# Niagara Integrated Regional Resource Plan

December 22, 2022

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# List of Acronyms

| Acronym | Definition |
|---|---|
| CDM | Conservation and Demand Management |
| CNPI | Canadian Niagara Power Inc. |
| DG | Distributed Generation |
| DR | Demand Response |
| DS | Distribution Station |
| FIT | Feed-in-Tariff |
| GS | Generating Station |
| HV | High Voltage |
| IESO | Independent Electricity System Operator |
| IRRP | Integrated Regional Resource Plan |
| kV | kilovolt |
| LDC | Local Distribution Company |
| LMC | Load Meeting Capability |
| LTR | Limited Time Rating |
| MTS | Municipal Transformer Station |
| MVA | Megavolt ampere |
| MW | Megawatt |
| NERC | North American Electric Reliability Corporation |
| NOTL | Niagara-on-the-Lake |
| NPCC | Northeast Power Coordinating Council |

| Acronym | Definition |
|---|---|
| NPEI | Niagara Peninsula Energy Inc. |
| ORTAC | Ontario Resource and Transmission Assessment Criteria |
| RIP | Regional Infrastructure Plan |
| TS | Transformer Station |

# 1. Introduction

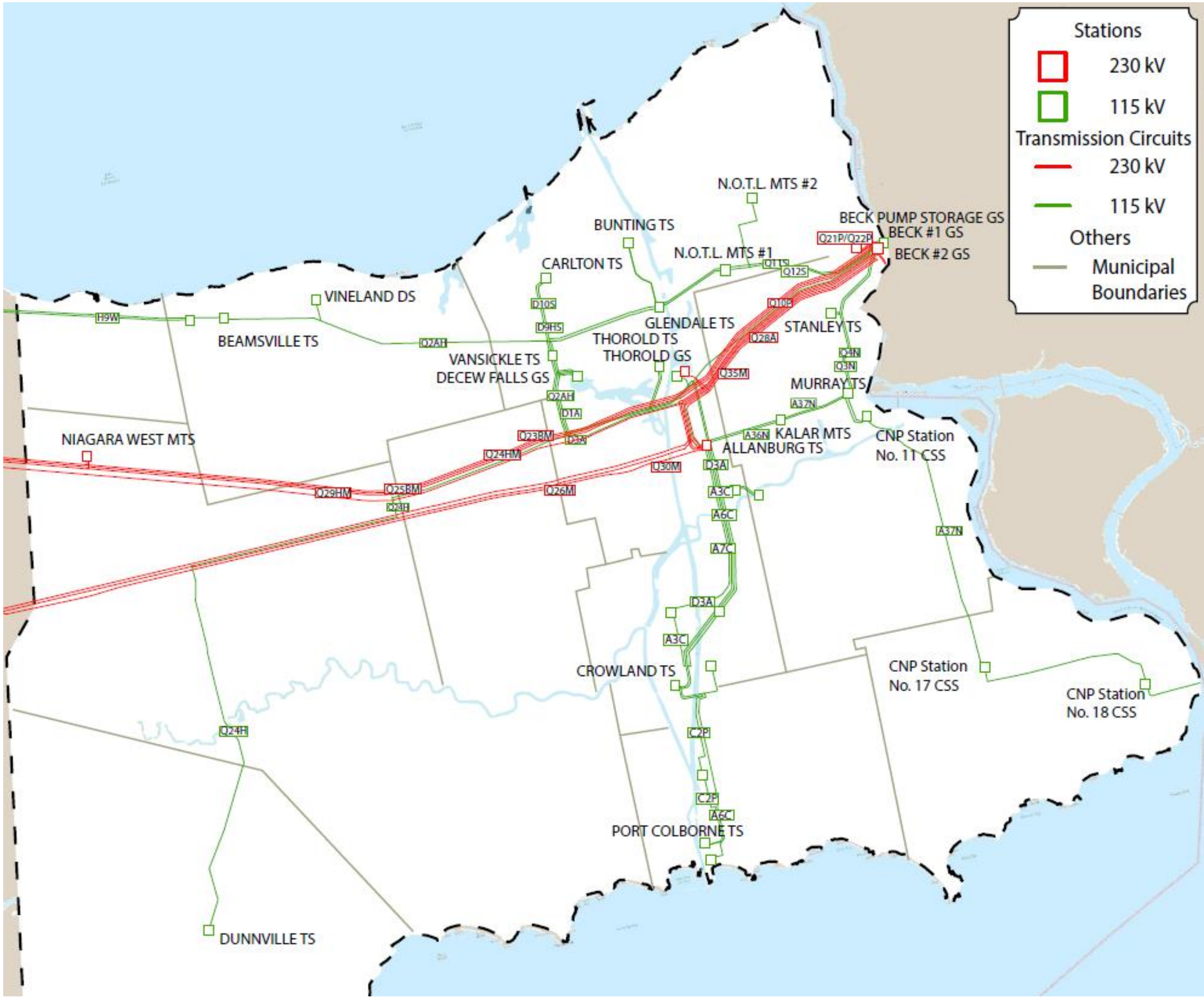
This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Niagara Region over the next 20 years, from 2022 to 2041. The Niagara Region is located between Lake Ontario and Lake Erie, and includes one upper-tier municipality (Regional Municipality of Niagara) and 12 lower-tier municipalities: Fort Erie, Grimsby, Lincoln, Niagara Falls, Niagara-on-the-Lake, Pelham, Port Colborne, St. Catharines, Thorold, Wainfleet, Welland, and West Lincoln.

