Kitchener-Waterloo-Cambridge-Guelph Integrated Regional Resource Plan

July 8, 2026

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List of Acronyms

Acronym	Definition
BESS	Battery Energy Storage System
CTS	Customer Transformer Station
DER	Distributed Energy Resource
DESN	Dual-Element Spot Network
DG	Distributed Generation
DS	Distribution Station
eDSM	electricity Demand-Side Management
EOL	End-of-life
FIT	Feed-in-Tariff
GBE	GrandBridge Energy
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
km	kilometre
kV	kilovolt
KWCG	Kitchener-Waterloo-Cambridge-Guelph
LDC	Local Distribution Company
LMC	Load-Meeting Capability
LTR	Limited Time Rating
MTS	Municipal Transformer Station
MVA	Megavolt ampere

Acronym	Definition
MW	Megawatt
MWh	Megawatt-hour
NWA	Non-Wires Alternative
ORTAC	Ontario Resource and Transmission Assessment Criteria
SS	Switching Station
TS	Transformer Station

Executive Summary

The Kitchener-Waterloo-Cambridge-Guelph Integrated Regional Resource Plan (KWCG IRRP) addresses electricity needs in the region over the twenty-year period from 2026-2045. The KWCG region is in southwestern Ontario, and encompasses the Region of Waterloo, the cities of Kitchener, Waterloo, Cambridge, and Guelph, and the townships of Wellesley, Woolwich, Wilmot, North Dumfries, portions of Perth, and Oxford. Wellington county and the municipalities of Blandford-Blenheim, Centre Wellington, Guelph/Eramosa, and Puslinch are also included.

Regional electricity planning for the KWCG region has occurred regularly, with this being the third IRRP published since 2015. This IRRP builds upon those previous regional and bulk plans to continue to ensure reliable electricity supply across the region. In this iteration, electricity demand in KWCG is expected to grow rapidly, driven by strong residential, commercial, and industrial development, increasing electrification, and new large loads such as data centres. Significant population and employment growth —alongside major developments like new housing, healthcare facilities, and commercial expansion — will further accelerate electricity needs. In addition, climate change and local climate action plans are expected to increase demand through greater adoption of electric heating, cooling, and electric vehicles, contributing to higher winter peaks.

Engagement was a key input to the development of this IRRP. The IESO engaged with municipalities, stakeholders, and the public throughout the planning process. Activities included targeted one-on-one discussions and four public webinars to share information and solicit written feedback. The overarching themes of feedback received primarily focused on demand forecast inputs and assumptions; leveraging existing and local generation; and regulations for reserving capacity for critical public infrastructure. The feedback received helped shape the demand forecast, identify local priorities, and inform the recommended solutions.

In response to significant growth, the Technical Working Group recommends both immediate actions and longer-term investments:

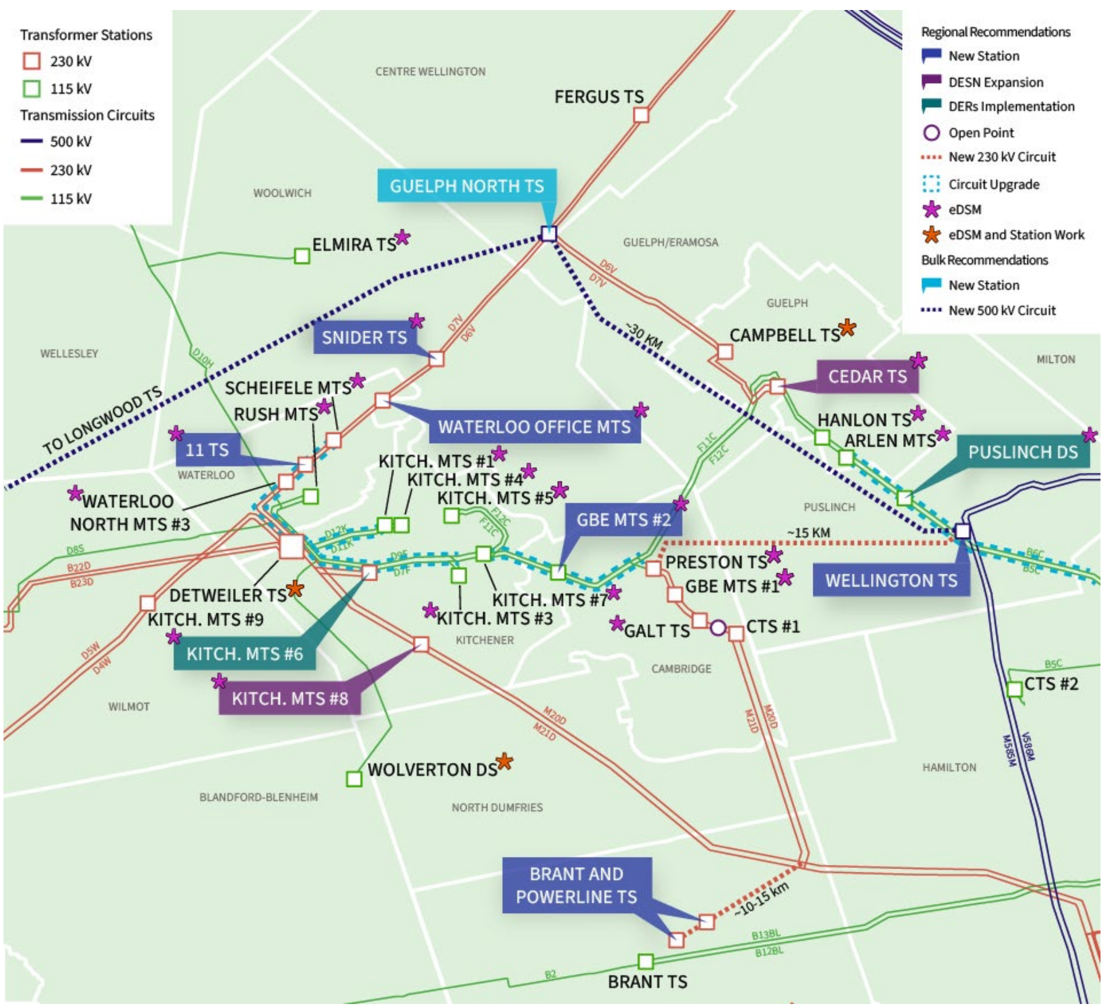
- Considering additional peak demand savings available from electricity demand-side management programming;
- Constructing a 500/230 kV autotransformer station in Puslinch, with a double-circuit 230 kV transmission line connecting it with Preston Transformer Station (TS);
- Conducting station work at Detweiler TS to mitigate the adverse impact of the existing operating instructions to manually trip the static VAR compensator or capacitor under certain breaker-open conditions, and exploring reactive support on the 115 kV sub-system;
- Converting Cedar T7/T8 to 230 kV upon its end of life to address the local station capacity need;
- Uprating various existing 115 kV circuits, as well as sections of the 230 kV circuits between Detweiler and Orangeville;
- Transferring loads on the distribution system to maximize the use of existing transformer stations and supply capability;

- Constructing new 115 kV and 230 kV transformer stations in Cambridge, Kitchener, Guelph, and the Waterloo area;
- Implementing station work at Campbell TS and Wolverton Distribution Station (DS) to increase their capacity; and
- Implementing distributed energy resources at Puslinch DS and Kitchener Municipal Transformer Station #6 to solve station capacity needs.

The Technical Working Group will continue to monitor growth across the region to determine if or when further reinforcements will be needed — including long-term options identified in this plan for a switching station at Galt and further 230 kV transmission lines to Waterloo or Kitchener. The Technical Working Group will meet to develop the Regional Infrastructure Plan, as well as annually between regional planning cycles to monitor any future community energy plans, electrification trends, customer connection queues, and changes to local generation. If underlying assumptions change significantly, plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.

The figure below visually depicts the near- to medium-term IRRP recommendations across the KWCG region (note that distribution-level load transfers are omitted for simplicity).

Figure 1 | Overview of Recommended Solutions for the KWCG IRRP



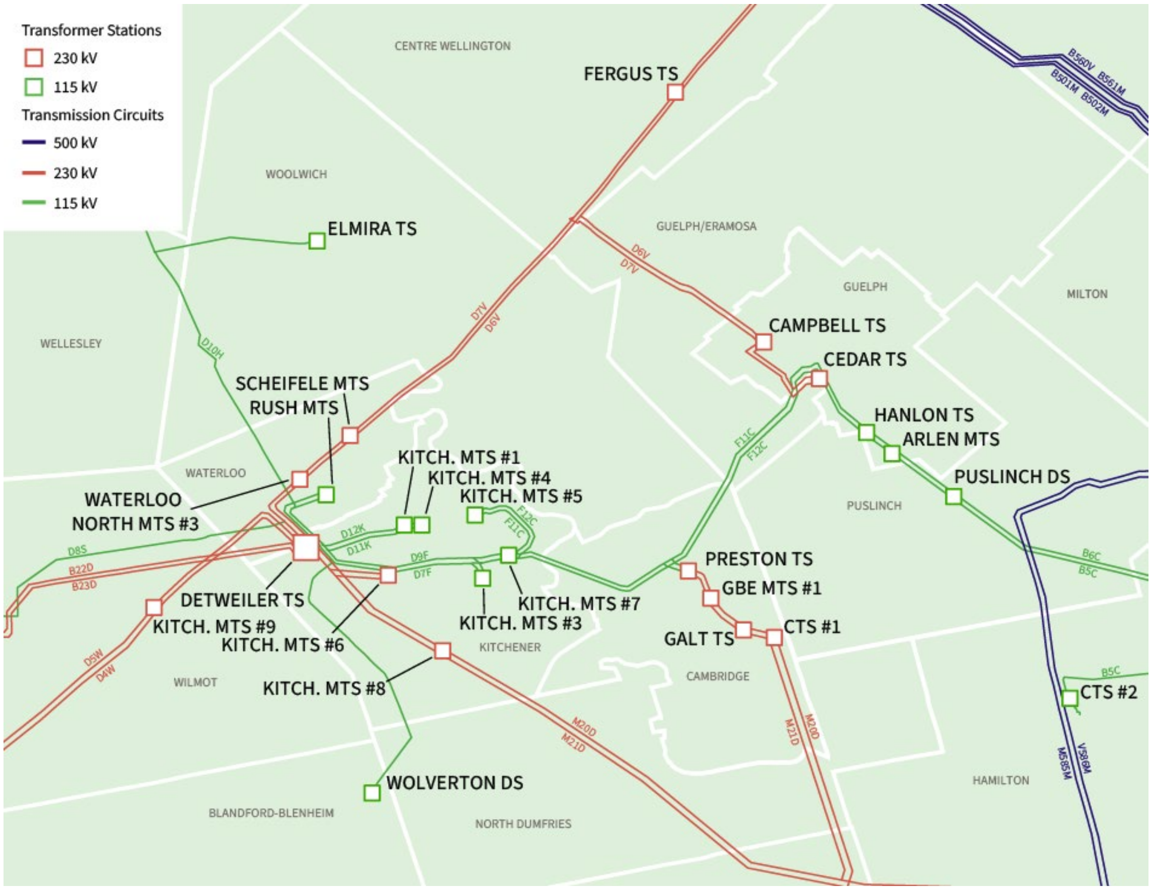
1. Introduction

This Integrated Regional Resource Plan (IRRP) addresses the electricity needs of the Kitchener-Waterloo-Cambridge-Guelph (KWCG) region over the 20-year period from 2026 to 2045. The KWCG region is in southwestern Ontario, and encompasses the Region of Waterloo, the cities of Kitchener, Waterloo, Cambridge, and Guelph, and the townships of Wellesley, Woolwich, Wilmot, North Dumfries, portions of Perth, and Oxford. Wellington county and the municipalities of Blandford-Blenheim, Centre Wellington, Guelph/Eramosa, and Puslinch are also included in the region.

The IESO also acknowledges that KWCG is the traditional territory of many nations, and is committed to ongoing, meaningful dialogue with Indigenous communities to inform long-term planning in the region and across Ontario. To raise awareness about the regional planning cycle in KWCG, and invite participation in the engagement process, the IESO's engagement efforts included outreach to Indigenous communities throughout the development of the plan, including to the Mississaugas of the Credit First Nation, Six Nations of the Grand River as represented by Six Nations Elected Council as well as the Haudenosaunee Confederacy Chiefs Council, and Métis Nation of Ontario. The region's electricity is delivered by eight Local Distribution Companies (LDCs): Enova Power, Alectra Utilities, GrandBridge Energy, Centre Wellington Hydro, Wellington North Power, Halton Hills Hydro Inc., Hydro One Networks Inc. ("Hydro One Distribution"), and Milton Hydro. Hydro One Networks Inc. ("Hydro One Transmission") is the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of a Technical Working Group, composed of the LDCs, Hydro One Transmission, and the IESO.

Figure 2 depicts the electrical transmission infrastructure for the KWCG region. Power is transmitted into the region via 230 kilovolt (kV) and 115 kV circuits originating from Detweiler Transformer Station (TS) and Burlington TS. There are also load stations supplied by double-circuit 230 kV lines connecting Detweiler TS from Orangeville TS (D6V & D7V), Middleport TS (M20D & M21D), and Buchanan TS (D2W & D5W).

Figure 2 | Map of the KWCG Region and Transmission System



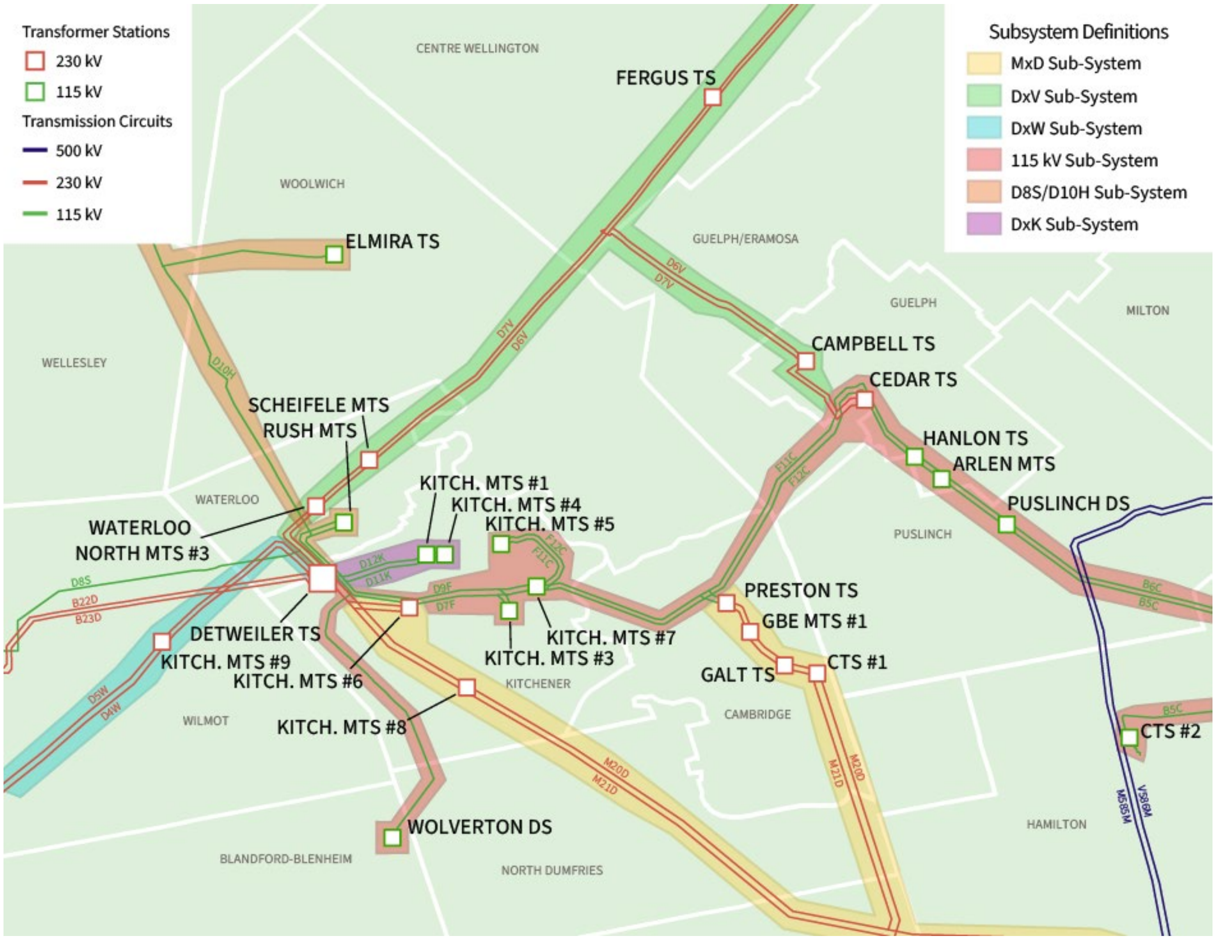
For the purposes of regional planning, the KWCG region has been divided into multiple electrical sub-systems, as shown below in Figure 3.

Detweiler is currently the key bulk supply point for the KWCG region, so many of the sub-systems are defined with this station. For instance, the **Middleport to Detweiler (MxD) sub-system** in the south of the region is electrically defined by the 230 kV supply that connects Detweiler TS in Kitchener to Preston TS in Cambridge, as well as beyond the KWCG region and into Brant. Multiple transformer stations across Kitchener and Cambridge are served by these MxD circuits.

KWCG is characterized by two other 230 kV sub-systems: the double-circuit lines that connect **Detweiler to Orangeville (DxV)**, and **Detweiler to Buchanan (DxW)**. These sub-systems connect the KWCG region to neighbouring regions, but they also supply stations across Waterloo, Wilmot, Guelph, and Centre Wellington.

Much of the KWCG region is otherwise supplied by three lower voltage sub-systems: the **115 kV sub-system** that serves most of Kitchener and to the northeast in Guelph and Puslinch, as well as radial 115 kV lines between **Detweiler and Elmira TS (D10H), Detweiler and Rush Municipal Transformer Station (MTS) (D8S/D10H)**, and **Detweiler and Kitchener MTS #1 and #4 (DxK)**.

Figure 3 | Map of the KWCG Region Sub-Systems



There are two transmission-connected customers in the region served by Customer Transformer Stations (CTS). The distribution-connected resources (DERs), or distributed generation (DG), in the region include solar and wind resources; there are currently no local generation resources connected at the transmission level.

This report is the culmination of the KWCG IRRP, which was initiated in July 2024 following the publication of the Needs Assessment Report in April 2024 by Hydro One, and the Scoping Assessment Outcome Report in July 2024 by the IESO. The Scoping Assessment identified needs requiring further assessment through an IRRP. The Technical Working Group was then formed to gather data, identify near- to long-term needs in the region, and recommend appropriate investments or other electricity system initiatives.

2. The Integrated Regional Resource Plan

The electricity demand forecast, provided by the LDCs for this IRRP, anticipates significant growth over the twenty-year period from 2026 to 2045, driven by population and employment growth, electrification, urban intensification, and commercial sector expansion in KWCG. This IRRP provides recommendations to address electricity needs that arise from this growth. Needs are identified based on the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC), as well as reliability standards governed by the North American Electric Reliability Corporation. The IRRP's recommendations are informed by an evaluation of different options to meet the needs, considering reliability, cost, technical feasibility, maximizing use of the existing electricity system (where economical), and feedback from stakeholders.

The IRRP recommendations below are organized by near-term, medium-term, and other ongoing or long-term initiatives to address needs within the KWCG network. This distinction reflects the different levels of forecast certainty, lead time for development, and planning commitment required over different time horizons. This approach ensures that the IRRP provides clear direction on investments needed in the near and medium term, while retaining flexibility over the long term as electrification, energy efficiency, and development plans evolve.

2.1 Status of Ongoing Work

Following the last cycle of region planning, several projects previously recommended have now been completed or are presently underway. The status of these projects is summarized in Table 1.

Table 1 | Summary of Ongoing and Recently Completed Projects

Circuit/Station	Need	Recommended Action	Status
B5C 115 kV transmission line	End of life (EOL)	Line section replacement; line tap section from Harper's JCT to CTS 1	Completed Q3 2025
Hanlon TS (T1 & T2)	EOL	Transformer replacement	Completed Q3 2022
Kitchener MTS #5 (T9 & T10)	EOL	Transformer replacement	Completed Q2 2025
Preston TS (T3 & T4)	EOL	Transformer replacement	Completed Q2 2026
Campbell TS (T1 & T2)	EOL	Breaker replacement	Expected completion in 2032

Circuit/Station	Need	Recommended Action	Status
Scheifele MTS (T1, T2, T3 & T4)	EOL	Transformer replacement	T3/T4 expected completion in 2029-2030; T1/T2 expected completion in 2033-2034
Galt TS	EOL	Breaker and component replacement	Hydro One will continue to monitor and take appropriate action
Fergus TS (T3 & T4)	EOL	Transformer replacement	Hydro One will continue to monitor and take appropriate action
GrandBridge Energy MTS #1 (T1 & T2)	Station Capacity	Load transfer to Galt TS and Preston TS	Underway
Preston TS	Station Capacity	Load transfer to Galt TS and GrandBridge Energy MTS #1	Underway
Scheifele MTS (T1+T3)/(T2+T4)	Station Capacity	Load transfer to Waterloo North MTS #3, Rush MTS, and Elmira TS	Evaluated by Enova Power and completed as needed
Campbell TS (T3 & T4)	Station Capacity	Load transfer to Cedar TS and Cedar TS T1/T2	Need re-evaluated and addressed in this IRRP

2.2 Near- to Medium-Term Plan

The Technical Working Group recommends the near- to medium-term plan outlined below, including several recommendations to accommodate load growth, maintain reliability, and optimize asset replacement. These investments include new stations in Cambridge, Puslinch, Waterloo, and Guelph, upgrades to existing transmission lines, station expansions and load transfers in Kitchener, new lines between Cambridge and Puslinch, additional electricity demand-side management (eDSM), and distributed resources.

Table 2 summarizes the near- to medium-term recommendations for KWCG, organized by need and timing.

Table 2 | Summary of the Near- to Medium-Term Plan

Need(s)	Technical Working Group Recommendation	Lead Responsibility	Expected In-Service Date
Wolverton DS station capacity need	Install fan monitoring project.	Hydro One Distribution	2027

Need(s)	Technical Working Group Recommendation	Lead Responsibility	Expected In-Service Date
DxV sub-system supply capacity need	Transfer load from DxV sub-system to DxW sub-system.	Enova Power	2028
115 kV sub-system supply capacity need	Uprate B5C/B6C, D7F/D9F, and F11C/F12C.	Hydro One Transmission	2028
Preston TS, GrandBridge Energy (GBE) MTS #1, and Galt TS station capacity needs	Construct a new 115 kV transformer station (GBE MTS #2) to supply up to 75 MW of load.	GrandBridge Energy	2028
Puslinch DS station capacity need	Implement distributed energy resources.	Hydro One Distribution, with IESO support to explore value-stacking opportunities	2030-2042
Rush MTS, Scheifele MTS, and Waterloo North MTS #3 station capacity needs	Construct 230 kV stations, including 11 TS, Office MTS, and Snider TS	Enova Power	2030+
Kitchener MTS #8 station capacity need	Expand with a new 230 kV Dual-Element Spot Network (DESN).	Enova Power	2030+
MxD sub-system supply, restoration, and security needs	Construct a new 500/230 kV autotransformer station (Wellington TS) in Puslinch, with new double-circuit 230 kV lines to Preston TS and a normally open point at Ameristeel junction. Per the 2024 Burlington to Nanticoke IRRP: Construct two new 230 kV DESNs within or in the vicinity of County of Brant, connecting to the MxD lines.	Hydro One Transmission	2031 or earlier

Need(s)	Technical Working Group Recommendation	Lead Responsibility	Expected In-Service Date
Campbell TS station capacity needs	Install additional metal-clad switchgear to fully utilize T3/T4 capacity and transfer load from T1/T2.	Alectra and Hydro One Transmission	2031
DxV sub-system supply capacity need	Uprate DxV and implement station work at Detweiler TS to mitigate existing operating instructions. Evaluate reactive support (such as low-voltage capacitor at Elmira TS) in the Regional Infrastructure Plan to meet interim needs.	Hydro One Transmission	2031
Cedar T1/T2 and T7/T8 station capacity needs, T7/T8 end-of-life need	Replace T7/T8 with a 230 kV DESN and transfer load from T1/T2 to T7/T8.	Alectra and Hydro One Transmission	2032
Rush MTS station capacity need	Transfer load to new 230 kV stations on DxV sub-system.	Enova Power	2032
Kitchener MTS #1, 4, 5, 6, 7 station capacity needs	Optimize existing station capacity and transfer load on the distribution system between stations.	Enova Power	2033
DxK supply capacity need	Uprate D11K/D12K.	Hydro One Transmission	2033
Kitchener MTS #6 station capacity need	Implement distributed energy resources.	Enova Power, with IESO support to explore value-stacking opportunities	2034-2042

2.3 Long-Term Plan and Other Initiatives

In the long term, the KWCG region's electricity demand is projected to continue to grow. This IRRP recommends long-term actions to ensure that options are preserved to address future needs in the most efficient and cost-effective way, if and when they ultimately arise. Table 3 summarizes the long-term recommendations for KWCG, organized by need.

Table 3 | Summary of the Long-Term Plan for the KWCG IRRP

Need(s)	Technical Working Group Recommendation	Lead Responsibility	Timing
Arlen TS and Hanlon TS station capacity needs	Monitor long-term load growth (including eDSM savings); provide update at the next Annual Technical Working Group meeting between regional planning cycles.	Alectra	2028 (next Annual Technical Working Group meeting)
MxD supply capacity and restoration needs	Monitor long-term load growth between Detweiler TS and Middleport TS and re-evaluate need for Galt Switching Station (SS).	Technical Working Group	2028 (next Annual Technical Working Group meeting)
Kitchener MTS #1, 4, 5, 6, 7 station capacity needs	Monitor distribution load transfers and long-term load growth. In the next regional planning cycle, re-assess needs and 230 kV supply options for a new 230 kV DESN in the Kitchener Freeport area.	Enova Power	2029 (next cycle of regional planning in KWCG begins)
DxV sub-system supply capacity need	Monitor long-term load growth and re-evaluate the need for double-circuit 230 kV lines from Guelph North TS to the Waterloo area in future planning cycles.	Hydro One Transmission, Enova Power	2029 (next cycle of regional planning in KWCG begins)
Preston TS, GBE MTS #1, and Galt TS station capacity needs	Construct a new 230 kV transformer station in Cambridge (GBE MTS #3).	GrandBridge Energy	2035 or earlier (in-service)

3. Development of the Plan

3.1 Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region — defined by common electricity supply infrastructure — over the near, medium, and long term, and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is led by the IESO, in collaboration with the transmitters and LDCs in each region. It consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3. An IRRP, led by the IESO, which identifies the appropriate mix of investments in conservation and demand management, generation, transmission facilities or distribution facilities, or other electricity system initiatives to address the identified needs of a region requiring coordinated planning; and/or
4. A Regional Infrastructure Plan (RIP), led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. Other types include bulk system planning and distribution system planning. There are inherent overlaps in all three levels of electricity infrastructure planning. Further details on the regional planning process and the IESO's approach to it can be found in the appendix.

The IESO has recently completed a review of the regional planning process, following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review, along with the final report, is posted on the IESO's website.

3.2 Kitchener-Waterloo-Cambridge-Guelph and IRRP Development

The development of the KWCG IRRP was initiated in July 2024, following the publication of the Needs Assessment report in April 2024 by Hydro One and the Scoping Assessment Outcome Report in July 2024 by the IESO. The Scoping Assessment recommended that the needs identified for the KWCG region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

4. Background and Study Scope

Electricity planning in Ontario typically occurs on a cyclical basis; this is the third cycle of regional planning for the KWCG region, with earlier IRRPs published in 2015 and 2021. The previous regional recommendations are summarized in the sections below, alongside information on current regional and bulk planning that impacts the KWCG region.

4.1 Previous Regional Planning Cycle

The previous cycle of regional planning for the KWCG region in 2021 implemented a multi-pronged approach to address electricity needs across the region. This includes:

- EOL transformer replacements at Hanlon TS (T1/T2), Kitchener MTS #5 (T9/T10), Preston TS (T3/T4), Scheifele MTS (T1/T2, T3/T4), and Fergus TS (T3/T4);
- EOL breaker replacements at Campbell TS (T1/T2) and Galt TS;
- EOL transmission line replacements on a section of the 115 kV B5/6C line; and
- Various load transfers off stations forecast to be at capacity (GBE MTS #1, Preston TS, Scheifele MTS, Campbell TS (T3/T4), Kitchener MTS #7 (T13/T14), and Kitchener MTS #8 (T15/T16).

The 2021 KWCG IRRP also identified multiple longer-term needs to monitor and assess: supply capacity needs along the B5C and D10H circuits, station capacity needs at Arlen MTS, Hanlon TS, Rush MTS, Elmira TS, Kitchener MTS #1, and Waterloo North MTS #3, and a load restoration need on the M20D/M21D 230 kV lines.

4.2 Bulk Planning and Other Developments

The KWCG region is included in the South and Central Bulk Plan, which the IESO developed to address transmission limitations in a wide-spanning geographic area from Bruce to the Greater Toronto Area, and along the Windsor to Hamilton corridor. The objectives of the study are to enable new generation, enable the phase-out of emitting resources, and support future growth and economic development across various load centres in Ontario.

4.3 Current Cycle of Regional Planning

The current cycle of regional planning began in 2024, with the publication of the Needs Assessment. The 2023 Scoping Assessment recommended an IRRP for the entire region to address needs in a coordinated manner. This report presents an integrated regional electricity plan that covers the time period from 2026 to 2045; recommendations are made to meet KWCG regional electricity needs in the near, medium, and long term.

