings	**Total**	**1.28**	**58/42**
	5,000 square feet or less (465 square metres or less)	1.18	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.06	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	1.10	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	1.42	
	Over 200,000 square feet (Over 18,580 square metres)	1.92	
Elementary and/or secondary schools	**Total**	**0.88**	**40/60**
	5,000 square feet or less (465 square metres or less)	0.70	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.33	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	0.91	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	0.84	
	Over 200,000 square feet (Over 18,580 square metres)	0.88	
Assisted daily/residential care facilities	**Total**	**1.30**	**49/51**
	5,000 square feet or less (465 square metres or less)	1.06	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.22	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	1.28	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	1.40	

	Over 200,000 square feet (Over 18,580 square metres)	1.14	
Warehouses Wholesale	**Total**	**0.82**	**43/57**
	5,000 square feet or less (465 square metres or less)	0.83	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.00	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	0.90	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	0.74	
	Over 200,000 square feet (Over 18,580 square metres)	0.63	
Hotels, motels or lodges	**Total**	**1.24**	**47/53**
	5,000 square feet or less (465 square metres or less)	1.33	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.28	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	1.24	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	1.33	
	Over 200,000 square feet (Over 18,580 square metres)	1.11	
Hospitals	**Total**	**2.44**	**40/60**
	5,001 to 10,000 square feet (466 to 929 square metres)	1.26	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	2.92	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	2.84	
	Over 200,000 square feet (Over 18,580 square metres)	2.37	
Food and beverage stores	**Total**	**1.86**	**72/28**
	5,000 square feet or less (465 square metres or less)	2.64	
	5,001 to 10,000 square feet (466 to 929 square metres)	2.24	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	2.61	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	2.33	
	Over 200,000 square feet (Over 18,580 square metres)	0.71	
Non-food retail stores	**Total**	**1.12**	**54/46**
	5,000 square feet or less (465 square metres or less)	1.37	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.06	

	10,001 to 50,000 square feet (930 to 4,645 square metres)	1.42	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	1.00	
	Over 200,000 square feet (Over 18,580 square metres)	1.02	
Other activity or function	**Total**	**1.20**	**46/54**
	5,000 square feet or less (465 square metres or less)	1.98	
	5,001 to 10,000 square feet (466 to 929 square metres)	1.29	
	10,001 to 50,000 square feet (930 to 4,645 square metres)	1.08	
	50,001 to 200,000 square feet (4,646 to 18,580 square metres)	0.93	
	Over 200,000 square feet (Over 18,580 square metres)	1.07	

Table A-4 Historical Number of Residential Buildings

Year	1990	1991	1992	1993	1994	1995	1996	1997	1998
Single Detached (thousands)	5,854	6,014	6,134	6247	6,346	6,456	6,544	6,614	6,693
Single Attached (thousands)	969	1,010	1,045	1,079	1,110	1,136	1,162	1,188	1,215
Apartments (thousands)	3,380	3,465	3,522	3,581	3,625	3,682	3,733	3,762	3,787
Year	1999	2000	2001	2002	2003	2004	2005	2006	2007
Single Detached (thousands)	6,772	6,864	6,950	7,055	7,165	7,280	7,386	7,490	7,594
Single Attached (thousands)	1,242	1,272	1,298	1,325	1,355	1,391	1,429	1,467	1,503
Apartments (thousands)	3,810	3,834	3,860	3,901	3,954	4,014	4,082	4,146	4,210
Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
Single Detached (thousands)	7,686	7,759	7,838	7,907	7,976	8,040	8,103	8,156	8,215
Single Attached (thousands)	1,540	1,573	1,604	1,635	1,666	1,699	1,733	1,768	1,802
Apartments (thousands)	4,287	4,358	4,422	4,486	4,553	4,630	4,708	4,802	4,890

Table A-5 Historical Energy Intensity of Residential subsectors

Year	1990	1991	1992	1993	1994	1995	1996	1997	1998
Single Detached, Energy Intensity (GJ/household)	184.2	176.3	175.3	178.7	179.9	172.1	178.7	170.4	157.2
ROW, Energy Intensity (GJ/household)	127.1	122.4	122.2	123.3	124.6	119.1	123.2	118.0	107.2
Apartments, Energy Intensity (GJ/household)	77.5	73.4	74.8	75.1	76.1	73.0	75.4	73.0	67.3
Year	1999	2000	2001	2002	2003	2004	2005	2006	2007
Single Detached, Energy Intensity (GJ/household)	159.4	163.1	154.0	159.9	157.6	154.9	150.2	142.6	151.8
ROW, Energy Intensity (GJ/household)	109.8	112.1	106.7	109.3	109.6	107.6	106.0	100.0	105.9
Apartments, Energy Intensity (GJ/household)	68.7	70.3	66.8	68.4	69.4	69.3	67.1	64.6	68.4
Year	2008	2009	2010	2011	2012	2013	2014	2015	2016
Single Detached, Energy Intensity (GJ/household)	150.1	143.4	140.1	146.4	138.2	141.8	144.3	136.8	126.9

ROW, Energy Intensity (GJ/household)	105.1	100.0	97.7	101.5	95.8	99.4	101.7	97.1	89.5
Apartments, Energy Intensity (GJ/household)	67.7	65.6	63.7	66.4	63.5	66.0	67.7	65.0	60.8

Appendix B
Detailed Estimation for Kanata-Marchwood

Table B-1 Residential Subsector Energy Consumptions for Kanata Feeders

Feeder #	Residential building type	Single family	ROW	Low rise	High rise
624F1	Annual Electricity consumptions (MWh)	15,405	5,628	924	0
624F2	Annual Electricity consumptions (MWh)	4,421	2,357	0	0
624F3	Annual Electricity consumptions (MWh)	1,071	1,029	452	993
624F5	Annual Electricity consumptions (MWh)	212	493	0	0
624F6	Annual Electricity consumptions (MWh)	6,293	5,756	0	0
Total	Annual Electricity consumptions (MWh)	27,404	15,264	1,376	993

Table B-2 Commercial Subsectors Energy Consumption, Feeder 624F1

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	14,527	2,623,735
Medical office buildings	145	8,429
Elementary and/or secondary schools	611	60,870
Assisted daily/residential care facilities	0	0
Warehouses Wholesale	2,054	226,601
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	7,888	158,598
Non-food retail stores	9,272	564,522
Other activity or function	941	64,539

Table B-3 Commercial Subsectors Energy Consumption, Feeder 624F2

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	39,901	2,082,994
Medical office buildings	0	0
Elementary and/or secondary schools	0	0
Assisted daily/residential care facilities	845	75,000
Warehouses Wholesale	2,071	117,597
Hotels, motels or lodges	2,848	167,436
Hospitals	0	0
Food and beverage stores	6,260	133,040
Non-food retail stores	556	26,500
Other activity or function	404	28,413

Table B-4 Commercial Subsectors Energy Consumption, Feeder 624F3

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	2,145	101,874
Medical office buildings	125	5,000
Elementary and/or secondary schools	2,889	300,000
Assisted daily/residential care facilities	0	0
Warehouses Wholesale	200	17,709
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	474	10,732
Non-food retail stores	0	0
Other activity or function	1,862	152,813

Table B-5 Commercial Subsectors Energy Consumption, Feeder 624F5

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	67,729	3,374,230
Medical office buildings	241	13,832
Elementary and/or secondary schools	127	8,719
Assisted daily/residential care facilities	559	32,579
Warehouses Wholesale	536	49,762
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	3,366	65,291
Non-food retail stores	921	48,055
Other activity or function	2,409	190,969

Table B-6 Commercial Subsectors Energy Consumption, Feeder 624F6

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	17,849	883,368
Medical office buildings	2,977	137,226
Elementary and/or secondary schools	1,209	126,880
Assisted daily/residential care facilities	68	4,780
Warehouses Wholesale	244	23,327
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	2,589	52,472
Non-food retail stores	1,868	112,481
Other activity or function	2,004	112,995

Table B-7 Commercial Subsectors Energy Consumption, Kanata MTS

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	142,151	9,066,201
Medical office buildings	3,488	164,487
Elementary and/or secondary schools	4,836	496,469
Assisted daily/residential care facilities	1,471	112,359
Warehouses Wholesale	5,107	434,996
Hotels, motels or lodges	2,848	167,436
Hospitals	0	0
Food and beverage stores	20,578	420,133
Non-food retail stores	12,617	751,558
Other activity or function	7,620	549,729

Table B-8 Residential Subsectors Energy Consumptions for Each Feeder, Marchwood MTS

Feeder #	Residential building type	Single family	ROW	Low rise	High rise
MWDF1	Annual Electricity consumptions (MWh)	10,290	3,910	298	2,058
MWDF2	Annual Electricity consumptions (MWh)	5,637	4,239	0	3,783
MWDF3	Annual Electricity consumptions (MWh)	13,851	5,415	414	0
MWDF4	Annual Electricity consumptions (MWh)	11,506	2,120	0	0
Total	Annual Electricity consumptions (MWh)	41,284	15,684	712	5,841

Table B-9 Commercial Subsectors Energy Consumption, Feeder MWDF1

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	1,485	57,977
Medical office buildings	2,301	104,548
Elementary and/or secondary schools	3,509	367,000
Assisted daily/residential care facilities	0	
Warehouses Wholesale	34	1,670
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	8,690	152,745
Non-food retail stores	14,759	837,260
Other activity or function	806	13,444

Table B-10 Commercial Subsectors Energy Consumption, Feeder MWDF2

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	2,502	124,541
Medical office buildings	323	19,204
Elementary and/or secondary schools	408	40,969
Assisted daily/residential care facilities	3,920	213,173
Warehouses Wholesale	256	24,198
Hotels, motels or lodges	4,637	273,441
Hospitals	0	0
Food and beverage stores	4,498	105,976
Non-food retail stores	1,110	55,249
Other activity or function	2,607	198,948

Table B-11 Commercial Subsectors Energy Consumption, Feeder MWDF3

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	5,624	291,611
Medical office buildings	0	0
Elementary and/or secondary schools	2,552	262,209
Assisted daily/residential care facilities	0	0
Warehouses Wholesale	139	13,100
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	0	0
Non-food retail stores	0	0
Other activity or function	2,665	209,580

Table B-12 Commercial Subsectors Energy Consumption, Feeder MWDF4

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	24,353	1,229,529
Medical office buildings	0	0
Elementary and/or secondary schools	726	65,720
Assisted daily/residential care facilities	127	7,761
Warehouses Wholesale	1,142	183,280
Hotels, motels or lodges	0	0
Hospitals	0	0
Food and beverage stores	0	0
Non-food retail stores	623	39,769
Other activity or function	337	23,695

Table B-13 Commercial Subsectors Energy Consumption for Marchwood MTS

Commercial Subsector	Annual Electricity Consumption (MWh)	Area (Square ft.)
Office buildings (non-medical)	33,964	1,703,658
Medical office buildings	2,624	123,752
Elementary and/or secondary schools	7,195	735,898
Assisted daily/residential care facilities	4,047	220,934
Warehouses Wholesale	1,571	222,248
Hotels, motels or lodges	4,637	273,441
Hospitals	0	0
Food and beverage stores	13,188	258,721
Non-food retail stores	16,493	932,278
Other activity or function	6,416	445,667