This region also includes the following First Nations and Métis Nation of Ontario councils:

- Mississaugas of the New Credit
- Oneida Nation of the Thames
- Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council)
- Métis Nation of Ontario Niagara Region Métis Council

The Niagara Region is summer-peaking and, over the last five years, peak electrical demand has remained steady at an average of 810 MW. Electrical supply is provided primarily through 230/115 kilovolt ("kV") autotransformers at Allanburg Transformer Station ("TS"), and is generally served by 230 kV and 115 kV transmission lines and step-down transformation facilities as shown in Figure 1. The region is defined electrically by the 230 kV transmission circuits that connect Sir Adam Beck Generating Station ("GS") #2 in the east to Burlington TS and Middleport in the west. Other large transmission-connected generating facilities include Sir Adam Beck GS #1 and Decew Falls GS connecting to the 115 kV system, and Thorold GS connecting to the 230 kV system.

**Figure 1 | Overview of the Niagara Region**




The region’s electricity is delivered by six local distribution companies (“LDCs”): Alectra Utilities, Canadian Niagara Power Inc. (“CNPI”), Grimsby Power Inc., Hydro One Networks Inc. (Distribution), Niagara on the Lake Hydro Inc., Niagara Peninsula Energy Inc. (“NPEI”), and Welland Hydro Electric System Corp. Hydro One Networks Inc. (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, and the IESO.

Development of the Niagara IRRP was initiated in August 2021, following the publications of the Needs Assessment report in May 2021 by Hydro One and the Scoping Assessment Outcome Report in August 2021 by the IESO. The Scoping Assessment identified needs for 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 develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;

- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and demand management and distributed generation assumptions, are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement activities is provided in Section 8; and
- The conclusion is provided in Section 9.

# 2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Niagara Region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC") and reliability standards governed by the North American Electric Reliability Corporation ("NERC"). The IRRP's recommendations are informed by an evaluation of different options to meet the needs and consider: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

The Niagara electricity demand forecast, provided by the LDCs, projects sustained growth driven by community area, employment area, and rural settlement expansions. This growth spans multiple municipalities, including (but is not limited to): Lincoln, West Lincoln, Welland, Thorold, and Niagara Falls.

The IRRP recommendations below are organized under a near-/medium-term plan and other ongoing or long-term initiatives. This distinction reflects the different levels of forecast certainty, lead time for development, and planning commitment required over these 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 Near-/Mid-Term Plan

The near- and mid-term plan comprises several recommendations to accommodate load growth, maintain reliability, and optimize asset replacement. Where possible, needs are grouped to align with integrated sets of solutions. These recommendations are summarized in Table 1 and further discussed below.

**Table 1 | Summary of the Near/Mid-Term Plan for the Niagara IRRP**

| Need(s) | Lead Responsibility | Technical Working Group Recommendation | Expected In-Service Date |
|---|---|---|---|
| • Beamsville TS station capacity | • Grimsby Power<br>• NPEI<br>• Hydro One Distribution | • Coordinate load transfers to offload Beamsville TS to Niagara West MTS in the near-term | • 2023 |

| Need(s) | Lead Responsibility | Technical Working Group Recommendation | Expected In-Service Date |
|---|---|---|---|
| • Beamsville TS, Niagara West Municipal Transformer Station ("MTS"), and Vineland Distribution System ("DS") station capacity<br>• Niagara 115 kV sub-system supply capacity | • Grimsby Power<br>• NPEI<br>• Hydro One Distribution<br>• Hydro One Transmission | • Initiate development of a new 230 kV station supplied from Q23BM and Q25BM, or an expansion of Niagara West MTS | • 2026-2027 |
| • Beamsville TS, Niagara West MTS, and Vineland DS station capacity | • Grimsby Power<br>• NPEI<br>• Hydro One Distribution | • Monitor load growth between regional planning cycles | • Ongoing |
| • Beamsville TS and Vineland DS station capacity | • Technical Working Group | • Investigate opportunities to target incremental conservation and demand management ("CDM") to Beamsville TS and Vineland DS | • Ongoing |
| • Crowland TS station capacity and asset replacement<br>• A6C/A7C load security<br>• Niagara 115 kV sub-system supply capacity | • Hydro One Transmission | • Initiate development for the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM and Q29HM | • 2028 |
| • Niagara 115 kV sub-system supply capacity | • Hydro One Transmission | • Develop and implement a new 115 kV sub-system load rejection scheme | • 2024 |

| Need(s) | Lead Responsibility | Technical Working Group Recommendation | Expected In-Service Date |
|---|---|---|---|
| • Niagara 115 kV sub-system supply capacity | • Hydro One Transmission | • Uprate Q28A | • 2024 |
| • Niagara 115 kV sub-system supply capacity | • Technical Working Group | • Monitor load growth between regional planning cycles | • Ongoing |
| • Niagara 115 kV sub-system supply capacity | • Technical Working Group | • Investigate opportunities to target incremental CDM to the 115 kV sub-system | • Ongoing |
| • Murray TS (T11/T12) station capacity | • NPEI<br>• Hydro One Transmission | • Monitor load growth and transfer load in excess of the station limit to Murray TS transformer 13 and 14 (T13/T14) | • 2023 |