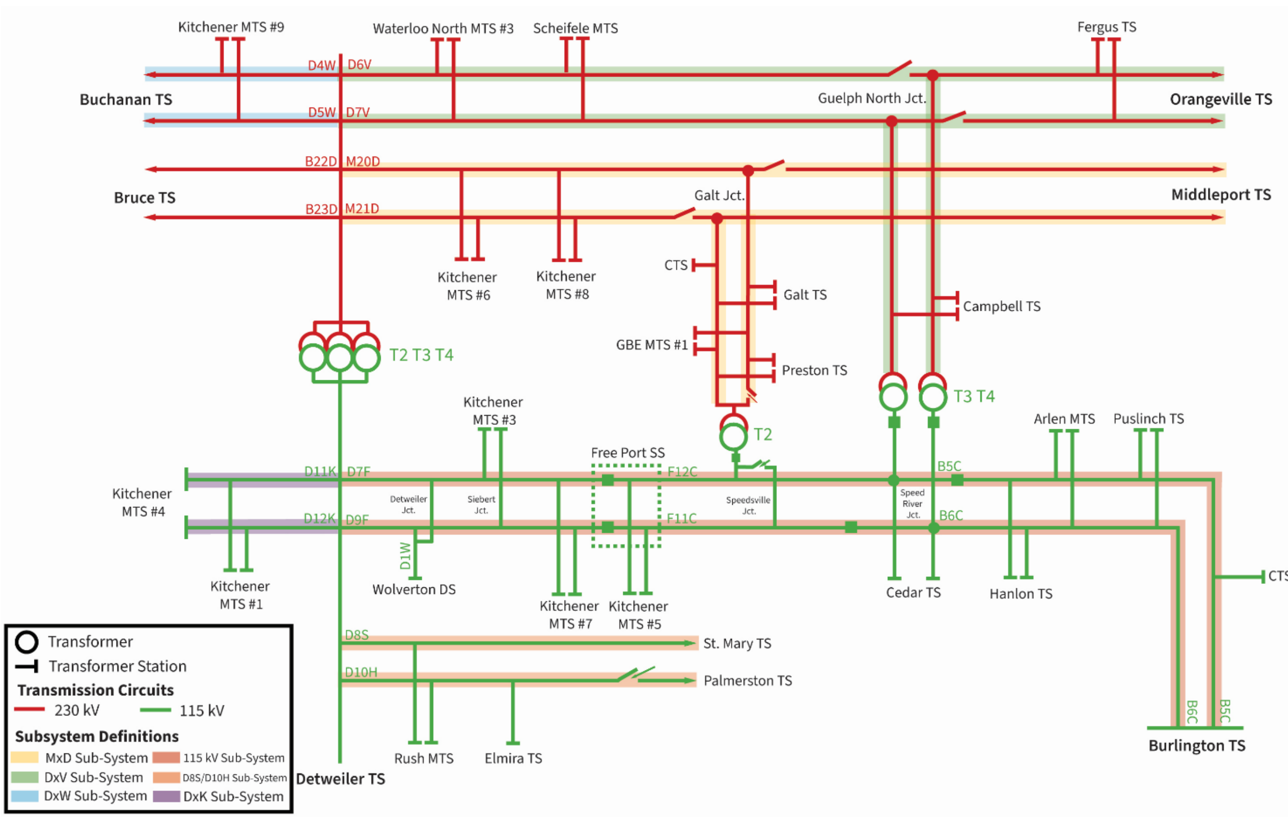
The plan was prepared by the IESO on behalf of the Technical Working Group, and considers forecast electricity demand growth, eDSM, DG, transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

The following transmission facilities were included in the scope of this study:

- Transformer stations: Arlen MTS, Campbell TS (T1/T2), Campbell TS (T3/T4), Cedar TS (T1/T2), Cedar TS (T7/T8), Elmira TS, GrandBridge Energy MTS #1, Fergus TS, Galt TS, Hanlon TS, Kitchener MTS # 1, Kitchener MTS # 3, Kitchener MTS # 4, Kitchener MTS #5, Kitchener MTS #6, Kitchener MTS #7, Kitchener MTS #8, Kitchener MTS #9, Preston TS, Puslinch DS, Rush MTS, Scheifele MTS, Waterloo North MTS #3, Wolverton DS, and two CTS.
- 115 kV transmission circuits: D7F/D9F, F11C/F12C, B5C/B6C, D11K/D12K, D8S, and D10H.
- 230 kV transmission circuits: D6V/D7V, M20D/M21D, D4W/D5W, and B22D/B23D.

The single line diagram of the KWCG region is shown in Figure 4. Note that the bulk system transfer capabilities into the region are not within the scope of the IRRP, and are encompassed in the South and Central Bulk Plan. The schedule of bulk planning activities is identified through the IESO's Annual Planning Outlook.

Figure 4 | Single Line Diagram of the KWCG Region



The KWCG IRRP was developed by:

- Establishing alternatives to address system needs, including (where feasible and applicable): generation, transmission and/or distribution, and other approaches such as non-wires alternatives, including additional eDSM.
- Engaging with the community on needs and possible alternatives.
- Evaluating alternatives to address near- and long-term needs.

- Considering the impact of the low and high forecast as a sensitivity of the flexibility and optionality of potential alternatives.
- Communicating findings, conclusions, and recommendations within a detailed plan.

5. Electricity Demand Forecast

Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the KWCG region. It highlights assumptions made for peak demand forecasts, including weather correction, the contribution of eDSM and DG, and the development of low and high growth forecast scenarios. The reference case "Planning Scenario" was derived based on firm loads (current and planned), organic growth, residential development, electrification, community energy plans, and industrial growth as described in more detail in the appendix. The "Planning Forecast" is net of existing DG and eDSM and corrected for extreme weather. It is used to assess the electricity needs of the area over the planning horizon.

The "High Scenario" incorporates potential demand growth that is less certain, in terms of timelines, magnitude, and location, into the Planning Scenario. The "High Forecast" is also the result of the High Scenario adjusted to be net of existing DG and eDSM, and corrected for extreme weather. The High Forecast is used as the basis for sensitivity analysis as described further in Section 5.7.2.

The "Low Scenario" accounts for uncertainty of growth and reconsiders committed growth that may not materialize due to delayed timelines and technological, economical, and political circumstances. The "Low Forecast" is also the result of the Low Scenario adjusted to be net of existing DG and eDSM, and corrected for extreme weather. The Low Forecast is used as the basis for sensitivity analysis as described further in Section 5.7.3.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. In the past, the KWCG region peak loading has historically occurred in the summer. However, with recent developments in electrification and decarbonization, the region is shifting towards winter-peaking.

5.1 Historical Demand

Summer peak electricity demand within the KWCG region has remained stable in the five years prior to this IRRP, which began in 2024. Figure 5 shows the summer coincident net actual, gross actual, and gross median weather-corrected historical demand. The summer gross median weather-corrected demand has averaged just under 1,400 MW over the past five years, with the peak demand hour for each year occurring between approximately 11 a.m. to 5 p.m. in the summer and 2 p.m. to 7 p.m. in the winter.

Since the forecast was developed in 2024, the 2023 summer and winter gross median weather-corrected peaks at each station in the KWCG region were used as the starting points for the forecast.

Figure 5 | Historical Summer Peak Demand in the KWCG Region

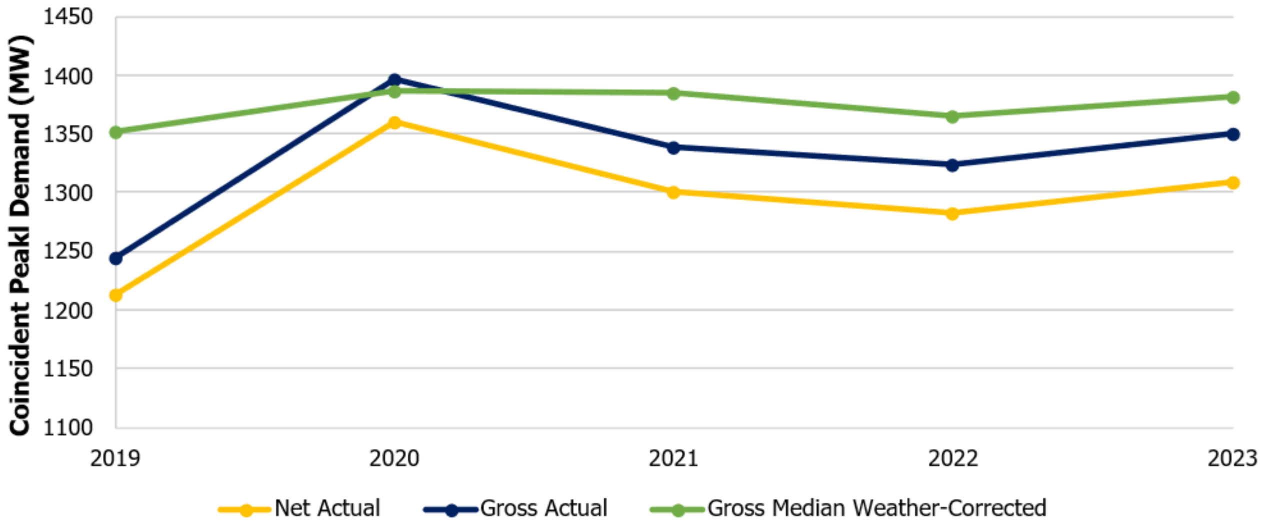
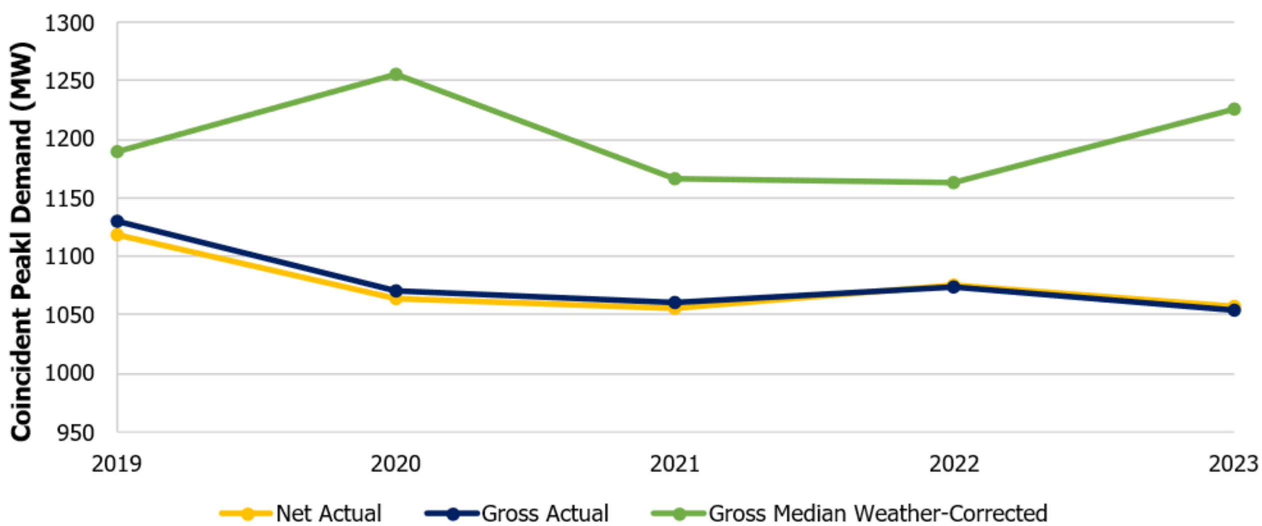


Figure 6 | Historical Winter Peak Demand in the KWCG Region



5.2 Current Drivers of Load Growth

Electricity demand in the KWCG region is projected to grow at a rapid pace due to residential, commercial, and industrial growth, electrification, and several new large developments. This includes several requests to connect from potential data centre customers. Broader economic development across the region and local climate action plans are also expected to be key factors for future electricity needs. These drivers of growth are used by the LDCs to inform the forecasts developed for the region and are discussed in more detail below.

Load growth based on organic growth in the residential, commercial, and industrial sectors is driven by population growth, employment growth, housing activities, and industrial and commercial building activities. The population in the KWCG region is expected to see a large increase over the next 25 years according to the Region of Waterloo Official Plan (923,000 increase by 2051) and City of Guelph Official

Plan (208,000 increase by 2051). This population growth will encourage residential development, and the region expects steady increases in housing as detailed in the Region of Waterloo, County of Wellington, and City of Guelph municipal plans. Employment in the KWCG region is also expected to see an increase over the next 25 years. This is accompanied by new commercial and industrial development, informed by the region's stakeholders which include cities, townships, and large customers. Some examples include new large-scale subdivision expansion, a new Waterloo hospital, planned expansion to existing customer facilities, and new large data centres.

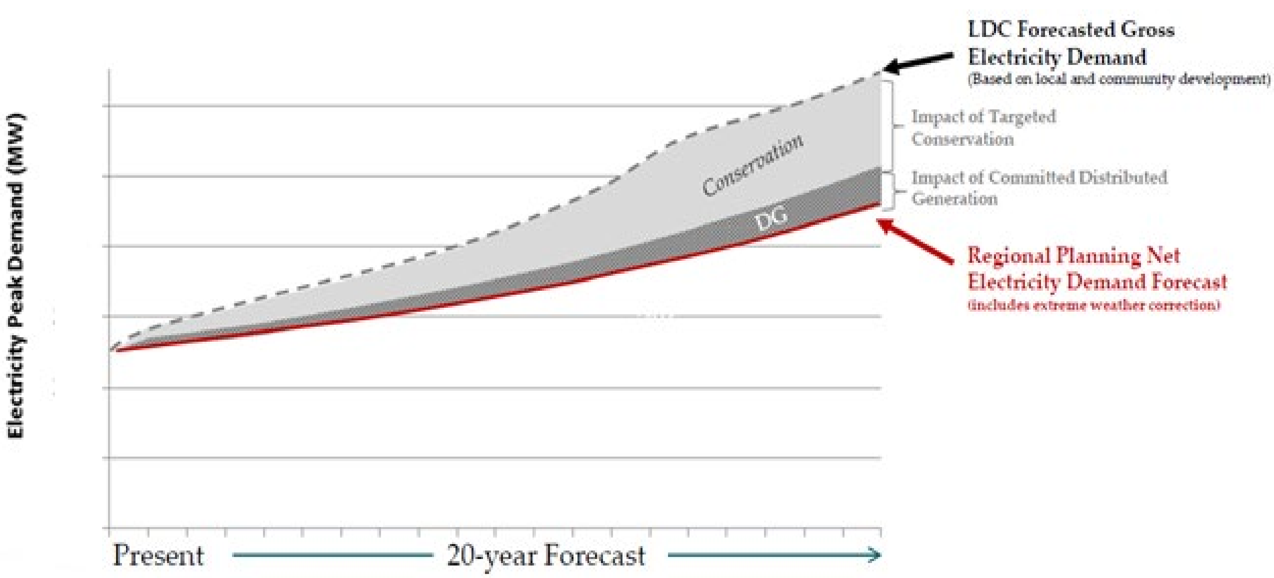
The region anticipates climate change and resulting extreme weather will have an impact on electricity demand due to electrification. As highlighted by Region of Waterloo and City of Guelph climate action plans, the KWCG region will see an increase in temperatures and number of warm days, driving up the need for electric cooling. The electrification of heating is also a key driver and contributes to higher winter demand peaks. In addition to electric heating, electric vehicle uptake is expected to increase in the area due to municipal fleets and more broadly by community members.

5.3 Demand Forecast Methodology

The steps taken to develop a 20-year IRRP peak demand forecast are depicted in Figure 7. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions (referred to as "normal weather"), were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through previous provincial programs, such as Feed-In Tariff (FIT) and microFIT, and adjusted to reflect extreme weather conditions to produce a Planning Forecast for planning assessments. This net forecast was then used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in the appendix. The Ontario Energy Board has also published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.

Figure 7 | Illustrative Development of Demand Forecast

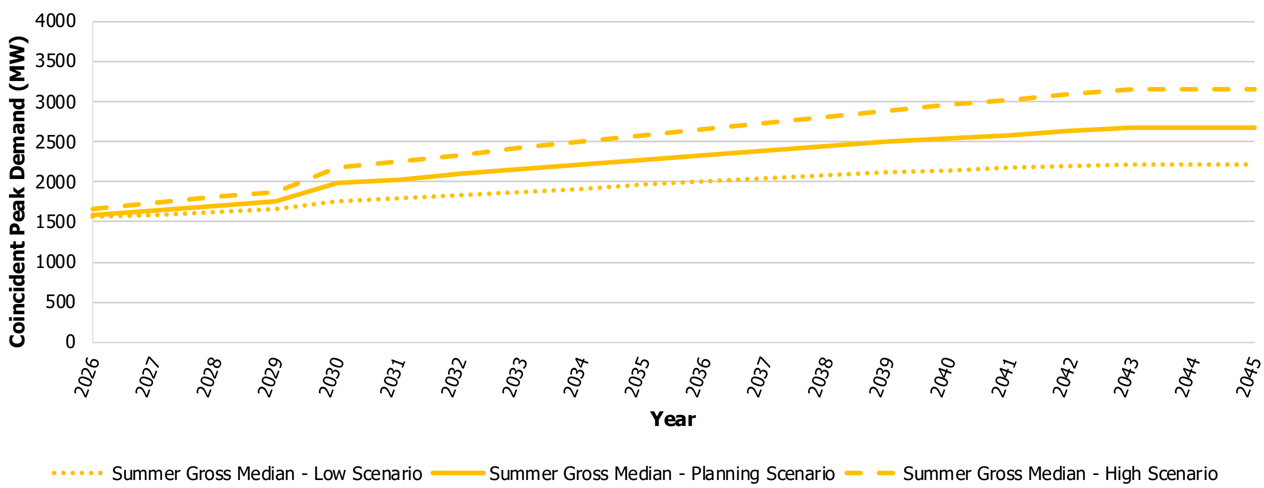


5.4 Gross LDC Forecasts

Each participating LDC in the KWCG region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development, plus known connection applications. The LDCs cited alignment with municipal and regional official plans and credited them as a source for input data. LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and in response to increasing electricity prices ("natural conservation"), but not for the impact of future DG or new conservation measures (such as codes and standards and eDSM programs), which are accounted for by the IESO (discussed in Section 5.5). The gross LDC forecasts assume median on-peak weather conditions and loading that is coincident to each station.

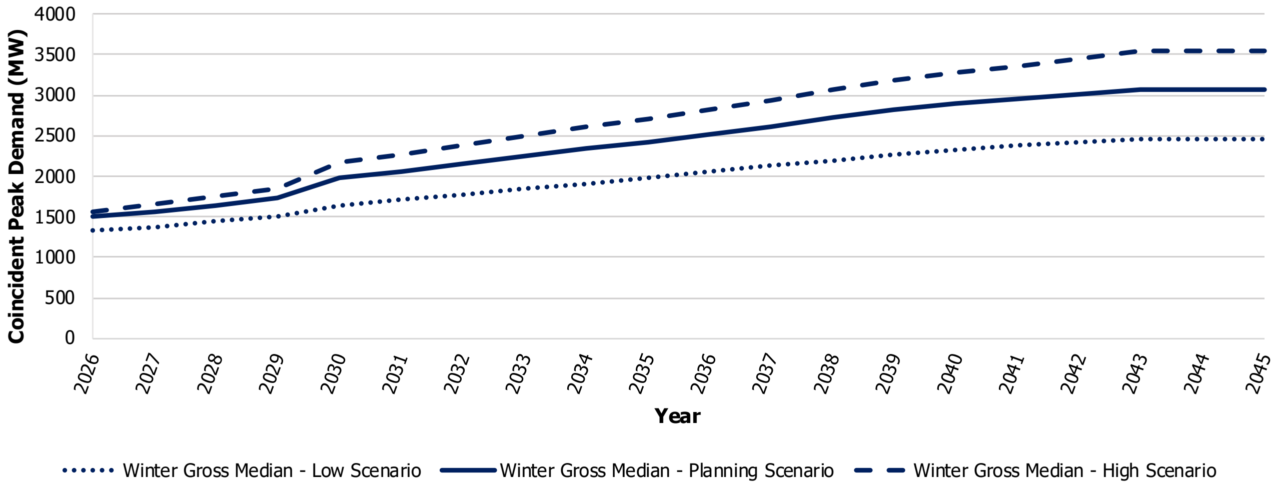
Figure 8 and Figure 9 show the gross coincident demand forecasts provided by the LDCs for the KWCG region under the Low Scenario, Planning Scenario, and High Scenario for summer and winter peak demand.

Figure 8 | Total Summer Gross Coincident Demand Forecasts Provided by LDCs (Median Weather)[1]



[1] Excludes existing transmission-connected industrial customers in the KWCG region (historically contributing an average of 9 MW to the summer coincident peak demand).

Figure 9 | Total Winter Gross Coincident Demand Forecasts Provided by LDCs (Median Weather)[2]



LDCs have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and the municipalities and communities that they serve. The IESO typically carries out demand forecasting at the provincial level. More details on LDC load forecast assumptions can be found in the appendix.

5.5 Contribution of Energy Efficiency to the Forecast

Energy efficiency is a clean and cost-effective resource that helps meet Ontario's electricity needs and is an integral component of provincial and regional planning. Energy efficiency is achieved through a mix of codes and standards amendments, as well as eDSM program-related activities. These approaches complement each other to maximize conservation results.

The estimate of demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings, and regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e., residential, commercial and industrial consumers).

The estimates of demand reduction due to eDSM program-related activities account for the 2021–2024 Conservation and Demand Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs. Under the 2021–2024 Conservation and Demand Management Framework, the IESO centrally delivered programs on a province-wide basis to serve business and residential customers, as well as Indigenous communities.

The KWCG demand forecast was finalized before approval of the new 2025–2036 eDSM Framework and its savings targets, and assumes that programs continue at 2021–2024 Conservation and Demand Framework levels, with adjustments for gross demand growth. The increased targets under the new framework may impact the exact scale and timing of needs.

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[2] Excludes existing transmission-connected industrial customers in the KWCG region (historically contributing an average of 7 MW to the winter coincident peak demand).

Figure 9 shows the estimated total yearly reduction to the demand forecast due to energy efficiency (from codes, standards, and eDSM programs) for each of the residential, commercial, and industrial consumers. Additional details are provided in the appendix.

Figure 10 | Total Summer Forecast Peak Demand Reduction (Codes, Standards, and eDSM Programs)

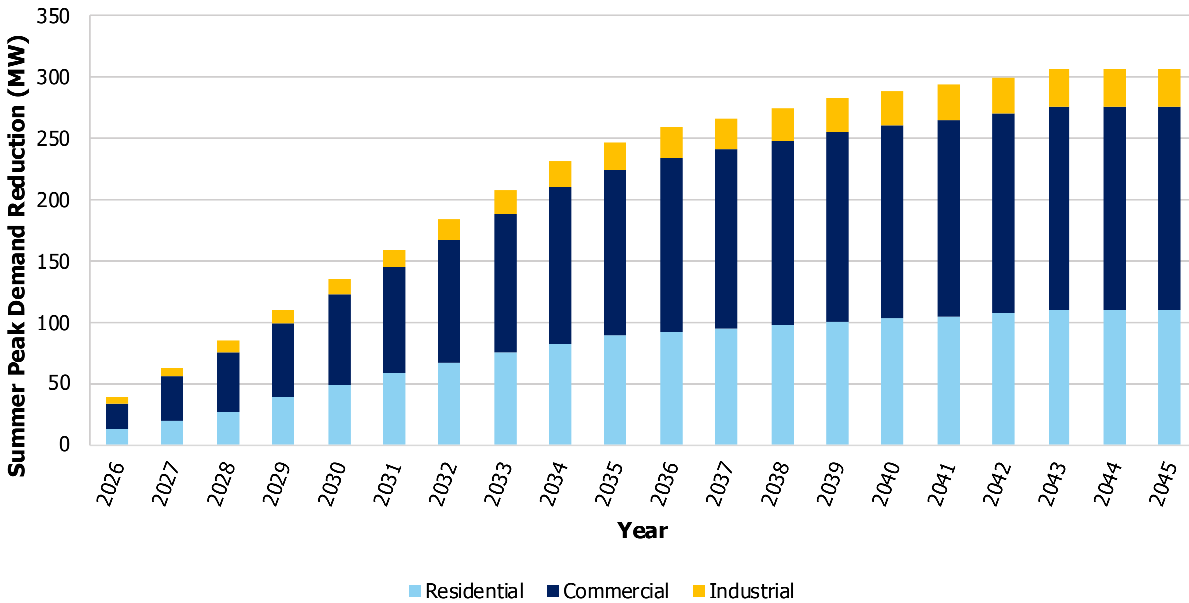
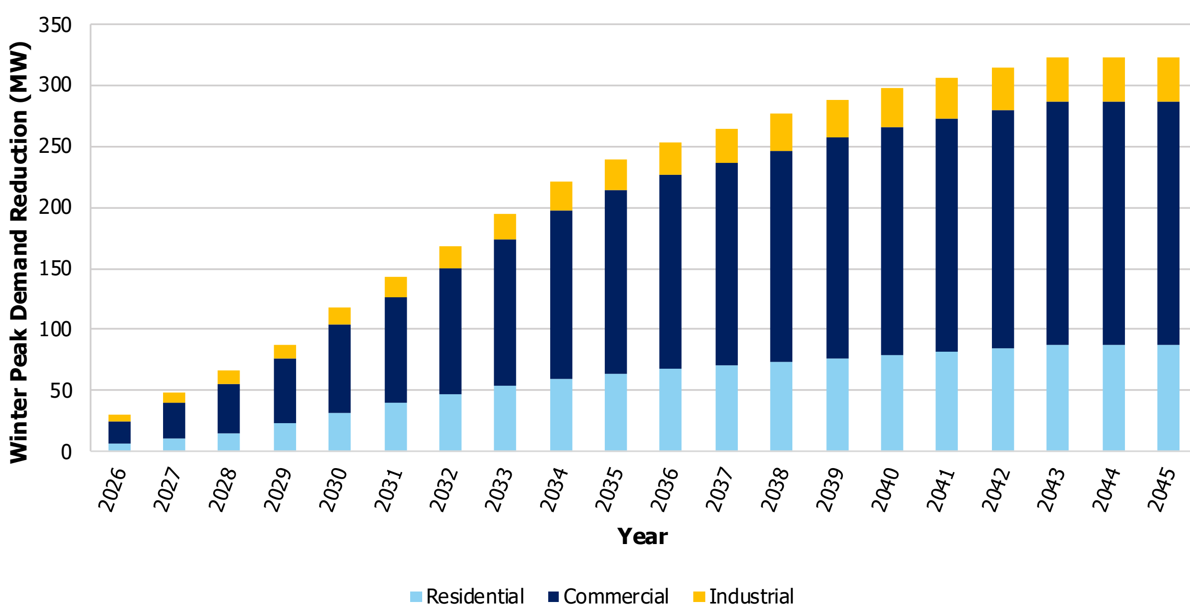


Figure 11 | Total Winter Forecast Peak Demand Reduction (Codes, Standards, and eDSM Programs)

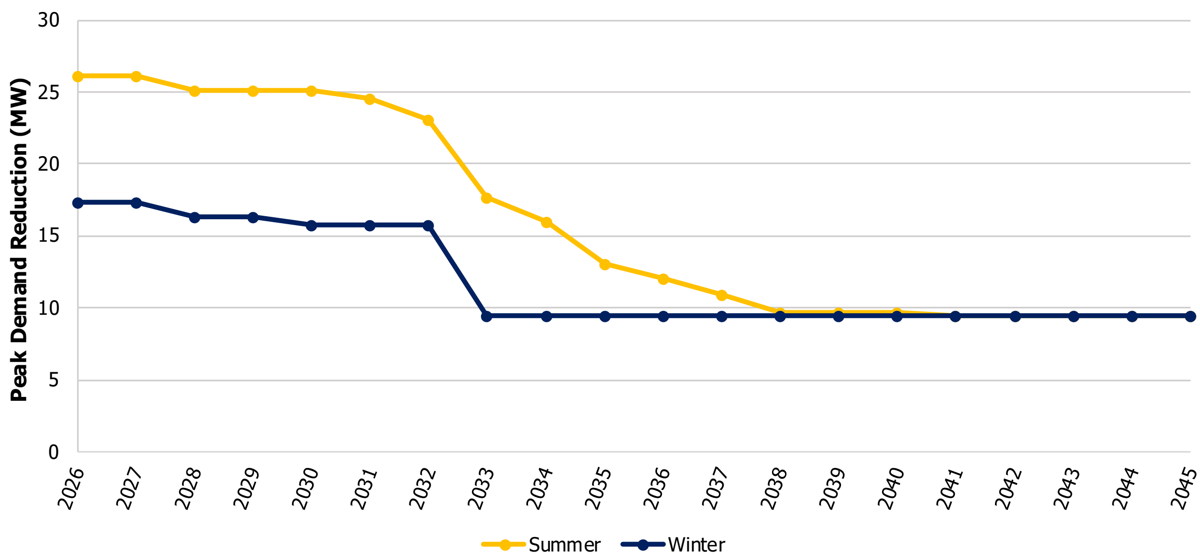


5.6 Contribution of Distributed Generation to the Forecast

In addition to energy efficiency, DG in the KWCG region is also forecast to offset peak demand requirements. The introduction of Ontario's FIT Program increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and contribution factor assumptions can be found in of the accompanying IRRP Data Tables (provided as a separate Excel file). All the installed DG capacity in the KWCG region is wind and solar.

After reducing the demand forecast due to energy efficiency (as described in Section 5.5), the forecast is further reduced by the expected contribution from contracted DG. Figure 12 shows the impact of DG on reducing the KWCG region demand forecasts. Note that facilities without a contract with the IESO were not included in the DG peak demand reduction forecast.

Figure 12 | Peak Demand Reduction Due to DG



5.7 Planning Forecasts

After taking into consideration the combined impacts of energy efficiency and DG, a 20-year net demand forecast was produced for the KWCG region considering the Low Scenario, Planning Scenario, and High Scenario. The following subsections describe the implementation of weather correction to create the Low Forecast, Planning Forecast, and High Forecast, and the total demand outlook for the region.

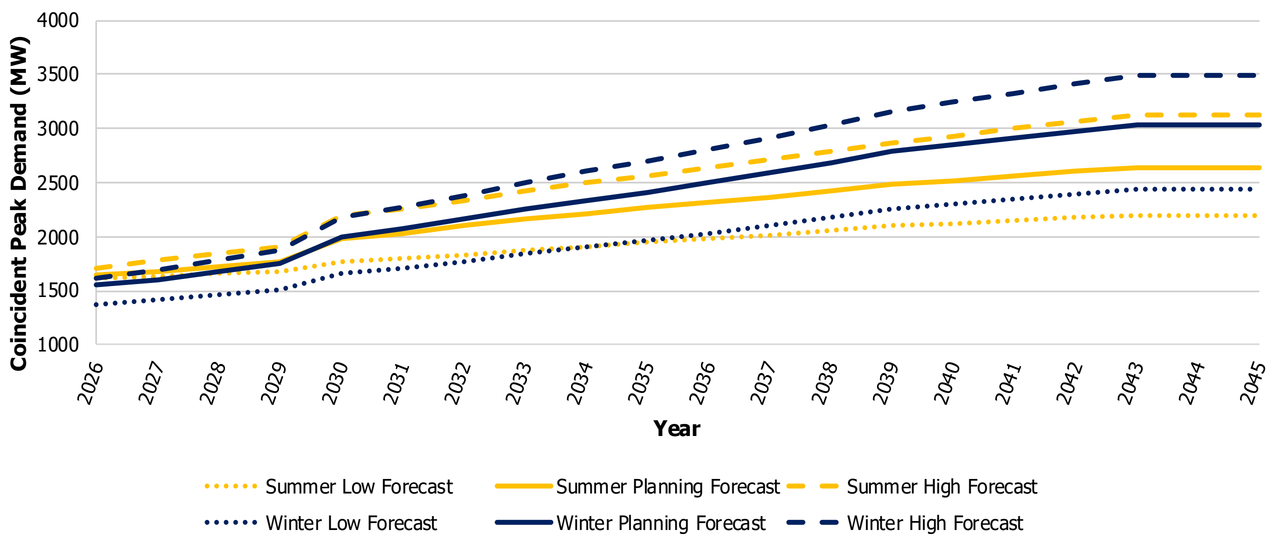
5.7.1 Net Extreme Weather Planning Forecast

The net extreme weather forecast is created by adjusting the net median weather forecast (the gross demand forecast including the forecast DG and eDSM impacts) for extreme weather conditions. The weather correction methodology is described in the appendix. The Planning Forecast results from the net extreme-weather forecast applied to the Planning Scenario.