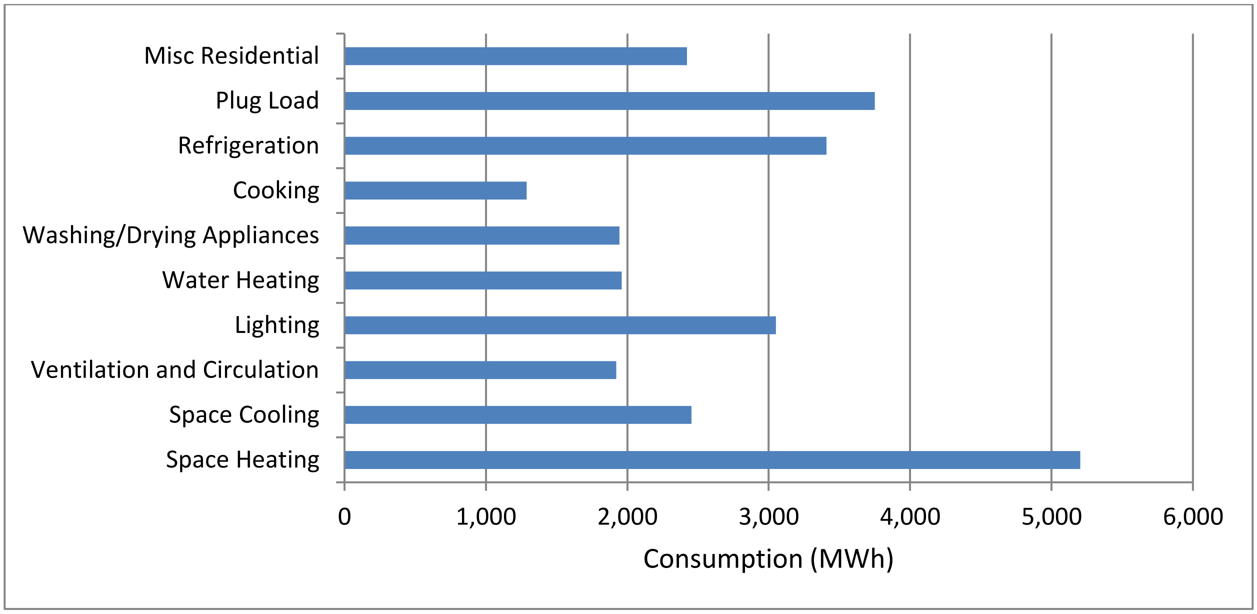


Figure B-1 End-use Segmentation for Single Family, Kanata MTS

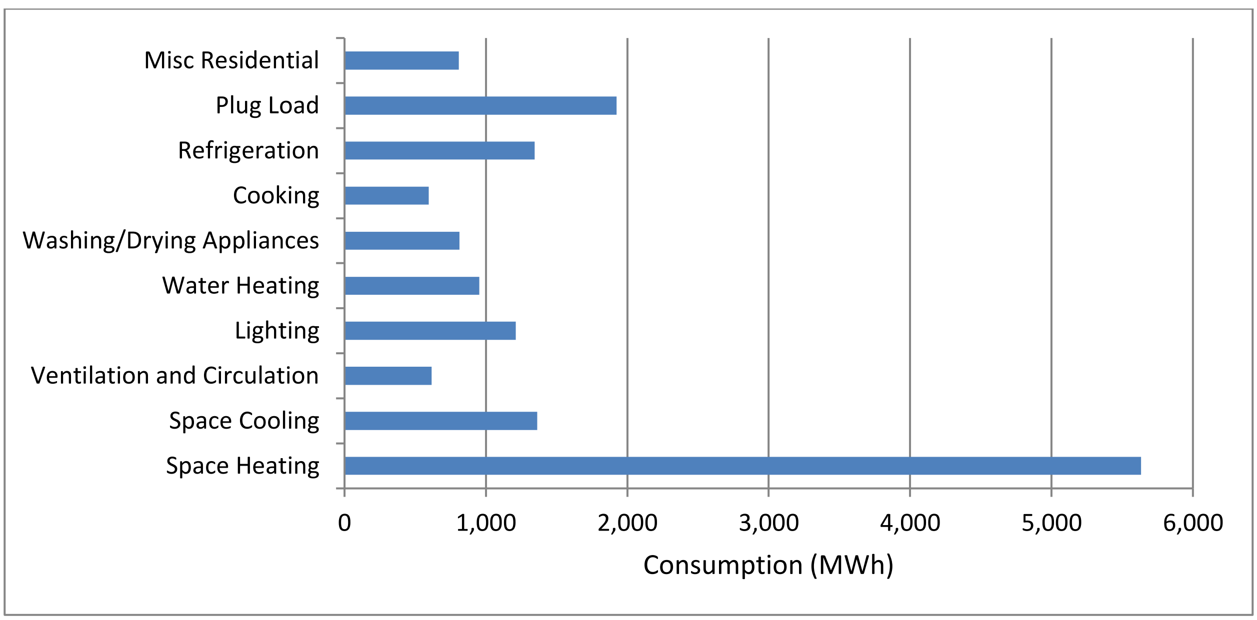


Figure B-2 End-use Segmentation for ROW, Kanata MTS

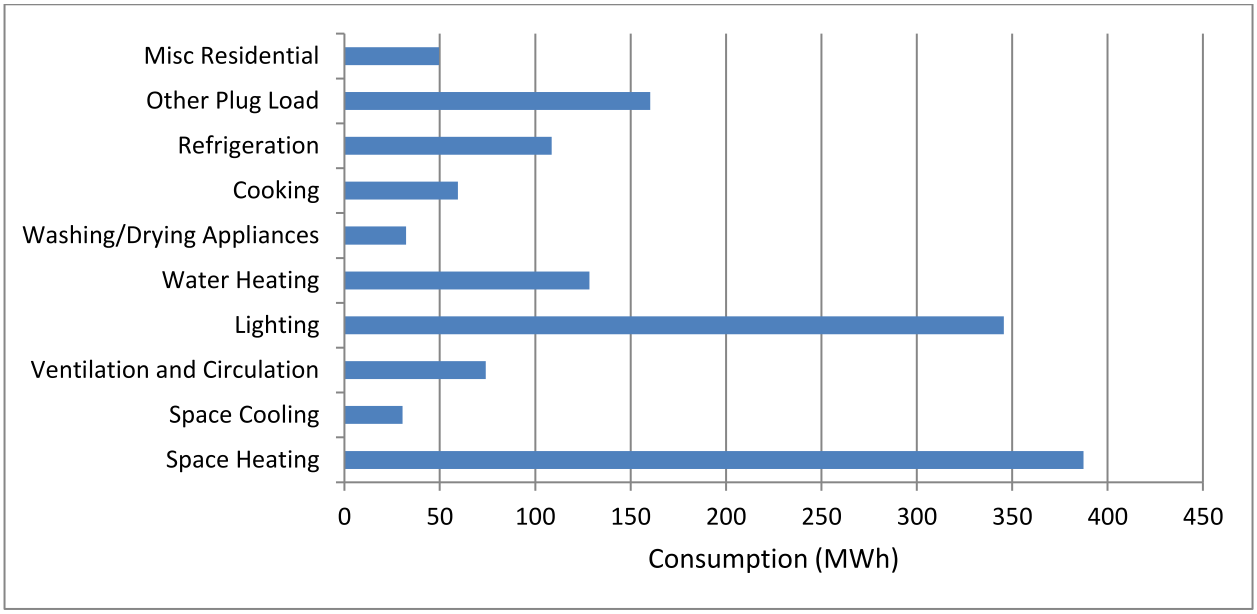


Figure B-3 End-use Segmentation for Low-Rise, Kanata MTS

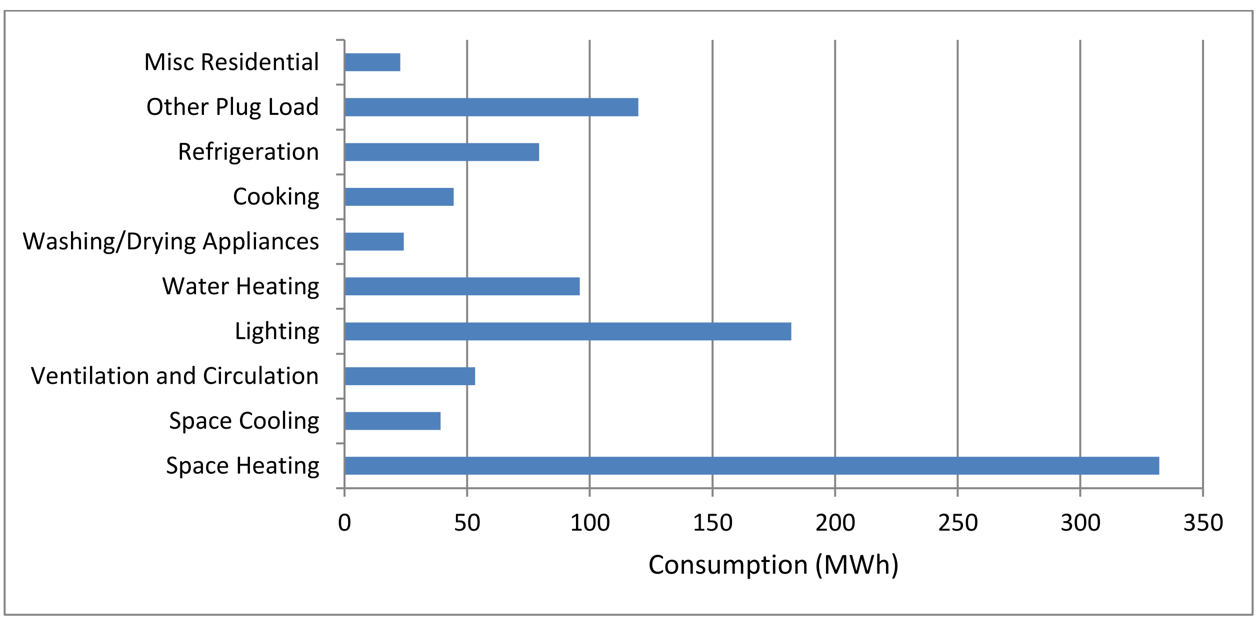


Figure B-4 End-use Segmentation for High-Rise, Kanata MTS

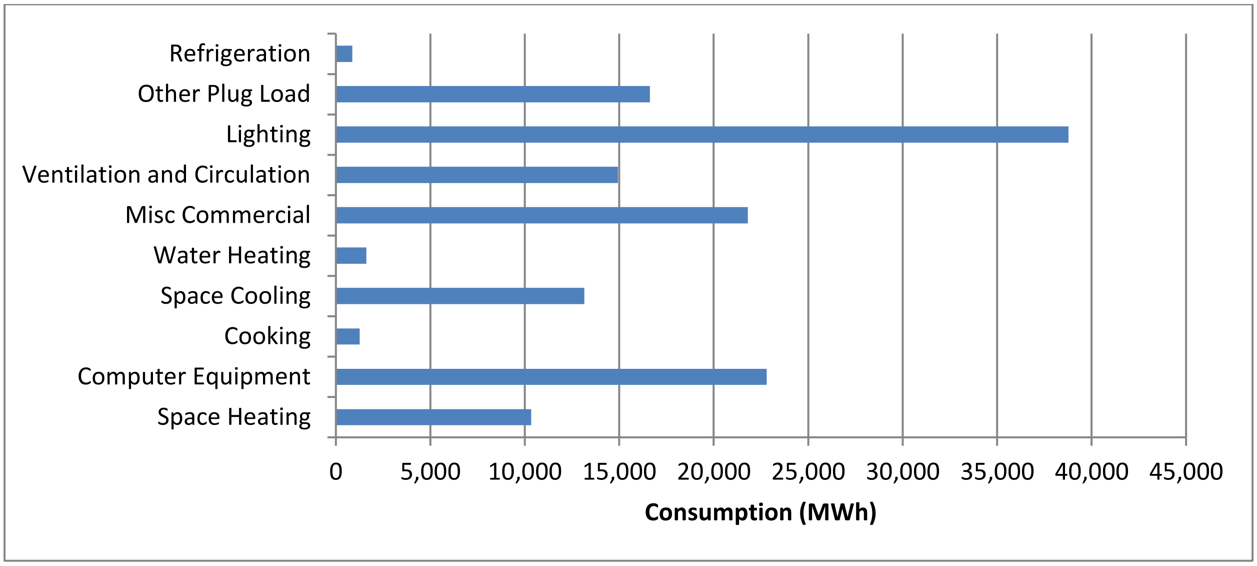


Figure B-5 End-use Segmentation for Office Buildings, Kanata MTS

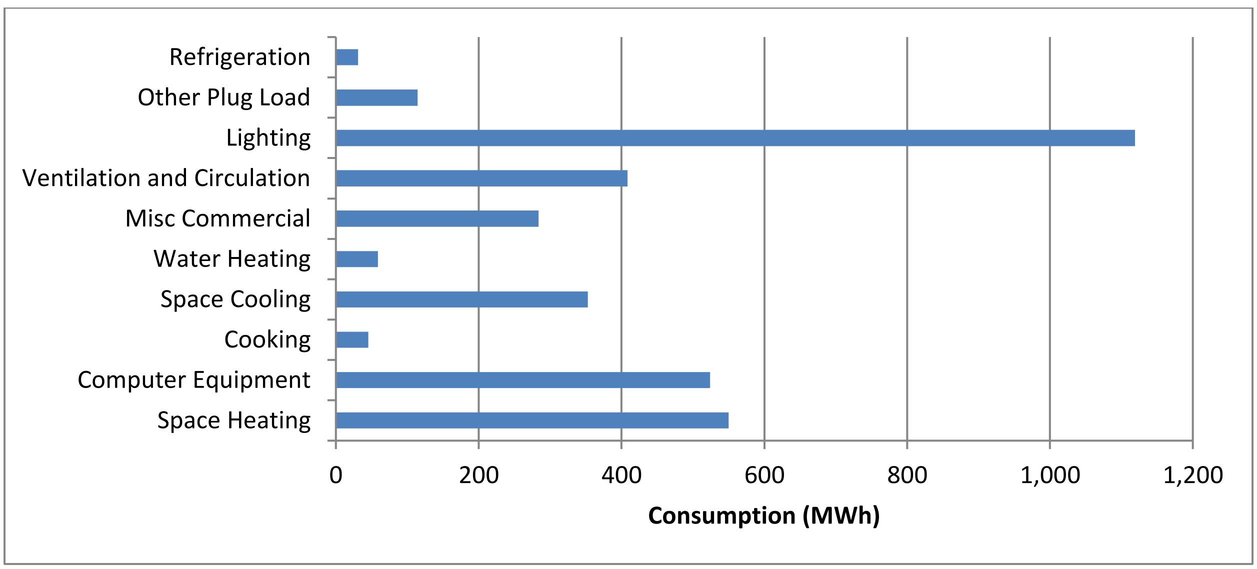


Figure B-6 End-use Segmentation for Medical Office Buildings, Kanata MTS

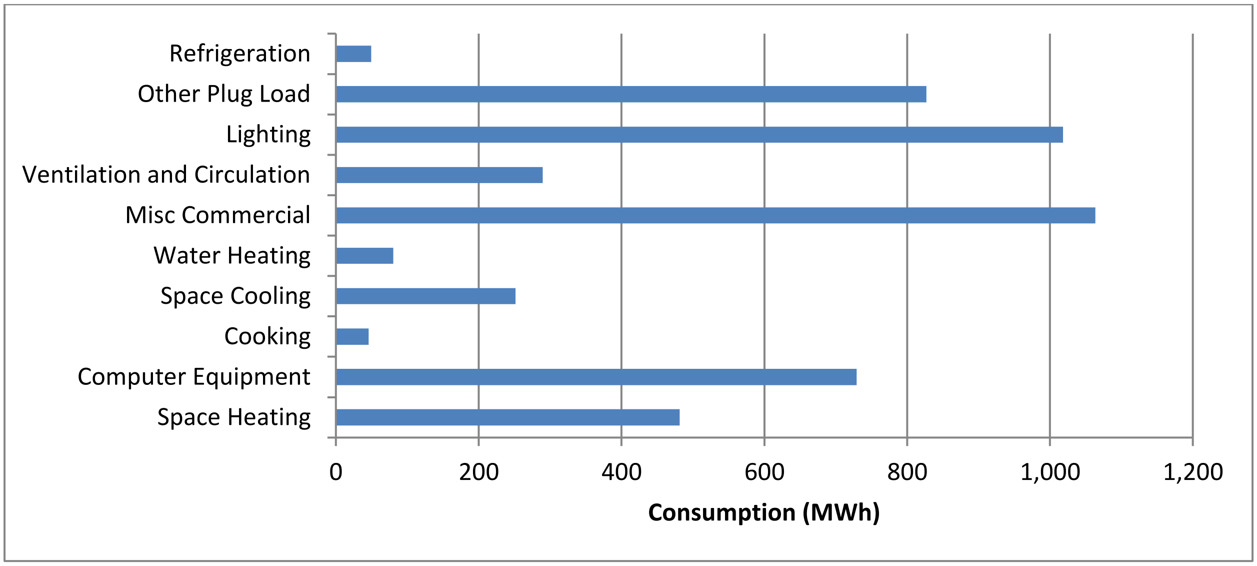


Figure B-7 End-use Segmentation for School, Kanata MTS

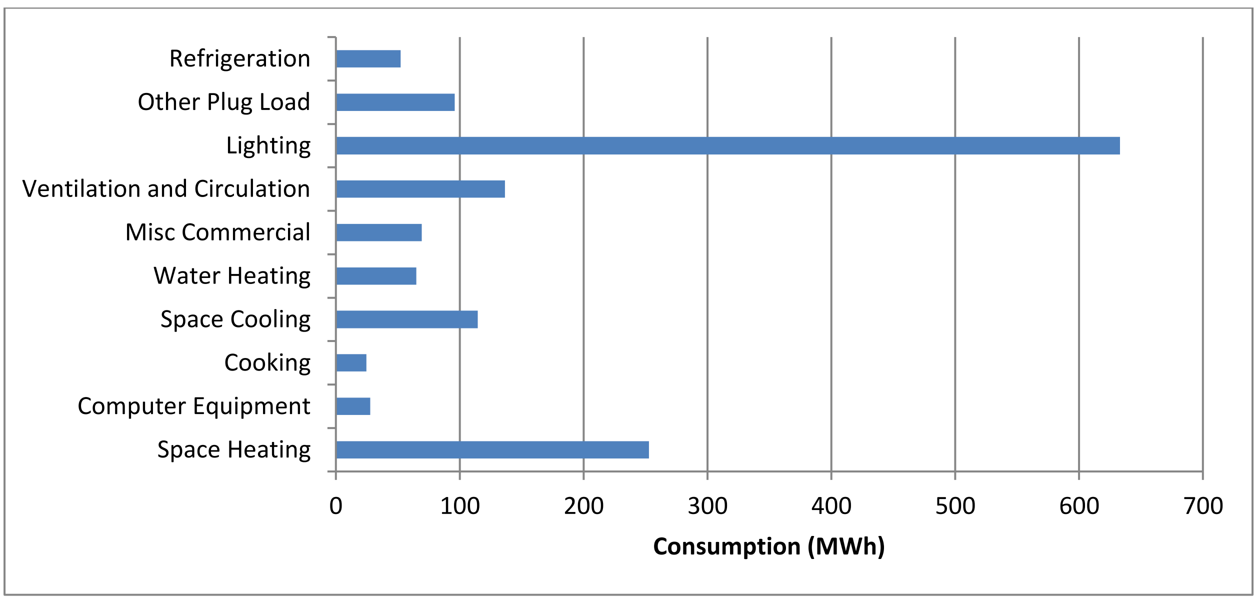


Figure B-8 End-use Segmentation for Residential Care, Kanata MTS

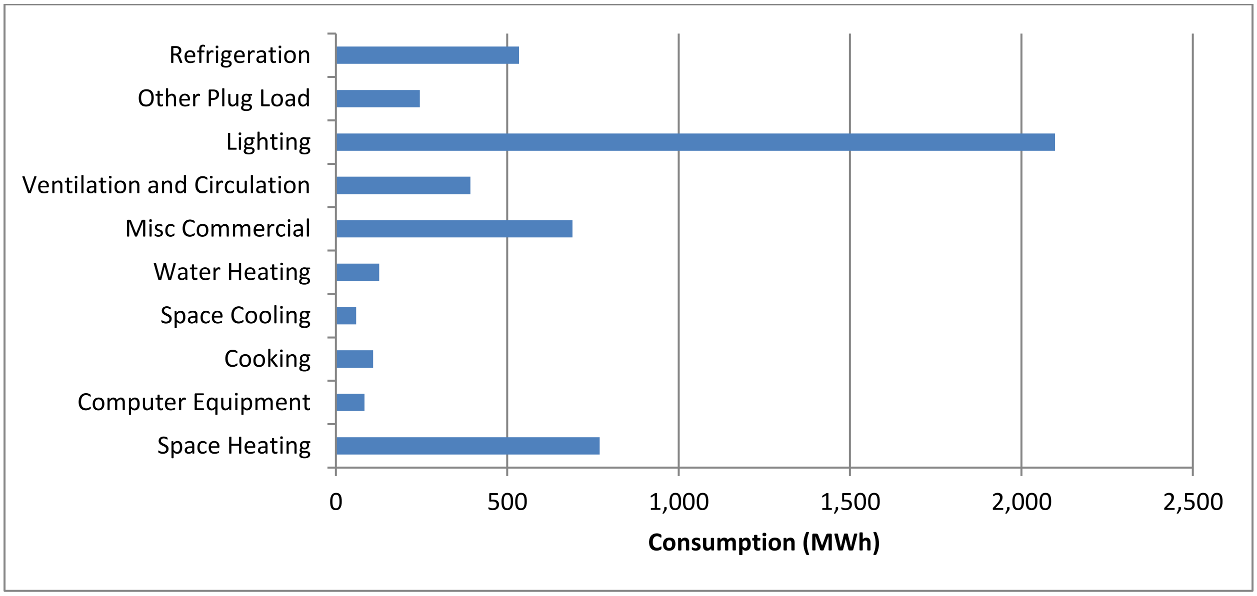


Figure B-9 End-use Segmentation for Warehouse Wholesale, Kanata MTS

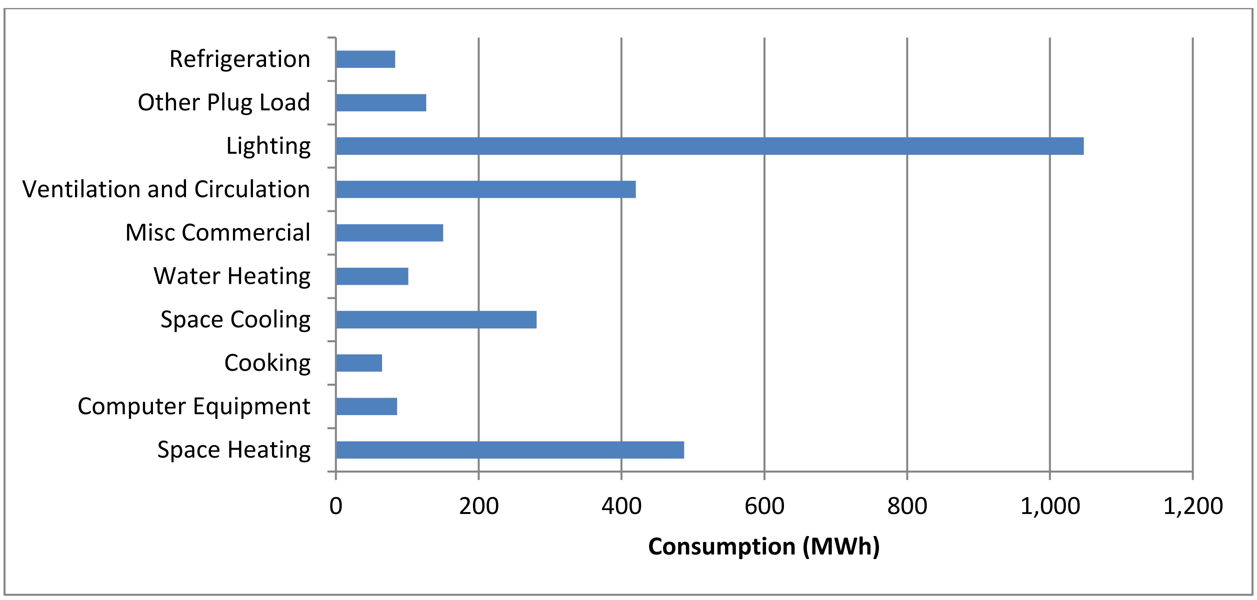


Figure B-10 End-use Segmentation for Hotels, Kanata MTS

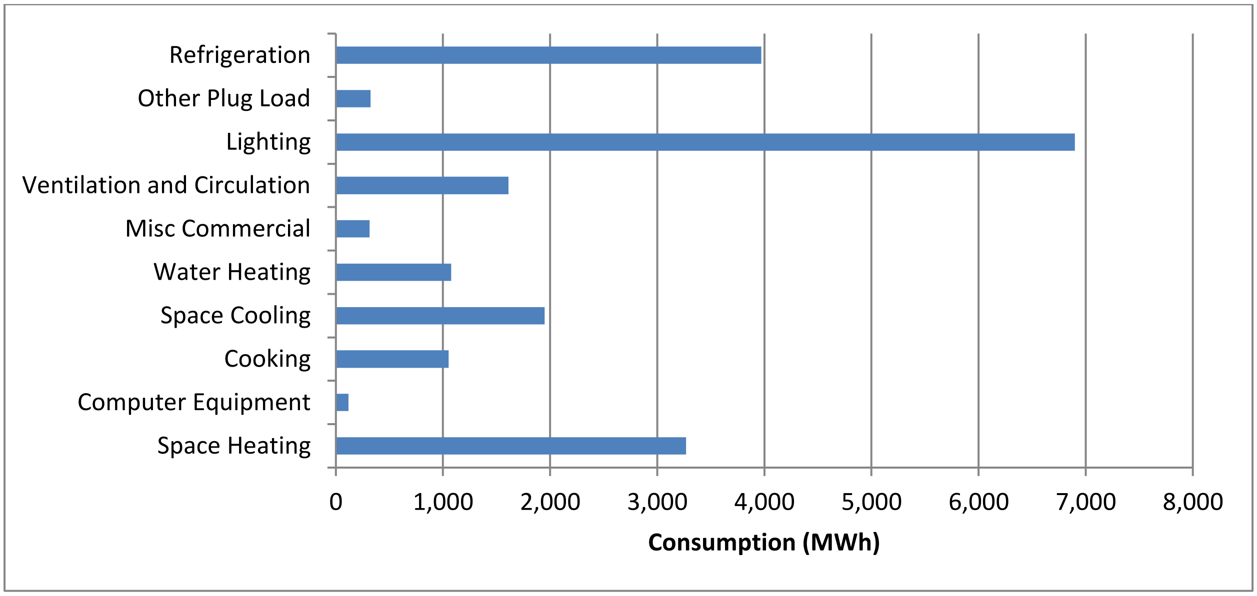


Figure B-11 End-use Segmentation for Food and Beverage Stores, Kanata MTS

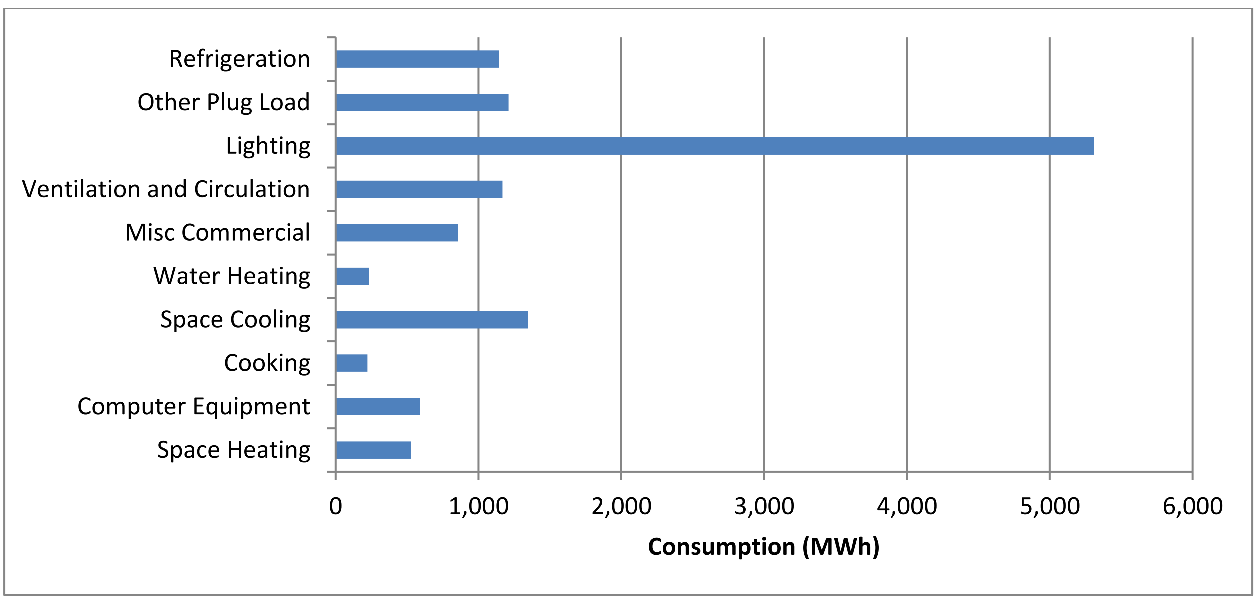


Figure B-12 End-use Segmentation for Non-Food retail Stores, Kanata MTS

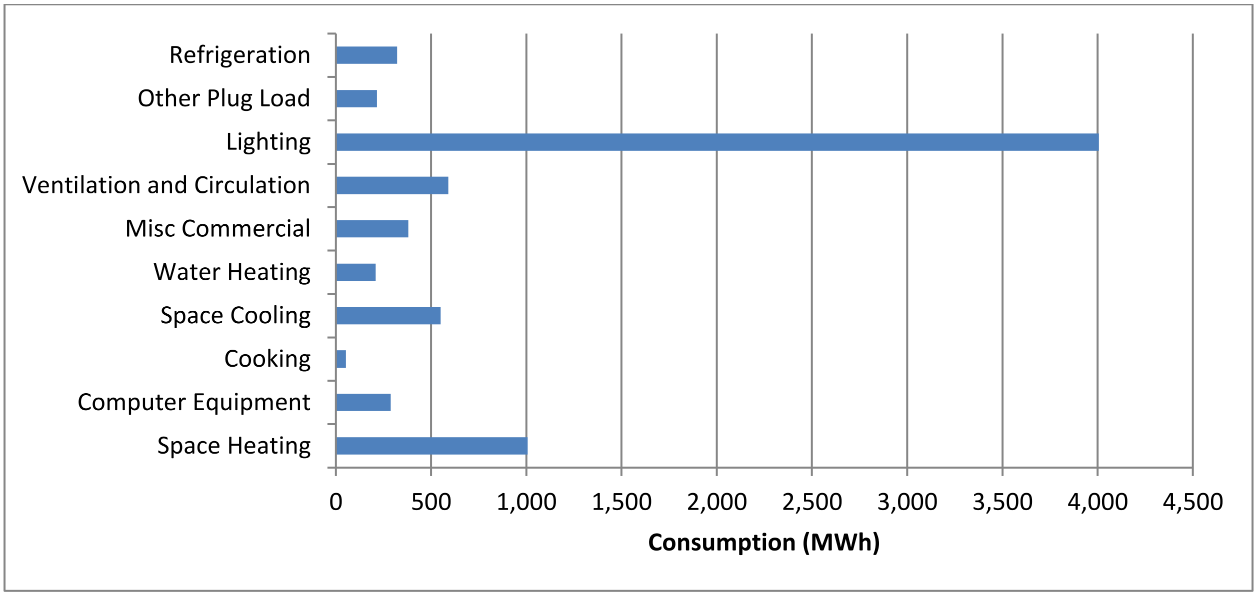


Figure B-13 End-use Segmentation for Other Commercial, Kanata MTS

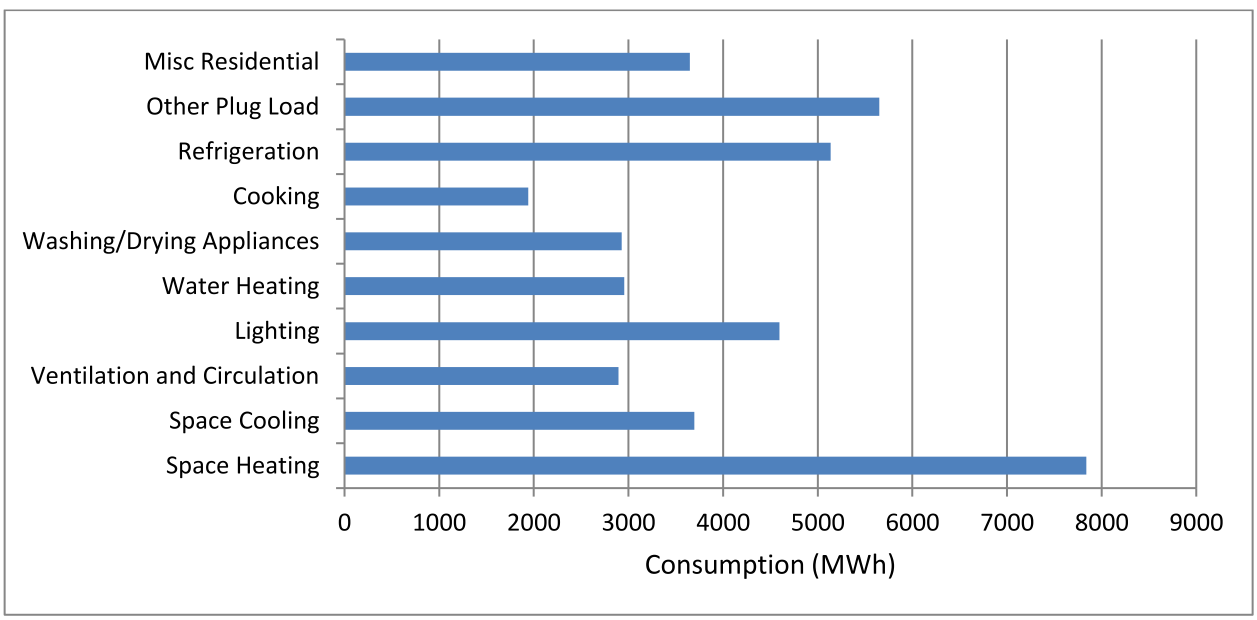


Figure B-14 End-use Segmentation for Single Family, Marchwood MTS

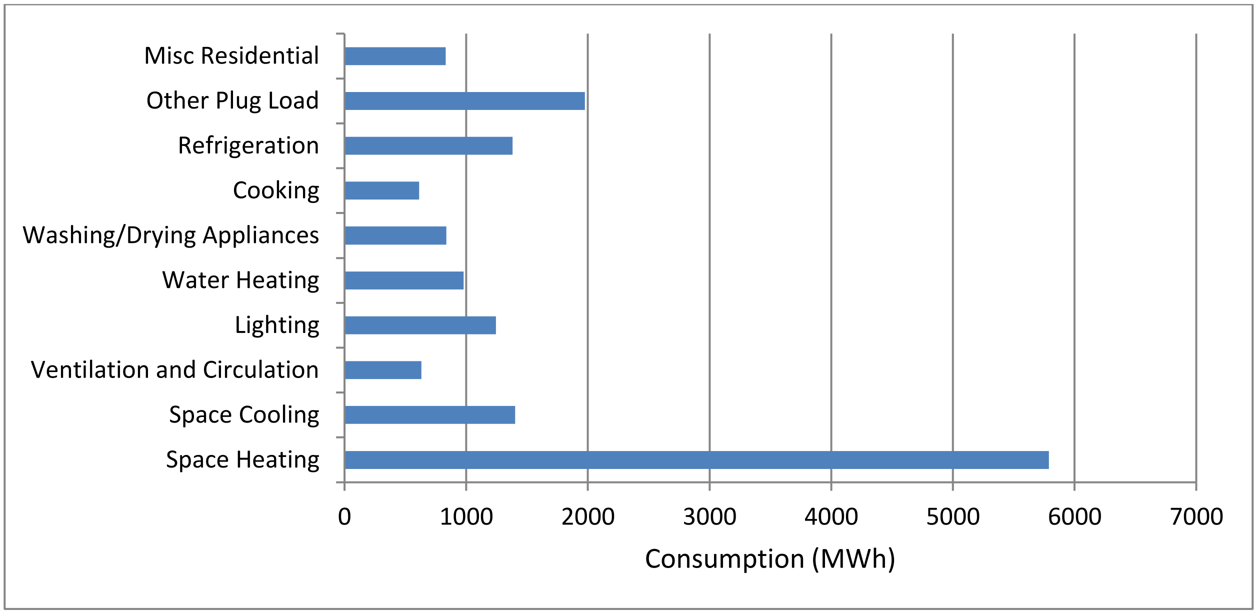


Figure B-15 End-use Segmentation for ROW, Marchwood MTS

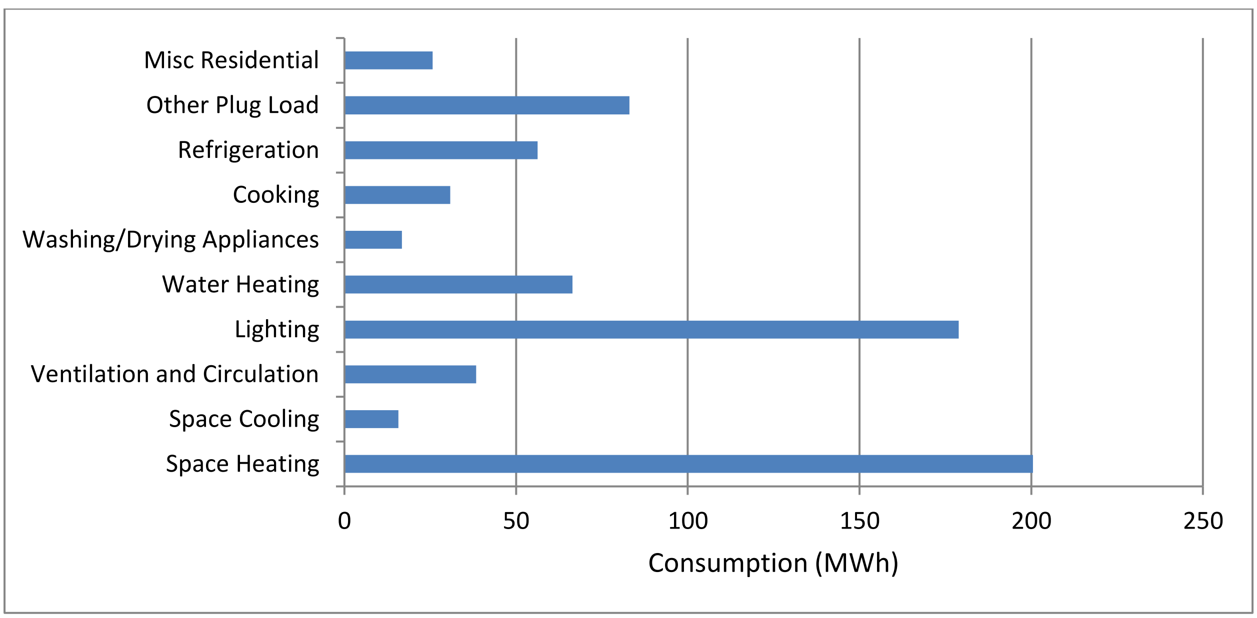


Figure B-16 End-use Segmentation for Low-Rise, Marchwood MTS

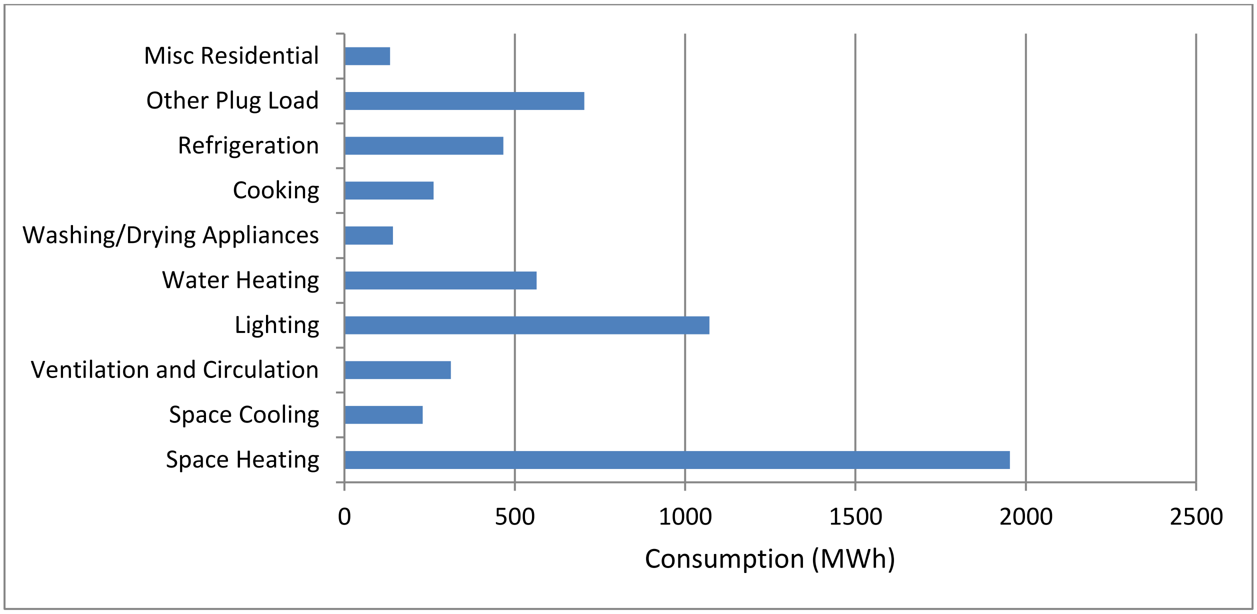


Figure B-17 End-use Segmentation for High-Rise, Marchwood MTS

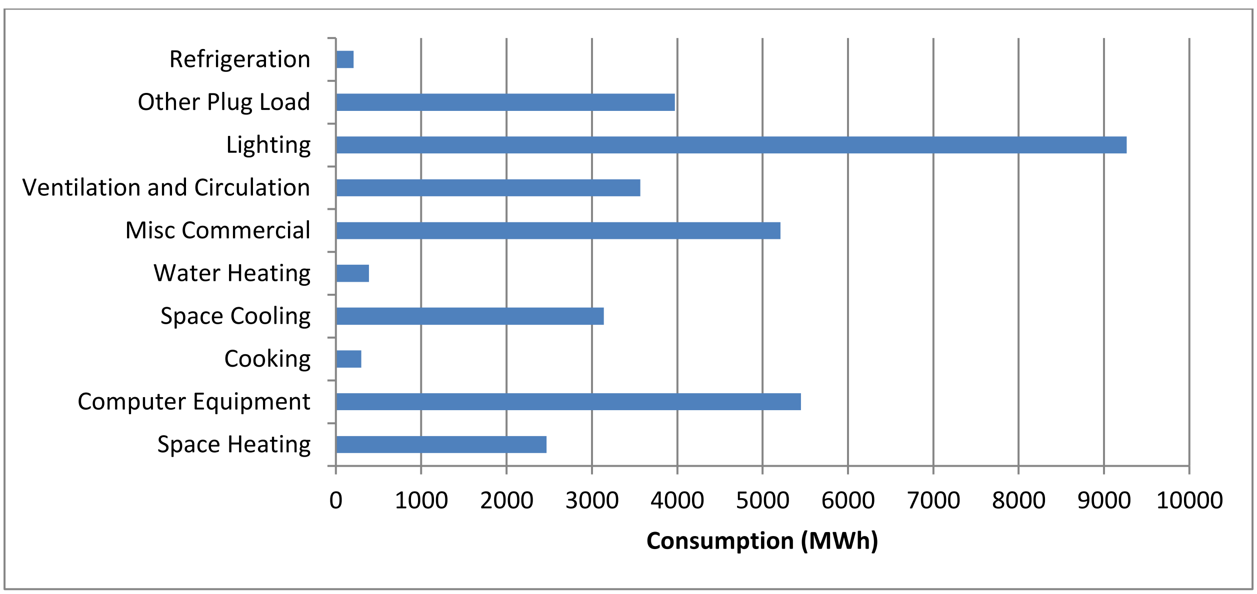


Figure B-18 End-use Segmentation for Office Buildings, Marchwood MTS

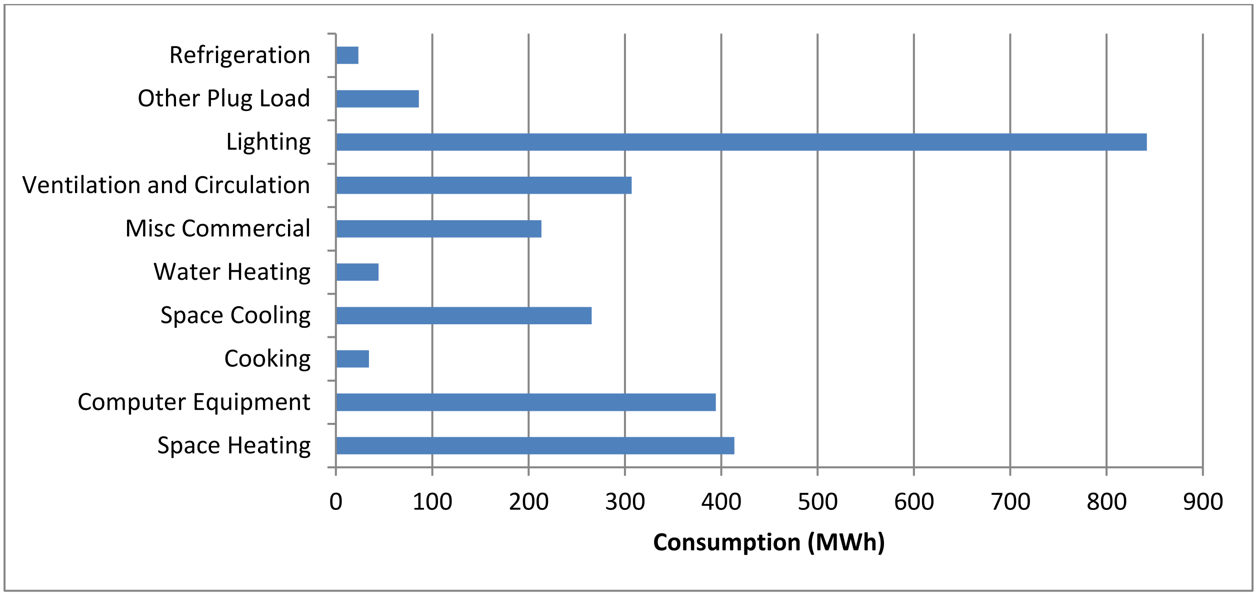


Figure B-19 End-use Segmentation for Medical Office Buildings, Marchwood MTS

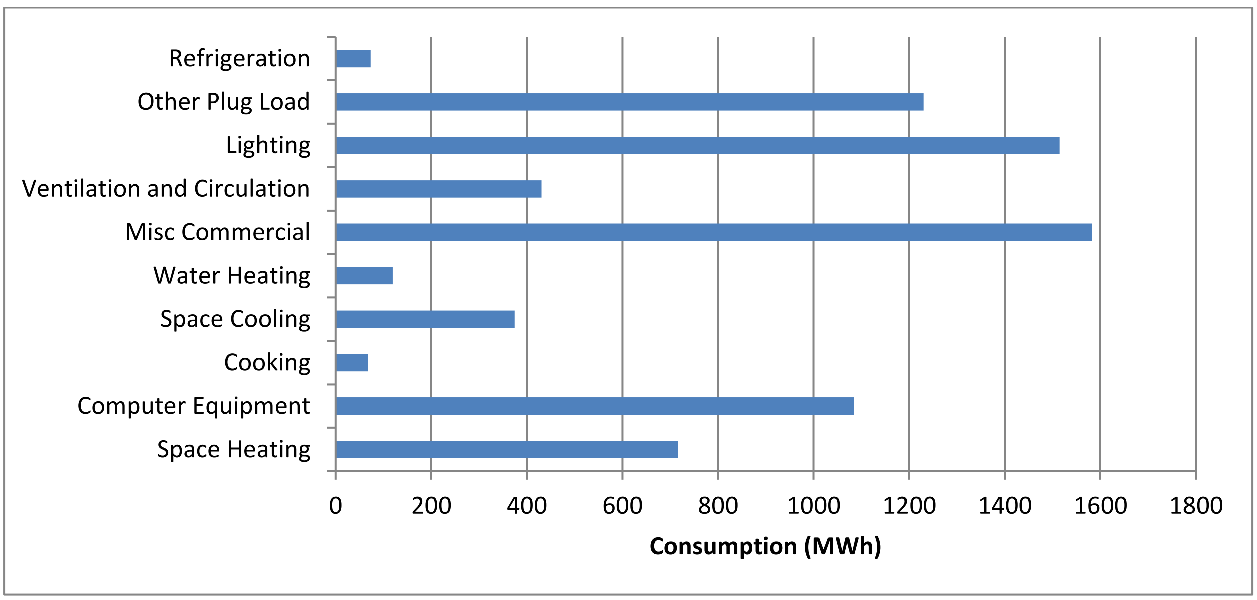


Figure B-20 End-use Segmentation for Schools, Marchwood MTS

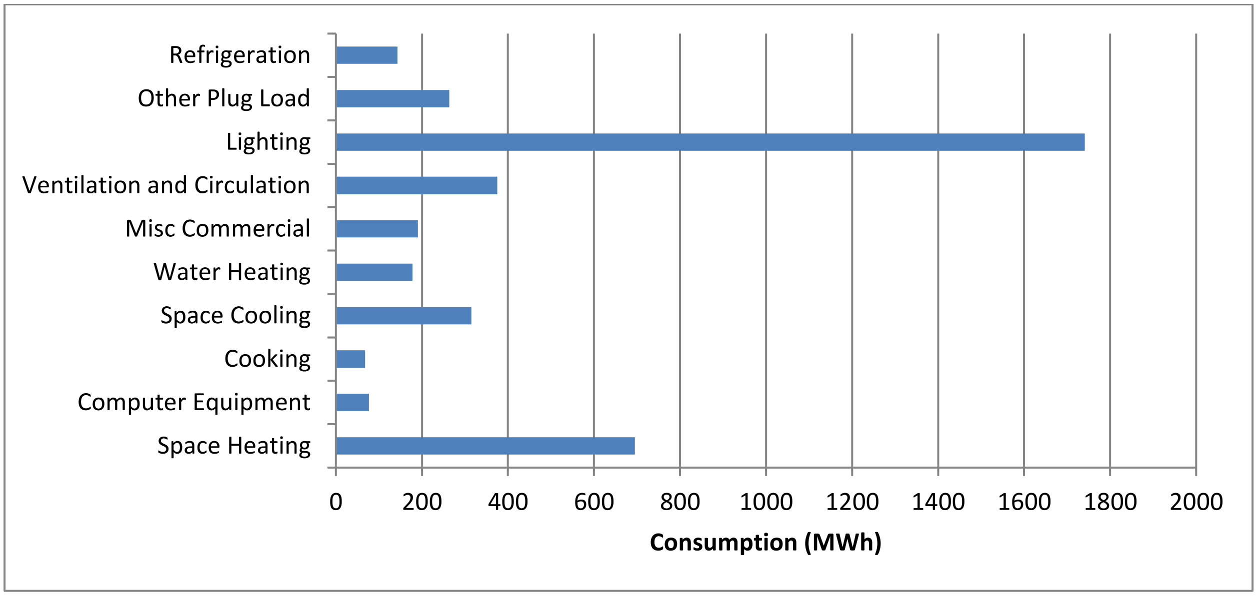


Figure B-21 End-use Segmentation for Residential Care Facilities, Marchwood MTS

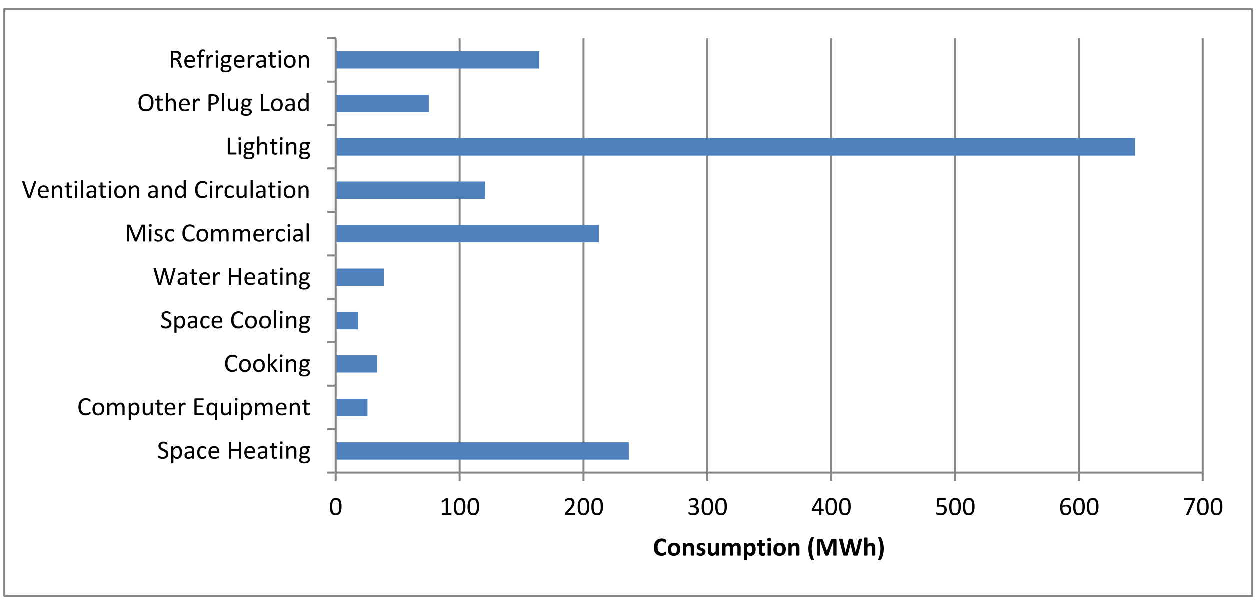


Figure B-22 End-use Segmentation for Warehouses Wholesale, Marchwood MTS

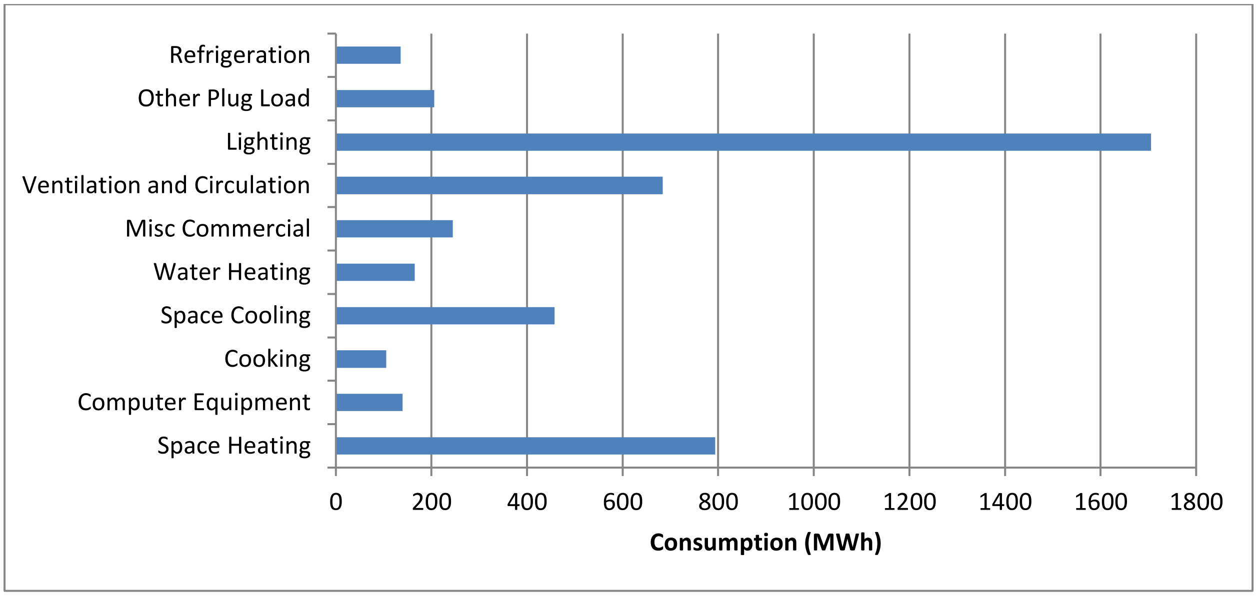


Figure B-23 End-use Segmentation for Hotels, Marchwood MTS

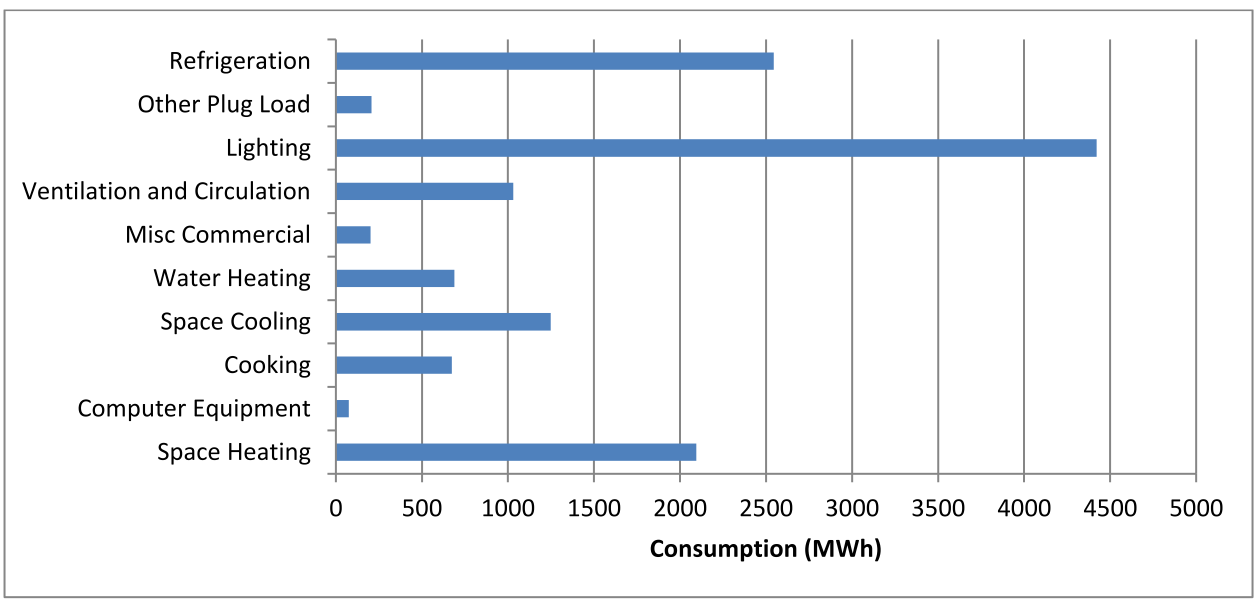


Figure B-24 End-use Segmentation for Food and Beverage Stores, Marchwood MTS

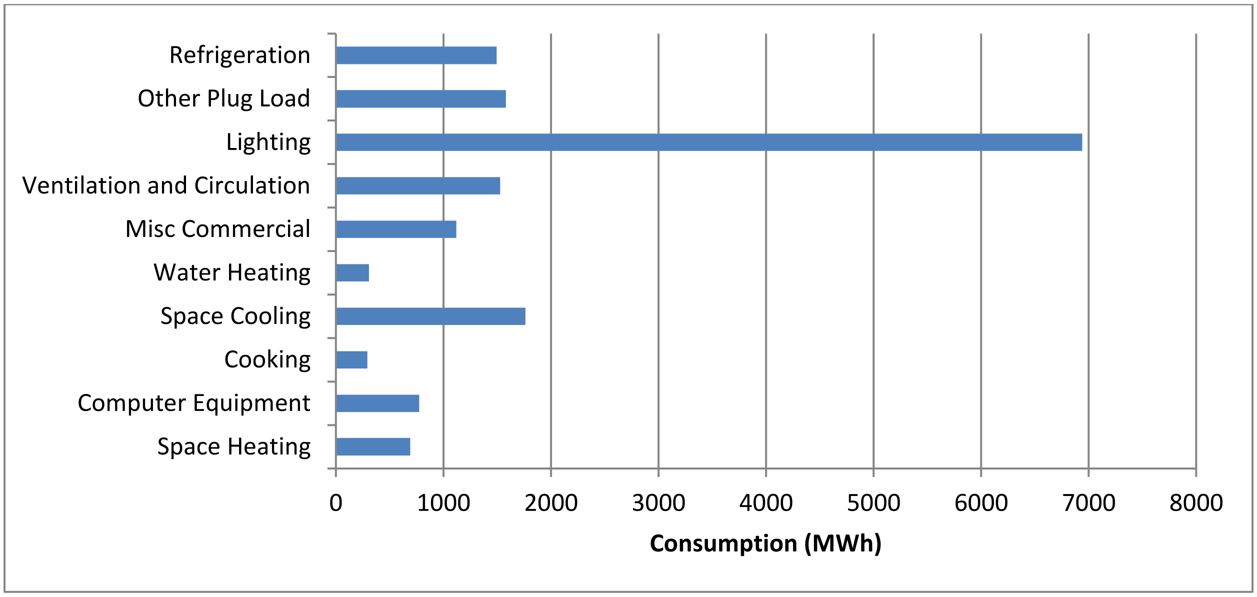


Figure B-25 End-use Segmentation for Non-Food Retail Stores, Marchwood MTS

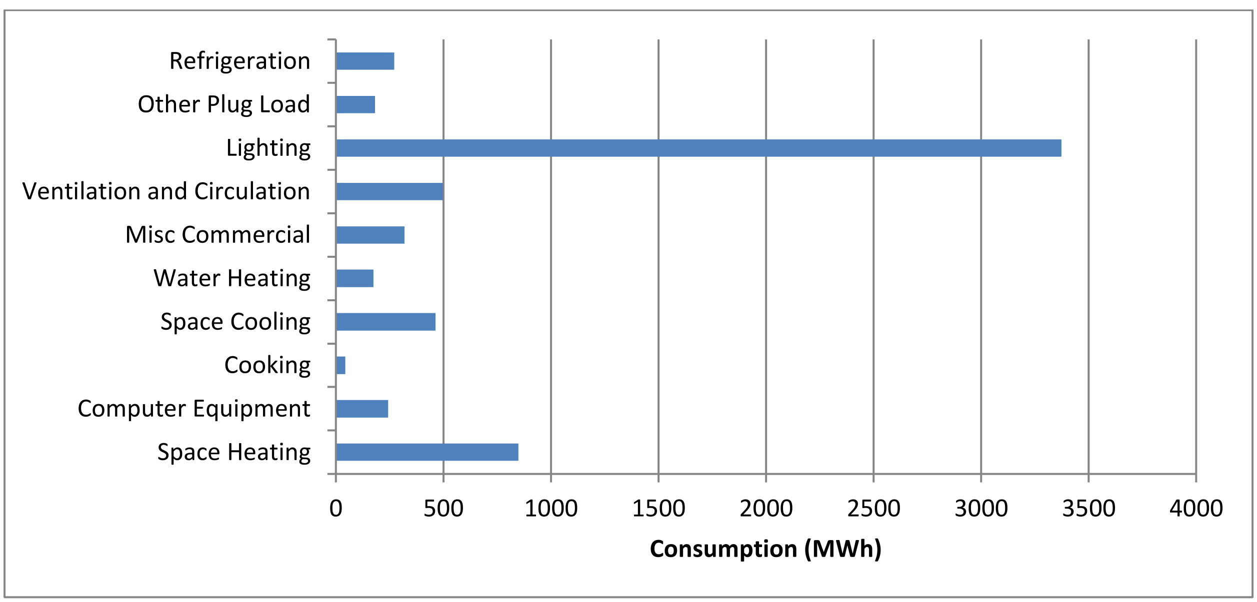


Figure B-26 End-use Segmentation for Other Commercial, Marchwood MTS

Table B-14 Number of Building Forecast with respect to 2018

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Single Detached w.r.t base year	1.006925	1.01759	1.028255	1.03892	1.049586	1.060251	1.070916	1.081581	1.092246	1.102912	1.113577
Single Attached w.r.t base year	1.074709	1.092708	1.110706	1.128705	1.146703	1.164702	1.1827	1.200698	1.218697	1.236695	1.254694
Apartments w.r.t base year	1.147382	1.159926	1.17247	1.185014	1.197558	1.210101	1.222645	1.235189	1.247733	1.260277	1.272821
Year	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Single Detached w.r.t base year	1.124242	1.134907	1.145572	1.156238	1.166903	1.177568	1.188233	1.198899	1.209564	1.220229	1.230894
Single Attached w.r.t base year	1.272692	1.290691	1.308689	1.326688	1.344686	1.362685	1.380683	1.398682	1.41668	1.434679	1.452677
Apartments w.r.t base year	1.285365	1.297908	1.310452	1.322996	1.33554	1.348084	1.360628	1.373172	1.385715	1.398259	1.410803

Table B-15 Energy Intensity Forecast with respect to 2018

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Single Detached w.r.t base year	0.985	0.971	0.956	0.941	0.927	0.912	0.898	0.883	0.868	0.854	0.839
Single Attached w.r.t base year	0.986	0.973	0.959	0.946	0.932	0.919	0.905	0.892	0.878	0.865	0.851
Apartments w.r.t base year	0.992	0.984	0.976	0.969	0.961	0.953	0.945	0.937	0.929	0.921	0.913
Year	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Single Detached w.r.t base year	0.824	0.810	0.795	0.780	0.766	0.751	0.737	0.722	0.707	0.693	0.678
Single Attached w.r.t base year	0.838	0.824	0.811	0.797	0.783	0.770	0.756	0.743	0.729	0.716	0.702
Apartments w.r.t base year	0.906	0.898	0.890	0.882	0.874	0.866	0.858	0.851	0.843	0.835	0.827

Table B-16 Annual Consumption Forecast for Residential Subsectors, Kanata MTS

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Single Detached (MWh)	27,190	27,069	26,941	26,804	26,658	26,504	26,341	26,169	25,989	25,801	25,604
ROW (MWh)	16,182	16,227	16,265	16,295	16,318	16,334	16,342	16,343	16,336	16,322	16,300
Low Rise (MWh)	1,567	1,571	1,576	1,580	1,584	1,587	1,590	1,593	1,596	1,598	1,600
High Rise (MWh)	1,130	1,134	1,137	1,140	1,142	1,145	1,147	1,149	1,151	1,153	1,155
Year	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Single Detached (MWh)	25,398	25,184	24,961	24,730	24,490	24,242	23,985	23,719	23,445	23,162	22,871
ROW (MWh)	16,271	16,235	16,191	16,139	16,081	16,014	15,941	15,860	15,771	15,675	15,572
Low Rise (MWh)	1,602	1,604	1,605	1,606	1,607	1,607	1,608	1,608	1,607	1,607	1,606
High Rise (MWh)	1,156	1,157	1,158	1,159	1,159	1,160	1,160	1,160	1,160	1,159	1,159

Table B-17 Annual Consumption Forecast for Residential Subsectors, Marchwood MTS

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Single Detached (MWh)	40,961	40,781	40,587	40,380	40,160	39,928	39,683	39,424	39,153	38,869	38,572
ROW (MWh)	16,627	16,674	16,713	16,744	16,768	16,784	16,792	16,793	16,786	16,771	16,749
Low Rise (MWh)	811	813	815	817	819	821	823	824	826	827	828
High Rise (MWh)	6,649	6,668	6,686	6,703	6,719	6,734	6,748	6,760	6,772	6,782	6,791
Year	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Single Detached (MWh)	38,263	37,940	37,604	37,256	36,895	36,520	36,133	35,733	35,320	34,895	34,456
ROW (MWh)	16,719	16,682	16,637	16,584	16,523	16,455	16,380	16,296	16,205	16,107	16,001
Low Rise (MWh)	829	830	831	831	832	832	832	832	832	831	831
High Rise (MWh)	6,805	6,811	6,815	6,819	6,821	6,822	6,822	6,820	6,818	6,814	6,805

Table B-18 Annual Consumption (MWh) Forecast for Commercial Subsectors, Kanata MTS

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Office buildings	134,861	135,637	136,416	137,198	137,982	138,769	139,559	140,351	141,146	141,944	142,744
Medical office	3,309	3,328	3,347	3,366	3,385	3,405	3,424	3,443	3,463	3,482	3,502
Schools	4,589	4,616	4,644	4,671	4,699	4,726	4,754	4,782	4,809	4,837	4,865
Residential care facilities	1,393	1,397	1,402	1,407	1,411	1,416	1,420	1,424	1,429	1,433	1,437
Warehouses Wholesale	4,832	4,846	4,861	4,875	4,889	4,903	4,917	4,931	4,945	4,958	4,971
Hotels	2,679	2,673	2,666	2,659	2,652	2,644	2,637	2,630	2,622	2,615	2,607
Hospitals	0	0	0	0	0	0	0	0	0	0	0
Food and beverage stores	19,463	19,516	19,567	19,618	19,667	19,716	19,764	19,810	19,856	19,901	19,945
Non-food retail	11,888	11,875	11,862	11,848	11,834	11,819	11,803	11,788	11,771	11,754	11,737
Other activity	7,226	7,265	7,303	7,342	7,381	7,420	7,459	7,497	7,536	7,575	7,615
Total	190,24	191,15	192,06	192,98	193,90	194,81	195,73	196,65	197,57	198,49	199,42
Year	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Office buildings	143,546	144,352	145,159	145,970	146,782	147,597	148,415	149,235	150,057	150,882	151,709
Medical office	3,522	3,542	3,561	3,581	3,601	3,621	3,641	3,661	3,681	3,702	3,722
Schools	4,893	4,920	4,948	4,976	5,003	5,031	5,059	5,086	5,114	5,142	5,169
Residential care facilities	1,441	1,445	1,449	1,453	1,457	1,461	1,465	1,469	1,472	1,476	1,479
Warehouses Wholesale	4,984	4,997	5,010	5,022	5,035	5,047	5,059	5,071	5,082	5,094	5,105
Hotels	2,599	2,591	2,583	2,575	2,567	2,559	2,550	2,541	2,533	2,524	2,515
Hospitals	0	0	0	0	0	0	0	0	0	0	0
Food and beverage stores	19,987	20,029	20,069	20,108	20,146	20,183	20,219	20,253	20,286	20,318	20,349
Non-food retail	11,719	11,701	11,682	11,662	11,642	11,622	11,600	11,579	11,556	11,534	11,510
Other activity	7,654	7,693	7,732	7,771	7,811	7,850	7,889	7,928	7,968	8,007	8,047
Total	200,34	201,26	202,19	203,11	204,04	204,97	205,89	206,82	207,75	208,67	209,60

Table B-19 Annual Consumption (MWh) Forecast for Commercial Subsectors, Marchwood MTS

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Office buildings	134,861	135,637	136,416	137,198	137,982	138,769	139,559	140,351	141,146	141,944	142,744
Medical office	3,309	3,328	3,347	3,366	3,385	3,405	3,424	3,443	3,463	3,482	3,502
Schools	4,589	4,616	4,644	4,671	4,699	4,726	4,754	4,782	4,809	4,837	4,865
Residential care facilities	1,393	1,397	1,402	1,407	1,411	1,416	1,420	1,424	1,429	1,433	1,437
Warehouses Wholesale	4,832	4,846	4,861	4,875	4,889	4,903	4,917	4,931	4,945	4,958	4,971
Hotels	2,679	2,673	2,666	2,659	2,652	2,644	2,637	2,630	2,622	2,615	2,607
Hospitals	0	0	0	0	0	0	0	0	0	0	0
Food and beverage stores	19,463	19,516	19,567	19,618	19,667	19,716	19,764	19,810	19,856	19,901	19,945
Non-food retail	11,888	11,875	11,862	11,848	11,834	11,819	11,803	11,788	11,771	11,754	11,737
Other activity	7,226	7,265	7,303	7,342	7,381	7,420	7,459	7,497	7,536	7,575	7,615
Total	190,20	191,13	192,08	192,93	193,90	194,88	195,77	196,67	197,58	198,49	199,42
Year	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Office buildings	143,546	144,352	145,159	145,970	146,782	147,597	148,415	149,235	150,057	150,882	151,709
Medical office	3,522	3,542	3,561	3,581	3,601	3,621	3,641	3,661	3,681	3,702	3,722
Schools	4,893	4,920	4,948	4,976	5,003	5,031	5,059	5,086	5,114	5,142	5,169
Residential care facilities	1,441	1,445	1,449	1,453	1,457	1,461	1,465	1,469	1,472	1,476	1,479
Warehouses Wholesale	4,984	4,997	5,010	5,022	5,035	5,047	5,059	5,071	5,082	5,094	5,105
Hotels	2,599	2,591	2,583	2,575	2,567	2,559	2,550	2,541	2,533	2,524	2,515
Hospitals	0	0	0	0	0	0	0	0	0	0	0
Food and beverage stores	19,987	20,029	20,069	20,108	20,146	20,183	20,219	20,253	20,286	20,318	20,349
Non-food retail	11,719	11,701	11,682	11,662	11,642	11,622	11,600	11,579	11,556	11,534	11,510
Other activity	7,654	7,693	7,732	7,771	7,811	7,850	7,889	7,928	7,968	8,007	8,047
Total	200,34	201,26	202,19	203,11	204,04	204,97	205,89	206,82	207,75	208,67	209,60

Hydro Ottawa Local Achievable Potential (LAP) Study

Identification of technically feasibly measures for addressing local area needs

Milestone #2 Report

SLI PROJECT NO.: 660803

3	Final Report	07/23/2019	EH	HA	TA
2	Issued for Review	07/03/2019	MA	HA	TA
1	Issued for Comments	06/13/2019	MA	HA	TA
0	Issued for Information	05/22/2019	MA	HA	TA
REV.	**DESCRIPTION**	**DATE**	**PRPD**	**CHKD**	**APPRD**
			SNC-Lavalin		

SUMMARY

This is the report for the second milestone of the study entitled "Hydro Ottawa Local Achievable Potential (LAP) Study," which commenced on Dec. 7, 2018. This study, undertaken at the request of Hydro Ottawa Ltd, Ontario, is conducted by SNC-Lavalin Inc. Toronto, Canada, as the Consultant.

The objective of Milestone #2 of this study is to identify the technically feasible measures for addressing local area needs.

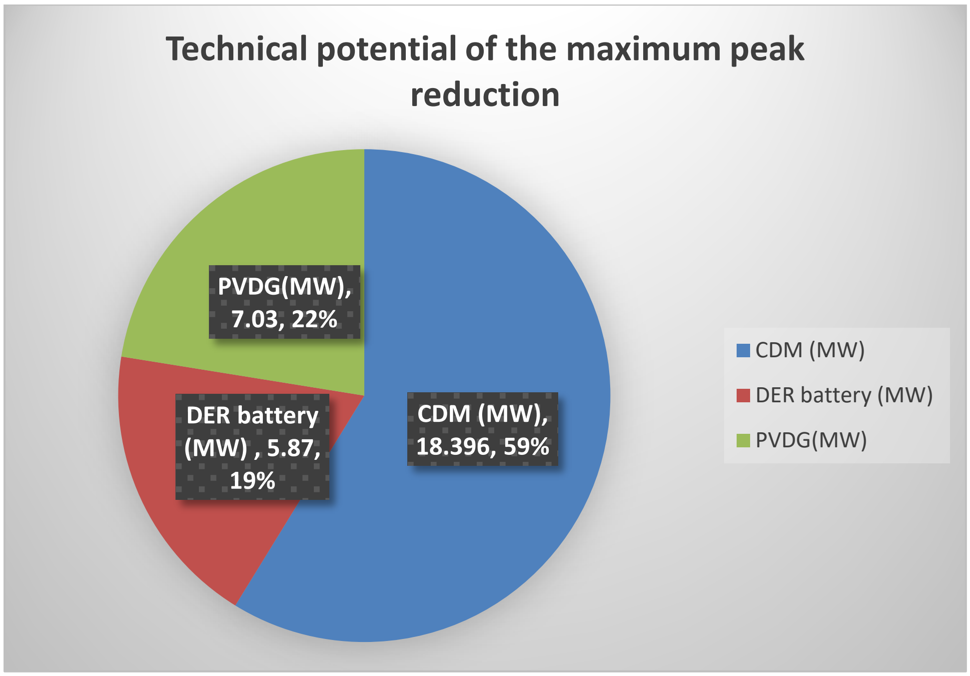
The project team collected data on the conservation and demand management (CDM) measures; the 2018 and 2019 IESO's Measure and Assumption lists (MAL) represent the basis for the measure research. In addition, the list of measures of the 2016's APS provided by the IESO for Ottawa is also included [1]. The integration of the additional measures achieved extra peak reduction of an additional 12% of the maximum peak reduction of the CDM. Moreover, other CDM measures from North American Jurisdictions (outside existing MAL), that could be rolled into the market quickly are added to the CDM list of measures used. For each measure, the team calculated the annual energy consumption saving as well as the peak demand savings. The team screened the available measures to determine the shortlisted measures that are addressing the summer peak demand at the Kanata North area; three screening stages are followed to exclude the measures that are not suitable for addressing the local area needs;

- Exclude measures of subsectors that are not existing in Kanata North area (e.g., hospitals, colleges, agribusiness,)
- Exclude measures that are no longer offered in 2018 and 2019 IESO list of measures.
- Exclude measures that have no impact on summer peak demand (e.g., space heating measures).

The team calculated the maximum potential for peak demand reduction for each measure based on the local area load segmentation developed in milestone #1, the number of equipment per subsector, the consumption of the total equipment as a percentage of the end-use consumption, and the fraction of equipment that is energy efficient. Finally, the team estimated the aggregated technical potential for peak reduction for all the CDM measures.

In addition to the CDM measures, the project team conducted an analysis to study the impact of the Distributed Energy Resources (DER) on Kanata-Marchwood summer peak; the analysis is categorized into load shifting using battery energy storage system and renewable-based distributed generation. The technical potential for peak reduction of the battery energy storage is calculated on the utility-scale and on the large customers-scale. Moreover, the technical potential of photovoltaic roof-top distributed generation mounted on the residential and commercial buildings is calculated. Based on the calculated technical potentials for the CDM and DER measures, the total technical potential for the peak reduction of Kanata North area is calculated.

The results presented in Figure ES-1 show that the maximum technical potential of the peak reduction due to the CDM program is 18.396 MW, for the DER battery the maximum reduction is 5.87MW for the 6 hours scenario. In addition, the technical potential of the photovoltaic PV Distributed generators DG is 7.03 MW.



ES-1 Percentage contribution of each of the technical potential on peak reduction

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List of acronyms

APS	Achievable Potential Study
CDM	Conservation and Demand Management
DER	Distributed Energy Resources
DG	Distributed Generation
HOL	Hydro Ottawa Ltd
HR	High Rise
IESO	Independent Electricity System Operator
kWh	Kilowatt-hour
LAP	Local Achievable Potential Study
LR	Low Rise
MAL	IESO's Measure and Assumption lists

1 Introduction

This report provides the methodology and the complete analyses of milestone #2 that aims to identify the technically feasible measures for addressing local area needs. This report is summarizing the following;

- Peak load analysis for Kanata North area,
- The collected list of CDM measures,
- The screening criterion and the shortlisted CDM measures mapped to sectors, subsectors, end-use, and competition groups,
- The technical potential of the shortlisted CDM measures,
- The technical potential of load shifting using battery energy storage,
- The technical potential of residential and commercial roof-top photovoltaic DER, and
- Summary of the total technical potential of the CDM and DER measures.

2 Peak Load Analysis for Kanata North Area

The project team carried out an analysis, based on the historical, forecasted, and current load profiles received from HOL, to determine the peak loading conditions for Kanata and Marchwood MTS.

2.1 Historical Peak Load Analysis

Based on the data received from HOL, the historical peak loading was analyzed, Figure 2-1 shows the coincidental combined peak load for the years 2012 to 2016 for Kanata MTS and Marchwood MTS. Kanata MTS contains 2 X 41.7 MVA transformers and Marchwood MTS has 2 X 33 MVA transformers. Thus, the combined N-1 ratings for the two stations is 74.7 MVA. The limited-time ratings (LTR) for Kanata MTS is 54.5 MVA, and for Marchwood, MTS is 34 MVA; thus, the combined LTR for the two stations is 88.5 MVA. It worth noting that all the maximum peak loading occurred at the Summer Season for all these years. The highest historical coincidental loading occurred in 2016 with a summer peak of 105.2 MW, while the winter coincidental peak load for this year was 77 MW. This historical data analysis shows that the Summer peak is always greater than the Winter peak for all available historical data. In addition, the Summer peak exceeded the combined LTR for the two stations over the historical years.

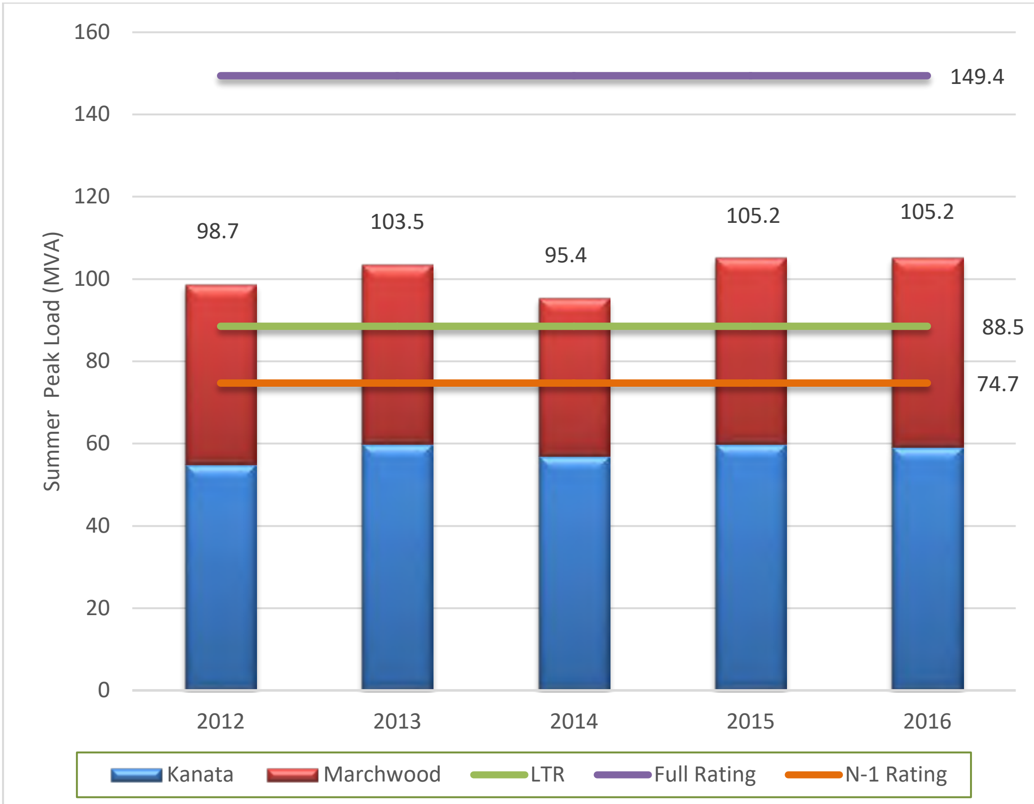

Figure 2-1 Historical Peak Loading for Kanata-Marchwood

2.2 Peak Load Forecast (Median Weather Condition)

The coincident peak loading forecasts for the summer season is estimated based on the noncoincidental peak demand provided by HOL and by using the diversity factor estimated using 2018 coincidental and noncoincidental peak demand. Tables A-1 and A-2 show the Summer peak loading forecast for the median weather for Kanata MTS and Marchwood MTS (received from HOL). The Summer peak is expected to exceed the combined LTR rating of the two stations (i.e., 88.5 MVA). ***We recommend reviewing the bulk load forecast of (Broccolini Business Park) and (550 Innovation (Ciena) as those two specific loads combined represent about 14 MVA of the forecast load growth. It would be beneficial to review how the assumptions used in reaching out this estimate and if Conservation and Demand Side measures are being considered in the development phase.***

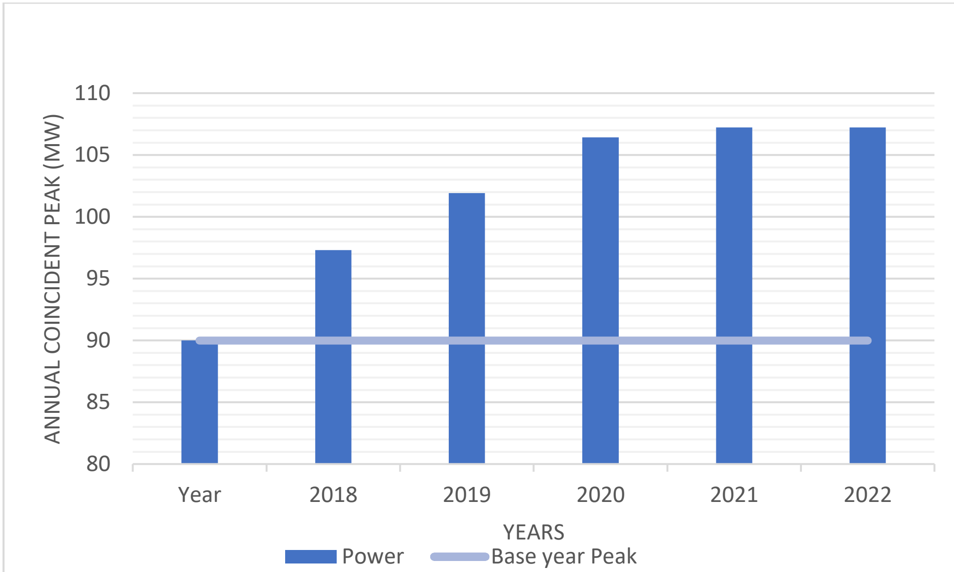

Figure 2-2 Forecasted Coincident Peak Loading for Kanata-Marchwood, Median Weather

2.3 Peak Load forecast (Extreme Weather Condition)

The coincident peak loading forecasts for the Summer season considering the extreme weather conditions is presented in Figure 2-2. The forecast was estimated using data provided by HOL and 2018 diversity factors.

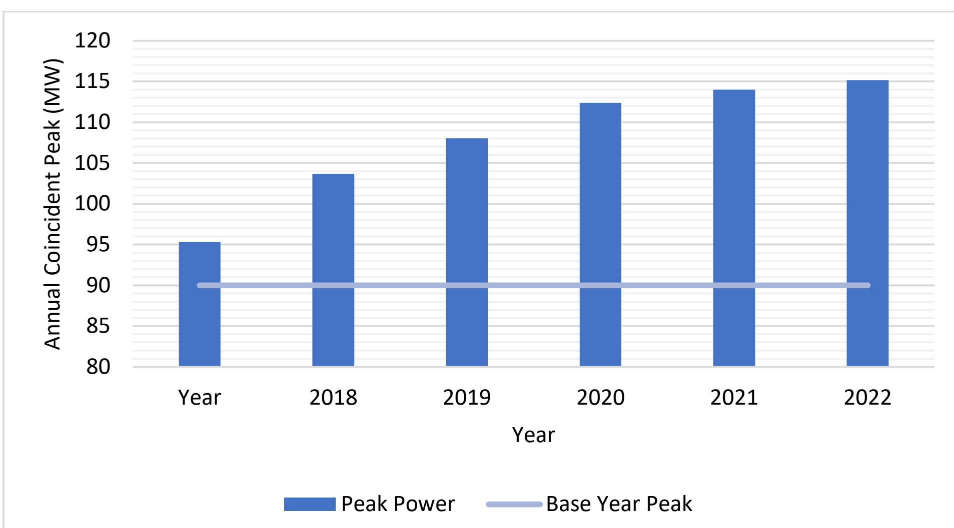

Figure 2-3 Forecasted Coincident Peak Loading for Kanata-Marchwood, Extreme Weather

2.4 Base Year Peak Load

Based on the feeder hourly loading profiles for years 2017 and 2018, the project team performed an analysis to determine the chronological loading curve for the Winter and Summer seasons. The chronological loading curves, for the peak day, for the Winter and Summer seasons are determined; Figure 2-2 shows the chronological loading curve for the summer peak. The highest peak loading during the summer was reached on July 5th, while for the Winter Season the highest peak was reached on January 5th. The winter peak is 14.7% less compared to Summer, and the total number of days for the Winter season where the peak loading exceeded the planning ratings are ten days, while this number increased to 52 days in the Summer Season. Based on this analysis, the Winter Peak will not be analyzed given the available data and the large difference between winter and summer peak. Therefore, non-wire solutions should be addressing the Summer peak to lower this peak below the planning ratings of the two stations.

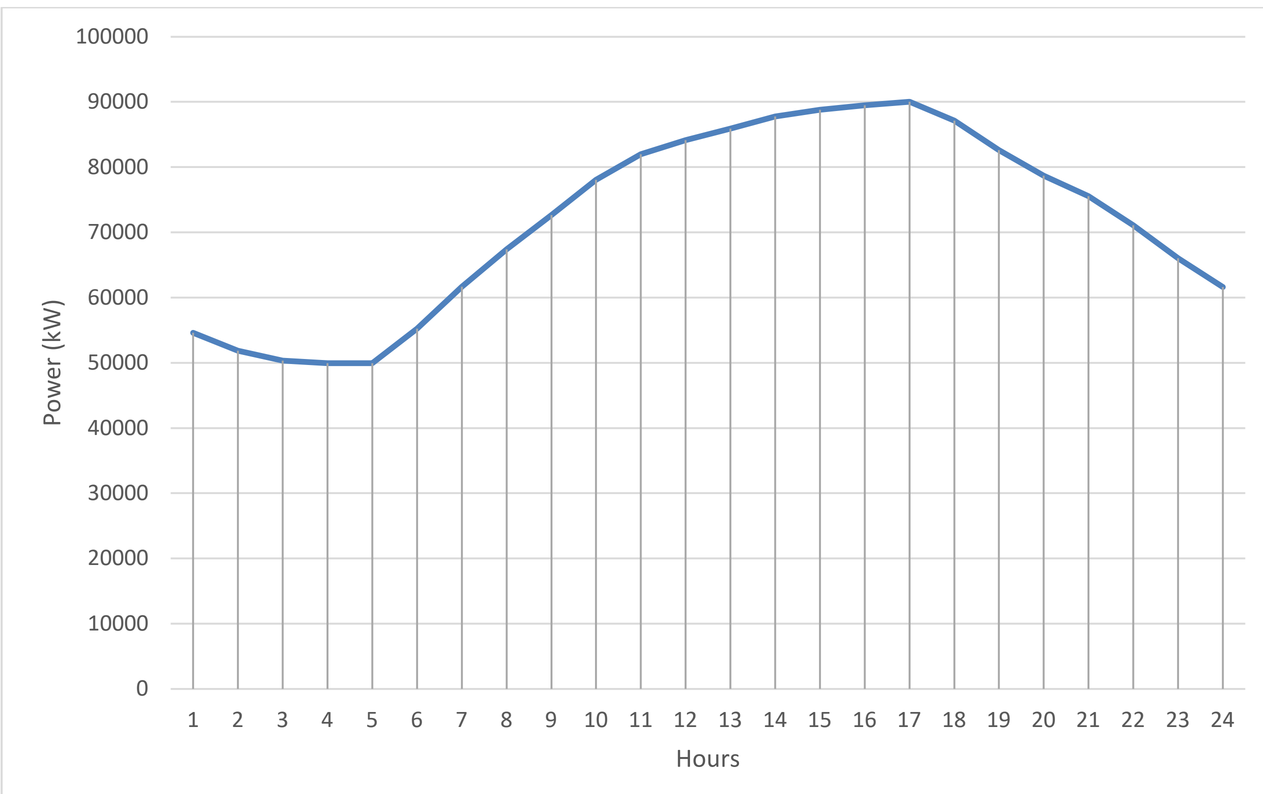

Figure 2-**3** Peak Coincident Loading Day for the Base Year for Kanata-Marchwood, Summer Season Year 2018

3 Technical Potential of CDM Measures

The technical potential scenario estimates the saving potential when all technically feasible non-wire solutions are implemented at their full technical potential. This saving potential is the maximum potential that is not considering the economics of the measures nor customer adoption. This section presents the methodology followed for shortlisting the available CDM measures in Ontario and for calculating the technical potential of these measures.

3.1 Methodology

The main project rationale is to determine the potential solutions to lower the summer peak demand in Kanata-Marchwood area. The achievable potential of Summer peak load reduction would allow for more efficient use of existing facilities and infrastructure and differ or eliminate the need for a new station. Based on HOL plan, the new station (new Kanata North) is planned to be in service in 2026. Therefore, the presented study focuses on the short-term technical potential scenarios that may differ or eliminate the need for the new station.

Since the presented study is targeting the short-term technical potential, the commercially available measures existing in the current CDM programs in Ontario are included in the CDM list of measures. Therefore, the 2018 and 2019 IESO's Measure and Assumption (M&A) lists represent the basis for the measure research. In addition, the list of measures of the 2016's APS provided by the IESO for Ottawa is also included. Moreover, other CDM measures from nearby jurisdictions, that could be rolled into market quickly are added to the CDM list of measures used. The market adoption of the additional measures will be evaluated in milestone #3 to assess their impact on short-term load reduction.

The methodology of the CDM analysis is summarized as follows;

1- The project team collected data on the available conservation measures from IESO's MAL, the 2016's APS, and from other North American Jurisdictions [2]-[5].

2- The team screened the measures to determine the measures that are addressing the summer peak demand at Kanata North area; three screening stages are followed to exclude the measures that are not suitable for addressing the local area needs (a sample of excluded measures are presented in Table A-3);

   - Exclude measures of subsectors/end uses not available in Kanata area (e.g., hospitals, colleges, agribusiness, etc.)
   - Exclude measures that are no longer offered in 2018 and 2019 IESO list of measures.
   - Exclude measures that have no impact on summer peak demand (e.g., space heating measures)

3- For each measure, compared to the base case equipment, the consumption, annual energy saving, and peak demand reduction are determined.

4- The measures are categorized by sectors and subsectors first, and then further categorization by end-use was done.

5- For each end-use, the competition groups will be developed. For example, for the lighting residential end-use, the competition groups will be indoor (screw-in lamps and lighting control), outdoor, and common area lighting. The obtained measures will be mapped to the competition groups/ end-use/ subsector/ sector. Table A-4 and Table A-5 present the list of residential and commercial CDM measures used classified by competition group.

6- For each measure in each competition group, the team collected data on:

- The fraction of equipment that is energy efficient
- The number of equipment per subsector, and the consumption of the total equipment as a percentage of end-use consumption.

7- The maximum potential for peak demand reduction for each measure is calculated as follows;

$$Potential\ of\ measure = Total\ number\ of\ base\ equipment \times (1 - energy\ efficient\ factor) \times measure\ peak\ reduction$$

Where;

$Total\ number\ of\ base\ equipment$: is the total number of base case equipment (non-efficient); this number is obtained for each subsector/end-use using the base case energy consumption per subsector/ end-use (obtained from milestone #1), the base case equipment share (i.e. consumption of the measure as a portion from the end-use consumption), and the annual energy consumption of the base case equipment.

$energy\ efficient\ factor$: is the fraction of equipment that is already energy efficient.

8- The aggregated measure savings potential for each competitive group is determined; double-count of potential savings is avoided by limiting the total adoption to 100% within each measure competition group.

3.2 Mapping of CDM Measures

The measure competition groups were developed for each subsector/end-use separately. Each competition group consolidates similar measures that could be an alternative to each other. For example, the competition groups for the space cooling end-use are a thermal envelope, space cooling control, room/window air conditions, and central AC. The measures in each competition group are alternatives to each other, while a measure from the room AC group cannot compete with measures of the central AC group. The complete list of competition groups mapped to subsectors, and end-use are presented in Table 3-1 and 3-2 for residential and commercial sectors, respectively. The subsectors mentioned in Table 3-2 are an office, medical office, hotels, residential care, non-food retailers, food retailers, schools, warehouse wholesale, and other commercials.

Table 3-1 Residential Sector Competition Groups

End-use	Competition Groups
Indoor Lighting	Screw-in lamps, light control
Outdoor Lighting	Screw-in lamps, light control
Common Area Lighting	Screw-in lamps, light control
Cooking	Wall Oven
Refrigeration	Refrigerators, Freezers
Space Cooling	Control, Thermal Envelope, Room AC, Central AC, Other Cooling
Water Heating	Pipe Insulation, Showerhead, Water heater, Aerator
Plug Loads	Dehumidifiers, Televisions, Water cooler, office equipment
Washer Dryer	Washing Machines, Dryers, Dishwashers

Table 3-2 Commercial Sector Competition Groups

End-use	Competition Groups
Subsector Lighting	Screw-in lamps, light control
Subsector space cooling	Packaged AC units, Chillers, Room AC
Subsector refrigeration	Residential size refrigerators, Walk-in refrigerators, Cabinet, pipes insulation, strip curtain, Gasket.
Subsector plug loads	Ice machine, Vending machine
Subsector computers	Computers
Subsector Domestic Hot Water	Water heater

3.3 Results and Discussion

The methodology described in section 3.1 is applied to the Kanata-Marchwood load profile developed in milestone #1, the year 2023 forecasted load, forecasted number of residential units and forecasted commercial areas were used to determine the technical potential, due to CDM measures, for this year. The factors required for calculating the technical potential; (i.e., the measure share, the energy-efficient factor, and the total number of equipment per household or square footage) are obtained from the residential survey provided by IESO and the commercial CDM data provided by HOL. The missed values or fractions are completed using NRCAN residential and commercial surveys [6]-[7] and EIA's Commercial Buildings Energy Consumption Survey (CBECS) [8]. Samples for the analysis and results for some CDM measures are presented in Appendix B. Moreover, an example of the calculations of the technical potential for peak reduction savings for one of the additional collected measures (Electric chillers) is presented in Appendix B.

3.3.1 Residential Sector

The technical potential peak reduction is calculated for each competition group of the residential subsector/ end-use, and the total technical potential peak reduction is calculated for each subsector and end-use. The total residential summer peak reduction in 2023 was estimated to be 4.713 MW. Figure 3-1 shows the technical potential Summer peak reduction for each subsector; the largest technical potential was estimated for the single-family subsector, which accounts for 62.725 % of the total peak reduction in 2023. Figures 3-2 to 3-5 show the reductions per residential end-use for each subsector.

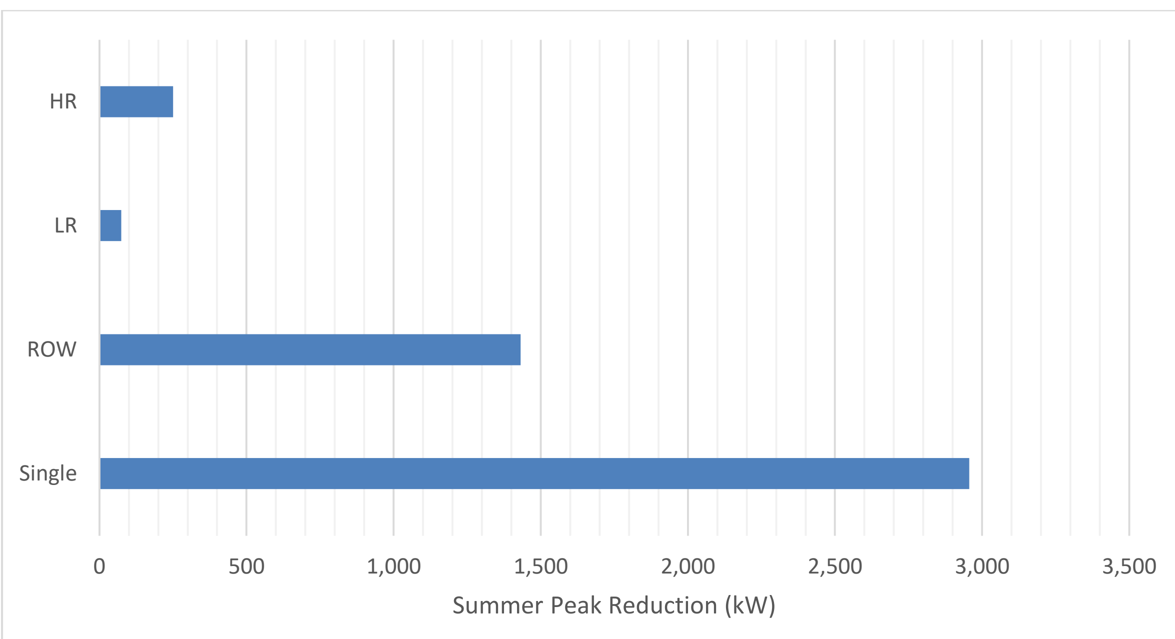

Figure 3-1 Technical Potential Peak Reduction by Residential Subsector in 2023

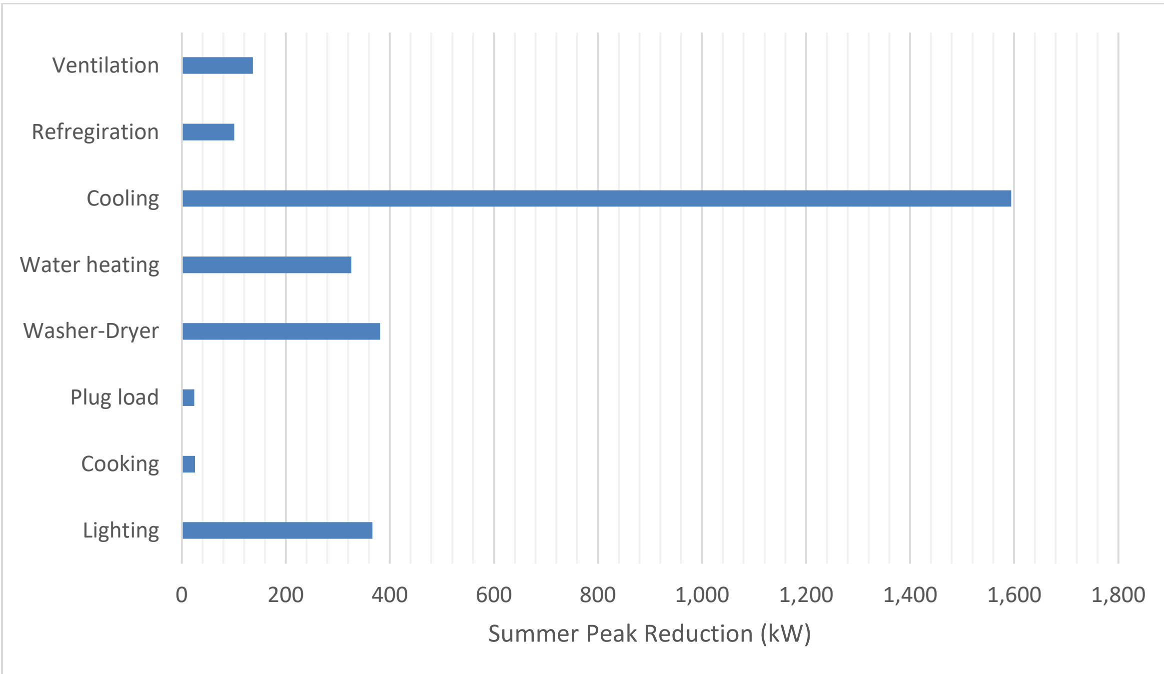

Figure 3-2 Technical Potential Peak Reduction by End-use in 2023, Single-family

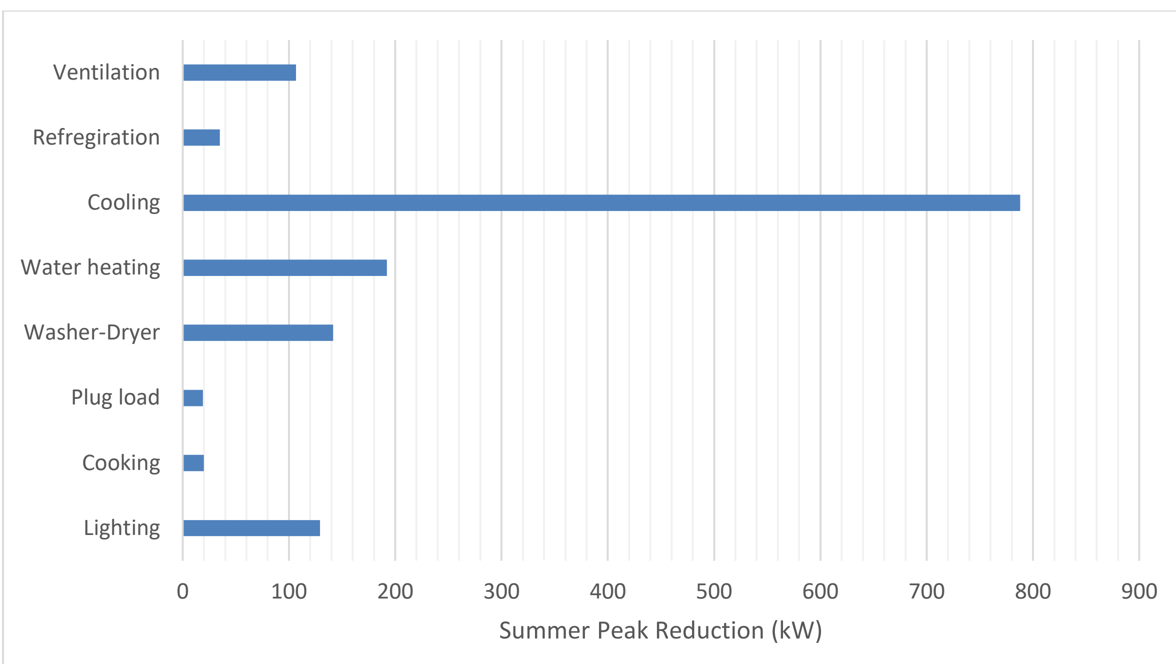

Figure 3-3 Technical Potential Peak Reduction by End-use in 2023, ROW

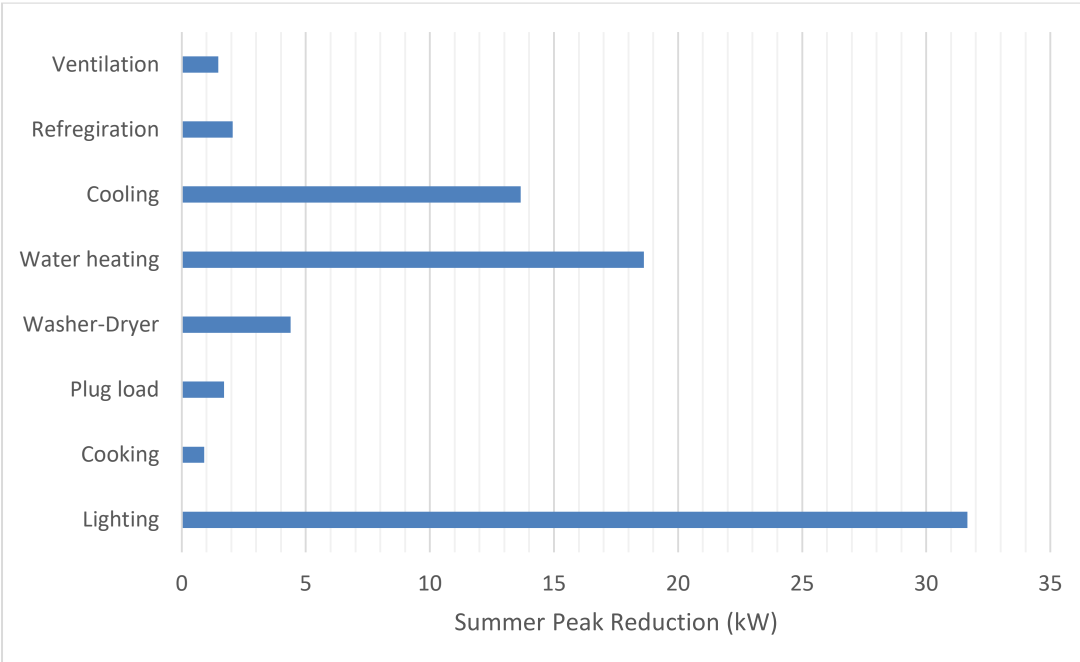

Figure 3-4 Technical Potential Peak Reduction by End-use in 2023, Low Rise

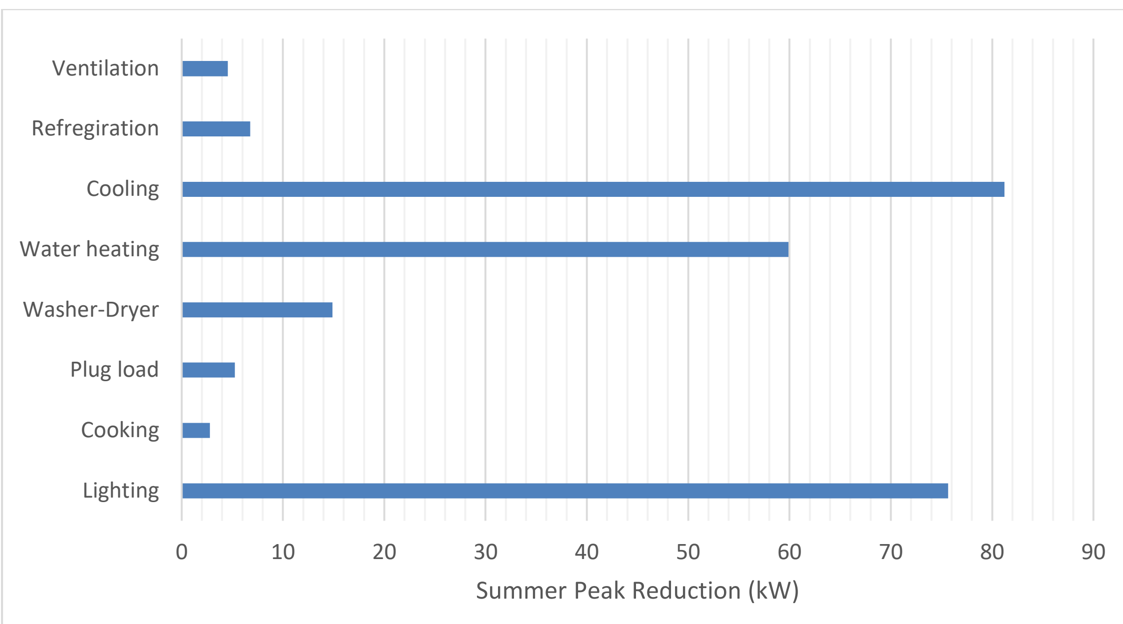

Figure 3-5 Technical Potential Peak Reduction by End-use in 2023, Low Rise

3.3.2 Commercial Sector

The technical potential peak reduction is calculated for each competition group of the commercial subsector/ end-use, and the total technical potential peak reduction is calculated for each subsector and end-use. The total commercial summer peak reduction in 2023 was estimated to be 12.217 MW. Figure 3-6 shows the technical potential Summer peak reduction for each subsector; the largest technical potential was estimated for the office subsector, which accounts for 63.6 % of the total peak reduction in 2023 followed by the food stores subsector that accounts for 11.15%. Figures 3-7 shows the total reductions per commercial end-use; the lighting end-use accounts for the largest peak reductions of 58.17% of the total reductions.

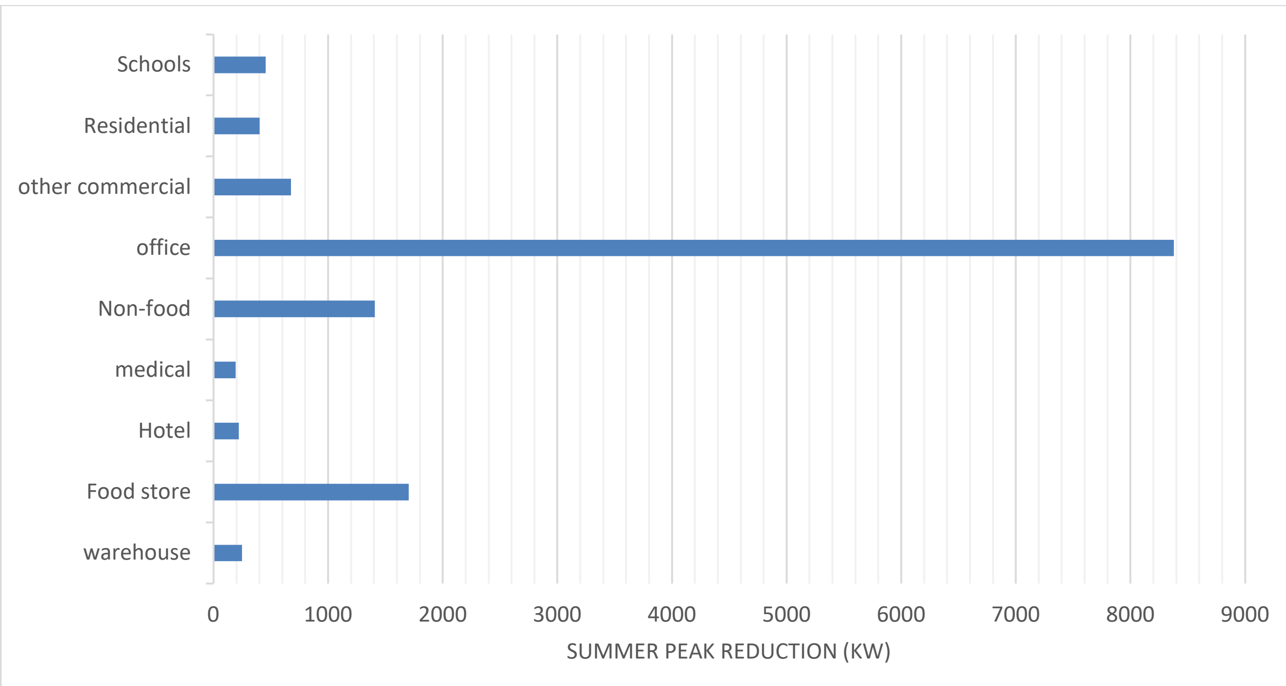

Figure 3-6 Technical Potential Peak Reduction by Commercial Subsectors in 2023

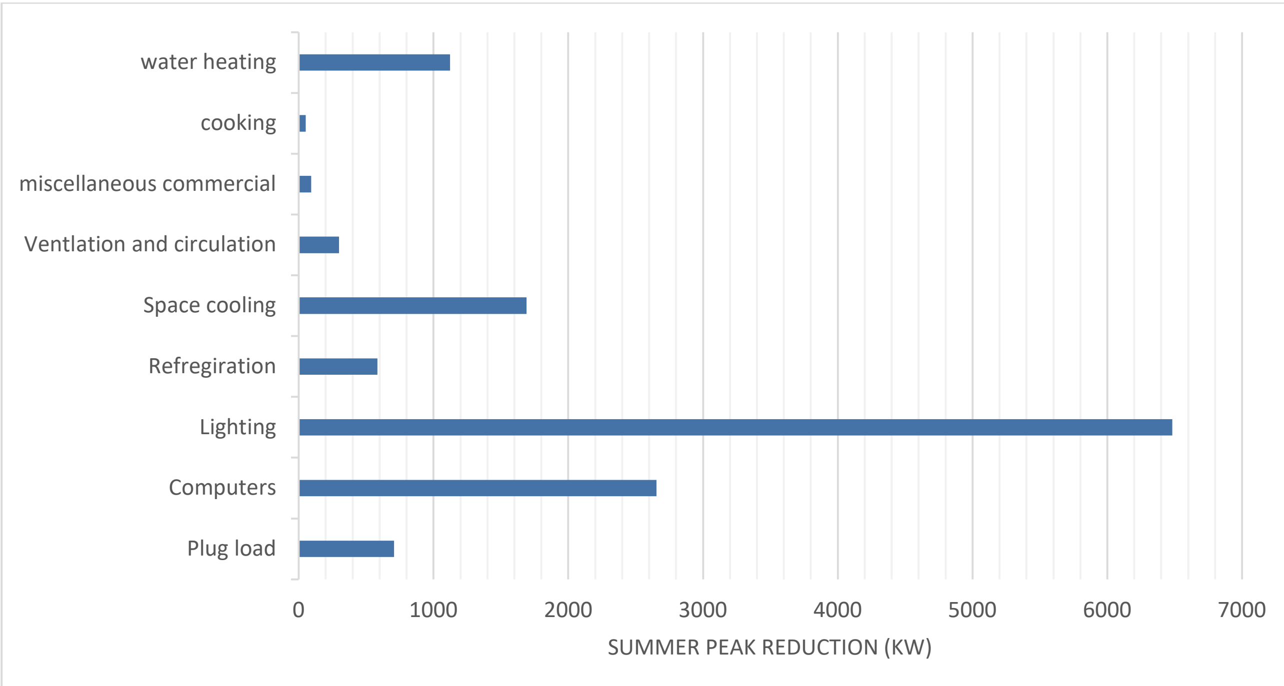

Figure 3-7 Technical Potential Peak Reduction by End-use, Commercial Sector

3.4 CDM Peak Reduction portfolio

The total technical potential reduction in 2023 was calculated to be 18,396 MW; the residential sector accounts for 26% while the commercial sector accounts for 74 %. As only one industrial building is located at Kanata-Marchwood, and there is no plan for expansion, the industrial sector CDM measures were not included in the shortlisted measures. In addition, the street lighting does not contribute to the Summer Peak reduction as the peak hour coincides with the daytime.

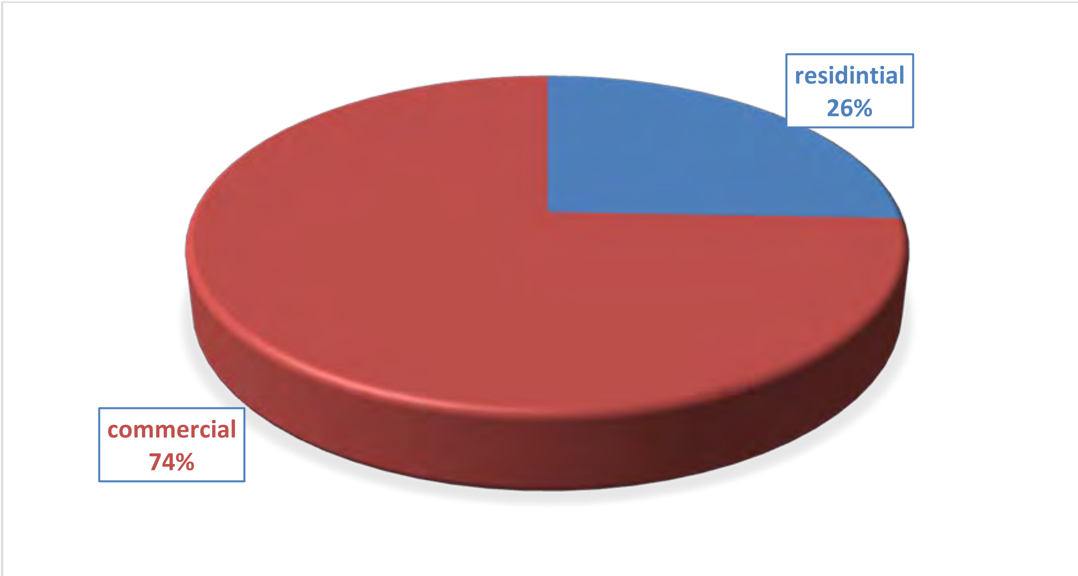

Figure 3-8 Total Technical Potential of CDM measures

3.6 Impact of the additional measures on the peak reduction

the Additional measures of APS 2016 provided by IESO shows have increased the commercial, technical peak reduction by 12% compared to the previously considered measures. The following charts show comparison between the peak reduction classified per the end-use and then by sector.