### 2.1.1 Load Transfers from Beamsville TS and a New or Expanded 230 kV Station

Stations limits are typically dictated by the lowest rated transformer. Beamsville TS is fully utilized today and there is no remaining capacity for growth. Nearby stations Niagara West MTS and Vineland DS are also forecast to reach their capacity limits by 2026 and 2030, respectively.

The IRRP considered the merits of a portfolio of "non-wires" (non-transmission) options as well as integrated "wires" (transmission) options. Based on planning-level cost estimates and its ability to address capacity shortfalls at the three stations, the Technical Working Group recommends that a new 230 kV station supplied by Q23BM and Q25BM is built. This could be accomplished by expanding the existing Niagara West MTS. Development and implementation for additional capacity should begin as soon as possible for a targeted in-service date of 2026-2027. The next stage of regional planning, the Regional Infrastructure Plan ("RIP") led by Hydro One, should confirm the party who will lead development work (i.e., Grimsby Power, NPEI, or Hydro One).

In the meantime, the IRRP recommends that the local distributors (Grimsby Power, NPEI, Hydro One Distribution), in conjunction with Hydro One Transmission where appropriate, develop a plan to transfer load from Beamsville TS to the other nearby stations (Niagara West MTS, Vineland DS) to manage the urgent Beamsville TS need until the new station is in-service.

### 2.1.2 Major High Voltage Equipment Replacement of Crowland TS, New 230 kV Transmission Lines, Q28A Upgrade, and Control Actions

The existing T5 and T6 transformers at Crowland TS will require major high voltage ("HV") equipment replacement in 2026, and are forecast to be fully utilized in 2022. Crowland TS, as well as other stations supplied by the A6C/A7C circuits, are also impacted by a load security need that exists today. Moreover, Crowland TS is included in the broader Niagara 115 kV sub-system whose supply capacity need exists today and continues to grow by the end of the planning horizon.

The IRRP developed and evaluated portfolios of non-wires options, standalone generation, and wires alternatives for the multiple needs in this area. Ultimately, the most feasible and cost-effective solution at this time requires wires reinforcements: the upgrade of Q28A, the replacement of 115 kV Crowland TS with a larger 230 kV station supplied by new 230 kV transmission lines from Q24HM and Q29HM, and a new load rejection scheme developed to manage the Niagara 115 kV sub-system load. The IRRP recommends that Hydro One should begin implementation as soon as possible for a targeted in-service dates of 2024, 2024, and 2028 for the load rejection scheme, Q28A upgrade, and new 230 kV station and lines, respectively. Measures to manage the HV equipment replacement infrastructure at Crowland TS should be implemented by Hydro One until the station replacement is in-service.

### 2.1.3 Load Transfers from Murray TS (T11/T12)

Murray TS (T11/T12) is forecast to be beyond capacity in 2022 during its station peak. Given the small magnitude of this need and the available capacity on the other set of transformers at Murray TS (T13/T14), the IRRP recommends that some load is re-allocated to T13/T14 and growth continues to be monitored.

## 2.2 Ongoing Initiatives

In addition to the near- and mid-term plan above, two ongoing actions were identified to manage needs expected in the long-term.

### 2.2.1 Monitor Load Growth

Carlton TS and Kalar MTS are expected to reach capacity in 2028 and 2030, respectively. In the case of Carlton TS, distribution-level load transfers to Bunting TS have been indicated as an option. Given the timing, no firm recommendation is required at this time for either need; the Technical Working Group will continue to monitor load growth and revisit these needs in the next cycle of regional planning. As part of broader monitoring, the Technical Working Group should also keep apprised of and participate in any future Community Energy Plans developed by municipalities of the Niagara Region.

### 2.2.2 Explore Opportunities for Targeted CDM

In addition to monitoring how the forecast demand materializes, the IRRP recommends continuing to consider opportunities for targeted CDM. During the options analyses, the benefits and potential of incremental, cost-effective CDM were identified – particularly if targeted to manage near-term needs until transmission reinforcements are in-service (as is the case for the Beamsville TS/Vineland DS/Niagara West MTS area, as well as the 115 kV sub-system), or to defer long-term needs (such as at Kalar MTS). The Technical Working Group should continue to support and monitor CDM uptake, and bring these insights into the next cycle of regional planning for the Niagara Region.

# 3. Development of the Plan

## 3.1 The 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 carried out by the IESO, in collaboration with the transmitters and LDCs in each region. The process 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 proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A 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 Appendix A.