Note that this Planning Forecast is coincident, meaning that each station forecast reflects its expected contribution to the regional peak demand level. This allows need dates to be identified for regional needs that are driven by more than one station. For station-specific needs, the non-coincident forecast is calculated by applying a non-coincidence factor. The factor is based on the historical non-coincident peaks of each station compared to the station's contribution to the region's coincident peaks over the past five years.

The coincident net extreme weather forecast for the KWCG region is shown in Figure 13 for the Low Forecast, Planning Forecast, and High Forecast representing peak summer and winter demand.

Figure 13 | Net Extreme Weather Planning Forecast, Low Forecast, and High Forecast for the KWCG Region



5.7.2 High Forecast Scenario

The Technical Working Group developed a High Forecast sensitivity scenario for the KWCG region, which is also shown in Figure 13. The High Forecast is meant to quantify prospective development in the KWCG region that is not yet committed. This higher demand scenario is driven by increased electrification rates and increased commitment from prospective large-scale customers looking to connect.

The High Forecast can be used as a proxy for a variety of factors that could drive demand higher over the next 20 years, including, but not limited to:

- electric vehicle charging;
- electrified space and water heating;
- a faster pace of residential development;
- unanticipated new industrial customers of growth among existing industrial customers; and
- data centres.

The higher demand scenario was not used to drive any firm recommendations for this IRRP; however, it was used to help the Technical Working Group identify where the future electricity concerns may be and when they could materialize. This information can also be useful for communities conducting community energy plans, for the Technical Working Group in determining areas to monitor in future planning cycles, and for communities and stakeholders to consider when planning various projects in the region. Moreover, while developing this IRRP, the Technical Working Group also considered the flexibility of evaluated options to accommodate greater long-term growth. This is later described in Section 7.

5.7.3 Low Forecast Scenario

The Technical Working Group also developed a Low Forecast sensitivity scenario, which is also shown in Figure 13. The Low Forecast is meant to consider slowed organic growth and prospective development in the KWCG region that is committed, but sensitive to economical, technological, political, and social factors. This lower demand scenario is primarily driven by lower electrification rates and lower demand from large-scale customers.

The lower demand scenario was not used to drive any firm recommendations for this IRRP; however, it was used to help the Technical Working Group identify where growth could slow down and where future electrical infrastructure improvements could be delayed. Similarly to the High Forecast scenario, this information can be useful for communities conducting community energy plans, for the Technical Working Group in determining areas to monitor in future planning cycles, and for communities and stakeholders to consider when planning various projects in the region. Moreover, while developing this IRRP, the Technical Working Group also considered the flexibility of evaluated options to accommodate lower long-term growth.

5.8 Hourly Forecast Profiles

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) were developed to characterize some needs with finer granularity. The profiles were based on historical load data and adjusted for variables that impact demand, such as calendar day (i.e., holidays and weekends) and weather. The profiles were then scaled to match the IRRP peak Planning Forecast for each year. As described later in Section 7, these profiles were used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of resource options.

Additional load profile details can be found in the appendix. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify precise hourly energy requirements. Real-time loading is subject to various factors, like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are only used to select suitable technology types and roughly estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of the implementation of the plan.

6. Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of ORTAC, North American Electric Reliability Corporation TPL-001-5.1, and Northeast Power Coordinating Council Directory #1 standards, the Technical Working Group identified electricity needs in the near-, medium- and long-term timeframes. These needs can be categorized according to the following:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating (LTR) of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by downstream or upstream equipment (i.e., breakers, disconnect switches, low-voltage bus, or high voltage circuits) or by voltage drop limitations, which are independent of thermal ratings.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is referred to as the load-meeting capability (LMC) of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-5.1, and Northeast Power Coordinating Council Directory #1. LMC studies are conducted using power system simulation analyses.
- **Asset Replacement Needs** are identified by the transmitter or LDC by an asset condition assessment, which is based on a range of considerations, such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early medium-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

Technical study results for the KWCG IRRP can be found in the appendix. The needs identified are discussed in Sections 6.3 to 6.7 for each season of each sub-system.

6.2 115 kV Sub-System

The 115 kV sub-system refers to the stations in Kitchener, Guelph, and Puslinch that are served by the Detweiler-Freeport (DxF), Freeport-Cedar (FxC), and Burlington-Cedar (BxC) double-circuit 115 kV circuits. There is an asset replacement need at Cedar TS T7/T8 and station capacity needs at Arlen TS, Cedar TS T1/T2, Cedar TS T7/T8, Hanlon TS, Kitchener MTS #5, Kitchener MTS #7, Puslinch DS, and Wolverton DS. There are also supply capacity needs on the 115 kV sub-system transmission circuits. The table below summarizes the needs for the 115 kV sub-system under the Planning Forecast.

Table 4 | Summary of 115 kV Sub-System Planning Needs

Need	Summer Need Date	Summer Need by 2045 (MW)	Winter Need Date	Winter Need by 2045 (MW)
Cedar TS T7/T8 end-of-life	2032	N/A	2032	N/A
Arlen TS station capacity	N/A	N/A	2042	4
Cedar TS T1/T2 station capacity	2034	25	2037	37
Cedar TS T7/T8 station capacity	2033	13	2037	19
Hanlon TS station capacity	2042	1	2038	15
Kitchener MTS #5 station capacity	2037	10	2043	<1
Kitchener MTS #7 station capacity	2036	12	2032	39
Puslinch DS station capacity	2029	13	2036	4
Wolverton DS station capacity	Immediately	17	Immediately	11
115 kV supply capacity	2037	22	2036	50

6.2.1 Asset Replacement Needs

6.2.1.1 Cedar TS T7/T8

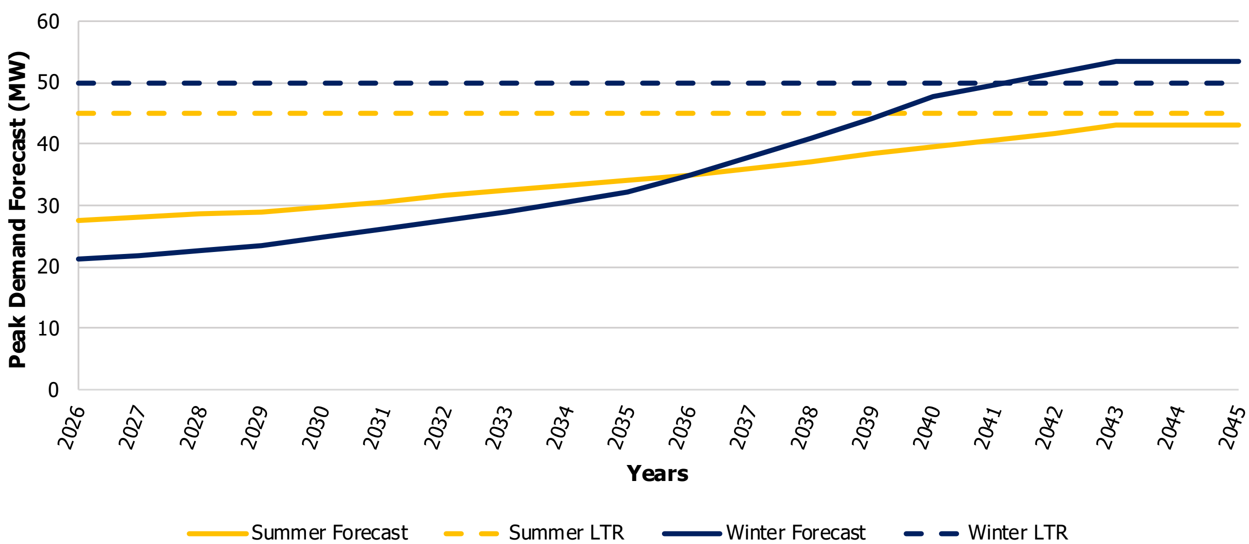
Cedar TS T7/T8 transformers were identified as requiring replacement based on asset condition by 2032. The IRRP 20-year demand forecast also identified station capacity needs at Cedar TS T7/T8, necessitating the need to consider increasing capacity over a like-for-like replacement.

6.2.2 Station Capacity Needs

6.2.2.1 Arlen TS

Arlen TS consists of two 115 kV/13.8 kV transformers with a summer LTR of 45 MW and a winter LTR of 50 MW. Arlen TS has a station capacity need of 2 MW in winter 2042, which increases to 4 MW by winter 2045. Figure 14 shows the Arlen TS demand forecast in relation to the summer and winter LTR values.

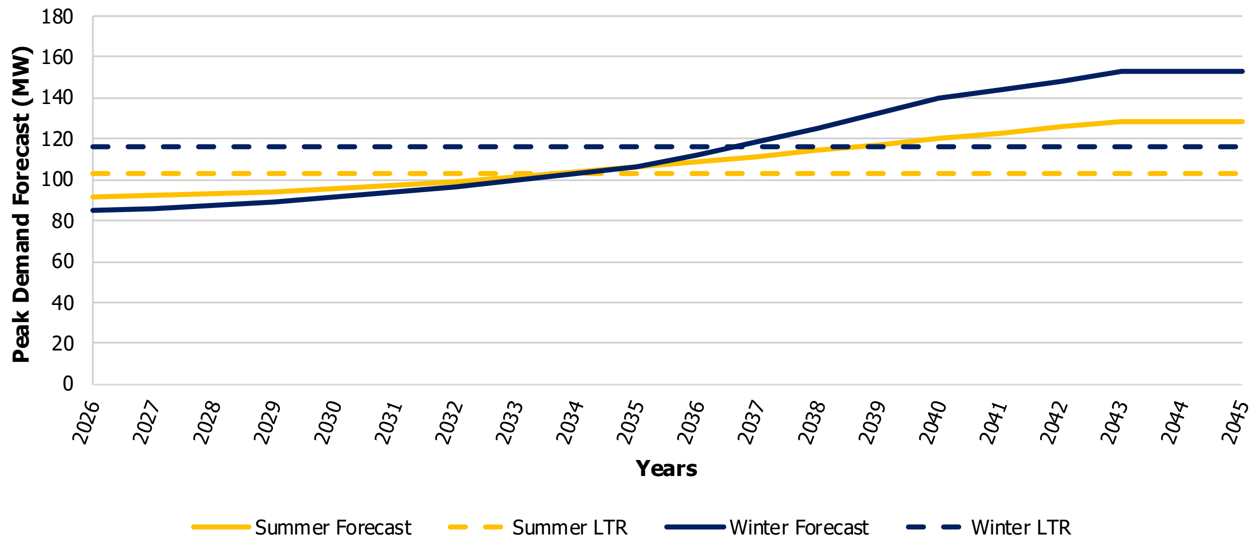
Figure 14 | Arlen TS Station Capacity Need



6.2.2.2 Cedar TS T1/T2

Cedar TS T1/T2 consists of two 115 kV/13.8 kV transformers with a summer LTR of 103 MW and a winter LTR of 116 MW. Cedar TS T1/T2 has a station capacity need of less than a megawatt in summer 2034, which increases to 37 MW by winter 2045. Figure 15 shows the Cedar TS T1/T2 demand forecast in relation to the summer and winter LTR values.

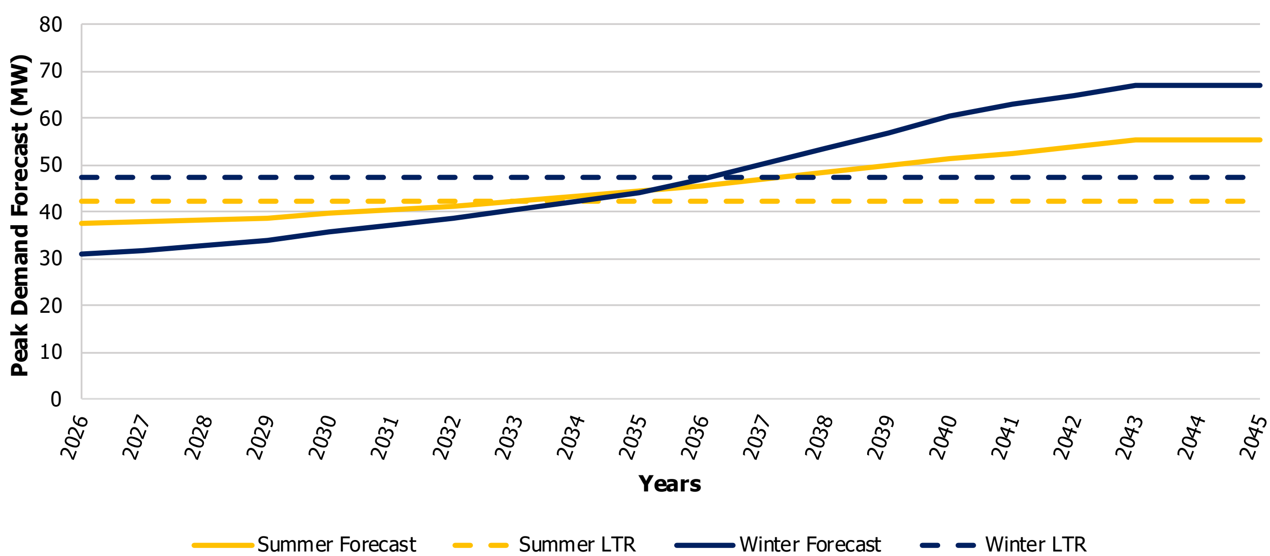
Figure 15 | Cedar TS T1/T2 Station Capacity Need



6.2.2.3 Cedar TS T7/T8

Cedar TS T7/T8 consists of two 115 kV/13.8 kV transformers with a summer LTR of 42 MW and a winter LTR of 47 MW. Cedar TS T7/T8 has a station capacity need of under one megawatt in summer 2033, which increases to 19 MW by winter 2045. Figure 16 shows the Cedar TS T7/T8 demand forecast in relation to the summer and winter LTR values.

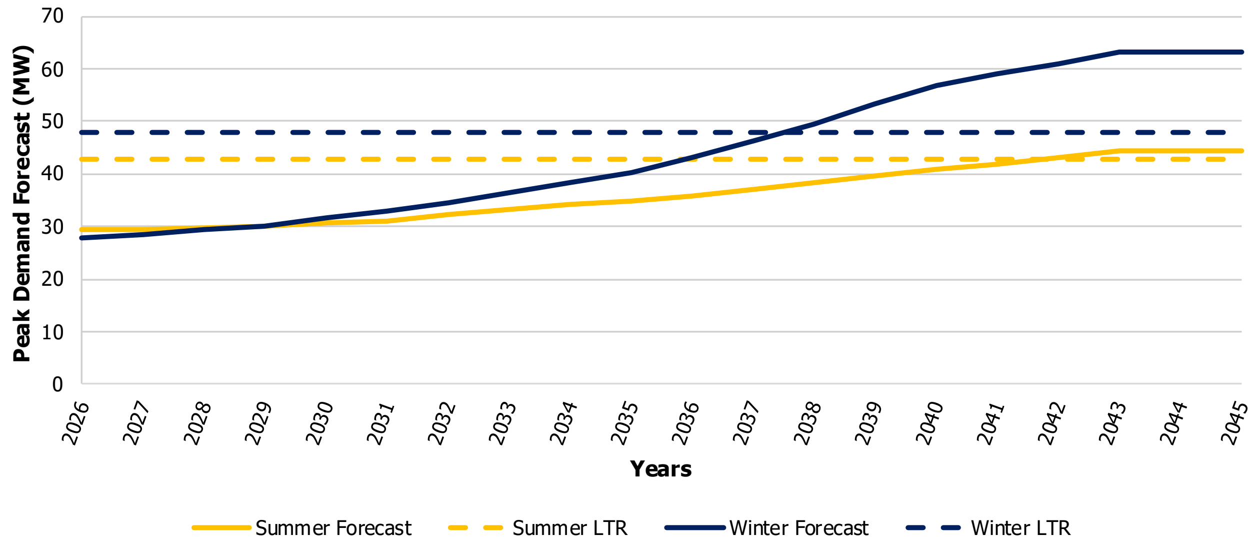
Figure 16 | Cedar TS T7/T8 Station Capacity Need



6.2.2.4 Hanlon TS

Hanlon TS consists of two 115 kV/13.8 kV transformers with a summer LTR of 43 MW and a winter LTR of 48 MW. Hanlon TS has a station capacity need of 2 MW in winter 2038, which increases to 15 MW by winter 2045. Figure 17 shows the Hanlon TS demand forecast in relation to the summer and winter LTR values.

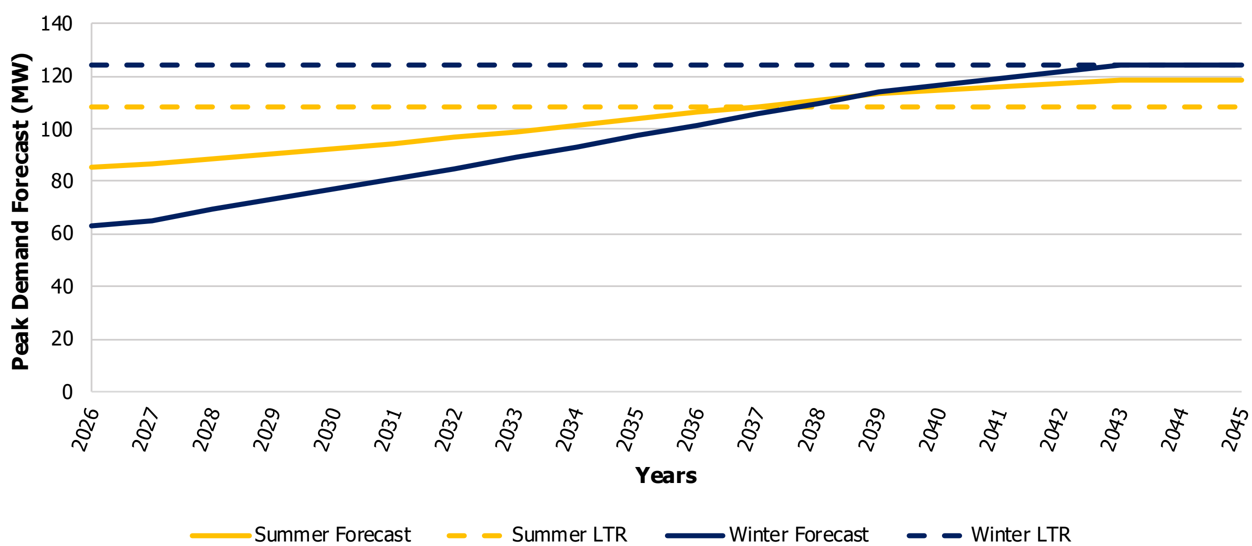
Figure 17 | Hanlon TS Station Capacity Need



6.2.2.5 Kitchener MTS #5

Kitchener MTS #5 consists of two 115 kV/13.8 kV transformers with a summer LTR of 108 MW and a winter LTR of 124 MW. Kitchener MTS #5 has a station capacity need of 1 MW in summer 2037, which increases to 10 MW by summer 2045. Figure 18 shows the Kitchener MTS #5 demand forecast in relation to the summer and winter LTR values.

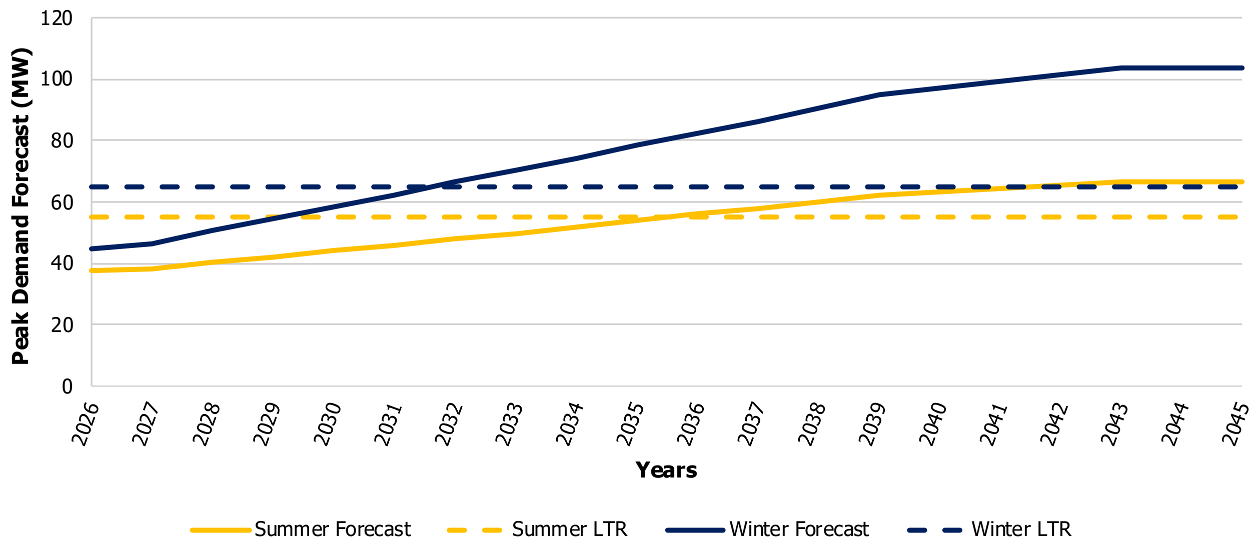
Figure 18 | Kitchener MTS #5 Station Capacity Need



6.2.2.6 Kitchener MTS #7

Kitchener MTS #7 consists of two 115 kV/13.8 kV transformers with a summer LTR of 55 MW and a winter LTR of 65 MW. Kitchener MTS #7 has a station capacity need of 2 MW in winter 2032, which increases to 39 MW by winter 2045. Figure 19 shows the Kitchener MTS #7 demand forecast in relation to the summer and winter LTR values.

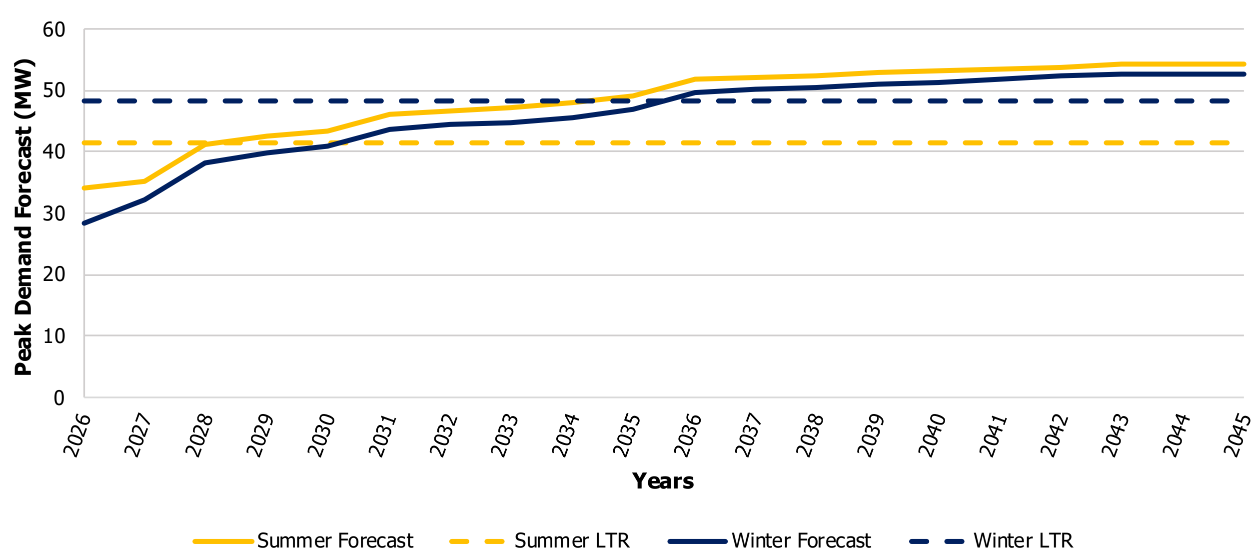
Figure 19 | Kitchener MTS #7 Station Capacity Need



6.2.2.7 Puslinch DS

Puslinch DS consists of two 115 kV/27.6 kV transformers with a summer LTR of 42 MW and a winter LTR of 48 MW. Puslinch DS has a station capacity need of 1 MW in summer 2029, which increases to 13 MW by summer 2045. Figure 20 shows the Puslinch DS demand forecast in relation to the summer and winter LTR values.

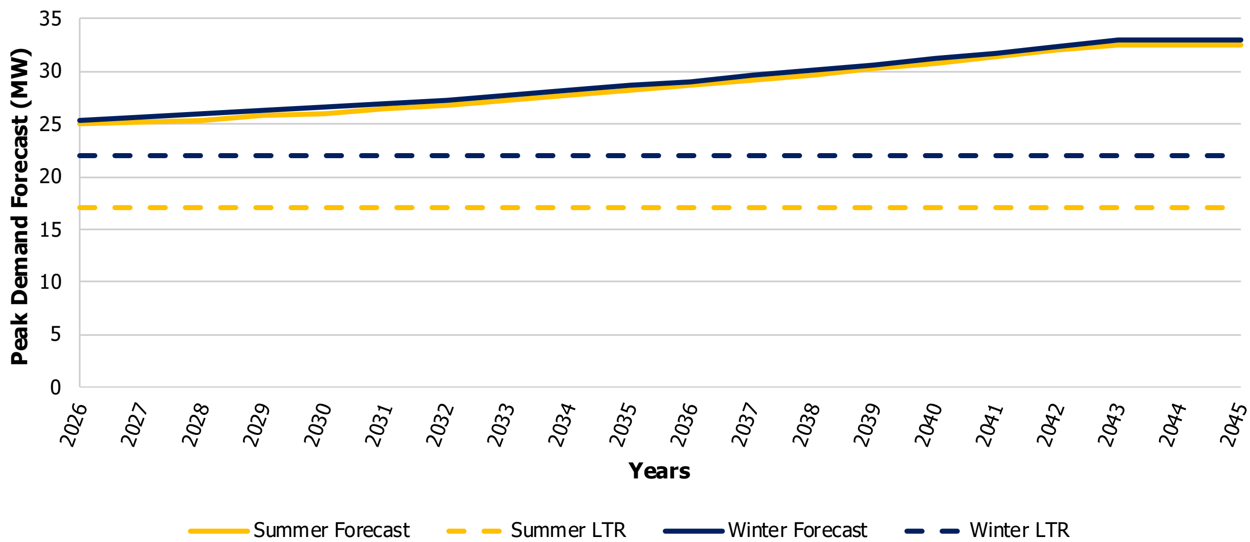
Figure 20 | Puslinch DS Station Capacity Need



6.2.2.8 Wolverton DS

Wolverton DS consists of two 115 kV/27.6 kV transformers with a summer LTR of 17 MW and a winter LTR of 22 MW. Wolverton DS has an immediate summer station capacity need of 8 MW, which increases to 16 MW by summer 2045. Figure 21 shows the Wolverton DS demand forecast in relation to the summer and winter LTR values.

Figure 21 | Wolverton DS Station Capacity Need



6.2.3 Supply Capacity Need

The load in the 115 kV sub-system is supplied through 115 kV transmission lines between Detweiler TS, Freeport SS, Cedar TS, and Burlington TS. The 230/115 kV autotransformers at Detweiler TS, Cedar TS, and Preston TS supply the 115 kV circuits and there is no local transmission-connected generation. There are two distinct load groups in the 11 5kV sub-system. One group consists of Kitchener MTS #3, Kitchener MTS #5, and Kitchener MTS #7 which are served by the 115 kV circuits between Detweiler TS and the Preston TS autotransformer. The second group consists of Hanlon TS, Arlen TS, and Puslinch DS which are served by the 115 kV circuits between Burlington TS and the Cedar TS autotransformers.

Supply on the 115 kV Sub-System Between Detweiler TS and Preston TS Autotransformer

The LMC of 115 kV supply between Detweiler TS and Preston TS autotransformer is limited to 230 MW in the summer and 260 MW in the winter based on the thermal capability of circuit sections from Detweiler TS going towards Freeport SS, under the various planning scenarios and applicable contingencies to the DxF circuits. Considering the forecast growth in the area, this part of the sub-system has a supply capacity need of 3 MW in summer 2037 which increases to 22 MW by summer 2045 and 50 MW by winter 2045.

Supply on the 115 kV Sub-System Between Burlington TS and Cedar TS Autotransformers

The LMC of 115 kV supply between Burlington TS and Cedar TS autotransformers are impacted by the loading between Detweiler TS and Preston TS autotransformer and the MxD sub-system. Considering the expected Detweiler TS-Preston TS autotransformer loading, the LMC of this part of the sub-system is limited to 155 MW in the summer and 187 MW in the winter based on the thermal capability of circuit sections from Burlington TS going towards Cedar TS, under the various planning scenarios and applicable contingencies to the MxD and BxC circuits.

There is no need on the BxC transmission lines if only accounting for load connected to BxC. However, increasing load on the MxD and 115 kV sub-systems between Detweiler TS and Preston autotransformer can introduce limitations on the BxC transmission lines. Therefore, BxC circuits become constraining for future load growth in these other load pockets.

6.2.4 Low and High Forecast Needs

Depending on the low or high forecast, the 115 kV supply capacity need ranges from 32 MW to 77 MW, and timing ranges from 2034 to 2038.

The station capacity needs of the stations in the 115 kV sub-system vary in need sizes and timing across the different planning scenarios and could be delayed as much as up to five years, or advanced by three years depending on the scenario.

6.3 MxD Sub-System

The MxD sub-system refers to the stations (primarily in Kitchener and Cambridge) that are served by the 230 kV Middleport to Detweiler circuits. In this sub-system, there are station capacity needs at Kitchener MTS #6, Kitchener MTS #8, Preston TS, GBE MTS #1, and Galt TS. There are also supply capacity, load security, and load restoration needs on the M21D/M22D circuits. The table below summarizes the needs for the MxD sub-system under the Planning Forecast.