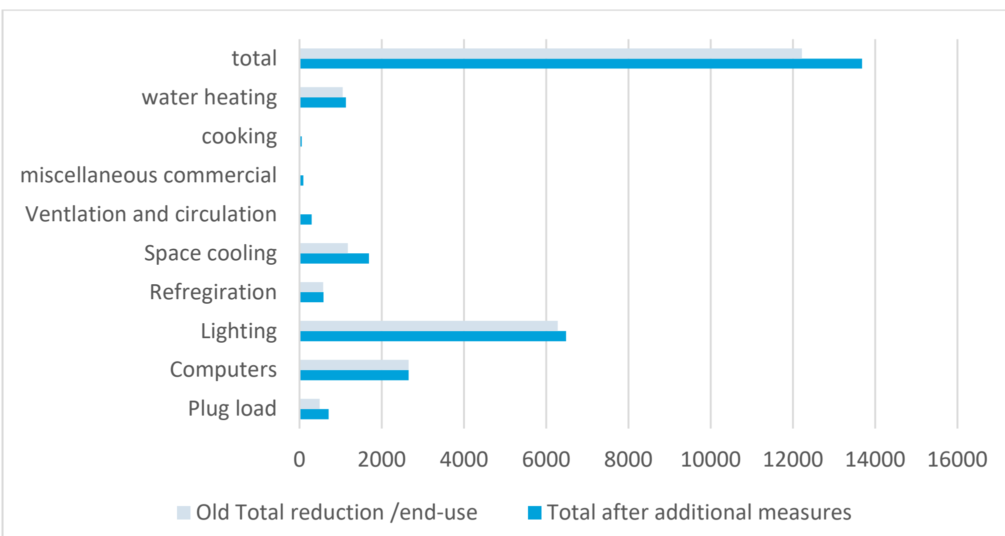

Figure 3-9 Impact of the additional measures on the end-use Kanata 2023

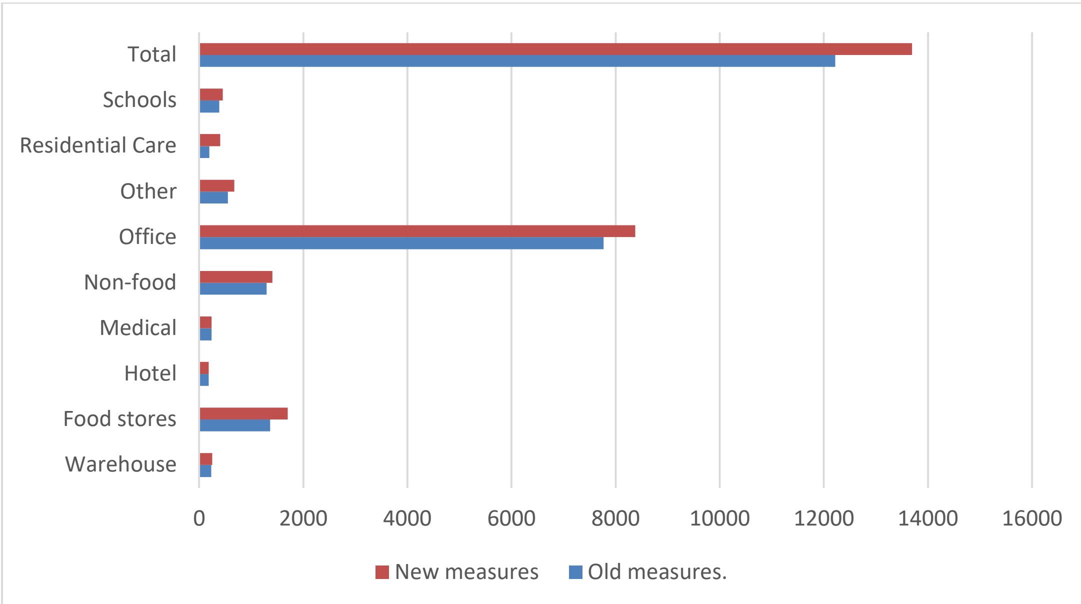

Figure 3-9 Impact of the additional measures on the sectors Kanata 2023

4 Technical Potential of Load Shifting Measures

The project team conducted an analysis to study the impact of load shifting on Kanata-Marchwood summer peak. One important measure to perform the load shifting is the time of use (TOU) pricing, HOL already adopted the TOU pricing for the Regulated Price Plan (RPP) customers. Most of the residential customers and the small commercial customers (i.e. 50kW to 1000 kW) are RPP customers. The larger commercial customers (i.e. Wholesale Market Participants (WMP)) purchase electricity through the IESO directly. Therefore, the TOU pricing is implicitly included in the wholesale energy prices. Thus, the project team concluded that the TOU pricing measure is already applied in Kanata North area, and no additional load shifting could be achieved using it.

The project team analyzed the possibility of load shifting using the battery energy storage system. This analysis was performed for two scenarios; i.e. utility-scale and large customers-scale. The load shifting analysis determined the technical potential of using a battery owned by HOL and installed at the substation. Moreover, the technical potential for installing batteries owned by large customers greater than 1000 KW was also determined.

4.1 Utility-Scale Battery Energy Storage

The total system peak is analyzed as shown in Figure 4-1, and the potential for peak reduction using substation scale battery storage is determined. Two scenarios are studied; i.e. batteries that are capable of discharging for 4 or 6 hours. The adequate battery size for the 4 hours scenario is 7,609 kWh, and this battery can reduce the system peak by 2.922 MW (shaving the peak from 90.05 MW to 87.113 MW). For the 6 hours scenario, the battery size is 24,125 kWh, and this battery can reduce the system peak by 5.87 MW. The economic potential of these proposed battery capacities will be assessed in milestone #3.

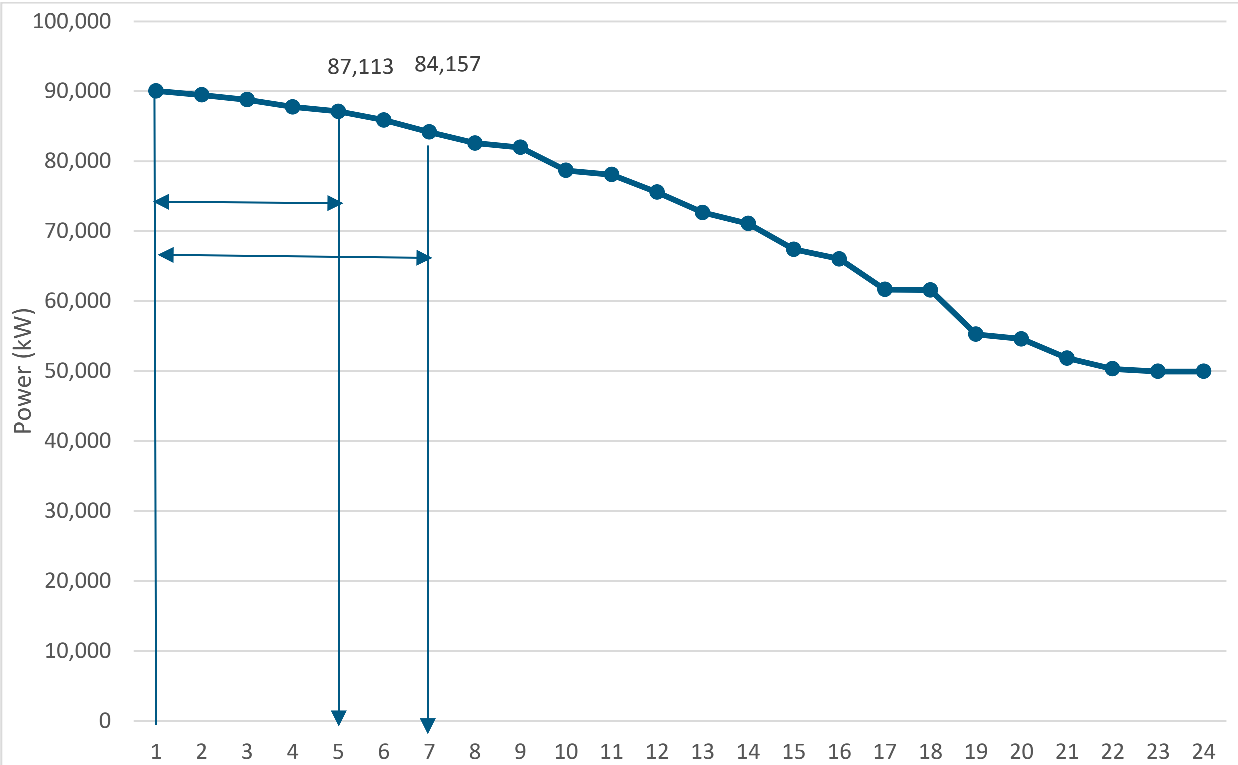

Figure 4-1 Load Duration Curve of the Summer Peak Day

4.2 Customer-Scale Battery Energy Storage

The potential for peak reduction using customer scale battery storage is determined. Two scenarios are studied; i.e. batteries that are capable of discharging for 4 or 6 hours. The adequate battery size for the 4 hours and 6 hours scenarios are determined for the large customers greater than 1000kW. The corresponding technical potentials of peak reduction for these batteries are obtained. Table 4-1 shows the customer meter reference number and the adequate battery sizes for both scenarios as well as the technical potential of these batteries. The total technical potential peak reduction for the 4-hour battery is 746 kW, while for the 6-hour battery, the reduction is 1,186 kW.

Table 4-1 Technical Potential of Large Customer Batteries

Meter Data Reference Number	Customer Maximum Load (kW)	Four Hours Scenario		Six Hours Scenario	
		Battery Capacity (kWh)	Technical Potential for Peak Reduction (kW)	Battery Capacity (kWh)	Technical Potential for Peak Reduction (kW)
1064575000	2,077	52.92	21.6	78.48	25.92
1323516000	1,013	129.6	72.9	181.08	82.08
2261516000	1,655	35.46	13.86	194.22	44.28
2313175000	2,173	166.88	69.44	327.6	100.24
2589675000	1,597	142.56	52.2	467.64	106.38
3948590255	2,278	62.04	19.92	141.36	34.32
5430710301	1,230	33.72	17.52	77.88	25.32
5649575000	1,479	75.24	29.76	263.52	65.04
6445807039	1,050	102.24	32.94	171	45.18
7489675000	1,055	68.13	27.45	121.5	36.99
8079416000	1,967	57.6	21.96	242.82	54.18
9046027318	2,098	15.48	6.3	55.08	12.96
9098675000	3,396	400.76	173.88	689.13	245.97
9771025037	1,097	31.32	17.16	34.8	17.76
9858616000	1,105	198.96	60.48	368.28	93.96
9866575000	3,594	40.079	25.32	97.68	36.54
9951516000	1,053	26.46	10.26	42.3	12.96
9982475000	8,273	227.67	91.41	545.73	145.95

5 Technical Potential of DG Measures

The Project team studied the impact of roof-top small-scale PV DGs located at residential and commercial buildings on the system peak. The team used helioscope software to determine the optimal distribution of the PV panels. The software utilized the actual solar irradiances at Kanata North area to develop the daily profile of the PV DG output power and the DG capacity. The minimum daily power profile for the Summer season was used to determine the technical potential for the Summer peak reduction using the PV DGs.

5.1 Technical Potential of Commercial DGs

One large commercial building located at Terry Fox Dr. is selected (shown in Figure 5-1) to determine the technical potential per square footage. The optimal PV module distribution is developed as shown in Figure 5-2 and the minimum Summer day output powers are obtained as presented in Fig 5-3. The results show that this PV DG can reduce the summer peak by 12.2 kW.

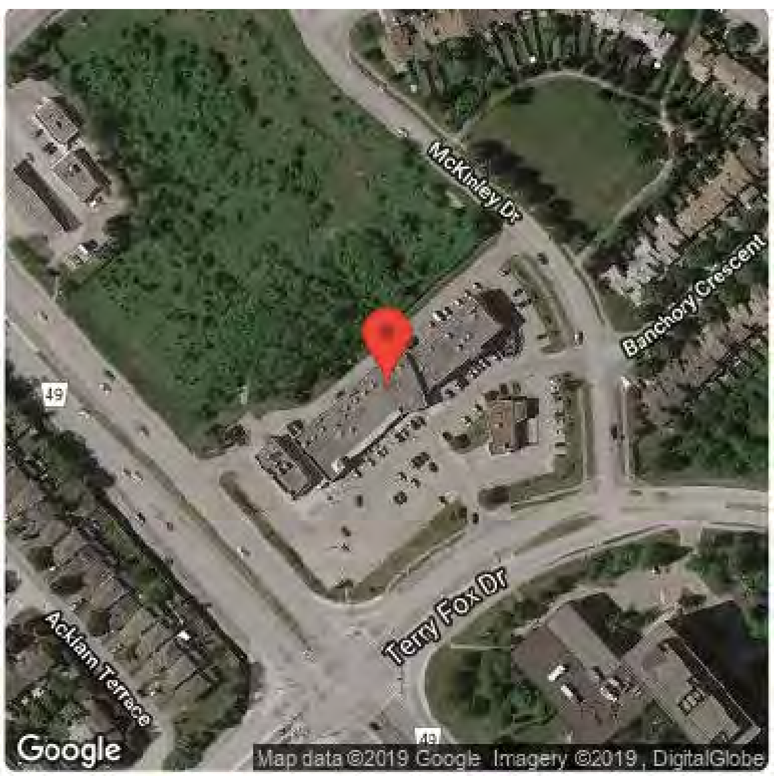

Figure 5-1 Location of the Selected Commercial Building

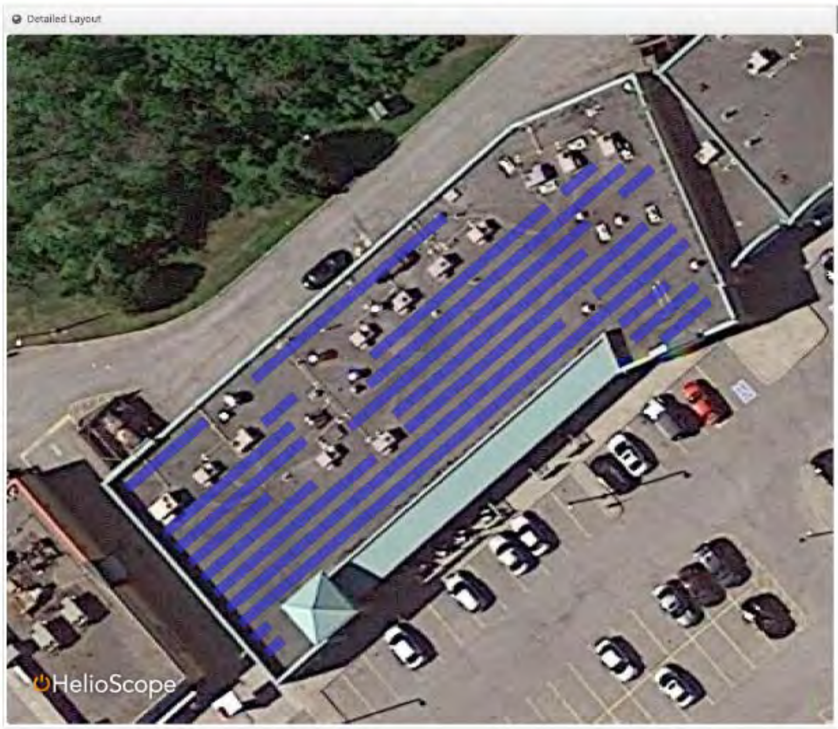

Figure 5-2 Layout of the PV arrays, Commercial Building

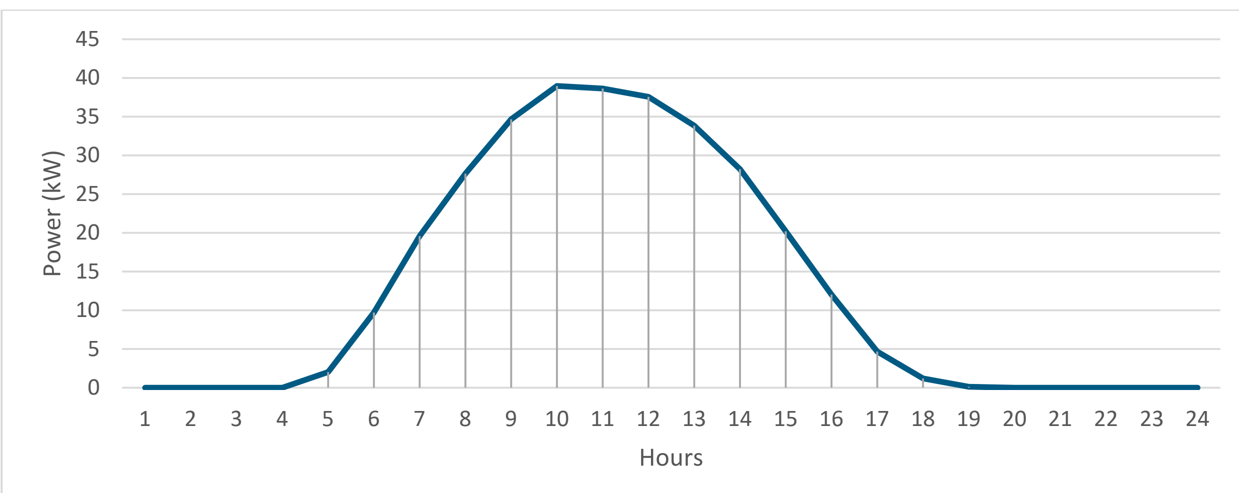

Figure 5-3 Minimum Hourly Output Power for a Summer Day, Commercial Building

The square area of the roof of the selected building is 13,788 square feet. The total square area of the roofs at Kanata North are obtained using MPAC data and adjusted using the square footage forecast developed in milestone #1. The total square footage forecasted in the year 2023 is found to be 7,945,730 square feet. Therefore, the total technical potential for peak reduction using roof-top PV DGs, mounted on commercial buildings, is 7.03 MW.

5.2 Technical Potential of Residential DGs

The same procedure is applied for the residential buildings, two houses were selected; one single-family house and one ROW house. Helioscope was used to determine the optimal PV module distribution. Figures 5-4 shows the optimal PV module distribution for the selected single-family house.

Figure 5-4 Layout of the PV arrays, Single-Family House

The minimum Summer day output powers are obtained as presented in Figure 5-5 and 5-6 for the single family and the ROW house respectively. The results show that the PV DG mounted on the single-family house reduced the Summer peak by 2.732 kW and that of the ROW house reduced the Summer peak by 1.793 kW.

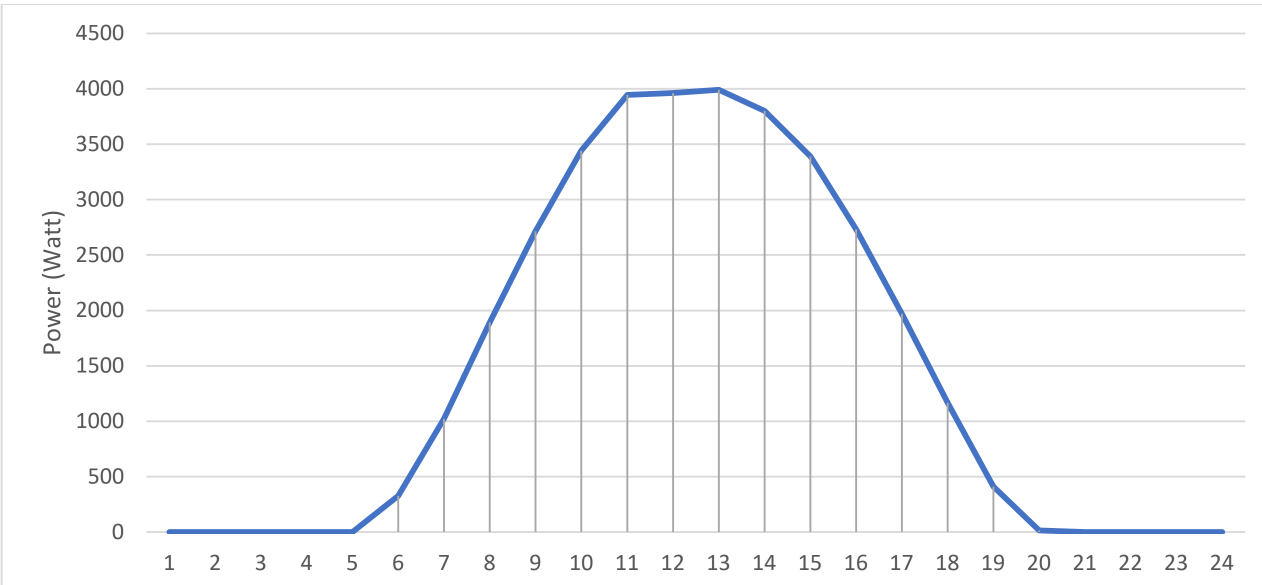

Figure 5-5 Minimum Hourly Output Power for a Summer Day, Single-Family House

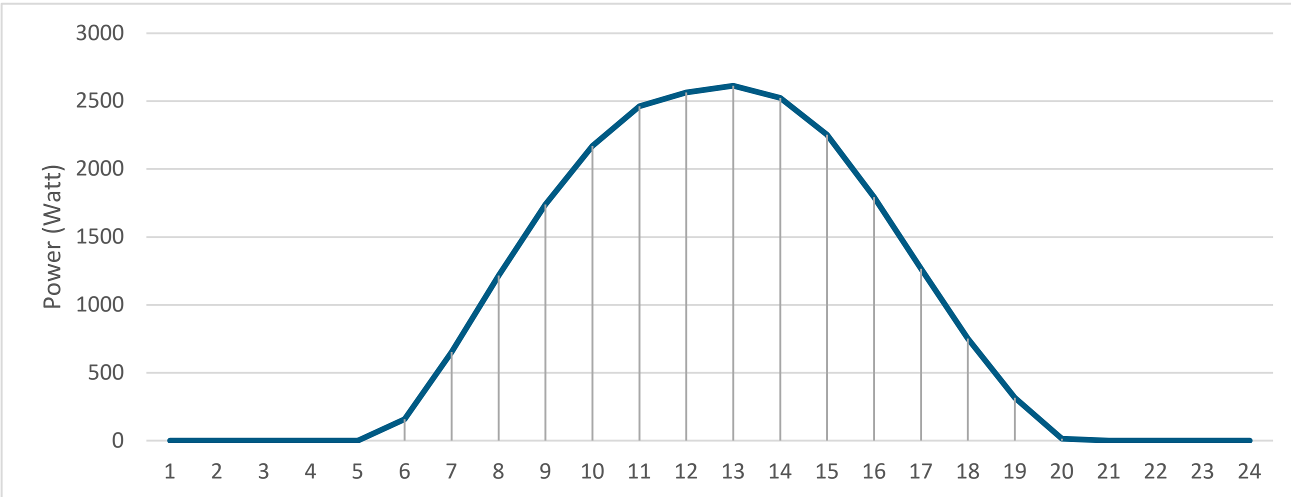

Figure 5-6 Minimum Hourly Output Power for a Summer Day, ROW House

To calculate the total technical potential for peak reduction for all residential buildings, the residential building forecast developed in milestone #1 was used. The total forecasted single-family houses in 2023 are 7,468 houses and the forecasted RO housed in 2023 are 5,826 houses. Therefore, the total technical potential for peak reduction using roof-top PV DGs is 20.4 MW for the single-family and 10.446 MW for the ROW. Therefore, the total technical potential of peak reduction for the residential sector is 30.84 MW and the total technical potential of the DER is 37.87 MW.

List of References

[1] APS 2016' Data provided by IESO

[2] Mid-Atlantic- Technical Reference Manual- Version 5; Available Online: https://neep.org/sites/default/files/resources/Mid-Atlantic_TRM_V5_FINAL_5-26-2015.pdf

[3] State of Ohio Energy Efficiency Technical Reference Manual; Available Online: http://s3.amazonaws.com/zanran_storage/amppartners.org/ContentPages/2464316647.pdf

[4] State of Pennsylvania- Technical Reference Manual; Available Online: https://neep.org/sites/default/files/resources/1333318.pdf

[5] Introduction to Technical Reference Manuals for Kentucky Energy Efficiency Programs; Available Online: https://emp.lbl.gov/publications/introduction-technical-reference

[6] Survey of Household Energy Use; Detailed Statistical Report http://oee.nrcan.gc.ca/publications/statistics/sheu/2011/pdf/sheu2011.pdf

[7] Survey of Commercial and Institutional Energy Use (SCIEU) - https://www.nrcan.gc.ca/energy/efficiency/17137

[8] https://www.eia.gov/consumption/commercial/reports/2012/lighting/

Appendix A

Table A-1 Connected Load Forecast for Kanata MTS

Year		2018	2019	2020	2021	2022	2023	2024	2025
Forecasted Peak Demand (MVA)		65.9	68.8	72.6	75.8	76.9	78.1	78.5	78.9
Added Load (MVA)	TOTAL (MVA)	0.3	3.3	7.1	10.2	11.4	12.5	12.9	13.3
	Kanata North CDP	0.0	0.0	0.0	0.5	0.9	1.3	1.7	2.1
	Beaverbrook Volt Conv.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	124 Battersea	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	469 Terry Fox	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	1136 Maritime	0.0	0.7	1.5	1.5	1.5	1.5	1.5	1.5
	15 Frank Nighbor Place - Com	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Richardson Ridge Phase 2C	0.0	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	20 Frank Nighbor PLI (CampMart Kanata)	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Brocollini Business Park Development	0.0	1.0	4.0	6.1	6.1	6.1	6.1	6.1
	471 Terry Fox	0.0	0.0	0.0	0.6	0.6	0.6	0.6	0.6
	777 Silver Seven	0.0	0.0	0.0	0.0	0.8	1.5	1.5	1.5

Table A-2 Connected Load Forecast for Marchwood MTS

Year		2018	2019	2020	2021	2022	2023	2024	2025
Forecasted Peak Demand (MVA)		55.7	61.4	65.9	67.4	68.9	69.9	70.9	71.9
Added Load (MVA)	TOTAL (MVA)	6.0	11.7	16.1	17.6	19.1	20.1	21.1	22.1
	5050 Innovation (Ciena)	1.6	5.0	8.0	8.0	8.0	8.0	8.0	8.0
	Kanata North CDP	0.0	0.0	0.0	0.0	0.0	1.0	2.0	3.0
	Katimavik Voltage Conversion	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0
	1100 Canadian Shield	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
	KNL Stage 9	0.0	0.0	0.5	1.0	1.5	1.5	1.5	1.5
	Best Western Hotel	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	Richardson Ridge Phase 3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Timberwalk Retirement Home	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
	Kanata Town Centre	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
	Kanata North Elementary School	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
	Ottawa Retirement Residence	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
	5100 Kanata Commercial	0.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	Minto Arcadia	1.0	2.0	3.0	4.0	4.0	4.0	4.0	4.0

Table A-3 Sample of Measures Excluded from Measure List

INITIATIVE	END-USE	CONSERVATION MEASURE	MEASURE DESCRIPTION	BASE MEASURE	FIRST YEAR DEMAND SAVINGS (KW)	FIRST YEAR ENERGY SAVINGS (KWH)	SUMMER PEAK DEMAND SAVINGS (KW)	REASON FOR EXCLUSION
Home Assistance Program (HAP)	Miscellaneous	HEAVY DUTY PLUG-IN TIMERS	Car Block Heater Timer	No timer on the car block heater	-	239.1	0	No impact on summer peak
Home Assistance Program (HAP)	Controls for Space Cooling and Heating - Residential	PROGRAMMABLE THERMOSTAT	Baseboard Heaters	Non-programmable thermostats installed on baseboard heaters	122.2	0	11	No impact on summer peak
Direct Install Pilot	Water Heating - Residential	Shower Start Ladybug	Showerhead adapter	Showerhead with Flow Rate = 7.57 L/min	78	0.008	10	Not offered in recent programs
Retrofit	Lighting - University Colleges	HIGH PERFORMANCE MEDIUM BAY T8 FIXTURES	Four-lamp High Performance T-8 fixtures (32W)	250 Watt Metal Halide	514.3	0.068	15	PSP-Business-University_Colleges-Subsector is not existing

Table A-4 Residential CDM Measures

CONSERVATION MEASURE	Competition group	Source
ENERGY STAR® QUALIFIED LED BULBS - General Purpose LED- Different ratings	Screw-in lamps	IESO's Measures
ENERGY STAR® QUALIFIED INDOOR LIGHT FIXTURE - Hard wired- Different Ratings	Screw-in lamps	IESO's Measures
ENERGY STAR® CEILING FAN	Screw-in lamps	IESO's Measures
ENERGY STAR® QUALIFIED LED BULBS- Different Ratings	Screw-in lamps	IESO's Measures
ENERGY STAR® QUALIFIED LED BULBS - SPECIALTY- Different Ratings	Screw-in lamps	IESO's Measures
≤11W ENERGY STAR® Qualified LED A Shape (60W) (minimum 600 Lumen output) (Formerly: 7W – 11W ENERGY STAR® Qualified LED A Shape)	Screw-in lamps	IESO's Measures
≤11W ENERGY STAR® Qualified LED MR 16 (minimum 400 Lumen output) (Formerly: 7W – 12W ENERGY STAR® Qualified LED MR 16 GU 5.3 Base)	Screw-in lamps	IESO's Measures
≤14W ENERGY STAR® Qualified LED A Shape (75W) (minimum 800 Lumen output) (Formerly:10W – 14W ENERGY STAR® Qualified LED A Shape)	Screw-in lamps	IESO's Measures
≤16W ENERGY STAR® Qualified LED PAR 20 (minimum 600 Lumen output) (Formerly: 8W – 12W ENERGY STAR® Qualified LED PAR 20)	Screw-in lamps	IESO's Measures
≤16W ENERGY STAR® Qualified LED PAR30 & PAR38 (minimum 600 Lumen output) (Formerly: 8W – 12W ENERGY STAR® Qualified LED PAR 30)	Screw-in lamps	IESO's Measures
≤23W ENERGY STAR® Qualified LED A Shape (100W) (minimum 1600 Lumen output) (Formerly: 17W – 23W ENERGY STAR® Qualified LED A Shape)	Screw-in lamps	IESO's Measures
≤23W ENERGY STAR® Qualified LED PAR (minimum 1100 Lumen output) (Formerly: 14W – 18W ENERGY STAR® Qualified LED PAR 38)	Screw-in lamps	IESO's Measures
≤6W ENERGY STAR® Qualified LED MR 16 / PAR 16 (minimum 250 Lumen output) (Formerly:7W – 10W ENERGY STAR® Qualified LED MR 16 / PAR 16 - GU 10 Base)	Screw-in lamps	IESO's Measures
LED Downlight with Light Output >600 and <800 lumens (Retrofit Measure List)	Screw-in lamps	IESO's Measures
LED Downlight with Light Output >800 lumens (Retrofit Measure List)	Screw-in lamps	IESO's Measures
DIMMER SWITCH (HARD-WIRED)	light control	IESO's Measures
LIGHTING TIMERS (HARD-WIRED, INDOOR)	light control	IESO's Measures
MOTION SENSORS (HARD-WIRED, INDOOR)	light control	IESO's Measures
Smart Burner Intelligent Cooking System	Wall Oven	IESO's Measures
ENERGY STAR® FREEZER- Different Ratings	Freezers	IESO's Measures
ENERGY STAR® REFRIGERATOR - Different Ratings	Refrigerators	IESO's Measures
SMART THERMOSTAT	Space cooling control	IESO's Measures
WEATHERSTRIPPING (DOOR FRAME)	Thermal Envelope	IESO's Measures
ENERGY STAR® ROOM AIR CONDITIONER- Different Ratings	Room AC	IESO's Measures
SEER 18 CAC	Central AC	IESO's Measures
Cold-climate Ductless ASHP w/baseline having Cooling	Other Cooling	IESO's Measures
Ducted ASHP w/baseline having Cooling	Other Cooling	IESO's Measures
Cold-climate Duct ASHP w/baseline having Cooling	Other Cooling	IESO's Measures
Cold-climate Ductless ASHP w/baseline having Cooling	Other Cooling	IESO's Measures
PIPE WRAP : Per 3' Pipe Wrap (5/8" Pipe)	Hot Water- Insulation	IESO's Measures
PIPE WRAP: Per 3' Pipe Wrap (1/2" Pipe)	Hot Water- Insulation	IESO's Measures

PIPE WRAP: Per 3' Pipe Wrap (3/4" Pipe)	Hot Water- Insulation	IESO’s Measures
EFFICIENT SHOWERHEAD (Low-flow)	Showerhead	IESO’s Measures
EFFICIENT SHOWERHEAD (HANDHELD)	Showerhead	IESO’s Measures
EFFICIENT SHOWERHEAD (STANDARD)	Showerhead	IESO’s Measures
Shower Start Ladybug	Showerhead	IESO’s Measures
Water Heater Blanket	Water heater	IESO’s Measures
Solar water heater	Water heater	North America
ENERGY STAR natural gas or propane water heater	Water heater	North America
EFFICIENT AERATORS: Bathroom - Flow Rate ≤ 3.8 L/min	Aerator	IESO’s Measures
EFFICIENT AERATORS: Kitchen - Flow Rate < 5.7 L/min	Aerator	IESO’s Measures
ENERGY STAR Clothes Washers- Different Ratings	Washer	IESO’s Measures
Energy star dishwasher	Dishwasher	North America
ENERGY STAR Clothes Dryers	Dryer	IESO’s Measures
Indoor Clothes Drying Rack, Retractable Clotheslines	Dryer	IESO’s Measures
Gas clothes dryer	Dryer	North America
ENERGY STAR® DEHUMIDIFIER	Dehumidifiers	IESO’s Measures
< 20" ENERGY STAR® Most Efficient TV	Television	North America
20 < 30" ENERGY STAR® Most Efficient TV	Television	North America
30 < 40" ENERGY STAR® Most Efficient TV	Television	North America
40 < 50" ENERGY STAR® Most Efficient TV	Television	North America
50 < 60" ENERGY STAR® Most Efficient TV	Television	North America
> 60" ENERGY STAR® Most Efficient TV	Television	North America
ENERGY STAR Water Coolers	Water Cooler	North America
Energy Star Computer	Office Equipment	North America
Energy Star Monitor	Office Equipment	North America
Energy Star Copier	Office Equipment	North America
Energy Star Fax	Office Equipment	North America
Energy Star Printer	Office Equipment	North America

Table A-5 Commercial CDM Measures

CONSERVATION MEASURE	Competition group	Source
LED RECESSED DOWNLIGHTS- Different Ratings	Indoor Screw-in	IESO's
LED REFLECTOR (FLOOD/SPOT) LAMP PIN & SCREW BASE	Indoor Screw-in	IESO's
ENERGY STAR LED DECORATIVE BLUB(E12 CANDELABRA BASE)	Indoor Screw-in	IESO's
LED TUBE RE-LAMP	Indoor Screw-in	IESO's
INTEGRAL LED RETROFIT KIT	Indoor Screw-in	IESO's
INTEGRAL LED TROFFERS / LINEAR AMBIENT FIXTURE	Indoor Screw-in	IESO's
ENERGY STAR® LED OMNIDIRECTIONAL A LAMPS- Different Ratings	Indoor Screw-in	IESO's
LED EXIT SIGN	Indoor Screw-in	IESO's
REFRIGERATED DISPLAY CASE LED FIXTURE - HORIZONTAL	Indoor Screw-in	IESO's
REFRIGERATED DISPLAY CASE LED FIXTURE - VERTICAL INSTALLATION	Indoor Screw-in	IESO's
LED EXTERIOR AREA LIGHTS: LED fixture (≤30W)	Outdoor- Screw-in	IESO's
LED EXTERIOR AREA LIGHTS: LED fixture (>30W to ≤60W)	Outdoor- Screw-in	IESO's
LED EXTERIOR AREA LIGHTS: LED fixture (>60W to ≤120W)	Outdoor- Screw-in	IESO's
LED EXTERIOR AREA LIGHTS: LED fixture (>120W to ≤200W)	Outdoor- Screw-in	IESO's
LED EXTERIOR AREA LIGHTS: LED fixture (≤530W)	Outdoor- Screw-in	IESO's
OCCUPANCY SENSORS: Switch Plate Mounted	Control	IESO's
OCCUPANCY SENSORS: Fixture Mounted Occupancy Sensor (High Bay) for fixtures	Control	IESO's
UNITARY AIR-CONDITIONING UNIT- Different Ratings	Packaged AC	IESO's
Energy efficient Air-cooled chiller: < 150 tons	Chillers	North
Energy efficient Air-cooled chiller: > 150 tons to < 300 tons	Chillers	North
Energy efficient Water-cooled positive displacement chiller: < 75 tons	Chillers	North
Energy efficient Water-cooled positive displacement chiller: 75 < and > 150 tons	Chillers	North
Energy efficient Water-cooled positive displacement chiller: 150 < and > 300 tons	Chillers	North
Energy efficient Water-cooled positive displacement chiller: 300 < and > 600 tons	Chillers	North
Energy efficient Water-cooled centrifugal Chiller: < 300 tons	Chillers	North
Energy efficient Water-cooled centrifugal Chiller: 300 < and > 600 tons	Chillers	North
Energy efficient Water-cooled centrifugal Chiller: > 600 tons	Chillers	North
Energy efficient RAC (with louvered sides): < 6000 BTU/hr	Room AC	North
Energy efficient RAC (with louvered sides): 6000-7999 BTU/hr	Room AC	North
Energy efficient RAC (with louvered sides): 8000-10999 BTU/hr	Room AC	North
Energy efficient RAC (with louvered sides): 11000-13999 BTU/hr	Room AC	North
Energy efficient RAC (with louvered sides): 14000-19999 BTU/hr	Room AC	North
Energy efficient RAC (with louvered sides): 20000-24999 BTU/hr	Room AC	North
Energy efficient RAC (with louvered sides): > 25000 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): < 6000 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): 6000-7999 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): 8000-10999 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): 11000-13999 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): 14000-19999 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): 20000-24999 BTU/hr	Room AC	North
Energy efficient RAC (without louvered sides): > 25000 BTU/hr	Room AC	North
Efficient electric resistance water heater- Different Ratings	Water heater	North
Heat Pump- Different Ratings	Water heater	North
NETWORK PC POWER MANAGEMENT SOFTWARE	Computer Software	IESO's
Multi-Residential In Suite Appliance	Residential size	IESO's
ECM MOTORS FOR EVAPORATOR FANS (REFRIGERATOR WALK-IN)	Walk-in refrigerators	IESO's
ENERGY STAR® REFRIGERATOR: Glass Glass Door (< 15 cu.ft.)	Cabinet	IESO's
ENERGY STAR® REFRIGERATOR: Glass Door (≥ 15 cu.ft. to < 30 cu.ft.)	Cabinet	IESO's

ENERGY STAR® REFRIGERATOR: Glass Door (≥ 30 cu.ft. to < 50 cu.ft.)	Cabinet	IESO’s
ENERGY STAR® REFRIGERATOR: Glass Door (≥ 50 cu.ft.)	Cabinet	IESO’s
ENERGY STAR® REFRIGERATOR: Solid Door (< 15 cu.ft.)	Cabinet	IESO’s
ENERGY STAR® REFRIGERATOR: Solid Door (≥ 15 cu.ft. to < 30 cu.ft.)	Cabinet	IESO’s
ENERGY STAR® REFRIGERATOR: Solid Door (≥ 50 cu.ft.)	Cabinet	IESO’s
ENERGY STAR® FREEZER: Glass Door (< 15 cu.ft.)	Cabinet	IESO’s
ENERGY STAR® FREEZER: Glass Door (≥ 15 cu.ft. to < 30 cu.ft.)	Cabinet	IESO’s
ENERGY STAR® FREEZER: Glass Door (≥ 30 cu.ft. to < 50 cu.ft.)	Cabinet	IESO’s
ENERGY STAR® FREEZER: Glass Door (≥ 50 cu.ft.)	Cabinet	IESO’s
installation of insulation on bare Cooler suction pipes	Pipes insulation	North
Strip curtains for walk-in coolers or Freezers	Strip Curtain	North
DOOR GASKETS FOR WALK-IN AND REACH-IN Coolers	Gasket	North
ENERGY STAR® ICE MACHINES- Different Ratings	Ice machine	IESO’s
BEVERAGE VENDING MACHINE CONTROLS	Vending Machine	IESO’s
Electric hot water heater, electric dryer	Washer-plug load	North
Electric hot water heater, gas dryer	Washer-plug load	North
ENERGY STAR Dishwasher	cooking	APS 2016
High-Efficiency Induction Cooking	cooking	APS 2016
Refrigerated Display Case LED	lighting	APS 2016
CEE Tier 2/Energy Star Clothes Washers	Misc. commercial	APS 2016
VFD on Pumps	Misc. commercial	APS 2016
VSD Air Compressor	Misc. commercial	APS 2016
VSD Air Compressor	Misc. commercial	APS 2016
Smart Strip Plug Outlets	other plug loads	APS 2016
Vertical Night Covers	refrigeration	APS 2016
Temperature Adjustment in Commercial Freezers	refrigeration	APS 2016
Suction Pipe Insulation Freezer/Refrigerator	refrigeration	APS 2016
Refrigeration Optimization	refrigeration	APS 2016
Refrigeration Commissioning	refrigeration	APS 2016
Anti-sweat heat (ASH) controls - Cooler/Freezer	refrigeration	APS 2016
Adding reflective (White) roof treatment or a green roof	Space cooling	APS 2016
Air Curtains	Space cooling	APS 2016
Duct Insulation, R8	Space cooling	APS 2016
Chilled Water Optimization	Space cooling	APS 2016
ECM MOTORS FOR HVAC APPLICATION (FAN-POWERED VAV BOX)	Space cooling	APS 2016
HVAC Optimization	Space cooling	APS 2016
Outside Air Economizer	Space cooling	APS 2016
Air Handler with Dedicated Outdoor Air Systems	Vent. & Circ.	APS 2016
CO Sensors for parking garage exhaust fans	Vent. & Circ.	APS 2016
Demand Control Kitchen Ventilation	Vent. & Circ.	APS 2016
Variable Frequency Drive (VFD)	Vent. & Circ.	APS 2016
Air Handler with Dedicated Outdoor Air Systems	water heating	APS 2016
CO Sensors for parking garage exhaust fans	water heating	APS 2016
Demand Control Kitchen Ventilation	water heating	APS 2016
Variable Frequency Drive (VFD)	water heating	APS 2016

Appendix B

The methodology presented in section 3.1 is applied to the collected CDM measures; this section presents examples for the calculations of the technical potential of the peak demand reduction. One example is for the peak reduction within the competition group dehumidifier- Residential single-family. First, the number of forecasted single-family units on the year 2023 is determined using the residential forecast developed in milestone #1. Secondly, the penetration of dehumidifiers for single-family subsector is determined from the HOL residential survey provided by IESO. Then, the ratio of energy star dehumidifiers to the total number of dehumidifiers in the single-family subsector is used to determine the energy efficient factor; this ratio was obtained from the residential survey. Finally, the measure summer peak reduction developed in IESO's MAL was used for the calculation of the total peak reduction as presented in the following equation.

$$\begin{aligned} &Potential\ of\ dehumidifier\ measu \\ &\quad = Total\ number\ of\ single\ family\ units \times dehumidifier\ penetration\ share \\ &\quad \times (1 - energy\ efficient\ factor) \times measure\ peak\ reduction \end{aligned}$$

$= 7468.85\ \times 27.6\,\%\ \times (100 - 21.7\%) \times 0.078\ kW$=125.9 kW

The same procedure is repeated for all measures lying in the competition group as shown in Table B-1; then, the total technical potential for the peak reduction from this group is obtained by assuming 100% adoption of the CDM measure. It should be noted that the exact adoption rate will be used in Milestone #3 to determine the achievable potential for peak reduction.

Table B-1 Dehumidifier competition group- Residential Single Family

CONSERVATION MEASURE	MEASURE DESCRIPTION	BASE MEASURE	SUMMER PEAK DEMAND SAVINGS (KW)	Base measure Share	Number of residential units	Energy Efficient Factor	Savings (KW)
ENERGY STAR® DEHUMIDIFIER	Dehumidifier Replacement (ENERGY STAR Qualified 21.3 - 25.4 l/day)	Non-Energy Star® Dehumidifier	0.064	27.60%	7468.85	21.7 %	103
ENERGY STAR® DEHUMIDIFIER	Dehumidifier Replacement (ENERGY STAR Qualified 14.2 - 21.2 l/day)	Non-Energy Star® Dehumidifier	0.078	27.60%	7468.85	21.7 %	125.90
ENERGY STAR® DEHUMIDIFIER	Dehumidifier Replacement (ENERGY STAR Qualified 25.5 - 35.5 l/day)	Non-Energy Star® Dehumidifier	0.059	27.60%	7468.85	21.7 %	95

Electric Chiller Example

This section presents the procedure used for the estimation of the savings associated with installing high-efficiency electric chillers as compared to conventional chillers. The peak demand reduction for chillers is calculated using one of the following equations; based on the chiller type;

a) Efficiency ratings in EER

$$\Delta kW_{peak} = Tons_{ee} \times 12 \times (\frac{1}{EER_{base}} - \frac{1}{EER_{ee}}) \times CF$$

b) Efficiency ratings in kW/Ton

$$\Delta kW_{peak} = Tons_{ee} \times \left(\frac{kW}{ton_{base}} - \frac{kW}{ton_{ee}}\right) \times CF$$

The definition and description of each variable are given in table B-2.

Table B-2 Chillers Parameters Definitions

Term	Description	Unit
$Tons_{ee}$	The capacity of the chiller	Tons
EER_{base}	Energy efficiency ratio of the baseline chiller	$\frac{Btu/hr}{W}$
$\frac{kW}{ton_{base}}$	Design rated efficiency of the baseline chiller	$\frac{kW}{ton}$
EER_{ee}	Energy efficiency ratio of the efficient chiller	$\frac{Btu/hr}{W}$
$\frac{kW}{ton_{ee}}$	Design rated efficiency of the efficient chiller	$\frac{kW}{ton}$
CF	Demand Coincidence Factor	Decimal

The rated capacities and efficiencies of the baseline chiller and the energy efficient chillers depend on the chiller type and size. This data, as well as the demand coincidence factor, are gathered from several North American distribution utilities. Table B-3 show a sample of the collected data for different chillers types and ratings. Moreover, the average demand coincidence factors (collected from different North American cities) for some commercial subsectors are presented in Table B-4. Finally, a sample of the calculated demand reductions for different commercial subsectors and chiller types are presented in Table B-5.

Table B-3 Electric Chiller Baseline Efficiencies

Chiller Type	Size	BaseLine Chiller	Energy Efficient Chiller
Air Cooled Chillers	< 150 tons	12.5 EER	15 EER
	> = 150 tons	12.75 EER	14.45 EER
Water Cooled	< 75 tons	0.630 kW/ton	0.62 kW/ton
	> = 75 tons and < 150 tons	0.615 kW/ton	0.6 kW/ton
	> = 150 tons and < 300 tons	0.580 kW/ton	0.46 kW/ton
	> = 300 tons	0.540 kW/ton	0.46 kW/ton
Water Cooled Centrifugal Chiller	< 300 tons	0.596 kW/ton	0.47 kW/ton
	> = 300 tons and < 600 tons	0.549 kW/ton	0.38 kW/ton
	> = 600 tons	0.539 kW/ton	0.38 kW/ton

Table B-4 Chiller Demand CFs

Building type	Average Demand Coincidence Factor
Education - Community College	0.408571
Education - Secondary College	0.145714
Education – University	0.375714
Health/medical – Hospital	0.497143
Health/medical – Nursing Home	0.258571
Lodging – Hotel	0.655714
Manufacturing – Bio/Tech	0.512857
Office – Large	0.307143
Office - Small	0.281429
Retailers	0.474286

Table B-5 Sample of the Chillers Calculations

END-USE	CONSERVATION MEASURE	MEASURE DESCRIPTION	BASE MEASURE	FIRST YEAR DEMAND SAVINGS (KW)	SUMMER PEAK DEMAND SAVINGS (KW)	EFFECTIVE USEFUL LIFE (YEAR)
Space Cooling-School	Energy efficient Air-cooled chiller	< 150 tons	Standard Air-cooled chiller	12.0	1.749	20.0
Space Cooling-School	Energy efficient Air-cooled chiller	> 150 tons to < 300 tons	Standard Air-cooled chiller	25.0	3.645	20.0
Space Cooling-School	Energy efficient Water-cooled positive displacement chiller	< 75 tons	Standard Water-cooled positive displacement chiller	0.4	0.055	20.0
Space Cooling-School	Energy efficient Water-cooled positive displacement chiller	75 < and > 150 tons	Standard Water-cooled positive displacement chiller	1.7	0.246	20.0
Space Cooling-School	Energy efficient Water-cooled positive displacement chiller	150 < and > 300 tons	Standard Water-cooled positive displacement chiller	27.0	3.934	20.0
Space Cooling-School	Energy efficient Water-cooled positive displacement chiller	300 < and > 600 tons	Standard Water-cooled positive displacement chiller	36.0	5.246	20.0
Space Cooling-School	Energy efficient Water-cooled centrifugal Chiller	< 300 tons	Standard Water-cooled centrifugal Chiller	25.4	3.694	20.0
Space Cooling-School	Energy efficient Water-cooled centrifugal Chiller	300 < and > 600 tons	Standard Water-cooled centrifugal Chiller	76.1	11.082	20.0
Space Cooling-School	Energy efficient Water-cooled centrifugal Chiller	> 600 tons	Standard Water-cooled centrifugal Chiller	95.4	13.901	20.0
Space Cooling-Large office	Energy efficient Air cooled chiller	< 150 tons	Standard Air cooled chiller	12.0	3.686	20.0

Space Cooling-Large office	Energy efficient Air cooled chiller	> 150 tons to < 300 tons	Standard Air cooled chiller	25.0	7.683	20.0
Space Cooling-Large office	Energy efficient Water cooled positive displacement chiller	< 75 tons	Standard Water cooled positive displacement chiller	0.4	0.115	20.0
Space Cooling-Large office	Energy efficient Water cooled positive displacement chiller	75 < and > 150 tons	Standard Water cooled positive displacement chiller	1.7	0.518	20.0
Space Cooling-Large office	Energy efficient Water cooled positive displacement chiller	150 < and > 300 tons	Standard Water cooled positive displacement chiller	27.0	8.293	20.0
Space Cooling-Large office	Energy efficient Water cooled positive displacement chiller	300 < and > 600 tons	Standard Water cooled positive displacement chiller	36.0	11.057	20.0
Space Cooling-Large office	Energy efficient Water-cooled centrifugal Chiller	< 300 tons	Standard Water-cooled centrifugal Chiller	25.4	7.786	20.0
Space Cooling-Large office	Energy efficient Water cooled centrifugal Chiller	300 < and > 600 tons	Standard Water cooled centrifugal Chiller	76.1	23.358	20.0
Space Cooling-Large office	Energy efficient Water-cooled centrifugal Chiller	> 600 tons	StandardWater-cooled centrifugal Chiller	95.4	29.301	20.0

Hydro Ottawa Local Achievable Potential (LAP) Study

Market Analysis of the Feasible Measures

Milestone #3 Report

SLI PROJECT NO.: 660803

00	Final Report	09/11/2019	AS	HA	TA
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REV.	**DESCRIPTION**	**DATE**	**PRPD**	**CHKD**	**APPRD**
			SNC-Lavalin		

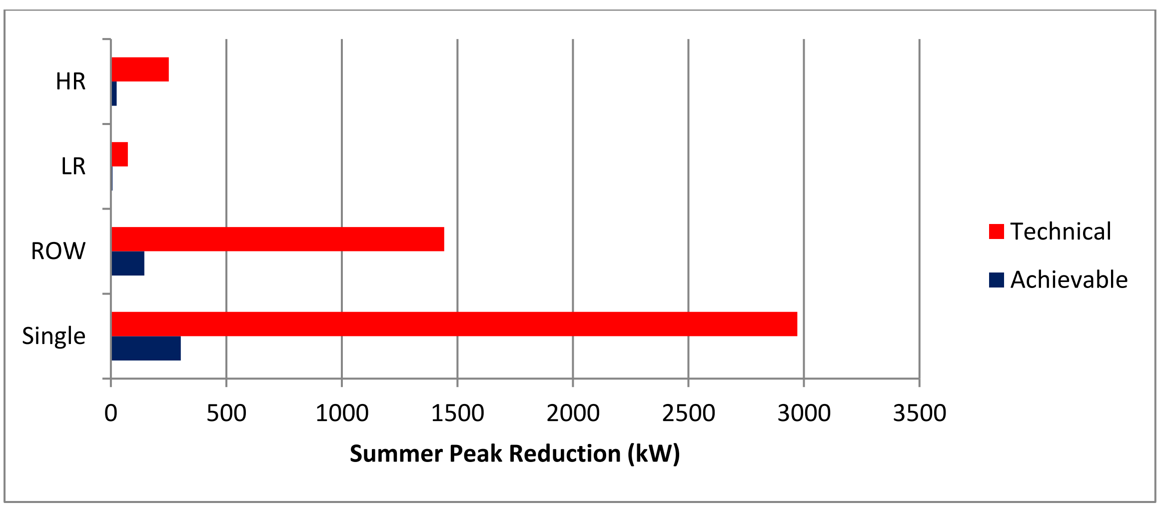
EXECUTIVE SUMMARY

The objective of Milestone #3 of this study is to determine the achievable potential of the technically feasible measures. For each measure, the project team conducted the analysis through the determination of the measure unit cost ($/kW), measure peak demand reduction, and the number of units. The project team ranked the measures in terms of their unit cost in ascending order to determine the measures with significant potential.

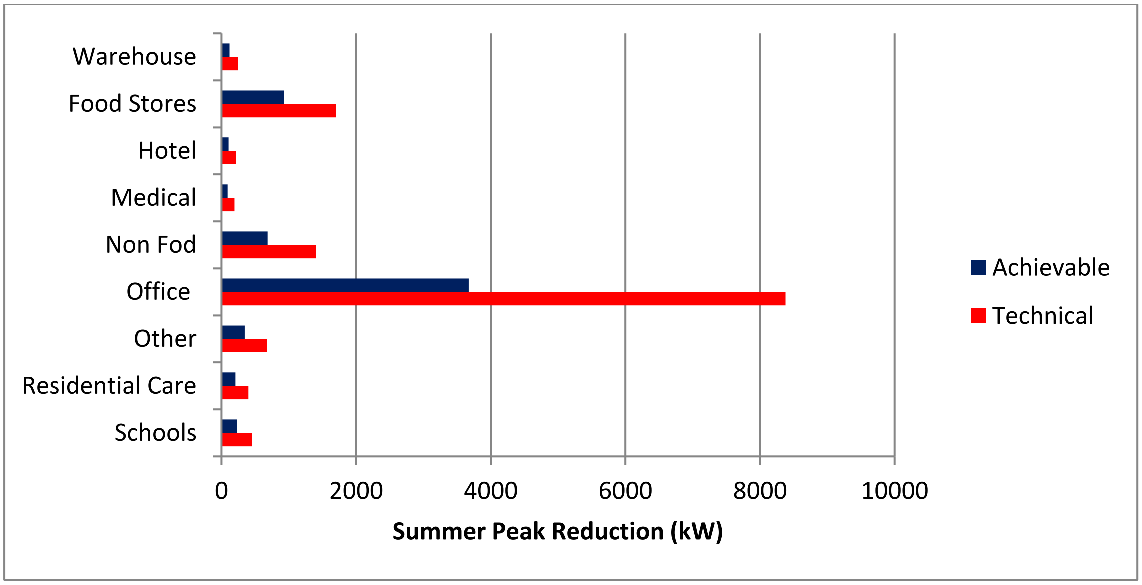
The team reviewed the HOL customer and business participation in the CDM programs to estimate the bass diffusion equations parameters. Then, the team developed the adoption curve for each measure based on the historical participation in CDM programs and the estimated value of the bass diffusion equation parameters. The project team estimated the aggregated achievable potential for peak reduction for all the CDM measures based on the developed adoption curves.

Based on the calculated achievable potentials for the CDM and DER measures, the total achievable potential for the peak reduction of Kanata North area is estimated at 6491.88kW. This reduction is mainly coming from CDM measures.

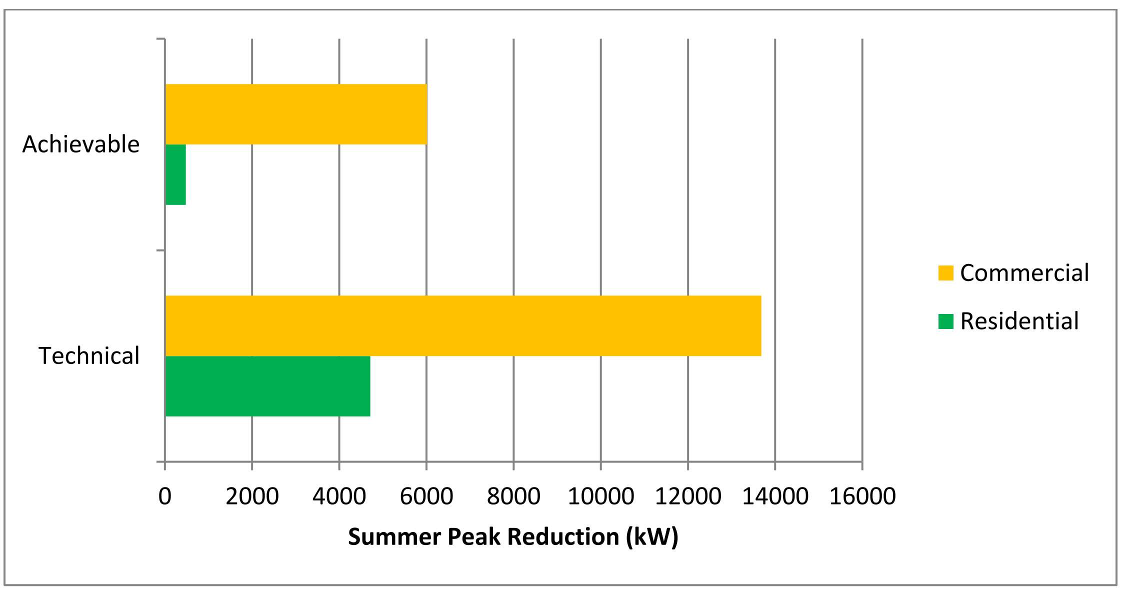
Figure ES-1, ES-2, and ES-3 show the estimated values for the achievable potential vs. technical potential of the residential and commercial measures.



ES-1 Technical and Achievable Potential Peak Reduction by Residential Subsector in 2023



ES-2 Technical and Achievable Potential Peak Reduction by Commercial Subsectors in 2023



ES-3 Total Technical and Achievable Potential Peak Reduction in 2023

The team conducted a cost analysis to study the impact of the Distributed Energy Resources (DER) on Kanata-Marchwood summer peak; the analysis is categorized into load shifting using battery energy storage (BES) system and renewable-based distributed generation. The analysis reveals the following:

- For commercial-scale battery storage, the required incentives levels are estimated between $5570-6930 per kW of peak reduction
- For utility-scale energy storage, the budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 to introduce peak reduction ranging from 3.75 MW-7.5 MW
- For residential PV rooftop, the incentives per installed kW are 1140.76 $/kW. This incentive level would provide the minimum attractive rate of return of 7%
- For commercial PV rooftop, the incentives per installed kW are 2200 $/kW. This incentive level would provide the minimum attractive rate of return of 7%

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List of acronyms

APS	Achievable Potential Study
BES	Battery Energy Storage
CDM	Conservation and Demand Management
DER	Distributed Energy Resources
DG	Distributed Generation
HOL	Hydro Ottawa Ltd
HR	High Rise
IESO	Independent Electricity System Operator
kWh	Kilowatt-hour
LAP	Local Achievable Potential Study
LR	Low Rise

1 Introduction

In Milestone #2, the technical potential was estimated assuming the implementation of all the feasible non-wire solutions. The market analysis and the adoption rate of the non-wire feasible solutions were not considered in the analysis of Milestone #2. In this report, we present the market analysis of the technically feasible measures identified in Milestone #2 to calculate the achievable potential for addressing local area needs.

2 Achievable Potential of CDM Measures

The achievable potential is estimated using the technical potential determined in Milestone #2 after considering the cost of the measures and customer adoption.

Based on HOL plan, the new station (new Kanata North) is planned to be in service in 2029. Therefore, the presented study focuses on short-term achievable potential scenarios. This section shows the methodology followed for calculating the achievable potential of the CDM measures.

2.1 Methodology

Assessing achievable potential requires: calculating the technical potential of the CDM measures (identified in Milestone #2), calculating the cost-effectiveness of each measure (see sample calculation in Appendix A) and estimating the rate at which cost-effective measures could be adopted over time. The following key items were considered and addressed in developing the methodology:

1- Historical performance of programs in HOL.
2- Development of adoption curves.
3- Mapping of measures to the adoption curves.

The development of the achievable potential scenario is accomplished by estimating the adoption curves of the technically feasible measures. The adoption curves are developed to estimate the achievable annual participation in each measure using the equation derived by the bass diffusion, the historic program participation and launch period of the program [1].

The steps implemented in developing the adoption curves are:

1- Measures categorized by sectors and subsectors first, and then further categorized by end-use was done
2- For each end-use, the competition groups were developed. The obtained measures were mapped to the competition groups/ end-use/ subsector/ sector. Tables 3-1 and 3-2 present the list of the used residential and commercial CDM measures classified by competition group.
3- The values of p, q, and m parameters in the bass diffusion equation were developed using statistical analysis of Ontario historic program participation data as provided by HOL.
4- Market adoption curves were aligned with the availability of historic program participation data.
5- The adoption curves were developed using the bass diffusion equations and historic program participation.

6- Measures were mapped to the adoption curves.

7- The achievable potential for peak demand reduction for each measure was calculated as follows:

$$Achievable potential of measure = \frac{Technical potential of measure \times \text{number of } adopters at year\ 2023}{eligible\ population}$$

8- The aggregated measure savings potential for each competitive group was determined; double-count of potential savings was avoided by limiting the total adoption to 100% within each measure competition group.

A demonstrative example is shown in Appendix A for the calculation of the Achievable Potential of Deep Freezer measure in the residential sector.

2.1.1 Mapping of CDM Measures

The measure competition groups were developed for each subsector/end-use separately. Each competition group consolidates similar measures that could be an alternative to each other. For example, the competition groups for the space cooling end-use area thermal envelope, space cooling control, room/window air conditions, and central AC. The measures in each competition group are alternatives to each other. The complete list of competition groups mapped to subsectors and end-use are presented in Table 2-1 and 2-2 for residential and commercial sectors, respectively. The subsectors mentioned in Table 2-2 are in offices, medical offices, hotels, residential care, non-food retailers, food retailers, schools, warehouse wholesale, and other commercials.

Table 2-1 Residential Sector Competition Groups

End-use	Competition Groups
Indoor Lighting	Screw-in lamps, light control
Outdoor Lighting	Screw-in lamps, light control
Common Area Lighting	Screw-in lamps, light control
Cooking	Wall Oven
Refrigeration	Refrigerators, Freezers
Space Cooling	Control, Thermal Envelope, Room AC, Central AC, Other Cooling
Water Heating	Pipe Insulation, Showerhead, Water heater, Aerator
Plug Loads	Dehumidifiers, Televisions, Water cooler, office equipment
Washer Dryer	Washing Machines, Dryers, Dishwashers

Table 2-2 Commercial Sector Competition Groups

End-use	Competition Groups
Subsector Lighting	Screw-in lamps, light control
Subsector space cooling	Packaged AC units, Chillers, Room AC
Subsector refrigeration	Residential size refrigerators, Walk-in refrigerators, Cabinet, pipes insulation, strip curtain, Gasket.
Subsector plug loads	Ice machine, Vending machine
Subsector computers	Computers
Subsector ventilation and circulation	Ventilation and circulation
Subsector miscellaneous commercial	Visc commercial
Subsector Domestic Hot Water	Water heater

2.2 Data provided by HOL and IESO

HOL provided historical participation in CDM programs for the years 2006 – 2018 for the residential sector and from 2015 – 2019 for the commercial sector. According to the residential sector data provided by HOL, the historical participation in all CDM programs from 2006 – 2014 is zero except for Central Air Conditioner (CAC) measures. However, the data for the years 2016 - 2018 is not consistent and not accurate; a sample of the historical participation for some measures is presented in Table 2-3.

IESO provided historical participation in CDM programs for the years 2015 – 2019 for the commercial sector. The data for the years 2015 - 2019 does not reveal a consistent trend.

A sample of historical participation is presented in Table 2-3 and Table 2-4.