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 Niagara and IRRP Development

The process to develop the Niagara IRRP initiated in August 2021, following the publication of the Needs Assessment report in May 2021 by Hydro One and the Scoping Assessment Outcome Report in August 2021 by the IESO. The Scoping Assessment recommended that the needs identified for the Niagara 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

This is the second cycle of regional planning for the Niagara Region. This region roughly encompasses the municipalities Fort Erie, Grimsby, Lincoln, Niagara Falls, Niagara-on-the-Lake, Pelham, Port Colborne, St. Catharines, Thorold, Wainfleet, Welland, and West Lincoln. This region also includes the following First Nations and Métis Nation of Ontario Councils: Mississaugas of the New Credit, Oneida Nation of the Thames, Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council), and the Métis Nation of Ontario Niagara Region Métis Council. Following a Needs Assessment and Scoping Assessment in 2016, a RIP was initiated by Hydro One and subsequently published in 2017, concluding the first planning cycle for the Niagara Region. An IRRP was not developed, as two electricity needs were identified in 2016, but no further regional coordination was required.

The current cycle of regional planning began in 2021 with the publication of the Needs Assessment Report, where several needs requiring further regional coordination were identified. The 2021 Niagara Scoping Assessment recommended an IRRP for the entire region to address needs in a coordinated manner. This report presents an integrated regional electricity plan for the next 20-year period starting from 2022.

This IRRP develops and recommends options to meet the electricity needs of the Niagara Region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Technical Working Group, and includes consideration of forecast electricity demand growth, CDM, distributed generation ("DG"), transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

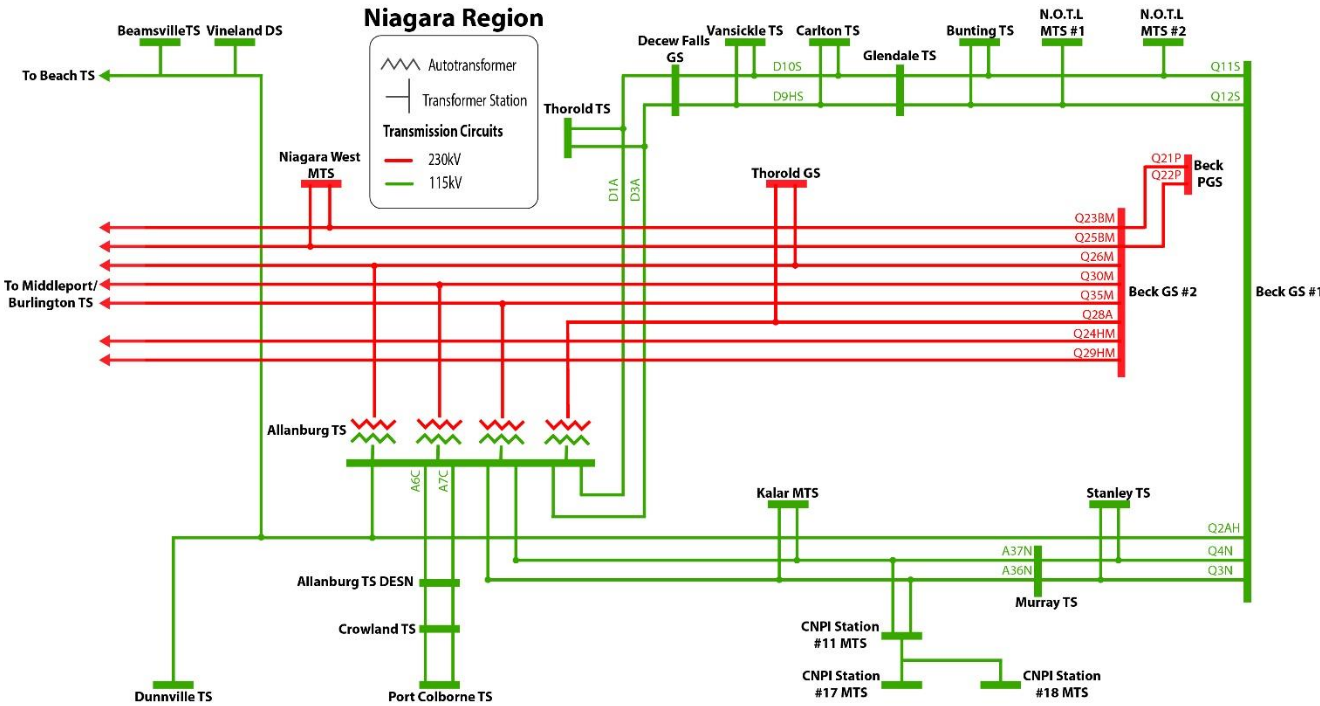
The following transmission facilities were included in the scope of this study:

- Transformer stations: Allanburg TS, Beamsville TS, Bunting TS, Carlton TS, Crowland TS, Dunnville TS, Glendale TS, Kalar MTS, Murray TS, Niagara West MTS, Niagara-on-the-Lake ("NOTL") York MTS, NOTL #2 MTS, Port Colborne TS, Stanley TS, Thorold TS, Vansickle TS, Vineland DS, CNPI #11 MTS, CNPI #17 MTS, CNPI #18 MTS. Except for Niagara West MTS, all stations are supplied from 115 kV transmission circuits.
- 115 kV transmission circuits: Q3N/Q4N, Q11S/Q12S, Q2AH, A36N/A37N, A6C/A7C, D1A/D3A, D9HS/D10S.
- 230 kV transmission circuits: Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M.