Table 5 | Summary of MxD Sub-System Planning Needs

Need	Summer Need Date	Summer Need by 2045 (MW)	Winter Need Date	Winter Need by 2045 (MW)
Kitchener MTS #6 station capacity	2034	16	2039	10
Kitchener MTS #8 station capacity	2029	40	2030	81
Preston TS station capacity	See note below			
GBE MTS #1 station capacity	See note below			
Galt TS station capacity	See note below			
MxD supply capacity	Immediate	230	2032	202
MxD load security	2033	159	2033	210
MxD load restoration	Immediate	472	Immediate	471

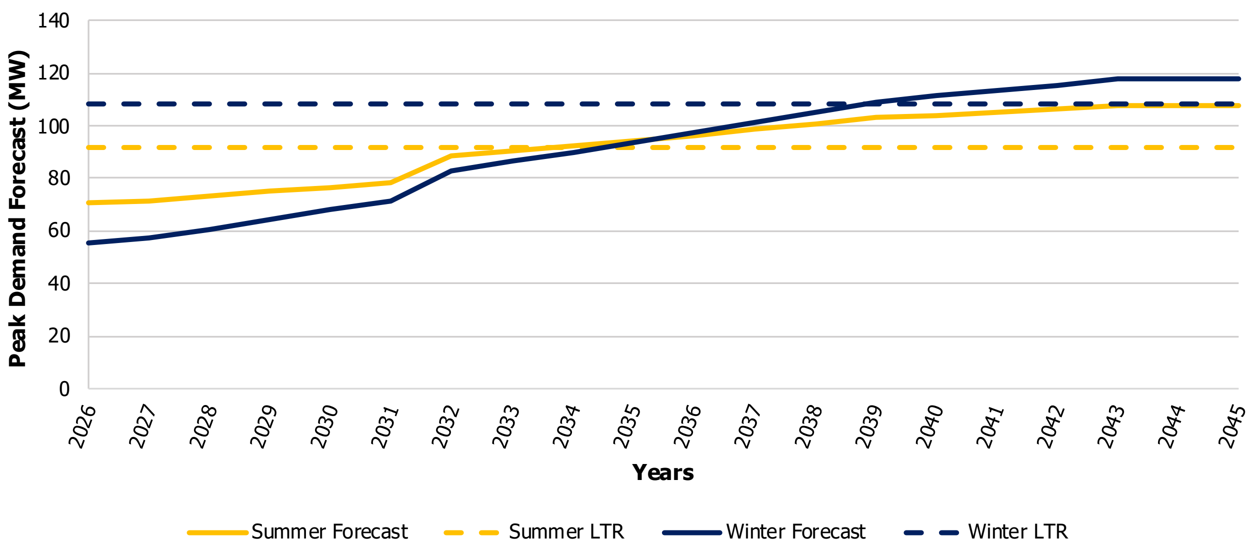
Preston TS, GBE MTS #1, and Galt TS have been loaded up to their LTRs in all planning scenarios. The cumulative need of these stations is 7 MW in 2029, and it increases to 147 MW in the summer 2045 and 130 in winter 2045. As there is no capacity at Preston TS, GBE MTS #1, and Galt TS, this additional load will have to be sited at a different station – this is explained further in Section 7.2.2.

6.3.1 Station Capacity Needs

6.3.1.1 Kitchener MTS #6

Kitchener MTS #6 consists of two 230 kV/13.8 kV transformers with a summer LTR of 92 MW and a winter LTR of 108 MW. Kitchener MTS #6 has a station capacity need of 1 MW in summer 2034, which increases to 16 MW by summer 2045. Figure 22 shows the Kitchener MTS #6 demand forecast in relation to the summer and winter LTR values.

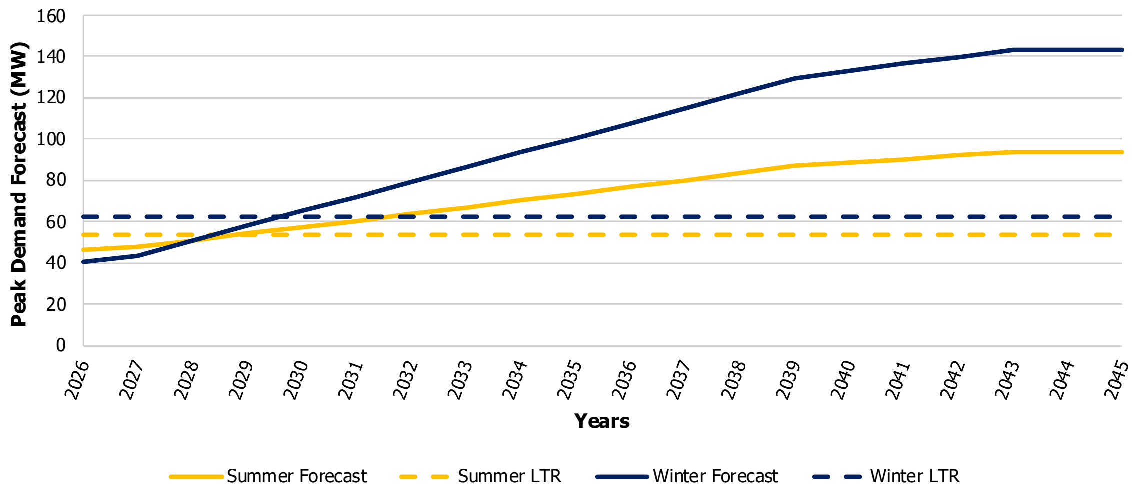
Figure 22 | Kitchener MTS #6 Station Capacity Need



6.3.1.2 Kitchener MTS #8

Kitchener MTS #8 consists of two 230 kV/13.8 kV transformers with a summer LTR of 54 MW and a winter LTR of 62 MW. Kitchener MTS #8 has a station capacity need of under a megawatt in summer 2029, which increases to 81 MW by winter 2045. The figure below shows the Kitchener MTS #8 demand forecast in relation to the summer and winter LTR values.

Figure 23 | Kitchener MTS #8 Station Capacity Need



6.3.1.3 Preston TS, Galt TS, and GBE MTS #1

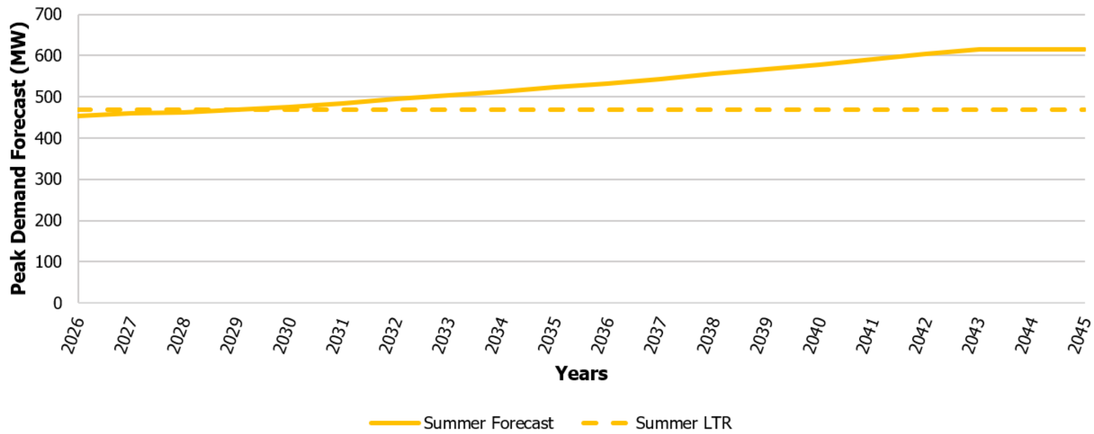
As noted with Table 5, Preston TS, GBE MTS #1, and Galt TS have been loaded up to their LTRs in all planning scenarios. Demand growth is expected to continue beyond the combined station capacity and will need to be sited at a future station (GBE MTS #2). Before a new station can be built, load will be managed between the existing MxD stations, which is described below.

- Preston TS consists of two 230 kV/27.6 kV transformers with a summer LTR of 190 MW and a winter LTR of 210 MW[3].
- Galt TS consists of two 230 kV/27.6 kV transformers with a summer LTR of 178 MW and a winter LTR of 201 MW.
- GBE MTS #1 consists of two 220 kV/27.6 kV transformers with a summer LTR of 102 MW and a winter LTR of 120 MW.

The figure below shows the cumulative Preston TS, Galt TS, and GBE MTS #1 station forecasts relative to their combined summer and winter LTR values. This highlights the outstanding station capacity need in this part of the sub-system.

[3] Upon completion of the ongoing Preston T3/T4 transformer replacement, new station LTR is expected to be in the range of 190 MW.

Figure 24 | Cumulative Preston TS, Galt TS, and GBE MTS #1 Station Capacity Needs[4]



6.3.2 Supply Capacity Need

The load in the MxD sub-system is supplied through 230 kV transmission lines between Galt junction and Detweiler TS, Preston TS, and Middleport TS. There is bulk supply at the 500/230 kV autotransformers at Middleport TS. Moreover, the MxD sub-system also connects to the KWCG region's 115 kV sub-system.

There are two distinct load groups in the MxD sub-system. One group consists of Preston TS, GBE MTS #1, Galt TS, and a CTS which are supplied by the MxD circuits between Galt junction and Preston TS. The second group consists of Kitchener MTS #6 and Kitchener MTS #8 which are supplied by the MxD circuits between Detweiler TS and Galt junction.

Load Supply Between Galt Junction and Preston TS

The load supply capacity between Galt junction and Preston TS is impacted by the loading between Detweiler TS and Galt junction. Accounting for expected Detweiler TS-Galt junction loading, the LMC between Galt TS and Preston TS is limited to 391 MW in the summer and 442 MW in the winter based on the thermal capability of the circuits between Preston TS and Galt junction under the various planning scenarios and applicable contingencies. Considering the forecast, this part of the sub-system has an immediate 17 MW summer supply capacity need which increases to 181 MW by summer 2045 and 129 MW by winter 2045.

Load Supply Between Galt Junction and Detweiler TS

The load supply capacity between Detweiler TS and Galt junction is impacted by loading between Galt TS and Preston TS. Accounting for expected Galt TS-Preston TS loading, the LMC of the sub-system between Detweiler TS and Galt junction is limited to 138 MW in the summer and 166 MW in the winter. This is due to the thermal capability of the BxC circuits in the 115 kV sub-system under the loss of D7V and M21D circuits; under these contingencies, flow through the BxC circuits from Burlington TS must increase to compensate for loss of supply from Detweiler TS. Considering the forecast, this part of the

[4] Winter forecast and LTR have been omitted as updates are required. Will be updated for the Regional Infrastructure Plan.

sub-system has a supply capacity need starting in summer 2032 with 3 MW, which increases to 49 MW by summer 2045 and 73 MW by winter 2045.

6.3.3 Load Security and Restoration Needs

As per ORTAC Section 2.4.10.1[5], no more than 150 MW is allowed to be interrupted by configuration following a single-element contingency, and no more than 600 MW by configuration following a two-element contingency. Over the forecast period, there is a load security need of 6 MW in 2033 which increases to 159 MW in summer 2045 and 210 MW by winter 2045 when there is a loss of both M20D and M21D circuits.

By the end of the study period, all forecast load (over 750 MW) on the MxD circuits would be interrupted following an outage to both circuits, M20D and M21D, by configuration. Of this load, Hydro One Transmission has indicated that approximately 100 MW Preston load, and the Kitchener MTS #6 and Kitchener MTS #8 load could be restored in a timely fashion through existing 230 kV in-line switches at Galt junction and Preston TS. Thus, the restoration targets of load in excess of 250 MW cannot be restored within 30 minutes, nor can the load in excess of 150 MW be restored within four hours. This is in violation of load restoration planning requirements (ORTAC Section 2.4.10.2) and is summarized below.

Table 6 | Load Restoration Planning Requirements on the MxD Supply Lines

Time Post-Contingency	ORTAC Requirement: Restoration Target	2045 Peak Load to be Restored	Achievable Based on the Current and Planned Transmission System?
Within 30 minutes	Load in excess of 250 MW	509 MW	No
Within four hours	Load in excess of 150 MW	609 MW	No, only 287 MW is achievable
Within eight hours	All load	759 MW	Exceeds 600 MW load security limits

6.3.4 Low and High Forecast Needs

Depending on the low or high forecast, the MxD supply capacity need ranges from 97 MW to 461 MW, but the timing is immediate regardless. This illustrates the urgency and magnitude of the supply need in this sub-system regardless of the forecast scenario. The timing and magnitude of load security and restoration needs would be adjusted similarly to the supply needs.

The station capacity needs at Kitchener MTS #6 and Kitchener MTS #8 could be delayed by up to 4 years, or advanced by 2 years depending on the forecast scenario.

The cumulative need at Preston TS, GBE MTS #1, and Galt TS could be delayed by up to eight years, or advanced by two years depending on the forecast scenario.

[5] The assumption is that there is no load curtailment and rejection.

6.4 DxV Sub-System

The DxV sub-system refers to the stations in Waterloo, Centre Wellington, and Guelph that are served by the double-circuit 230 kV DxV lines. There are multiple forecast station capacity needs. There are also supply capacity, load restoration, and load security needs affecting the overall DxV sub-system; the LMC is limited to 350 MW based on the thermal capability of the circuits between Detweiler TS and Waterloo North MTS #3. DxV supply can also be limited depending on other scenarios and applicable contingencies; its LMC is interdependent with the load on the DxW sub-system. Table 7 summarizes the needs for the DxV sub-system under the Planning Forecast.

Table 7 | Summary of DxV Sub-System Planning Summer Needs

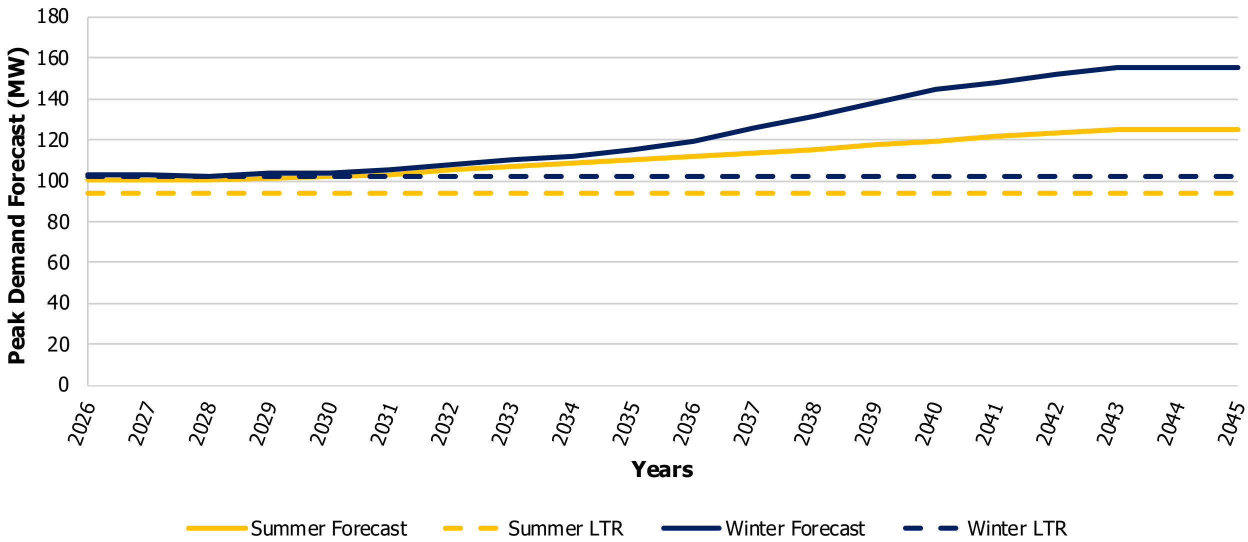
Need	Summer Need Date	Summer Need by 2045 (MW)	Winter Need Date	Winter Need by 2045 (MW)
Campbell TS T1/T2 station capacity	Immediate	31	Immediate	54
Campbell TS T3/T4 station capacity	Immediate	17	2035	22
Scheifele MTS station capacity	2028	144	2029	185
Waterloo MTS #3 station capacity	Immediate	254	2028	243
DxV supply capacity	Immediate	574	Immediate	640
DxV load security	2030	324	2030	435
DxV load restoration	Immediate	663	Immediate	774

6.4.1 Station Capacity Needs

6.4.1.1 Campbell TS T1/T2

Campbell TS T1/T2 consists of two 230 kV/13.8 kV transformers with a summer LTR of 93 MW and a winter LTR of 101 MW. It has an immediate summer station capacity need, growing to a 54 MW need in the winter of 2045. The figure below shows the Campbell TS T1/T2 demand forecast in relation to the summer and winter LTR values.

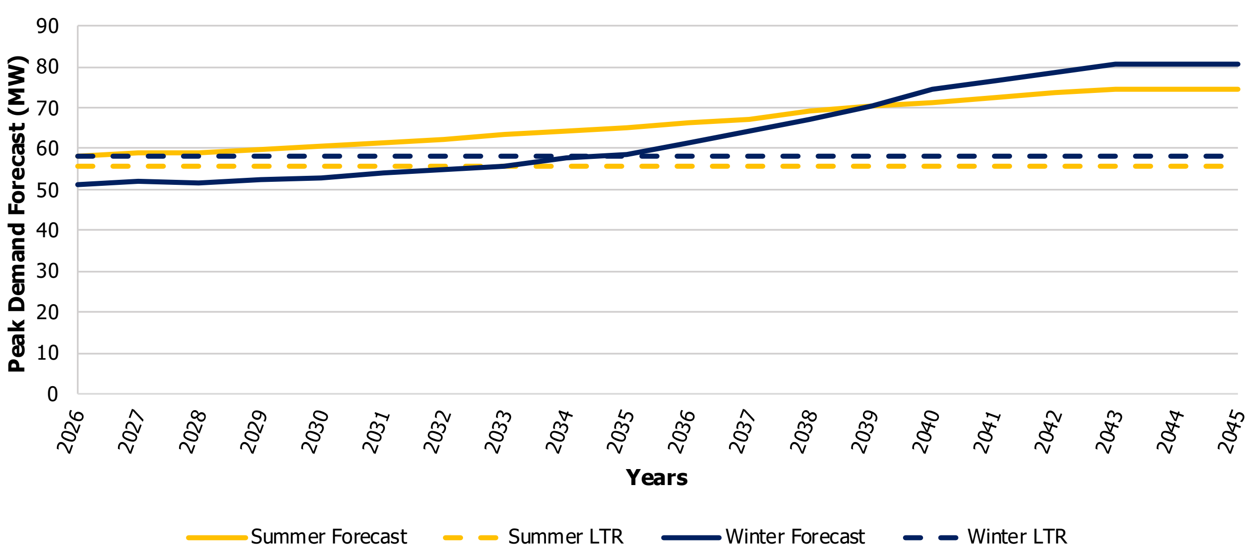
Figure 25 | Campbell TS T1/T2 Station Capacity Need



6.4.1.2 Campbell TS T3/T4

Campbell TS T3/T4 consists of two 230 kV/13.8 kV transformers with a summer LTR of 56 MW and a winter LTR of 58 MW. It has an immediate summer station capacity need, growing to a 22 MW need in the winter of 2045. Figure 26 shows the Campbell TS T3/T4 demand forecast in relation to the summer and winter LTR values.

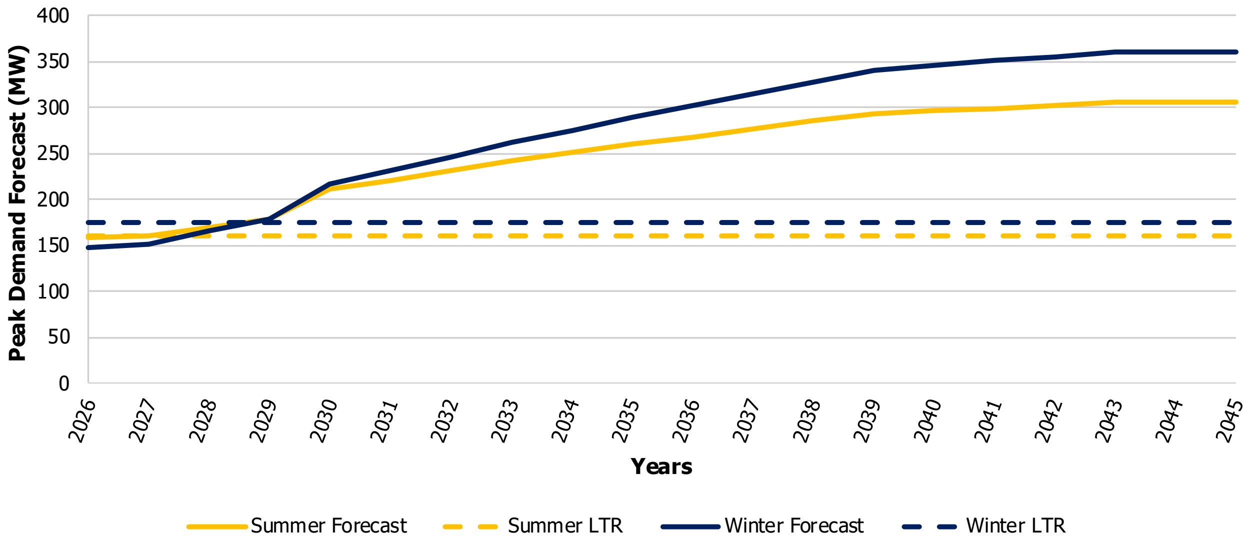
Figure 26 | Campbell TS T3/T4 Station Capacity Need



6.4.1.3 Scheifele MTS

Scheifele MTS consists of four 230kV/13.8kV transformers with a summer LTR of 161 MW and a winter LTR of 175. It is forecast to have a summer station capacity need starting in 2028, growing to a 185 MW need in the winter of 2045.

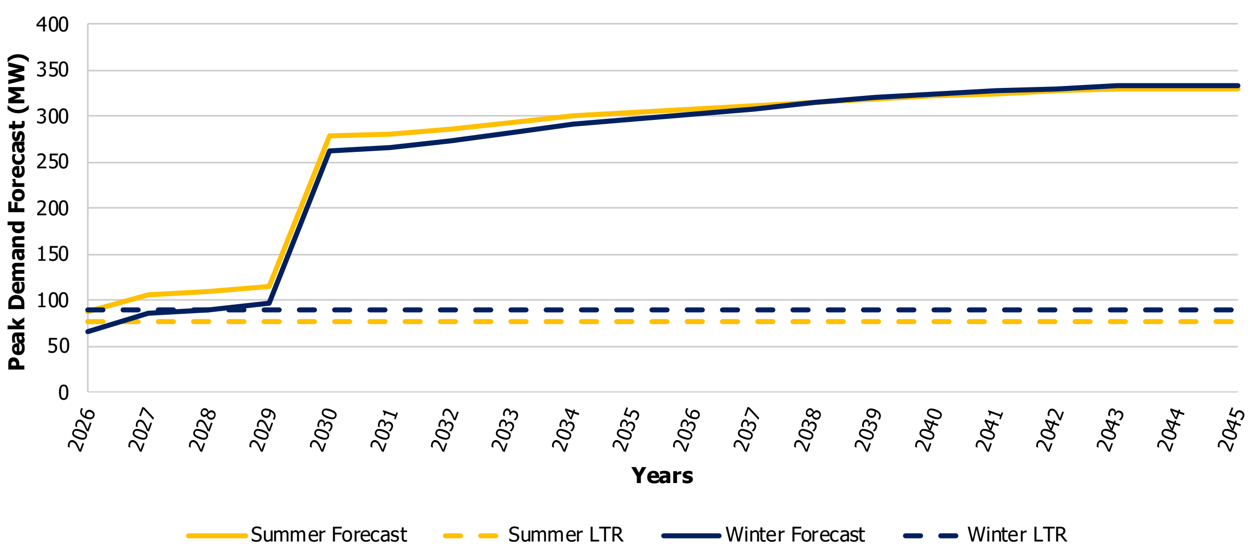
Figure 27 | Scheifele MTS Station Capacity Need



6.4.1.4 Waterloo North MTS #3

Waterloo North MTS #3 consists of two 230 kV/27.6 kV transformers with a summer LTR of 76 MW and a winter LTR of 90 MW. It is forecast to have a summer station capacity need starting in 2026, growing to a 254 MW need in the summer of 2045.

Figure 28 | Waterloo North MTS #3 Station Capacity Need



6.4.2 Supply Capacity Need

The 230 kV DxV transmission lines connect from Detweiler TS in Kitchener to Fergus TS in Centre Wellington, to Cedar TS in Guelph. The sub-system does not have any local transmission-connected generation. The LMC is limited to 350 MW in the summer and 395 MW in the winter, and it is based on the thermal capability of the circuits between Detweiler TS and Waterloo North MTS #3.[6] Considering the forecast growth in the sub-system, there is an immediate supply capacity need in both summer and winter that increases to 574 MW by summer of 2045 and 640 MW in the winter.

6.4.3 Load Security and Restoration Needs

As per ORTAC Section 2.4.10.1, no more than 150 MW is allowed to be interrupted by configuration following a single-element contingency, and no more than 600 MW by configuration following a two-element contingency. Over the forecast period, there is a load security need of 129 MW in 2030 which increases to 324 MW in summer 2045 and 435 MW by winter 2045 when there is a loss of both D6V and D7V circuits.

By the end of the study period, all forecast load (more than 900 MW) on the DxV circuits would be interrupted following an outage to both circuits, D6V and D7V, by configuration. Of this load, Hydro One Transmission has indicated that only approximately 260 MW of the load could be restored in a timely fashion through existing 230 kV in-line switches. Thus, the restoration targets of load in excess of 250 MW cannot be restored within 30 minutes, nor can the load in excess of 150 MW be restored within four hours. This is in violation of load restoration planning requirements (ORTAC Section 2.4.10.2) and is summarized in Table 8.

Table 8 | Load Restoration Planning Requirements on the DxV Lines

Time Post-Contingency	ORTAC Requirement: Restoration Target	2045 Peak Load to be Restored	Achievable Based on the Current and Planned Transmission System?
Within 30 minutes	Load in excess of 250 MW	676 MW	No
Within four hours	Load in excess of 150 MW	776 MW	No, only 260 MW is achievable
Within eight hours	All load	926 MW	Exceeds 600 MW load security limits

6.4.4 Low and High Forecast Needs

Depending on the low or high forecast, the DxV supply capacity need ranges from 403 MW to 801 MW, and the timing is immediate regardless. This illustrates the urgency and magnitude of the supply need in this sub-system regardless of the forecast scenario. The timing and magnitude of load security and restoration needs would be adjusted similarly to the supply needs.

The station capacity needs at Campbell TS, Scheifele MTS, and Waterloo North MTS #3 could be delayed by up to one year, or advanced by two years depending on the forecast scenario.

[6] This is based on the simultaneous forecast loading on the DxW sub-system, since the LMCs for the DxW and DxV sub-systems are interdependent.

6.5 DxW Sub-System

The 230 kV DxW transmission lines supply Detweiler TS from Buchanan TS in London and includes no local transmission-connected generation. The LMC of the DxW sub-system is interdependent with the LMC of the DxV subsystem; it also is impacted by assumed loading at Preston TS. With a total of approximately 400 MW at Preston, GBE MTS#1 and Galt TS, and with the load on the DxV circuits at the maximum limit (350 MW, as described in Section 6.4.2), DxW supply is limited to 100 MW. This is due to voltage violations at Preston TS or GBE MTS#1 TS after contingencies resulting in the loss of an MxD circuit and the static VAR compensator or a shunt capacitor at Detweiler TS. Increased loading between Preston TS and Galt TS degrades the DxV and DxW LMCs further on the existing system – in fact, additional load on the MxD and 115 kV sub-systems generally can reduce DxV and DxW supply.

There is no direct need on the DxW transmission lines if only accounting for the Kitchener MTS #9 forecast. However, as described above, the DxW LMC depends on the DxV sub-system loading. This is described further in Section 7.2.3.

6.6 D8S/D10H Sub-System

The D8S-D10H sub-system refers to the stations within the KWCG region that are served by the Detweiler-Seaforth (D8S) and Detweiler-Hanover (D10H) circuits. There is a station capacity need at Rush MTS and a supply capacity need on the D8S-D10H circuits transmission circuits, which are 115 kV circuits from Detweiler TS towards Seaforth TS and Hanover TS. Table 9 summarizes the needs for the D8S/D10H sub-system under the Planning Forecast.

Table 9 | Summary of D8S/D10H Sub-System Planning Needs

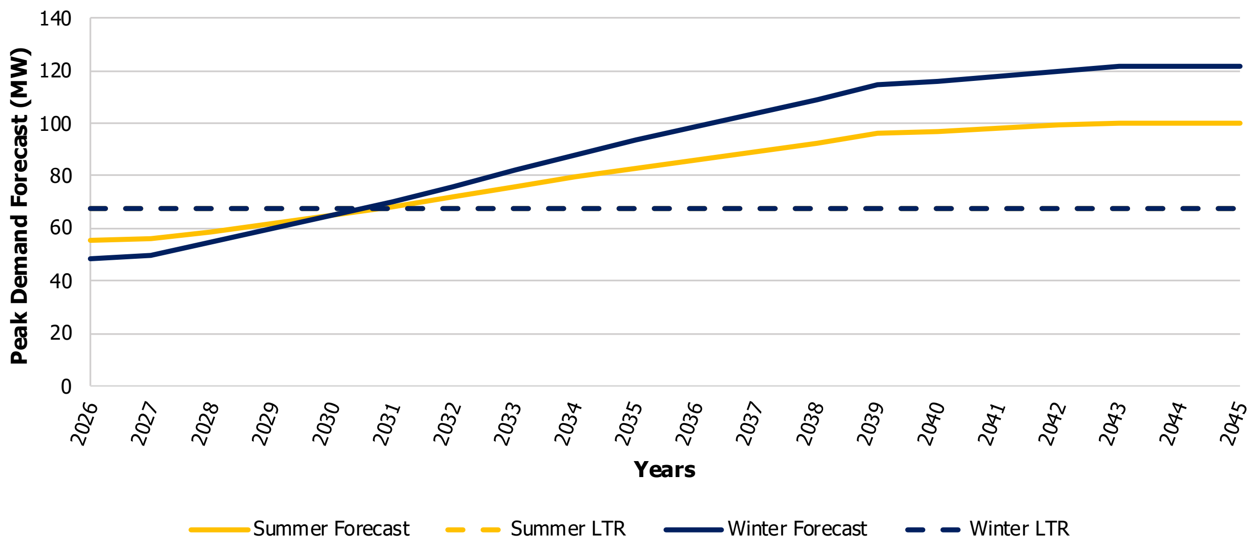
Need	Summer Need Date	Summer Need by 2045 (MW)	Winter Need Date	Winter Need by 2045 (MW)
Rush MTS station capacity	2031	33	2031	54
D8S-D10H supply capacity	2033	26	2037	19

6.6.1 Station Capacity Needs

6.6.1.1 Rush MTS

Rush MTS consists of two 115 kV/13.8 kV transformers with an LTR of 68 MW. Rush MTS has a station capacity need of 3 MW in winter 2031, which increases to 54 MW by winter 2045. Figure 29 shows the Rush MTS demand forecast in relation to the summer and winter LTR values.

Figure 29 | Rush MTS Station Capacity Need



6.6.2 Supply Capacity Need

The load in the D8S-D10H sub-system is supplied through 115 kV transmission lines between Detweiler TS, Seaforth TS, and Hanover TS. The 230/115 kV autotransformers at Detweiler TS supply the D8S-D10H sub-system. The LMC of the sub-system is limited to 120 MW in the summer and 144 MW in the winter based on the thermal capability of the circuits between Detweiler TS, Leong junction, and Waterloo junction. Considering the forecast growth in the area, this sub-system has a 2 MW supply capacity need starting in 2033 that increases to 26 MW by 2045.