Table 2-3 Historical Participation Provided by HOL

Measure / Year	2011-2014	2015	2016	2017	2018
Energy star qualified fixtures	0	3743	41	8102	7726
Freezer	0	352	0	0	0

Table 2-4 Historical Participation Provided by IESO

Program	2015	2016	2017	2018	2019
Save on energy small business lighting program	662	54	530	278	176
Save on energy retrofit program	109	192	6,108	741	-

2.2.1 Assumptions

Due to the inconsistency of the data provided by HOL and IESO and since the historical participation in CDM programs four consecutive years at least are needed to estimate the bass diffusion equation parameters, the following assumptions are made in the development of the adoption curves:

1- The CDM programs for both residential and commercial sectors were launched in 2011 [2].
2- The historical participation of the CDM-HOL residential programs for the year 2015 is considered consistent and accurate and used in the analysis to estimate the ultimate number of adopters in the residential sector
3- Due to the deficiency in data, the remaining parameters were in adopted form [2].

2.3 Results and Discussion

The methodology described in section 3.1 is applied to the Kanata-Marchwood technically feasible measures developed in Milestone #2. The factors required for calculating the achievable potential (i.e., the technical potential, the historical participation in CDM programs, and the unit cost of each measure); are determined as illustrated in section 2.1 and 3.1. Sample for the analysis implemented in the development of the adoption curves for CDM measure is presented in Appendix A.

2.3.1 Residential Sector

The achievable potential peak reduction is calculated for each competition group of the residential subsector/ end-use, and the total achievable potential peak reduction is calculated for each subsector and end-use. Figure 2-1 shows the technical and achievable potential summer peak reduction for each subsector; the largest achievable potential was estimated for the single-family subsector, which accounts for 63.13% of the total peak reduction in 2023. Figures 2-2 to 2-5 show the reductions per residential end-use for each subsector. The total achievable residential summer peak reduction in 2023 was estimated to be 480.31 kW, which accounts for 10.22% compared with the technical potential of the residential measures that had a value of 4.7 MW.

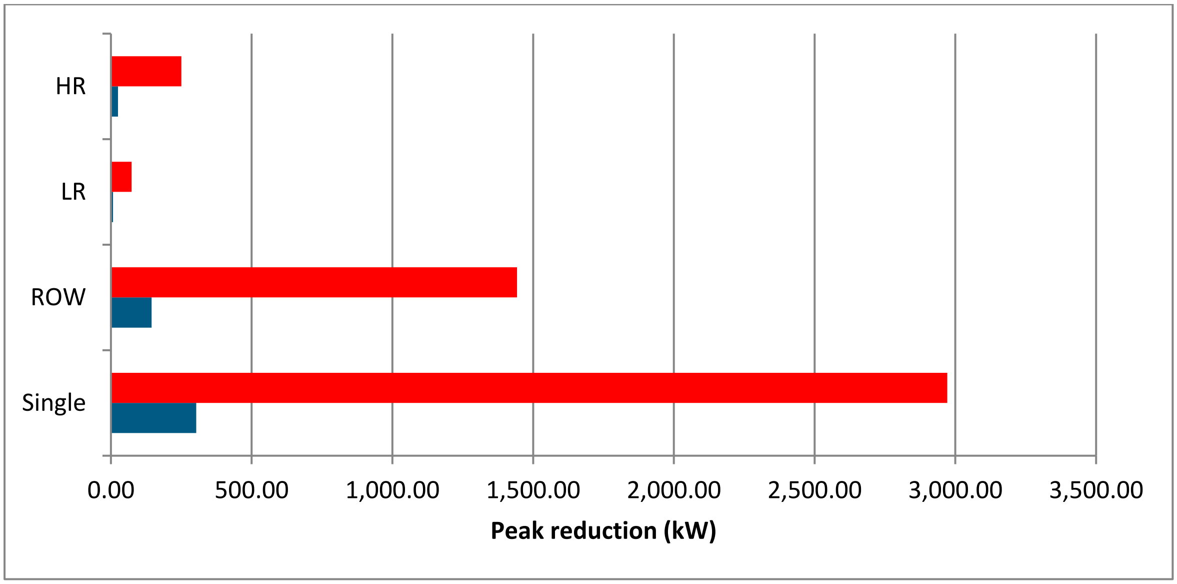

Figure 2-1 Technical and Achievable Potential Peak Reduction by Residential Subsector in 2023

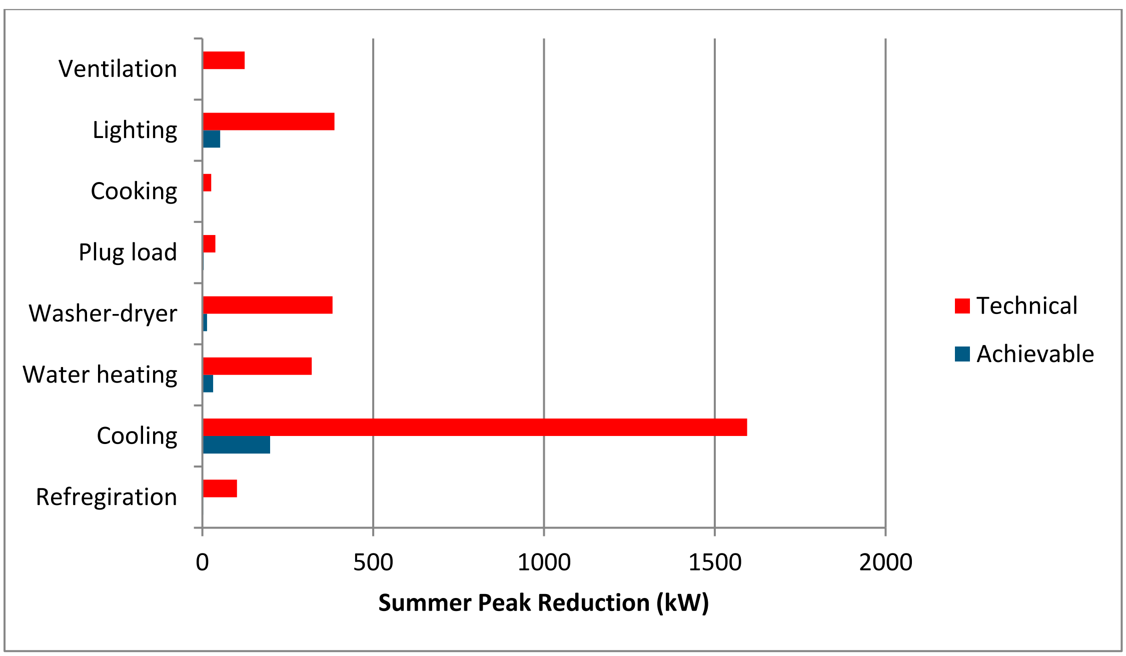

Figure 2-2 Technical and Achievable Potential Peak Reduction by End-use in 2023, Single-family

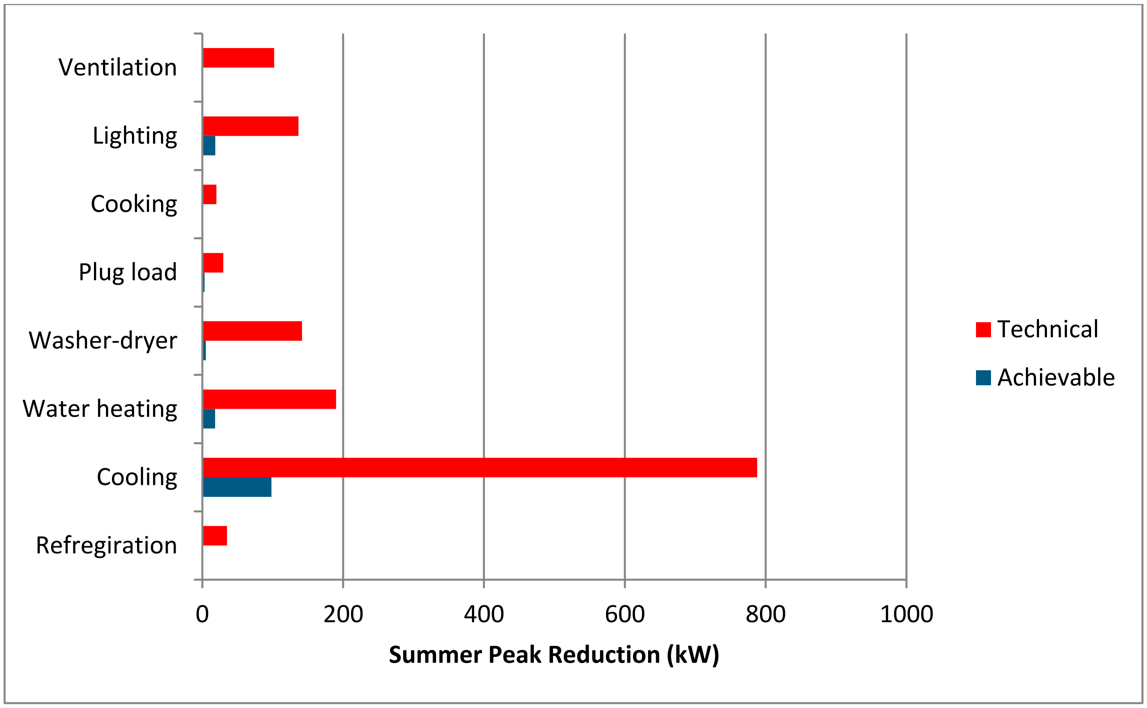

Figure 2-3 Technical and Achievable Potential Peak Reduction by End-use in 2023, Row

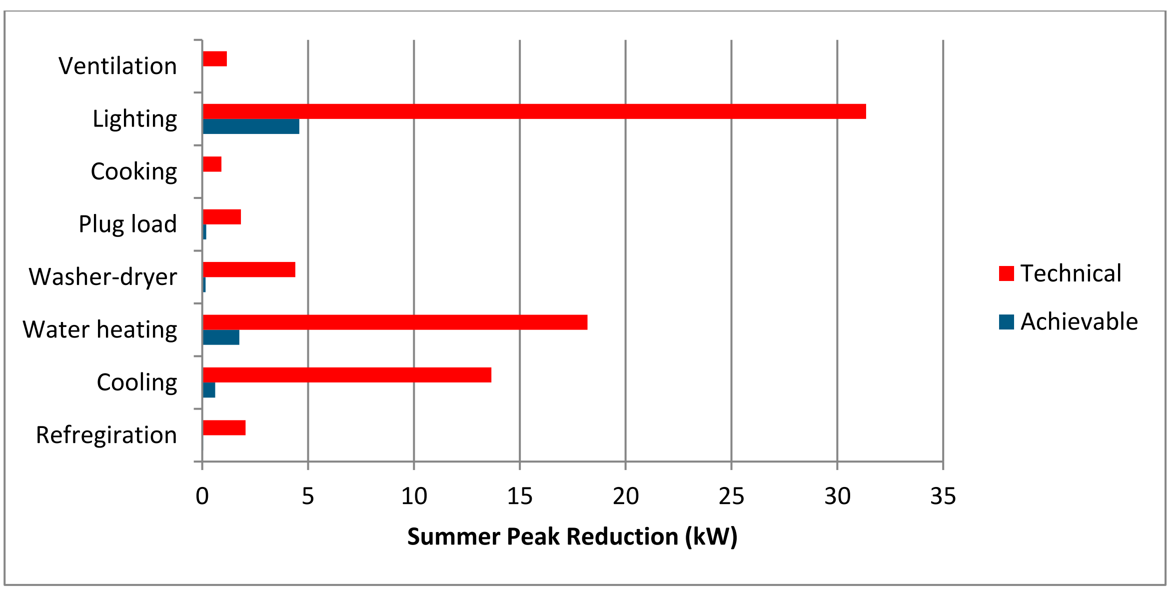

Figure 2-4 Achievable Potential Peak Reduction by End-use in 2023, Low Rise

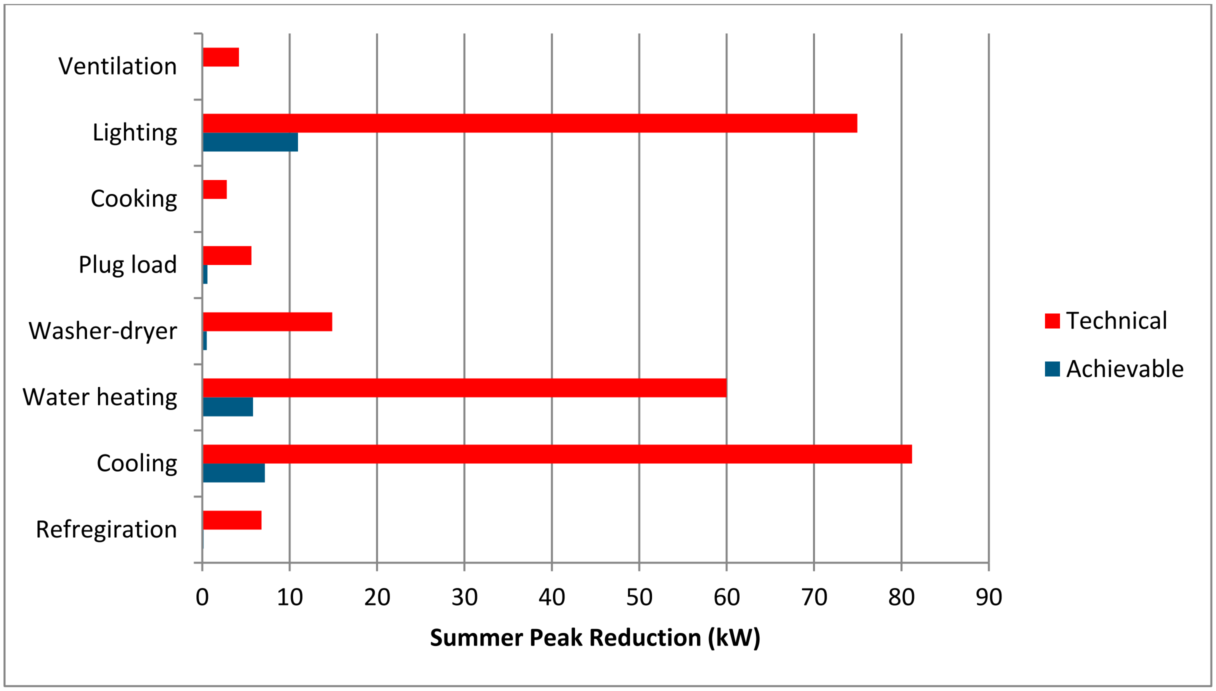

Figure 2-5 Achievable Potential Peak Reduction by End-use in 2023, High Rise

2.3.2 Commercial Sector

The achievable potential peak reduction is calculated for each competition group of the commercial subsector/ end-use, and the total achievable potential peak reduction is calculated for each subsector and end-use. Figure 2-6 shows the technical and achievable potential summer peak reduction for each subsector; the largest achievable potential was estimated for the office subsector, which accounts for 57.58 % of the total peak reduction in 2023 followed by the food stores subsector that accounts for 14.48%. Figure 2-7 shows the total reductions per commercial end-use; the lighting end-use represents the largest peak reductions of 60.51% of the total reductions. The total achievable commercial summer peak reduction in 2023 was estimated to be 6011.57 kW.

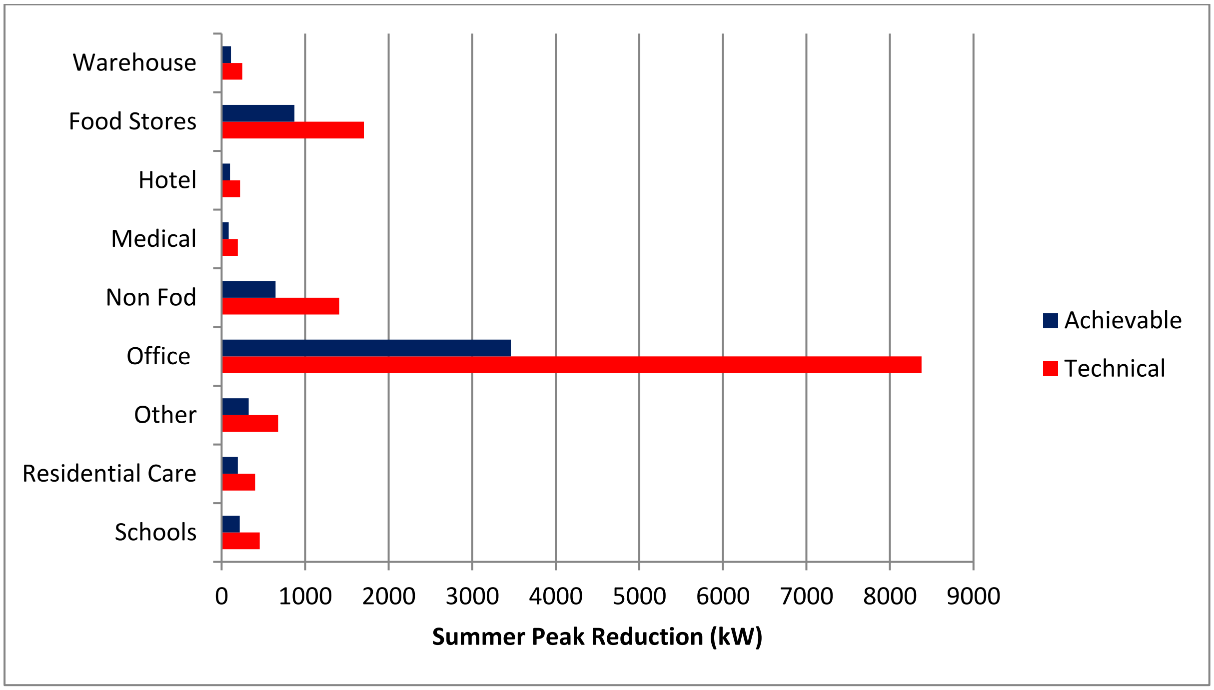

Figure 2-6 Technical and Achievable Potential Peak Reduction by Commercial Subsectors in 2023

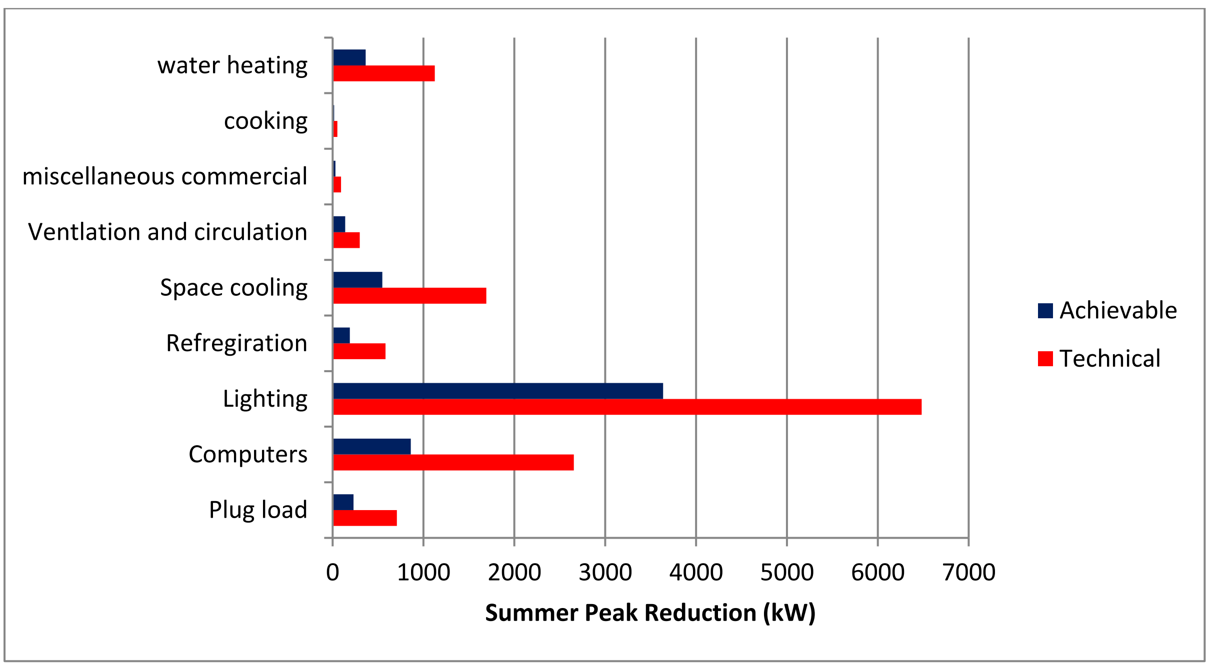

Figure 2-7 Technical and Achievable Potential Peak Reduction by End-use, Commercial Sector

3 Cost Analysis of Load Shifting Measures

The project team analyzed the possibility of load shifting using the Battery Energy Storage (BES) system. This analysis was performed for two scenarios; i.e., utility-scale and large customers-scale. In Milestone #2, the technical potential for using a battery owned by HOL and installed at the substation was determined. Moreover, the technical potential for installing batteries owned by large customers greater than 1000 kW was also determined. For each scenario, two cases were studied; i.e., batteries that are capable of discharging for 4 or 6 hours. In this section, the cost analysis for the BES is analyzed as will be illustrated in the next subsections.

3.1 Customer-Scale Battery Energy Storage

The presented methodology, in this section, aims to determine the level of incentive required for the BES project investment to be profitable, for the customer-scale BES. The concept of a minimum attractive rate of return (MARR) is selected for achieving the objective. If the internal rate of return (IRR), i.e., the rate of return that yields zero present worth value of cash flow, of the project is equal to or higher than the MARR, the project is considered profitable. The income of the BES investment is calculated at different levels of incentives, and the minimum level of incentives is determined. This minimum incentive level is the value that makes the IRR equal to MARR. For accurate economic assessment of the BES project; cash flow is performed. The following procedure is used to calculate the minimum incentives of the BES:

1) Calculate the battery capital cost (Cap) using (1)

$$Cap = [Capitalcost] - [(Incentives — kWh) \times batterycapacity] \quad (1)$$

2) Calculate the income per year for the project lifetime using (2), considering the BES rated capacity as base power.

$$Inc\ (y) = \sum_{m=1}^{12} \Delta Peakofmonth \times demandpeakrate] \quad (2)$$

3) Calculate the inflation-adjusted cash flow (C(y)) for each year using (3)

$$C(y) = \frac{Inc\ (y)}{(1 + inflationindex)^y} \quad (3)$$

4) Calculate the minimum incentives/kW of the BES project capacity using (4); the net present value is equalized to zero, and the project IRR is replaced by the MARR.

$$NPV = Cap - \sum_{y=1}^{N} \frac{C(y)}{(1 + MARR)^y} = 0 \quad (4)$$

3.1.1 Case Study

For the customer-scale BES, presented in the Milestone #2 report, the customer with reference number 1323516000 was selected. The maximum load of this customer was 1,013 kW with BES of capacity 129.6kW and 181kW for the 4-hour and 6-hour case, respectively. The technical peak reduction was found to be 72.9 and 82 kW for the 4-hour and 6-hour case, respectively.

The economic analysis presented in the previous procedure is executed based on an average capital cost of $410,391 and $573,155 for the 4-hour and 6-hour case, respectively [3]. The MARR is set to 7%. The income is calculated based on the average regulated price plan for small business in HOL [4]. The inflation rate is set to 2.4% [5], the cash flow is calculated as presented in Table 3-1 and the required incentives to achieve the 7% MARR for the 4-hour and 6-hour cases are $406,102 and $568,330 which means the incentive range between $ 5570-6930 per kW peak reduction. These incentives are significantly high relative to the corresponding savings and are not economically viable. As a result, the customer-scale BES will be excluded from the achievable potential analysis as discussed with HOL and IESO in the meeting held on July 4th, 2019.

Table 3-1 Cash Flow for Customer-Scale BES

	4-Hour Case				6-Hour Case			
Year	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)
0	410391				573155			
1		386.66	379.08	354.28		434.93	426.40	398.50
2		399.73	384.19	335.57		449.61	432.15	377.46
3		412.76	388.96	317.50		464.29	437.51	357.14
4		425.82	393.39	300.11		478.97	442.49	337.58
5		438.87	397.49	283.41		493.65	447.11	318.79
6		451.92	401.29	267.40		508.33	451.38	300.77
7		464.97	404.78	252.08		523.01	455.31	283.54
8		478.02	407.98	237.45		537.69	458.91	267.09
9		491.07	410.91	223.51		552.37	462.20	251.41
10		504.12	413.56	210.23		567.05	465.18	236.47
11		517.17	415.94	197.61		581.73	467.86	222.28
12		530.22	418.08	185.63		596.41	470.27	208.80
13		543.28	419.97	174.27		611.09	472.39	196.03
14		556.33	421.63	163.51		625.77	474.26	183.92
15		569.38	423.06	153.33		640.45	475.86	172.48
16		582.43	424.27	143.71		655.13	477.23	161.65
17		595.48	425.27	134.63		669.81	478.35	151.43
18		608.53	426.07	126.06		684.49	479.25	141.79
19		621.58	426.67	117.98		699.17	479.93	132.71
20		634.63	427.09	110.37		713.85	480.40	124.15
PV of Adjusted Income Considering MARR (A)				4288.65	PV of Adjusted Income Considering MARR (A)			4824
Capital Cost (B)				410391	Capital Cost (B)			573155
Incentive (B)-(A)				406102	Incentive (B)-(A)			568330
Peak Reduction kW				72.9	Peak Reduction kW			82
Incentive $/KW of peak reduction				5570	Incentive $/KW of peak reduction			6930

3.2 Utility-Scale Battery Energy Storage

The total system peak for the year 2023 was analyzed in Milestone #2, and the potential for peak reduction using substation-scale battery storage was determined for the 4-hour and 6-hour batteries. For utility-scale BES, no incentives will be provided since the BES is owned by HOL, and hence, only the economic analysis will be analyzed for this scenario.

The adequate battery size for the 4 hour scenario was 9,846 kWh, which can reduce the system peak by 3.782 MW. For the 6 hour scenario, the battery size was 31,216 kWh, which can reduce the system peak by 7.607 MW.

An example indicative order of magnitude capital costs for implementing distribution scale lithium-ion batteries to meet the requirements is summarized in Table 3-2. The budgetary cost for implementing this project is estimated at C$ 9,575,000 and C$ 22,650,000 for the 4-hour and 6-hour scenarios, respectively. The estimate is built based on recent budgetary quotes received for a project of similar nature, and the average cost of $/kW and $/kWh are within the ranges published in [3]. It is to be noted the price is very sensitive for the battery cost and in this example the cost is estimated at C$ 390/kWH for Li batteries.

Estimates published by various resources suggested decline price for the LI batteries as the market of storage increase.

Table 3-2 Distribution Scale Battery Installation Cost

Scenario	4-Hour Scenario	6-Hour Scenario
Proposed Capacity Rating	3.75 MW	7.5 MW
Proposed Duration	4 Hrs	6 Hrs
MWH	15	45
Total Energy Storage System Cost		
KWh Driven		
DC Modules & BMS Equipment (excl. PCS)*	5850000	17550000
General conditions, EPC & Commissioning	2,000,000	2,000,000
KW Driven		
Power Conversion System Equipment	750,000	1,500,000
Electric BoS	125,000	250,000
General conditions, EPC & Commissioning	750,000	1,250,000
Misc.	100,000	100,000
Total Cost	9,575,000	22,650,000
Avg. Cost $/KWh	638	503
Avg. Cost $/KW	2553	3020

Assuming the cost of Li-Battery is 390CAD/KWh

4 Economic Analysis of DG Measures

The presented methodology, in this section, aims to determine the level of incentive required for the DG project investment to be profitable and to calculate the achievable potential for the DG measures.

The concept of MARR is selected for determining the level of incentives. The income of the DG investment is calculated, and the minimum level of incentives is determined. For accurate economic assessment of the PV DG project; cash flow is performed. The proposed algorithm for the minimum incentive level determination is discussed as detailed below in section 4-1 and 4-2, while the achievable potential calculation is discussed in section 4-3.

4.1 PV DGs installed on residential rooftops

The following procedure is used to calculate the minimum incentives of the residential scale PV DGs:

1) Calculate the DG capital cost (Cap) using Equation (5)

$$\mathrm{Cap} = [\mathrm{Capital\ cost/\ kW} \times \ \mathrm{DG\ Capacity}] - [\mathrm{Incentives\ /\ kW} \times \mathrm{DG\ Capacity}] \tag{5}$$

2) Calculate the income per year for the project lifetime using (7), considering the DG rated capacity as base power.

$$\mathrm{Inc\ (y)} = \sum_{m=1}^{12} \sum_{hr=1}^{24} [E_g(y, m, hr) \times P_r(m, hr)] \ \times \ N_d(m) \tag{6}$$

Where Inc (y) is the DG project income for certain year (y), Eg (y,m,hr) is the DG generated energy at certain hour (hr) at certain month (m) for a certain year, Pr (m, hr) is the time of use (TOU) electricity rates at certain hour at certain month and Nd (m) represents the number of days per month (m).

3) Calculate the inflation-adjusted cash flow (C(y)) for each year using (7)

$$C(y) = \frac{\mathrm{Inc\ (y)}}{(1 + \mathrm{inflation\ index})^y} \tag{7}$$

4) Calculate the minimum incentives/kW of the DG project capacity using (8); the net present value is equalized to zero, and the project IRR is replaced by the MARR.

$$\mathrm{NPV} = \mathrm{Cap} \ - \sum_{y=1}^{N} \frac{C(y)}{(1 + \mathrm{MARR})^y} = 0 \tag{8}$$

Where NPV is the net present value, and N is the project lifetime.

4.1.1 Case Study

For the PV DGs installed on the single-family house, presented in the Milestone #2 report, the PV DG installed capacity is 8.68 kW with annual generated energy of 9.231 MWh. This generated energy is still lower than the average annual electricity consumption for a single house (9652 MWh; obtained from Milestone #1 load segmentation report). This means according to the net energy metering, the PV DG will not inject any energy to the grid, and all the generated energy will be used to lower the electricity bill. Based on the average capital cost of 2.53 $/W [6], the economic analysis presented in the previous procedure is executed with a MARR of 7%. The income is calculated based on the generated energy/hr, residential electricity price as per [7], and an inflation rate of 2.4%. The cash flow is calculated as presented in Table 4-1, and the required incentives to achieve the 7% MARR is 9,867$, which means the incentives per installed kW is 1140.76 $/kW.

Table 4-1 Cash Flow for PV Installed on Residential Rooftop

Year	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)
0	21960.4			
1		1039.20	1018.83	952.17
2		1084.36	1042.26	910.35
3		1131.49	1066.23	870.36
4		1180.66	1090.75	832.13
5		1231.97	1115.83	795.57
6		1285.51	1141.49	760.62
7		1341.37	1167.74	727.21
8		1399.66	1194.60	695.27
9		1460.49	1222.07	664.73
10		1523.96	1250.18	635.53
11		1590.19	1278.93	607.61
12		1659.29	1308.34	580.92
13		1567.98	1212.10	502.98
14		1659.29	1257.54	487.69
15		1659.29	1232.88	446.85
16		1576.23	1148.20	388.94
17		1559.73	1113.90	352.63
18		1551.48	1086.28	321.39
19		1543.22	1059.32	292.91
20		1534.97	1032.99	266.94

4.2 PV DGs installed on commercial buildings

The following procedure is used to calculate the minimum incentives of the commercial-scale PV DGs:

1) Calculate the DG capital cost using (9)

$$Cap = [Capitalcost/\ kW \times DGCapacity] - [Incentives\ /\ kW \times DGCapacity] \tag{9}$$

2) Calculate the income per year for the project lifetime using (10), considering the DG rated capacity as base power.

$$Inc\ (y) = \sum_{m=1}^{12} [E_g(m) \times [A_{WPR}(m)] \tag{10}$$

$E_G(m)$ is the DG generated energy for certain month (m) for a certain year, $A_{WPR}(m)$ is the averaged weight hourly price at certain month m.

3) Calculate the inflation-adjusted cash flow (C(y)) for each year using (11)

$$C(y) = \frac{Inc\ (y)}{(1 + inflationindex)^y} \tag{11}$$

4) Calculate the minimum incentives/kW of the DG project capacity using (12); the net present value is equalized to zero, and the project IRR is replaced by the MARR.

$$NPV = Capcost - \sum_{y=1}^{N} \frac{C(y)}{(1 + MARR)^y} = 0 \tag{12}$$

4.2.1 Case Study

For the PV DGs installed on commercial buildings, presented in Milestone #2 report, the PV DG installed capacity is 58.5 kW with annual generated energy of 73.79 MWh. This generated energy is still lower than the average annual electricity consumption for a single commercial building. This means according to the net energy metering, the PV DG will not inject any energy to the grid, and all the generated energy will be used to lower the electricity bill. Based on the average capital cost of 2.53 $/W, the economic analysis presented in the previous procedure is executed. The MARR is set to 7%. The income is calculated based on the energy price in Ontario [7], and on the inflation rate of 2.4%, the cash flow is calculated as presented in Table 4-2, and the required incentives to achieve the 7% MARR is $ 129,442 which means the incentives per installed kW is 2200 $/kW.

Table 4-2 Cash Flow for PV Installed on Commercial Rooftop

Year	Capital Cost	Income	Inflation-Adjusted Income	Adjusted Income (considering MARR)
0	21960.4			
1		1742.01	1707.85	1596.12
2		1800.81	1730.88	1511.82
3		1859.60	1752.35	1430.44
4		1918.40	1772.31	1352.08
5		1977.20	1790.81	1276.82
6		2036.00	1807.91	1204.69
7		2094.80	1823.65	1135.68
8		2153.60	1838.07	1069.78
9		2212.40	1851.23	1006.95
10		2271.19	1863.17	947.14
11		2329.99	1873.93	890.29
12		2388.79	1883.54	836.32
13		2447.59	1892.07	785.14
14		2506.39	1899.53	736.67
15		2565.19	1905.97	690.81
16		2623.98	1911.43	647.47
17		2682.78	1915.94	606.54
18		2741.58	1919.54	567.92
19		2800.38	1922.27	531.52
20		2859.18	1924.14	497.24

4.3 Achievable Potential of PV DGs

The project team identified the DERs contract capacity as well as the potential for expansion based on the input data received from the HOL and IESO in Milestone #1. The installed DER capacity at Kanata-Marchwood was given as 1.1498 MW, and it is forecasted to be at the same level in 2023 based on the current DERs programs and incentives offered in Ontario. Given the capital cost of the DERs as 2.53 $/W, the total cost of the installed capacity is $ 2,908,994. The installed capacity (1.1498 MW) would reduce the summer peak demand by 0.3603 MW as illustrated in Milestone # 2 report, and hence the unit cost of peak reduction associated with the PV DGs is calculated as follows:

$$\text{Unit cost}\left(\frac{\$}{\text{kW}}\right) = \frac{\text{Incremental life cost}}{\text{Summer peak demand savings per unit (kW)}} = \frac{2{,}908{,}994}{360.3059} = 8073.67\ \$/\text{kW} \qquad (13)$$

5 Cost Curve

The cost curve is constructed based on the unit peak demand reduction cost of all the CDM measures, under the achievable potential scenario.

The curve shows each measure as a step in the curve, with the horizontal length of each step indicating the peak demand reduction of the measure and its height above the horizontal axis indicates how much it costs per unit of reduction. Measures are sorted in order of increasing cost.

The advantage of developing a cost curve is that the overall cost-effective potential can be estimated using one graph as illustrated in Figure 5-1 for the residential CDM measures.

The unit cost of the commercial CDM measures is still under development as we are missing the unit cost associated with the measures of the 2016's APS provided by the IESO. The availability of the unit cost data will be discussed with IESO during the next meeting

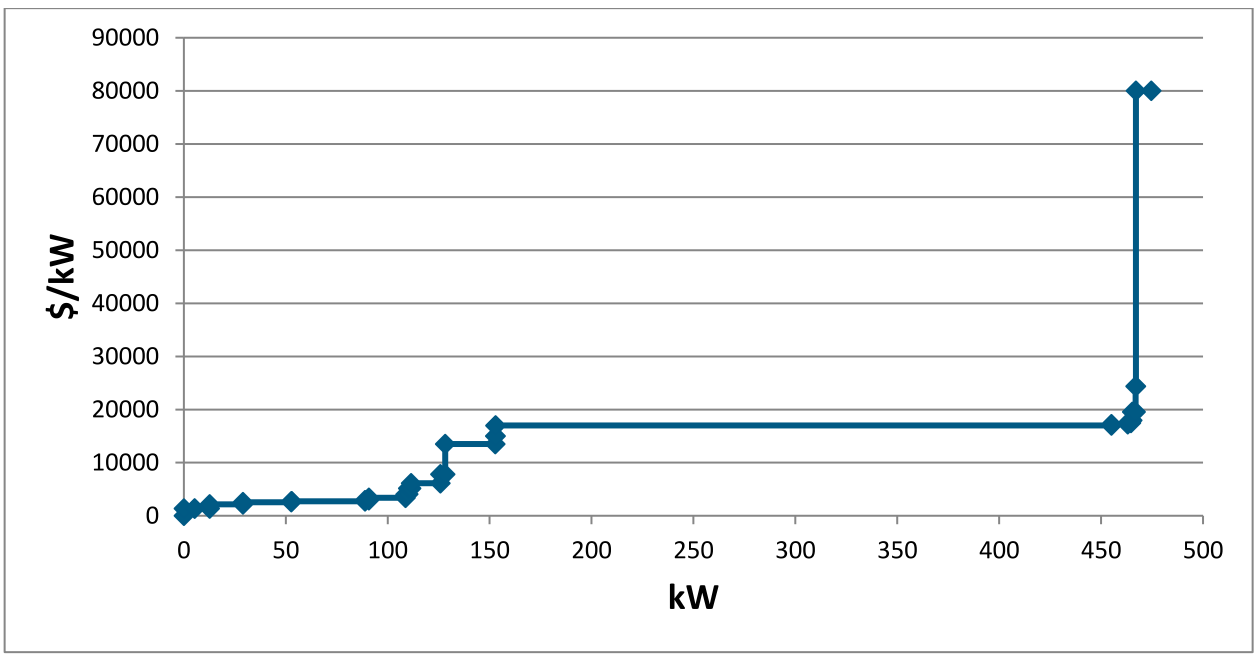

Figure **5-1 Cost Curve of Residential CDM Measures**

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Appendix A

Calculation of Achievable Potential Example

This Appendix presents an example for the calculation of the achievable potential of the peak demand reduction. One example is for the peak reduction within the competition group freezer. Table A-1 and Table A-2 summarize the data obtained from Milestone #2 for the freezer measure.

Table A-1 Freezer Data

Sector	Conservation measure	Summer Peak Demand Reduction (kW)	Base Case kW	Base Case kWh	Incremental Life Cycle Cost ($)
Consumer	Fixture	0.014	0.056	491.25	273.50

Table A-2 Freezer Data

Sector Single	Single	Row	Low Rise	High Rise
Measure Base Share	30.90%	30.10%	16.50%	16.50%
Consumption (MWh)	8313.373	2916.292	189.7909	628.1477
Remaining Factor	65.45%	65.45%	65.45%	65.45%

The kW savings are calculated using Equations A-1

$$\begin{aligned}\text{Savings (kW)} \\ &= \text{Measure Base Share} \times \text{Consumption (MWh)} \times \text{Remaining factor} \times 1000 \\ &\times \text{Summer Peak Demand Savings} \div (\mathit{Base\ Case\ kWh})\end{aligned} \qquad \text{(A1)}$$

The number of units, the unit cost per kW, and the total cost are calculated using Equation (A2), (A3), and (A4), respectively

$$\begin{aligned}\text{Number of units} &= \frac{\text{Savings (kW)}}{\text{Summer peak demand savings per unit (kW)}} \\ &= \frac{\text{Savings (kWh)}}{\text{Firstyear energy savings per unit (kWh)}}\end{aligned} \qquad \text{(A2)}$$

$$\text{Unit cost }\left(\frac{\$}{\text{kW}}\right) = \frac{\text{Incremental life cost}}{\text{Summer peak demand savings per unit (kW)}} \qquad \text{(A3)}$$

$$\text{Total cost} = \text{Incremental life cost} \times \text{number of units} \times \text{Summer peak demand savings per unit (kW)} \quad \text{(A4)}$$

The results are summarized in Table A-3.

Table A-3 Freezer kW savings

	Single	Row	Low Rise	High Rise	Sum
kW savings	47.912304	16.372268	0.5840779	1.9331122	66.8018
Number of units	3422.307	1169.448	41.71985	138.0794	4772
Unit cost ($/kW)	$19,535.71				
Total cost	$936,101.23	$319,878.18	$11,411.60	$37,768.77	$1,305,159.78

The number of eligible populations is determined as follows:

$$\text{Eligible population} = \frac{\text{Number of base units}}{\text{Effective useful life}} \quad \text{(A5)}$$

Table A-4 shows the eligible freezer population estimated using Eq (A5)

Table A-4 Eligible Population of Freezer

	Single-Family	Row	LR	HR	Sum
Eligible Population	475.3821	162.4444	5.795175	19.18019	662.8018628

The actual number of adopters, which is obtained from solving the bass model, the equation given in (A6).

$$n(t) = \frac{dN(t)}{dt} = m\,\frac{p\,(p+q)^2 e^{-(q+p)t}}{(p+q\,e^{-(q+p)t})^2} \quad \text{(A6)}$$

The values of p, q, and m parameters are estimated for each of the adoption curves using statistical analysis of Ontario historic program participation data. After the estimation of p, q, and m, the forecasting of the number of adopters per year is achievable, and hence, the development of the adoption curve, as shown in Figure A-1.

As shown in Figure A-1, the market share at 2023 is 2.28 % of the eligible population; therefore, the achievable potential is given by:

$$Achievable\ Potential = \frac{Technical\ Potential \times Number\ of\ adopters\ at\ 2023}{Eligible\ Population} \tag{A7}$$

$$= \frac{145.1 \times 2.28}{100\%} = 3.319\ kW$$

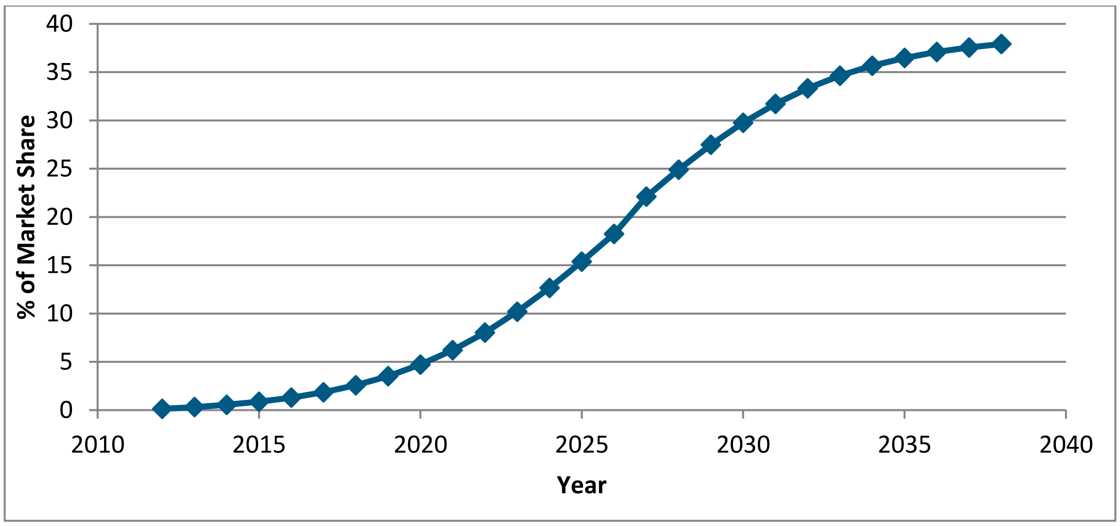

Figure **A-1** Adoption Curve for Freezer Measure

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TECHNOLOGY ROADMAP AND AMI STRATEGY

SUMMARY REPORT

Hydro Ottawa

25 MARCH 2019

BLACK & VEATCH
Building a world of difference.

Table of Contents

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Executive Summary

SUMMARY OF KEY FINDINGS

Black & Veatch's began working with Hydro Ottawa (HOL) in November 2018 to develop the AMI Strategic Plan and Roadmap. Our approach consisted of five main tasks as shown in the below figure.

Figure 1 - Methodology

The key activities are summarized in the table below.

DATE	ACTIVITIES
November 1, 2018	• Project Kick-off • Meetings to review existing IT/OT systems
November 8, 2018	• Executive Leadership Strategy Discussion
November 27 – 28, 2018	• AMI Opportunity Discovery Workshops o Customer Care o Distribution Automation o Market Engagement o Metering
December 6, 2018	• Regulatory Discovery Workshop
January 17, 2019	• AMI Technology & Vendor Overview • Honeywell Discovery Meeting
February 5 – 6, 2019	• Various AMI and communication vendor meetings and demonstrations at DistribuTech with HOL participation
February 22, 2019	• Review of AMI Roadmap & Business Release

Figure 2 - Program Activities

AMI STRATEGY RECOMMENDATIONS

AMI Strategy Framework

Black & Veatch developed a recommended sequence of strategic steps that HOL might take to prudently address the remaining and new opportunities of AMI. The strategic steps (or phases) formed the basis of the Technology Roadmap which are depicted in the strategic framework diagram below.

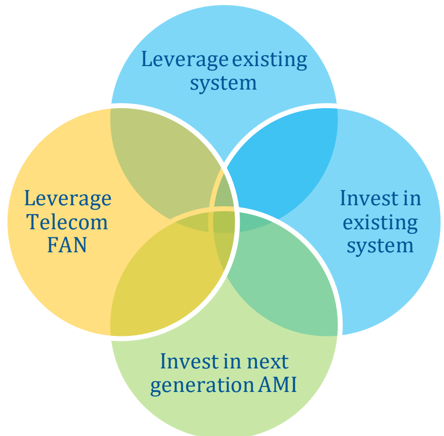


Figure 3 – AMI Strategy Framework

The phases developed were influenced and shaped based on our understanding of several factors:

- Understanding of the current system operation and functionality,
- The desired and prioritized opportunities and requirements discovered in the workshops, and
- The influence of the HOL Telecom Plan.

The AMI related opportunities were mapped to the four identified phases with the exception of those that were already achieved.

Thus, the four key phases of the AMI Roadmap can be characterized as follows:

1. Capabilities that can be enabled with existing Honeywell AMI system (REX1/REX2 meters, existing mesh network nodes, existing backhaul, existing HES) but which require changes to downstream systems	2. Incremental investments in existing AMI system (selective replacement of existing meters or other low volume field devices, network collectors, backhaul, HES) to mitigate obsolescence risks and enable high value capabilities	3. Investment in operational capabilities which may be enabled by the planned FAN network	4. Re-investment in AMI replacement technology to enable benefits dependent on mass meter replacement or other endpoint deployments
• Applications that do NOT require any significant changes to the existing AMI system • Provides capabilities and benefits through downstream system releases	• Upgrade of headend system to mitigate support risk and enable transition to REXU meter to avoid meter production obsolescence • Applications that may require limited replacements of field devices, or upgrades to the existing AMI network and/or head end • Provides high value benefits while bridging to future AMI Solution	• Applications that may be more efficiently addressed by direct communications to endpoints via the planned FAN network • Provides benefits that may be dependent on final Telecom FAN plan	• Applications that require replacement of AMI system, including electric meters or deployment of DA (or other) dedicated network and endpoints • Dependent on meter population depreciation (to avoid stranded assets), Measurement Canada new requirements, AMI vendor strategies, and Final HOL FAN plan

Figure 4 - AMI Strategy Phases

Key dependencies such as the HOL Telecom plan, meter depreciation schedules, and future Meter Canada requirements were factored into the AMI Technology Roadmap timing and implementation sequence.

Additionally, key components of the HOL AMI System are reaching end of life or becoming obsolete due to advances in technology and changing business requirements. The key components include the EnergyAxis headend system v9.x which is scheduled to be at end of support life in Q2 2019, REX2 meters that are near end of production (no date confirmed yet from Honeywell), and REXU replacement meters that would require an upgraded headend system. Thus, mitigating the risk of system obsolescence (i.e. lack of system support) and meter product obsolescence (discontinued production availability) is also an important dependency on the timing and sequencing of the four phases. With these key dependencies considered, the Roadmap logically becomes sequenced in the following strategy:

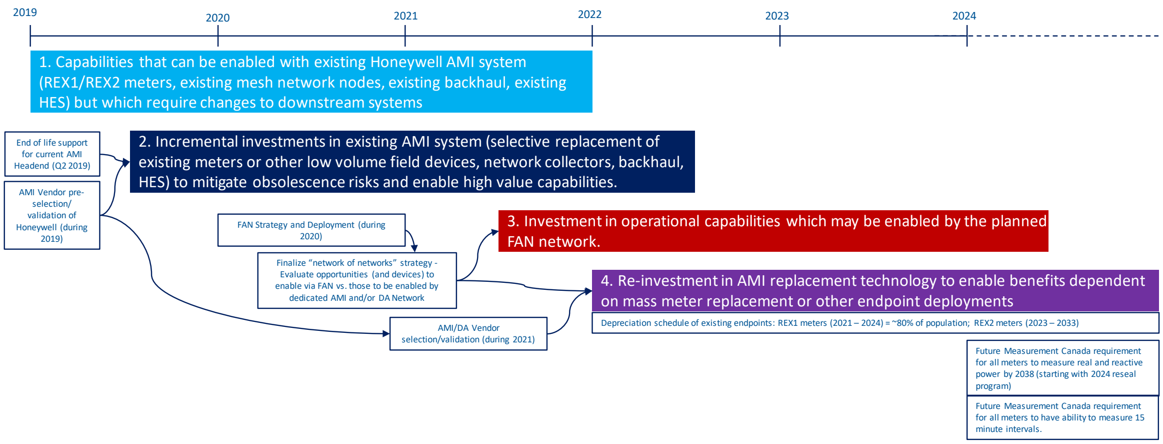


Figure 5 - AMI Strategy Sequence and Timing

Within each phase, opportunities are further described as Business Releases. Additional details on the potential business releases contained within each phase are provided below and further explained in the Recommendation Details section.

Business Release Plan

The functional requirements and IT system impacts that were identified with each opportunity were integrated into logical groupings of system development initiatives (or business releases). These business releases combined related capabilities, enhancements, or synergistic system work efforts to describe likely IT/OT system development efforts required to enable the desired AMI opportunities.

It is important to note that the business releases within each phase are not presented in any particular sequence or order of priority. Thus, each business release within each phase should be evaluated independently and planned for in an appropriate time period.

A summary of the business release plan and systems impacted during each release is shown in the following table.

Business Release 1 - Leverage Existing AMI System		
a. Billing System Enablement b. Data Analytics + Distribution Modeling c. Outage Reporting Metrics d. Customer Usage Analytics + Enhanced Customer Portal e. Forecasting + Rate Design	Analytics Billing System MDMS CSR and Customer Portal	Planning & Forecasting OMS Dispatch / MTU GIS
Business Release 2 - Incremental Investment in Existing AMI System		
a. Enhanced Operational Processes b. Outage Management using AMI Data c. Enhanced Data Analytics d. Customer Portal + In-Home Data Device e. Upgrade AMI Headend	Analytics Billing System CSR and Customer Portal IVR	AMI Headend OMS Dispatch / MTU GIS
Business Release 3 - Alternative FAN / System Communication Technologies		
a. DERMS Implementation b. DA/DMS c. Smart City Sensor Integration d. DERMS and DA Integration	Analytics	DMS DERMS Dispatch / MTU GIS
Business Release 4 - Replacement AMI Solution		
a. AMI Replacement b. Data Analytics + DMS/OMS Enhancements c. Planning & Forecasting d. Enhancements to Billing + MDMS + Customer Portal	Analytics Billing System MDMS CSR and Customer Portal	Planning & Forecasting OMS Dispatch / MTU

Figure 6 - Business Releases by Phase

AMI Roadmap Phases and Business Releases

Phase 1 - Leverage existing investments

Phase 1 is focused on extending the use of data and information already available from HOL's current Honeywell AMI system. It involves enhancements to downstream systems to extract additional value and enable opportunities from the existing AMI solution.

The Phase 1 business releases are focused on expanding upon and enabling the opportunities that can be accomplished using the existing AMI system.

Recommendations for enabling Phase 1 opportunities by business release are shown in the below table.

BR1a Billing System Enablement	BR1b Data Analytics Application & Initial Distribution Modeling	BR1c Outage Preventative Maintenance	BR1d Customer Usage Analytics & Enhanced Customer Portal	BR1e Forecasting and rate design improvements
• Summary Billing • EV Charging (Rate, Revenue Metering, Aggregation for potential Market Participation) • Green Pricing Rate	• Data Analytics and Distribution Modeling • Distribution System Planning (Capacity Sizing/Deferment) • Virtual Metering/Aggregation of Load • Load Analysis & Equipment Sizing • Phase Load Balancing • Real & Apparent Loss Allocation • Improved Distribution Modeling & Calibrations	• Improved Maintenance Planning based on Momentary and Blink Outage reporting	• Improved LIHEAP • Improved Billing Exception Handling • EV Charging Details on Portal (HOL/3rd Party) • Improved Conservation through Portal • Improved Account Monitoring (active/inactive) • Improved Low Income Home Energy Assistance Program • Improved Rate Design	• Increased Accuracy/ Reduced Labor for Customer Class Allocation & Cost of Service • Improved Rate Design • Forecasting system improvements using AMI data

Figure 7 - Phase 1 Business Releases

Phase 2 - Incrementally invest in existing system

Phase 2 is focused on additional opportunities that can be leveraged from the existing Honeywell AMI system through incremental and selective investments to upgrade or enhance the existing system. The AMI Roadmap recommends that HOL conduct an RFI or other appropriate exercise to validate the value of each incremental investment as these may result in short term investments only pending the final solutions from Phase 3 based on the HOL Telecom FAN and/or from Phase 4 which contemplates a complete AMI system replacement.

The Phase 2 business releases are focused on enabling the opportunities that can be accomplished with incremental investments in the AMI infrastructure. These investments include upgrading the AMI headend, replacing the backhaul communications on all collectors to cellular, fiber, or other communication technologies as recommended in the HOL Telecom FAN Plan.

Recommendations for enabling Phase 2 opportunities by business release are shown in the below table.

BR2a Enhanced Operational Processes using Disconnect Switch	BR2b Outage Management Utilizing AMI Data	BR2c Enhanced Data Analytics	BR2d Customer Portal & In-Home Data Devices	BR2e Upgrade AMI headend

• Reduction in Field Trips for Move In/Move Out
• Reduction in Field Trips for Service On/Off
• Reduced accounts in arrears and Consumption on Inactive Accounts
• Improved Employee Safety and Reduction in Injuries/Claims
	• Improved Outage & Reliability Index Reporting
	• Improved System Reliability Planning from Post Outage Analysis
	• Improved Customer Outage Communications
		• Identification of Lost/Orphan Meters
		  • Reduction in Unbilled Usage
		  • Reduced Field Trips to Identify Meters
		• Improved AMI Alert & Exception Management
		  • Improved Operations
		  • Reduction In Loss due to Defective Meters
		  • Faster Detection & Collection of Theft
			• Near Real Time Usage Data for Customer
			  • Enable Conservation
			  • Enable Peak Usage Reduction
			  • Enhance Customer Capability to Follow TOU Schedule & Reduce Bill
			• AMI Enabled Load Control
			• Connected Thermostat/In Home Display
			• Home Energy Management
			• EV Charging Demand Monitoring & Management (HOL Metered & Demand Threshold)
				• Upgrade of existing EnergyAxis head end software to new version to mitigate "end of life support" obsolescence
				• Enable transition to REXU meter to mitigate risk of production obsolescence of current REX2 meters

Figure 8 - Phase 2 Business Releases

Phase 3 - Leverage Telecom FAN

Phase 3 is focused on opportunities that may leverage the planned HOL Telecom FAN implementation.

The Phase 3 business releases are focused on enabling smart grid applications such as smart city sensors, distribution automation, volt/var control, EV charging control, distributed energy resource management, demand response and load control. The primary dependency for the opportunities identified in Phase 3 is the plans for the implementation of the Telecom Plan FAN network, the timing of that implementation, and the extent to which the HOL FAN is expected to serve as a backhaul network for AMI and DA systems (i.e. a "network of networks" strategy) or the FAN is expected to serve as the primary network which provides end-to-end connectivity to specific endpoint devices (such as AMI meters, DA devices, in home devices, etc.).

Recommendations for enabling Phase 3 opportunities by business release are shown in the below table.

BR3a Initial DERMS System Implementation	BR3b Initial DA/DMS	BR3c Smart City Sensor Integration	BR3d DERMS and DA integration
• EV Charging Capacity Management • On Premise Storage Monitoring and Individual Demand Management (HOL metered with Demand Thresholds) • On premise Storage Monitoring and Individual Demand Management (HOL metered with Processed interval data) *Note: DERMS can be Standalone Application or a Module in DMS*	• Automated Reclosers and/or Switches • Faulted Circuit Indicators (FCI) • FLISR (Fault Location, Isolation and Service Restoration) • Reduction in O&M Costs for Distribution Monitoring Communication Infrastructure • Volt/VAR Management	• Streetlight Automation • Snow Level Monitoring • Traffic Congestion Monitoring • Waste Collection & Bin Level Monitoring • Indoor Air Quality Monitoring (Commercial/Industrial/Municipal) • Noise Level Monitoring • Surface Monitoring for Walkways and Roadways • Surface Temperature • Vibration Monitoring • Wind Speed • Fire / Smoke detection • Outdoor Air Quality Monitoring • Parking Monitoring	• EV Charging Demand Monitoring and Management (HOL Metered with Interval Consumption Thresholds) • On Premise Storage Monitoring and System Capacity Management • Conservation Voltage Reduction (CVR) • Community Based Energy Storage

Figure 9 - Phase 3 Business Releases

Phase 4 - Invest in next generation AMI

Phase 4 opportunities are based on the potential complete replacement of the AMI solution. It involves upgraded systems, networks, and all meters. Thus, this phase is dependent on the resolution of the HOL Telecom FAN plan, it's ultimate architecture as a reliable communications path to connect directly to all meters and other endpoints or its role as primarily a backhaul network for a new AMI "network within a network". This phase does not pre-assume that the next generation solution will continue to be based on Honeywell technology or another vendors solution. As such, this phase is preceded by a recommended vendor solution validation or selection exercise, with full understanding of the Telecom FAN solution and expected role in HOL's long term AMI system.

The Phase 4 business releases are focused on the opportunities presented from replacing the existing AMI system Applications that require replacement of the AMI system (including electric meters or deployment of DA (or other) dedicated network and endpoints) or transitioning to the next generation Honeywell AMI system to enable smart meter functionality that exists in next generation AMI systems. The primary dependency for the opportunities identified in Phase 4 is the schedule for the depreciation of the existing meter population. This becomes a key dependency to avoid stranded assets. Additionally, the need to comply with new Measurement Canada requirements adds another dependency that will affect the timing of this phase.

Recommendations for enabling Phase 4 opportunities by business release are shown in the below table.

Figure 10 - Phase 4 Business Releases

While all of these capabilities and the subsequent business releases which enable them were deemed to provide incremental value to HOL, the final determination to invest additional funds into any or all of these opportunities should be predicated with a specific and individual business case to validate the ultimate prudency of each investment in time, effort, or capital.

Methodology

Black & Veatch's approach to develop the Hydro Ottawa (HOL) AMI Strategic Plan and Roadmap consisted of five main tasks as shown in the below figure and further described below.

Figure 11 - Methodology

KICKOFF, AND DOCUMENTATION REVIEW

Documentation Review

Black & Veatch conducted an initial kick-off meeting on November 1, 2018 with key stakeholders that are participating in the project. The primary purpose for the meeting was to share the overall project approach and gain an understanding of stakeholders needs and concerns.

Black & Veatch reviewed several key documents that provided insight into system architecture and business strategy. Key documents reviewed include the following:

- HOL Enterprise Architecture Landscape
- Meter to Cash Flow Architecture
- Hydro Ottawa Annual Report, 2017
- Hydro Ottawa Strategic Direction, 2016-2020
- Smart Energy Roadmap for Hydro Ottawa (draft)
- Telecommunications Blueprint and Roadmap, July 2014

This information provided the basis of understanding of the Current State from which Hydro Ottawa would implement AMI and the Strategy Roadmap going forward.

STRATEGY DISCUSSIONS AND ARCHITECTURE REVIEWS

Strategy Roadmap workshop

Black & Veatch conducted a strategy workshop on November 8, 2018 with members from the Hydro Ottawa leadership team including:

- Lance Jeffries - Chief Electricity and Distribution Officer
- Julie Lupinacci - Chief Customer Officer
- Mark Fernandes - Chief Information and Technology Officer
- Adnan Khokhar - Envari, Chief Energy & Infrastructure Services Officer
- Guillaume (Gee) Paradis - Operations Director
- Laurie Heuff – Project Metering Systems Manager

The workshop included a presentation of existing and emerging AMI / smart utility technologies with focus on what other utilities are pursuing. The full presentation is provided in Appendix A. The outcome of the workshop was identifying the main AMI strategic drivers for the leadership team as they might relate to the expected AMI Strategy and Roadmap.

In addition to the kick-off meeting and strategy review workshop, two architecture review sessions were conducted to understand current and planned IT / OT infrastructure and Meter to Cash architecture. Additional discussions were held with the project lead to ensure alignment with approach and gain insight into the AMI strategic drivers.

AMI BENEFITS AND OPPORTUNITIES DISCOVERY

Black & Veatch conducted a series of workshops focused on systematically reviewing an extensive list of potential opportunities from implementing AMI technology. The outcome of the benefits discovery workshops provided a qualified and prioritized list of potential key opportunities for operational efficiencies, business transformation, revenue enhancement, cost management, customer care, or extended business opportunities that may be available to Hydro Ottawa. Black & Veatch utilized our comprehensive *AMI Opportunities* framework to facilitate this assessment.

FUNCTIONAL REQUIREMENTS DEVELOPMENT

Following the benefits discovery workshop, Black & Veatch extended the understandings of the prioritized opportunities into expected key functional capabilities required to enable these goals and benefits. This included identifying those opportunities already achieved, the system elements that would be required to enable each new or expanded opportunity, the relative cost and effort for each, and the extent to which each opportunity might be achievable with the existing HOL AMI system or with incremental improvements to this system.

This included several meetings and discussions with Honeywell to understand the capabilities of the current system and qualify the incremental improvements needed.

The final details of the prioritized opportunities, their functional requirements, prioritization, level of effort, and Roadmap phase were all incorporated into the *AMI Opportunities* framework which is included as Appendix B.

TECHNOLOGY ROADMAP AND BUSINESS RELEASE PLANNING

Roadmap Planning

Based on the understanding of the current system, the desired and prioritized opportunities, and the influence of the HOL Telecom Plan, Black & Veatch developed a recommended sequence of strategic steps that HOL might take to prudently address the remaining and new opportunities of AMI. The strategic steps (or phases) formed the basis of the Technology Roadmap. All of the AMI related opportunities not already achieved were mapped to the four identified phases of the technology roadmap to identify what can be accomplished throughout the roadmap steps and what dependencies impact the timing and implementation of each step.

Business Release Planning and Sequencing

The functional requirements and IT system impacts that were identified with each opportunity (within each Roadmap phase) were then integrated into a logical sequence of system development steps (or business releases). These business releases combined related capabilities enhancements or synergistic system work efforts to describe likely IT/OT system development efforts required to enable the desired opportunities beyond strict AMI investments. The business release plan is included in Appendix C.

Key Findings

CURRENT STATE ASSESSMENT

Hydro Ottawa Enterprise Strategies

Strategic Direction 2016-2020

Black & Veatch reviewed the HOL Strategic Direction 2016-2020 document to identify key initiatives that may influence or be influenced by AMI technologies. This review revealed the following items that should be considered within the AMI Roadmap:

The Strategic Direction identifies three key drivers of change for HOL, all of which may be influenced by or drive changes in AMI technology strategy. These include:

1. Cost
2. Technology
3. Public policy and regulation relating to energy

Clearly stated within the Strategic Direction was that customer centrality represents the single most important change in the fundamentals of the utilities business:

- *"Customer focus has been the key driver of Hydro Ottawa's business strategy over the past several years, and will continue to be our focus over the next five years"*
- *"HOL will focus on positioning customers to be much more active participants in the power system and the power market"*

More specifically, this Strategic Direction foresees that HOL will enable the following customer-oriented capabilities (some of which are specifically addressed in the AMI Roadmap):

- Prosumers – Producers and Consumers of energy
- Sellers of consumption reduction – Automated Demand Response
    a. Aggregators – enabling "Set and forget" automated DR
- Distributed energy, DR, Energy Management
- EV infrastructure

The Strategic Direction portrays that these changes are most likely to occur according to the following expected sequence of adopters:

1. Large Businesses and Institutions
2. Farms and warehouses
3. Residential - slower to adopt, particularly where the upfront costs are high
    a. New subdivisions and high-rise apartments – distributed generation, micro-grids, EV infrastructure energy efficiency (Key driver will be government standards that emerge to encourage or require this)

Finally, the Strategic Direction predicts that the utility Business Model is likely to adjust based on the following shifts:

- Utility revenues will in future be made up of a greater mix of regulated distribution service charges and new revenue streams that result from leveraging the utility's core competencies to provide value-added services
- The customers for these services may be within or outside of the distributor's traditional service territory, and in some cases, may be other utilities.
- The continued push to transition to renewable energy sources also represents a continued revenue opportunity for utilities that have a core strength in this area.