The single line diagram of the Niagara Region is shown in Figure 2 below. Note that the bulk system transfer capabilities on the Queenston Flow West interface[1] through the region is not within the scope of the IRRP and would be separately studied in a bulk transmission plan, as required. The schedule of bulk planning activities is identified through the IESO's Annual Planning Outlook.

[1] Includes flow out at Beck (Q25BM + Q23BM + Q24HM + Q29HM) and flow in at Middleport (Q30M + Q26M + Q35M).

**Figure 2 | Single Line Diagram of the Niagara Region**




The Niagara IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps);
    - Examining the load meeting capability ("LMC") and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC criteria;
    - Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid;
    - Confirming identified asset replacement needs and timing with the transmitter and LDCs;
- 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 CDM;
- Engaging with the community on needs and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

# 5. Electricity Demand Forecast

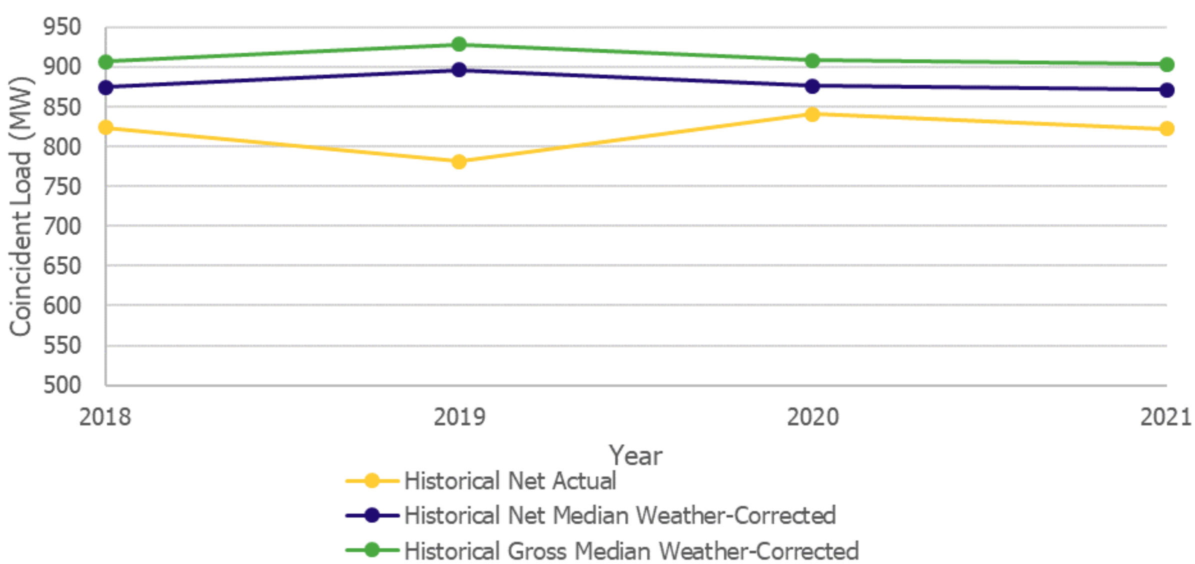
Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the Niagara Region. It highlights the assumptions made for peak demand forecasts, including weather correction, the contribution of CDM and DG, and the development of a high growth scenario. The reference net extreme weather demand forecast is used in assessing the electricity needs of the area over the planning horizon; the high forecast scenario, used as the basis for a sensitivity analysis, is described further in Section 5.7.

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. Within the Niagara Region, the peak loading hour for each year has historically occurred in the summer.

## 5.1 Historical Demand

Peak electricity demand within the Niagara Region has been steady over the last four years. Figure 3 below shows the coincident net actual (as observed at the metering point), net median weather-corrected (adjusted to reflect median weather conditions), and gross median weather-corrected (contribution of DG removed) historical demand. The gross median weather-corrected demand has averaged 910 megawatts ("MW") over the past four years, with the peak demand hour for each year occurring consistently in the summer between approximately 4 PM to 7 PM. The 2021 gross median weather-corrected peak at each station in the Niagara Region was used as the starting point for the forecast.