6.6.3 Low and High Forecast Needs

Depending on the low or high forecast, the D8S-D10H supply capacity need ranges from 2 MW to 47 MW, and timing ranges from 2030 to 2041. This suggests that the need is sensitive to different forecast scenarios and growth should be closely monitored.

The station capacity need at Rush MTS could be delayed by five years, or advanced by one year depending on the forecast scenario.

6.7 DxK Sub-System

The DxK sub-system refers to Kitchener MTS #1 and Kitchener MTS #4 and their radial double-circuit 115 kV supply from the Detweiler-Kitchener transmission circuits. There are station capacity needs at Kitchener MTS #1 and #4, and a supply capacity need on the DxK circuits. Table 10 summarizes the needs for the DxK sub-system under the Planning Forecast.

Table 10 | Summary of DxK Sub-System Planning Summer Needs

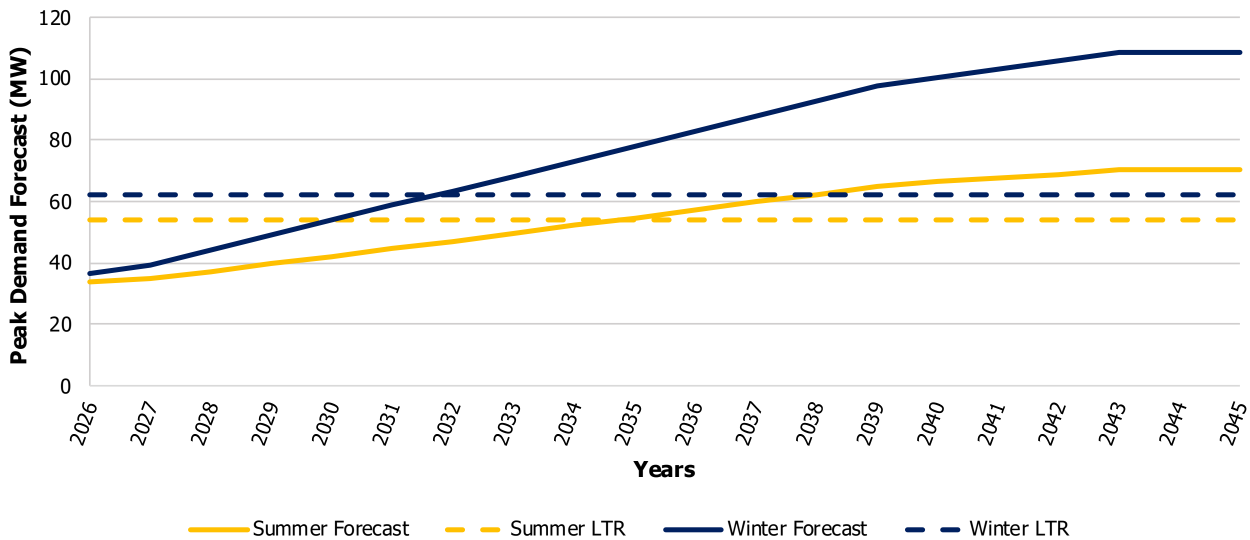
Need	Summer Need Date	Summer Need by 2045 (MW)	Winter Need Date	Winter Need by 2045 (MW)
Kitchener MTS #1	2035	16	2032	46
Kitchener MTS #4	2035	19	2032	50
DxK supply capacity	2033	42	2031	96

6.7.1 Station Capacity Needs

6.7.1.1 Kitchener MTS #1

Kitchener MTS #1 consists of two 115 kV/13.8 kV transformers with a summer LTR of 54 MW and a winter LTR of 62 MW. Kitchener MTS #1 has a station capacity need of 1 MW in winter 2032, which increases to 46 MW by winter 2045. Figure 30 shows the Kitchener MTS #1 demand forecast in relation to the summer and winter LTR values.

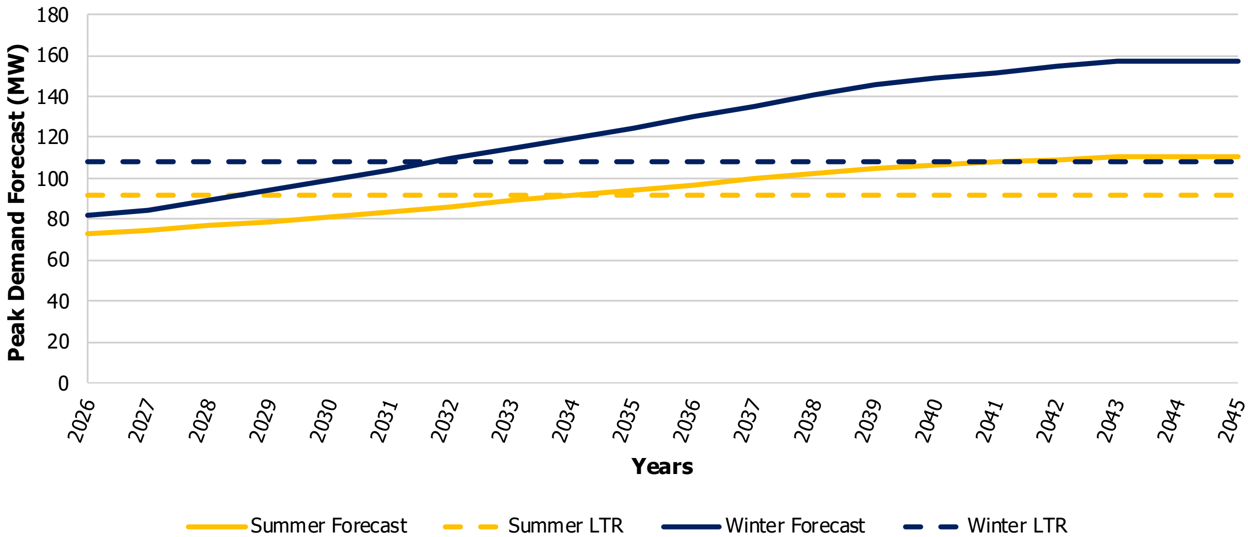
Figure 30 | Kitchener MTS #1 Station Capacity Need



6.7.1.2 Kitchener MTS #4

Kitchener MTS #1 consists of two 115 kV/13.8 kV transformers with a summer LTR of 92 MW and a winter LTR of 108 MW. Kitchener MTS #4 has a station capacity need of 1 MW in winter 2032, which increases to 50 MW by winter 2045. Figure 31 shows the Kitchener MTS #4 demand forecast in relation to the summer and winter LTR values.

Figure 31 | Kitchener MTS #4 Station Capacity Need



6.7.2 Supply Capacity Need

The load in the DxK sub-system is supplied through radial 115 kV transmission lines from the Detweiler TS 115 kV bus. The LMC of the sub-system is limited to 127 MW in the summer and 148 MW in the winter based on the thermal capability of the circuits between Detweiler TS, Kitchener MTS #1, and Kitchener MTS #4. Considering the forecast growth in the area, this sub-system has a 1 MW supply capacity need starting in 2031 which increases to 96 MW in 2045.

6.7.3 Low and High Forecast Needs

Depending on the low or high forecast, the DxK supply capacity need ranges from 79 MW to 117 MW, and timing ranges from 2031 to 2032. This illustrates the magnitude and firmness of the supply need in this sub-system regardless of the forecast scenario.

The station capacity needs at Kitchener MTS #1 and Kitchener MTS #4 could be either delayed or advanced by one year depending on the forecast scenario.

6.8 Operability and Operational Issues

Operational issues are not defined as planning needs. However, if they affect the reliability of the region, the Technical Working Group may consider opportunities to address operational issues while addressing planning needs.

Operational issues that impact reliability were identified for the KWCG region; they are driven by the switchyard/breaker configuration at Detweiler TS. Detweiler TS is a major supply point for the region and these operational issues have significant impact on potential LMCs.

With the existing Detweiler switchyard configuration, the Detweiler static VAR compensator or capacitors may cause damaging ferroresonance oscillations or high voltages under certain forced or planned outage conditions – for example, a bus fault if followed by specific secondary forced outages. To protect equipment from damage, Hydro One has operating procedures to manually remove the

Detweiler static VAR compensator or capacitors from service under these outage conditions before the secondary forced outages occur.

If these operating restrictions are executed, there are post-outage instances in which up to six elements at Detweiler TS, including both capacitors and the static VAR compensator, would be lost. This can significantly reduce the supply capability for the region.

As the Technical Working Group explores solutions to eliminate the need for these operating procedures (such as protection schemes and/or reconfiguring the Detweiler TS switchyard), their impact on the reported LMCs was ignored. This is described further in Section 7.2.3.

6.9 Bulk Supply into KWCG

The focus of regional planning is to ensure reliable supply within a region. Supply into the region is out of scope, but it is studied in the South and Central Bulk Plan, which was developed in parallel with the KWCG IRRP. This bulk plan includes:

- Identifying/confirming the transmission required to enable the connection of future bulk generation resources.
- Exploring the transmission required to enable decreased reliance on emitting resources.
- Determining transmission required to enable reliable supply under high economic growth/ electrification scenarios, including the connection of new large loads and data centres in the Greater Toronto Area and the Hamilton to Windsor corridor.
- Identifying opportunities to assess and preserve potential new or expanded corridors for future electricity infrastructure.

7. Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in the KWCG region. When developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, federal regulations, technical feasibility, cost effectiveness, lead time, local preferences, and consistency with longer-term needs in the area.

There are generally two approaches to address regional needs:

- Build new transmission or distribution infrastructure. These are commonly referred to as wire options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, upgrades to existing infrastructure, or distribution-level load transfers. Wire options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system's existing capability. These are commonly referred to as non-wire alternatives (NWAs) and can include things like local utility-scale generation or storage, distributed energy resources (including distribution-connected generation and demand response), or additional eDSM.

Section 7.1 provides a more in-depth overview of the NWA considerations in this IRRP. Subsequently, Section 7.2 presents the options that were ultimately developed and evaluated (including a cost comparison) before the Technical Working Group made a recommendation.

7.1 Non-Wires Analysis Process in IRRPs

Wires options are always considered in regional planning, and while they are always viable options for regional needs, NWAs may be more suitable for specific need types and characteristics. To select and appropriately size NWAs like generation or battery storage, additional work is required — including the creation of an hourly load profile, as described in Section 5.8. The most suitable technology type and capacity is chosen by examining the unserved energy profile, which is the hourly demand above the existing station or system capability The profile indicates the duration, frequency, magnitude, and total energy associated with each need. More details on the NWA process and analysis are provided in appendix.

7.1.1 Approach to Needs Screening

NWAs are suitable for specific types of needs, as described in the Integrated Regional Resource Plans: Guide to Assessing Non-Wires Alternatives. An initial screening step is performed to identify which NWAs may be suitable for the type of need addressed.

High-level cost estimates for wire options are based on input provided by the transmitter and transmission benchmark costs. Similarly, cost estimates for non-wire options are based on benchmark capital and operating cost characteristics for each resource type and size. The complete list of assumptions used in the needs screening and options analysis is provided in the appendix.

The IESO is mandated to centrally deliver province-wide eDSM programs for Ontario that target businesses, residential customers, and First Nations. The IESO offers incentives and rebates to electricity customers through a suite of Save On Energy programs, which provide a valuable and cost-effective system resource that helps customers better manage their energy costs. Demand savings from centrally-delivered energy efficiency programs under the 2021–2024 Conservation and Demand Management Framework and Save on Energy brand are already included in the load forecast, as discussed in Section 5.5. This forecast assumed the programming continues through the forecast period at levels consistent with the 2021-2024 CDM Framework.

Additional eDSM above and beyond that included in the demand forecast can also play a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply. Results from the IESO's latest (2022) provincial energy efficiency Achievable Potential Study inform estimates of the additional peak demand savings potential available from eDSM programming, and the cost to acquire those peak demand savings.

The new 2025-2036 eDSM Framework provides the IESO with a twelve-year mandate and $10.9B budget ceiling to expand and enhance eDSM programming. Higher provincial savings targets under the new framework relative to the 2021-2024 CDM Framework may contribute to delivering additional eDSM recommended to address specific regional needs. The new framework also establishes new mechanisms for IESO and Local Distribution Company eDSM collaboration, including specific funding for LDC-delivered programming that provides both local and regional or provincial benefits.

Generally, additional eDSM programming is suitable for needs where growth is slow and the magnitude of the overload relative to the total demand is very small (i.e., on the order of few per cent per year). These considerations are discussed further in Section 7.1.2. LDCs can also use the Ontario Energy Board's Non-Wires Solutions Guidelines for Electricity Distributors to leverage distribution rates to help address distribution and transmission system needs using NWAs. In some cases, NWAs can help manage needs in the interim before wires reinforcements are in-service.

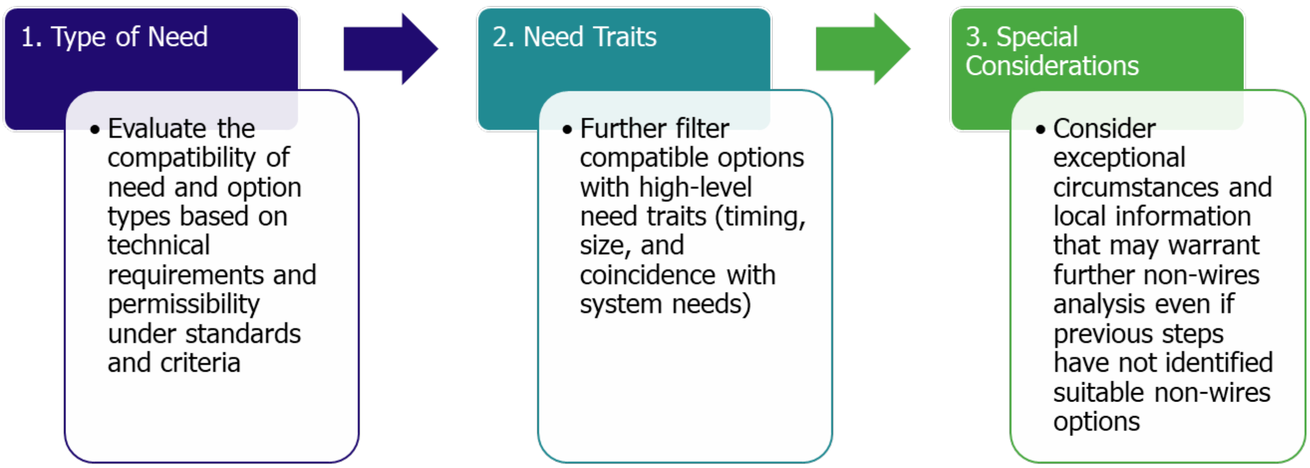
Where NWAs are screened in and determined to be feasible, the upfront capital and operating costs for both wire options and NWAs are compiled to generate levelized annual capacity costs (measured in dollars per kW per year). In this scenario, the cash flow of the levelized costs for the options are compared over the lifespan of the wire option and the net present value of these levelized costs is the primary basis through which feasible options are compared. Where NWAs are screened out or determined to be infeasible for meeting the need, overnight capital costs for wire options are used instead.

NWAs are subject to uncertainties in the procurement in terms of both the resource costs bid my proponents and the overall success of the procurement. Moreover, it is important to recognize that there is a significant uncertainty around cost estimates at the planning stage (from minus 50 per cent on the low side to plus 100 per cent on the high side), as they are only intended to enable comparison between options during the IRRP. The transmitter-led Regional Infrastructure Plan (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine cost estimates of wire options before implementation work begins. The IESO continues to participate in the Technical Working Group during the Regional Infrastructure Plan and revisits these recommendations if cost estimates differ significantly.

7.1.2 Non-Wires Screening Results

Screening occurs early in the IRRP development – after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed NWA analysis (hourly need characterization, options development, financial analysis, and engagement) toward the most promising options. The three-step, high-level approach is shown in Figure 32.

Figure 32 | IRRP Screening Mechanism



The results of applying the screening mechanism to the KWCG IRRP needs are summarized and described in the sections below. More details on the steps and inputs used in the screening mechanism can be found in the appendix. The list of assumptions made in the needs screening and option analysis can also be found in the appendix.

Table 11 | Results of the KWCG IRRP Screening

Sub-System	Need	Options Screened In	Options Screened Out[7]
Middleport to Detweiler, MxD	Station capacity, supply capacity, load restoration and security	Additional eDSM DG Demand response Transmission-connected generation Wires	
115 kV	Station capacity and supply capacity	Additional eDSM Demand response DG Wires	Transmission-connected generation

[7] Since the IESO is mandated to centrally deliver provincial eDSM programs, the incremental eDSM potential is estimated for each need regardless of its ability to meet the need.

Sub-System	Need	Options Screened In	Options Screened Out[7]
Detweiler to Orangeville, DxV	Station capacity, supply capacity, load restoration and security	Additional eDSM Wires	DG Demand response Transmission-connected generation
Detweiler towards Elmira, D8S/D10H	Station capacity and supply capacity	Additional eDSM Wires	Transmission-connected generation
Detweiler to Kitchener MTS #1 and #4, DxK	Station capacity and supply capacity	Additional eDSM DG Demand response Transmission-connected generation Wires	

7.2 Options Evaluation and Recommendations

7.2.1 115 kV Sub-System

Options for Station Capacity Needs

Arlen TS and Hanlon TS

With station capacity needs arising in the long term (more than 10 years out), options for Arlen TS and Hanlon TS are not required currently. This is applicable even under the high forecast scenario. However, the Technical Working Group can continue to monitor load growth the Guelph area and re-assess these station capacity needs in the next cycle of regional planning.

Cedar TS

Additional eDSM programs could meet 19 MW of the 38 MW summer station capacity need in 2045, as illustrated below. The estimated cost of achieving these eDSM savings is $58 million, which is considered cost effective for provincial adequacy needs.

Figure 33 | Estimated Incremental eDSM Potential for Cedar T1/T2

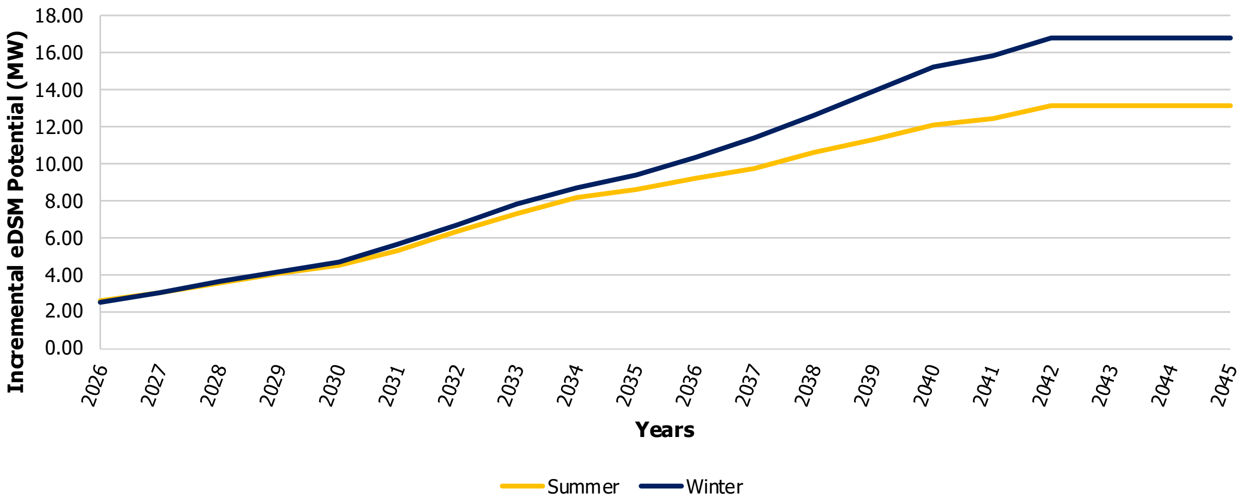
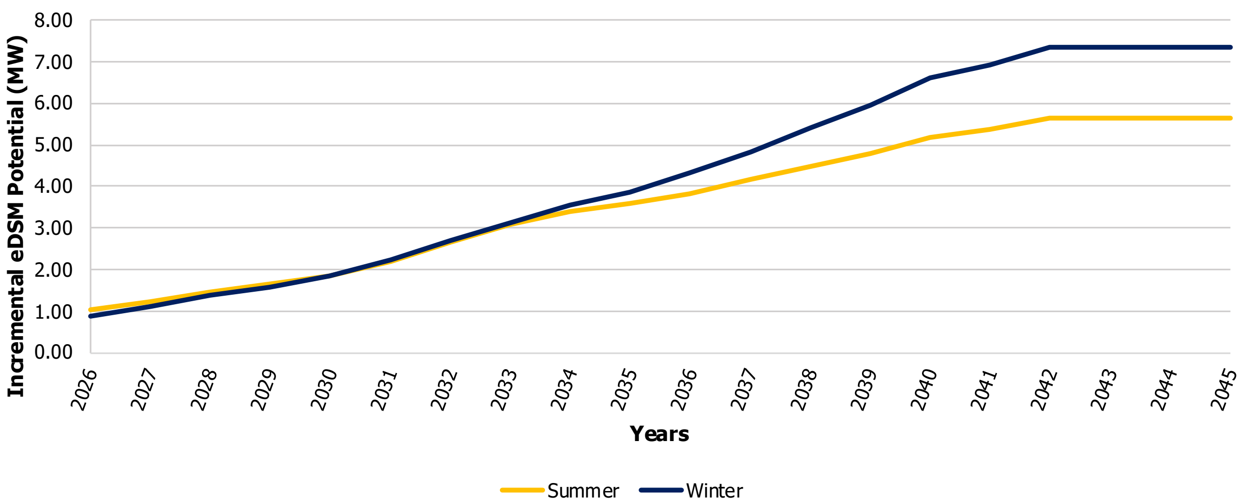


Figure 34 | Estimated Incremental eDSM Potential for Cedar T7/T8



For the end-of-life need at Cedar T7/T8 in 2032, only wires options were considered:

1. Like-for-like 115 kV transformer replacement ($20 million, three-years lead time);
2. Upsized 115 kV transformer replacement ($55 million, four-years lead time)[8]; or
3. Voltage conversion of existing 115 kV DESN to a new 230 kV DESN ($60M, four-years lead time).

Option 1 addresses the end-of-life need and increases the LTR to 58 MVA (52 MW), which does not meet the T7/T8 station capacity need in the long term. Options 2 and 3 provide more station capacity, with both offering an LTR of 140 MVA (126 MW). This not only accommodates the capacity need at T7/T8 but can address the capacity need at T1/T2 if load is transferred on the distribution system.

Option 3 offers an additional benefit to offload the constrained 115 kV sub-system. 230 kV supply to a new 230 kV Cedar T7/T8 is enabled by the DxV sub-system recommendations (see Section 7.2.3); in

[8] Assumes new transformers and second metal-clad switchgear.

contrast, option 2 is not feasible without further 115 kV sub-system reinforcements — beyond those described later in this in section.

Kitchener MTS #5 and #7

Additional eDSM programs could meet 13 MW of the Kitchener MTS #5's summer station capacity need of 10 MW in 2035 and 7 MW of MTS #7's summer station capacity need of 12 MW in 2035, as illustrated in Figure 38. The estimated cost of achieving these eDSM savings is $72.7 million, which is considered cost effective for provincial adequacy needs.

Figure 35 | Estimated Incremental eDSM Potential for Kitchener MTS #5

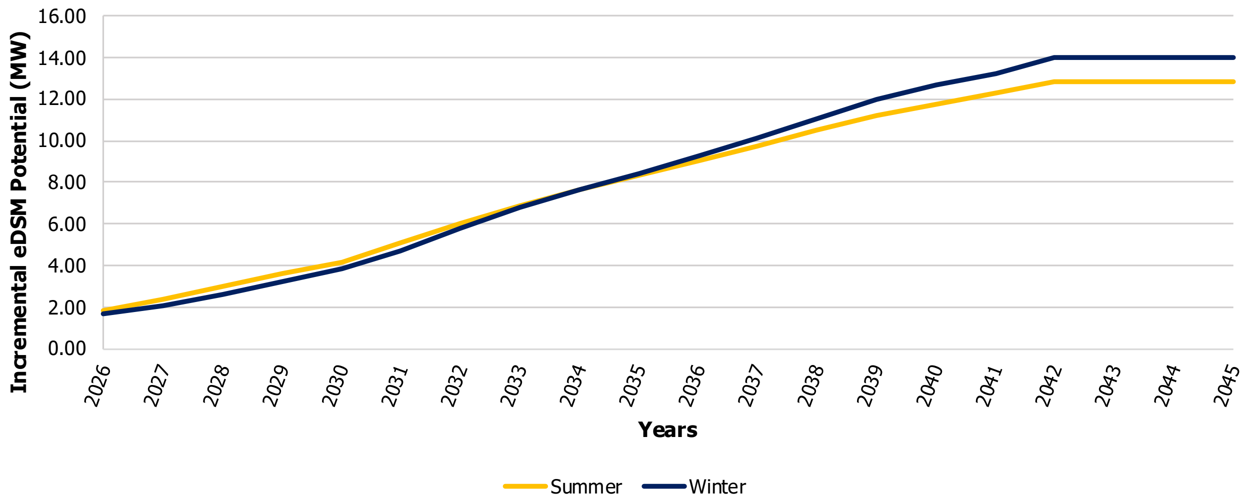
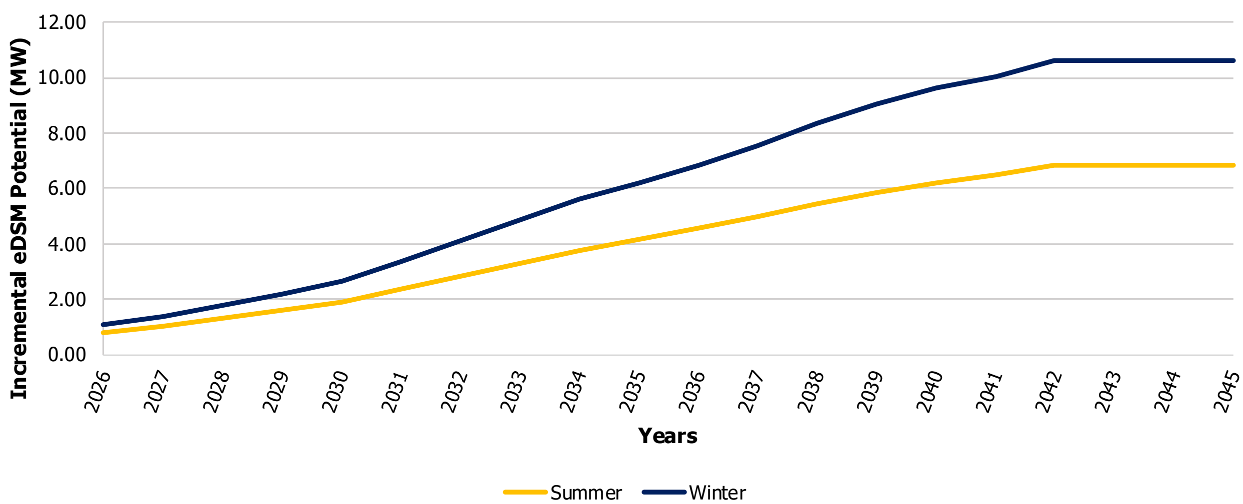


Figure 36 | Estimated Incremental eDSM Potential for Kitchener MTS #7



Given the nearer term need at Kitchener MTS #7, other non-wires options were evaluated:

1. DG; and
2. demand response.

By 2045, the need profile for Kitchener MTS #7 net of additional eDSM peaks at 32 MW, lasts up to 90 consecutive hours, and sums to approximately 40,000 MWh of energy. The need also occurs primarily in the winter. Based on these need characteristics, the following options were screened in:

- wind;
- BESS;
- combined wind and BESS;
- combined wind and solar;
- combined solar and BESS;
- combined solar, wind, and BESS; and
- demand response.

Solar as a standalone option was screened out due to the winter need, and small modular reactors were screened out since the need size does not warrant this type of technology. Natural gas was screened out to focus the analysis on options that reduce reliance on emitting resources. This complements the municipal preferences of the city of Kitchener.

Among the screened-in generation options, none were feasible either because of the need profile and size, and/or the available DG connection capacity at the station. For the latter, consideration was given to Enova Power undertaking feeder breaker and switchgear replacement work to increase the short circuit rating by 20 per cent. Even if ignoring DG connection capacity, feasible options would have a land requirement (like wind and BESS, at an estimated total of 15 km^2) that can be difficult to accommodate near Kitchener MTS #7.

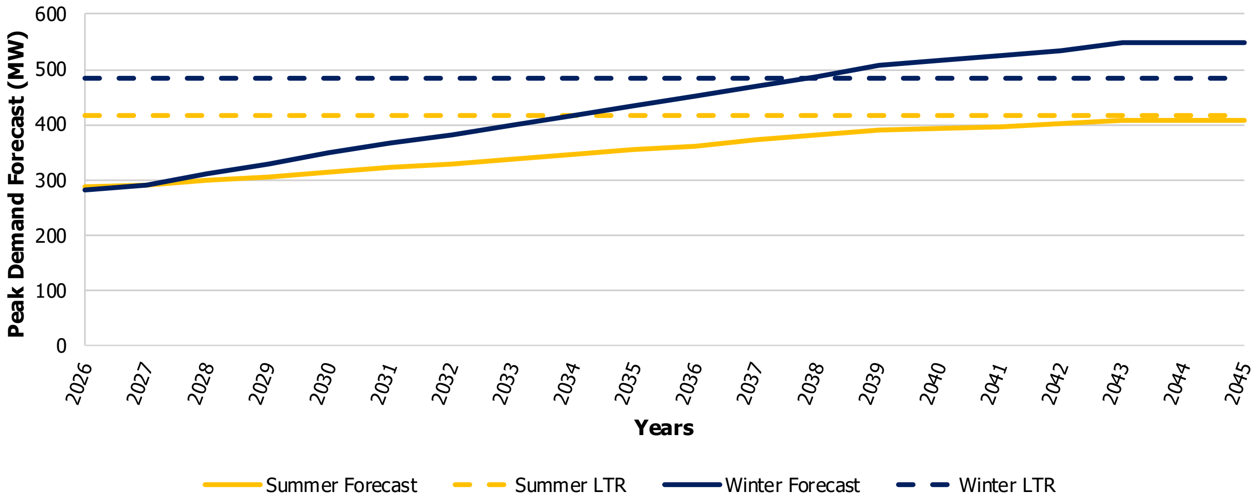
For the station capacity needs at Kitchener MTS #5 and #7, the following wires options were evaluated:

1. load transfers on the distribution system starting in 2032[9]; and
2. new station in Kitchener.

Option 1 is to leverage capacity on the existing transmission system to transfer and optimize load between the 115 kV Kitchener stations (both in the 115 kV sub-system and in the DxK sub-system). Currently, Kitchener MTS #5 has ties with MTS #1, #4, and #7; MTS #7 has ties with MTS #3 and #5. There is sufficient station capacity for the 115 kV Kitchener stations until 2039 (including those served by the DxK sub-system), assuming distribution-level load transfers to enable the optimal load reallocation are possible. Each new distribution tie is estimated to cost $500,000.