Strategy Workshop

Black & Veatch conducted a strategy workshop with members of the Hydro Ottawa leadership team including:

- Lance Jeffries - Chief Electricity and Distribution Officer
- Julie Lupinacci - Chief Customer Officer
- Mark Fernandes - Chief Information and Technology Officer
- Adnan Khokhar - Envari, Chief Energy & Infrastructure Services Officer
- Guillaume (Gee) Paradis - Operations Director
- Laurie Heuff – Project Metering Systems Manager

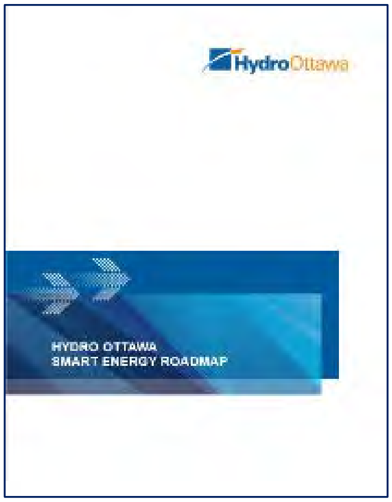
During this workshop, the group explored key directions and/or expectations from AMI. Some of the key takeaways of this session included the following key concepts and drivers:

- Customers should not need to inform us when there is an outage
- Customer flexibility
    - energy efficiency models
    - mine data and utilization of data
    - forecasting and predicting what customers' needs are - this needs to be baseline before any prepay or other programs,
    - home and commercial building automation - build and resell
- "Support" home automation rather than directly "own/control" home automation
- Real Time availability of data is the key utility differentiator from aggregators and retailers
- Enablement new business models over improvement of performance statistics

All these themes seem to reinforce those from the Strategic Direction in that they are strongly focused on customer capabilities enablement, customer services, and changing business models.

Smart Energy Strategy

Finally, Black & Veatch reviewed the Smart Energy Strategy as portrayed in the Smart Energy Roadmap. This yielded a more granular view of the intention for expanded Smart Grid programs and the specific expected timing of many programs that are either dependent on the AMI strategy or may be precursors to elements of the AMI Strategy.



Smart Energy Vision Statement

The Smart energy vision will be realized through a roadmap of projects and programs, which are aligned with Smart Energy strategic imperatives and desired strategic outcomes.

Smart Energy Strategic Outcomes

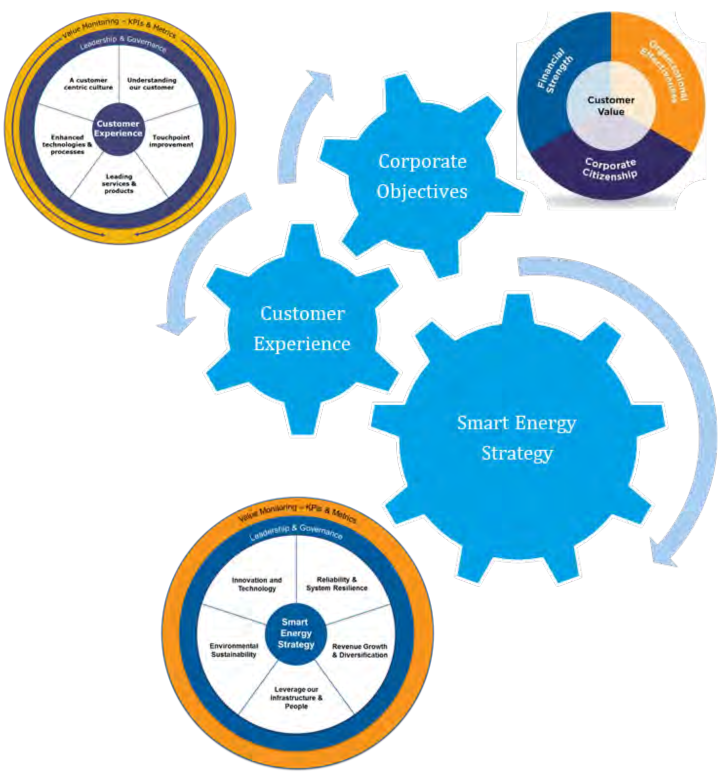
100% Reliable Service - Develop enhance grid reliability, and service offerings to enable provision of 100% reliability electrical service guarantee.

Customer Energy Solutions - Position Hydro Ottawa as the provider of proactive and innovative energy solutions which are driven by our customers' needs, preferences, and objectives.

Expanding Current Businesses - Expand current value and revenue streams building on our core areas of strength in the provision of electricity and related services.

As with the Strategic Direction and the executive workshop, common themes emerge of enabling customer solutions and exploring new business models (while maintaining reliable service).

Alignment with other Initiatives



The smart energy steering committee is one of the initiatives through which Hydro Ottawa will achieve its overall corporate strategic objectives. To deliver on the corporate objective of Customer Value, alignment between the Smart Energy Steering Committee, the Customer Experience Steering Committee and other Strategic initiatives is required.

The Smart Energy Roadmap describes a number of project specific initiatives which embody the execution of this roadmap, they include the following projects, many of which will be directly or indirectly enabled by the AMI Roadmap:

Smart Energy Initiatives

1. Telecommunication Master Plan
   A robust communication infrastructure to support, Hydro Ottawa and our customer smart energy applications.
2. Enabling Transactive Marketplace (GREAT-DR)
   Preparing for the shifted role of the utility moving to provide, integrated energy solutions, supporting customer transaction, in community and Across the grid.
3. Enhanced Mobile Workforce Management
   Extend workforce management for all HOL distribution field activities.
4. Self-Healing Grid
   Distribution system can automatically Isolate faults and restore power.
5. Outage Intelligence
   Automatically locate, and identify root cause distribution system faults
6. Outage Analytics and Leveraging Existing Data
   Deliver custom reporting, and analytics at our staffs finger tips.
7. Storage for Reliability
   Deploy Storage to enable a 100% reliability for our customers.
8. Outage Notification
   Automatic notification of customer power outage.
9. EV Enabling Charging Infrastructure
   Deployment of private charging infrastructure (Commercial & Residential)
10. District Thermal Business
    Provide integrated energy solutions to meet customer needs.
11. Smart Assessment and Repair
    Damage assess tools to support and streamline grid event response.
12. Analytic Field Assistant (KITT)
    Process assistant (AI) to help in triage and prioritization distribution system response.
13. Smart System Planning
    System information available at our finger tips, to support decisions that align to the real condition of our system.
14. Dynamic Grid
    Distribution system can dynamically respond to operating environment.
15. Electrification of transportation
    B2B enabling of Commercial vehicles and charging infrastructure.
16. Outage Prediction
    Machine learning and artificial intelligence to identify and prevent incipient faults.
17. Asset Lifecycle Information
    All information associated with Asset available in a single source.
18. Smarty Pants
    Wearable Technology to support field operations.

Additional Opportunities:

1. Microgrids - Campus
   Hydro Ottawa to provide integrated energy solution to campus and community partners that meet the customer(s) supply security and/or environmental criteria.
2. Biomass for District Thermal
   Hydro Ottawa able to offer bio-mass as part of heating and electricity solution to its customers.
3. Electrify HOL Fleet
   Build Reputation as a trusted advisor in the shift to electrified transportation by converting HOL fleet.
4. Storage for Capacity Management
   Hydro Ottawa to participate in the deployment of local storage, to manage solar generation, manage customer loads such as EV charging

All these initiatives are mapped against the identified AMI Roadmap stages in the Recommendations Section to portray any interdependencies that these Smart Energy initiatives may have with the planned AMI Roadmap phases.

State of the AMI Lifecycle

Advanced Metering Infrastructure (AMI) within the North American electric utility industry has become a regularly adopted solution for improving operational efficiencies and managing many common business challenges. These challenges include aging infrastructure, system operational management, integrity, customer service, and conservation objectives. In fact, many utilities are already facing the new challenge of addressing the opportunities for replacing a first-generation AMI system with the latest technology available.

Hydro Ottawa is in this more common situation of assessing the "Renewal Strategy" for addressing an aging "first-generation" AMI technology. The "Renewal Strategy" stage is one of the key steps in the Black & Veatch model for managing the AMI Lifecycle. This Black & Veatch approach to supporting the complete lifecycle of a successful AMI program is portrayed in the following graphic:

Figure 12 - AMI Lifecycle

HOL has extracted significant value from the 1st generation AMI system which has been operating for 12+ years. It is understood that this system was originally intended to enable the provincial requirements for universal TOU rates and interval data to be provided to the provincial MDMS system. The current system has successfully provided this required functionality and the information needed to address this initial requirement.

However, as HOL has sought to expand the usefulness of the AMI system and extract additional value from the system, it has experienced several technical and system integration hurdles. These hurdles can be characterized as falling into three key categories:

1. Obstacles in extracting available data via the current AMI network either due to bandwidth/latency limitations or backhaul connectivity limitations (dial up modems)

2. Obstacles in developing additional enhancements to downstream system to enhance their potential use of AMI data that may already be available

3. Obstacles borne from core metering and/or data capabilities of the sealed electric meters currently in the field.

Advanced Metering Current State

System Obsolescence

The HOL AMI system is over 12 years old and faces two significant technology obsolescence issues:

1. **Meters**: Approximately 61% of the metering endpoints consists of early generation Honeywell REX1 meters. The other 39% of the meter population consists of Honeywell REX2 generation meters, which HOL continues to purchase to maintain network compatibility. The following table represent the approximate population of meter types currently in the HOL system.

	# Meters Installed				
Seal Year	All Rex Meters	Rex 1	Rex 2	Fully Depreciated Year	% of Total
2006	89622	89622	0	2021	28%
2007	86020	86020	0	2022	27%
2008	51871	18476	33395	2023	16%
2009	21302	396	20906	2024	7%
2010	5090	0	5090	2025	2%
2011	5725	0	5725	2026	2%
2012	9320	0	9320	2027	3%
2013	8548	0	8548	2028	3%
2014	7236	0	7236	2029	2%
2015	9975	0	9975	2030	3%
2016	8453	0	8453	2031	3%
2017	7172	0	7172	2032	2%
2018	6157	0	6157	2033	2%
Total	316491	194514	121977		
		61%	39%		

Figure 13 - Meter Population Installation Age

The REX2 meter is likely to be discontinued by Honeywell soon in lieu of their newest metering product offering, the REXU and future Alpha 4 residential meter. Thus, HOL is likely to be forced to transition their supply from the REX2 product to the REXU product. The REXU product can be utilized in the current HOL AMI network in place of the REX2, provided that HOL upgrades the Headend software application to the Connexo NetSense

10.2 or higher. Specifically, the meter/network compatibility for the current and newer vintage of meters from Honeywell is understood to be as follows:

- REX1 meters limit mode of network operation to LAN1 only (currently the mode of operation for the HOL AMI network to accommodate the population of REX1 meters currently deployed)
- REX2 meters can operate on LAN1 or LAN2 (the REX2 meters deployed at HOL are operating in LAN1 mode to remain network compatible with the older REX1 meters still on the system)
- REXU meters can operate on LAN1 or LAN2 or the newer SynergyNet IPv6 network protocol that is the latest offering from Honeywell. However, REX1 and REX2 meters are not compatible with next generation Honeywell network (SynergyNet).
- The next generation Alpha 4 meter is only supported on the SynergyNet network.

2. **AMI Headend**: The AMI system is currently operating using the Honeywell EnergyAxis v9.x headend software application. This version of software is currently two major versions behind the currently offered production software (v11.2) which makes it an "N-2" version of software application. As can be seen from the following chart of support services offered by Honeywell, this current version has reached "end of life" status with Honeywell and carries a significantly escalated support cost structure in addition to increased exposure to the inability to correct software problems.

Version		Version @ 01/01/19	Fee Structure	Support Status
N		11.2	SMA	The release is fully supported
N-1		10.2	SMA	The release is fully supported
N-2	EOL	9.x	SMA + 30%	The release has reached end of life, and system support will be limited to Severity 1 issues defined in Appendix D-3 while allowing Licensee time to complete system upgrades.
N-3 & Less	EOS	All other releases	SMA + 30% plus $500 an hour	The release has reached end of life support (EOS). Support is limited to technical assistance and emergency recovery, this does not include any new software or firmware fixes. Recommended that the Licensee upgrade its release as soon as possible.

Current Releases:

- The current general availability major release is 11.2, launched in April 2018.
- The next EnergyAxis major release is 12.x, planned for the first quarter of 2019.

Figure 14 - Honeywell Head End Application Support Status

Furthermore, Honeywell has announced that it plans to release the next major version of AMI headend software in Q2 2019; version 12.x. With this release, the HOL version 9.x headend software will become an "N-3" version and will reach "end of life support" status with Honeywell whereby Honeywell will not commit to any further ongoing support. This will leave HOL severely exposed to technical risks if the current software were to become inoperable.

System Deficiencies

Beyond system obsolescence, the HOL AMI system performance is hindered by a key network communications deficiency which hampers several potential AMI opportunities. That is, the backhaul network which is used to communicate to the A3 based AMI collectors relies on dial up phone connections for retrieving data. In many cases, this phone connection is a shared line with the customer on whose premise the meter/collector resides. Thus, in its current configuration, it is not operating as a true two-way network and is unable to transmit real time, push alarms from the endpoints when received. These alarms and events can only be retrieved when the head end dials up the collectors on a schedule or on demand to retrieve data held at the collectors.

Because of this deficiency, no AMI benefits that are dependent on real time alarms or push notifications are possible.

Measurement Canada Requirements

Measurement Canada has issued new metering requirements under PS-E-18 that may impact future HOL metering strategies. For example, the following table describes two specific sections of PS-E-18 which may create future compliance issues for HOL:

Section 13-6.1.11 (Interval Data Memory)	The LR interval data shall not be overwritten before a period of time which is the longer of two identified below has occurred: - 35 days - The time required to fill memory to capacity.	REX1 has a maximum memory storage capacity to hold 60-minute interval data for 20 days.
Sections 6.5 - 6.6 (Reactive and Apparent Energy)	• Reactive energy used in calculating apparent energy shall be measured directly and not calculated from other legal units of measure. • Meters shall establish apparent energy based on continuous measurement of active and reactive energy flow in all directions.	REX1 does not record reactive and apparent energy

Figure 15 - Excerpt of Measurement Canada metering requirements

Note: The above table is not intended to be an all-inclusive list of all new requirements that current HOL REX1 meters will not meet. It is intended to provide examples of Measurement Canada requirements which may require HOL to change metering capabilities to avoid non-compliance.

Honeywell has indicated that the REX2 meter will also not meet the requirements of PS-E-18. The REXU does not currently meet the standards to calculate energy values (WH and VARH) from fundamental only signals but Honeywell indicates that a code set could be implemented to the metrology engine. The A4 meter is expected to meet the standard; however, facilities are not yet available in Canada to test these meters. The REXU, as it currently stands, does not calculate these energy values from fundamental only signals and changes would have to be made to the metrology engine.

This PS-E-18 specification will become a compliance requirement January 1, 2022. However, a grandfather provision has been included which allows for electricity meters that are currently in service (i.e. the legacy REX1 and REX2 meters that would not comply with PS-E-18) to may remain in service until the end of their current and subsequent reverification periods. The allowable re-verification periods are as follows:

Table 2

Electronic-type				
Column I	Column II		Column III	
Type	Initial Reverification Period		Subsequent Reverification Period	
5. **Electrical Energy Functions**– watt-hour, reactive-volt-ampere-hour, volt-ampere-hour, Q-hour, A^2hour, V^2hour including those with integrated pulse initiators and/or receivers, multi-tariff registers, remote-meter-reading or automatic-meter-reading (AMR) features.				
	Qualifying under clause 5.4	All Others	Qualifying under clause 5.4	All Others
a) single-phase types	10 years	6 years	8 years	4 years
b) polyphase types	10 years	6 years	8 years	4 years
6. **Electrical Demand (Power) Functions**– watt, reactive-volt-ampere or volt-ampere including those with integrated energy meters and associated functions				
a) single-phase types	10 years	6 years	8 years	4 years
b) polyphase types	10 years	6 years	8 years	4 years

Figure 16 - Measurement Canada Seal Periods

Thus, the Measurement Canada functional requirements may not be an immediate forcing trigger for HOL to replace the current REX1 and REX2 meters as HOL can continue to re-verify REX1 and REX2 meters until the end of 2038. However, ultimately HOL will need to upgrade the entire population of REX1 and REX2 meters to Measurement Canada compliant meters.

Meters and Meter Reading

HOL has a population of 1st generation AMI meters which already contain metrology and data capabilities that meet current requirements for TOU and enable additional HOL use cases to drive business value. However, newer vintage meters have added more capabilities which may enhance HOL Smart Meter use cases if/when they replace the existing Honeywell REX1 and REX2 meters. These enhanced capabilities include:

- Integrated service disconnect switches
- Voltage threshold alerts
- Meter temperature alarms
- Outage notifications (last-gasp)
- Additional recording channels
- Meter data encryption
- Bi-directional and net metering

Thus, none of the opportunities available from these features can be implemented without requiring a selective or complete change-out of the meter population.

Meter Depreciation and Potential Replacement

The current population of residential AMI meters is represented in the following table. It is VERY important to note that all the REX1 meters and approximately 80% of the entire residential meter population becomes fully depreciated in the next 5 years (by 2024).

While this may create an opportunity to embark on an upgrade of these older meters with newer, more capable meters without stranding these existing assets, this will only accommodate 80% of the existing population. In addition, this only considers the assets depreciation schedule and may or may not align with the retained book value of these assets. Finally, there will always be some part of the existing population which is not fully depreciated when a mass meter upgrade is planned.

	# Meters Installed			
Seal Year	All Rex Meters	Rex 1	Rex 2	Fully Depreciated Year
2006	89622	89622	0	2021
2007	86020	86020	0	2022
2008	51871	18476	33395	2023
2009	21302	396	20906	2024
2010	5090	0	5090	2025
2011	5725	0	5725	2026
2012	9320	0	9320	2027
2013	8548	0	8548	2028
2014	7236	0	7236	2029
2015	9975	0	9975	2030
2016	8453	0	8453	2031
2017	7172	0	7172	2032
2018	6157	0	6157	2033

Figure 17 - Meter Population Installation Age

Thus, the depreciation schedule for the existing population provides a significant opportunity to upgrade to a newer metering capability but it does not provide a 100% basis for a system-wide replacement exercise.

Plans for HOL Field Area Network (FAN)

HOL has been finalizing and implementing a Telecom Master Plan to address all layers of the enterprise communications requirements. As part of this plan, HOL has a specific element that is meant to address the Field Area Network (FAN) element of the required communications needs. This FAN has the potential to serve as the HOL owned backhaul network to carry data from the AMI local area network (LAN) back to the AMI headend OR, depending on regulatory enablement, may be able to serve as the FAN and LAN for AMI, DA, and DER endpoints. Thus, depending on the final determination of the capabilities and limitations of the FAN technology to be implemented, the AMI Roadmap could include a significant leverage of the FAN as the primary AMI/DA/DER communications network OR the AMI Roadmap could lead to a "network of networks" concept whereby a more traditional AMI solution, as offered by the existing AMI vendors, provides the LAN connection to AMI/DA/DER endpoints while the HOL FAN provides the traditional AMI backhaul role. This key driver of the AMI Roadmap results in a specific phase of the roadmap that is directly dependent on this outcome.

This FAN plan and implementation is currently dependent on regulatory and governmental bodies to enable HOL to own and manage their own private cellular networks. It is understood that this plan will be finalized and the regulatory constrictions fully understood by the end of 2020. Thus, the opportunities that might directly leverage this FAN, and the ultimate strategy for the long-term AMI solution for HOL are dependent on this final FAN strategy determination.

Current State of IT System elements

HOL has a robust system architecture consisting of a full portfolio of appropriate IT and OT systems. The following diagrams portrays a representation of the current state of HOL operational systems.

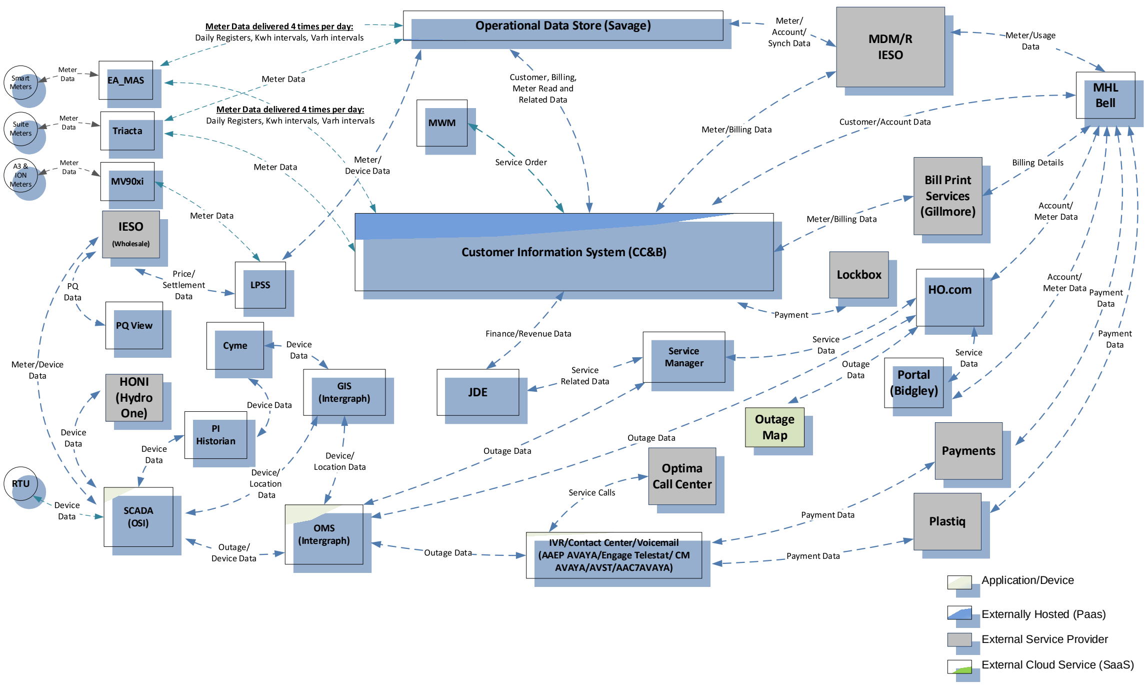


Figure 18 - Current State IT Systems diagram

Security

In today's digitally enabled world, it is critical to recognize and plan for the fact that AMI solutions measure, store, and transmit data associated with individual household activities and enable critical grid system controls. Thus, it is vitally important that all AMI technology implementations should not compromise on security. End-to-end security must be integrated into all considered and implemented AMI technology investments.

The minimum standard for communications security for AMI solutions is often identified as emulating the security profile of cellular encryption and authentication models. This minimum standard requires that all transmitted data is encrypted to protect the data stream.

If HOL implements a cellular AMI solution (by virtue of the HOL Telecom FAN plan), this standard should be incorporated into the cellular endpoint solutions. If HOL implements a private RF network, it should also require the network and endpoint devices to enable encryption strategies.

It is understood that the current Honeywell EnergyAxis solution does not support network and/or endpoint encryption. This significant deficit of the current AMI solution may form a primary driver for accelerated replacement of the current AMI architecture. However, this concern has not been raised by HOL stakeholders and, therefore, is not currently considered a primary driver for replacement of the existing Honeywell solution as part of the AMI Roadmap portrayed herein.

That said, given HOL's intent to leverage the planned Telecom FAN for elements of AMI communications, the security profile for cellular service should be considered as the minimum standard for AMI security connections between remote system elements. Cellular service providers typically use an authentication and encryption approach for moving data in a secure fashion. This profile (or an emulation of this profile) should be applied for all remote system connections; including meter to concentrator and concentrator to AMI Head End applications.

Privacy

Deployment of an AMI system creates a significant amount of consumer related consumption and activity data to be collected by the utility and potentially displayed on internet and mobile accessible sites. Ensuring the privacy of data is paramount to a good customer service interaction and being a trusted service provider.

Specific privacy policy choices should include:

- Encryption of stored data – to minimize unauthorized access to data stored at the vendor facility
- Authentication rules for access to on-line customer data through a portal – to protect access to customers data

Thus, Hydro Ottawa will need a definitive policy for customer data privacy to govern customer usage and billing information. Examples from other utility initiatives can provide a basis for developing this policy. Specifically, the California PUC developed a Smart Meter Data Privacy framework (based on the Fair Information Practice Principles from the U.S. Department of Homeland Security developed as its privacy framework). This framework addresses the following data privacy elements:

- Transparency
- Individual participation
- Purpose specification
- Data minimization
- Use limitation
- Data quality and integrity
- Security
- Accountability and auditing

AMI OPPORTUNITIES AND POTENTIAL BENEFITS

Black & Veatch conducted a series of Stakeholder workshops to explore the possibilities and prioritization of potential opportunities from AMI technologies. This provided a rich list of AMI use cases, some of which have already been achieved and some of which are purely future opportunities not available today.

A graduated ranking system was used to identify the importance of these opportunities according to the following scale:

5 = Must Have

4 = High Priority

3 = Needed but not priority

2 = Like to have but does not drive priority

1 = Not necessary

0 = Not applicable

The following is an example excerpt that portrays, the information gathered. The complete AMI Opportunities matrix is included in the Appendix:

Benefit Category	Hydro Ottawa Stakeholder Group	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Use Case Summary
Billing	Customer Care	Fully Achieved	**Billing Exceptions (Level 1) - Reduced number and resolution time of billing exceptions/issues**	X	X		5	Daily readings provides more readings available to derive accurate bill determinants. Thus, fewer billing exceptions are generated.
Billing	Customer Care	Future	**Summary / Consolidated Billing - Improve cash flow for existing Summary Billing customers**	X	X		4	Billing reads available for every day to enable summary aggregation for summary accounts on any given day. This will allow all summary billing accounts effective bill date to be accelerated to the bill cycle for the first read meter.
Billing	Customer Care	Fully Achieved	**Flexible Billing dates - Improved cash flow from accelerated billing date: improved working capital from flexible billing options**	X	X		3	Processing of meter readings daily; enablement of Billing System to bill based on first available meter reading in bill window potentially accelerating cash flow. Billing determinants available on any day enable any customer to be billed on any day. Requires flexible billing dates enabled by Billing System.
Billing	Customer Care	N/A	**Reduction in Manual Bill processing**		X		0	High percentage of automated daily readings provides more readings available to derive accurate bill determinants without manual intervention for complex bill processing
DER	Market Engagement	Future	**EV Charging Aggregation and Market participation (HOL separately metered)**	X	X		5	Enable consumption and aggregation of private charging infrastructure (Commercial & Residential) to provide for HOL or Third Party market participation.
DER	Market Engagement	Future	**Customer Portal information for EV Charging (HOL provided)**	X	X		3	Provide detailed charging consumption profiles of private charging infrastructure (Commercial & Residential)
DER	Market Engagement	Partially Achieved	**Disaggregation of Load / Appliance Monitoring (individually metered)**	X	X		2	Measure usage of individual devices behind the meter such as HVAC, water heater, and appliances by using individual metering devices. Metering does not need to be revenue grade.
Distribution Operations	Customer Care	Future	**Outage Management - Improved Customer Communication**	X	X		5	Proactive communication to customers caused by improved outage event situational awareness. Highly efficient restoration updates with system wide pinging/polling to confirm OMS outage information. Restoration tracking and confirmation: status of individual service restoration by enabling customer service representatives to ping meter.

Figure 19 - Excerpt from AMI Opportunities matrix

A view of the number of opportunities by priority rating indicates that the team sees a significant number of high priority opportunities remaining. All Opportunities prioritized as 3 or higher were deemed to be significant enough to specifically address within the Roadmap and Business Release plan.

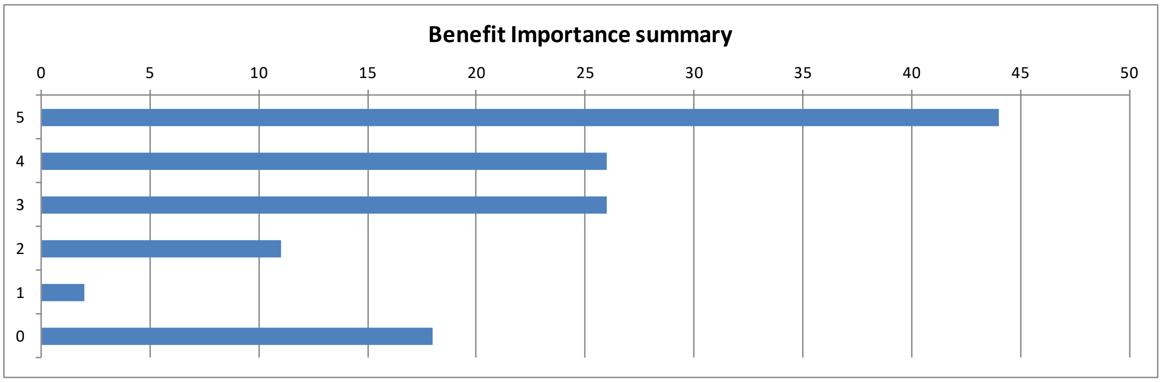


Figure 20 - Benefit Importance Bar Diagram summary

A further analysis of the raw count of the opportunities identified provides some insight into the focus areas:

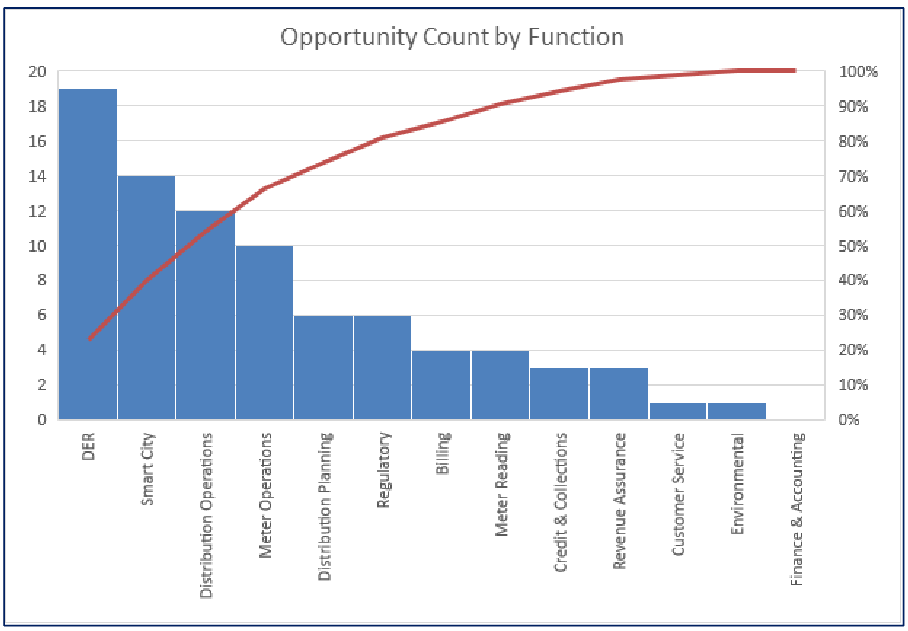


Figure 21 - Opportunity Counts by Function

This analysis of the opportunities clearly indicates that HOL has achieved many of the traditional meter-to cash opportunities and has a strong desire to extend AMI capabilities to support expanded use cases beyond traditional meter-to-cash operations. This is evident in the number of opportunities rated 3, 4, or 5 which are related to Distributed Energy Resources (DER), Smart City enablement, and Automated Distribution Operations. This distribution also supports the overall goals for the HOL Strategic Directions report.

Qualifying Opportunities by Cost and Level of Effort

Following the qualification of the identified opportunities by priority, a further qualification was developed to provide a hi-level, subjective assessment of the expected relative cost and level of effort to achieve the prioritized (3,4,5) opportunities. Each prioritized opportunity was assessed as to the expected Cost and Level of Effort as follows:

Cost:	5 - Hi Cost	4 - Med Cost	3 - Lo Cost
Level of Effort:	5 – Significant Effort	4 – Moderate Effort	3 – Low Effort

This assessment provided a subjective relative cost element to the opportunity assessment.

Combined with the priority ranking this provided a relative "net ranking" qualification to the opportunities such that a high-level analysis of the opportunities might provide further insights into the potential impacts of further AMI enhancements. Thus, re-examining the potential opportunities when including both priority and relative cost/effort yields the following:

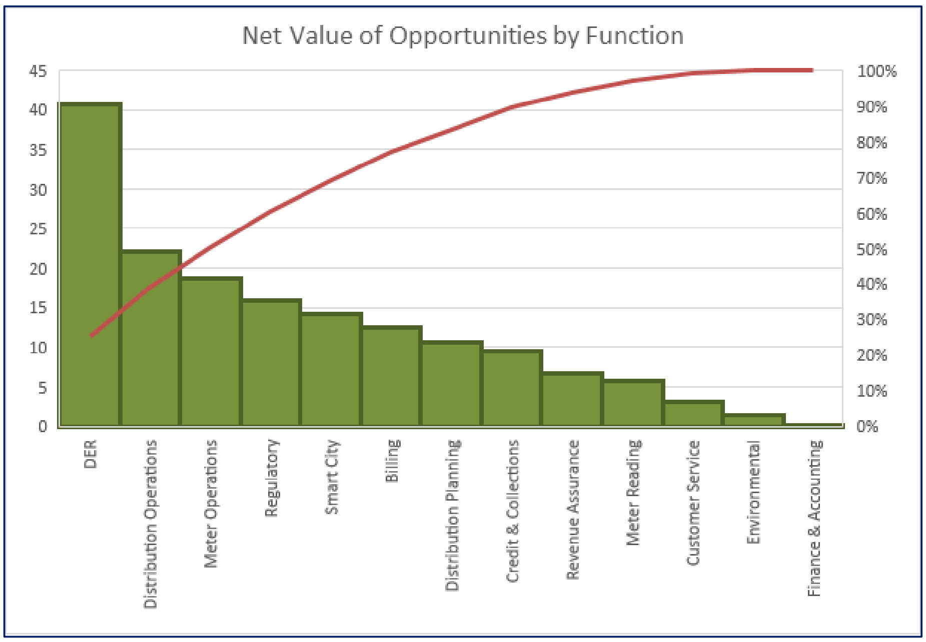


Figure 22 - Opportunities by Function; ranked by net value

This analysis infers that the opportunities for DER and Distribution Operations still provide the greatest net value to HOL but that more traditional operations and rate/regulatory opportunities may also carry interesting net value.

IT AND COMMON SYSTEM ELEMENTS

System Integration Architecture

HOL's current system architecture utilizes dedicated point to point integration of data streams between source and target systems. Given the expected amount of additional data potentially available from AMI systems and the expected leverage of that data across additional downstream systems, it may become important to consider new system integration architectures for improved and more efficient use of AMI data across multiple systems.

Consideration of new system integration architectures is not included in the Business Release plans portrayed in the Roadmap recommendations. The Business Release plans are focused on functional integration of new system capabilities and the consideration for alternative integration techniques is considered a distinct IT decision.

That said, some of the key integration approaches include:

- Point to Point integration - involves development of custom integration interfaces.
- Messaging-based integration using Message Oriented Middleware (MOM) such as MQ Series, TIBCO rendezvous, etc.
- SOA & ESB-based integration using integration middleware supporting SOA and ESB. BPM-based integration providing integration between data, applications and people together through a common business process.
- Pre-built integrations packages may provide a productized integration between two applications.

AMI System Head End applications as Common System Elements

As described previously, the existing version of the EnergyAxis Management System (EA_MS) is two versions behind the current Honeywell Connexo NetSense headend and is expected to be three versions behind when Honeywell introduces v12.x in Q1 2019. In addition to being unsupported, the existing EA_MS 9.x version does not support key functionality required for advanced use cases such as temperature readings, voltage monitoring, advanced metrology functionality, instrumentation data using on request reads for A3 meters, and REXU meters. A comparison of features for EA_MS and NetSense is provided in Appendix D.

The need to have a supported AMI headend with an advanced platform that enables functionality for future use cases and securely manages the data collection from multiple devices (with various communications platforms) to feed downstream systems is a key requirement to evolve to the next generation AMI.

Meter Data Management Capabilities

The current Savage ODS meets HOL's requirements along with IESO's MDMR. Meter data is stored in ODS and interval data (alarms/events) are sent to MDMR for calculating billing determinants which are then sent back to HOL for billing. HOL has access to the data and can utilize it to for their requirements.

In the future, ODS will require changes as new meter data (intervals less than 60 minutes, new events and alarms) will have to be stored and processed. The interface to MDMR will not change as IESO requirements are fixed and HOL cannot change them. HOL will need to evaluate changes to ODS interfaces as more systems are interconnected in conjunction with their data warehouse strategy. This evaluation is required to determine what interfaces can be supported by ODS. For example:

- Can it support web services and other interfaces to meet real time requirements?

- Does it have the capability to store water or other types of data such as smart city use cases?
- Can it provide data separation for electric and water as they will be different utilities and data privacy/security is required?

Additionally, the operational efficiency and capability to process the increased data must be evaluated for future interval data which is likely to be more granular than the current 60-minute intervals.

Technology Review

Black & Veatch provided an overview of AMI technology and the AMI vendor landscape as part of an on-site meeting and further arranged numerous meetings at DistribuTECH with key AMI and communication vendors in which HOL participated. The below sections highlight the AMI technologies and considerations in selecting an AMI technology. Nonproprietary sections of the presentation material is also provided in Appendix E.

ADVANCED METERING INFRASTRUCTURE TECHNOLOGIES

A smart metering/AMI system is traditionally characterized by its remote, fixed network communications infrastructure, its ability to collect data from various sensor and control devices located in fixed locations throughout the service territory, and its bi-directional communication capabilities. Typically, an AMI system operated as a full two-way system is capable of the following functionalities:

- Requesting and receiving "on-request" data retrieval to allow personnel to query the endpoints as needed.
- Realtime alarms or alerts that provide additional information on grid issues, customer use or device problems to allow more proactive resolution.
- Remote firmware updates for the network elements and endpoints that allows for focused or system-wide updates and reduces technology obsolescence risks (within allowable Measurement Canada sealing requirements).
- Time synchronization of the network, endpoints, and the Head End software application (HES) to allow for complete system data synchronism.

There are several common network structures in use today for AMI focused networks, including the following:

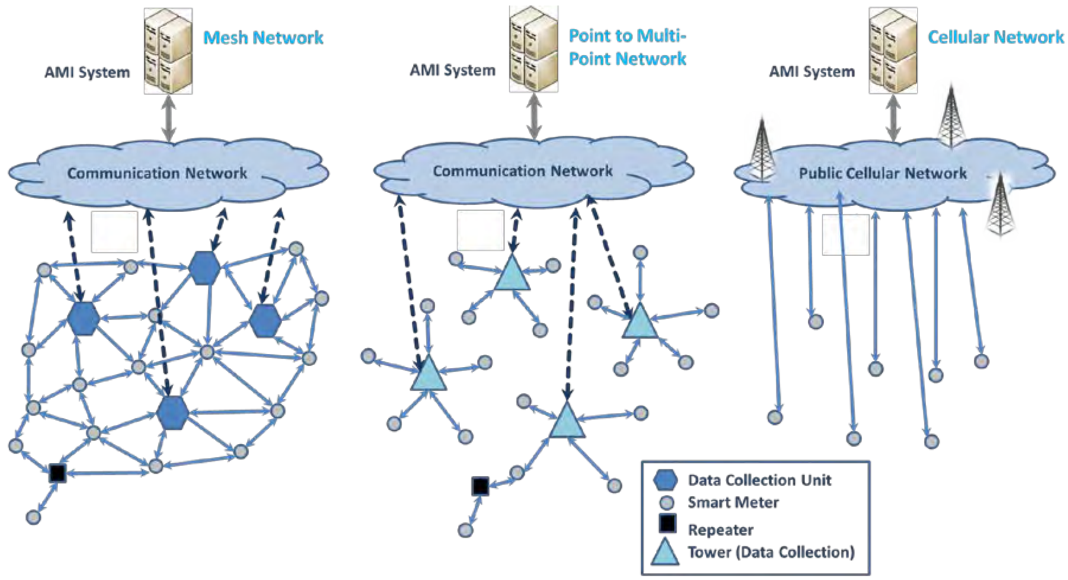


Figure 23 - Common AMI Network Structures

The selection of a network type is dependent upon several factors in the service area of the utility. The availability of public carrier (cellular) coverage, proximity of the meters to each other, the uniformity of the service territory, the physical location of meter assets (indoors, etc.,), availability of utility assets to mount network infrastructure, and the topography of the service area all contribute to the determination of the type and amount of network infrastructure required for a reliable network.

More recently, the availability and viability of private cellular networks has presented additional options for potential AMI networks.

There are several layers of technology choices implicit in the selection of a preferred AMI solution. These include:

1. Private network versus Public Network

2. If Private network; Private cellular versus Private/proprietary RF

3. If RF network; Mesh RF architecture versus STAR RF architecture and licensed frequency versus un-licensed frequency

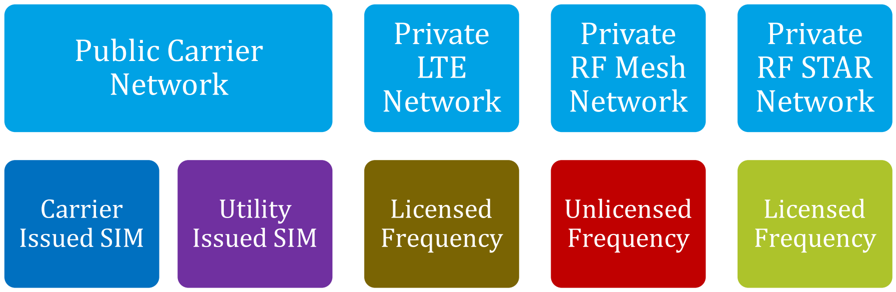


Figure 24 - Network technology options

Public (Cellular) Network

Public Network with Public Carrier provided SIM

This network configuration assumes that the cellular modem is either embedded in the meter MIU or a cellular device is attached to the endpoint for data access (i.e. DA devices or in-home devices). In this scenario a cellular provider is responsible for connectivity from the meter to the Head End System or to any other application that is reliant on the endpoint data.

The advantage of a public cellular solution is that it requires no network deployment by the utility. The public carrier (Telecom Company) cell towers are utilized to collect data from the meters and transmit to the AMI HES.

The major disadvantage of the cellular system is that the utility is fully reliant of the phone company for the availability of the communications to the endpoint. Whereas in private RF networks, the Telecom carrier is typically only providing backhaul communications and the RF network provides significant redundancy to overcome and reliability exposure to the Telecom service provides. Another disadvantage is that each endpoint (meter, DA device, in-home device, and sensor) will have a recurring monthly service charge for communications. This serves to add to the utilities O&M costs while private network options limit these O&M charges by investing in utility owned network capital.

Public Network with Utility issued SIM

As an alternative to the traditional Public Carrier provided service, whereby the Public Carrier issues the SIM cards required to provision the endpoint devices onto the Carriers network, HOL is exploring the possibility of garnering regulatory approval to issue their own SIM cards for provisioning HOL endpoint devices across Public Carrier networks, but utilizing the bulk carrier, wholesale roaming charge rates. This option, if enabled, may dramatically reduce the monthly O&M fees for communicating to endpoint devices while still utilizing the existing network infrastructures provided by the public carriers. Thus, this option reduces HOL's required capital investment and manages the monthly O&M fees required for each endpoint device to a minimum level. However, this option still retains full dependency on the public carrier for maintaining availability and reliability of the network for maintaining communications to potentially critical endpoints (such as DA devices).

Private Network

There are three available architectures and two available choices in the private network option. These include Private RF, including Mesh Network or Star Network configurations, and Private Cellular.

In the private connectivity model, the AMI provider will provide connectivity from the meter to a gateway or collector. This is included as part of the cost of the overall solution.

Private Network Architecture Considerations

Star RF Network

A star network is a point-to-multi point architecture and is a common type of fixed network AMI system used for electric, gas, and water in North America. In this system the meter or MIU transmits its data to a centralized network hub known as a collector or DCU. In its simplest form, a star network consists of a number of collectors and an AMI headend software application (HES), which manages the networks configuration and acts as a conduit to transmit data. Once the data is received by a collector, the collector transmits the data back to the AMI HES via a "backhaul" data network link (public carrier network or private utility network).

The advantage of having a star network is that it sets up and expands easily and propagation studies provide reliable projection of coverage. Non-centralized failure has little impact to the entire network, end-point failure is easy to detect, and the data is easily sent directly to data collectors without being repeated through another device. A potential disadvantage of having a star network is that if a collector fails, there is a higher risk of lost communications from the end-points that are assigned to that collector That said, transmitter signals can communicate to all collectors within their transmission footprint. As a result, it is common practice to provide overlapping collector coverage in the network to create network redundancy in the event of a DCU failure. It should also be noted that migrating AMR to AMI units does not allow drive-by AMR to be conducted if the AMI system fails.

Mesh RF Network

Another common type of fixed network system is the mesh network. In a mesh network, smart endpoints act as repeaters, passing the data to other nearby devices before arriving at a main collector. Thus, a mesh network is more data and communications intensive on the MIUs. It allows for continuous connections and reconfiguration around broken or blocked paths by "hopping" from endpoint to endpoint until the destination is reached. Mesh networks differ from other networks in that the component parts can all connect to each other via multiple hops.

One major advantage of a mesh network is that it is self-healing. The network can still operate if an endpoint breaks down or a connection fails. As a result of the self-healing, a very reliable network is formed. One disadvantage with mesh networks is that any battery-operated endpoints may consume more power for the increased frequency of transmitting, thereby reducing battery life expectancy of the MIUs. In actual practice today, most mesh systems rely on electrically powered devices to perform the majority of the mesh management and data repetition. Thus, most mesh systems that have been deployed to support water or gas AMI or battery operated Smart City sensors often will utilize electrically powered devices such as electric meters or repeaters to provide the "hopping" mesh node operations thus allowing the battery-operated endpoints to reduce the number of required transmissions.

Radio Frequency Considerations

Current AMR and AMI offerings operate in either a licensed or unlicensed frequency spectrum. The primary benefit of a licensed system is that the spectrum band that the system utilizes permits a higher power signal (2 watts for licensed frequencies versus a maximum of 1 watt in unlicensed frequencies), which enables a greater distance between the transmitter and receiver units (i.e., fewer network components required compared to an unlicensed band system), and the system utilizes a specific frequency band that is closed to outside users so there is significantly less chance of interference by other electronic devices in the area. To minimize interference on an unlicensed network, the system typically uses specialized modulation and encryption techniques that allow the system to share the band with other users in a reliable and robust fashion. Hydro Ottawa has not reported any problems with their unlicensed frequency equipment.

Private Cellular

Private Network with Utility issued SIM

As an alternative to the traditional Public Carrier provided service, HOL is also exploring the possibility of garnering regulatory approval to deploy their own completely private cellular network using HOL procured and deployed cellular devices. As a private cellular carrier, HOL would privately procure LTE network spectrum and invest in Private cellular/LTE network devices to establish a private cellular network and issue private SIM cards for desired endpoint devices.

This option, if enabled, may enable HOL to mirror a more traditional AMI RF network while using cellular compatible devices. Thus, this option eliminates the recurring O&M fees associated with monthly cellular service charges while substituting capital investment for a privately owned network.

Summary

	PROS	CONS
Public Carrier (Cellular) – Carrier issued SIM	■ The cellular companies can deliver the data directly to the HES. There is no need for the utility to have any utility owned network components or facilities as part of the data delivery to the HES. Thus, all network management is done by the cellular vendor. ■ Cellular will provide security both in authentication and encryption from the meter to the delivery point of the HES. ■ Easiest to deploy assuming cellular network coverage exists at each endpoint. ■ Enables multi-vendor endpoint strategies as multiple MIU vendors can share the same public network (may require multiple head end systems)	■ Likely not all points will have cellular coverage so a second connectivity method may be required for hard to reach devices. ■ Monthly recurring O&M charges will be incurred on a per device basis (telecom companies may offer up front "setup" charges in lieu of some monthly fees which may be capitalized) ■ Endpoint modem obsolescence may occur more rapidly than under owned network architectures as cellular providers upgrade networks to meet consumer demand. This may leave earlier version modems obsolete (as occurred with 2G modems on previous vintage utility devices). ■ Redundancy may be an issue. Cellular

		coverage could be available only from one cell tower. If a failure occurs at that location the device could go offline. ■ Load is managed by the cellular company. High use areas could still see network congestion thus inhibiting connectivity. Utility endpoints will not have any priority for recovery efforts by cellular company in times of outages
Public Carrier (Cellular) – Private SIM	■ Same as Public Carrier (Cellular) – Carrier issued SIM ■ Reduced monthly service fees – roaming rates	■ Same as Public Carrier (Cellular) – Carrier issued SIM except reduced monthly service fees
Private Network (Cellular)	■ Recurring, per endpoint telecom fees are eliminated. Additional endpoint devices don't increase recurring costs under private network ■ System design can be tailored to maximize the coverage based on the location of actual endpoints ■ Network infrastructure investment provides recoverable capital asset	■ Utility must operate, optimize and maintain a communications network increasing O&M costs and requiring RF network expertise
Private Network - unlicensed Mesh	■ No Industry Canada licensing to maintain ■ Self-healing network to route around communications problems	■ Lower power, shorter range; thus, more network infrastructure to maintain, potential battery life limitations ■ Many devices share the same spectrum. Unlicensed frequencies can still be prone to interference in heavily equipment populated areas.
Private Network – licensed STAR	■ Spectrum protected from interference ■ Can utilize higher power to provide more range and less network infrastructure to maintain; thus, easier "umbrella" network to deploy, fewer network attachment issues	■ Industry Canada license to maintain; more spectrum requires more licensing

Figure 25 - Summary table of Network Technology options

Recommendations

AMI TECHNOLOGY ROADMAP

Overview

The AMI Technology Roadmap is influenced by business, financial and regulatory issues that have created timing or opportunity dependencies that have been considered. There are four key roadmap dependencies which force specific phases of the AMI Technology Roadmap as follows:

- Obsolescence of existing AMI Headend and pending obsolescence of current meter version
- Plans for HOL Field Area Network
- Depreciation schedule of current electric meter population

- Future Measurement Canada metrology requirements

The implications of these dependencies and drivers are described in more detail in previous sections of the report. The dependencies and drivers such as obsolescence, HOL reseal program, new Meter Canada standards, and depreciation schedules have specific dates and are shown in the below timeline.

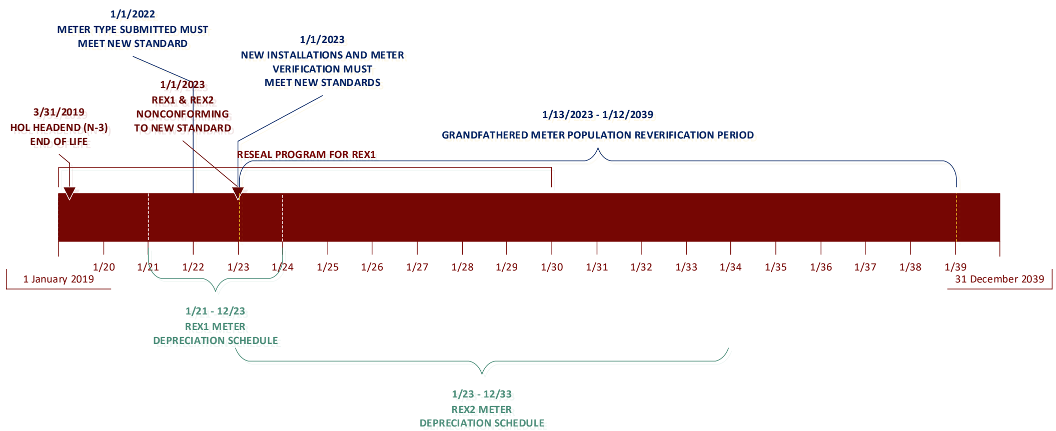


Figure 26 - AMI Strategy dependencies timeline

Based on the understanding of the current system, the desired and prioritized opportunities, and the influence of the HOL Telecom Plan and other dependencies, Black & Veatch recommends a sequence of strategic steps (or phases) that HOL might take to prudently address the remaining and new opportunities of AMI. The four strategic steps are illustrated in the diagram below.

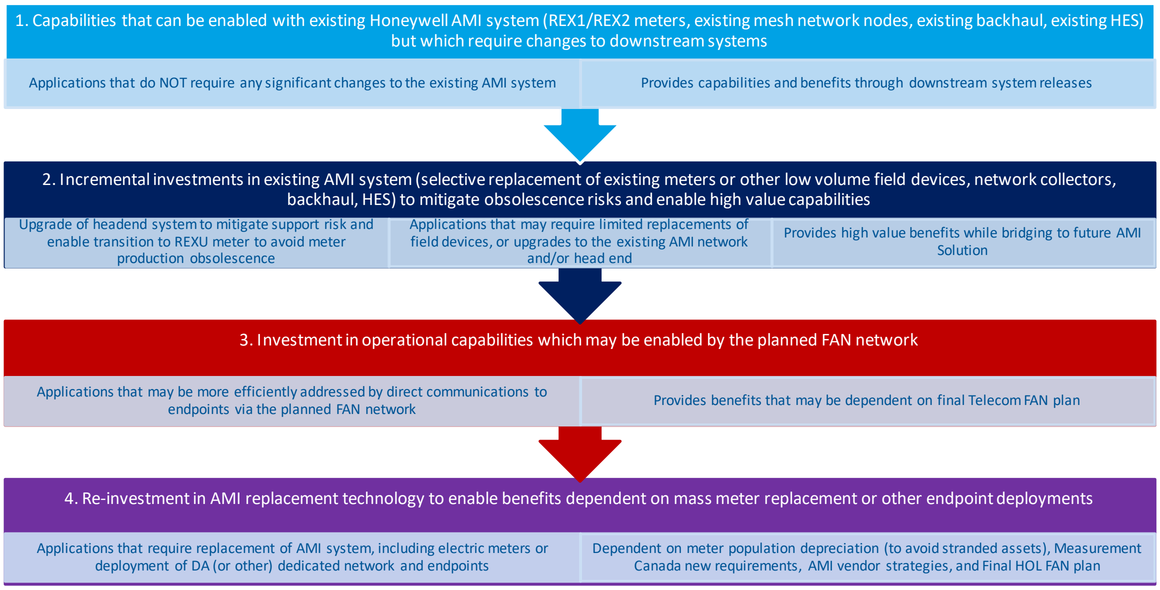


Figure 27 - AMI Strategy Phases

These phases then formed the basis of the Technology Roadmap which is shown in the below timeline.

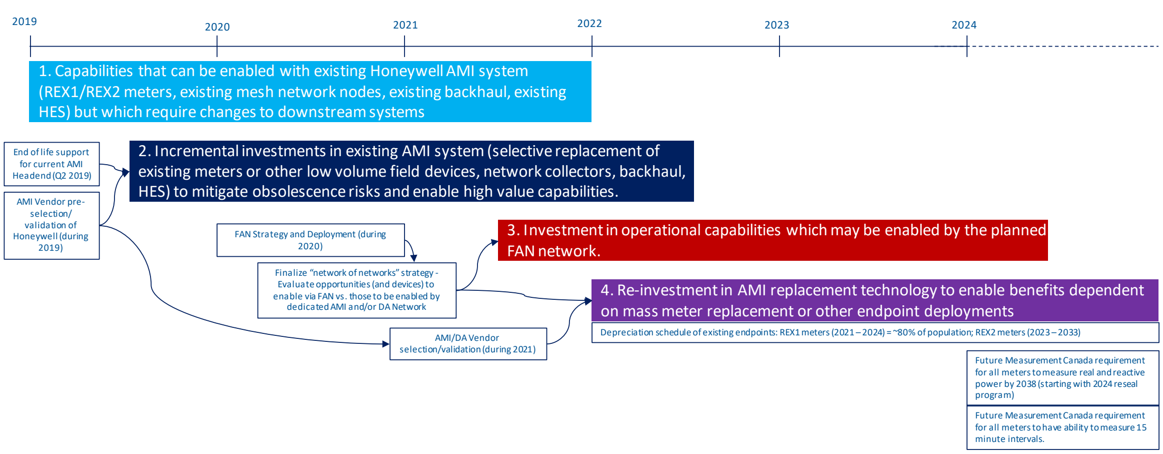


Figure 28 - AMI Strategy Phase sequence and timeline

Each of these phases is further defined below.

Phase 1 – Leverage existing AMI System

Phase 1 - Overview

- **Phase 1 implementation dependencies:**

- Validate selected opportunities included in the business releases. This would include a further prioritization and more detailed justification of the individual use cases, project implementation plans, project approvals and funding, and the assignment of appropriate project management resources
- Implementation of specific recommended capabilities contained in each business release may conflict with other planned upgrades to impacted systems (such as the Billing system upgrades)

■ **To Do during Phase 1:**

As HOL implements the opportunities offered in Phase 1, preparation for Phase 2 will begin. Thus, in preparation for Phase 2, the following activities should be undertaken during Phase 1:

- Develop and issue a Request for Information (RFI), or other suitable instrument, for AMI Technology. The RFI will serve three primary purposes as follows:
  1. To better understand the AMI vendor and technology landscape, the possible alternatives to the Honeywell solutions, and the likely future costs in order to better inform the choices to be made in Phases 2, 3, and 4.
  2. To qualify the likelihood that Honeywell remains the vendor of choice for incremental, near-term investments and, ultimately, for long-term replacement investments:
     - A deeper evaluation of the prudency in making the incremental investments in the existing system that are posed in Phase 2 is in order before embarking on Phase 2 investments. Each selective Phase 2 investment proposed in the existing Honeywell system may end up providing only short-term benefits, given the subsequent Phases 3 & 4 which may lead ultimately to a complete system replacement. Thus, it is prudent to evaluate whether each proposed incremental investment provides the benefits expected to warrant the size of the investment in the Honeywell system as well as the downstream systems.
     - The prudency of the proposed Phase 2 incremental investments may be influenced not only by the cost/benefit evaluation of each opportunity but also, more significantly, by the likelihood that Honeywell may remain the vendor of choice for the long-term Hydro Ottawa AMI solution and the investments contemplated in Phase 3 and 4.
  3. Analysis and Planning for the proposed AMI Head End system upgrade proposed to take place during Phase 2. While this head end upgrade is proposed as a business release during phase 2 (as it is considered an incremental investment in the Honeywell system), the planning activity to enable this upgrade to occur early during Phase 2 should be considered an action item to be completed during Phase 1.

Phase 1 - Business Releases

Phase 1 business releases are focused on expanding upon and enabling the opportunities that can be accomplished using the existing AMI system without incremental investments in the AMI system elements. That said, most of the opportunities will require enhancements or additional functional capabilities to downstream IT/OT systems to enable the further use of the AMI data that HOL already possesses or can retrieve from the existing AMI system.

During this phase, HOL may also want to begin reviewing organizational structures to sustain a multi-year, cross-functional, project oriented organization and governance structure. This could provide relief on operational resources as they will still need to be focused on operational issues and may do so at the detriment of progressing the projects. Additionally, the early development of this organization could transition to a full Program Management Office (PMO) in later Phases if HOL decides to replace or significantly upgrade their AMI system.

The following two graphics summarize the specific business releases recommended for Phase 1 of the AMI Roadmap as well as the IT systems expected to be impacted:

BR1a Billing System Enablement	BR1b Data Analytics Application & Initial Distribution Modeling	BR1c Outage Preventative Maintenance	BR1d Customer Usage Analytics & Enhanced Customer Portal	BR1e Forecasting and rate design improvements
• Summary Billing • EV Charging (Rate, Revenue Metering, Aggregation for potential Market Participation) • Green Pricing Rate	• Data Analytics and Distribution Modeling • Distribution System Planning (Capacity Sizing/Deferment) • Virtual Metering/Aggregation of Load • Load Analysis & Equipment Sizing • Phase Load Balancing • Real & Apparent Loss Allocation • Improved Distribution Modeling & Calibrations	• Improved Maintenance Planning based on Momentary and Blink Outage reporting	• Improved LIHEAP • Improved Billing Exception Handling • EV Charging Details on Portal (HOL/3rd Party) • Improved Conservation through Portal • Improved Account Monitoring (active/inactive) • Improved Low Income Home Energy Assistance Program • Improved Rate Design	• Increased Accuracy/ Reduced Labor for Customer Class Allocation & Cost of Service • Improved Rate Design • Forecasting system improvements using AMI data

Figure 29 - Phase 1 Business Releases

Business Release 1 - Leverage Existing AMI System		
a. Billing System Enablement b. Data Analytics + Distribution Modeling c. Outage Reporting Metrics d. Customer Usage Analytics + Enhanced Customer Portal e. Forecasting + Rate Design	Analytics Billing System MDMS CSR and Customer Portal	Planning & Forecasting OMS Dispatch / MTU GIS

Figure 30 - Phase 1 Systems Impacted

Business Release BR1a – Billing System Enablement

The potential opportunities from AMI that were explored during the benefits discovery sessions described in the "AMI opportunities and potential benefits" section were examined to create the specific business releases. The opportunities that were ranked 3, 4, or 5 (i.e. desirable to HOL) and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
DER	Future	**EV Charging Aggregation and Market participation (HOL separately metered)**	X	X		5	Lo Cost	Targeted meter replacement	Low Effort		3	3.9	Enable consumption and aggregation of private charging infrastructure (Commercial & Residential) to provide for HOL or Third Party market participation.
DER	Partially Achieved	**EV Charging Rate and Revenue Metering for EV Charging Infrastructure**	X	X		5	Lo Cost	Meters installed by customer on EV Chargers	Low Effort	Customer manages charging but HOL monitors M&V impacts	3	3.9	Develop distinct TOU and Demand rates for Commercial & Residential EV Charging Separate revenue metering of private charging infrastructure (Commercial & Residential). Measuring consumption of the EV charger not consumption of individual vehicle.
Billing	Future	**Summary Billing - Increase number of Summary Billing customers**	X	X		4	Lo Cost		Low Effort		3	3.1	Billing reads available for every day to enable summary aggregation for summary accounts on any given day. This will allow more customers to aggregate sites together into summary billing accounts more easily.
Billing	Future	**Summary Billing - Reduction in labor costs associated with Summary Billing**		X		4	Lo Cost		Low Effort		3	3.1	Billing reads available for every day to enable summary aggregation for summary accounts on any given day. Summary bill aggregation from daily reads can be automated in MDMS on an automated report or billing determinant output.
Billing	Future	**Summary / Consolidated Billing - Improve cash flow for existing Summary Billing customers**	X	X		4	Lo Cost		Low Effort		3	3.1	Billing reads available for every day to enable summary aggregation for summary accounts on any given day. This will allow all summary billing accounts effective bill date to be accelerated to the bill cycle for the first read meter.
Regulatory	Future	**Green Pricing Rates**		X		3	Lo Cost	Use existing hourly interval data	Moderate Effort	Develop and implement Green Rate billing	3.5	1.9	Provide green energy rates associated with customers utilizing clean DER such as solar and wind.

Figure 31 – Business Release 1a Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

<table>
<tr><th></th><th>Metering</th><th>Network</th><th>MDMS</th><th>Billing</th><th>CSR & Customer Portals</th><th>Planning & Forecasting</th></tr>
<tr><td>Summary Billing</td><td></td><td></td><td>Aggregate timestamped interval data.</td><td>Aggregate multiple accounts into summary bill</td><td></td><td></td></tr>
<tr><td>EV Charging</td><td>EV charger meter providing timestamped interval consumption data (discrete HOL metering device).</td><td rowspan="2">Timestamped interval data from total consumption and individually metered DER devices.</td><td rowspan="2">Separate DER generation sources from total consumption.

Post daily consumption profile to customer portal.

Post daily consumption profile to CSR portal</td><td rowspan="2">Create distinct DER generation source buckets. Request billing determinants from MDMS. Assign DER credits and total consumption and generate bill. Enable aggregated charged usage billing to third parties and/or market aggregators</td><td rowspan="2">Visibility to Customer bill. Visibility to total customer consumption and DER generation. Visibility to breakdown of bill into billing buckets and DER credits.</td><td>EV aggregation data to be used for Distribution planning & forecasting. PI Historian to store all data for CYME.</td></tr>
<tr><td>Green Pricing Rate</td><td>Total consumption interval data (timestamped) from revenue meters.

Distinct HOL metering device on DER generation sources (solar,</td><td></td></tr>
</table>

	wind, etc.) for Green Rate.					