**Figure 3 | Historical Demand in the Niagara Region**

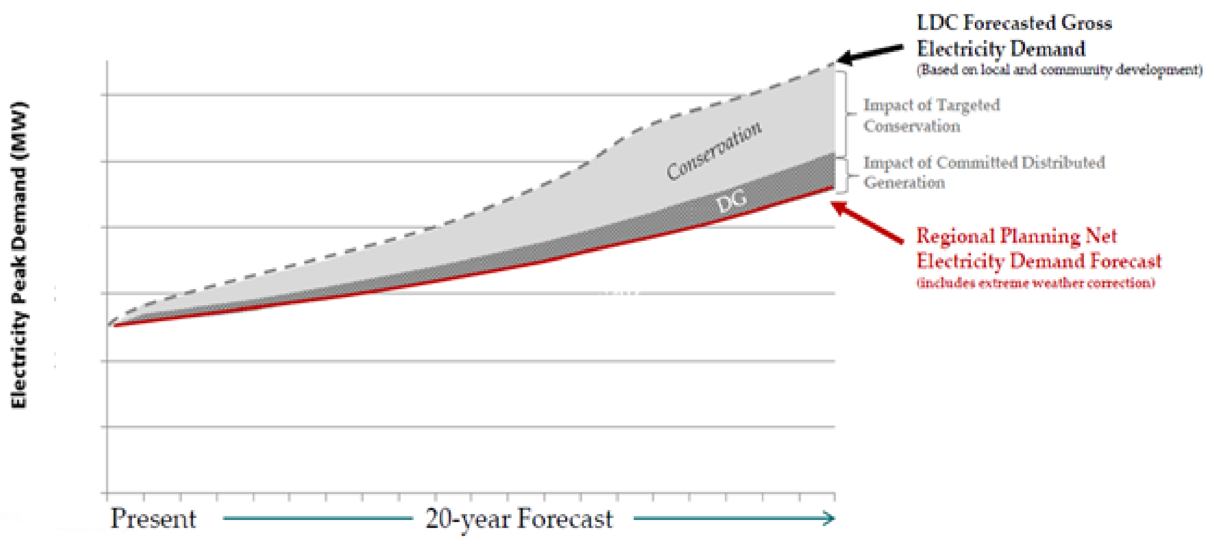


## 5.2 Demand Forecast Methodology

The steps taken to develop a 20-year IRRP peak demand forecast are depicted in Figure 4. 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 in order to produce a reference 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 Appendix B. Though the Niagara IRRP forecast was created prior to October 2022, the Ontario Energy Board also since published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.

**Figure 4 | Illustrative Development of Demand Forecast**

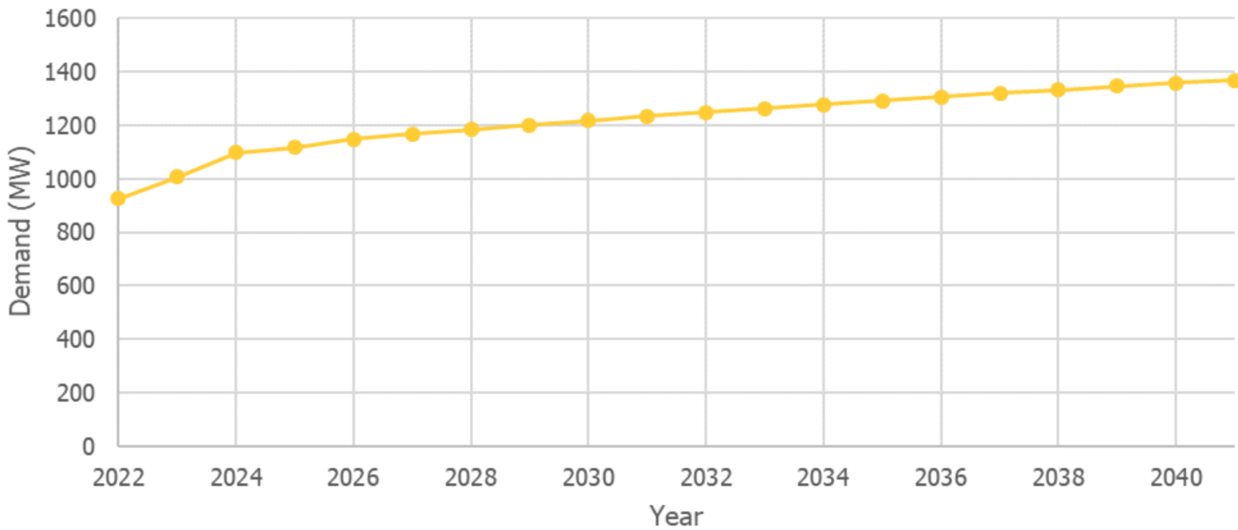



## 5.3 Gross LDC Forecast

Each participating LDC in the Niagara 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 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 CDM programs), which are accounted for by the IESO (discussed in Section 5.4). The gross LDC forecast assumes median on-peak weather conditions, and station loading that is coincident to the region.

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 municipalities and communities which they serve. The IESO typically carries out demand forecasting at the provincial level. More details on the LDCs' load forecast assumptions can be found in Appendix B.2 to B.8. Figure 5 below shows the total gross demand forecast provided by the LDCs for the Niagara Region.

**Figure 5 | Total Gross Demand Forecast Provided by LDCs (Median Weather)[2]**




## 5.4 Contribution of Conservation to the Forecast

Conservation and demand management is a clean and cost-effective resource that helps meet Ontario's electricity needs, and has been an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments, as well as CDM 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 through 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 program-related activities account for the 2021-2024 CDM Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs. The 2021 – 2024 CDM Framework is the main piece, in which the IESO centrally delivers programs on a province-wide basis to serve business and low-income customers, as well as Indigenous communities.

Figure 6 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards, and CDM programs) for each of the residential, commercial, and industrial consumers. Additional details are provided in Appendix B.9.