[9] Could be delayed depending on the amount of additional eDSM savings are achieved.

Figure 37 | Cumulative Station Capacity Needs at 115 kV Kitchener Stations[10]



Option 2 can be considered alongside option 1 for an integrated solution. Option 2 involves a new station sited in Kitchener in the Freeport area to provide enough station capacity (at least 70 MW) for the cumulative station needs at Kitchener MTS #1, 4, and 7. It would be required starting in 2039 if distribution load transfer capability allows all existing station capacity to be utilized, but could also be later depending on additional eDSM savings. If the new station is connected to the 230 kV system, options include:

- A 6.5 km, 230 kV double-circuit line extension from Kitchener MTS #6 to Kitchener MTS #7, where:
  - MTS #7 is converted to 230 kV ($2-5 million); or
  - a new 230 kV station is built on its existing property ($30-45 million).

About 1.3 km of the 230 kV line extension may utilize the existing underground duct bank and cost $30 million; the remaining overhead line is expected to cost $44 million. It is also possible for the new 230 kV double-circuit line extension to come from Preston TS to the Kitchener Freeport area.

Alternatively, new station capacity in Kitchener could be added at the 115 kV level. Given the 115 kV sub-system limitations described in Section 6.2, this can occur in two ways:

- reinforcements to the 115 kV sub-system beyond the circuit upgrades recommended in later this this section; or
- long-term offloading of the 115 kV sub-system through a 230 kV line extension from Preston TS to a converted GrandBridge Energy MTS #2 (also described in Section 7.2.2).

Puslinch DS

The following non-wires options were evaluated for the station capacity need at Puslinch DS:

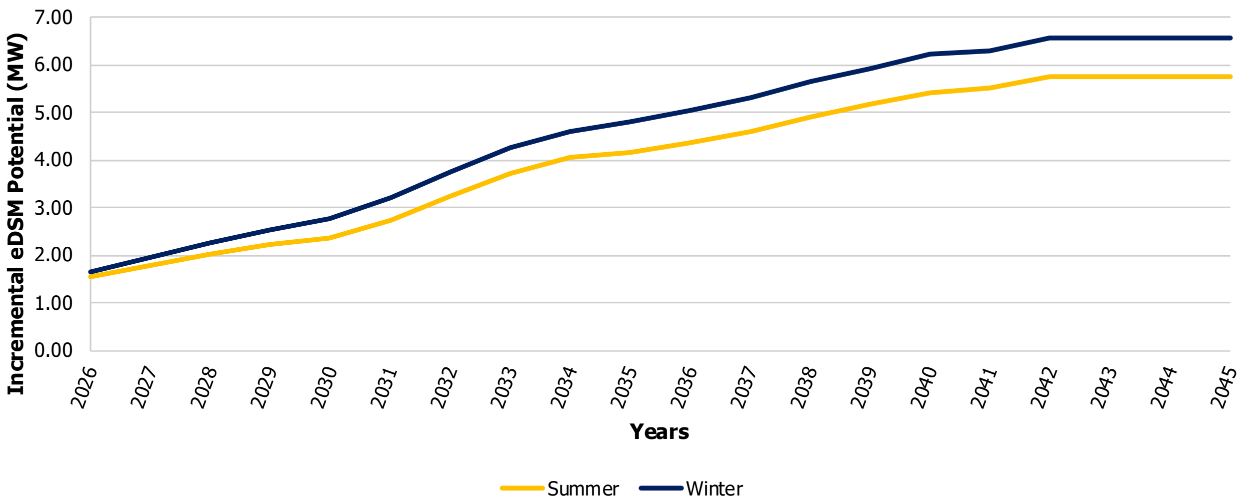
1. Additional eDSM;
2. DG; and

[10] Graph includes Kitchener MTS #1, 3, 4, 5, and 7.

3. demand response.

Additional eDSM programs could meet 6 MW of the 13 MW summer station capacity need in 2035. The estimated cost of achieving these eDSM savings is $15.6M, which is cost-effective for provincial adequacy needs.

Figure 38 | Estimated Incremental eDSM Potential for Puslinch DS



By 2045, the need profile for Puslinch DS peaks at 13 MW, lasts up to 17 consecutive hours, and sums to approximately 2,500 MWh of energy. Based on these need characteristics, the following non-wires options were screened in:

- solar;
- BESS;
- combined solar and BESS;
- combined solar, wind, and BESS;
- demand response; and
- natural gas.

Wind as a standalone option and wind with BESS were screened out due to the need primarily occurring during summer daylight hours, and small modular reactors were screened out since the need size does not warrant this type of technology.

Among the screened-in DG options, only two could meet the need profile into the long term:

- 12 MW of solar and 8 MW/47 MWh of BESS[11] deployed between 2030 and 2042; or
- 13 MW of natural gas.[12]

[11] Could meet the reference need until 2042.

[12] While this IRRP has primarily focused on options that reduce the reliance on emitting resources, gas generation was explored to help provide context on the cost and feasibility of alternatives to the solar and BESS option.

Between the feasible options, solar and BESS are estimated to cost $41-50 million compared to $101 million for natural gas. Of these total costs, up to $41 million and $34 million could be attributed to system benefits (i.e., contribute to provincial resource adequacy needs), respectively. Therefore, the net cost of the most cost-effective non-wires option of solar and BESS is $0 to $9 million, with the latter being more applicable since it represents distribution-connected rather than utility-scale resources. Distribution-connected resources are required for station capacity needs.

A wires option was also considered for the Puslinch DS need: reconfiguring the station to a new 230 kV DESN for $65 million with a five-year lead time. This option is more expensive, however, does offer additional station capacity for growth beyond the high forecast. The station should be at the 230 kV level given the constrained 115 kV sub-system in the KWCG region.

The economic assessment for the options at Puslinch DS is summarized in the table below. Note that these are planning-level cost estimates subject to change during implementation.

Table 12 | Summary of Economic Assessment of Options for Puslinch DS[13]

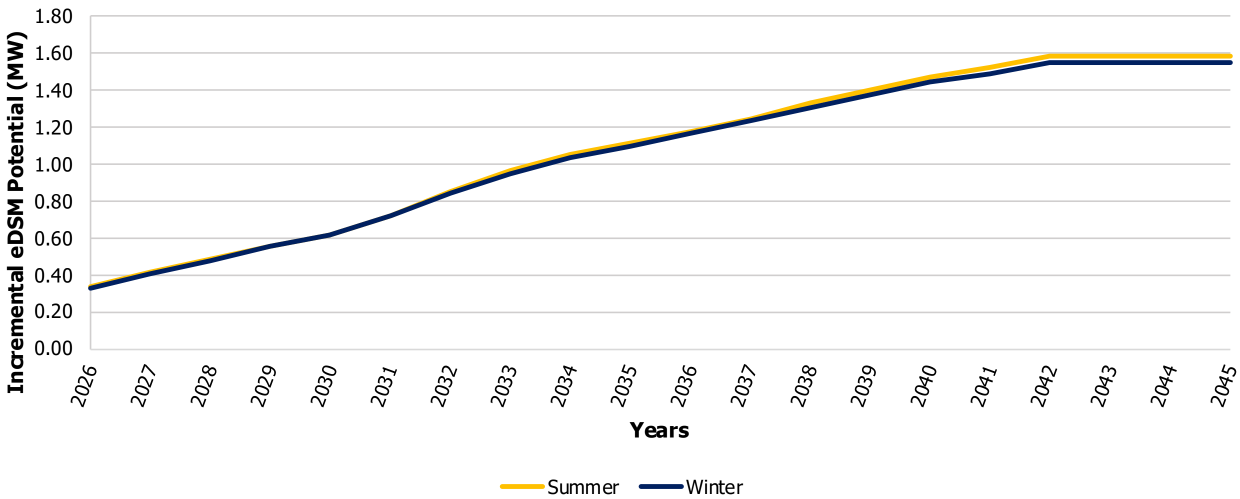
Option	Total Cost	System Benefits (Utility Scale)[14]	Net Benefit (Cost to Ratepayer)
New 230 kV station with overnight capital cost of $65M	$65M	$0M	-$65M
BESS and solar	$41M to $50M	$41M	$0M to -$9M
Natural gas	$101M	$34M	-$67M

Wolverton DS

Additional eDSM targeted to Wolverton DS could meet 2 MW of the 16 MW summer station capacity need in 2035. The estimated cost of achieving these eDSM savings is $5.2 million, which is cost-effective for provincial adequacy needs.

[13] Costs are net present values for 2026 to 2073 in 2025 real dollars.
[14] Estimates based on changing system needs as identified by the Annual Planning Outlook.

Figure 39 | Estimated Incremental eDSM Potential for Wolverton DS

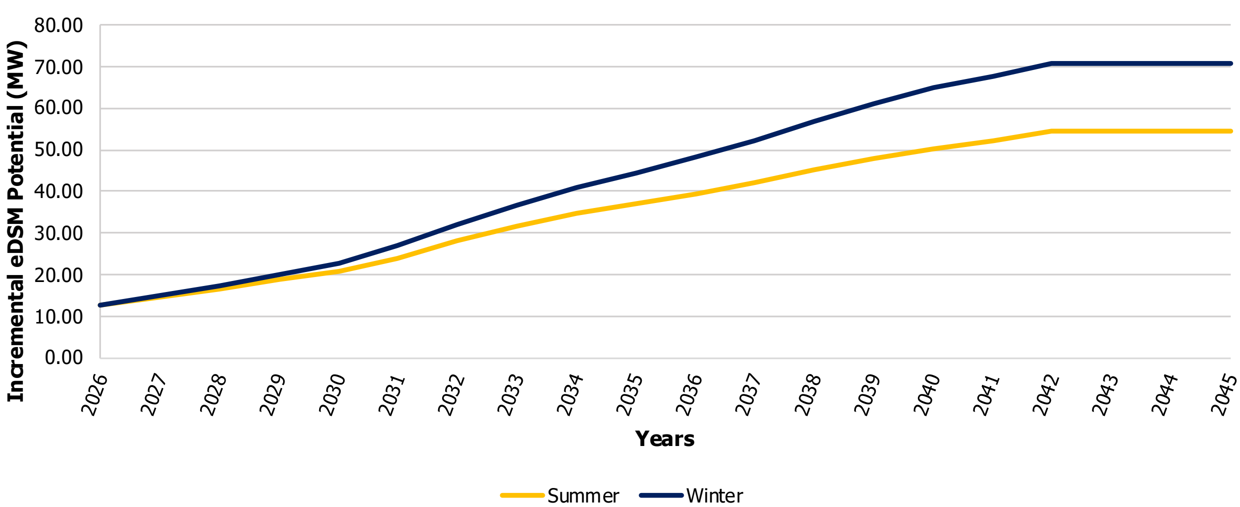


The wires option considered for the Wolverton need is the fan monitoring project already underway by Hydro One Distribution. Once implemented by early 2027, the LTR increases to 31 MVA and 40 MVA for summer and winter respectively. Combined with additional eDSM, this project defers the Wolverton DS station capacity need to 2041.

Options for 115 kV Supply

Given the nature of the 115 kV sub-system supply constraints described in Section 6.2, the only non-wires option considered was additional eDSM (see Figure 40). Additional eDSM programs could meet 54 MW of the 90 MW summer station capacity need in 2045, as illustrated below. The estimated cost of achieving these eDSM savings is $172.2 million, which is considered cost-effective for provincial adequacy needs.

Figure 40 | Estimated Incremental eDSM Potential for 115 kV Sub-System



Other non-wires options, such as transmission-connected resources, were screened out from further analysis due to increased operational complexity and the specific requirements of any resource option:

- Multiple generation units would have to be sited at both Freeport junction and Puslinch TS and connected to both 115 kV circuits.
- A three-breaker ring bus configuration ($60M, two-to-three-year lead time) or tap ($3 million, one-to-two-year lead time) would be required for each generation connection.
- Deliverability of resources connected to the BxC and FxC circuits was limited per the LT2 RFP connection guidance.

Alternatively, three sets of circuit uprates were evaluated for wires options:

1. B5C between Burlington and Harper ($3.5M) and D9F between Detweiler and Siebert ($12 million);
2. B6C between Harper and Puslinch ($2.2M) and F12C between Speedville and Freeport ($18 million); and
3. further uprates to B5C between Harper and Puslinch, and B6C between Burlington and Harper ($3 million total).

With uprates sets #1 and #2, the 115 kV sub-system supply capacity need is addressed, with additional room for up to 75 MW. Set #3 of uprates increases this by another 20 MW, depending on where on the 115 kV network load is added. Beyond these uprates, the 115 kV sub-system becomes voltage-limited.

Upgrading the companion sections on the D7F circuit at an estimated cost of $6 million, as well as the F11C circuit at an estimated $9 million, enables more flexibility for future connections to be supplied by both circuits in the double-circuit line.

Recommendations

Additional eDSM that is cost-effective to the system should be targeted to all station capacity needs in the KWCG 115 kV sub-system.

For the station capacity need at Wolverton DS, Hydro One Distribution should proceed with the fan monitoring project to increase the station LTR by early 2027.

To address the 115 kV sub-system supply capacity need, it is recommended for Hydro One to implement upgrades to increase the thermal ratings of B5C/B6C, D7F/D9F, and F11C/F12C by 2028, per sets 1 and 2 upgrades described above.

To address the station capacity needs at Cedar T1/T2 and T7/T8 DESN, as well as the end-of-life need at the latter, it is recommended that T7 & T8 are replaced by 2032 with a new 230 kV DESN supplied by the existing DxV transmission lines.

Starting in 2033, load between Kitchener MTS #5 and #7 should be transferred off as required to respect their station LTRs. This is recommended to be implemented through the distribution system between Kitchener MTS #1, 3, 4, and 6. In the long-term, a new station is required in the Kitchener Freeport area. In future planning, the Technical Working Group should consider cost-effective opportunities for 230 kV reinforcements to address long-term needs, given the constraints and less flexibility of the 115 kV sub-system.

In the long term, load growth (including the impact of eDSM savings) should be monitored at Arlen TS and Hanlon TS to manage potential station capacity needs.

To address the Puslinch DS station capacity need, it is recommended to implement distribution-connected resources between 2030 and 2042.

Two key considerations accompany this non-wires recommendation:

- potential for Hydro One Distribution's low or high forecast at Puslinch DS to materialize; and
- implementation mechanisms for DERs for regional planning needs.

While the most cost-effective, feasible option for Puslinch DS' reference case need is the combination of solar and BESS, Hydro One Distribution should consider the potential for its low or high forecast to occur. Load trending closer to the low forecast scenario would re-affirm the value of proceeding with non-wires options that can be sized in smaller increments and staged over multiple years to avoid overbuilding — as opposed to the wires alternative of a 230 kV DESN that offers excess capacity. In contrast, if load trends beyond the high forecast scenario, the integrated non-wires recommendation should be re-evaluated and a new station may be required or may be more cost-effective.

The analysis in this IRRP also specifically identified that an integrated package of 12 MW of solar and 8 MW/47 MWh of BESS, staged over the period of 2030 to 2042, is the most cost-effective solution given the wires alternative for Hydro One Distribution's station capacity need. The non-wires solution also has system value – it can contribute as part of the new resources that otherwise would have to be acquired for provincial resource adequacy needs, as signaled through the Annual Planning Outlook. Any resources participating in IESO procurements would need to ensure they are able to comply with the requirements of those procurements and associated contractual obligations. Other combinations and timing of distributed resources may be sufficient for Puslinch DS, if they can adequately address the need profile (see KWCG IRRP Data Tables), meet technical requirements, and are more cost-effective than the wires alternative explored in this IRRP.

At least three years is the typical lead time for new solar and BESS, but timelines may vary depending on the implementation approach. The IESO signals system needs through connection guidance and future procurement processes, including the LT2 RFP. These procurements are technology-agnostic and are open to distribution-connected projects. Distributed resources can also participate in the Capacity Auction to help meet system needs. In parallel, various initiatives are underway by the Ontario Energy Board that can impact the implementation of non-wires options, including initiatives on distribution system operator capabilities. Related, the Benefit-Cost Analysis Framework sets out guidance for LDCs when assessing the economic feasibility of non-wires solutions for distribution need — including an Energy System Test that accounts for impacts to the broader energy system.

The implementation mechanism for the non-wires recommendations for Puslinch DS will be identified after the IRRP. As a next step, the Technical Working Group will monitor Puslinch DS' forecast such that the wires alternative of a new 230 kV DESN is triggered if still required and the non-wires recommendation cannot be implemented in time. The IESO will work with the LDC to support the exploration of value-stacking opportunities.

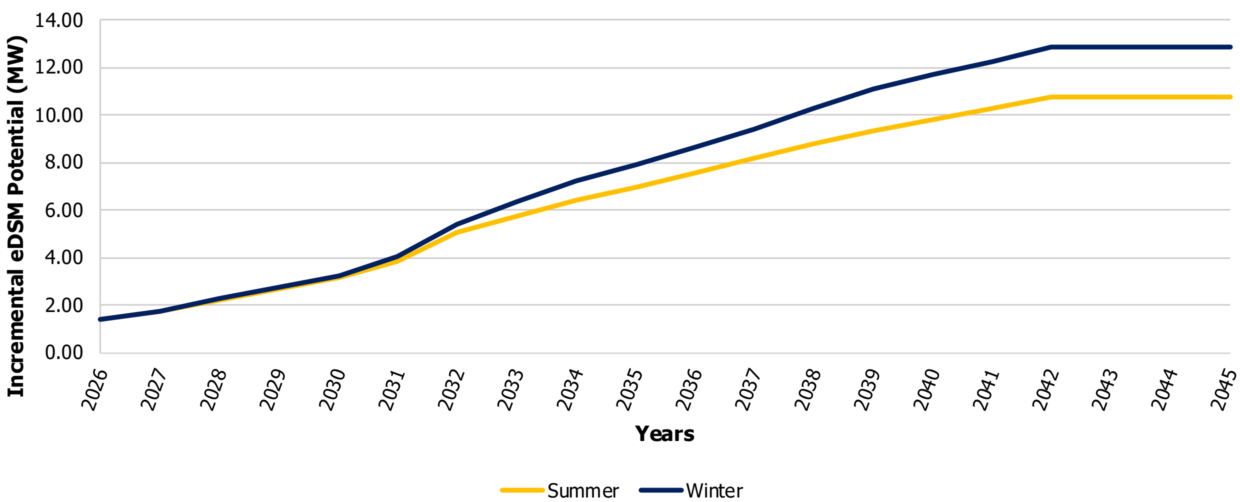
7.2.2 MxD Sub-System

Options for Station Capacity Needs

Kitchener MTS #6

Additional eDSM programs could meet 11 MW of the 16 MW summer station capacity need in 2045, as illustrated below. The estimated cost of achieving these eDSM savings is $40.5 million, which is considered cost effective for provincial adequacy needs.

Figure 41 | Estimated Incremental eDSM Potential for Kitchener MTS #6



Other non-wires options were evaluated:

1. DG; and
2. Demand response.

By 2045, the need profile for Kitchener MTS #6 net of additional eDSM peaks at 12 MW, lasts up to eight consecutive hours, and sums to approximately 290 MWh of energy. The need also occurs primarily in the summer evening.

Based on these need characteristics, BESS was screened in for further evaluation. Solar and wind as standalone options were screened out due to the primarily summer need occurring in the evenings. Small modular reactors were screened out since the need size does not warrant this type of technology. Demand response is possible only until 2036 as the energy shortfall and number of consecutive hours of need grows over the planning horizon. Lastly, natural gas was screened out to focus the analysis on options that reduce reliance on emitting resources. This complements the City of Kitchener's participation in ClimateActionWR, a collaborative effort with local municipalities and organizations to reduce community-wide GHG emissions. The City has set GHG reduction targets, including an 80 per cent reduction by 2050 from 2010 levels, with interim goals such as a 30 per cent reduction by 2030.

12 MW/58 MWh of BESS, deployed between 2034 and 2042, was assessed to be feasible to meet the need profile and estimated to cost $25-30 million. Of these total costs, $25 million could be attributed to system benefits (i.e., contribute to provincial resource adequacy needs). Therefore, the net cost of the cost-effective non-wires option of BESS is $0 to $4 million, with the latter being more applicable

since it represents distribution-connected rather than utility-scale resources. For the Kitchener MTS #6 station capacity need, the BESS should be distribution-connected at or downstream of the MTS. Land requirements for the BESS are estimated to be 0.002 km^2.

A wires option was also considered for MTS #6: expanding the station with a new 230 kV DESN for $30-45M. This option is more expensive but offers additional station capacity for growth beyond the high forecast. Kitchener MTS #6 also has distribution ties for load transfers with MTS #4 and #8, but those stations are also reaching their LTRs.

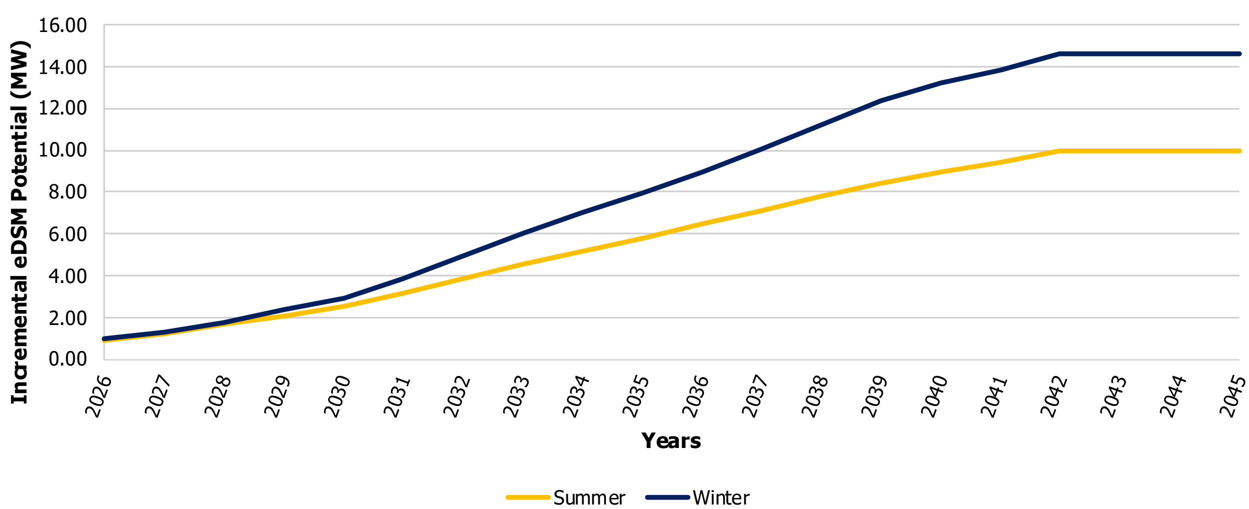
Table 13 | Summary of Economic Assessment of Options for Kitchener MTS #6[15]

Option	Total Cost	System Benefits (Utility Scale)[16]	Net Benefit (Cost to Ratepayer)
New 230 kV station with overnight capital cost of $30M to $45M	$26M to $39M	$0M	-$26M to -$39M
BESS-only	$25M to $30M	$25M	$0M to -$4M

Kitchener MTS #8

Additional eDSM was screened in for further consideration at Kitchener MTS #8. This non-wires option could meet 10 MW of the 40 MW summer station capacity need in 2045, as illustrated in Figure 33. The estimated cost of achieving these eDSM savings is $38.6 million, which is considered cost effective for provincial adequacy needs.

Figure 42 | Estimated Incremental eDSM Potential for Kitchener MTS #8



15 Costs are net present values for 2026 to 2073 in 2025 real dollars. Note that these are planning-level cost estimates subject to change during implementation.

16 Estimates based on changing system needs as identified by the Annual Planning Outlook.

While eDSM can help reduce the station capacity need, it is not sufficient alone and does not defer it. A wires alternative is to expand Kitchener MTS #8 with a new 230 kV DESN at a cost estimate of $30-45 million, in-service by 2030 when the need arises. There are also distribution ties for load transfers to Kitchener MTS #3 and #6, but capacity at the former is already required to offload some of the 115 kV Kitchener stations. At the latter, there is already a station capacity need.

Preston TS, GBE MTS #1, and Galt TS

Due to the urgent and large station capacity needs between Preston TS, GBE MTS #1, and Galt TS, eDSM was considered to help manage needs until wires options could be implemented. Additional eDSM could address 49 MW of the station capacity needs between Preston TS, GBE MTS #1, and Galt TS by 2045. The estimated cost of achieving these eDSM savings is $144.3 million, which is considered cost effective for provincial adequacy needs.

Otherwise, the Technical Working Group focused on the following wires options:

1. 115 kV station ($40 million) supplied by the existing F11C/F12C circuits; or
2. 230 kV station ($45 million) supplied by a new 230 kV double-circuit line from Preston TS ($75M).

These options' ability to meet the collective KWCG station capacity needs in GrandBridge Energy's service territory are closely intertwined with the 115 kV sub-system and MxD sub-system supply needs.

Option 1 provides station capacity in the Cambridge area as early as 2028 since its preferred location enables connection to existing 115 kV circuits. However, there is limited 115 kV supply capacity, even after accounting for the circuit upgrades recommended in Section 7.2.1. In contrast, Option 2 requires longer to implement for two reasons: new 230 kV double-circuit lines are needed to connect the station (depending on where the station can be sited), and reinforcements for MxD supply also need to be in-service first (see next section).

An integrated solution is also possible. With the 115 kV circuit upgrades recommended in Section 7.2.1, option 1 can provide 75 MW of station capacity to the Cambridge area in the near term, meeting the cumulative need until 2035 (or earlier, if load materializes at a faster rate than in the reference forecast). After, when the MxD supply reinforcements are in-service, a new larger 230 kV DESN can meet the remaining capacity needs in the longer term.[17] Its siting in the eastern part of Cambridge (near the Speedsville and Maple Grove area) is subject to where GrandBridge Energy load growth materializes in the 2030s, as well as routing of new 230 kV transmission lines connecting Puslinch with Cambridge.

Wires Options for MxD Supply, Load Restoration, and Load Security

The following wires options were considered to address MxD supply capacity needs:

1. Reconductor 19 km of the MxD line, from Cambridge junction to Galt junction ($40 million);
2. Rebuild 19 km of the MxD line, from Cambridge junction to Galt junction ($115 million);

[17] Planning-level cost estimate is subject to the size of the new DESN, depending on how load materializes.

3. Sectionalize the MxD lines at Galt junction with a new 230 kV SS (including two 195 MVAR capacitor banks) ($170 million), reconductor between Galt and Preston, and build:
    a. 32 km double-circuit 230 kV lines to Detweiler ($380 million); or
    b. 25 km double-circuit 230 kV lines to Middleport ($310 million).
4. Build new 500/230 kV autotransformer station ("Wellington TS") near Puslinch (including two 100 MVAR capacitor banks[18]) and 15 km double-circuit 230 kV line to Preston TS ($280 million total), with:
    a. Normally open point at Ameristeel junction; or
    b. 230 kV switching station at Galt junction ($160 million).
5. Build new 46 km double-circuit 230 kV line from Middleport to Galt to Preston ($480 million); and
6. Build new 53 km double-circuit 230 kV line from Detweiler to Galt to Preston ($550 million).

Option 1 increases the supply capability between Galt TS and Preston TS by approximately 50 MW; Option 2's performance is similar, though offers higher thermal ratings on the transmission lines.

Options 3a and 3b increase supply capability between Galt SS and Preston TS by approximately 110 MW and 130 MW, respectively. In contrast, options 4a and 4b increase supply capability between Preston TS and Wellington TS by about approximately 100-170 MW[19] and 400 MW[20], respectively. Since these options address the MxD supply capacity needs, the more expensive options 5 and 6 were not studied further.

Consideration for Brant and Powerline Load

In the 2024 Burlington to Nanticoke IRRP, two 230 kV DESNs were recommended to address capacity needs at Brant TS and Powerline MTS in the County of Brant. These new stations are to be connected to the MxD circuits, pending outcomes of the KWCG IRRP.

Therefore, the KWCG Technical Working Group considered each MxD wires option and their LMC for load supply to the Brant/Powerline area:

- Options 3a and 3b enable the new DESNs to be connected with new radial 230 kV lines from Galt SS. However, neither provide sufficient capacity for the forecast (300 to 350 MW) required for Brant/Powerline.
- Options 4a and 4b allow the new DESNs to tap the MxD lines between Detweiler TS and Middleport TS, or Galt SS, respectively, and enables up to the 600 MW load security limit on the Kitchener MTS #6/#8 and Brant/Powerline side.

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[18] Additional capacitor banks may be required in the longer term as load grows.

[19] Supply capability ultimately depends on where additional load (such as GBE MTS #3) is sited; if close to Preston TS, the LMC increases by 170 MW. If load is sited closer to Galt TS, the LMC will be lower.

[20] The 600 MW total load security criterion will be limiting first.

Consideration for Load Security and Restoration Needs

As described in Section 6.3.3, supply capacity needs on the MxD sub-system are also accompanied by load security and load restoration needs. Therefore, the Technical Working Group considered the security and restoration benefits offered by options 4a and 4b (the only wires options capable of solving the supply capacity needs, as described above).

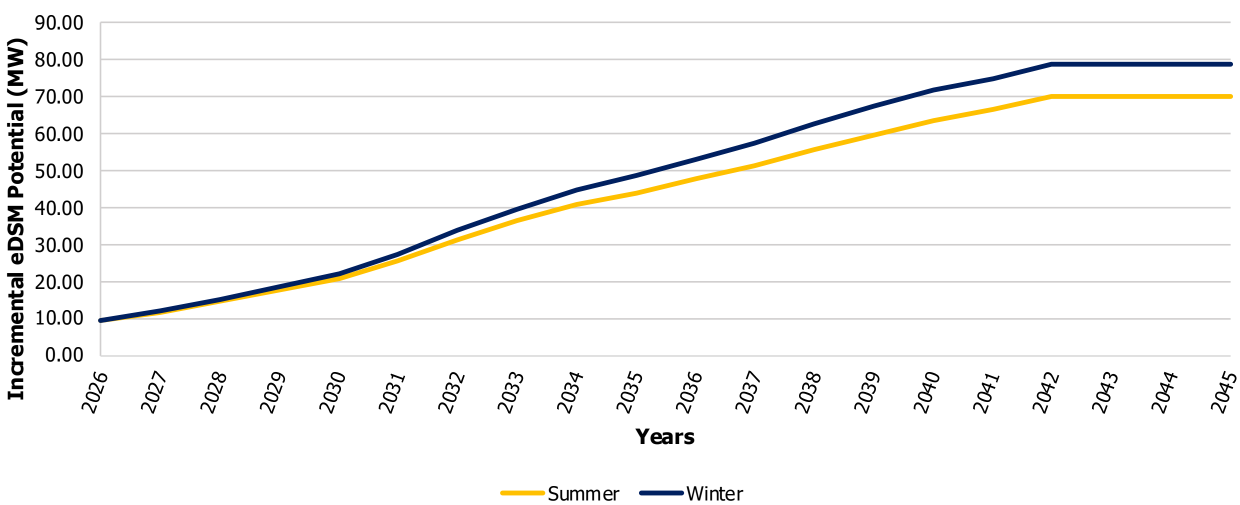
With either the open point or SS, security needs are resolved because the loads on the current MxD lines would be sectionalized such that no more than 600 MW of load could be interrupted by a contingency event based on configuration of the system alone. There are also load restoration benefits: with option 4a, motorized switches on both the Detweiler side and Middleport side of Galt junction allow the restoration of Kitchener MTS #6 and #8, as well as Brant/Powerline load, depending on where the contingency occurs. Restoration of loads between Galt TS and Preston TS would be possible from Wellington TS. The Galt SS in option 4b offers even greater restoration capability through re-termination of the existing MxD circuits at Galt junction.