Figure 32 – Business Release 1a Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

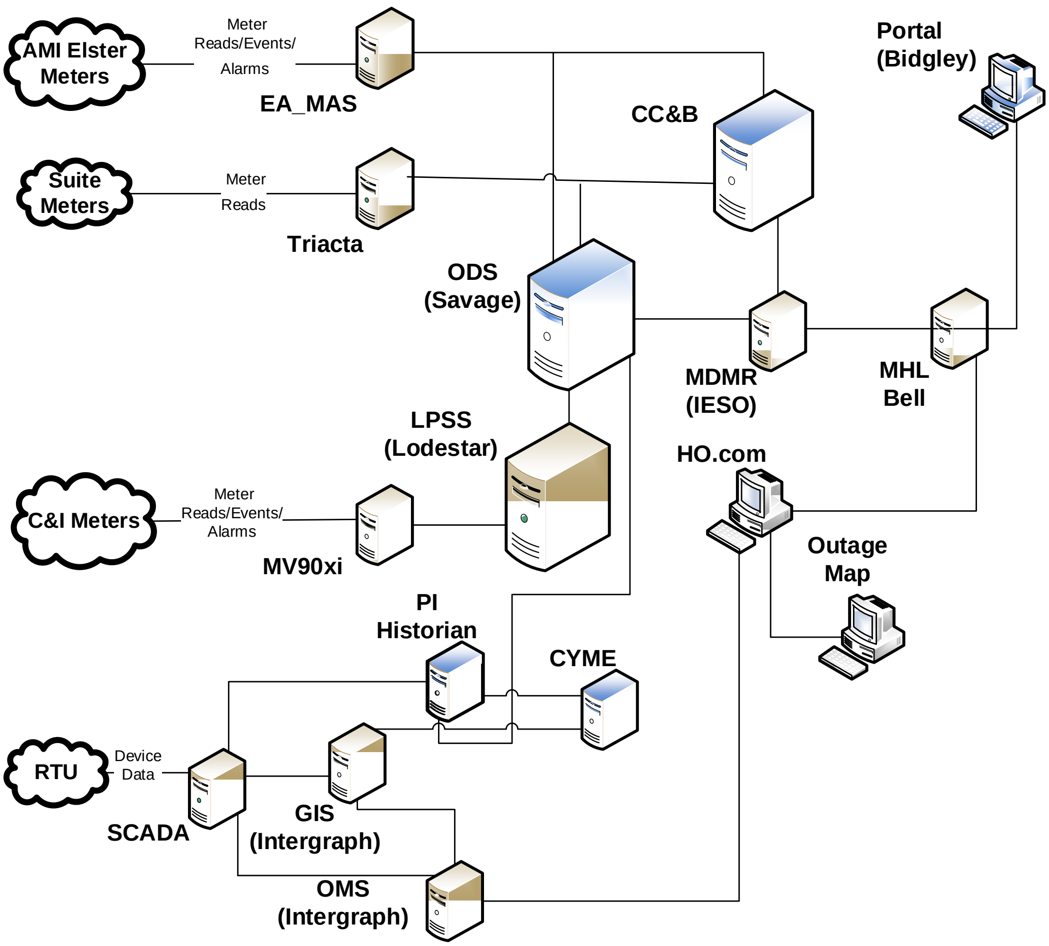


Figure 33 - Business Release 1a System Diagram

Minor Change to Existing Application/Portal

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)

Business Release BR1b – Data Analytics Application & Initial Distribution Modeling

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Distribution Planning	Future	**Defer Distribution system capacity requirements**		X		4	Lo Cost	Use existing hourly interval data	Moderate Effort	Enable distribution modeling using interval data	3.5	2.5	Processing of hourly metering data, provision of hourly data to Distribution Modeling for improved ability to model for max day and max hour demands near real-time. Improved Max Day/Hour Demand models; Drives down system design costs and saves capital.
Distribution Planning	Partially Achieved	**Aggregation of Load at Virtual Nodes for Distribution System Analysis, Transformer / Device Load Analysis and Equipment Sizing**		X		4	Lo Cost	Use existing hourly interval data	Moderate Effort	Enable distribution load aggregation using interval data + Data Analytics	3.5	2.5	Provide interval data and ability to aggregate interval data to distribution device nodes such as transformers to determine if equipment is properly sized.
Distribution Operations	Future	**Improved real and apparent loss allocation**		X		3	Lo Cost	Bellwether meter	Moderate Effort	Virtual metering aggregation + Data Analytics	3.5	1.9	Interval data processing on revenue and district meters; Virtual metering aggregation. Analytics for district and virtual metering losses
Distribution Operations	Future	**Phase Load Balancing**		X		3	Lo Cost		Moderate Effort		3.5	1.9	Interval meter data can be used to determine loads on each phase of the transformer.
Distribution Planning	Partially Achieved	**Improved Distribution Modeling and Calibration**		X		3	Lo Cost	Use existing hourly interval data	Moderate Effort	Enable distribution modeling using interval data	3.5	1.9	Processing of interval data; Improve system modeling for loss and correlation for seasonal loss detection

Figure 34 - Business Release 1b Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

<table>
<tr><th></th><th>Metering</th><th>Network & HES</th><th>MDMS</th><th>Data Analytics</th><th>GIS</th><th>Planning & Forecasting (CYME)</th></tr>
<tr><td>Defer Distribution system capacity requirements</td><td rowspan="2">Timestamped consumption interval data. Time stamp to be accurately aligned to system time to enable time synchronization.</td><td rowspan="2">Retrieve and process timestamped interval data daily.

Export to MDMS</td><td>VEE.
Export interval data sets to Planning & Forecast</td><td></td><td></td><td>Aggregate distribution load flows to discrete distribution devices and capacities. Determine system capacity margins based on rolled up endpoint load flows.</td></tr>
<tr><td>Aggregation of Load at Virtual Nodes for Distribution System Analysis, Transformer /</td><td>Process timestamped Aggregate interval data associated with</td><td>Aggregation of timestamped interval data to a virtual node. Analysis of load and distribution equipment</td><td>Provide distribution device connectivity model and device load</td><td></td></tr>
</table>

Device Load Analysis and Equipment Sizing			identified grid nodes.	specifications to determine if equipment is sized properly.	capacities to analytics tools.	
Improved real and apparent loss allocation			VEE. Provide real and apparent power flows to data analytics.	Analyze consumption data, connectivity model, SCADA data, etc. for loss calculations		
Phase Load Balancing				Analyze totalized interval data of endpoints assigned to each phase to determine out of balance loads	Phase assignment of each endpoint.	
Improved Distribution Modeling and Calibration			VEE. Export interval data sets to Planning & Forecast			Consume and analyze interval data. Provide interval data to planning and forecasting models to improve accuracy and calibration.

Figure 35 - Business Release 1b Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

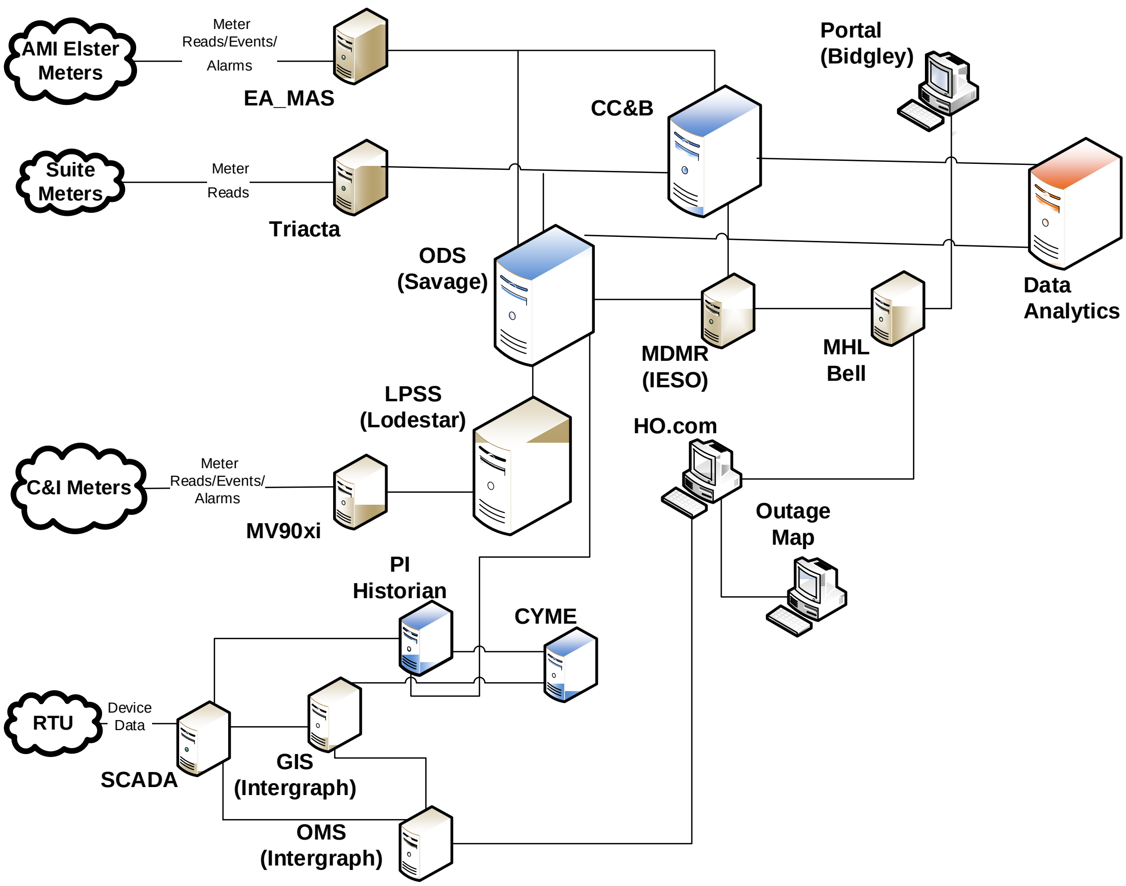
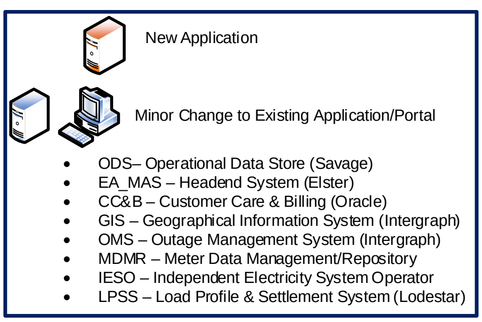


Figure 36 - Business Release 1b System Diagram



Business Release BR1c – Outage Preventative Maintenance

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by “Net Value”):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Distribution Operations	Future	**Outage Management** - Improved Momentary and Blink outages	X	X		5	Lo Cost		Moderate Effort	Analytics + OMS	3.5	3.1	Proactive maintenance to address potential circuit performance problems. An ideal preventative indicator of conditions, which may evolve into a sustained SAIDI outage event - vegetation management secondary, weather head/service drop issues, loose meter socket connections, and recloser/breaker operations. Ability to validate repair after job completion. Can support use of MAIFI indicator.

Figure 37 - Business Release 1c Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Network & HES	MDMS	Data Analytics	DMS/OMS
Outage Management - Improved Momentary and Blink outages	Power Status Event Log (timestamped) - Blink count	Retrieve and process momentary outage event logs daily.	Process outage event log and pass to Data Analytics	Analyze and correlate momentary outage events to circuit connectivity model to identify "trouble" areas for preventative maintenance.	Analyze and correlate momentary outage events to circuit connectivity model to identify "trouble" areas for preventative maintenance.

Figure 38 - Business Release 1c Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

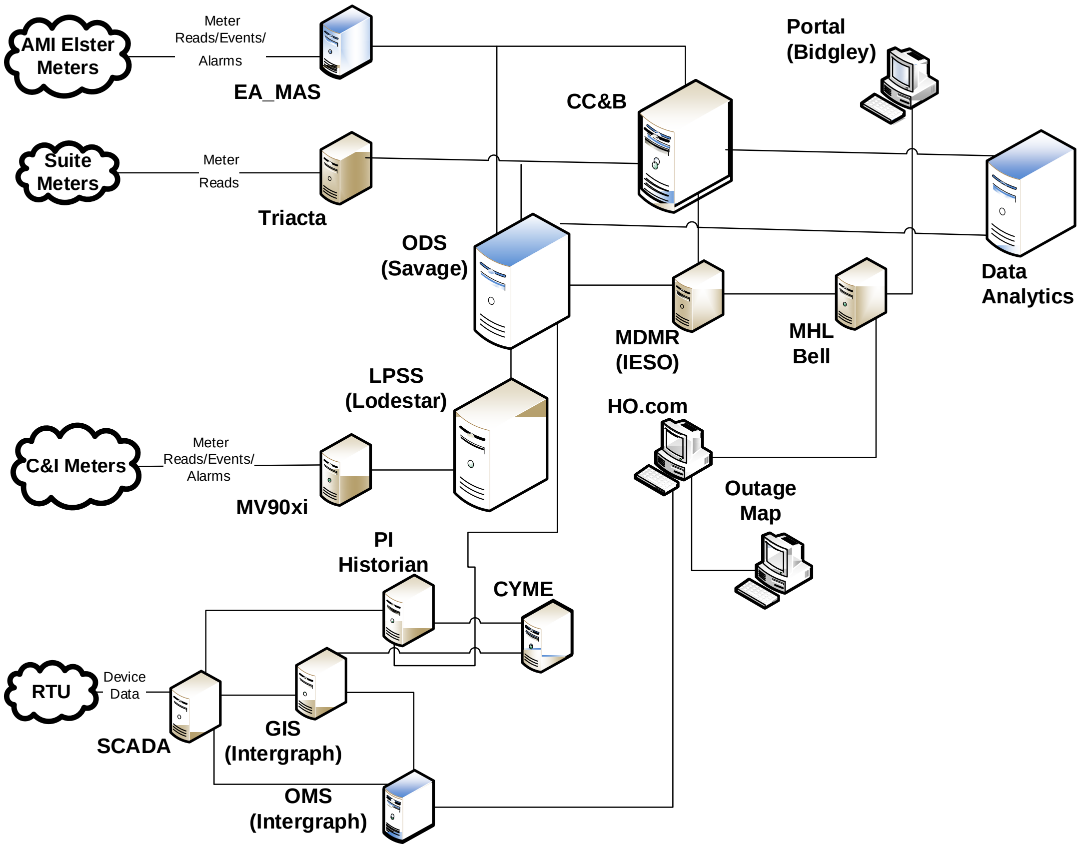


Figure 39 - Business Release 1c System Diagram

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)

Business Release BR1d – Customer Usage Analytics & Enhanced Customer Portal

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by “Net Value”):

Benefit Category	Hydro Ottawa Stakeholder Group	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Credit & Collections	Customer Care	Partially Achieved	**More rapid resolution of accounts in arrears (using field service dispatched service disconnect)** Reduction in labor to manage collections process; Reduction in uncollectables charge offs and short-term interest charges due to aggressive cut-off for non-pay		X	X	5	Lo Cost		Low Effort		3	3.9	Threshold monitoring of consumption; rapid dispatch of cut off field service reduces amount and number of collections issues.
Credit & Collections	Customer Care	Partially Achieved	**Reduced uncollectable charges via customer notification of forecasted bill (e.g., budgeting)**	X	X		4	Lo Cost		Low Effort		3	3.1	Reduced uncollectable charges due to improved customer understanding of usage and control over spending; Forecasted future usage based on historical usage; Threshold monitoring of forecasted consumption against customer identified usage; Customer Portal access/presentation/alerts
Billing	Customer Care	Partially Achieved	**Billing Exceptions (Level 2) - Reduced number and resolution time of billing exceptions/issues**	X	X		5	Lo Cost		Moderate Effort		3.5	3.1	Customer usage profile enablement on customer accessible portal improves customers ability to better understand bill and reduces need to inquire with utility to explain discrepancies. Availability of detailed customer usage profiles for CSR's enables faster and first call resolution of billing questions by CSR's.
Revenue Assurance	Market Engagement	Partially Achieved	**Reduced consumption on inactive accounts (using field disconnect visit)**		X	X	5	Lo Cost	Use existing hourly interval data	Moderate Effort	Analytics + Auto Dispatch	3.5	3.1	Daily monitoring of inactive accounts for "consumption on inactive accounts", data analytics to determine thresholds, field dispatch
DER	Market Engagement	Future	**Customer Portal information for EV Charging (HOL provided)**	X	X		3	Lo Cost	Meters installed by customer on EV Chargers	Low Effort		3	2.3	Provide detailed charging consumption profiles of private charging infrastructure (Commercial & Residential)
DER	Market Engagement	Future	**Enable / Improve Customer Conservation Programs**	X	X		3	Lo Cost		Moderate Effort	Enable bill forecasting engine	3.5	1.9	Customer portal providing consumption pattern, ability to use tools to forecast or check bills based on usage etc. Apps, emails, texts or other communications can be used to set up alerts or provide scheduled reports to customers.
DER	Market Engagement	Future	**Improved Effectiveness of Low Income Home Energy Assistance Program**	X	X		3	Lo Cost		Moderate Effort		3.5	1.9	Processing of meter data to develop hourly usage profile; Forecasting of usage (and bill) against LIHEAP usage caps; Customer profile enablement on customer accessible portal; CSR usage enablement of customer usage profiles

Figure 40 - Business Release 1d Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	MDMS	Data Analytics	Work Management	Billing	CSR & Customer Portal
More rapid resolution of accounts in arrears and reduced consumption on inactive accounts (using field disconnect visit)			Monitor usage and establish thresholds for disconnect of service. Identify accounts exceeding collections limits. Issue report for disconnect.	Dispatch field order to disconnect service. Provide disconnect service order information.	Issue virtual work orders for disconnect - reconnect of service based on exceeding allowable consumption in arrears.	
Reduced uncollectable charges via customer notification of forecasted bill (e.g., budgeting)		Forecast expected daily consumption for remainder of billing period based on historical profile of individual premise usage.				Enable forecasting of total bill (usage + charges) and provide access to CSR and customer
Reduced number and resolution time of billing exceptions/ issues		VEE. Process outage events to validate zero usage intervals as outages and not estimate across them.				Visibility to Customer bill. Visibility to customer consumption profile.

Customer Portal information for EV Charging (HOL provided)	EV charger interval consumption measurement (discrete HOL device).					Visibility to EV consumption profile.
Enable / Improve Customer Conservation Programs. **Improved Effectiveness of Low Income Home Energy Assistance Program**		VEE. Post daily consumption profile to customer portal. Post daily consumption profile to CSR portal				Enable advanced features such as energy load profiling and neighborhood energy comparisons. Enable forecasting of total bill (usage + charges) and present to customer. Forecast likely timing of reaching LIHEAP limits.

Figure 41 - Business Release 1d Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

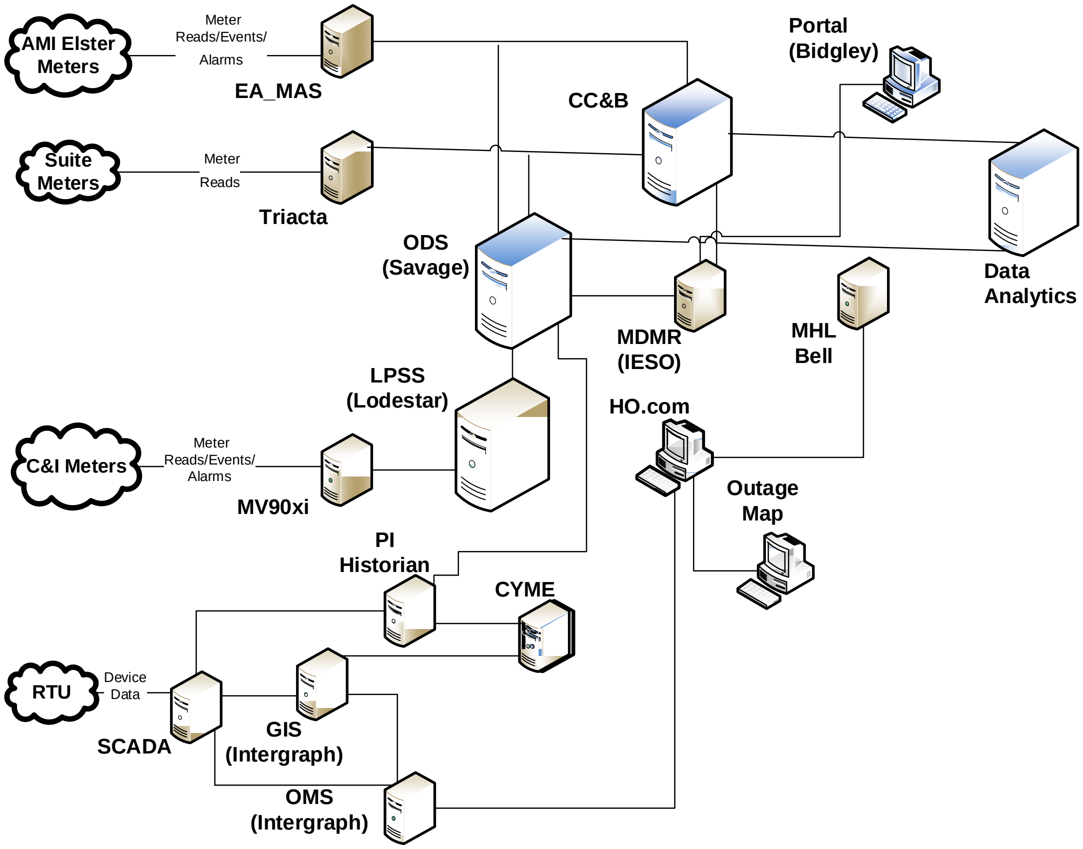


Figure 42 - Business Release 1d System Diagram

Minor Change to Existing Application/Portal

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)

Business Release BR1e – Forecasting and rate design improvements using AMI data

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by “Net Value”):

Benefit Category	Hydro Ottawa Stakeholder Group	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Regulatory	Market Engagement	Partially Achieved	**Improved accuracy in rate design**			X	5	Lo Cost		Low Effort		3	3.9	Processing and storage of hourly consumption data support advanced tariff bill rate design
Regulatory	Market Engagement	Partially Achieved	**Increase accuracy of customer class allocations of cost of service**			X	5	Lo Cost		Low Effort		3	3.9	Processing of Daily/hourly usage profiling; Aggregation into customer class aggregations
Regulatory	Market Engagement	Partially Achieved	**Reduced labor to develop customer class allocations of cost of service**			X	5	Lo Cost		Moderate Effort	Aggregation using Data Analytics	3.5	3.1	Processing of Daily/hourly usage profiling; Aggregation into customer class aggregations
Distribution Planning	Distribution Automation	Future	**Improved Forecasting Capability**		X		5	Med Cost	15 minute interval data (assumes Forecasting is performed at 15 minute granularity)	Significant Effort	Enable nodal pricing and forecasting	4.5	1.9	Future direction from ISO is to move to nodal pricing which will require ability to forecast at a more granular level such as feeder level.

Figure 43 - Business Release 1e Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Network & HES	MDMS	Data Analytics	Planning & Forecasting
Improved accuracy and reduced labor in rate design, customer class allocations, and cost of service			VEE. Post daily consumption profile to Data Analytics	Analyze usage information for rate design opportunities and impacts; customer class and cost of service allocations.	
Improved Forecasting Capability	Timestamped consumption interval data. Time stamp to be accurately aligned to system time to enable time sync.	Retrieve and Process timestamped interval data daily. Export to MDMS	VEE. Export interval data sets to Planning & Forecast		Consume and analyze interval data. Develop forecasting model which applies load flow at nodal level.

Figure 44 - Business Release 1e Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

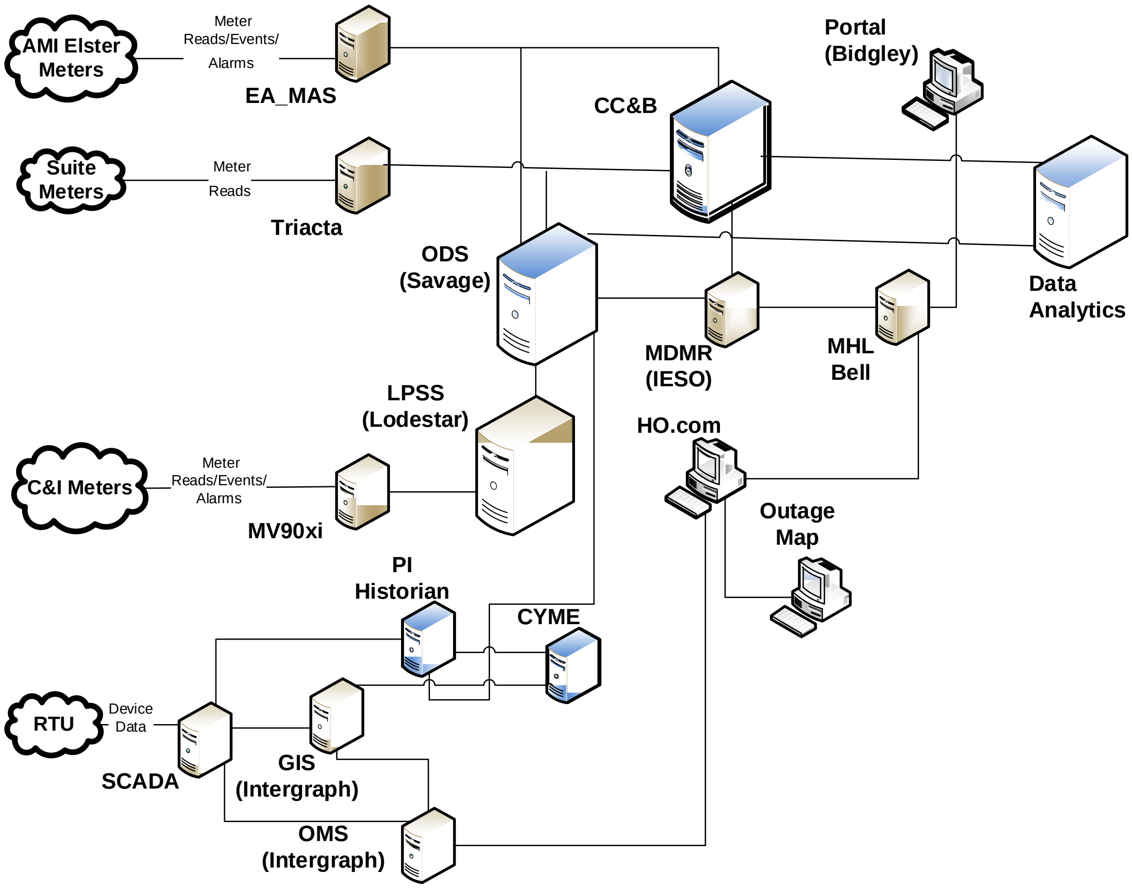
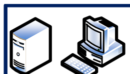


Figure 45 - Business Release 1e System Diagram



- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)

Phase 2 – Incremental investments in Existing AMI

The following AMI Roadmap diagram is replicated here for convenience and to provide context for the activities of Phase 2:

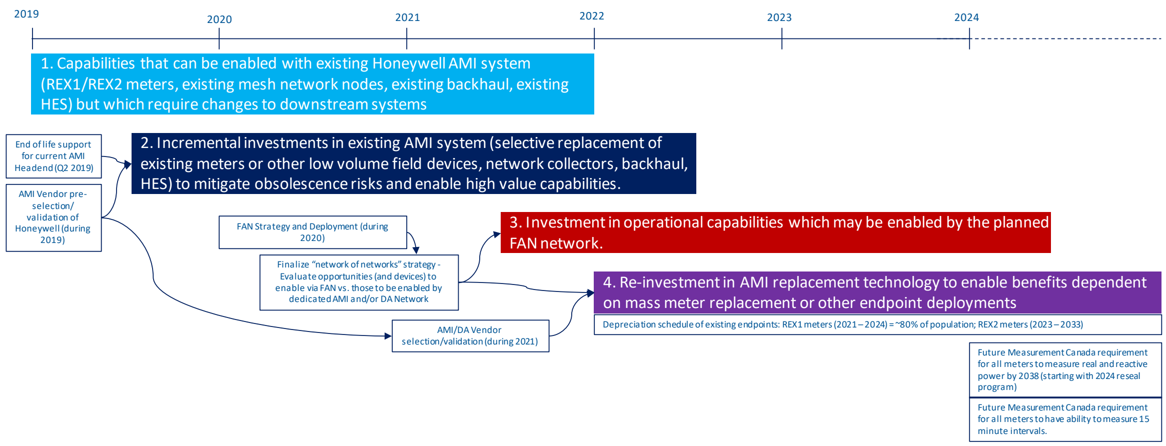


Figure 46 - AMI Roadmap Sequence and Timeline

Phase 2 – Overview

- **Dependencies:**
  - Finalize the strategy for enabling "always on, real-time" backhaul communications as the planned Phase 2 replacement of the shared POTs lines currently used in "one-way" dialup mode for AMI collectors. Specifically, will HOL want to utilize the planned Telecom FAN for this segment of the existing Honeywell AMI solution or simply utilize public carrier services as a bridge to a future HOL owned backhaul network?
    - This is considered a "soft" dependency as HOL can certainly upgrade the existing backhaul, shared service "dial-up" phone lines with dedicated phone lines from traditional telecom service providers.
    - If/when HOL replaces the POTs line then they will need to consider implications to commercial/industrial customers whose lines they currently share (especially those whose shared lines are currently used not just for connection to the AMI collector meter but are also used to connect to MV-90). Upgrading these to cellular nodes may impact:
      - The ability of customers to access their data
      - The ability for HOL to read the A3 meter as it converts from dialup to cellular due to coverage, and the reprogramming of modems in MV-90
  - Completion of AMI RFI and/or validation of the risk of further investments in the Honeywell AMI solution for short-term opportunities. As the recommended opportunities of Phase 2 all involve selective investments in or supporting the Honeywell AMI solution, many of them will be dependent on HOL's determination of the business value of incrementally investing more into this current solution.
- **To Do during Phase 2:**

As HOL implements the chosen opportunities offered in Phase 2, preparation for Phase 3 will begin. Thus, in preparation for Phase 3, the following activities should be undertaken during Phase 2:

1. Finalize and begin implementation of the definitive HOL Telecom FAN Plan. Based on this FAN plan, develop the long-term AMI Technology Plan that is best supported by the finalized FAN Plan is finalized. The AMI Technology plan is dependent on the ability of the FAN to provide supporting AMI functions versus direct AMI functions. The strategies and choices to be reconciled include:
    a. The extent to which the FAN is able to support a full portfolio of commercially available endpoint devices (i.e. meters, DA devices, in-home devices, Smart City devices, etc.). The extent to which the FAN has proven mitigation techniques to reach "hard to reach" endpoints.
    b. The extent to which a "network of networks" strategy provides greater coverage, reachability mitigation options, commercially available endpoints or financial benefits
2. Develop a meter replacement strategy to mitigate the likely production obsolescence of the current REX2 meters. It is expected that meters will start to become fully depreciated and information will become clearer on the planned AMI alternatives and Measurement Canada regulations. Specifically, the following Honeywell operational characteristics will need to be accommodated in an obsolescence mitigation strategy that will need to be determined during Phase 2.
    a. REX1 limits the mode of operation to LAN1 mode. There is no path to migrate REX1 to LAN2 mode or the newer SynergyNet network.
    b. To move to LAN2 mode, all REX1 meters must be replaced on that node (geographic area).
    c. Replacement of A3 Collectors (gatekeepers) with Pole Mounted Collectors will NOT (significantly) improve coverage area, speed, or enable less devices due to operating those collectors in LAN1 mode because of REX1 meters.
    d. Migration to the SynergyNet IPv6 network would require the REXU meter (or A4) and new collector/router as an overlay to the existing network. SynergyNet is not backward compatible for REX1 or REX2 meters.

    Thus, the outcome of the RFI process described in the Phase 2 dependencies will influence the meter replacement strategy and the extent to which HOL wants to progress down the path to ultimately migrate to the full Honeywell SynergyNet solution or simply mitigate the REX2 obsolescence with the REXU meter (but utilized in the LAN2 mode).

Phase 2 - Business Releases

Phase 2 business releases are focused on enabling the opportunities that can be accomplished with incremental investments in the AMI infrastructure. These investments include the following potential selective investments:

- Upgrading the AMI headend
- Replacing the backhaul communications on all collectors to cellular, fiber, or other communication
- Selectively replacing meters with service disconnect equipped meters

The opportunities identified in Phase 2 have the potential to improve field meter operations, enhance outage management processes, provide more analytics to better assess customer and operational issues, and enable additional customer programs.

Organizational considerations during this phase will include evaluation of AMI Operations and how to best support multiple departmental needs for information. Those departments are likely to include Engineering, Distribution Operations, Emergency Response, Dispatch and Marketing / Customer Programs. Each of these departments will be reliant on AMI data and staffing, roles and responsibilities, and service levels may need to be evaluated to balance the needs of the core AMI functionality and the new requirements.

The following two graphics summarize the specific business releases recommended for Phase 2 of the AMI Roadmap as well as the IT systems expected to be impacted:

BR2a Enhanced Operational Processes using Disconnect Switch	BR2b Outage Management Utilizing AMI Data	BR2c Enhanced Data Analytics	BR2d Customer Portal & In-Home Data Devices	BR2e Upgrade AMI headend

• Reduction in Field Trips for Move In/Move Out
• Reduction in Field Trips for Service On/Off
• Reduced accounts in arrears and Consumption on Inactive Accounts
• Improved Employee Safety and Reduction in Injuries/Claims
	• Improved Outage & Reliability Index Reporting
	• Improved System Reliability Planning from Post Outage Analysis
	• Improved Customer Outage Communications
		• Identification of Lost/Orphan Meters
		  • Reduction in Unbilled Usage
		  • Reduced Field Trips to Identify Meters
		• Improved AMI Alert & Exception Management
		  • Improved Operations
		  • Reduction In Loss due to Defective Meters
		  • Faster Detection & Collection of Theft
			• Near Real Time Usage Data for Customer
			  • Enable Conservation
			  • Enable Peak Usage Reduction
			  • Enhance Customer Capability to Follow TOU Schedule & Reduce Bill
			• AMI Enabled Load Control
			• Connected Thermostat/In Home Display
			• Home Energy Management
			• EV Charging Demand Monitoring & Management (HOL Metered & Demand Threshold)
				• Upgrade of existing EnergyAxis head end software to new version to mitigate "end of life support" obsolescence
				• Enable transition to REXU meter to mitigate risk of production obsolescence of current REX2 meters

Figure 47 - Phase 2 Business Releases

Business Release 2 - Incremental Investment in Existing AMI System		
a. Enhanced Operational Processes b. Outage Management using AMI Data c. Enhanced Data Analytics d. Customer Portal + In-Home Data Device e. Upgrade AMI Headend	Analytics Billing System CSR and Customer Portal IVR	AMI Headend OMS Dispatch / MTU GIS

Figure 48 - Phase 2 Systems Impacted

Business Release BR2a – Enhanced Operational Processes using Disconnect Switch

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Meter Operations	Partially Achieved	**Field Employee Safety - reduced technician field trips for shut off for non-pay.**		X		5	Med Cost		Moderate Effort		4	2.5	Remote Connect/Disconnect functionality almost eliminates the need for field visits for disconnection of service or reconnection.
Credit & Collections	Partially Achieved	**More rapid resolution of accounts in arrears (using meter enabled disconnect switch)** Reduction in labor to manage collections process; Reduction in uncollectables charge offs and short-term interest charges due to aggressive cut-off for non-pay		X	X	5	Med Cost	Replacement of POTs backhaul + Targeted deployment of RCD meters	Moderate Effort		4	2.5	Threshold monitoring of consumption; remote disconnect reduces amount and number of collections issues.
Meter Operations	Partially Achieved	**Reduction in Meter Operations field orders for "disconnects / reconnects for non pay" by using remote disconnects / reconnect functionality.**		X		5	Med Cost	Replacement of POTs backhaul + Targeted deployment of RCD meters	Moderate Effort		4	2.5	Remote Connect/Disconnect switch included in meter eliminates the need for field visits for disconnection and reconnection of service due to unpaid balance. If customer notices must be left at premise during disconnect a lower skilled resource could be utilized or process modified to eliminate need.
Revenue Assurance	Partially Achieved	**Reduced consumption on inactive accounts (using service disconnect switch)**		X	X	5	Med Cost	Replacement of POTs backhaul + Targeted deployment of RCD meters	Moderate Effort	Analytics + Auto Dispatch	4	2.5	Daily monitoring of inactive accounts for "consumption on inactive accounts", data analytics to determine thresholds, remote service disconnect
Meter Operations	Future	**Reduction in Meter Operations field orders for "move-in / move-out" by using remote disconnects / reconnect functionality.**	X	X		4	Med Cost	Replacement of POTs backhaul + Targeted deployment of RCD meters	Moderate Effort		4	2.0	Remote Connect/Disconnect switch eliminates the need for field visits for disconnection and reconnection of service due to move ins/ move outs. If customer notices must be left at premise during disconnect a lower skilled resource could be utilized or process modified to eliminate need.
Meter Operations	Partially Achieved	**Reduced injuries & claims**		X		3	Med Cost	Replacement of POTs backhaul + Targeted deployment of RCD meters	Moderate Effort	Analytics	4	1.5	Reduction in meter reading and operations field visits leads to reduction in hazardous exposure.
Environmental	Partially Achieved	**Carbon Offset Value - reduction in vehicle emissions due to reduced field trips**			X	3	Med Cost	Replacement of POTs backhaul + Targeted deployment of RCD meters	Moderate Effort	Data Analytics + Auto Dispatch	4	1.5	Provide remote disconnect / reconnect switches and improved field maintenance analytics to eliminate un-necessary field visits; thereby reducing the carbon footprint and fuel costs.

Figure 49 - Business Release 2a Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

<table>
<tr><th></th><th>Meters</th><th>Network & HES</th><th>Data Analytics</th><th>Work Management</th><th>Billing</th></tr>
<tr><td>Reduction in Meter Operations field orders for "disconnects / reconnects for non-pay" and for "move-in / move-out".</td><td rowspan="2">Service disconnect switch.
Hourly consumption interval data.
Alarms and alerts.</td><td rowspan="2">Process inputs from billing/work order systems prompting disconnect and reconnect commands.
Send commands to meter to disconnect and reconnect service.
Receive and process switch state change verification and provide to billing / work order system.
Maintain switch status information.</td><td rowspan="2">Monitor usage and establish thresholds to indicate un-acceptable consumption on an expected inactive account or accounts which exceed collections limits.
Send report to billing system to issue disconnect command.
.</td><td></td><td rowspan="2">Identify inactive accounts and/or accounts exceeding allowable consumption in arrears to MDMS and data analytics.
Issue disconnect command based on data analytics identifying un-acceptable consumption on expected inactive accounts.</td></tr>
<tr><td>Reduced consumption on inactive accounts.

Rapid resolution of accounts in arrears.
Reduction in labor to manage collections;
Reduction in uncollectables and short-term interest.</td><td></td></tr>
<tr><td>Reduced Field Trips due to improved operational analytics.

Improved Field Employee Safety, Reduced injuries & claims. Reduced Carbon footprint.</td><td></td><td>Issue disconnect and reconnect.
Provide switch status.
Process register data daily.</td><td>Develop meter maintenance algorithms to correlate interval, register, and alarm data with work management systems to improve diagnostics and triage of field work.
Capture avoided field trips</td><td>Automate field work dispatch based on data analytics outputs.
Align correct resource skills to triaged and filtered</td><td></td></tr>
</table>

			and mileage to calculate carbon reduction.	field maintenance work.	

Figure 50 - Business Release 2a Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

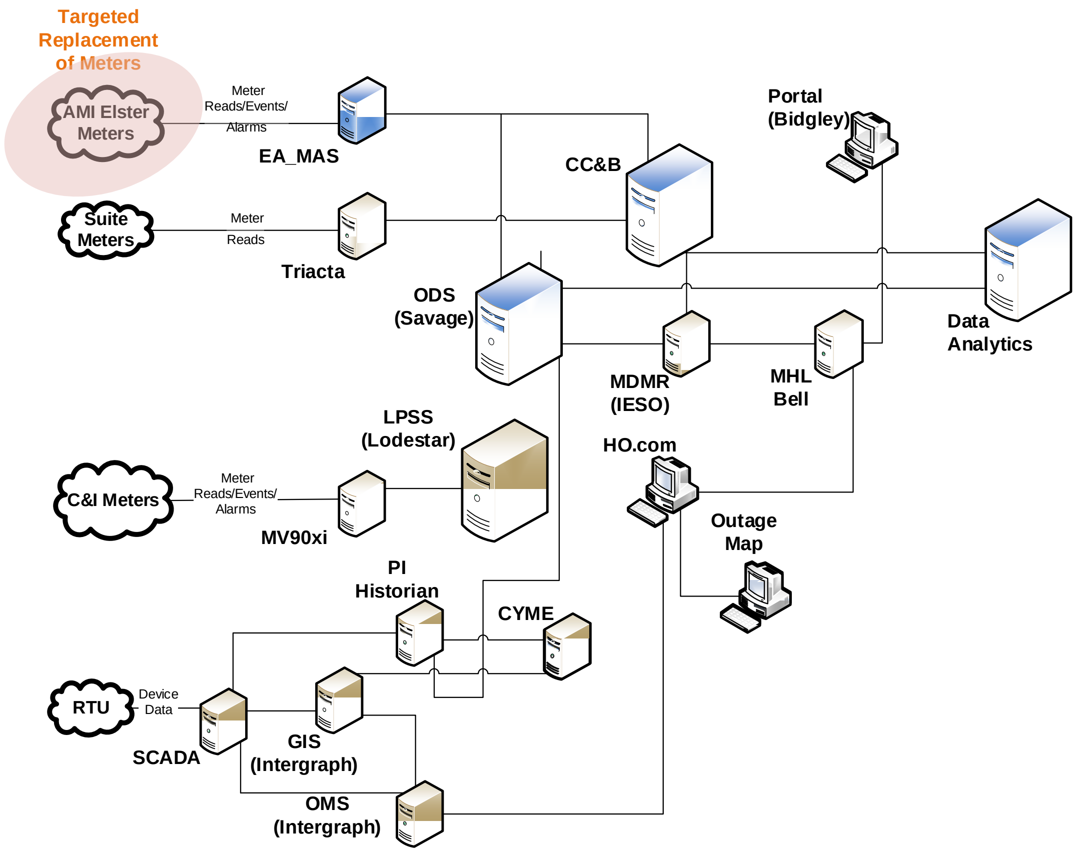
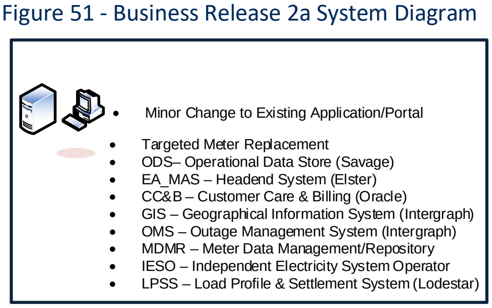


Figure 51 - Business Release 2a System Diagram



Business Release BR2b – Outage Management Utilizing AMI Data

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Distribution Operations	Future	**Outage Management - Reduced Trouble Calls (single lights out)**	X	X		5	Med Cost	Replacement of POTs backhaul	Moderate Effort	OMS system enablement +IVR	4	2.5	Leverage AMI ping power verification capabilities to reduce O&M costs associated with field investigations for these types of outage calls. Provide ability to ping the meter and determine whether there is utility side power to the service prior to dispatch. The customer service tool is to perform the preliminary assessment before opening an outage ticket.
Distribution Operations	Future	**Outage Management - Improved Outage and Reliability Index Reporting and System Reliability Planning through post event analysis.**		X		5	Med Cost	Replacement of POTs backhaul	Moderate Effort	OMS enablement	4	2.5	Improved knowledge of system performance and validation of exact outage durations. Post-event reliability analysis to identify improvements for long range reliability/capacity planning (outage and voltage events). Post-event restoration analysis to identify potential improvements and efficiencies to the restoration plan. Verification of SAIDI/CAIDI calculations. Post-event system reliability analysis data to identify areas in which system reliability can be improved based on actual outage information, and analysis of pre-event conditions.
Distribution Operations	Future	**Outage Management - Improved Customer Communication**	X	X		5	Med Cost	Replacement of POTs backhaul	Significant Effort	OMS system enablement + Customer Portal enablement	4.5	1.9	Proactive communication to customers caused by improved outage event situational awareness. Highly efficient restoration updates with system wide pinging/polling to confirm OMS outage information. Restoration tracking and confirmation: status of individual service restoration by enabling customer service representatives to ping meter.

Figure 52 - Business Release 2b Opportunities

Business Release 2b will require HOL to replace the current dial-up, shared phone lines that are used to connect to the network collectors with dedicated, always on, two-way communications to enable outage alarms and events to be passed to HOL in real time.

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Network & HES	Data Analytics	CSR & Customer Portal	IVR	DMS/ OMS
Reduced Trouble Calls (single lights out)	Power status ping response provided in real-time.	Retrieve power status on-demand in real-time.		Enable pinging power status	Enable "call-back" to customer for reported outage.	Disconnected meters need to be put in exclusion list to remove them from outage list.
Improved Outage and Reliability Index Reporting and System Reliability Planning through post event analysis.	Power Status Alerts (Last Gasp outage alert + Power restoration) timestamped and transmitted in real-time. Power status ping response provided in real-time.	Retrieve and Process power status event logs and provide to OMS.	Use timestamped restoration and power out events to perform post storm analysis to ensure accurate CAIDI / SAIFI and to identify target areas for reliability improvement strategies			OMS - Modify event times based on power status events. Use power status events as inputs into outage modeling.

Improved Customer Communication	Power Status Alerts (Last Gasp outage alert + Power restoration) timestamped and transmitted in real-time. Power status ping response provided in real-time.	Communicate power outage alerts and ping responses in real-time with high reliability. Process outage alerts and ping responses in real-time and send to OMS.		Outage information, status, and ETR updated on customer portal or custom outage portal	Ability to push outage status and ETR messages to customers for outages	Import outage event alerts to improve outage dispatch. Predictive analytics to improve estimated restoration time. Automated ping process to validate power restoration. Disconnected meters need to be put in exclusion list to remove them from outage list.

Figure 53 - Business Release 2b Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

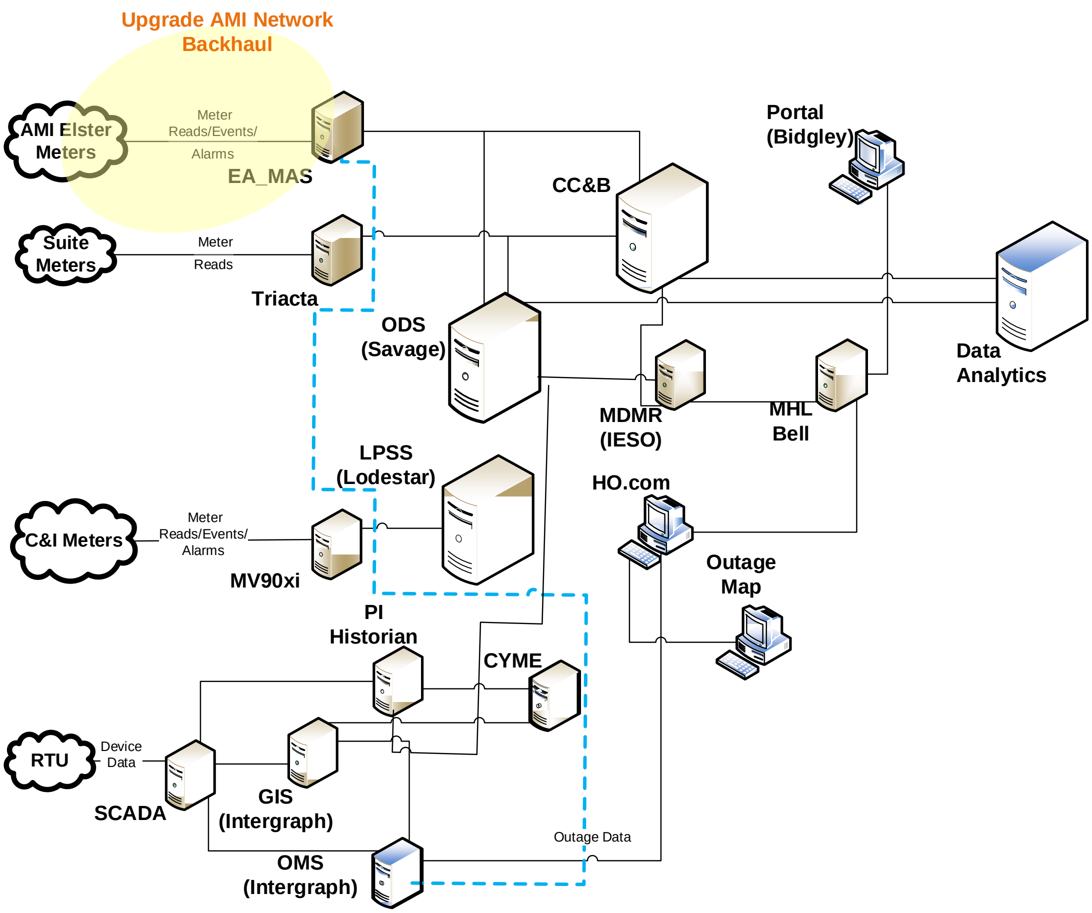


Figure 54 - Business Release 2b System Diagram

- New Interface to Utilize AMI Outage Data
- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)

Business Release BR2c – Enhanced Data Analytics

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Meter Operations	Partially Achieved	**Reduced unaccounted for usage and field labor due to improved identification of lost or orphan (a.k.a. data nodes) meters**	X	X	X	5	**Lo Cost**		**Moderate Effort**		3.5	**3.1**	Identification of orphan accounts through correlation of Billing System and AMI Head end to find active meters with no assigned account. Locate orphans through GPS assignments, RF triangulation, or field searches.
Meter Operations	Partially Achieved	**Improve AMI Alert and Exception Management by back end systems.**		X		4	**Med Cost**	Replacement of POTs backhaul + Time Stamped data + real time alerts	**Significant Effort**	Deploy network upgrades + Analytics + Auto Dispatch	4.5	**1.5**	Provide robust system to perform filtering, data management and analytics to filter, aggregate, analyze and provide advanced alert and exception processing.
Revenue Assurance	Partially Achieved	**Faster detection of and collection of theft**		X	X	3	**Med Cost**	Replacement of POTs backhaul + Time Stamped data + real time alerts	**Significant Effort**	Deploy backhaul upgrades + Analytics + Auto Dispatch	4.5	**1.1**	Processing of tamper alarms plus analytics and correlation of usage profile analysis to identify high probability theft

Figure 55 - Business Release 2c Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Network & HES	MDMS	Data Analytics	GIS	Work Mgnt.
Reduced unaccounted for usage and field labor due to improved identification of lost or orphan meters		Identify all network devices which "hear" the lost or orphaned meter. Network diagnostics to determine mesh communication pathways.		Identify all meters that are transmitting data from the field but which are not assigned to a registered account. Triangulate RF signals to identify location of meters with no accounts assigned	Capture GPS location of endpoint upon field installation and store in GIS.	
Improve Alert and Exception Management by back end systems.	Timestamped consumption interval data. Timestamped meter data (alerts, events, etc.) Time stamp to be accurately aligned to system time to enable time synchronization.	Retrieve timestamped interval data daily. Retrieve timestamped meter data daily and real-time for certain events/alarms. Process timestamped interval data daily. Process timestamped	Process timestamped interval data. Process timestamped meter data	Analyze and correlate usage profiles, alarms and events to determine abnormal meters.		Issue work dispatch for critical events based on indicated priority from Data Analytics. Provide Data Analytics information to support expectation

Faster detection of and collection of theft		meter data daily and real-time for certain events/alarms		Analyze and correlate usage profiles, alarms and events to determine likely tamper events meters. Issue tamper target lists based on likelihood probabilities to work dispatch system.		Issue work dispatch for theft/tamper based on indicated priority from Data Analytics. Provide Data Analytics information to support expectation of tamper/theft.

Figure 56 - Business Release 2c Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

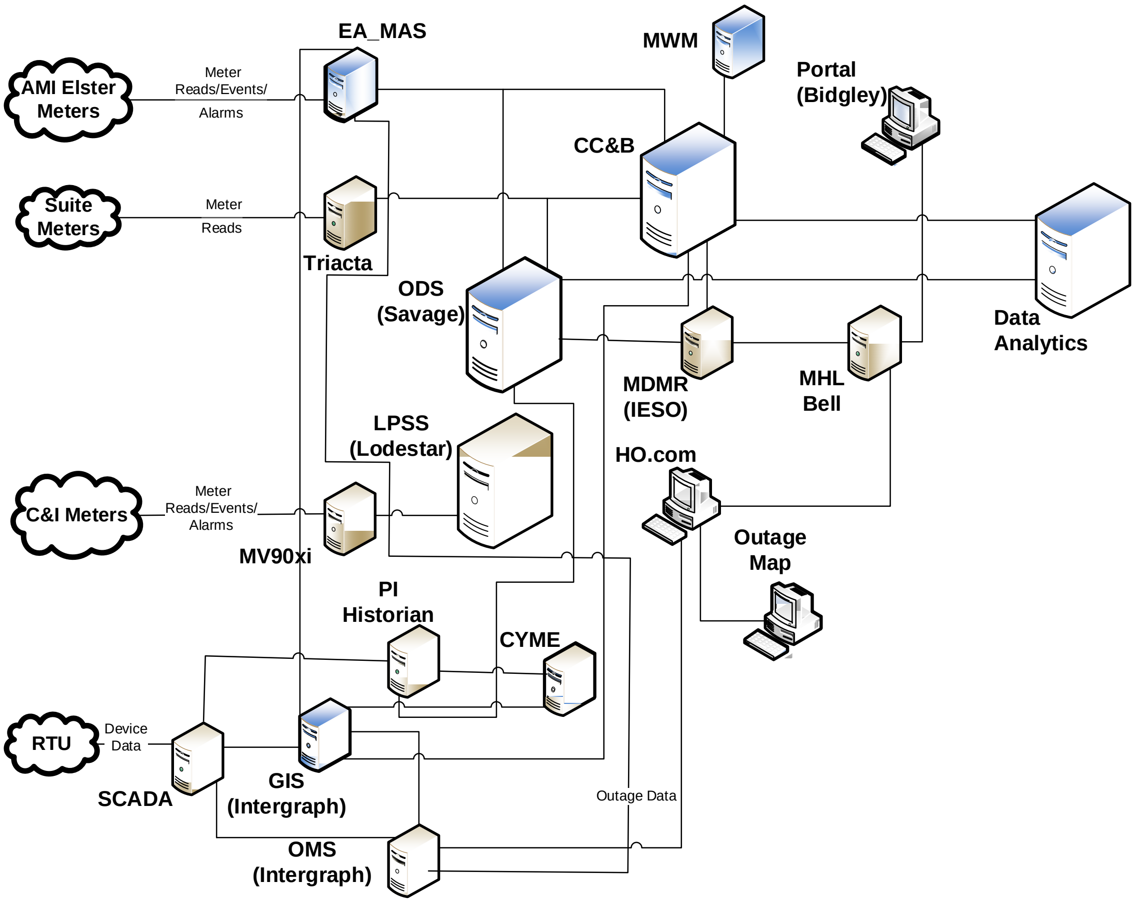


Figure 57 - Business Release 2c System Diagram

Minor Change to Existing Application

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- MWM – Mobile Workforce Management

Business Release BR2d – Customer Portal & In-Home Data Device

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by “Net Value”):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Customer Service	Future	**Enable Residential Customer Direct Access to Meter Usage (near real-time)**	X			5	Med Cost	Targeted meter replacement	Low Effort		3.5	3.1	Provide near real-time consumption data to residential customers to enable enhanced home energy management
DER	Partially Achieved	**Home Energy Management**	X			5	Lo Cost	Customer provided Home Energy Management System + Targeted meter changeout	Significant Effort	Upgrade HES	4	2.3	Home Energy Management system to provide customer managed, in-home energy management. HOL to provide real-time energy consumption to customer owned home energy management system.
DER	Partially Achieved	**Load Control - Utility Enabled (AMI system compatible)**	X	X		5	Med Cost	Load control switches on loads required. Available Q4	Significant Effort	Upgrade HES	4.5	1.9	Utility controlled Demand Response events using AMI enabled load control devices, measurement and verification of load control events.
DER	Partially Achieved	**Connected Thermostat/In-Home Display**	X			5	Med Cost	HOL provided thermostats + Targeted meter changeout (ZigBee)	Significant Effort	Upgrade HES	4.5	1.9	Provide real-time data to display on connected thermostat; Provide setting signals to setback thermostat during DR events.
DER	Future	**EV Charging Demand Monitoring and Management (HOL metered with Demand Thresholds)**	X			5	Hi Cost	Smart Inverter + FAN + Software	Significant Effort	IT intensive	5	1.4	Direct monitoring and management of EV charging infrastructure (Commercial & Residential) to enable individual demand management

Figure 58 - Business Release 2d Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	In Home Devices	Network & HES	HES	Customer Portal
Enable Residential Customer Direct Access to Meter Usage (near real-time) using Smart Thermostat, in home display, or Home Energy Management System	Energy consumption data transmitted via: ZigBee Wi-Fi Other TBD real-time communication channel	Smart Thermostat, In home display, or Home Energy Management System to view real-time energy usage and other information pushed by utility	Retrieve interval data. Push messages and/or event alerts to In-Home device	Process real-time commands, events, and alarms.	Reconcile differences between VEE data and real-time data customer views on portal
Load Control - Utility Enabled (AMI system compatible)	Hourly consumption interval data	Load Control Switches compatible with AMI communications	Retrieve interval data daily. Provide on/off control signals to LCS devices. Retrieve switch status alerts from load control devices.	Process DR commands, events, and alarms. Process interval data to validate DR impacts.	
EV Charging Demand Monitoring and Management (HOL metered with Demand Thresholds)	EV charger real-time KW demand measurement (discrete HOL device) with demand thresholds and real-time threshold alert communications.	Load Control Switches compatible with AMI communications	Retrieve demand threshold alerts in real-time	Process demand threshold alerts in near real-time. Pass demand threshold alert to EV Control System. Enable re-programming of demand threshold alert settings.	

Figure 59 - Business Release 2d Functional Requirements

Note: Identify How Secure Pairing with Meter and Provisioning will be done, it is also Important for In-Home Device Information to be Stored in CC&B and ODS to tie it to the Meter/Account. Security and Provisioning are Important and can be done through EA_MAS or ODS/MDMS

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

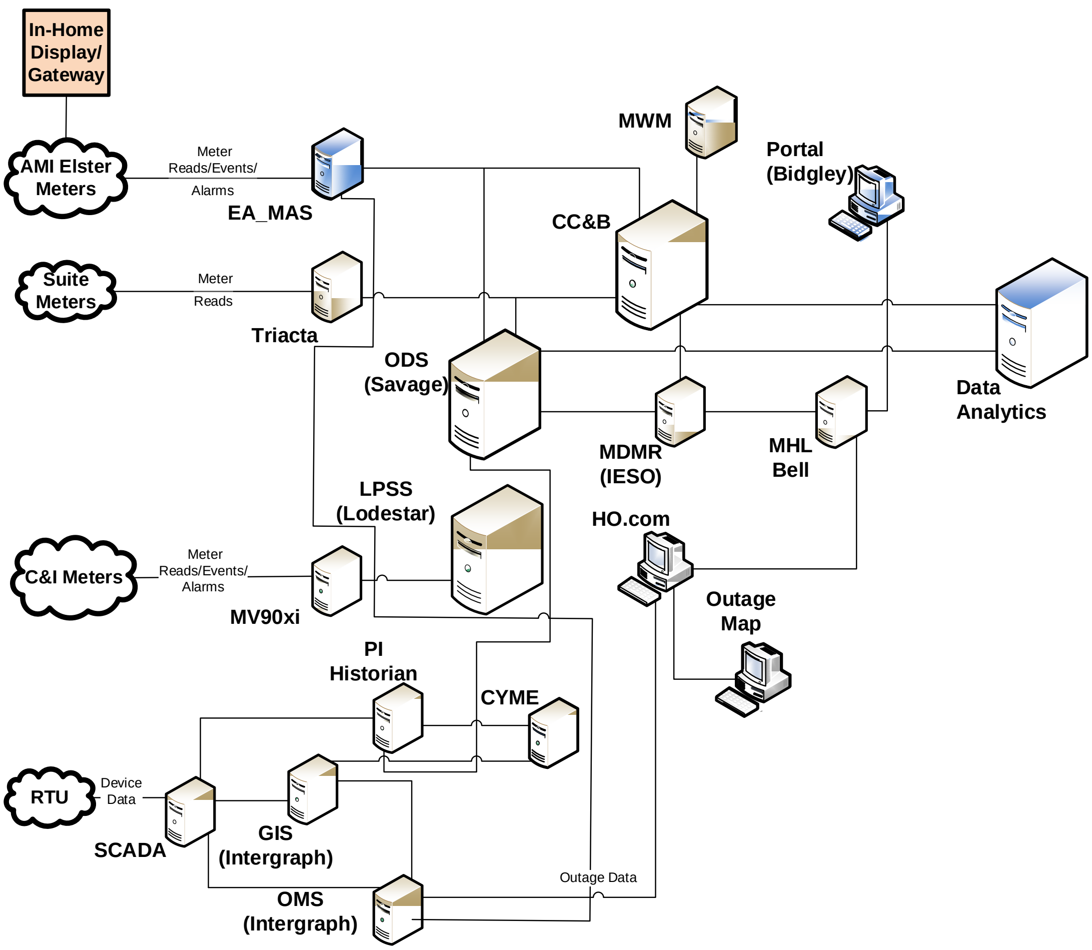


Figure 60 - Business Release 2d System Diagram

New Device/Application

Minor Change to Existing Application

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- MWM – Mobile Workforce Management

Business Release BR2e – Upgrade AMI Head End

As this business release is primarily focused on mitigation of obsolescence and the loss of application support there were no specific opportunities identified as tied to this upgrade.

However, the specific goals of this upgrade to the EnergyAxis Headend application are intended to avoid the risk of obsolescence of the current Honeywell EnergyAxis system elements, including:

- EnergyAxis headend system v9.x – scheduled to be at end of support life in Q2 2019
- REX2 meters – near end of production (no date confirmed yet from Honeywell); replaced by REXU (requires upgraded headend system to enable)

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

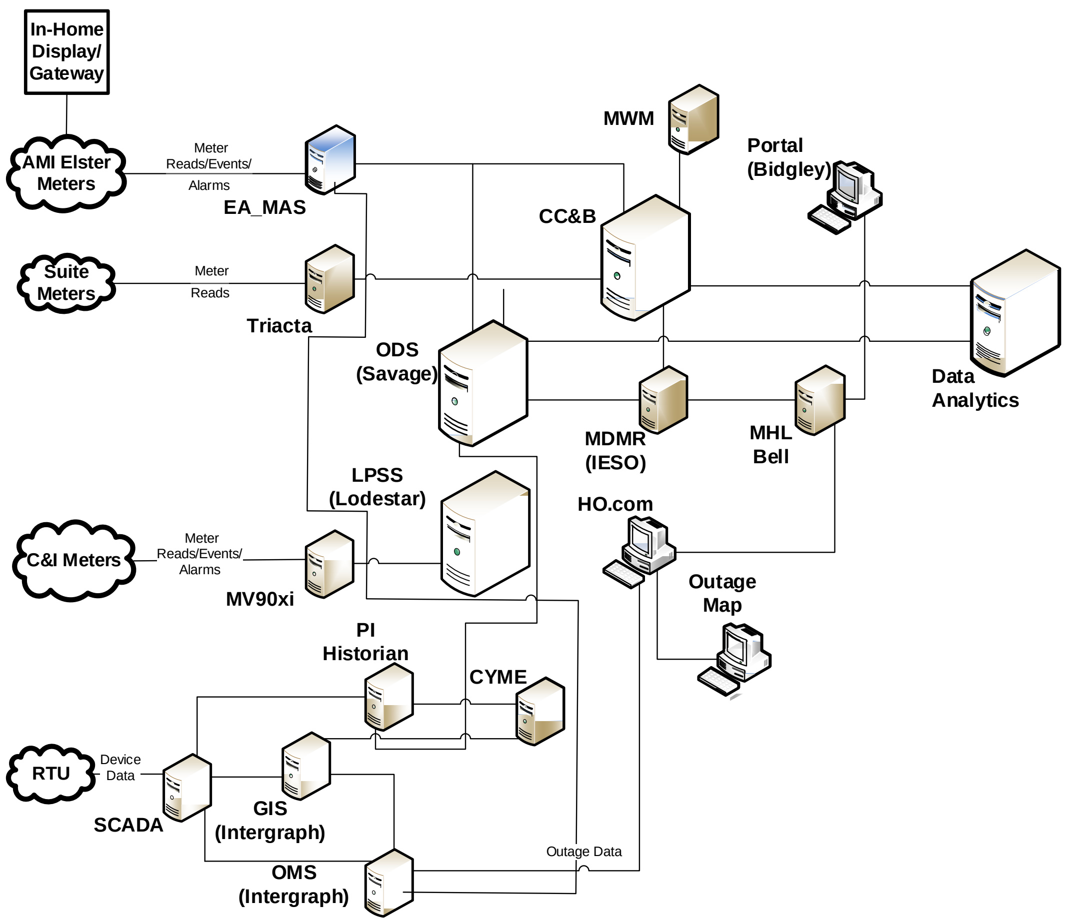


Figure 61 - Business Release 2e System Diagram

New Device/Application

Minor Change to Existing Application

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- MWM – Mobile Workforce Management

Phase 3 – Alternative FAN / Communications Technologies

The following AMI Roadmap diagram is replicated here for convenience and to provide context for the activities of Phase 3:

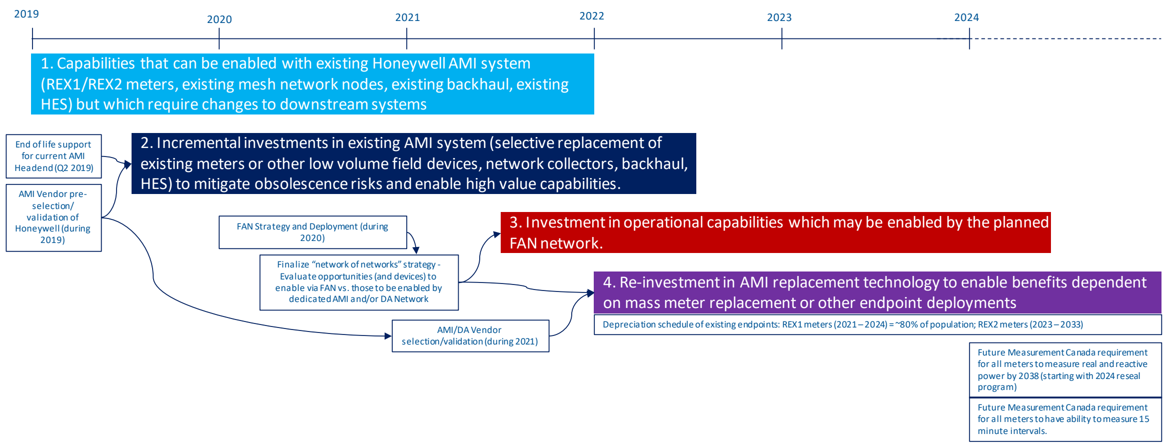


Figure 62 - AMI Strategy Phase Sequence and Timing

Phase 3 - Overview

- **Dependencies:**
  - HOL Telecom FAN plan finalization and implementation
  - AMI RFI results
- **To Do during Phase 3:**

As HOL implements the chosen opportunities offered in Phase 3, preparation for Phase 4 will begin. Thus, in preparation for Phase 4, the following activities should be undertaken during Phase 3:

- Develop and launch AMI RFP to finalize selection of potential AMI replacement solution. This selection will be dependent on the outcome of the RFI process executed during Phase 1 as this will determine whether HOL has already committed to the Honeywell solution as the long term vendor of choice (in which case Phase 4 will focus on migration to the latest Honeywell AMI platform) or whether another solution is contemplated (either another AMI vendor or a private Telecom FAN based solution).