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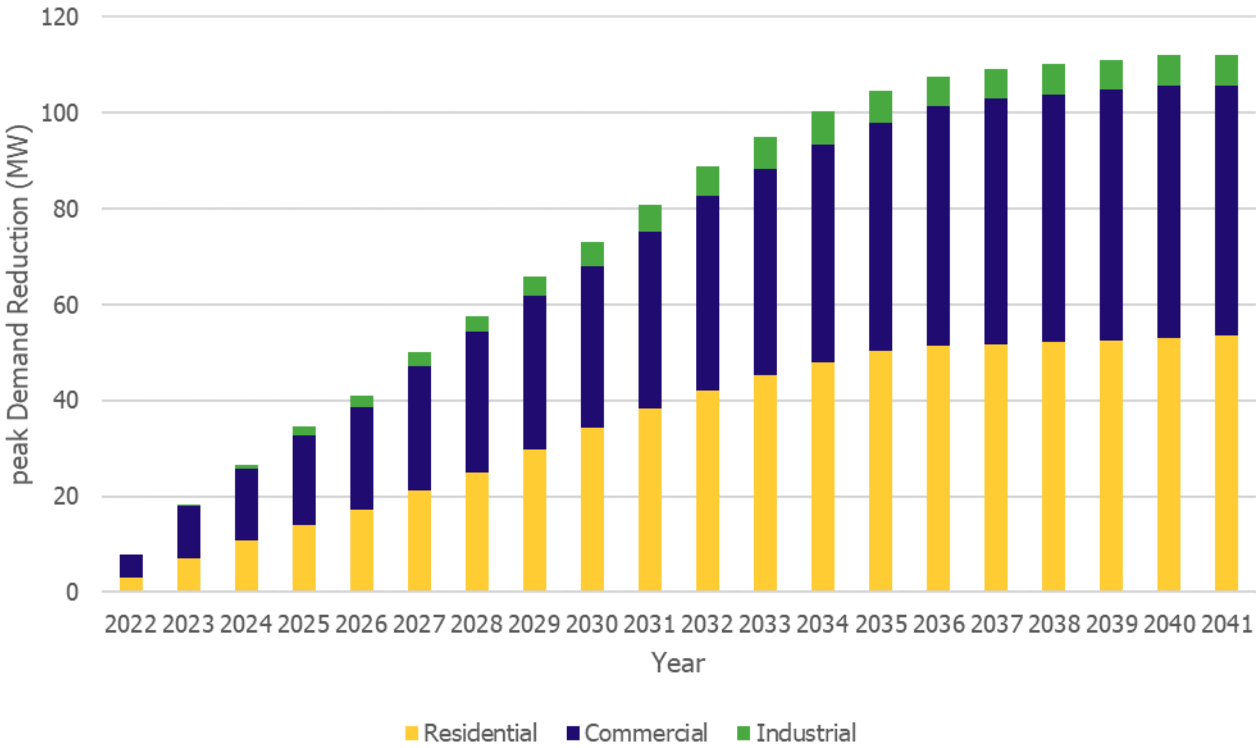
[2] Excludes existing transmission-connected industrial customers in the Niagara Region (historically contributing an average of 15 MW to the coincident peak demand).

**Figure 6 | Total Forecast Peak Demand Reduction (Codes, Standards, and CDM Programs)**

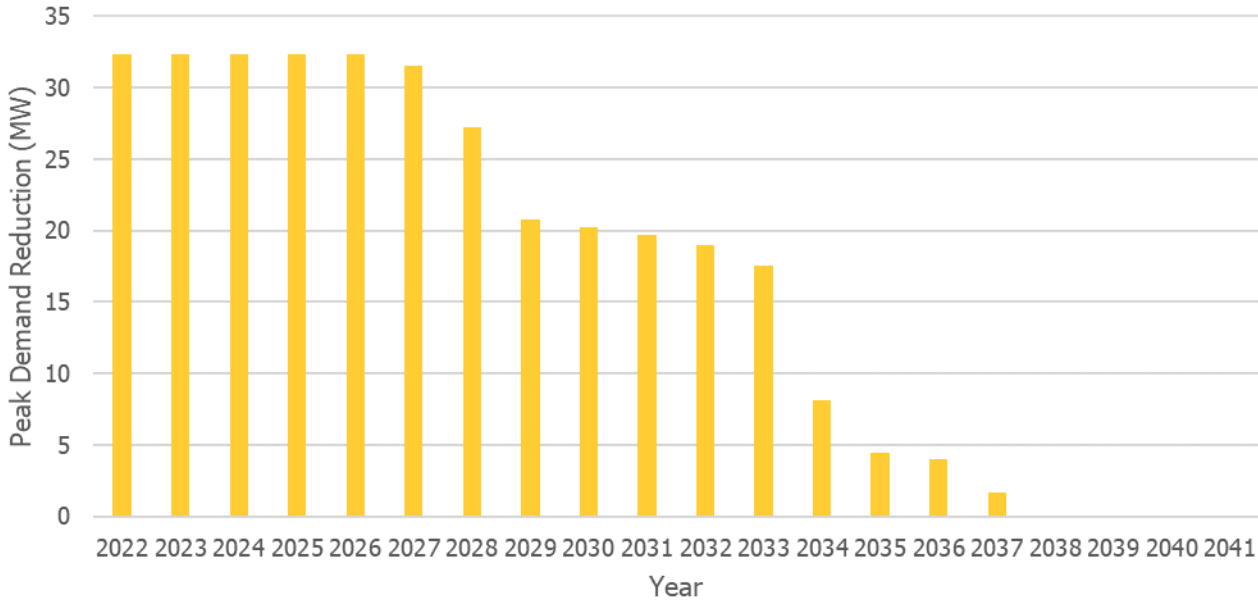



## 5.5 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, DG in the Niagara 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 Appendix B.10. Most of the total contracted installed DG capacity in the Niagara Region is solar, wind, and waterpower, with some biogas, landfill gas, and natural gas facilities.