Non-Wires Options for MxD Supply

For the MxD supply capacity need, two types of non-wires options were evaluated: additional eDSM and transmission-connected resources.

Additional eDSM programming targeting load supplied by the MxD sub-system could meet 79 MW of the 202 MW winter 2045 need. This is illustrated below. The estimated cost of achieving these eDSM savings is $246.5 million, which is considered cost effective to the system.

Figure 43 | Estimated Incremental eDSM Potential for MxD Sub-System



Given the magnitude of needs affecting the MxD sub-system, the Technical Working Group considered the feasibility of an integrated solution where a new transmission-connected resource is implemented alongside a Galt SS to defer additional 230 kV transmission lines. To achieve this and meet the need, the resource would have to be sited on the 230 kV side of Preston TS. It would also necessitate a three-breaker ring bus at Preston TS ($60 million, two to three-year lead time).

By 2045, the need profile for this resource (after additional eDSM is accounted for) peaks at 337 MW, lasts up to 334 consecutive hours, and sums to approximately 865,000 MWh of energy. Based on these characteristics, the following resource types were screened in:

- combined wind and BESS;
- combined solar and BESS; and
- combined solar, wind, and BESS.

Solar, wind, and BESS as standalone options were screened out due to the need characteristics, and small modular reactors were screened out since the need size does not warrant this type of technology. Natural gas was screened out given municipal preferences to phase out natural gas, and federal policy direction per the Clean Electricity Regulations at the time of IRRP development.

All screened-in generation options have a large land requirement, and of them, only the combination of wind, solar, and BESS could meet the need profile. This option is estimated to require almost 400 km^2 (1,115 MW of wind, 432 MW of solar, and 1,089 MW/10,000 MWh of BESS). This is not feasible given the specific siting requirements for the generation, and the dense urban area and limited space around Preston TS.

Recommendations

Additional eDSM that is cost-effective to the system should be targeted to all station capacity needs in the KWCG MxD sub-system.

To address the station capacity needs in the near term, a new 230 kV DESN expansion at Kitchener MTS #8 is recommended by 2030. In Cambridge, a new 115 kV station (GBE MTS #2) supplied by F11C/F12C should be implemented by 2028, accommodating up to 75 MW.

GrandBridge Energy may choose to explore a dual-voltage TS for its MTS #2, with a primary operating voltage of 115 kV and 230 kV and a secondary distribution voltage of 27.6 kV, at an additional cost of $2 million. This 230 kV capability may offer flexibility for future load connection requirements, which could be considered in subsequent planning cycles as circumstances evolve.

For the broader MxD supply, security, and restoration needs, a 500/230 kV autotransformer station (Wellington TS) in the Puslinch area is required by 2031 (or as early as 2029), as well as a new 230 kV double-circuit line from this station to Preston TS and a normally open point at Ameristeel junction.

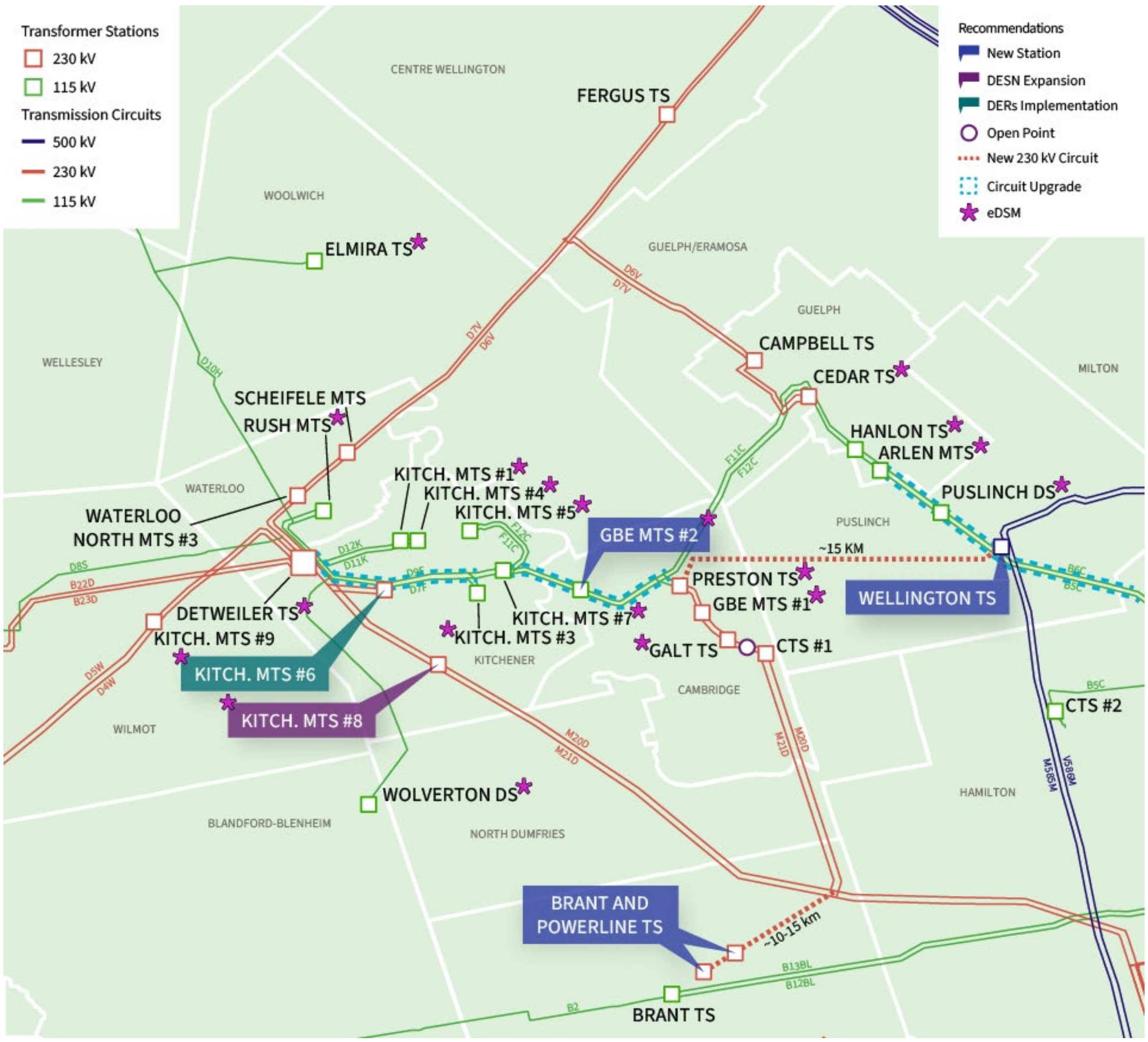
A subsequent 230 kV DESN (GBE MTS #3) is recommended by 2035 (or earlier, depending on how load materializes) for longer term station capacity needs in Cambridge after MTS #2 is fully subscribed.

The siting of GBE MTS #3 and its 230 kV supply is subject to where long-term load growth materializes in GrandBridge Energy's service territory and the routing of the new 230 kV Wellington TS to Preston

TS line. MTS #3 may be required earlier depending on the pace of forecast growth – under the high scenario, it should be in-service by 2031. At the time of this IRRP publication in 2026, GrandBridge Energy's forecast information indicates that load is trending towards the high scenario, with MTS #3 potentially required as early as 2032.

Note that the recommendations above also enable connection of two new 230 kV transformer stations to Galt junction. This enables the offloading of the 115 kV Brant TS and Powerline TS, as recommended by the 2024 Burlington to Nanticoke IRRP to address immediate capacity needs in the Brant 115 kV Extended Area.

Figure 44 | Map of MxD Sub-System Near- to Medium-Term Recommendations[21]



In the long-term, the Technical Working Group should monitor the amount of load supplied by the MxD transmission lines; when forecast demand between Detweiler TS and Middleport TS exceeds the load security threshold of 600 MW, a switching station at Galt junction is required. The need for this switching station is not expected in this IRRP's planning horizon under the reference scenario.

[21] Distribution-level load transfers are not shown, for simplicity.

For the station capacity need at Kitchener MTS #6, it is recommended to implement additional eDSM immediately, as well as distribution-connected resources starting in 2034.

The analysis in this IRRP identified that 12 MW/58 MWh of BESS, staged over the period of 2034 to 2042, is the most cost-effective solution given the wires alternative for Enova Power's station capacity need. The BESS option also has system value — these distributed energy resources can contribute as part of the new resources that otherwise would have to be acquired anyway for provincial resource adequacy needs, as signaled through the Annual Planning Outlook. Any resources participating in IESO procurements would need to ensure they are able to comply with the requirements of those procurements and associated contractual obligations. Other combinations and timing of distributed resources may be sufficient for Kitchener MTS #6, if they can adequately address the need profile (see KWCG IRRP Data Tables), meet technical requirements, and are more cost-effective than the wires alternative explored in this IRRP and summarized in Table 13.

At least three years is the typical lead time for new BESS, but timelines may vary depending on the implementation approach. The IESO signals system needs through connection guidance and future procurement processes, including the LT2 RFP. These procurements are technology-agnostic and open to distribution-connected projects. Distributed resources can also participate in the Capacity Auction to help meet system needs. In parallel, various initiatives are underway by the Ontario Energy Board that can impact the implementation of non-wires options, including initiatives on distribution system operator capabilities. Related, the Benefit-Cost Analysis Framework sets out guidance for LDCs when assessing the economic feasibility of non-wires solutions for distribution need — including an Energy System Test that accounts for impacts to the broader energy system.

The implementation mechanism for the non-wires recommendations for Kitchener MTS #6 will be identified following the IRRP. The IESO will work with the LDC to support the exploration of value-stacking opportunities. The Technical Working Group will monitor Kitchener MTS #6's forecast such that the wires alternative of a new 230 kV DESN is triggered if still required and the non-wires recommendation cannot be implemented in time.

7.2.3 DxV Sub-System

As presented in Section 6.4, station and supply capacity needs were identified for the DxV sub-system. Options to address these needs are described below.

Wires Options for Campbell TS

A wires option to address station capacity needs at Campbell TS is to install additional metal-clad switchgear on T3/T4's spare winding to utilize the full LTR potential of 100 MVA (90 MW). This is estimated to cost $25 million and can be implemented as early as 2031. The additional station capacity at T3/T4 can also be used to accommodate forecast growth at Campbell T1/T2 through load transfers on the distribution system.

Non-Wires Options for Campbell TS

New eDSM programs in the area could meet 19 MW of the 50 MW summer station capacity need in 2035, as illustrated below. The estimated cost of achieving these eDSM savings is $52.6 million, which is considered cost effective for provincial adequacy needs.

Figure 45 | Estimated Incremental eDSM Potential for Campbell T1/T2

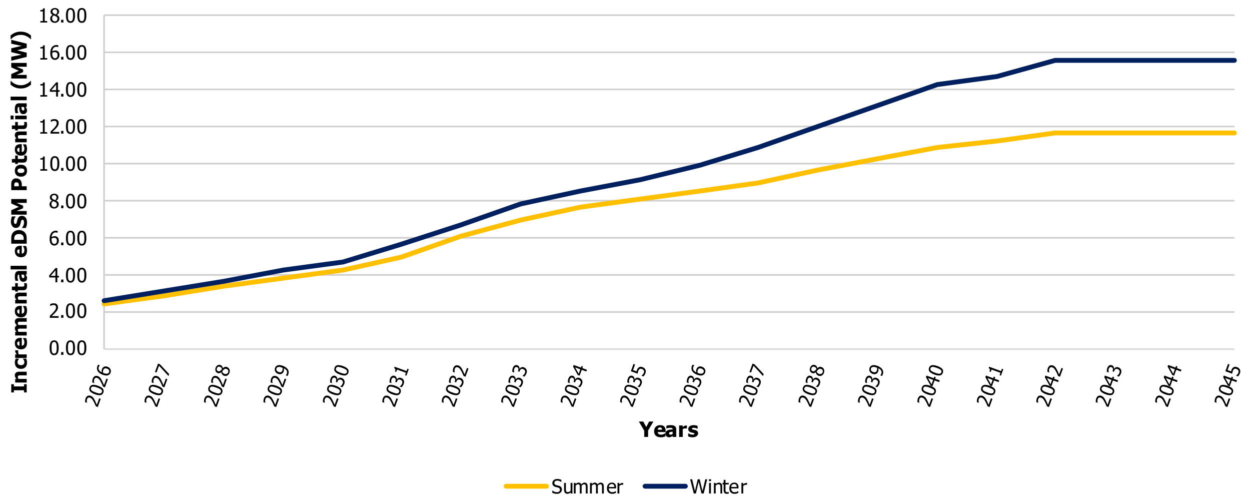
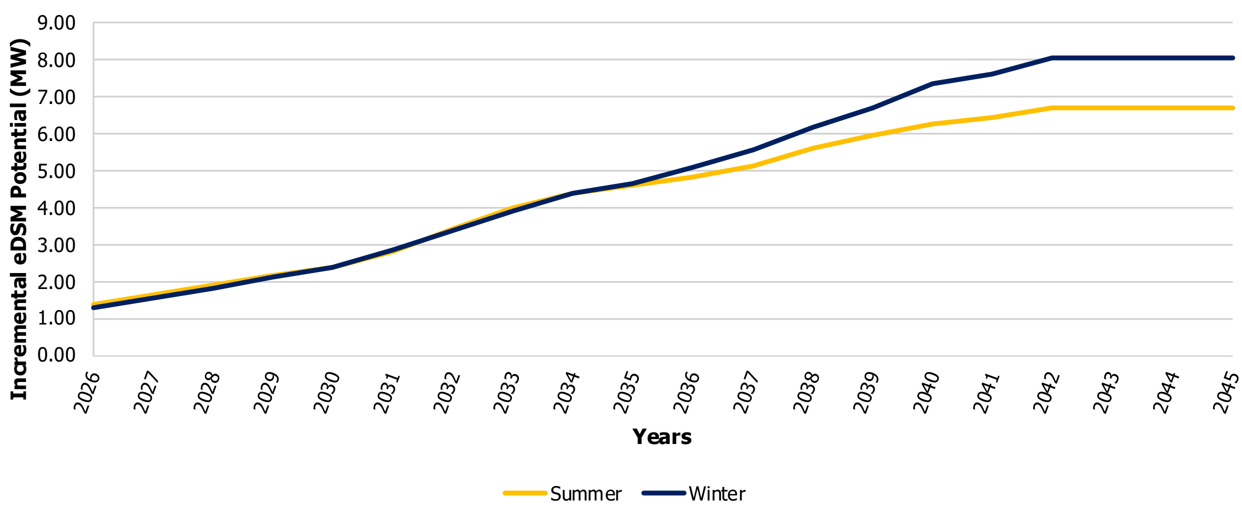


Figure 46 | Estimated Incremental eDSM Potential for Campbell T3/T4



Wires Options for Other DxV Sub-System Needs

Based on the location of forecast growth and new large load customers, Enova Power identified three potential new 230 kV stations (11 TS, Office MTS, and Snider TS) in Waterloo that, together, would provide sufficient station capacity for needs at Rush MTS, Scheifele MTS, and Waterloo North MTS #3.

To address the supply capacity needs of the DxV sub-system and to enable new 230 kV stations, transmission expansion options were evaluated. Given the scale and urgency of the needs, options to address thermal and voltage limitations in the near- to medium-term were assessed alongside longer term supply options for when DxV loads exceeded the 600 MW load security threshold. Moreover, due to the phased approach taken during the development of the IRRP where recommendations for the MxD sub-system were made first, the second option below accounts for reinforcements described in Section 7.2.2 and includes Wellington TS. LMCs specified below also assume the DxW sub-system forecast of about 50 MW by 2045.

DxV Sub-System: Near-Term Options

The following wires options were evaluated to increase DxV supply capability in the near term:

1. Voltage support at the Preston 230 kV junctions ($95 million) and at Speedville 115 kV junctions ($95M), plus uprates to the DxV circuits between Detweiler TS and the new Waterloo stations ($15 million);
2. A double-circuit 230 kV line ($150 million) from Wellington TS to Cedar TS, a 230 kV switchyard at Cedar TS ($65 million), DxV uprates between Detweiler TS and the new Waterloo stations ($15 million), and additional capacitor bank at Elmira TS ($5 million); or
3. Reconfiguration work at Detweiler TS, and DxV uprates between Detweiler TS and the new Waterloo stations ($15 million).

With each option, the DxV LMC is still limited by the ORTAC load security criteria at 600 MW. Option 1 requires four years of development and comes at a cost estimate of $205M. Option 2 is the most expensive near/medium-term option at a cost of $235 million and can take up to five years, though it can be considered in future planning cycles for supply to the Guelph area.

Option 3 has the potential to be the most cost-effective option and fastest to implement among the three options above. Specifically, option 3 aims to mitigate the most limiting contingency at Detweiler TS that defines the DxV sub-system LMC; this includes the existing operating instructions that would result in the removal of Detweiler static VAR compensator and/or 230kV capacitor bank(s) upon 230 kV bus fault or specific breaker failures contingencies.

Option 3 also has the benefit of increasing the DxV supply capability in near to medium term, as well as in the long term. In the near to medium term, option 3 can increase DxV supply capability to the 600 MW load security limit. It is also required to achieve the LMC described in the next section for option C of the DxV long-term options.

In addition to the three options listed above, up to 150 MW of load transfers to the DxW sub-system is possible based on supply capability with Wellington TS in-service. As described in Section 6.5, the LMCs between the DxV and DxW sub-systems are related. Depending on the location of the load growth, distribution buildout, and existing distribution ties, Enova Power could leverage the DxW supply capability for some forecast load currently allocated to stations served by the DxV sub-system.

DxV Sub-System: Medium- to Long-Term Options

In the medium to long term, further reinforcements and points of supply to the DxV area are still required given the magnitude of the needs.

Hydro One Transmission input during early options development indicated limited feasibility to expand Detweiler 230 kV yard or construct a new 500 kV yard at the existing Detweiler site. As such, the following wires options were considered to address DxV supply capacity needs in the long term and to supply Enova Power’s proposed transformer stations in the Waterloo area ($30–45 million each):

A. Build a double-circuit 230 kV line ($360 million) from Wellington TS to new transformer stations in Waterloo;

B. Leverage the preliminary bulk option identified in the South and Central Bulk Plan: build a single-circuit 500 kV line from Longwood TS to a 500/230 kV station near Detweiler TS on the DxW circuits ("Detweiler #2 TS"), and a single-circuit 500 kV line from Detweiler #2 TS to Milton TS; or

C. Leverage the final bulk option identified in the South and Central Bulk Plan: build a single-circuit 500 kV line from Longwood TS to a 500/230 kV station at Guelph North junction ("Guelph North TS") ($270 million), and a single-circuit 500 kV line from Guelph North TS to Wellington TS.

Option A can increase supply to Waterloo by 400 MW, but the overall LMC depends on the amount of load served by the 230 kV circuits from Wellington TS to Preston TS (recommended in Section 7.2.2). Option B was determined infeasible for regional needs because it necessitates extensive circuit and tower upgrades for the DxV and DxW paths, and separate reinforcements for 115 kV system voltage violations. Conversely, Option C increases supply between Detweiler TS and Guelph North TS on the existing DxV lines to approximately 900 MW. However, the load security limit of 600 MW applies. With new, approximately 15 km, radial, double-circuit, 230 kV lines to Waterloo from Guelph North TS ($180 million), another 600 MW can be supplied to the area.

While both options A and C meet the reference forecast supply and load security needs, option C has a few key advantages for regional needs:

- It offers more total supply capability than option A — enough for the high forecast scenario.
- The introduction of Guelph North TS sectionalizes the existing DxV circuits, which allows new stations in Waterloo to be sited and supplied directly from the DxV circuits rather than from new longer (30 km) radial lines (as is the case for option A).
- Option C can be staged in a flexible way such that radial lines/or other options are not triggered until needed, unlike with option A.
- It increases capacity for the DxV sub-system without using up the supply capability from Wellington TS for MxD sub-system needs.
- It introduces a new supply point through Guelph North TS, which sectionalizes and re-terminates the existing DxV lines – therefore offering more restoration capability to the DxV sub-system and diversifying paths of supply to the region.

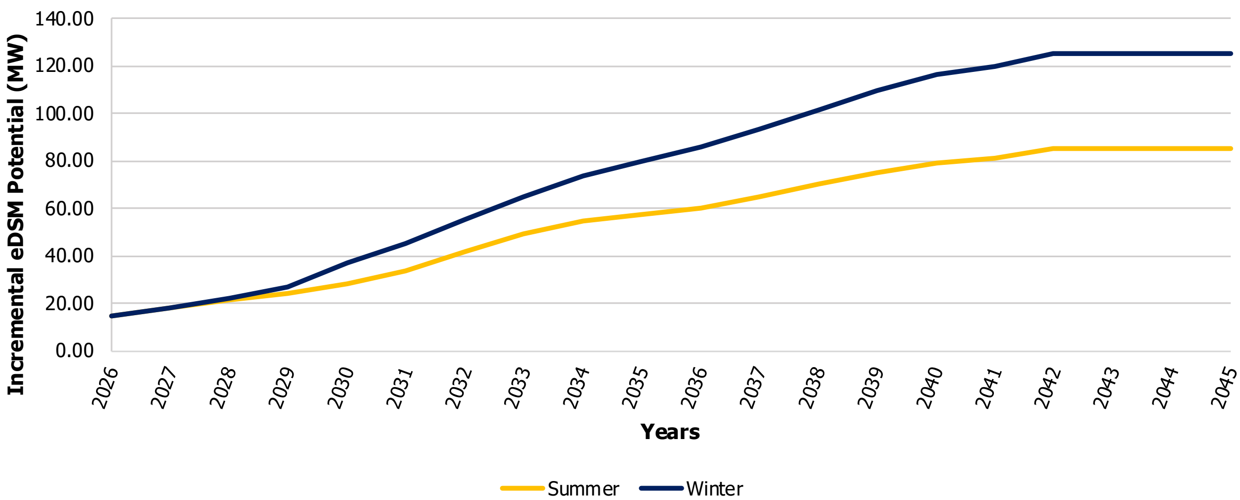
Option C is enabled by the South and Central Bulk Plan recommendations. The 500 kV reinforcements from Longwood TS to the KWCG region, enabled by new 500 kV supply points at Guelph North TS and Wellington TS, are required for addressing bulk system transfer needs. These options were studied as part of the bulk plan's Portfolio B, which are the preferred set of recommendations to meet the South and Central Bulk Plan objectives. The bulk needs and options are described in detail in the final report issued in Q3 2026.

Recognizing that long-term solutions could have a longer lead time relative to the pace of load growth, the Technical Working Group investigated interim solutions of implementing reactive support within KWCG's 115 kV sub-system, such as at Elmira TS, at 10-20 MVAR each. Analysis shows that, while the addition of capacitor(s) cannot fully satisfy the sub-system's load forecast, it increases the DxV sub-system LMC in the interim until bulk reinforcements for 500 kV supply into the region is in-service. Once 500 kV bulk supply into Guelph North TS is in-service, supply capacity needs are met even without this additional reactive support.

Non-Wires Options for Other DxV Sub-System Needs

As presented in Section 7.1.2, eDSM was screened in further consideration for the DxV needs. Under the existing eDSM framework and programs, up to 85 MW of additional total summer peak savings could be achieved at an expected cost of $247.8 million. eDSM is important for managing demand in Ontario and plays a key role in maximizing the useful life of existing infrastructure and maintaining reliable supply.

Figure 47 | Estimated Incremental eDSM Potential for the Overall DxV Sub-System



Recommendations

It is recommended to target additional eDSM programs in the DxV sub-system to increase capacity and provide broader system benefits.

Considering the uncertainty among the forecast drivers in the region and the increased eDSM targets under the new 2025–2036 eDSM Framework, the Technical Working Group will continue to monitor growth in the region to determine whether sector trends and connection requests indicate a need for development beyond the reference planning forecast.

In the near term, the recommendation to address the Campbell TS station capacity need is to implement additional system cost-effective eDSM and install metal-clad switchgear at T3/T4 to increase its LTR. After this is implemented by 2031, 19 MW of load should be transferred through the distribution system from T1/T2 to T3/T4. Needs in the interim, before additional station capacity is available, will be monitored and evaluated by Alectra.

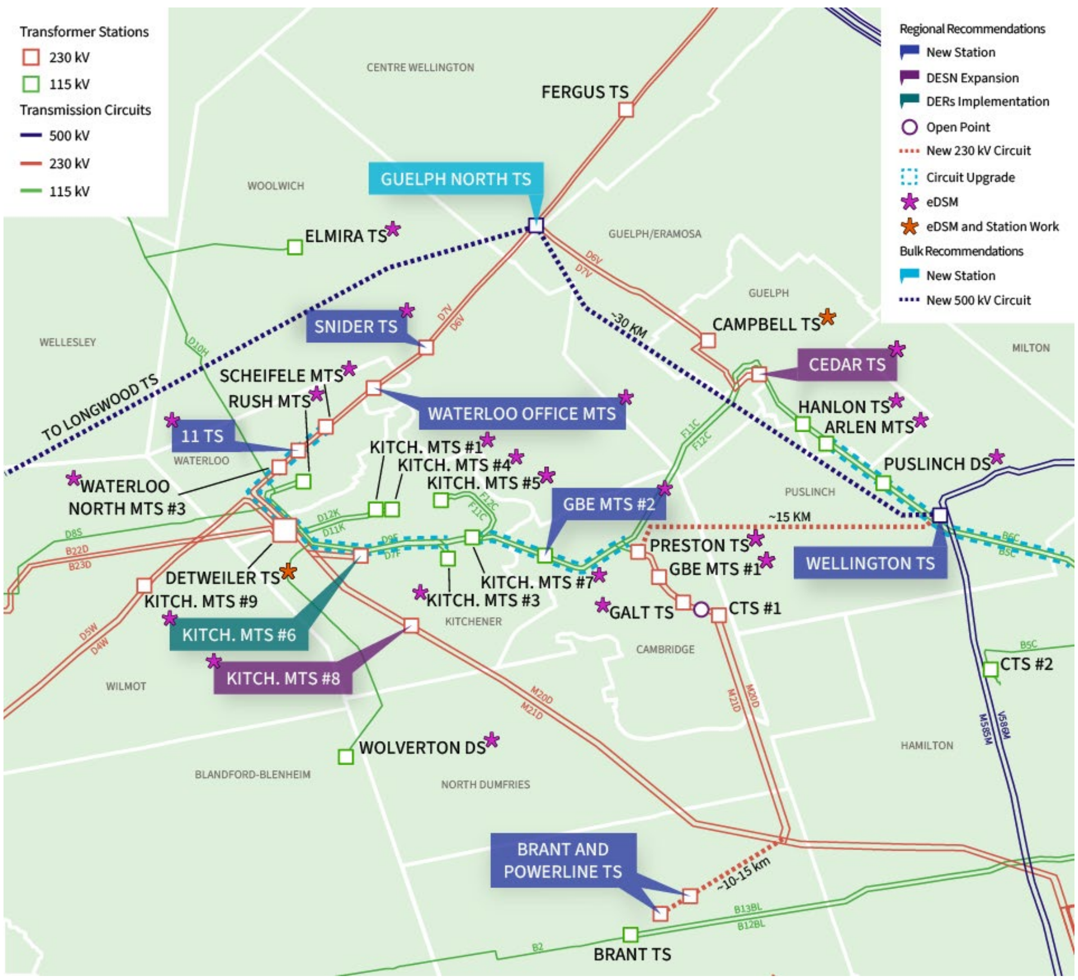
To address the remaining DxV station capacity, supply capacity, load security, and load restoration needs, the Technical Working Group recommends the integrated wires option that includes, in the near term: DxV uprates and station work at Detweiler TS mitigate the impact of existing operating instructions. By the mid-2030s, bulk reinforcements recommended from the South and Central Plan are required: a new 500/230 kV Guelph North TS, and a single-circuit 500 kV line from Longwood TS to Guelph North TS to Wellington TS. Specifically, the Guelph North TS and 500 kV line to from Guelph North TS to Wellington TS should be advanced to 2031 for regional needs.

The Technical Working Group should closely monitor the pace of load growth on the DxV sub-system. If the longer-term recommendations are delayed, additional load growth in the near term should be enabled by installing a new 10-20 MVAR capacitor at Elmira TS.

Lastly, new 230 kV transformer stations in Waterloo are recommended to be supplied by the existing DxV lines. In the long term, the Technical Working Group should monitor load growth and re-evaluate the need for new radial 15 km double-circuit 230 kV lines from Guelph North TS to the Waterloo area.

This set of recommendations is shown in Figure 48.

Figure 48 | Map of DxV and MxD Sub-System Near- to Medium-Term Recommendations[22]



22 Distribution-level load transfers are not shown, for simplicity.

The KWCG Regional Infrastructure Plan, led by Hydro One after the IRRP, should further assess and refine the scope of work at Detweiler TS required to mitigate the loss of a static VAR compensator and/or capacitor after outages. Additionally, the cost and feasibility for low voltage capacitors at Elmira TS or on the 115 kV sub-system should be evaluated to bridge the supply capacity gap until the long-term solution for 500 kV bulk reinforcements to the region are implemented. Other alternatives, such as operational measures like undervoltage load shedding schemes, for resolving post-contingency voltage decline violations, can also be considered.