Phase 3 - Business Releases

Phase 3 business releases are focused on enabling smart grid applications such as smart city sensors, distribution automation, volt/var control, EV charging control, distributed energy resource management, demand response and load control. All of these solutions will be dependent on the determination of the network solution. That is, direct leverage of the HOL Telecom FAN as the communications path directly to the endpoint device OR a "network of networks" strategy whereby the HOL Telecom FAN provides the backhaul for a dedicated AMI and/or DA network to connect to endpoints.

The following two graphics summarize the specific business releases recommended for Phase 3 of the AMI Roadmap as well as the IT systems expected to be impacted:

BR3a Initial DERMS System Implementation	BR3b Initial DA/DMS	BR3c Smart City Sensor Integration	BR3d DERMS and DA integration
• EV Charging Capacity Management • On Premise Storage Monitoring and Individual Demand Management (HOL metered with Demand Thresholds) • On premise Storage Monitoring and Individual Demand Management (HOL metered with Processed interval data) *Note: DERMS can be Standalone Application or a Module in DMS*	• Automated Reclosers and/or Switches • Faulted Circuit Indicators (FCI) • FLISR (Fault Location, Isolation and Service Restoration) • Reduction in O&M Costs for Distribution Monitoring Communication Infrastructure • Volt/VAR Management	• Streetlight Automation • Snow Level Monitoring • Traffic Congestion Monitoring • Waste Collection & Bin Level Monitoring • Indoor Air Quality Monitoring (Commercial/Industrial/Municipal) • Noise Level Monitoring • Surface Monitoring for Walkways and Roadways • Surface Temperature • Vibration Monitoring • Wind Speed • Fire / Smoke detection • Outdoor Air Quality Monitoring • Parking Monitoring	• EV Charging Demand Monitoring and Management (HOL Metered with Interval Consumption Thresholds) • On Premise Storage Monitoring and System Capacity Management • Conservation Voltage Reduction (CVR) • Community Based Energy Storage

Figure 63 - Phase 3 Business Releases

Business Release 3 - Alternative FAN / System Communication Technologies		
a. DERMS Implementation b. DA/DMS c. Smart City Sensor Integration d. DERMS and DA Integration	Analytics	DMS DERMS Dispatch / MTU GIS

Figure 64 - Phase 3 Systems Impacted

Business Release BR3a – Initial DERMS System Implementation

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
DER	Future	**On premise Storage Monitoring and individual Demand Management (HOL metered with Demand Thresholds)**	X			5	Hi Cost	Replacement of POTs backhaul + Software	Significant Effort	DERMS implementation and management	5	1.4	Enable dispatch of privately owned energy storage for individual demand management
DER	Future	**On premise Storage Monitoring and individual Demand Management (HOL metered with processed interval data)**	X			5	Hi Cost	Replacement of POTs backhaul + Software	Significant Effort	DERMS implementation and management	5	1.4	Enable dispatch of privately owned energy storage for individual demand management
DER	Future	**EV Charging Capacity Management**		X		5	Hi Cost	Smart Inverter + FAN + Software	Significant Effort	IT intensive	5	1.4	Direct management of EV charging infrastructure (Commercial & Residential) to enable system capacity management. Future requirements will require measuring output of all customer DER rated at 10 kW and greater. Metering does not need to be revenue grade. DER > 50 kW is

Figure 65 - Business Release 3a Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Network & HES	Alternative FAN Network	HES	MDMS	DERMS	DMS/ OMS

On premise Storage Monitoring and individual Demand Management (HOL metered with Demand Thresholds)	Premise metering with real-time KW demand measurement with demand thresholds and real-time threshold alert communications.	Retrieve demand threshold alerts in real-time	Storage Control system to enable dispatch of storage energy based on Demand Threshold alert and HOL signal.	Process demand threshold alerts in near real-time. Enable re-programming of demand threshold alert settings.		Dispatch DM signals to storage devices. Verify reduced demand based on demand threshold.	
On premise Storage Monitoring and individual Demand Management (HOL metered with processed interval data)	Premise metering with interval consumption measurement and real-time interval data communications.	Retrieve interval data near real-time	Storage Control system to enable dispatch of storage energy based on Calculated Demand Threshold alert and HOL signal.	Process interval data near real-time. Pass to MDMS in real time.	Process interval data near real-time. Calculate demand in near real-time. Calculate demand threshold alerts in near real-time. Pass demand threshold alerts to Energy Storage Control System.	Dispatch DM signals to storage devices. Verify reduced demand based on calculated demand.	
EV Charging Capacity Management			EV Control system to enable discontinuance of charging based on HOL capacity situation and DM signal.			Dispatch nodal DM signals to EV chargers. Verify reduced Nodal demand.	Identify HOL system capacity event and dispatch nodal DM signals to DERMS.

Figure 66 - Business Release 3a Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

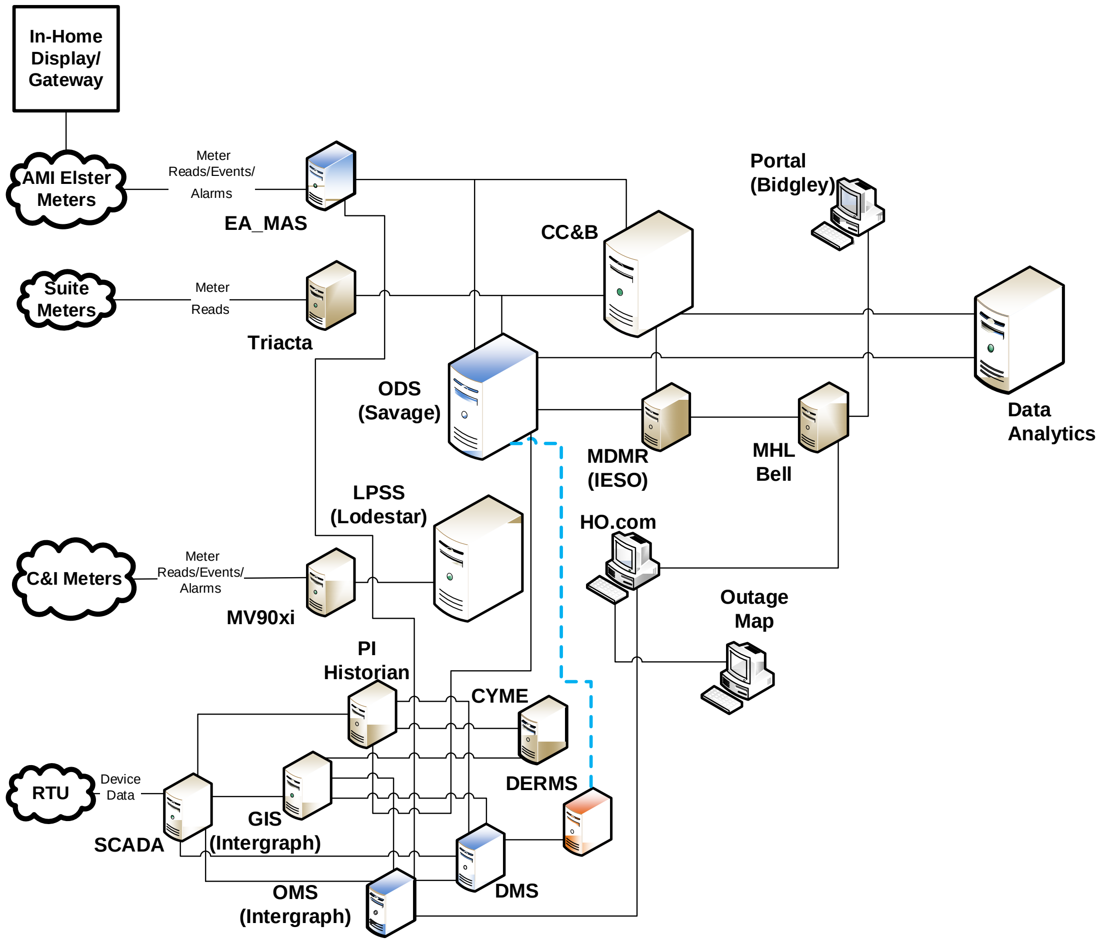


Figure 67 - Business Release 3a System Diagram

New System/Application
New Interface for DERMS - Tentative

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation

Business Release BR3b – Initial DA/DMS

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Distribution Operations	Partially Achieved	**FLISR**		X		4	Hi Cost	DA Comms module + DA FAN	Significant Effort	DA FAN deployment + DA HES + DMS	5	1.1	Enable Fault Isolation and Restoration with and without operator intervention. Distribution system can automatically Isolate faults and restore power. Deployment of Auto Restore and Auto-Generated switching order, on key portions of the distribution system.
Distribution Operations	Partially Achieved	**Automated Reclosers and/or switches**		X		4	Hi Cost	DA Comms module + DA FAN	Significant Effort	DA FAN deployment + DA HES + DMS	5	1.1	Deploy AMI/DA communications to automated reclosers to improve grid understanding and improve switch controls.
Distribution Operations	Partially Achieved	**Faulted Circuit Indicators**		X		4	Hi Cost	DA Comms module + DA FAN	Significant Effort	DA FAN deployment + DA HES + DMS	5	1.1	Fault circuit indicators with communication capability to interface with AMI network
Distribution Planning	Future	**Volt/VAR Management**		X		4	Hi Cost	Replacement of POTs backhaul + Bellwether meter + DA Network + Voltage Regulator and/or Cap Bank controller modules	Significant Effort	DA Network deployment + Enable proactive VVO in DMS	5	1.1	Monitor voltages at bellwether and "end of line" meters to provide real-time feedback as inputs to VVO management.

Figure 68 - Business Release 3b Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	DA Devices	AMI Network	DA Network	AMI HES	DA HES	Work Mgnt.	DMS/ OMS
FLISR **Automated Reclosers and/or switches** **Faulted Circuit Indicators**		DA devices (FCI's, reclosers, switches) compatible with DA communications		Communicate real-time with DA devices		Process real-time commands, events, and alarms. Monitor/Assure continuous comms. connectivity	Dispatch crews with information on executed FLISR scheme and required work. Dispatch crews with information on executed FLISR scheme and required work.	Consume real-time DA device information from DA headend. Process for identification of Fault Location. Identify isolation strategy. Send commands to DA Headend to execute isolation switch scheme. Identify optimized restoration strategy. Send commands to DA Headend to execute restoration switching scheme. Identify required field work required &

								send to dispatch.
Volt/VAR Mgnt.	Voltage data - instantaneous and historical profile. Voltage threshold alerts.	Voltage regulators and/or Capacitor Control devices compatible with DA communications	Retrieve timestamped voltage profiles daily and real-time voltage at set intervals and on-demand.		Process timestamped voltage profiles daily and real-time voltage at set intervals and on-demand. Send voltage data to DMS.	Send commands to voltage regulators and/or Capacitor controls to adjust voltage or VAR levels.		Consume real-time voltage data from AMI headend. Provide Volt and/or VAR correction commands to DA Head End to adjust voltage or Cap settings on specific feeders.

Figure 69 - Business Release 3b Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

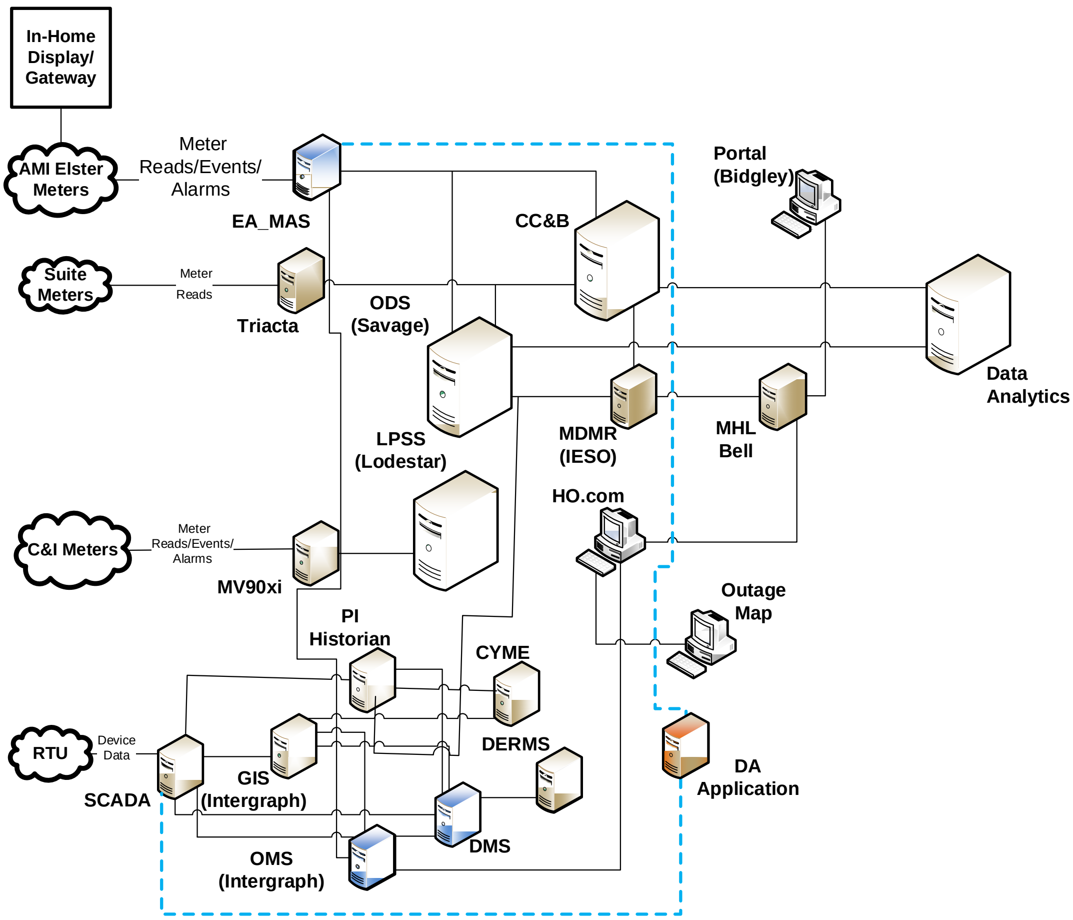


Figure 70 - Business Release 3b System Diagram

New System/Application
New Interface for DA - Tentative
- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- CVR – Conservation Voltage Reduction

Business Release BR3c – Smart City Sensor Integration

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by “Net Value”):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Smart City	Partially Achieved	**Streetlight Automation**		X	X	5	Med Cost	Streetlight sensors/ controllers + Network upgrade	Significant Effort	Field deployment of devices + Streetlight controls software module	4.5	1.9	Communication modules on streetlight controls compatible with AMI system are used for streetlight control. Vendors may offer advanced capability which can be used for security/warning or conservation purposes.
Smart City	Future	**Snow Level Monitoring**			X	4	Hi Cost	Sensors + Network upgrade	Significant Effort	Field deployment of devices + Software integration	5	1.1	Snow level detection of specific locations to enable optimized snow removal planning and dispatch.
Smart City	Future	**Traffic Congestion Monitoring**			X	4	Hi Cost	Sensors + Network upgrade	Significant Effort	Field deployment of devices + Software integration	5	1.1	Traffic monitoring for congestion relief and for long term traffic planning.
Smart City	Future	**Waste Collection & Bin Level Monitoring**			X	4	Hi Cost	Sensors + Network upgrade	Significant Effort	Field deployment of devices + Software integration	5	1.1	Monitoring of waste container levels to optimize waste collection cycles and routes.
Smart City	Partially Achieved	**Indoor Air Quality Monitoring (Commercial/Industrial/Municipal)**			X	4	Hi Cost	Sensors + Network upgrade	Significant Effort	Field deployment of devices + Software integration	5	1.1	Monitoring Air Quality Sensors for specific customers to alert air quality issues and/or provide long term air quality trends as service to customers.
Smart City	Future	**Noise Level Monitoring**			X	4	Hi Cost	Sensors + Network upgrade	Significant Effort	Field deployment of devices + Software integration	5	1.1	Neighborhood disturbance monitoring.
Smart City	Future	**Wind Speed**			X	3	Hi Cost	Sensors + Network upgrade	Significant Effort	Field deployment of devices + Software integration	5	0.8	Wind speed to determine potential hazardous conditions
Smart City	Future	**Fire / Smoke detection**			X	3	Hi Cost	Sensors + Network upgrade	Significant Effort	Field deployment of devices + Software integration	5	0.8	Community fire/smoke detection to provide rapid response.
Smart City	Future	**Outdoor Air Quality Monitoring**			X	3	Hi Cost	Sensors + Network upgrade	Significant Effort	Field deployment of devices + Software integration	5	0.8	Monitoring Air Quality Sensors to alert air quality issues and/or provide long term air quality trends without cost of field visits.
Smart City	Future	**Parking monitoring**			X	3	Hi Cost	Sensors + Network upgrade	Significant Effort	Field deployment of devices + Software integration	5	0.8	Monitor Parking lot flows to identify full/empty lots
Smart City	Future	**Surface Monitoring for Walkways and Roadways**			X	3	Hi Cost	Sensors + Network upgrade	Significant Effort	Field deployment of devices + Software integration	5	0.8	Monitoring road conditions for hazardous conditions (snow, ice, flooding) and congestion using a combination of various sensor devices.
Smart City	Future	**Surface Temperature**			X	3	Hi Cost	Sensors + Network upgrade	Significant Effort	Field deployment of devices + Software integration	5	0.8	Measurement of surface temperature for various applications.
Smart City	Future	**Vibration Monitoring**			X	3	Hi Cost	Sensors + Network upgrade	Significant Effort	Field deployment of devices + Software integration	5	0.8	Monitor street, building, earthquake vibrations and alert via AMI network

Figure 71 - Business Release 3c Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Smart City Sensors	AMI Network & HES	AMI HES
Streetlight Automation	Streetlight sensors compatible with AMI communications	Communicate streetlights controls and consumption / timing metrics.	Streetlight monitoring / control system integrated with AMI communications
Smart City Sensors • Wind Speed • Fire / Smoke detection • Outdoor Air Quality Monitoring • Snow Level Monitoring • Traffic Congestion Monitoring	Sensor directly compatible with AMI network OR Gateway device compatible with sensor providing event or analog data near real-time or event based	Sensors integrated with AMI network	Receive and process analog or event data from Sensors or gateway module in real-time. Pass to Smart City system or other designated system of action.

• Waste Collection & Bin Level Monitoring • Indoor Air Quality Monitoring (Commercial/Industrial/Municipal) • Noise Level Monitoring • Surface Monitoring for Walkways and Roadways • Surface Temperature • Vibration Monitoring			
Parking monitoring	Parking slot or entry/exit Sensor data near real-time.	Pass count data from Sensors or gateway module in real-time.	Receive and process count data from Sensors or gateway module in real-time. Pass to Smart City system or other designated system of action.

Figure 72 - Business Release 3c Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

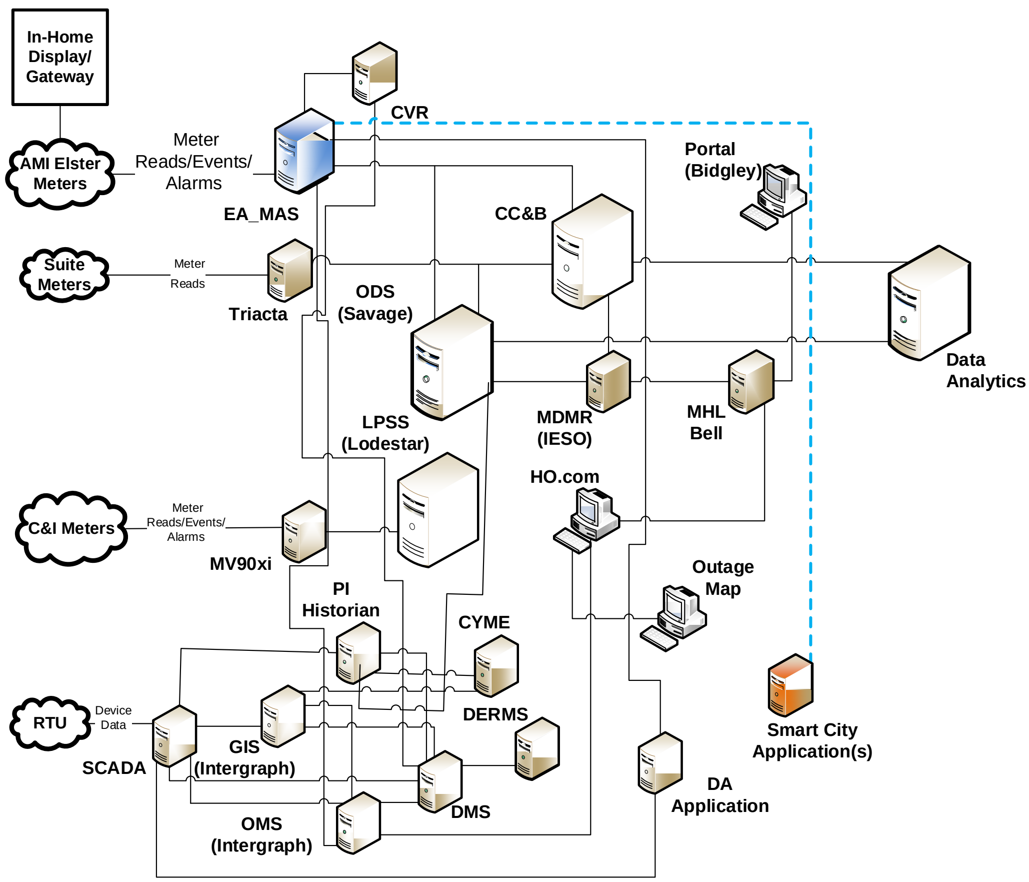


Figure 73 - Business Release 3c System Diagram

- New System/Application
- New Interface for Smart City Applications - Tentative
- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- CVR – Conservation Voltage Reduction

Business Release BR3d – DERMS and DA integration

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by “Net Value”):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
DER	Future	**On premise Storage Monitoring and System Capacity Management**		X		5	Hi Cost	Smart Inverter + FAN + Software	Significant Effort	IT intensive	5	1.4	Enable dispatch of privately owned energy storage for system capacity management. Future requirements will require measuring output of all customer DER rated at 10 kW and greater. Metering does not need to be revenue grade. DER > 50 kW is expected to be monitored with SCADA in the future. Additionally system planning requires greater knowledge of DER and Energy Storage devices on system to properly size equipment. Dependencies on having a DMS.
DER	Future	**Conservation Voltage Reduction (CVR)**		X		4	Hi Cost	Replacement of POTs backhaul + Bellwether meters + Software	Significant Effort	DERMS implementation and management	5	1.1	Monitor voltages at meters to provide feedback loop for management of CVR. Use of interval consumption data can validate energy conservation. Benefit is reduced energy consumption. Proactively adjust voltage through controls to cap banks, voltage regulator, or voltage control devices.
DER	Future	**EV Charging Demand Monitoring and Management (HOL metered with Interval Consumption Thresholds)**	X			5	Hi Cost		Significant Effort		5	1.4	Direct monitoring and management of EV charging infrastructure (Commercial & Residential) to enable individual demand management
DER	Future	**Community based energy storage**		X		4	Hi Cost		Significant Effort		5	1.1	Deploy storage to enable improved reliability in capacity constrained locations

Figure 74 - Business Release 3d Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	DA Devices	AMI Network	Alternate FAN Network	AMI HES	DA HES	DERMS	DMS/ OMS
On premise and/or Community based energy storage **Monitoring and System Capacity Mgnt.**	Bi-directional energy storage measurement (discrete HOL device).		Retrieve interval data near real-time	Storage Control system to enable charging and dispatch of storage energy based on HOL capacity situation and DM signal.	Process interval data near real-time.		Dispatch nodal DM signals to storage devices. Verify reduced Nodal demand based on processed interval data.	Identify HOL system capacity event and dispatch nodal DM signals to DERMS.
EV Charging Demand Monitoring and Mgnt. (HOL metered)	EV charger interval consumption measurement (discrete HOL device) and real-time interval data communications.		Retrieve interval data near real-time	EV Control system to enable discontinuance of charging based on Demand Threshold alert / HOL signal.	Process interval data near real-time. Calculate demand in near real-time. Calculate demand threshold alerts in near real-time. Pass demand threshold alerts to EV Control System. Enable re-programming of demand			

					threshold alert settings.			
Conservation Voltage Reduction (CVR)	Voltage data - instantaneous and historical profile. Voltage threshold alerts.	Voltage regulators and/or Capacitor Control devices compatible with DA communications	Retrieve timestamped voltage profiles daily and real-time voltage at set intervals and on-demand.		Process timestamped voltage profiles daily and real-time voltage at set intervals and on-demand. Send voltage data to DMS.	Send commands to voltage regulators and/or Capacitor controls to adjust voltage levels.	Consume real-time voltage data from AMI headend. Provide voltage reduction commands to DA Head End to adjust voltage levels on specific feeders.	Consume real-time voltage data from AMI headend. Provide voltage reduction commands to DA Head End to adjust voltage levels on specific feeders.

Figure 75 - Business Release 3d Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

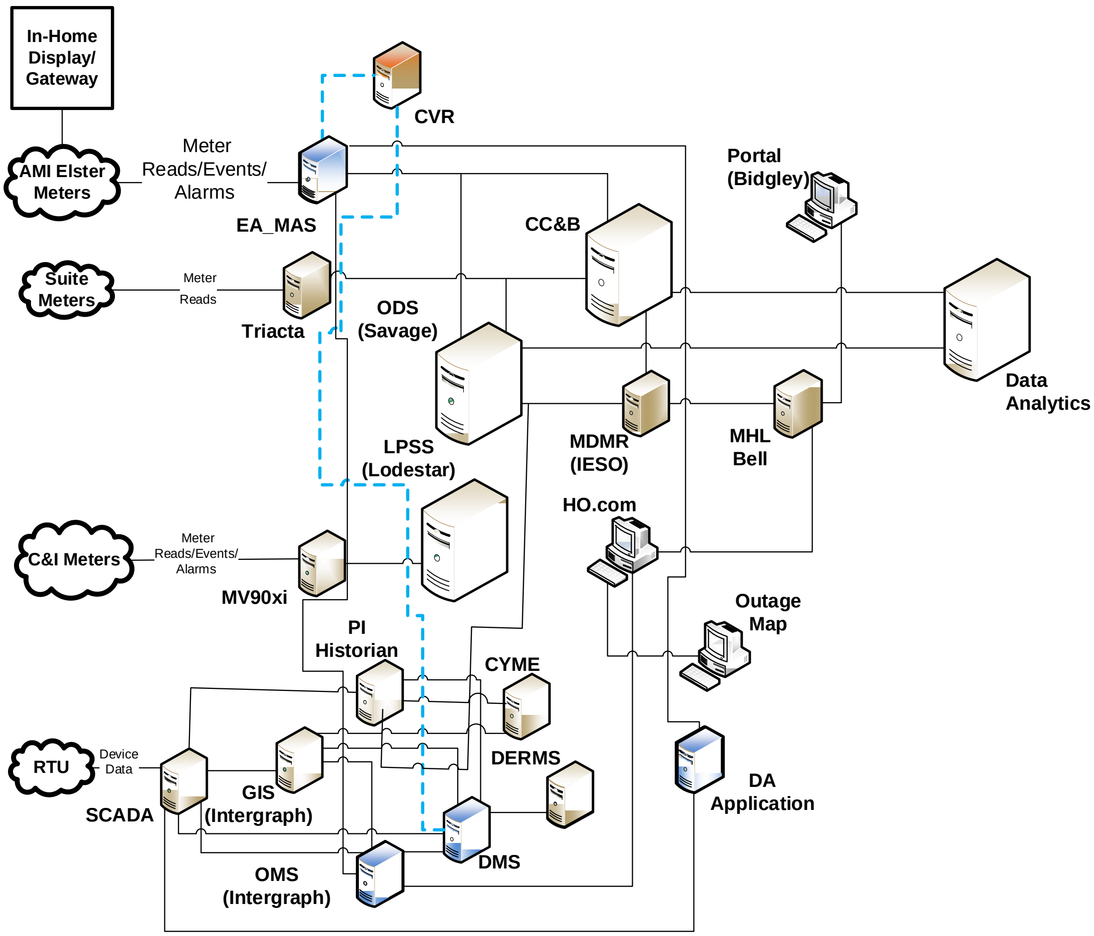


Figure 76 - Business Release 3d System Diagram

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- CVR – Conservation Voltage Reduction

Phase 4 – Replacement AMI Solution

The following AMI Roadmap diagram is replicated here for convenience and to provide context for the activities of Phase 3:

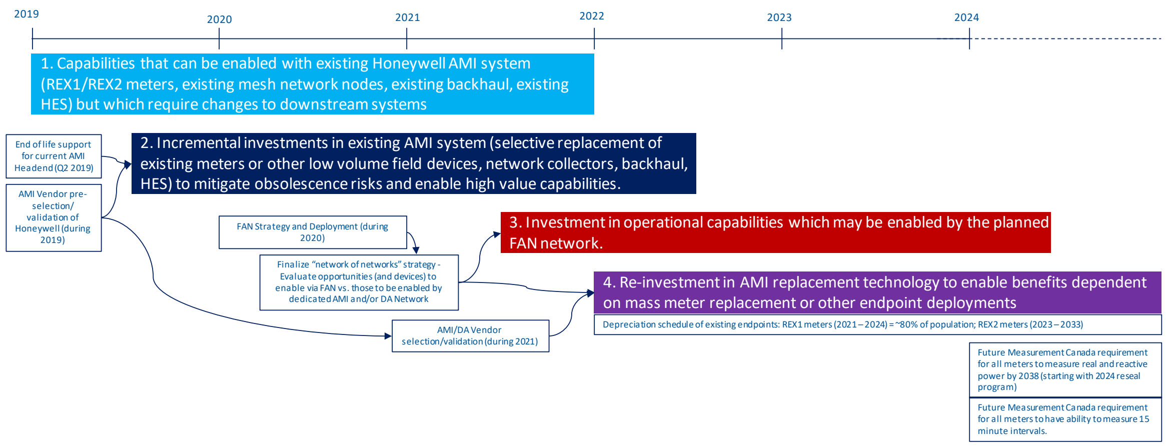


Figure 77 - AMI Strategy Phase Sequence and Timing

Phase 4 - Overview

- **Dependencies:**
  - Telecom FAN Plan final strategy and implementation
  - RFP for AMI technology vendors and validation of next generation AMI system to be employed
  - Outcome of Measurement Canada new meter regulations
  - Depreciation schedule of endpoints vs. book value of endpoints vs. seal period of endpoints
- **To Do during Phase 4:**

As HOL implements the chosen opportunities offered in Phase 4, the following activities are recommended to support the completion of the final phase of the AMI Roadmap:

- Establish Program Management Office (PMO) and governance structure for potential large scale AMI system and endpoint rollout
- Determine system and endpoint rollout strategy. This will be dependent on the following choices:
  - Whether the Telecom FAN will serve as the AMI network, all the way to the endpoints
  - If HOL chooses to follow a “network of networks” approach, the selection of the AMI solution to be employed (i.e. migration to the Honeywell SynergyNet solution or replacement of the existing network with a different AMI vendor provided solution)
  - Endpoint deployment strategy and duration to optimize benefit achievement and meter depreciation versus program deployment costs and potential stranded asset write-off

Phase 4 - Business Releases

Phase 4 business releases are focused on replacing the existing AMI system or transitioning to the next generation Honeywell AMI system to enable smart meter functionality that exists in next generation AMI systems.

During this phase, HOL will need to implement a PMO and governance structure to oversee the implementation of the AMI technology selected.

The following two graphics summarize the specific business releases recommended for Phase 3 of the AMI Roadmap as well as the IT systems expected to be impacted:

BR4a Meter, Network & HES Replacement	BR4b Data Analytic and/or DMS/OMS Enhancements	BR4c Planning and Forecasting	BR4d Billing, MDMS and/or Customer Portal Enhancement
• Real Time Ping Capability • Real Time Outage/Restoration Notification • On Demand Read • Remote Connect/Disconnect for Meters • New Measurement Capability in Meters • Voltage • 15 Minute Intervals for Residential Meters • Reactive Power • Temperature • Reactive Power • Power Quality etc *New Network – DA can be on Shared or Segregated Network if both are from the same Vendor (Reduced Cost for DA). If AMI & DA are from Different Vendors, then a Separate Network is Required*	• Improved AMI Alerts/Exception Management – Edge based Intelligence • Improved Voltage Diagnostics	• Improved Forecast Accuracy	• Prepayment Program/Rates • Critical Peak Pricing or Peak Time Rewards

Figure 78 - Phase 4 Business Releases

Business Release 4 - Replacement AMI Solution		
a. AMI Replacement b. Data Analytics + DMS/OMS Enhancements c. Planning & Forecasting d. Enhancements to Billing + MDMS + Customer Portal	Analytics Billing System MDMS CSR and Customer Portal	Planning & Forecasting OMS Dispatch / MTU

Figure 79 - Phase 4 Systems Impacted

Business Release BR4a – Meter, Network & HES Replacement

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Meter Reading	Future	**Measurement of 15 minute consumption profiles for Residential Customers**	X	X		5	Hi Cost	Replace all meters + Upgrade Ntework to handle bandwidth	Significant Effort	Replace all meters	5	1.4	Enable 15 minute consumption data at all endpoints to provide increased granularity and visibility to usage impacts. Future requirement for all residential customers - currently at 1 hour.
Meter Reading	Future	**Measurement of Real and Reactive Power**		X	X	5	Hi Cost	Replace all REX1 meters + upgrade network to handle bandwidth	Significant Effort		5	1.4	Provide real and reactive power profiles to all endpoints to provide increased visibility to power demands. Future Measurement Canada requirement is for all meters to have ability to measure real and reactive power beginning in 2038 with implementation starting during the 2024 reseal program.
Meter Operations	Future	**Improve safety associated with poor meter installations by monitoring Temperature within Meter**		X		3	Hi Cost	Replacement of POTs backhaul + Replace all meters	Significant Effort	Replace AMI System + Data Analytics + Auto Dispatch	5	0.8	Utilize temperature monitoring and temperature threshold alarms to provide rapid dispatch for correction of "hot sockets".
Smart City	Future	**Metering for Other Municipal Services (Water)**			X	3	Hi Cost	Existing electric meters do not support comms to water meter	Significant Effort	Field deployment of devices + HES Software integration	5	0.8	The AMI system should have be able to support additional metering for other municipal services such as water. Hydro Ottawa to provide services to deliver meter reads to other utility (no asset management or billing)

Figure 80 - Business Release 4a Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	Smart City Sensors	AMI Network & HES	MDMS	Work Mgnt.	CSR and Customer Portals
15 minute consumption profiles for Residential Customers	15 minute consumption interval data (timestamped) Timestamp to be accurately aligned to system time to enable time synchronization.		Retrieve and process timestamped interval data daily. Export to MDMS	VEE. Post daily consumption profile to customer and CSR portal.		Visibility to customer consumption profile.
Real and Reactive Power	Timestamped consumption interval data. Timestamped reactive interval data. Time stamp to be accurately aligned to system time to enable time synchronization.		Retrieve and process real and reactive power profile data daily. Export to MDMS.	Process and retain timestamped real and reactive power interval data.		
Improve safety associated with poor meter installations by monitoring Temperature within Meter	Temperature sensors within meter with temperature threshold alarm settings.		Retrieve and process temperature readings on demand and temperature threshold events in real-time.		Dispatch field investigations due to high meter temperature alarms. Provide high meter temperature alarm information.	

			Send to work dispatch.			
Metering for Other Municipal Services (Water)		Water meter, Gas Meter, Sewage meter modules (typically battery powered discrete retrofitted modules)	Provision and support water metering and other module types. Retrieve water and other meter/module data including consumption registers, consumption interval data, events, and alarms. Ability to parse data and track by company.	VEE and other functionality for water and other services being measured. Parse data by jurisdiction/ company. Provide segregated data to each Municipal service provided for individual billing.		

Figure 81 - Business Release 4a Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

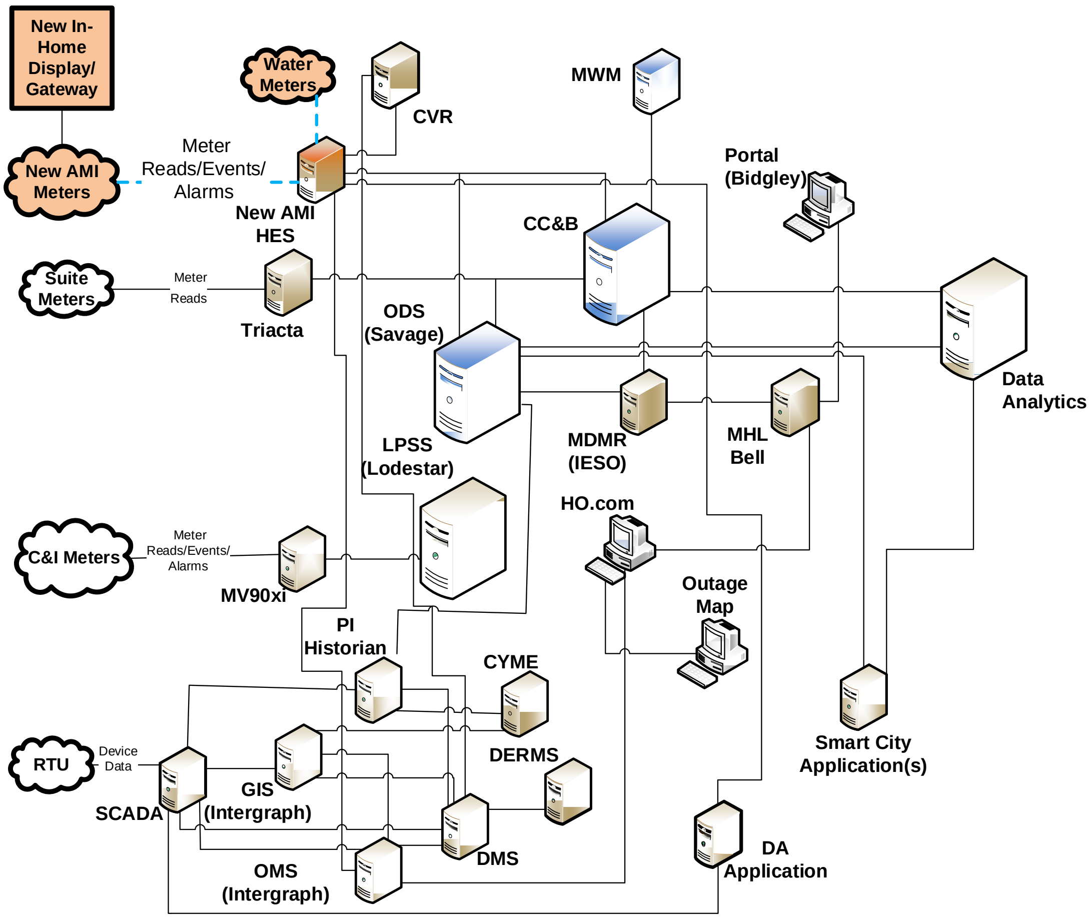


Figure 82 - Business Release 4a System Diagram

- New AMI Network
- New AMI HES
- New AMI Meters/Water Meters
- New In-Home Displays/Gateway
- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- HES – Headend System
- CVR – Conservation Voltage Regulation

Business Release BR4b – Data Analytics and/or DMS/OMS Enhancements

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by “Net Value”):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Distribution Operations	Future	**<u>Outage Management</u> - Improved System Reliability Through Reduced Outage Times.**	X	X		5	Hi Cost	Replacement of POTs backhaul + REX1 meters	Significant Effort	Field deployment of REX1 + replacement of POTS backhaul + OMS system enablement	5	1.4	Reduced outage assessment and restoration times improves SAIDI and CAIDI. Reduced storm restoration time and crew costs. In major events, OMS algorithms can incorrectly "roll up" an outage to an upstream device. AMI provides a real measure of outage/restoration status to confirm OMS outage logic and remaining outages. OMS uses the meter power status alerts to determine whether an outage should be upgraded to the transformer, fuse, recloser, etc. Use of AMI alarms and pinging improves storm restoration efficiency and aids in the identification of nested outage conditions. Similarly, operators can confirm restoration in a similar manner. Reduce dependency on customer outage reporting - particularly in major events.
Distribution Operations	Future	**Value of Service (VOS) / Revenue Improvement Through Improved Reliability**	X	X		4	Hi Cost	Replacement of POTs backhaul + REX1 meters	Significant Effort	Field deployment of REX1 + replacement of POTS backhaul + OMS system enablement	5	1.1	Increase in value of service (and/or revenues) because of lower SAIFI, CAIDI and MAIFI.
Meter Operations	Future	**Edge based intelligence to improve AMI Alert and Exception Management**		X		4	Hi Cost	Replacement of Collectors + POTs backhaul + REX1 meters	Significant Effort	Edge computing + automated self healing network	5	1.1	Provide Smart collectors to filter, aggregate, analyze and perform distributed field processing (edge computing) to enable automated self healing exception management.
Meter Operations	Future	**Voltage Diagnostics**	X	X		4	Hi Cost		Significant Effort		5	1.1	AMI systems can deliver voltage information and voltage threshold alarms to improve customer service and detect system issues.

Figure 83 - Business Release 4b Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	AMI Network & HES	Data Analytics	Work Mgnt.	DMS/ OMS	Planning & Forecasting
Outage Management - Improved System Reliability Through Reduced Outage Times.	Power Status Alerts (Last Gasp outage alert + Power restoration) timestamped and transmitted in real-time. Power status ping response provided in real-time.	Retrieve and process power status alerts and ping request and response in real-time.	Use power outage, power restoration, and status pinging to identify nested outages. Use timestamped power out events to perform post storm analysis to ensure accurate CAIDI / SAIFI. Analyze, filter and validate power status event to minimize false alarms.		OMS - Use power status events as inputs into outage modeling. Enable pinging power status for single meter and groups of meters based on connectivity model.	
Value of Service (VOS) / Revenue Improvement Through Improved Reliability	Power Status Alerts (Last Gasp outage alert + Power restoration) timestamped and transmitted in real-time. Momentary outage event logs.	Capture, transmit, and process high percentage of last gasp and power restoration alerts and send to OMS/DMS. Transmit and process Momentary outage event log daily.	Measure reduction in CAIDI minutes to calculate revenue		Process outage alerts to improve outage responsiveness and dispatch of crews.	Process momentary outage event logs to target low reliability circuits.

		Send to reliability/ planning.				
Edge based intelligence to improve AMI Alert and Exception Management	Timestamped register data. Real-time voltage data. Timestamped meter data (alerts, events, etc.) provided in real-time.	Process voltage and alarm/alert data to identify correlated changes to voltage and/or outage events. Submit triaged exception analytics to AMI Head End. Process submitted network triaged exceptions.	Process submitted network triaged exceptions to add historical data for further analytics. Analyze and correlate usage profiles, alarms and events to determine abnormal meter or network conditions.			
Voltage Diagnostics	Voltage data - instantaneous and historical profile. Voltage threshold alerts.	Retrieve and process timestamped voltage profiles daily and real-time voltage at set intervals and on-demand. Receive and transmit voltage threshold alarms in real-time.	Analyze voltage profiles, and thresholds. Process voltage threshold alarms to determine work order requirements. Issue work order reports to address low/high voltage conditions.	Dispatch work orders to address Lo/High voltage conditions. Provide data analytics information to support work orders to address Lo/High voltage conditions.		

Figure 84 - Business Release 4b Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

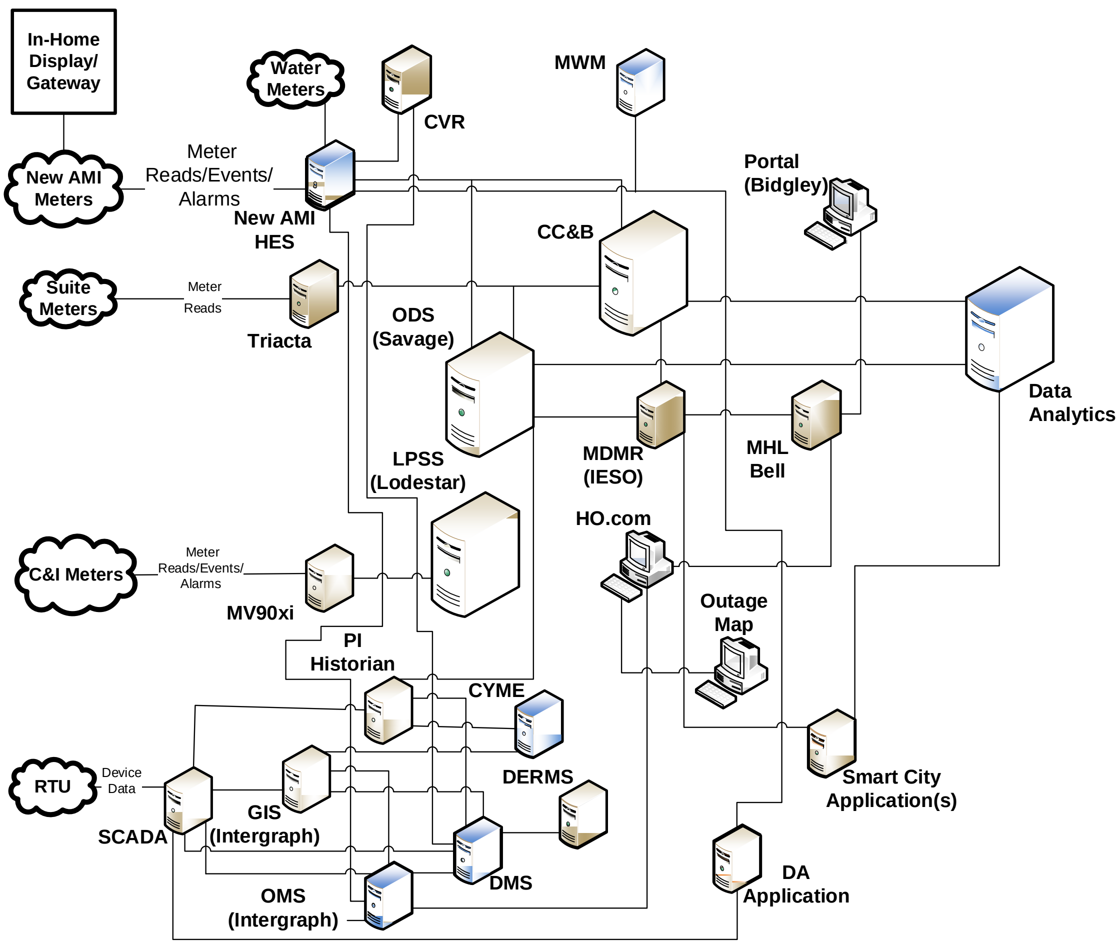


Figure 85 - Business Release 4b System Diagram

Minor Change to Existing Application/Portal

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- HES – Headend System
- CVR – Conservation Voltage Regulation

Business Release BR4c – Planning and Forecasting

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by "Net Value"):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Distribution Planning	Future	**Improved forecast accuracy**		X		3	**Hi Cost**	Replace all meters + Upgrade Ntework to handle bandwidth	**Significant Effort**	Replace all meters + Enable improved forecasting using individual and aggregated profiles	5	**0.8**	Processing of 15 minute interval data; provision of data to forecasting system (Assumes forecasting is performed at 15 minute intervals)

Figure 86 - Business Release 4c Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	AMI Network & HES	MDMS	Planning & Forecasting
Improved forecast accuracy	15 minute consumption interval data (timestamped) Timestamp to be accurately aligned to system time to enable time synchronization.	Receive and process timestamped interval data daily. Export to MDMS.	VEE. Export interval data sets to Planning & Forecast.	Consume and analyze interval data. Apply improved endpoint load analysis into forecasting models for improved accuracy.

Figure 87 - Business Release 4c Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

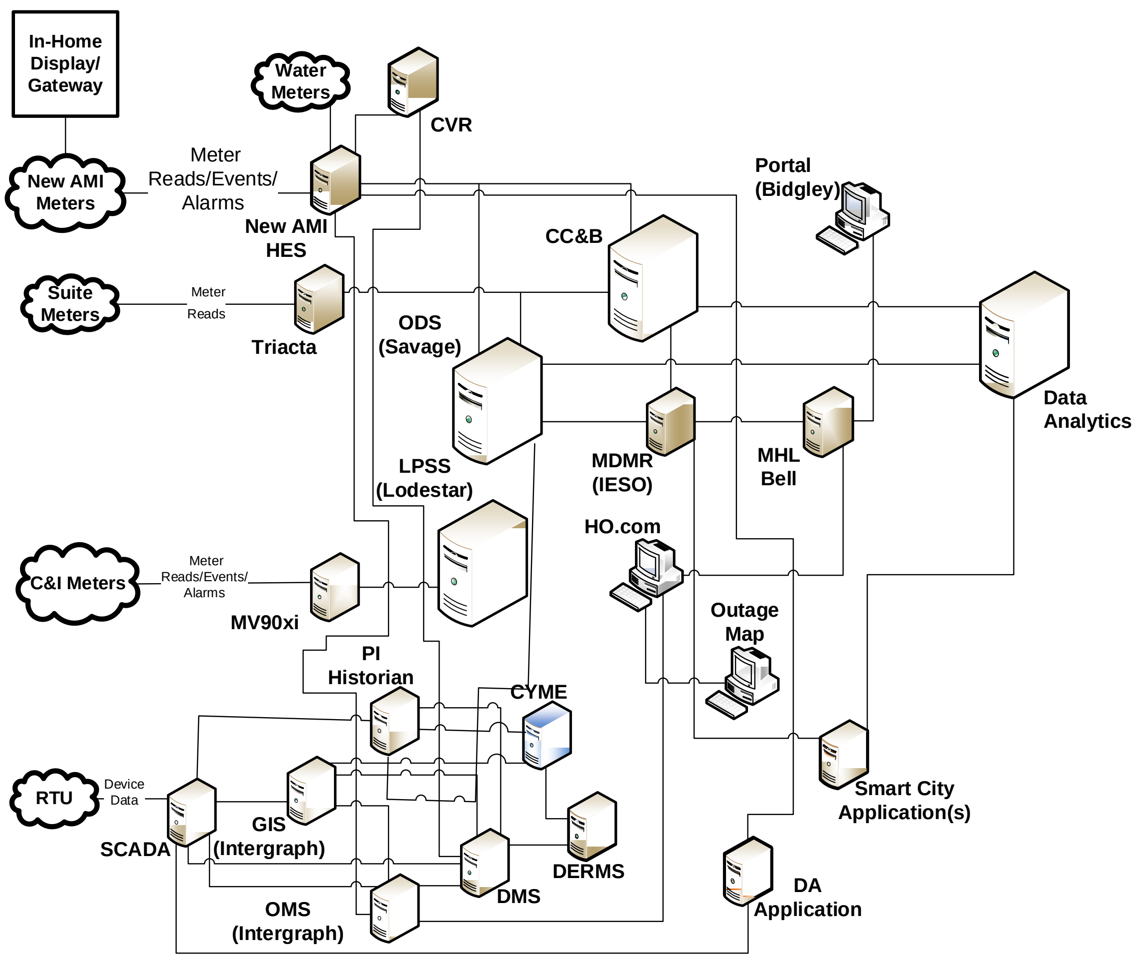


Figure 88 - Business Release 4c System Diagram

Minor Change to Existing Application/Portal

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- HES – Headend System
- CVR – Conservation Voltage Regulation

Business Release BR4d – Billing, MDMS and/or Customer Portal Enhancement

The opportunities that were ranked 3, 4, or 5 and that were organized into this business release were the following (ranked by “Net Value”):

Benefit Category	Already Achieved or New	Potential Opportunity	Customer	Operational	Societal	Priority/Value (50% weight)	Cost/Investment (25% weight)	Cost/ Investment Comments	Effort/Complexity (25% weight)	Effort/Complexity Comments	Net Cost/Effort	Net Value	Use Case Summary
Regulatory	Future	**Prepayment Programs / Rates**		X		5	**Med Cost**	Targeted RCD meter replacement for Prepaid customers	**Significant Effort**	Implement Prepay system	4.5	**1.9**	Threshold monitoring of daily consumption, Prepay debiting and payment mechanism, rapid dispatch of remote disconnect. Benefits include improved accounts receivable balances, reduced working capital, reduced deposit requirements, fewer cuts for nonpay, increased customer satisfaction, and energy conservation.
Regulatory	Future	**Critical Peak Pricing or Peak Time Rewards**		X		4	**Hi Cost**	Replace all meters + Upgrade Ntework to handle bandwidth + Realtime alerts	**Significant Effort**	Replace all meters + Customer alerts, billing enablement, rate design	5	**1.1**	Notification of Peak Pricing hours to customer; Processing of hourly data into Peak hours rate buckets; Billing System billing based on Peak Pricing time rates

Figure 89 - Business Release 4d Opportunities

The functional capabilities that would be required to enable these opportunities are portrayed in the following table:

	Metering	AMI Network & HES	Prepay Solution	MDMS	Billing	CSR and/or Customer Portal
Prepayment Programs / Rates	Service disconnect switch. Hourly consumption interval data.	Enable disconnect and reconnect. Provide switch status. Retrieve register data daily. Issue disconnect and reconnect. Provide switch status. Process interval data daily.	Prepayment Solutions offered by various vendors to manage credits/debits and communications to customer (via web, mobile, text, etc.)	VEE. Post cumulative consumption to Prepayment application.	Calculate "to-date" monthly bill (including all charges); provide to Prepayment Solution to compare against available credit and post to customer portal. Receive input from Prepayment application when current charges exceed available credit. Send disconnect command to AMI head end upon exhaustion of credit. Receive input from Prepayment application when credit had been applied to exceed current charges. Send reconnect command to AMI head end upon posting of credits.	Prepayment application: Post "to-date" monthly bill (including all charges); compare against available credit; post to customer portal or send to in-home display.
Critical Peak Pricing or Peak Time Rewards	15 minute consumption interval data (timestamped)	Retrieve timestamped interval data daily.		VEE. Separate usage into Peak and Off Peak periods for	Identify Peak Time periods to MDMS for usage disaggregation.	Visibility to Customer bill. Visibility to customer

	Timestamp to be accurately aligned to system time to enable time synchronization.	Process timestamped interval data daily. Export to MDMS		bill determinant processing. Post billing route files to Billing System.	Request billing determinants from MDMS and generate bill.	consumption profile. Identification of Peak Time periods, consumption per period, and billing amounts.

Figure 90 - Business Release 4d Functional Requirements

Finally, the systems expected to be impacted within the overall IT infrastructure are identified in the following hi-level system diagram:

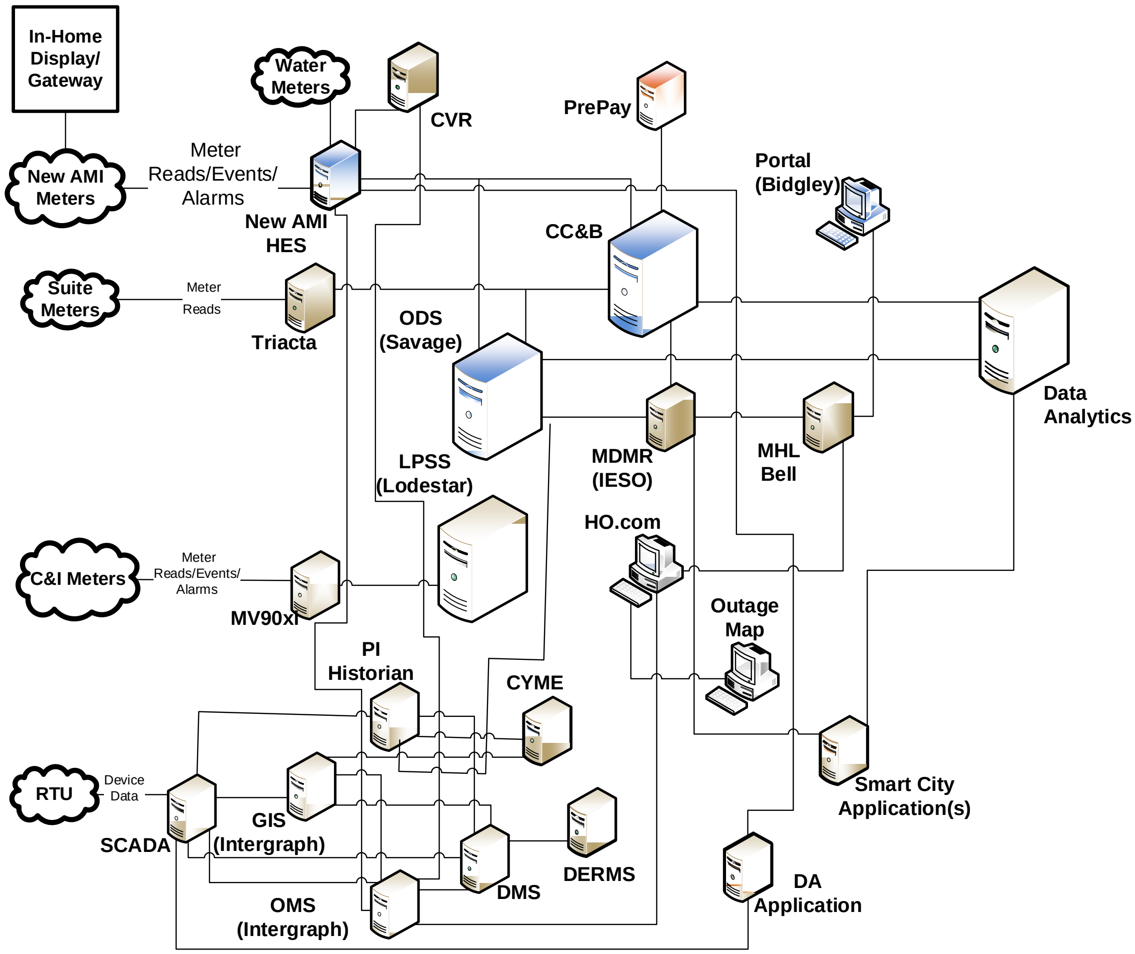


Figure 91 - Business Release 4d System Diagram

Minor Change to Existing Application/Portal

- ODS– Operational Data Store (Savage)
- EA_MAS – Headend System (Elster)
- CC&B – Customer Care & Billing (Oracle)
- GIS – Geographical Information System (Intergraph)
- OMS – Outage Management System (Intergraph)
- MDMR – Meter Data Management/Repository
- IESO – Independent Electricity System Operator
- LPSS – Load Profile & Settlement System (Lodestar)
- DMS – Distribution Management System
- DERMS – Distributed Energy Resource Management System
- DA – Distribution Automation
- HES – Headend System
- CVR – Conservation Voltage Regulation

Smart Energy Strategy alignment

As previously described, HOL has developed a well-defined Strategic Plan (reference: Strategic Direction 2016-2020) and a detailed strategy for the programs anticipated in a longer-term transition to a Smart Energy provider (reference: Smart Energy Strategy). The strategic directions serve to ensure that both the Smart Energy Strategy and the AMI Roadmap maintain adherence to overall HOL goals. However, the AMI Roadmap and the defined projects of the Smart Energy Strategy have a much closer potential inter-dependency. As such, the following diagram serves to portray which programs of the Smart Energy Strategy are dependent on which phases of the AMI Strategy, and vice versa.

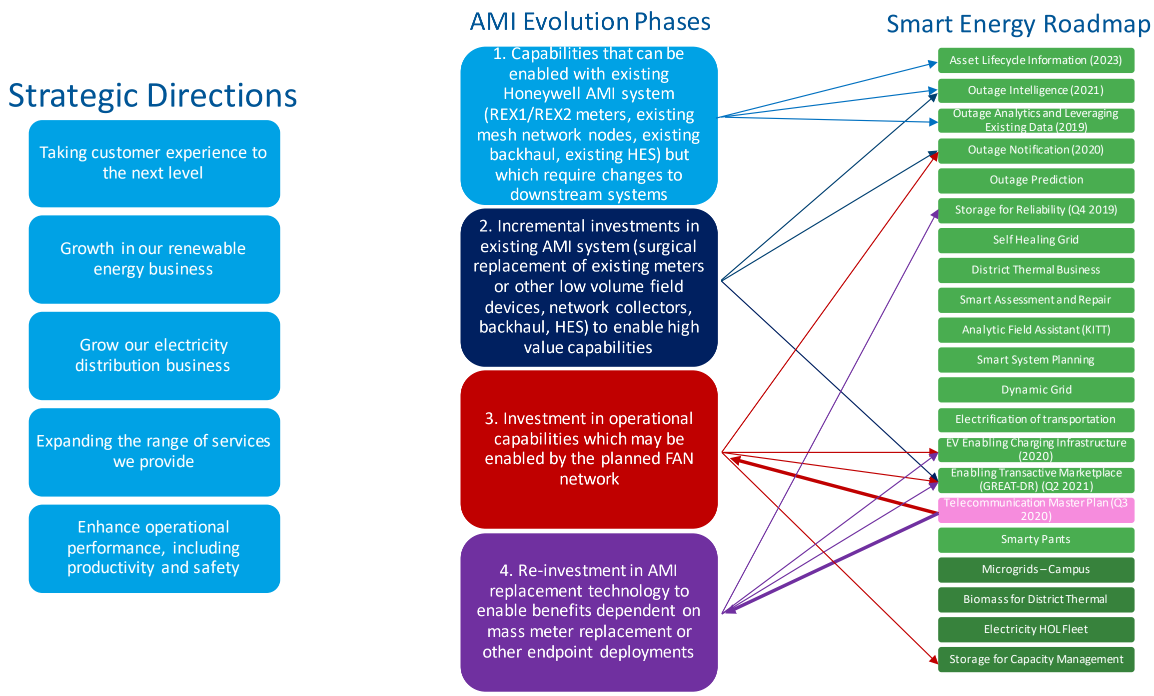


Figure 92 - AMI Roadmap Strategy Alignment

KEY IT SYSTEMS IMPACTED

While the business releases recommended in this Roadmap are organized around business opportunities, they are implemented through a sequence of functional capability enhancements for several key IT systems. Thus, to support IT planning activities, the following sections alternatively describe the various business releases from the perspective of several of the key HOL IT systems.

Billing System

Enhancements to the Billing system, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Billing System Requirements
BR1a	Enable / Expand Summary Billing	Create single bill from aggregated consumption into single, multi-site bill
	Green Pricing Rates	Create distinct DER generation source buckets. Request billing determinants from MDMS. Assign DER credits and total consumption and generate bill.
	EV Charging Aggregation and Market participation (HOL separately metered)	Enable aggregated charged usage billing to third parties and/or market aggregators.
	EV Charging Rate and Revenue Metering for EV Charging Infrastructure	Request billing determinants from MDMS and generate EV Charger bill.
BR1d	Reduced consumption on inactive accounts (using field disconnect visit)	Identify inactive accounts to MDMS and data analytics. Issue disconnect work order based on data analytics identifying un-acceptable consumption on expected inactive accounts.
BR2a	Improve Operations Safety & Carbon Footprint through Increased Utilization of Remote Connect Disconnect: - Reduced field trips for move-in / move-out and non-pay customers - Reduced injuries, claims and environmental impact - Rapid resolution of accounts in arrears - Reduce consumption on inactive accounts	Identify account status (active/inactive) to MDMS and data analytics. Issue virtual work orders for disconnect - reconnect of service and commands based on specific data analytics for the business process. Synch meter switch status with AMI head end.
BR4d	Prepayment Programs / Rates	Calculate "to-date" monthly bill (including all charges); provide to Prepayment application to compare against available credit and post to customer portal or send to in-home display. Receive input from Prepayment application when current charges exceed available credit. Send disconnect command to AMI head end upon exhaustion of credit. Receive input from Prepayment application when credit had been applied to exceed current charges. Send reconnect command to AMI head end upon posting of credits.
	Critical Peak Pricing or Peak Time Rewards	Identify Peak Time periods to MDMS for usage disaggregation. Request billing determinants from MDMS and generate bill.