7.2.4 D8S/D10H Sub-System

Options for Rush MTS

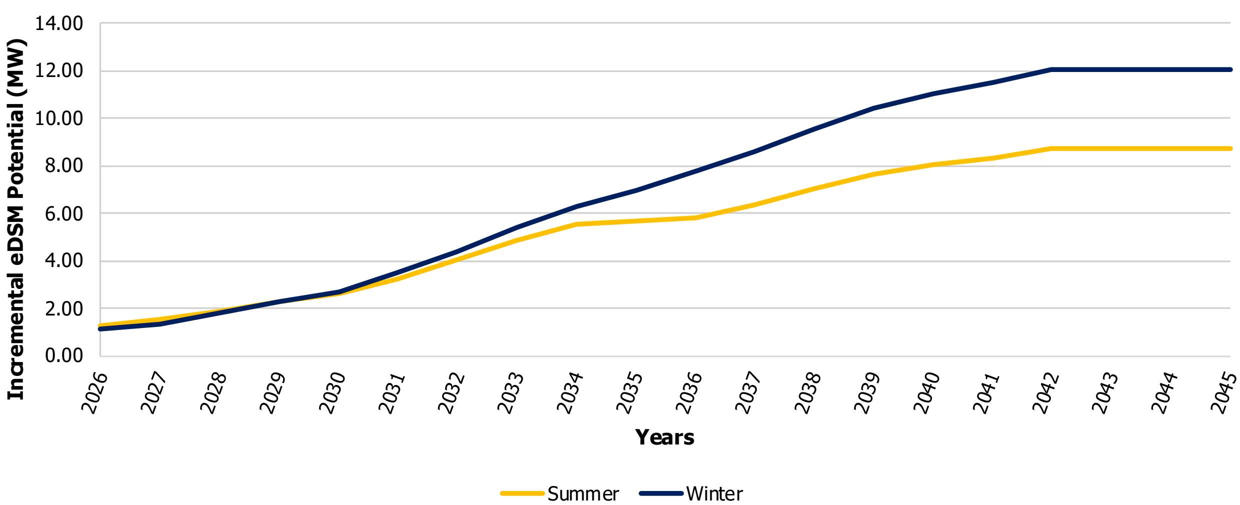
Wires options for the station capacity need at Rush MTS were considered in conjunction with Enova Power's station needs at Scheifele MTS and Waterloo North MTS #3. As described in Section 7.2.3, the three new 230 kV stations proposed (11 TS, Office MTS, and Snider TS) should be sized to meet the cumulative station capacity needs between Rush MTS, Scheifele MTS, and Waterloo North MTS #3.

For Rush MTS, the following non-wires options were also assessed:

1. Additional eDSM; and
2. DG.

Additional eDSM programs could meet 9 MW of the 33 MW summer station capacity need in 2035, as illustrated in Figure 49. The estimated cost of achieving these eDSM savings is $26 million, which is considered cost effective to the system.

Figure 49 | Estimated Incremental eDSM Potential for Rush MTS



By 2045, the need profile for Rush MTS peaks at 51 MW, lasts up to 94 consecutive hours, and sums to approximately 42,000 MWh of energy. Based on these need characteristics, the following non-wires options were screened in:

- wind;
- BESS;

- combined wind and BESS;
- combined wind and solar;
- combined solar and BESS; and
- combined solar, wind, and BESS.

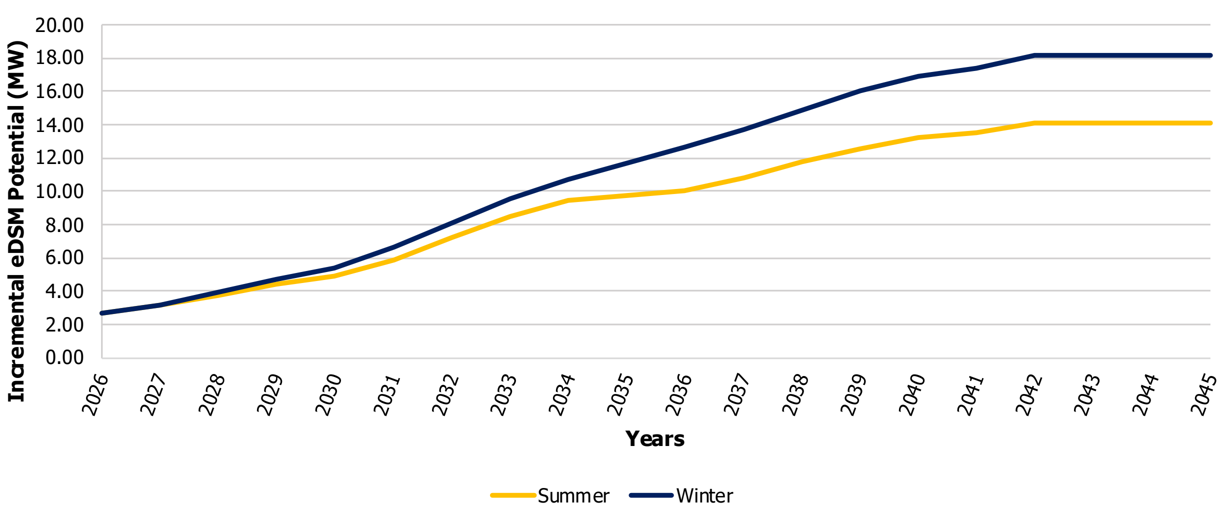
Solar as a standalone option was screened out due to the need occurring in both summer and winter and often at night. Small modular reactors were screened out since the need size does not warrant this type of technology. Natural gas was screened out to focus the analysis on options that reduce reliance on emitting resources. Note that the City of Waterloo has set greenhouse gas reduction targets similar to the City of Kitchener, reducing community-wide emissions by 30 per cent by 2030 and 80 per cent by 2050, through the TransformWR strategy from ClimateActionWR.

Among the screened-in generation options, none were feasible given the need profile and/or the DG connection capacity at Rush MTS, even if assuming Enova Power undertakes feeder breaker and switchgear replacement work to increase the short circuit rating by 20 per cent. Moreover, if these solutions were feasible, they would have to be sited relatively close to Rush MTS on primarily residential land.

Options for D8S/D10H Supply

Additional eDSM programs (savings shown in Figure 50) could meet 14 MW of the 26 MW D8S/D10H supply capacity need and defer the need until 2032. The estimated cost of achieving these eDSM savings is $40.7 million, which is considered cost effective to the system.

Figure 50 | Estimated Incremental eDSM Potential for D8S/D10H Sub-System



A few wires options were also considered:

1. reconductoring the D8S and D10H circuits to 719 A and 920 A, respectively ($3.5M to $5M, one to two years lead time); or
2. offloading some load from Rush MTS to the DxV sub-system through the new 230 kV stations recommended in Section 7.2.3.

Recommendations

In the near term, the recommendation to address the Rush MTS station and D8S/D10H supply capacity needs is to implement additional system cost-effective eDSM.

By 2032, load in excess of the Rush MTS LTR should be transferred on the distribution system to instead be served by the DxV sub-system.

These recommendations are sufficient to meet the reference need for this IRRP's planning horizon. In the long term, or if higher growth materializes, the reconductoring of D8S and D12H may be required – this results in supply capacity for approximately another 28 MW beyond Rush MTS' current LTR, as well as another 25 MW beyond Elmira TS' current LTR.

7.2.5 DxK Sub-System

Wires Options for Kitchener MTS #1 and #4

For the station capacity needs at Kitchener MTS #1 and #4, the same wires options were evaluated as for Kitchener MTS #5 and #7:

1. Load transfers on the distribution system starting in 2032.
2. New station in Kitchener.

Considering option 1, Kitchener MTS #1 has distribution-level ties with MTS #3 and #4; MTS #4 has ties with MTS #1 and 6. Option 2 was described in more detail in Section 7.2.1.

Non-Wires Options for Kitchener MTS #1 and #4

For Kitchener MTS #1 and #4, the following non-wires options were assessed:

1. Additional eDSM;
2. DG; and
3. demand response.

eDSM programs targeting load supplied by Kitchener MTS #1 and #4 could meet 10 MW of the 16 MW summer 2035 station capacity need and 11 MW of the 19 MW summer 2035 station capacity need, respectively. The estimated cost of achieving these eDSM savings is $40 million and $42 million respectively, which is considered cost effective to the system.

Figure 51 | Estimated Incremental eDSM Potential for Kitchener MTS #1

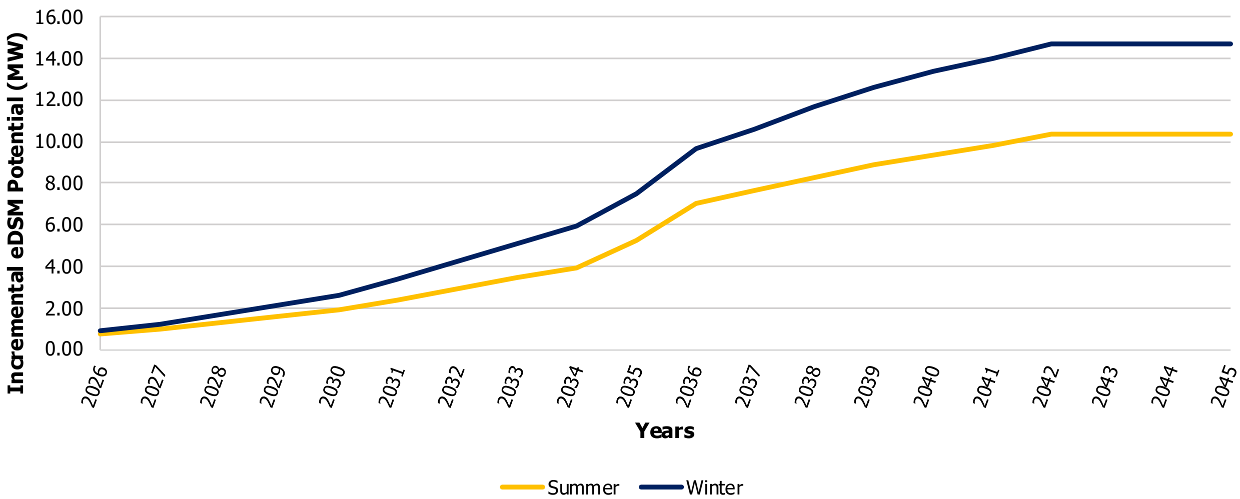
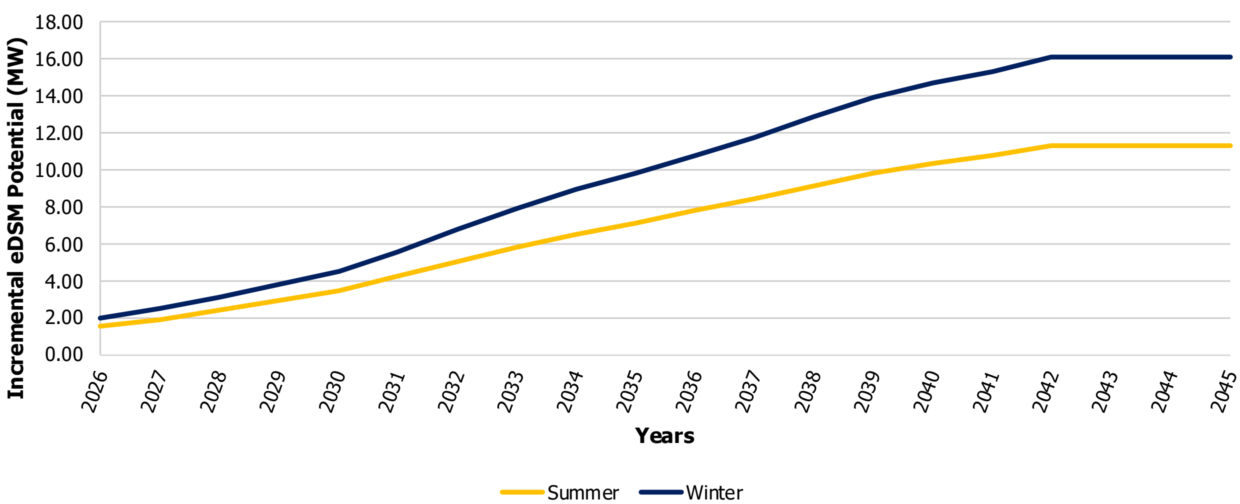


Figure 52 | Estimated Incremental eDSM Potential for Kitchener MTS #4



By 2045, the need profile for Kitchener MTS #1 peaks at 43 MW, lasts up to 21 consecutive hours, and sums to approximately 30,000 MWh of energy. Based on these need characteristics, the following non-wires options were screened in:

- wind;
- BESS;
- combined wind and BESS;
- combined wind and solar;
- combined solar and BESS;
- combined solar, wind, and BESS; and
- demand response.

Solar as a standalone option was screened out due to the need occurring in the winter, and small modular reactors were screened out since the need size does not warrant this type of technology. Natural gas was screened out to focus the analysis on options that reduce reliance on emitting resources. There are also municipal preferences that support the reduction of greenhouse gas emissions.

Among the screened-in generation options, none were feasible given either the need profile and/or the DG connection capacity at Kitchener MTS #1, even if assuming Enova Power undertakes feeder breaker and switchgear replacement work to increase the short circuit rating by 20 per cent. Even if these solutions were feasible, they would have to be sited relatively close to Kitchener MTS #1 on heavily developed residential and commercial urban land.

For Kitchener MTS #4, the non-wires analysis yielded similar results. By 2045, the need profile for Kitchener MTS #4 peaks at 47 MW, lasts up to 46 consecutive hours, and sums to approximately 44,000 MWh of energy. Based on these need characteristics, the same resource types were screened in for further analysis as for Kitchener MTS #1. Outcomes of the evaluation were also similar: the NWAs were infeasible given the need profile and/or the DG connection capacity at Kitchener MTS #4, even if assuming upgrades to increase short circuit capability. Depending on the option, up to 9 km^2 of land would be required near the station in urban Kitchener.

Wires Options for DxK Supply

A wires option to address DxK supply is the reconductoring of D11K and D12K to increase its summer Long-Term Emergency thermal rating to 1035 A (and 1180 A for winter). This is expected to cost $6.3 million and take 1-2 years, and with additional DSM, will meet the summer supply need and delay the winter need until 2041.

Non-Wires Options for DxK Supply

For the DxK supply capacity need, the same non-wires options were assessed as for Kitchener MTS #1 and #4: wind, BESS, solar, demand response, and additional eDSM (as illustrated in the figures earlier). However, given the nature of supply capacity needs, potential resource options can also be transmission-connected (not just distribution-connected).

By 2045, the need profile for the DxK supply need grows to 90 MW and more than 100,000 MWh. The need occurs in the winter and lasts up to 141 consecutive hours – requiring infeasibly large resource options in a dense urban area.

Meanwhile, the cumulative additional eDSM at Kitchener MTS #1 and #4 can delay the DxK supply need until 2033.

Recommendations

In the near term, the recommendation to address the Kitchener MTS #1 and #4 station capacity needs is to implement additional system cost-effective eDSM, and optimize and transfer load through the distribution system starting in 2033 between Kitchener MTS #1, 3, 4, and 6. In the long-term, a new station is required in the Kitchener Freeport area, should the reference load forecast materialize.

Considering long-term forecast uncertainty in the region and potential for increased eDSM, the Technical Working Group will continue to monitor where, when, and how much electricity demand grows. These factors, alongside any new resources and other system changes, can influence the need and options for long-term Kitchener station capacity needs.

In the medium-term, the recommendation to address the DxK supply capacity need is to reconductor both D11K and D12K to increase its summer Long Term Emergency thermal rating to 1035 A (and 1180 A for winter).

Given the Planning Forecast, this uprate should be implemented by 2033. Under the low and high reference scenarios, timing of the uprate can shift up to two years.

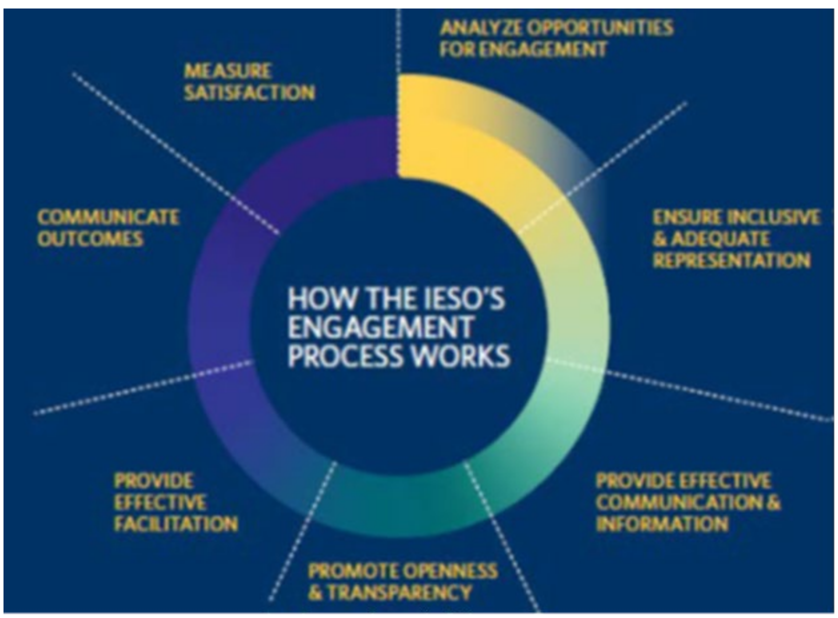
8. Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, which for these purposes, refers to Indigenous communities, market participants, municipalities, stakeholders, communities, customers and the general public, to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to date for the KWCG IRRP.

8.1 Engagement Principles

The IESO's External Relations Engagement Framework is built on a series of key principles that respond to the needs of the electricity sector, communities and the broader economy. These principles ensure that diverse and unique perspectives are valued in the IESO's processes and decision-making. We are committed to engaging with purpose with external audiences to foster trust and build understanding as the energy transition continues.

Figure 53 | The IESO's Engagement Principles



8.2 Engagement Approach

To ensure that the IRRP reflects the unique needs and perspectives of market participants, municipalities, stakeholders, communities, Indigenous communities, customers and the general public, engagement involved:

- Leveraging the KWCG engagement webpage to post updated information, engagement opportunities, meeting materials, input received and IESO responses to feedback.
- Timely and targeted discussions with municipalities to help inform the engagement approach for this planning cycle.

- Sharing letters with relevant Mayors and Councillors to provide informative updates on the plan to foster purposeful engagement.
- Hosting a series of public webinars at major junctions in the plan development to share plan details, understand feedback and answer questions.
- Encouraging all interested parties to stay informed on the planning underway through communications and other engagement tactics to enable a broad participation through email and IESO's weekly Bulletin updates.
- Hosting targeted discussions with specific communities and stakeholders to clearly communicate updates as planning progressed and ensure that their identified needs are addressed.

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for the third round of planning for the KWCG region, and to establish new relationships and dialogue where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report that involved sending an invitation to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and invite interested parties to provide input on the KWCG Scoping Assessment Outcome Report. A public webinar was held in June 2024 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed planning approach moving forward. The final report was posted later in July 2024, identifying the need for a coordinated regional planning approach and development of an IRRP.

Later in December 2024, a targeted outreach meeting involving all municipalities in the region was hosted to ensure growth and development plans were accurately captured in the Technical Working Group's draft demand forecast, and to solicit early feedback on the IESO's approach to engagement. The launch of a broader engagement initiative followed, with an invitation to subscribers of IESO updates for the KWCG region to ensure that all interested parties were made aware of this opportunity for input.

Four public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected following a comment period after each webinar. The four stages of engagement at which input was invited were:

1. The draft engagement plan, electricity demand forecast, and early identified needs — to set the foundation of this planning work.
2. The identified priority electricity needs for the region and high-level screening of potential options to meet the identified priority needs.
3. The analysis of options and draft IRRP recommendations to address priority needs, and the high-level screening of potential options to meet the identified remaining needs.
4. The analysis of options and draft IRRP recommendations to address remaining needs.

Comments received during public engagements primarily focused on:

- Questions regarding inputs and assumptions considered by the IESO when developing the demand forecast scenarios, and how municipalities can influence routing and property impacts.
- Significant population growth, transit and economic development projects across the region.
- Alignment of electricity planning with local priorities, such as local Climate Action Plans.
- Regulations regarding reserving capacity for critical public infrastructure.
- The importance of addressing immediate capacity needs to ensure the region remains resilient.
- Interest in leveraging existing and local generation.
- Exploring and understanding alternative solutions, such as non-wire options, to meet the area's electricity needs.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations.

In recognition of the interdependencies between a parallel South and Central Bulk Plan looking at the provincial electricity system's broad capability to support future generation connections, and demand growth in key areas throughout southern and central Ontario, KWCG engagement focused on establishing linkages between the bulk and regional electricity plans. The IESO has undertaken efforts to ensure engagement activities and recommendations for the KWCG IRRP are aligned and integrated with those of the South and Central Bulk Plan.

All interested parties were kept informed throughout this engagement initiative via email to KWCG subscribers, municipalities, and Indigenous communities. Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP and recommended actions aligned with the significant forecasted growth and development both within specific municipalities and the region more broadly (e.g., new large-scale customers and electrification, planned development and growth). Through the development of the IRRP it was determined that the existing electricity system did not meet reliability standards. With that, another key focus area was developing an approach to quickly identify, engage on, and develop solutions to address priority electricity needs while also balancing addressing remaining electricity needs. These insights have been valuable to the IESO — as they supported an understanding of local growth and an accurate electricity demand forecast, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's KWCG engagement webpage.

8.4 Involving Municipalities in the Plan

The IESO held meetings with municipalities to seek input on its planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with all municipalities in the KWCG electrical region to share key developments and to provide an opportunity for municipal feedback on the forecasted regional electricity needs, options for meeting the region's future needs, and broader community engagement. Through engagement it was learned that the tiered approach of addressing needs in the region added an extra layer of complexity in understanding the development of the IRRP.

To address this feedback, additional engagement was conducted to foster education and understanding of the recommendations to address priority needs. This included the IESO engaging elected officials and all municipalities impacted by the recommendations to address priority needs by sharing letters prepared for mayors and councillors and hosting an information session with elected officials and municipal staff to review the electricity planning developments, and to provide an opportunity for discussion. These meetings helped to inform the municipal and community electricity needs and priorities, establish new relationships, and provide opportunities for ongoing dialogue beyond this IRRP process.

Through these discussions, valuable feedback was received and considered in the final IRRP recommendations, including:

- The City of Kitchener encouraged the inclusion of multiple forecast scenarios in the IRRP process and collaboration between municipalities and local distribution companies to understand the development of the electricity demand forecast scenarios. Additionally, the City emphasized their commitment to supporting the energy transition by leveraging its role as a gas distributor and focusing on the electrification of transportation and space and water heating. The City also encouraged the IESO to consider efficient, low-carbon heating solutions, including the use of waste heat from large electricity users.
- The City of Guelph recommended sharing the assumptions used when calculating the electricity demand forecast scenarios, addressing short circuit limitations at Campbell TS as it is hindering solar PV projects, and also raised the need for additional support to promote eDSM initiatives.
- Several municipalities emphasized that population growth, transit expansion, climate action, and energy plans should be reflected in electricity demand forecasts, and they encouraged the use of non-wire alternatives to support their net-zero and decarbonization goals.
- Municipalities also suggested improving future engagement materials by clearly outlining municipal boundaries on study-area maps, reducing industry-specific terminology to more easily understand the process to develop the IRRP, and providing increased clarity on the interaction of eDSM and electrification efforts on a region's electricity capacity and needs.
- Enbridge Gas Inc. recommended co-ordinated energy system (gas and electric) planning be completed and due consideration be given to a diversified energy system approach in the forecasts for the KWCG electrical region.

8.5 Engaging with Indigenous Communities

The IESO remains committed to an ongoing, meaningful dialogue with Indigenous communities to help shape long-term planning in regions across Ontario. This engagement was part of a broader commitment to fostering respectful relationships, ensuring transparency, and supporting informed participation in regional energy planning. Throughout the development of this plan, the IESO's engagement with Indigenous communities included inviting Indigenous communities to participate in online information sessions (held on December 12, 2024, May 27, 2025, September 23, 2025 and June 10, 2026), as well as extending the opportunity to meet one-on-one to ask questions and provide input.

To share information about the regional planning activities and invite participation in the engagement process, outreach was made to the following Indigenous communities:

- Mississauga of the Credit Frist Nation;
- Six Nations of the Grand River, represented by the Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council; and
- Métis Nation of Ontario.

Detailed non-confidential feedback submitted to the IESO and the IESO's responses can be viewed on the KWCG engagement webpage. However, the IESO did not receive feedback from the identified First Nation communities. Although invitations were extended to participate in the webinar and to engage in one-on-one meetings, no responses or feedback were provided.

Indigenous Participation and Engagement in Transmission Development

Indigenous engagement during the regional planning process assists the IESO in its assessment of various options to address future transmission system needs. By conducting regional planning, the IESO determines the most reliable and cost-effective option after it has engaged with stakeholders and Indigenous communities and publishes those recommendations in the applicable IRRP. Where the IESO determines that the lead time required to implement those solutions requires immediate action, the IESO may provide those recommendations ahead of the publication of a planning report, such as through a hand-off letter to the lead local transmitter in the region.

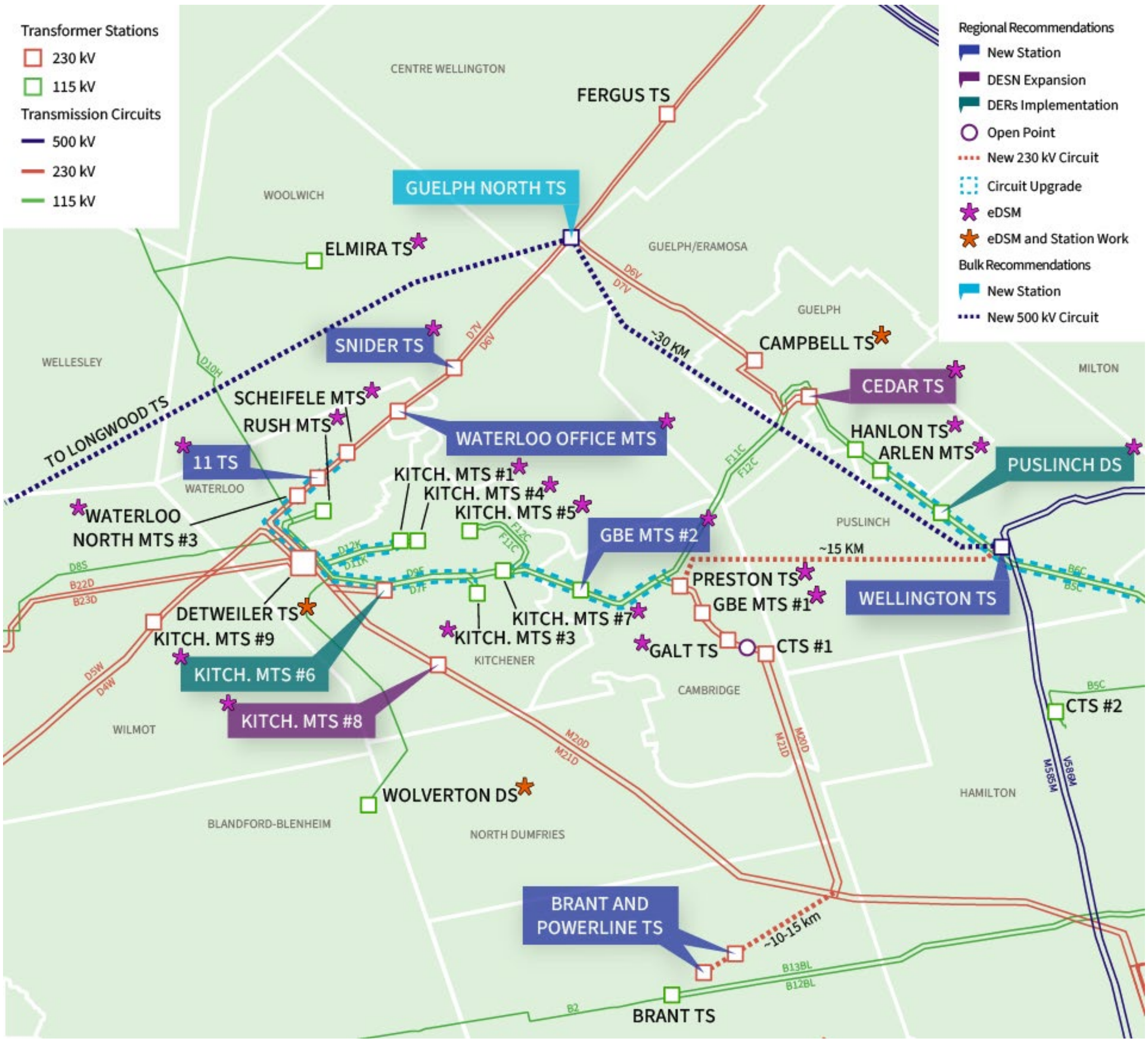
If a recommendation is made in an IRRP to proceed with a transmission solution, the transmission project proponent (not the IESO) will be responsible for obtaining applicable regulatory approvals from the provincial and/or federal governments, including an Environmental Assessment (EA). Where an EA is required, Indigenous consultation will be undertaken as part of the EA process. Other regulatory processes may also trigger the duty to consult. The relevant Crown entity is responsible for consultation but will delegate certain aspects of consultation to the proponent to carry out. In addition to fulfilling these delegated consultation obligations, project proponents are encouraged to engage early with Indigenous communities on ways to enable participation in particular projects.

In addition to the EA process, a project proponent will need to submit a Leave to Construct application to the Ontario Energy Board prior to starting construction. The *Ontario Energy Board Act, 1998* limits the scope of the Ontario Energy Board's determination on whether the project is in the public interest to consideration of price, reliability, and quality of electricity service. Accordingly, it is not within the Ontario Energy Board's purview to assess whether the Crown's duty to consult has been satisfied in respect of the transmission project.

9. Conclusion

The KWCG IRRP identifies electricity needs in the region over the 20-year period from 2026 to 2045, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. Figure 54 visually depicts these recommendations across the region.

Figure 54 | Overview of Recommended Near- to Medium-Term Solutions for KWCG IRRP[23]



Overall, the Technical Working Group recommends targeting eDSM programs across the KWCG region to support both near-term and long-term growth.

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[23] Distribution-level load transfers are not shown, for simplicity.

In the near and medium term, the Technical Working Group recommends multiple integrated solutions: 115 kV line upgrades, new 115 kV and 230 kV stations in Waterloo, Cambridge, and Kitchener, a 500/230 kV autotransformer stations, a new double-circuit 230 kV line, and a normally open point at Ameristeel junction. Projects should also proceed to increase station capacity: at Wolverton DS and Campbell TS, through station work; at Cedar TS, through the conversion to 230 kV when T7/T8 reach end of life. Moreover, the Technical Working Group recommends the optimization of existing station capacity where possible by leveraging distribution load transfers. Finally, at Puslinch DS and at Kitchener MTS #6, distribution-connected resources are required.

Some of these near-term recommendations were issued before this IRRP was finalized, through an urge letter focused on the immediate supply needs on the Middleport to Detweiler transmission lines. This was coordinated with the 2024 Burlington to Nanticoke IRRP recommendations for the Brant 115 kV Extended Area.

In the long term, the Technical Working Group should continue monitoring and re-assessing regional needs through future planning cycles and annual Technical Working Group meetings. In particular, demand growth, eDSM savings, and distribution load transfers should be monitored at Arlen TS, Hanlon TS, the MxD sub-system, and across multiple Kitchener MTS — especially those at the 115 kV voltage level. The need for a switching station at Galt junction should also continue to be considered, as well as a new 230 kV station and 230 kV connection lines in the Kitchener Freeport area.

The IESO will continue to participate in the Technical Working Group during the next phase of regional planning, the Regional Infrastructure Plan, to provide input and ensure a co-ordinated approach. The Technical Working Group will continue to monitor growth across the region to determine if or when further reinforcements will be needed. This includes any future community energy plans, electrification trends, customer connection queues, changes to local generation, and changes to eDSM programs. The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. If underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.

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