Figure 93 - Billing System Functional Requirements

Note: An Upgrade to the AMI Headend is recommended due to end of life support and should be done as part of Release 2 (BR2e).

MDMS

Enhancements to the MDMS, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Meter Data Management System Requirements
BR1a	Enable / Expand Summary Billing	Aggregate multiple accounts into summary bill
	EV Charging Aggregation and Market participation (HOL separately metered)	Aggregate timestamped interval data from metered EV charger(s)
	EV Charging Rate and Revenue Metering for EV Charging Infrastructure	Process billing determinants for separately metered EV charger(s)
	Green Pricing Rates	Separate DER generation sources from total consumption. Post daily consumption profile to customer portal and CSR portal.
BR1b	Improve Distribution Modeling and Defer Distribution System Capacity Requirements	Export interval data sets to Planning & Forecast
	Aggregation of Load at Virtual Nodes for Distribution System Analysis, Transformer / Device Load Analysis and Equipment Sizing	Aggregate interval data associated with identified grid nodes.
	Improve real and apparent loss allocation	Process real and apparent power from AMI meters and provide flows to Data Analytics.
BR1c	Outage Management - Improve Momentary and Blink outages	Process outage event logs from AMI meters and pass to Data Analytics
BR1d	Reduced uncollectable charges via customer notification of forecasted bill (e.g., budgeting)	Forecast expected daily consumption for remainder of billing period based on historical profile of individual premise usage.
	Billing Exceptions (Level 2) - Reduced number and resolution time of billing exceptions/issues	Process outage events to correctly validate zero usage intervals as outages and not estimate across them. Post daily consumption profile to customer portal and CSR portal.
	Enable / Improve Customer Conservation Programs and LIHEAP	Post daily consumption profile to customer portal and CSR portal.
BR1e	Improved Rate Design and Customer Class Cost Allocations	Post daily consumption profile to Data Analytics
	Improve Forecasting Capability	Export interval data sets to Planning & Forecasting system.
BR4a	Measurement of 15 minute consumption profiles for Residential Customers	Process, store, aggregate 15 minute interval data; Post daily consumption profile to customer portal and CSR portal.D3
BR4a	Measurement of Real and Reactive Power	Process and retain timestamped real and reactive power interval data.
BR4a	Metering for Other Municipal Services (Water)	VEE and other functionality for water and other services being measured. Parse data by jurisdiction/company. Provide segregated data to each Municipal service provided for individual billing.
BR4b	Edge based intelligence to improve AMI Alert and Exception Management	Process submitted network triaged exceptions to add historical data for further analytics.
BR4c	Improve Forecast Accuracy	Export interval data sets to Planning & Forecast
BR4d	Prepayment Programs / Rates	Post cumulative consumption to Prepayment application.
	Critical Peak Pricing or Peak Time Rewards	Separate usage into Peak and Off Peak periods for bill determinant processing. Post billing route files to Billing System.

Figure 94 - MDMS Functional Requirements

CSR & Customer Portal

Enhancements to the Customer and Customer Service Representative Portals, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Customer Service Representative Portal Requirements
BR1a	Green Pricing Rates	Visibility to total customer consumption and DER generation. Visibility to breakdown of bill to billing buckets and DER credits.
BR1d	Reduced uncollectable charges via customer notification of forecasted bill (e.g., budgeting)	Enable forecasting of total bill (usage + charges) and provide access to CSR
BR1d	Improved Effectiveness of Low Income Home Energy Assistance Program	Forecast of consumption and likely timing of reaching LIHEAP limits.
BR2b	Outage Management - Reduced Trouble Calls (single lights out)	Enable pinging power status
BR4d	Critical Peak Pricing or Peak Time Rewards	Identification of Peak Time periods, consumption per period, and billing amounts.

Figure 95 - CSR Portal Functional Requirements

Business Release #	Potential Opportunity	Customer Web Portal Requirements
BR1a	**Green Pricing Rates**	Visibility to total customer consumption and DER generation. Visibility to breakdown of bill to billing buckets and DER credits.
BR1d	**Reduced uncollectable charges via customer notification of forecasted bill (e.g., budgeting)**	Enable forecasting of total bill (usage + charges) and present to customer
	Customer Portal information for EV Charging (HOL provided)	Visibility to EV consumption profile.
	Enable / Improve Customer Conservation Programs	Enable advanced features such as energy load profiling and neighborhood energy comparisons. Enable forecasting of total bill (usage + charges) and present to customer
	Improved Effectiveness of Low Income Home Energy Assistance Program	Forecast of consumption and likely timing of reaching LIHEAP limits.
BR2b	**Outage Management - Improved Customer Communication**	Outage information, status, and ETR updated on customer portal or custom outage portal
BR2d	**Enable Residential Customer Direct Access to Meter Usage (near real-time)**	Reconcile differences between VEE data and real-time data customer views on portal
BR4d	**Prepayment Programs / Rates**	Prepayment application: Post "to-date" monthly bill (including all charges); compare against available credit; post to customer portal or send to in-home display.
	Critical Peak Pricing or Peak Time Rewards	Identification of Peak Time periods, consumption per period, and billing amounts.

Figure 96 - Customer Portal Functional Requirements

Dispatch/MTU

Enhancements to the Dispatch and Mobile Terminal systems, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Field Work Dispatch / Mobile Terminal System Requirements
BR1d	More rapid resolution of accounts in arrears (using field service dispatched service disconnect)	Dispatch virtual field order to disconnect service. Provide disconnect service order information to MTU.
	Reduced consumption on inactive accounts (using field disconnect visit)	Dispatch physical field order to disconnect service. Provide disconnect service order information to MTU.
BR2a	Carbon Offset Value - reduction in vehicle emissions due to reduced field trips	Automate field work dispatch based on data analytics outputs. Align correct resource skills to triaged and filtered field maintenance work.
BR2c	Improve AMI Alert and Exception Management by back end systems.	Issue work dispatch for critical events based on indicated priority from Data Analytics. Provide Data Analytics information to support expectation to MTU.
	Faster detection of and collection of theft	Issue work dispatch for theft/tamper based on indicated priority from Data Analytics. Provide Data Analytics information to support expectation of tamper/theft to MTU.
BR3b	FLISR	Dispatch crews with information on executed FLISR scheme and required work.
BR3c	Enable Smart Cities Functionality	Ability to support multiple non-traditional work types for dispatch. - Streetlight Automation - Parking Monitoring - Other Smart Cities Sensors and Devices as applicable
BR4a	Improve safety associated with poor meter installations by monitoring Temperature within Meter	Dispatch field investigations due to high meter temperature alarms. Provide high meter temperature alarm information to MTU.
BR4b	Voltage Diagnostics	Dispatch work orders to address Lo/High voltage conditions. Provide data analytics information to support work orders to address Lo/High voltage conditions to MTU.

Figure 97 - Dispatch System Functional Requirements

DMS/OMS

Enhancements to the Outage Management and DMS systems, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Distribution Management and Outage Management Systems Requirements
BR1c	Outage Management - Improved Momentary and Blink outages	OMS - Analyze and correlate momentary outage events to circuit connectivity model to identify "trouble" areas for preventative maintenance.
BR2b	Outage Management - Reduced Trouble Calls (single lights out)	OMS - Disconnected meters need to be put in exclusion list to remove them from outage list.
	Outage Management - Improved Outage and Reliability Index Reporting and System Reliability Planning through post event analysis.	OMS - Modify event times based on power status events. Use power status events as inputs into outage modeling.
	Outage Management - Improved Customer Communication	OMS - Import outage event alerts to improve outage dispatch. Predictive analytics to improve estimated restoration time. Automated ping process to validate power restoration. Disconnected meters need to be put in exclusion list to remove them from outage list.
BR3a	EV Charging Capacity Management	DMS - Identify HOL system capacity event and dispatch nodal DM signals to DERMS.
BR3b	FLISR	DMS - Consume real-time DA device information from DA headend. Process for identification of Fault Location. Identify isolation strategy. Send commands to DA Headend to execute isolation switch scheme. Identify optimized restoration strategy. Send commands to DA Headend to execute restoration switching scheme. Identify required field work required & send to dispatch.
	Automated Reclosers and/or switches	DMS - Consume real-time recloser information from DA headend. Issue recloser commands as needed.
	Faulted Circuit Indicators	DMS - Consume real-time FCI information from DA headend.
	Volt/VAR Management	DMS - Consume real-time voltage data from AMI headend. Provide Volt and/or VAR correction commands to DA Head End to adjust voltage or Cap settings on specific feeders.
BR3d	On premise Storage Monitoring and System Capacity Management	DMS - Identify HOL system capacity event and dispatch nodal DM signals to DERMS.
	Conservation Voltage Reduction (CVR)	DMS - Consume real-time voltage data from AMI headend. Provide voltage reduction commands to DA Head End to adjust voltage levels on specific feeders.
	Community based energy storage	DMS - Identify HOL system capacity event and dispatch nodal DM signals to DERMS.
BR4b	Outage Management - Improved System Reliability Through Reduced Outage Times.	OMS - Use power status events as inputs into outage modeling. Enable pinging power status for single meter and groups of meters based on connectivity model.
	Value of Service (VOS) / Revenue Improvement Through Improved Reliability	OMS - Process outage alerts to improve outage responsiveness and dispatch of crews.

Figure 98 - DMS/OMS Functional Requirements

GIS

Enhancements to the GIS system, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Geographic Information System Requirements
BR1b	Aggregation of Load at Virtual Nodes for Distribution System Analysis, Transformer / Device Load Analysis and Equipment Sizing	Provide distribution device connectivity model and device load capacities to analytics tools.
	Phase Load Balancing	Phase assignment of each endpoint.
BR2b	Outage Management - Improved Outage and Reliability Index Reporting and System Reliability Planning through post event analysis.	Use timestamped restoration and power out events to perform post storm analysis to identify target areas for reliability improvement strategies.
BR2c	Reduced unaccounted for usage and field labor due to improved identification of lost or orphan (a.k.a. data nodes) meters	Capture GPS location of endpoint upon field installation and store in GIS.
BR3c	Enable Smart Cities Functionality	Ability to map various sensors including analog data and/or events for the following: - Streetlights - Wind Speed data - Fire/Smoke sensor data - Air Quality sensor data - Parking data - Snow level sensor - Traffic monitoring data - Waste collection levels - Noise level data - Road surface conditions - Surface temperatures - Vibration sensor data

Figure 99 - GIS Functional Requirements

Planning & Forecasting

Enhancements to the Planning and Forecasting systems, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Planning / Forecasting Requirements
BR1a	Enable EV Charging Rates, Revenue Metering, Load Aggregation & Market Participation	Aggregation of EV charger data to be used for Distribution planning & forecasting. PI Historian to store all data for CYME.
BR1b	Defer Distribution system capacity requirements	Aggregate distribution load flows to discrete distribution devices and capacities. Determine system capacity margins based on rolled up endpoint load flows..
	Improved Distribution Modeling and Calibration	Consume and analyze interval data. Provide interval data to planning and forecasting models to improve accuracy and calibration.
BR1e	Improved Forecasting Capability	Consume and analyze interval data. Develop forecasting model which applies load flow at nodal level.
BR4b	Value of Service (VOS) / Revenue Improvement Through Improved Reliability	Process momentary outage event logs to target low reliability circuits.
BR4c	Improved forecast accuracy	Consume and analyze interval data. Apply improved endpoint load analysis into forecasting models for improved accuracy.

Figure 100 - Planning & Forecasting Functional Requirements

KEY NEW SYSTEMS

Some of the business releases recommended in this Roadmap include the likelihood of new systems capabilities that do not currently exist within the HOL IT architecture. Thus, the following section describes these key systems and their required hi-level functionality.

Data Analytics

Analytics is a key enabler to extracting value from AMI data. Specifically, many of the opportunities identified by HOL as having high priority will be dependent on leveraging existing and additional AMI data to improve operational processes and customer insights.

The functional capabilities of the Data Analytics system, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Data Analytics Requirements
BR1b	Aggregation of Load at Virtual Nodes for Distribution Planning and Operations.	Aggregation of timestamped interval data to a virtual node. Analysis of load and distribution equipment specifications to determine if equipment is sized properly.
	Improved real and apparent loss allocation	Analyze consumption data, connectivity model, SCADA data, etc. for loss calculations
	Phase Load Balancing	Analyze totalized interval data of endpoints assigned to each phase to determine out of balance loads
BR1c	Outage Management - Improved Momentary and Blink outages	Analyze and correlate momentary outage events to circuit connectivity model to identify "trouble" areas for preventative maintenance.
BR1d	More rapid resolution of accounts in arrears and reduced consumption on inactive accounts	Monitor usage and establish thresholds to indicate un-acceptable consumption on an inactive account or which exceed collections limits. Issue report to work management system upon exceeding consumption threshold.
BR1e	Improved accuracy in rate design	Analyze usage information for rate design opportunities and impacts, customer class and cost of service allocations.
BR2a	Improved AMI Alert and Exception Management. Faster detection of and collection of theft.	Develop meter maintenance algorithms to correlate interval, register, and alarm data with work management systems to improve diagnostics and triage of field work. Analyze and correlate usage profiles, alarms and events to determine likely tamper events meters. Issue tamper target lists based on likelihood probabilities to work dispatch system.
BR2b	Improved Outage and Reliability Index Reporting and System Reliability Planning.	Use timestamped restoration and power out events to perform post storm analysis to ensure accurate CAIDI / SAIFI and to identify target areas for reliability improvement strategies.
BR2c	Reduced unaccounted for usage and field labor due to improved identification of lost or orphan meters	Identify all meters that are transmitting data from the field but which are not assigned to a registered account. Triangulate RF signals to identify location of meters with no accounts assigned.
BR3c	Smart Cities Sensor Analytics	Perform real-time analysis and trending of: - Streetlight data - Wind Speed data - Fire/Smoke sensor data - Air Quality sensor data - Parking data - Snow level sensor - Traffic monitoring data - Waste collection levels - Noise level data - Road surface conditions - Surface temperatures - Vibration sensor data Send alert to City to respond to Sensor threshold based alarms.
BR4b	Improved System Reliability Through Reduced Outage Times.	Use power outage, power restoration, and status pinging to determine nested outages prior to crews leaving area. Analyze, filter and validate power status event to minimize false alarms. Measure reduction in CAIDI minutes to calculate revenue
	Voltage Diagnostics	Analyze voltage profiles, and thresholds. Process voltage threshold alarms to determine work order requirements. Issue work order reports to Work Order Management to address low/high voltage conditions.

Figure 101 - Data Analytics Functional Requirements

Unfortunately, HOL's current IT architecture does NOT include any specific platform to provide the detailed analytics that will be required. While there are several options for accomplishing data analytics; including MDMS modules, hosted services from Data Analytics vendors (such as Oracle), or dedicated applications, a significant element in the IT Business Release plan will be to enable data analytics capabilities. Specifically, the three approaches that HOL may consider include:

- Platform or use case enabled application
  - The analytics "platform" approach is a build-it-yourself strategy. In this approach, Hydro Ottawa would architect the databases, the dashboards, the extracts, and the algorithms to analyze the data based on their own use case definitions and process automation descriptions. This approach should only be undertaken by organizations that are very adept at complex data base architecture designs, with strong in-house data science and analytical capabilities, and expert data presentment skills.
  - This approach is based on sourcing an analytics solution from a vendor who can provide not only their own underlying "platform" but also the rules engines, configuration and

programming tools, and (most importantly) implemented use cases from other utilities. This would be the preferred approach for utilities with well-defined use case targets which should be the case at HOL based on the opportunities assessments.

- MDMS or Head End System module alternative
  - Many of the top tier MDMS vendors offer data analytics modules as add-on applications to their MDMS solutions. Based on whether the current MDMS vendor (Savage) can provide data analytics applications, leveraging their data analytics solution may provide an opportunity for more efficient access to data analytics and reduced implementation risk.
  - Several of the top tier AMI vendors offer data analytics modules as options for their AMI system head end application. Based on the long-term AMI solution vendor of choice, this may become a viable option for HOL to consider.
- Full service/SaaS or DBRT
  - Full Service and Software as a Service (SaaS) vendors provide not only the platform, the application, the use cases, but also the data scientist and professional services to develop new use cases and data tests as Hydro Ottawa's needs evolve. Specifically, Oracle provides this capability via their prior acquisition of DataRaker, which is offered as a hosted service.
  - Design, Build, Run, Transfer (DBRT) strategies leverage application suppliers and consultants to develop and configure the platform and application, develop and implement the initial use cases, integrate the use cases into automated business processes, help run the new automated processes with Hydro Ottawa, and finally transfer the platform, application, and the developed use cases over to Hydro Ottawa for long term operation and support.

Hence, the first step in preparing for the data analytics release and the solution selection process for Hydro Ottawa will be a diligent identification and prioritization of the desired use cases that Hydro Ottawa believes will drive value from expanded AMI data availability. Many of these are readily identifiable from the AMI Opportunities Matrix.

Distributed Energy Resource Management (DERMs)

Based on the strong proponent for expanding HOL's Distributed Energy Resources and Market Participation, it is anticipated that HOL may need to explore and implement some advanced Distributed Energy Resource management capabilities to help gather information from distributed resources as well as manage and control generation, storage, and loads using an integrated system.

The functional capabilities of the Distributed Energy Resource Management system, in support of the desired business opportunities include the capabilities described in the following table:

Business Release #	Potential Opportunity	Distributed Energy Resource Management System Requirements
BR3a	Energy Storage and Demand Management	Dispatch DM signals to storage devices. Verify reduced demand based on demand threshold or calculated demand.
	EV Charging Capacity Management	Dispatch nodal DM signals to EV chargers. Verify reduced Nodal demand.
BR3d	Energy Storage and System Capacity Management	Dispatch nodal DM signals to storage devices. Verify reduced Nodal demand based on processed interval data.
	Conservation Voltage Reduction (CVR)	Consume real-time voltage data from AMI headend. Provide voltage reduction commands to DA Head End to adjust voltage levels on specific feeders.

Figure 102 - DERMS Functional Requirements

Enterprise DERMS can be defined as:

> "***a utility enterprise system that enables the monitoring, management, coordination and optimization of numerous DERs owned and operated by the utility, its customers or third-party aggregators.***"

The types of DERs supported by a true "Enterprise DERMS" include:

- Distributed Generation
  - PV (grid-scale, rooftop)
  - Wind
  - Backup generators/spinning mass
  - Fuel cells
- Energy Storage (generation and consumption)
  - Batteries
  - Electric Vehicles
- Demand Response/Curtailment
  - Heating/cooling/thermostats
  - Lighting
  - Pumps and appliances

This includes utility-owned, third-party, customer, "in front of" and "behind" the meter DER assets. No commercially available DERMS systems are known to be able to provide all of these capabilities.

DERMS systems are integrated with DMS/OMS systems supporting situational awareness and grid operations management. DERMS may also support market participation operations for both wholesale and (future) distribution markets.

Figure 103 - DERMS Vendors

The DERMS vendor landscape has become a very crowded space. Each DERMS solution requires significant investment and system integration to work with the DMS/OMS systems and with the DER assets on the grid. At some point, it should be anticipated that vendors may combine DERMS with ADMS systems, making integration with operational systems easier.

Appendices (separate attachments)

APPENDIX A – STRATEGY WORKSHOP PRESENTATION

18 Hydro Ottawa AMI Strategy.pdf

APPENDIX B – AMI REQUIREMENTS MATRIX

AMI Opportunities 20190318 v14.xlsx

APPENDIX C – BUSINESS RELEASE PLAN

AMI Roadmap & Business Release Stra

AMI Roadmap IT Requirements 20190:

APPENDIX D – NETSENSE FEATURE MATRIX COMPARISON TO EA_MS

NetSense Feature Matrix.pdf

APPENDIX E – AMI TECHNOLOGY OVERVIEW

AMI Technology Overview - 20190117.

METSCO
MAKING IT POSSIBLE

Mark Wojdan, P.Eng,
Supervisor, Maintenance & Reliability
Hydro Ottawa Limited

Dear Mark:

Re: Review of Hydro Ottawa's Asset Condition Assessment Framework

METSCO was requested by Hydro Ottawa Ltd. ("Hydro Ottawa") to review their asset condition assessment (ACA) framework. This framework represents an integral component as part of Hydro Ottawa's broader asset management (AM) framework, leveraging information captured from maintenance programs, including visual inspection, testing and monitoring data, in order to produce health index (HI) results that allow the utility to proactively manage its fleet of distribution assets and ensure that the right actions are undertaken to the right assets at the right time.

METSCO decided to undertake this assignment as per the following three stages: (a) review of the overarching processes, systems and associated input data that are supporting the ACA framework, (b) review of the asset-class HI formulations, including the produced results and sample sizes, and (c) review of the end-state applications produced by the ACA framework, including how the HI results are ultimately integrated into broader AM deliverables.

METSCO's review of Hydro Ottawa's ACA framework produced the following conclusions:

(a) Review of the Overarching Processes, Systems & Associated Input Data

METSCO's review has found that Hydro Ottawa's ACA framework is well integrated within AM-related processes, procedures and outcomes. Hydro Ottawa has developed detailed and robust documentation for both the ACA framework, which includes the underlying health index formulations, as well as the underlying maintenance programs that supply inputs into the ACA framework.

Hydro Ottawa is constantly striving for continuous improvements, and in this regard, they continue to enhance and evolve their ACA framework and associated business processes. This includes efforts to transition from manual to automated procedures with respect to ingesting input data, including inspection, testing and monitoring data, in order to process health index results in a turn-key manner, and with an eventual goal to store this data into enterprise systems, such that the results can be better integrated into other planning procedures. Hydro Ottawa has also developed detailed and robust documentation both for the ACA framework itself, including the underlying health index formulations, as well as for the underlying maintenance programs that supply inputs to the ACA framework.

Maintenance work procedure documentation continues to be enhanced and evolved within the organization. Currently, Hydro Ottawa's procedures for overhead lines have been found to be the most detailed, providing field crew workers with a clear understanding of how to differentiate between the different condition grades for each degradation factor. Hydro Ottawa continues to expand this level of detail to their other asset groups, including underground lines, substation and manhole assets.

(b) Review of the HI Formulations, including Results & Sample Sizes

Hydro Ottawa currently uses Microsoft Excel to store the associated input data and perform the necessary calculations to produce the desired HI results. Microsoft Excel provides a flexible and open architecture, thereby allowing asset managers to quickly learn the mechanics of the HI calculations, as well as identifying the potential gaps regarding the underlying maintenance data, such that continuous improvements can be quickly introduced. The Excel environment also permits Hydro Ottawa to quickly introduce necessary improvements and enhancements to the framework should any gaps or anomalies be identified.

In this regard, Hydro Ottawa has implemented a number of enhancements to the ACA framework since METSCO's initial assessment was performed. The current configuration of the ACA framework allows for HI results to be calculated in a consistent manner, leveraging as much available input data (i.e. inspection, testing and monitoring data) as possible, such that the sample size of HI results can be maximized as effectively as possible. As noted in part (a), Hydro Ottawa is also continuing to transition away from the Excel environment and transition their ACA framework and HI calculations into enterprise system environments, which will introduce more automation, and also allow for expanded applications and use cases, such as the storage of historical health index results, which can be used further validate the formulas and also develop utility-specific condition-based failure probability functions.

On an overall whole, Hydro Ottawa's ACA framework can be described as utilizing robust formulations that are aligned with best practices.

(c) Review of the End-State Applications produced by the ACA Framework

Hydro Ottawa is applying continuous improvements to their ACA framework, which includes the development of automated connections to end-state products, such that these products can be delivered and deployed in a turn-key manner. Currently, HI results, once computed within the Excel environment, are loaded into enterprise systems for further assessment. This includes loading ACA data into Hydro Ottawa's asset investment planning (AIP) software, which is designed to manage key elements within the capital expenditure process, including risk assessment, project prioritization and optimization. As first explained in part (a), Hydro Ottawa continues to transition away from the Excel environment as part of continuous improvements, such that all calculations will be managed within enterprise system environments. This will not only allow greater efficiencies to be realized, but also for more end-state applications to be produced.

Hydro Ottawa is also leveraging an industry-derived function that allows for the conversion of the health index into an effective probability of failure value. This function is applied as part of a broader risk modelling approach for substation assets in order to perform a reliability risk assessment on a station level for major substation assets. This analysis considers not only the probability of failure but also the impacts of failure based upon customer impacts and derives a risk cost to quantify the total effects of asset failure. In METSCO's view, Hydro Ottawa is well-positioned to continuously improve upon and evolve this framework into an economically-driven risk-based AM approach, in which the costs of risk are balanced against the capital costs of offsetting these risks in order to determine an economic end-of-life result for the evaluated assets in question. This form of analysis allows for Hydro Ottawa to establish risk-based business cases for each investment within their system, which aligns closely with their ongoing initiative of certifying the organization to the ISO 55000 asset management standard.

Hydro Ottawa has established an implementation roadmap in order to achieve a desired end-state such that ACA results are available in a common, auditable, accessible and convertible format. One of the key features of this future state is having input data accessible from a central electronic repository, and being able to upload results from the ACA framework into their enterprise systems for further analysis and evaluation. It is recommended that Hydro Ottawa continue to execute upon this roadmap as they continuously improve upon and evolve their ACA and broader AM frameworks respectively.

Overall Conclusions

METSCO has found Hydro Ottawa's ACA framework as utilizing robust formulations that are in alignment with best practices, and to be tightly integrated with Hydro Ottawa's broader AM-related processes, procedures and outcomes. With the framework now established, and with asset managers fully understanding the underlying methodologies and concepts, Hydro Ottawa continues to strive forward with improvements and enhancements, including the integration of their framework into enterprise systems. As Hydro Ottawa continues to apply their framework to their asset base, they will also be able to execute improvements in a targeted, cost-effective and prudent manner, thereby proportionally enhancing their ACA outputs and applications. This will further elevate the maturity levels of the framework, and ensure that the right actions are being undertaken to the right assets at the right time.

Yours Truly,

Robert Otal
Director of Asset Management & Analytics

METSCO
MAKING IT POSSIBLE

metsco.ca

Suite 215; 2550 Matheson Blvd. East,
Mississauga, ON, L4W 4Z1
Phone: 905–232–7300
Cell: 416–617-5554
Fax: 905–232–7405
Email: info@metsco.ca

CAPITALIZATION POLICY

In accordance with section 2.2.2.5 of the *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications,* as updated on July 12, 2018 and addended on July 15, 2019, Hydro Ottawa's Capitalization Policy is provided in this Schedule. Hydro Ottawa converted to International Financial Reporting Standards ("IFRS") effective January 1, 2015. No changes have been made to Hydro Ottawa's capitalization policy since its last rebasing application.[1]

International Accounting Standard 16 - *Property, Plant and Equipment* ("IAS 16") requires that the useful life of an asset be reviewed at least at each financial year-end. After undertaking a review, Hydro Ottawa is proposing to change its depreciation expense policy with respect to the useful life of laptop computers. Notwithstanding the fact that laptops have an operational or functional lifespan, the primary reason for the replacement of laptops is obsolescence due to advances in software and hardware technology. With the ongoing adoption of data analytics and automated tools, Hydro Ottawa is processing more information and running heavier applications, which requires newer and faster technology. The need to keep computer software and hardware technology current is essential to maintaining and improving user productivity. Moreover, planned obsolescence is a key consideration in Hydro Ottawa's Information Technology replacement strategy.

While there are many studies and opinions in the public domain regarding how often to replace a laptop, the general consensus is between two to four years.[2] Bearing this in mind, Hydro Ottawa is requesting to reduce the useful life of its laptops from five to four years. (For more information, please refer to Attachment 4-3-1(A): OEB Appendix 2-BB - Service Life Comparison). Hydro Ottawa is also requesting to make changes to the useful life of its transportation equipment. (See Attachment 2-4-3(F): Fleet Replacement Program for further details).

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[1] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).

[2] For example: VBS iT Services, "How Often Should Your Company Replace Computers?" (February 13, 2016); BiTs, "How Often Should Your Company Replace Its Computers" (April 4, 2017).

The requested years of useful life of laptops and transportation equipment are within the ranges contained in the Asset Depreciation Study for the OEB prepared by Kinectrics Inc. dated July 8, 2010.[3]

[3] Kinetrics Inc., *Asset Depreciation Study for the Ontario Energy Board,* Report No. K-418033-FA-001-R000 (July 8, 2010).

HYDRO OTTAWA CORPORATE POLICY

Subject: Capitalization		
Category: Finance		**Policy Number**: POL-Fi-013.01
Administrator: Director, Finance	**Owner:** Chief Financial Officer	**Approver:** President and Chief Executive Officer

1. **PURPOSE**
The purpose of this policy is to define the criteria for acquisition, capitalization, transfer and retirement of Hydro Ottawa capital assets.

2. **SCOPE**
This policy applies to Hydro Ottawa.

3. **DEFINITIONS**
Capital assets include tangible and intangible assets, exclusive of goodwill
Commissioned or energized, in the context of this policy, is when a capital asset is placed into service or when the enhancement or betterment to an existing capital asset is complete
Directly Attributable Costs are costs that bring the asset to the location and condition intended for use, and include direct labour, inventory, outside services, non-stock materials and specific burdens
Enhancement or Betterment is an expenditure that contributes towards improving an asset's productivity or output or useful life
Goodwill, as defined by IAS 38, is the difference between the purchase price of an asset and the net amount of the acquired asset and assumed liability
Grouped Assets are asset purchases that are pooled into a single capital asset category as, by their nature, it would be impractical to identify individual units. These grouped assets are managed as a single asset for the purposes of depreciation
Hydro Ottawa refers to Hydro Ottawa Holding Inc. and its affiliates
IAS refers to International Accounting Standards
IAS 16 refers to the International Accounting Standard titled Property, Plant and Equipment
IAS 23 refers to the International Accounting Standard titled Borrowing Costs
IAS 38 refers to the International Accounting Standard titled Intangible Assets
IASB refers to the International Accounting Standards Board
IFRS refers to International Financial Reporting Standards
Intangible Assets, as defined by IAS 38, are identifiable non-monetary assets without physical substance
OM&A refers to operating, maintenance and administrative expenses
PP&E refers to Property, Plant and Equipment or Tangible Assets
Readily Identifiable Assets are discrete capital assets that are easily identifiable, so the asset can be individually recorded and depreciated
Residual Value is the estimated amount that an entity would currently obtain from disposal of the asset, after deducting the estimated costs of disposal, if the asset were already of the age and in the condition expected at the end of its useful life
Tangible Assets, as defined by IAS 16, include PP&E that are used on a continuing basis in the production or supply of goods and services and are not intended for sale in the ordinary course of business

4. **POLICY DIRECTIVES**
   a) Hydro Ottawa will capitalize assets based on the standards established by the IASB under IAS 16 and IAS 38 whereby qualifying expenditures have to meet the following criteria:
      i. It is probable that further economic benefits associated with the item, for more than one year, will flow to the entity; and
      ii. the cost of the item can be measured reliably.
   b) Capital asset are recorded using the cost method, whereby the cost of a capital asset comprises:
      i. its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates.

ii. any costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management. This shall include borrowing costs, in accordance with IAS 23, to finance capital projects with a duration greater than six months and accumulated cost is in excess of $100,000.
iii. the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period.

c) Contributed plant that meets the definition of a capital asset is measured at fair value.
d) The following cost allocation rates included in directly attributable costs are based on management's best estimates of the applicable cost allocation determinants:
   i. Direct Labour - The hourly rate recovers direct labour and benefits costs. It will be applied to all direct labour hours through timesheet reporting.
   ii. Vehicle and Equipment - Vehicle and equipment hourly rates capture the directly attributable costs associated with fleet usage. Individual rates are developed for major vehicle classifications based on expected utilization. Charges will be accomplished through vehicles timesheet reporting.
   iii. Supervision Burden - The supervision burden rate recovers the directly attributable costs associated with the supervision of internal labour and outside services.
   iv. Engineering Burden - The engineering burden rate recovers the directly attributable engineering costs. It will be applied to Distribution Capital projects where applicable.
   v. Supply Chain Burden - The supply chain burden rate recovers the directly attributable procurement and warehouse costs.
   vi. These rates are reviewed and monitored on an annual basis. Material adjustments for over or under recoveries will also be recorded at the end of the fiscal year.
e) Subsequent enhancement or betterment costs which are incurred after the original asset is available for use will be capitalized based on the same criteria as the initial capital investment.
f) The materiality value for capitalizing newly acquired readily identifiable assets or additions to existing assets will be $500.
g) The materiality value for capitalizing grouped assets will be $1,000.
h) Equipment such as switchgear, transformers and meters that are reserved for emergency (capital spares) should be accounted as capital assets otherwise these items will be accounted for as inventory.
i) Depreciation of capital assets is based on the straight-line method in accordance with IAS 16 and 38. The useful lives of assets are reviewed annually.
j) Costs that are incurred to maintain the existing service potential of capital assets should be considered repairs and will be recognized in the profit or loss in the period in which they occur.
k) Hydro Ottawa may incur expenditures for amounts paid to other distributors or transmitters for capital projects. These expenditures, once available for use, should be recorded as Intangible Assets – Capital Contributions Paid.
l) Customer contributions associated with capital projects will be treated as deferred revenue and amortized to income over the life of the assets to which they relate.
m) When assets are retired from service, the capital cost and accumulated depreciation will be removed from Hydro Ottawa's financial statements with any gain or loss (after salvage proceeds, if applicable) charged to OM&A in the period in which the decommissioning occurs.

5. RELATED POLICIES, PROCEDURES AND REFERENCE DOCUMENTS

Hydro Ottawa Code of Business Conduct

6. EXCLUSIONS

There are no exclusions from this policy

7. ADDITIONAL POLICY ELEMENTS

There are no additional policy elements

8. COMPLIANCE

Employees must report incidents of non-compliance relating to this policy in a timely manner to the Policy Owner.

All instances of non-compliance shall be addressed immediately and may result in progressive disciplinary action. All members of the work group who had prior knowledge of the non-compliance may also be subject to progressive discipline. Repeat instances of non-compliance, or those that appear to be of a serious nature, must be immediately reported directly to the Director, Finance.

9. APPROVAL HISTORY

Revision	Effective Date	Description of Changes	Policy Owner:	Approved by:
.00	January 2015	Supersedes Policy FIN5-001-02 published on January 1, 2009	G. Simpson, Chief Financial Officer	B. Conrad, President and CEO
.01	October 2019	Minor updates to wording to match IFRS Standards and clause added regarding CCRA payments	DocuSigned by: Geoff Simpson 43DC885CF33E43F... G. Simpson, Chief Financial Officer	DocuSigned by: Bryce Conrad 8EDB4595749C4E3... B. Conrad, President and CEO
Scheduled Re-affirmation Date: **October 2022**		Responsibility: **Chief Financial Officer**		
Signatures on original only; original retained by Chief Financial Officer Division				

10. POLICY EXCEPTIONS

Exceptions to the above directives and/or changes to this policy must receive written pre-authorization from the President and CEO. For clarification on any aspect of this policy, contact the Director of Finance.

UPDATED CAPITALIZATION OF OVERHEAD

Effective January 1, 2012, Hydro Ottawa revised its capitalization methodology used to apply overhead costs to property, plant, and equipment and intangible assets to be in accordance with International Financial Reporting Standards ("IFRS"). Under IFRS, International Accounting Standard 16 – *Property, Plant and Equipment* ("IAS 16") and International Accounting Standard 38 – *Intangible Assets* ("IAS 38") prohibit the capitalization of administration and other general overhead costs. As a result, the amount of capitalized overhead was significantly reduced as many of the costs that were capitalized prior to the revision of the policy were considered administrative or other general overhead. There have been no changes to Hydro Ottawa's capitalization of overhead since January 1, 2012 (and thus there have likewise been no changes since the utility's last rebasing application).

Hydro Ottawa applies overhead costs to capital through three separate burden rates: Supervision burden, Engineering burden, and Supply Chain burden. The use of multiple burden rates allows overhead costs to be applied more precisely to the particular projects that are associated with the various types of overhead costs. Please refer to Attachment 2-4-4(A): Capitalization Policy for Hydro Ottawa's capitalization policy.

As shown in UPDATED Attachment 2-4-5(A): OEB Appendix 2-D - Overhead Expenses, the overhead costs capitalized (including labour and fleet) from 2017-2021 are in the range of 26% to 29%.

UPDATED - Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Bridge Year	2021 Test Year
Distribution Operations	$ 42,072,595	$ 42,985,534	$ 40,399,152	$ 44,455,558	$ 45,958,946
Engineering & Design	$ 12,437,569	$ 13,398,062	$ 12,507,395	$ 13,977,990	$ 14,167,879
Customer Billing	$ 8,936,703	$ 8,912,271	$ 9,120,268	$ 9,274,258	$ 9,619,556
Customer & Community Relations	$ 7,300,361	$ 7,010,829	$ 6,477,554	$ 8,003,925	$ 8,617,580
Collections, Acct & Activities	$ 3,781,614	$ 2,948,863	$ 2,371,317	$ 3,278,626	$ 3,377,588
Facilities	$ 6,443,441	$ 7,127,723	$ 9,919,789	$ 7,338,521	$ 7,475,608
Finance	$ 3,847,245	$ 3,963,955	$ 3,303,451	$ 3,340,269	$ 3,441,938
Human Resources & Training	$ 3,889,418	$ 4,056,098	$ 3,316,757	$ 3,853,861	$ 3,939,877
Information Mgt & Technology	$ 10,722,068	$ 10,884,225	$ 10,101,028	$ 11,952,687	$ 10,310,302
Metering	$ 2,856,917	$ 2,621,587	$ 2,454,821	$ 2,967,981	$ 3,074,131
Regulatory Affairs	$ 2,037,050	$ 2,157,111	$ 2,019,155	$ 2,248,403	$ 2,998,222
Safety, Environment & Bus Cont	$ 2,261,796	$ 3,434,261	$ 4,228,570	$ 3,662,418	$ 3,719,278
Supply Chain	$ 2,632,039	$ 2,465,807	$ 2,489,293	$ 2,267,583	$ 2,321,330
Corporate Costs	$ 5,854,631	$ 6,385,206	$ 5,041,203	$ 7,070,979	$ 7,625,461
Total OM&A Before Capitalization (B)	$ 115,073,447	$ 118,351,532	$ 113,749,753	$ 123,693,059	$ 126,647,696

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Bridge Year	2021 Test Year	Directly Attributable? (Yes/No)	Explanation for Change in Overhead Capitalized
Supply Chain	$ 1,160,695	$ 1,213,508	$ 1,200,746	$ 1,205,476	$ 1,231,474	Yes	
Supervision	$ 2,365,426	$ 2,539,391	$ 2,315,815	$ 2,287,211	$ 2,530,939	Yes	
Engineering	$ 3,020,405	$ 3,235,342	$ 3,153,225	$ 2,910,979	$ 3,184,311	Yes	
Fleet	$ 2,954,501	$ 3,101,160	$ 3,010,871	$ 3,333,470	$ 3,317,225	Yes	
Labour	$ 23,327,587	$ 21,398,793	$ 20,956,236	$ 21,965,502	$ 22,461,088	Yes	
Total Capitalized OM&A (A)	$ 32,828,614	$ 31,488,194	$ 30,636,893	$ 31,702,638	$ 32,725,037		

% of Capitalized OM&A (=A/B)	29%	27%	27%	26%	26%		

SERVICE QUALITY AND RELIABILITY PERFORMANCE

1. INTRODUCTION

Hydro Ottawa reports service quality indicators, which consist of Service Quality Requirements ("SQRs") and service reliability metrics, to the OEB on an annual basis. As per section 2.2.2.8 of the *Chapter 2 Filing Requirements for Electricity Distribution Rate Applications*, as updated on July 12, 2018 and addended on July 15, 2019, this Schedule provides the reported SQR and service reliability metrics reported to the OEB for the last five Historical Years. As required, a summary of the Major Event Days ("MEDs") experienced by Hydro Ottawa since 2016 is presented in section 3 below, along with a comprehensive cause code analysis for the 2014-2018 period. In addition, the OEB's Appendix 2-G is included as Attachment 2-4-6(A). Hydro Ottawa confirms that the information presented in this Schedule and in Appendix 2-G is consistent with the Electricity Utility Scorecard.

2. SERVICE QUALITY PERFORMANCE

Section 7 of the *Distribution System Code* outlines the OEB's expectations regarding SQRs for electricity distributors. As shown in Table 1 below, Hydro Ottawa's SQR results have remained steadily above the OEB minimum standard for the last five Historical Years (2014-2018). On average, Hydro Ottawa's SQR performance exceeded the OEB minimum standard by 9% for the 2014-2018 period. In some cases, the utility exceeded the minimum standard by over 20%. (For example, Hydro Ottawa's 2018 Telephone Accessibility SQR result is 23.7% above the OEB's minimum standard). At no time over the 2014-2018 period did Hydro Ottawa fail to meet the OEB's minimum standard for any service quality indicator.

Table 1 – Five-Year Historical Summary of Service Quality Requirements

Indicator	OEB Minimum Standard	2014	2015	2016	2017	2018
Low Voltage Connections*	**90%**	100%	100%	100%	100%	100%
High Voltage Connections	**90%**	100%	100%	100%	100%	100%
Telephone Accessibility*	**65%**	80.3%	82.5%	83.8%	85.1%	88.7%
Appointments Met*	**90%**	98.3%	97.1%	99.6%	99.4%	99.7%
Written Responses	**80%**	100%	100%	100%	100%	100%
Emergency Urban Response	**80%**	98.8%	98.0%	97.8%	99.5%	96.6%
Emergency Rural Response[1]	**80%**	n/a	n/a	n/a	n/a	n/a
Telephone Call Abandon Rate	**10%**	2.3%	1.7%	1.8%	1.7%	0.4%
Appointment Scheduling	**90%**	100%	100%	100%	100%	100%
Rescheduling a Missed Appointment	**100%**	100%	100%	100%	100%	100%
Reconnection Performance Standard	**85%**	100%	100%	100%	100%	100%
Billing Accuracy*	**98%**	99.6%	99.8%	99.9%	99.9%	99.9%

* indicates measure appears on the Electricity Utility Scorecard

Hydro Ottawa aims to maintain all SQRs above the OEB's minimum standard. For detailed discussion on Hydro Ottawa's performance with respect to key SQRs that appear on the Electricity Utility Scorecard, please see Attachment 1-1-12(C).

3. RELIABILITY PERFORMANCE

Hydro Ottawa continually assesses the distribution system's service reliability. Where issues are found, the appropriate analysis and action is undertaken to address weaknesses and improve performance. Hydro Ottawa's Reliability Council is one example of how continued focus is maintained and actioned with regards to system and customer reliability. Comprised of stakeholders from across the utility, the purpose of this council is to further foster a robust

[1] Hydro Ottawa's service territory is a mix of urban and rural areas, with approximately 60% of the territory considered rural. The administrative complexity of capturing urban and rural response rates relative to Hydro Ottawa's emergency response rate overall is not cost-effective or insightful for the utility. Rather, Hydro Ottawa strives to adhere to the urban emergency response rate (60 minutes as opposed to 120 minutes) for both rural and urban customers.

culture of reliability and drive change from a diverse set of perspectives to deliver solutions. The council meets monthly to review system performance and operational issues.

Consistent with OEB requirements and best industry practices, two principal metrics employed by Hydro Ottawa to measure the utility's reliability performance are the following: System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI"). In the Electricity Utility Scorecard, the OEB utilizes plain language metrics as substitutes for these terms: "Average Number of Hours that Power to a Customer is Interrupted" is synonymous with SAIDI, while "Average Number of Times that Power to a Customer is Interrupted" is synonymous with SAIFI. For the purpose of this Schedule, Hydro Ottawa will use the terms SAIDI and SAIFI.

Hydro Ottawa's reliability performance in 2018 was significantly impacted by three severe weather events: freezing rain and windy conditions on April 16th, heavy winds on May 4th, and tornadoes on September 21st. These major events experienced during 2018 included significant outage impacts resulting from Loss of Supply ("LoS") from the Ontario grid. Out of an overall SAIDI score of 22.08 in 2018, 19.29 is attributable to these events.

Table 2, Table 3, and Table 4 below present information on Hydro Ottawa's five-year reliability performance under the different parameters which Hydro Ottawa reports to the OEB through the Reporting and Record Keeping Requirements ("RRRs") – namely, with either one or both of LoS and MEDs excluded or included.

Table 2 – Five-Year Historical Summary of SAIDI and SAIFI (including LoS and MEDs)

Index	Including outages caused by Loss of Supply and including Major Event Days					5-Year Historical Average
	2014	2015	2016	2017	2018	
SAIDI	1.66	1.62	1.21	1.58	22.83	*5.780*
SAIFI	1.08	1.42	0.95	1.03	2.03	*1.302*

Table 3 – Five-Year Historical Summary of SAIDI and SAIFI (excluding LoS and including MEDs)

Index	Excluding outages caused by Loss of Supply and including Major Event Days					5-Year Historical Average
	2014	2015	2016	2017	2018	
SAIDI	1.59	1.15	1.13	1.51	3.54	*1.784*
SAIFI	0.86	0.75	0.78	0.83	1.19	*0.882*

Table 4 – Five-Year Historical Summary of SAIDI and SAIFI (excluding LoS and MEDs)

Index	Excluding outages caused by Loss of Supply and excluding Major Event Days					5-Year Historical Average
	2014	2015	2016	2017	2018	
SAIDI	1.08	1.08	1.00	1.11	0.85	*1.024*
SAIFI	0.73	0.71	0.74	0.73	0.78	*0.734*

In order to facilitate an understanding of how the utility's 2014-2018 reliability performance compared against utility-specific reliability targets established by the OEB, Hydro Ottawa has included Table 5 below.

Table 5 – Five-Year Historical Summary of SAIDI and SAIFI (excluding LoS and MEDs) vs. OEB-Assigned Reliability Targets

Index	Excluding outages caused by Loss of Supply and excluding Major Event Days				
	2014	2015	2016	2017	2018
SAIDI	1.08	1.08	1.00	1.11	0.85
SAIFI	0.73	0.71	0.74	0.73	0.78
Index	5-Year Average Targets[2]				
	2014	2015	2016	2017	2018
SAIDI	1.04	1.09	1.15	1.12	1.13
SAIFI	1.02	0.99	0.98	0.90	0.83

Over the course of 2014-2018, Hydro Ottawa successfully achieved its SAIDI and SAIFI targets, which were based on historical five-year averages. The lone exception was in 2014, when the SAIDI value excluding LoS and MEDs exceeded the five-year average by 0.04. The 2014 SAIDI value excluding LoS and MEDs was an improvement over the SAIDI results in the three preceding years (2011-2013). In those years, Hydro Ottawa had experienced lower than historic service reliability marked by significant impacts of adverse weather and defective equipment interruptions. The utility's improving trend leading to 2014 and continued maintenance of target results in subsequent years can be attributed to a review and update of its vegetation management program, aimed at storm-hardening its system by removing all tree overhang in 2014 and 2015, as well as to continued targeted renewal of distribution assets.

The average number of hours of customer power interruption (i.e. SAIDI) in 2018 was 0.85 (excluding LoS and MEDs), which represents an improvement over historical performance. With LoS and MEDs excluded, Hydro Ottawa's SAIFI results were generally consistent over the 2014-2018 period.

[2] Targets are determined by the OEB such that they represent reliability performance that is equivalent or superior to the previous five-year average.

3.1. MAJOR EVENT DAYS

Since Hydro Ottawa's last rebasing in 2016,[3] and through the end of the 2018 calendar year, Hydro Ottawa has experienced six MEDs. The utility determines MEDs based on the IEEE Standard 1366 method. In 2018, there was a noted increase in the severity of MEDs with regards to the number of customer interruptions and number of customer hours of interruption experienced during each event. For further information on this increase, please see section 4.3.2 of Exhibit 2-4-3: Distribution System Plan.

Table 6 below provides key details on each of the MEDs experienced by Hydro Ottawa during the 2016-2018 timeframe.

Table 6 – Summary of Major Event Days (2016-2018)

Date of Major Event	Primary Cause of Interruption	Description	Number of Interruptions	Number of Customer Interruptions	Number of Customer Hours of Interruption
September 21, 2018	Loss of Supply	Tornadoes	39	216,001	6,808,300
May 4, 2018	Adverse Weather	High Winds	41	63,869	244,733
April 16, 2018	Adverse Weather	Freezing Rain	63	55,101	257,931
September 27, 2017	Tree Contact	High Winds	40	11,391	94,006
January 4, 2017	Tree Contact	Freezing Rain and Heavy Snow	38	19,130	38,115
July 1, 2016	Adverse Weather	Thunderstorm, Lightning and Tree Contact	16	12,297	41,791

[3] Hydro Ottawa Limited, *2016-2020 Custom Incentive Rate-Setting Distribution Rate Application*, EB-2015-0004 (April 29, 2015).

3.2. CAUSE CODE ANALYSIS

Hydro Ottawa records all outage causes and monitors the primary causes for trends. Where trends are identified, the utility performs detailed analysis into the root causes to assess risk and identify investment needs. Table 7 below provides a breakdown of each primary cause set out in section 2.1.4.2.5 of the RRRs for the last five years.

From 2014-2018, the four primary contributors to SAIFI and SAIDI were the following: Loss of Supply, Defective Equipment, Scheduled Outages, and Adverse Weather. These four cause codes account for 64% of the SAIFI and 89% of the SAIDI, as shown below in Tables 8 and 9, and in Figures 1 and 2.

Table 7 – Reliability Performance by Cause Code (2014-2018)

Primary Cause		2014	2015	2016	2017	2018
Unknown/Other	Number of Interruptions	34	52	37	39	49
	Customer Interruptions	11,751	18,802	32,593	17,961	43,021
	Customer-Hours	18,575	10,639	16,156	10,625	19,463
Scheduled Outage	Number of Interruptions	1,068	1,200	1,031	863	762
	Customer Interruptions	24,851	34,162	31,446	20,436	20,103
	Customer-Hours	76,844	101,699	97,984	62,770	40,273
Loss of Supply	Number of Interruptions	28	24	11	17	52
	Customer Interruptions	71,072	214,891	58,466	66,181	278,727
	Customer-Hours	23,371	148,471	26,002	23,557	6,436,022
Tree Contacts	Number of Interruptions	73	99	88	191	157
	Customer Interruptions	15,652	16,253	26,006	39,675	54,923
	Customer-Hours	24,950	25,578	58,121	115,929	183,236
Lightning	Number of Interruptions	37	17	32	33	27
	Customer Interruptions	29,279	11,957	24,130	15,711	21,822
	Customer-Hours	77,122	23,319	18,739	6,919	22,298
Defective Equipment	Number of Interruptions	276	210	200	364	369
	Customer Interruptions	88,483	82,008	58,747	62,993	89,393
	Customer-Hours	120,603	113,818	94,802	109,659	133,733
Adverse Weather	Number of Interruptions	72	29	40	67	101
	Customer Interruptions	43,110	6,715	17,467	27,839	113,916
	Customer-Hours	117,892	8,693	35,612	93,957	727,176
Adverse Environment	Number of Interruptions	12	18	5	10	2
	Customer Interruptions	287	19,935	1,960	13,338	167
	Customer-Hours	870	26,612	5,389	17,794	378
Human Element	Number of Interruptions	24	19	20	33	31
	Customer Interruptions	32,295	34,456	27,288	38,459	21,144
	Customer-Hours	38,396	36,966	5,624	42,095	14,676
Foreign Interference	Number of Interruptions	146	124	155	163	186
	Customer Interruptions	27,097	16,547	32,989	36,021	33,803
	Customer-Hours	28,608	23,829	35,659	36,999	38,512

Table 8 – Annual Contribution to SAIFI by Cause Code (2014-2018)

Cause Code		2014	2015	2016	2017	2018	5-Year Average
0	Unknown/Other	3.42%	4.13%	10.48%	5.30%	6.35%	*5.94%*
1	Scheduled Outage	7.23%	7.50%	10.11%	6.04%	2.97%	*6.77%*
2	Loss of Supply	20.67%	47.15%	18.79%	19.54%	41.17%	*29.46%*
3	Tree Contacts	4.55%	3.57%	8.36%	11.72%	8.11%	*7.26%*
4	Lightning	8.51%	2.62%	7.76%	4.64%	3.22%	*5.35%*
5	Defective Equipment	25.73%	18.00%	18.88%	18.60%	13.20%	*18.88%*
6	Adverse Weather	12.54%	1.47%	5.61%	8.22%	16.83%	*8.93%*
7	Adverse Environment	0.08%	4.37%	0.63%	3.94%	0.02%	*1.81%*
8	Human Element	9.39%	7.56%	8.77%	11.36%	3.12%	*8.04%*
9	Foreign Interference	7.88%	3.63%	10.60%	10.64%	4.99%	*7.55%*

Figure 1 – SAIFI by Cause Code: Five-Year Average (2014-2018)

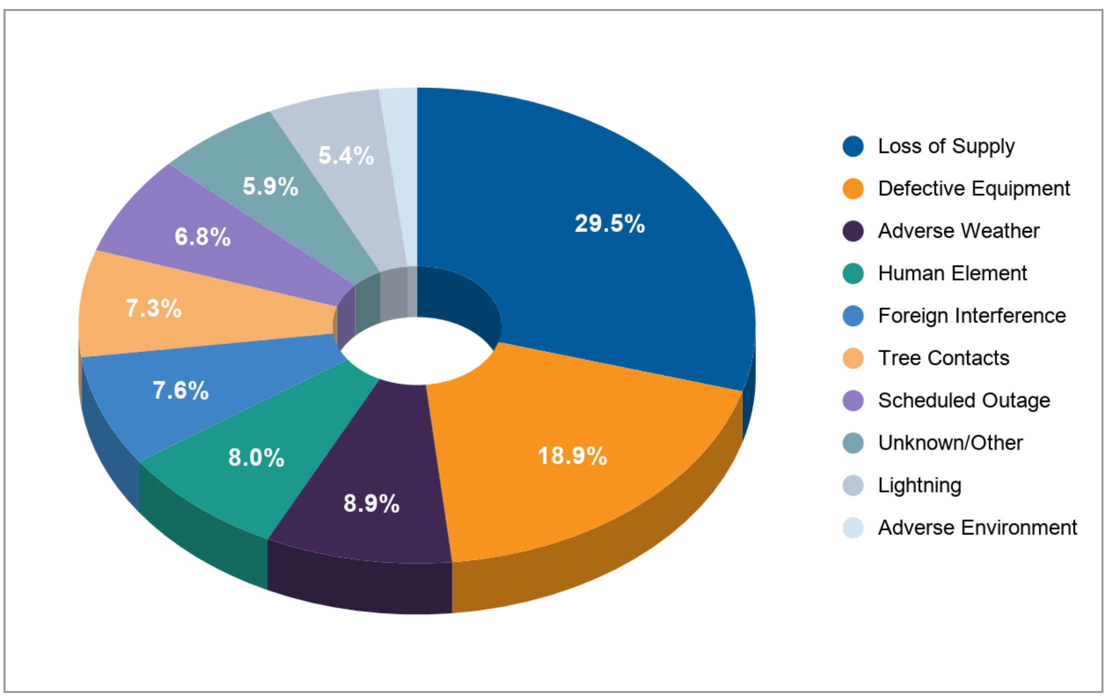
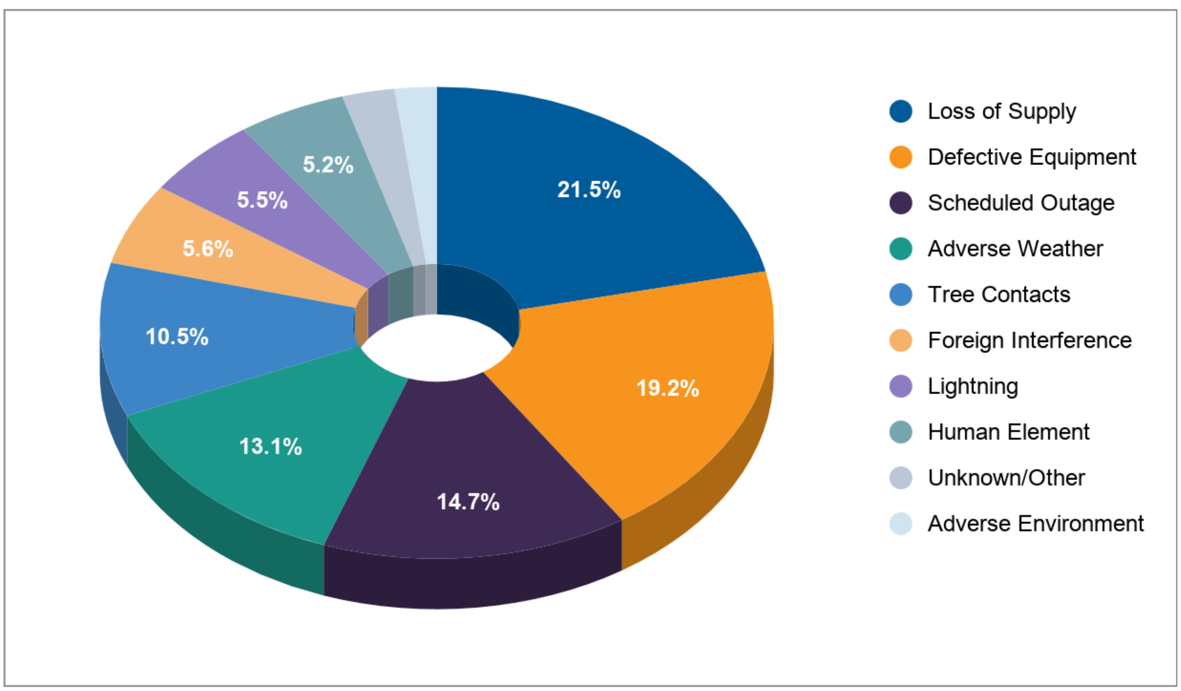


Table 9 – Annual Contribution to SAIDI by Cause Code (2014-2018)

Cause Code		2014	2015	2016	2017	2018	5-Year Average
0	Unknown/Other	5.40%	2.33%	5.19%	3.14%	0.26%	*3.26%*
1	Scheduled Outage	22.35%	22.32%	31.50%	18.54%	0.53%	*19.05%*
2	Loss of Supply	6.80%	32.58%	8.36%	6.96%	84.51%	*27.84%*
3	Tree Contacts	7.26%	5.61%	18.68%	34.24%	2.41%	*13.64%*
4	Lightning	22.43%	5.12%	6.02%	2.04%	0.29%	*7.18%*
5	Defective Equipment	35.07%	24.98%	30.47%	32.38%	1.76%	*24.93%*
6	Adverse Weather	34.28%	1.91%	11.45%	27.75%	9.55%	*16.99%*
7	Adverse Environment	0.25%	5.84%	1.73%	5.25%	0.00%	*2.61%*
8	Human Element	11.17%	8.11%	1.81%	12.43%	0.19%	*6.74%*
9	Foreign Interference	8.32%	5.23%	11.46%	10.93%	0.51%	*7.29%*

Figure 2 – SAIDI by Cause Code: Five-Year Average (2014-2018)



3.2.1. Unknown/Other

Outages due to Unknown/Other are on a slightly increasing trend over the last five years, as shown in Table 7 above. Hydro Ottawa strives to identify the root causes of outages through line patrols and fault point analysis.

3.2.2. Scheduled Outage

Scheduled Outages were a significant contributor to the annual customer reliability results, representing 19% of the SAIDI result and 7% of the SAIFI result. While scheduled interruptions are essential to completing distribution work safely and efficiently, Hydro Ottawa has made the effort to reduce the impact on customers when planning outages. These efforts can be seen in a decreasing trend in both Scheduled Outage SAIDI and SAIFI over the last five years, as indicated in Table 7 above. Hydro Ottawa has made the effort to reduce the impact on customers when planning outages. This includes installing temporary switches and using live-line techniques to minimize the number of customers affected.

3.2.3. Loss of Supply

The reliability and redundancy of the system supply is continuously evaluated as part of system planning exercises. The overall reliability result was significantly impacted by the unprecedented LoS impacts associated with major events in 2018. Excluding the 2018 result, LoS has tracked to 14% of SAIDI and 27% of SAIFI. From 2014-2017, LoS had a relatively constant frequency and customer impact, as shown in Table 7. Hydro Ottawa works proactively to identify and address supply reliability issues, whether working with the transmitter (Hydro One Networks Inc.), addressing supply issues, or mitigating their impact through distribution interties.

3.2.4. Tree Contacts

As per the information displayed in Table 7, outages due to Tree Contacts are on an upward trend over the last five years. The increasing trend is attributed largely to an increase in large tree limbs and full trees falling onto wires from outside the powerline corridor, typically as a result of extreme weather events. Hydro Ottawa has reviewed and continues to evaluate the performance of its vegetation management program and is increasingly working with customers to address risk trees outside the trim zones wherever possible.

3.2.5. Lightning

The impact associated with Lightning outages is on a declining trend, as shown in Table 7 above. Hydro Ottawa mitigates sustained outages through its system design and application of lighting protection and shielding.

3.2.6. Defective Equipment

Defective Equipment was the second largest contributor to annual customer reliability, representing 25% of the SAIDI result and 19% of the SAIFI result. Outages due to Defective Equipment are on an increasing trend over the last five years. However, despite its increasing trend, the impact of these outages on the number of customers interrupted and customer-hours is relatively constant, as indicated above in Table 7. Hydro Ottawa has been mitigating risk due to asset failures by prioritizing renewal investments and targeting asset classes with higher reliability impact. Analysis of contributions to the overall results of different asset groups can be found in section 4.1.3.1 of Exhibit 2-4-3: Distribution System Plan.

3.2.7. Adverse Weather

Adverse Weather was another major contributor to the annual customer reliability results, contributing to 17% of SAIDI and 9% of SAIFI. Outages due to Adverse Weather are on an increasing trend over the last five years, as per Table 7 above. Historical outages have been largely due to high winds and freezing rain weather. Many of the extreme weather events have resulted in the classification of MEDs, as described above in section 3.2 above. The impact of these extreme weather events on Hydro Ottawa’s assets and operations has increased over the past decade. In response to these events, Hydro Ottawa has undertaken the preparation of a Climate Vulnerability Risk Assessment and subsequent development of an adaptation plan as part of its distribution planning activities. For more information, please see section 8.1.6.3 of Exhibit 2-4-3: Distribution System Plan, Attachment 2-4-3(H): Distribution System Climate Risk and Vulnerability Assessment, and Attachment 2-4-3(I): Hydro Ottawa Climate Change Adaptation Plan.

3.2.8. Adverse Environment

As shown in Table 7 above, outages due to Adverse Environment are on a declining trend over the last five years. Historical outages have been largely due to pole fires occurring as a result of salt contamination on insulators, caused by the City of Ottawa's winter de-icing efforts. Hydro Ottawa has mitigated these risks by performing a bi-annual insulator wash program to clean insulators of salt and other contamination. In addition, renewal and replacement of insulators with polymer insulators which are less susceptible to this failure mode continues to reduce the overall risk profile.

3.2.9. Human Element

Outages due to Human Element have occurred on a relatively steady basis over the last five years; however, the impact of these outages are on a declining trend, as indicated in Table 7 above. Historical outages have been largely due to incorrect records and switching errors. Each incident is reviewed and appropriate actions such as records updates, procedural changes, or employee training are undertaken to prevent reoccurrence.

3.2.10. Foreign Interference

Outages due to Foreign Interference have shown an increasing trend over the last five years, as captured above in Table 7. However, the number of Foreign Interference interruptions in 2013 were nearly equivalent to the 2018 outcome, suggesting a long-term level trend. Historical outages have been largely due to animals and foreign objects contacting the lines. Hydro Ottawa's standard for new construction requires the incorporation of animal guards. In addition, legacy construction is being retrofitted in a targeted and prioritized manner.

Appendix 2-G
Service Quality and Reliability Indicators

Service Reliability

Index	Including outages caused by loss of supply and including Major Event Days					Excluding outages caused by loss of supply and including Major Event Days					Excluding outages caused by loss of supply and excluding Major Event Days				
	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018	2014	2015	2016	2017	2018
SAIDI	1.66	1.62	1.21	1.58	22.83	1.59	1.15	1.13	1.51	3.54	1.08	1.08	1.00	1.11	0.85
SAIFI	1.08	1.42	0.95	1.03	2.03	0.86	0.75	0.78	0.83	1.19	0.73	0.71	0.74	0.73	0.78

5 Year Historical Average

SAIDI		5.780		1.784		1.024
SAIFI		1.302		0.882		0.738

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2014	2015	2016	2017	2018
Low Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
High Voltage Connections	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Telephone Accessibility	65.0%	80.3%	82.5%	83.8%	85.1%	88.7%
Appointments Met	90.0%	98.3%	97.1%	99.6%	99.4%	99.7%
Written Response to Enquires	80.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Emergency Urban Response	80.0%	98.8%	98.0%	97.8%	99.5%	96.6%
Emergency Rural Response	80.0%	n/a	n/a	n/a	n/a	n/a
Telephone Call Abandon Rate	10.0%	2.3%	1.7%	1.8%	1.7%	0.4%
Appointment Scheduling	90.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	100.0%	100.0%	100.0%