After reducing the demand forecast due to conservation, as described in Section 5.4, the forecast is further reduced by the expected contribution from contracted DG. Figure 7 shows the impact of DG on reducing the Niagara Region demand forecast. Note that any facilities without a contract with the IESO are not currently included in the DG peak demand reduction forecast.

**Figure 7 | Peak Demand Reduction to Demand Forecast, Due to DG**




In the long term, the contribution of DG is expected to diminish as their contracts expire. A total of 32 MW of peak contribution is identified for the Niagara Region in 2022, reducing throughout the 2030s to 0 MW by 2038. This reduction is reflected in the high forecast scenario (see Section 5.7 for more details on its development and assumptions), but not the reference forecast. Rather, the reference Niagara IRRP forecast assumes a constant contribution of approximately 32 MW each year for the entire study period. This aligns with the Technical Working Group decision to assume that already-existing DG facilities with expired contracts will continue to offset demand.

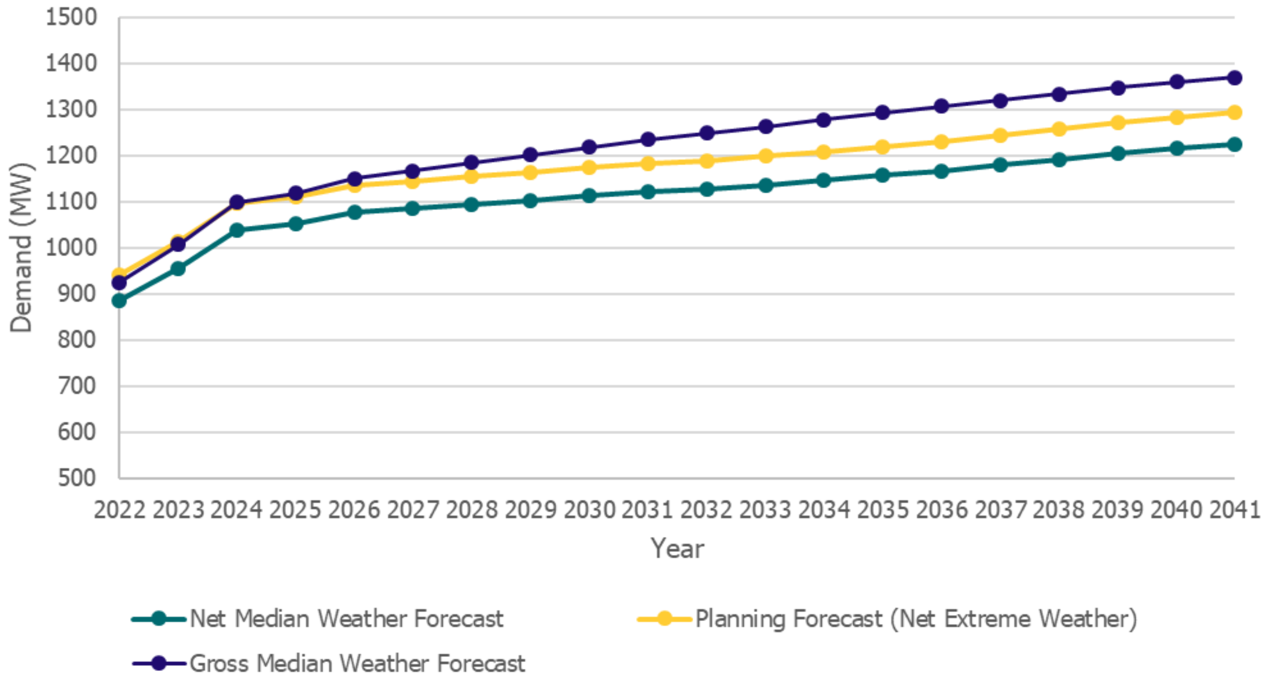
## 5.6 Net Extreme Weather ("Planning") Forecast

The net extreme weather forecast, also known as the "planning" forecast, is created by adjusting the net median weather forecast (the gross demand forecast, plus the forecast DG and conservation impacts as described above) for extreme weather conditions. The weather correction methodology is described in Appendix B.1.

Note that this planning forecast is coincident, meaning that each station forecast reflects its expected contribution to the regional peak demand level. This supports the identification of need dates 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 six years.

The coincident net extreme weather forecast for the Niagara Region is shown in Figure 8 below.

**Figure 8 | Net Extreme Weather ("Planning") Forecast for the Niagara Region[3]**



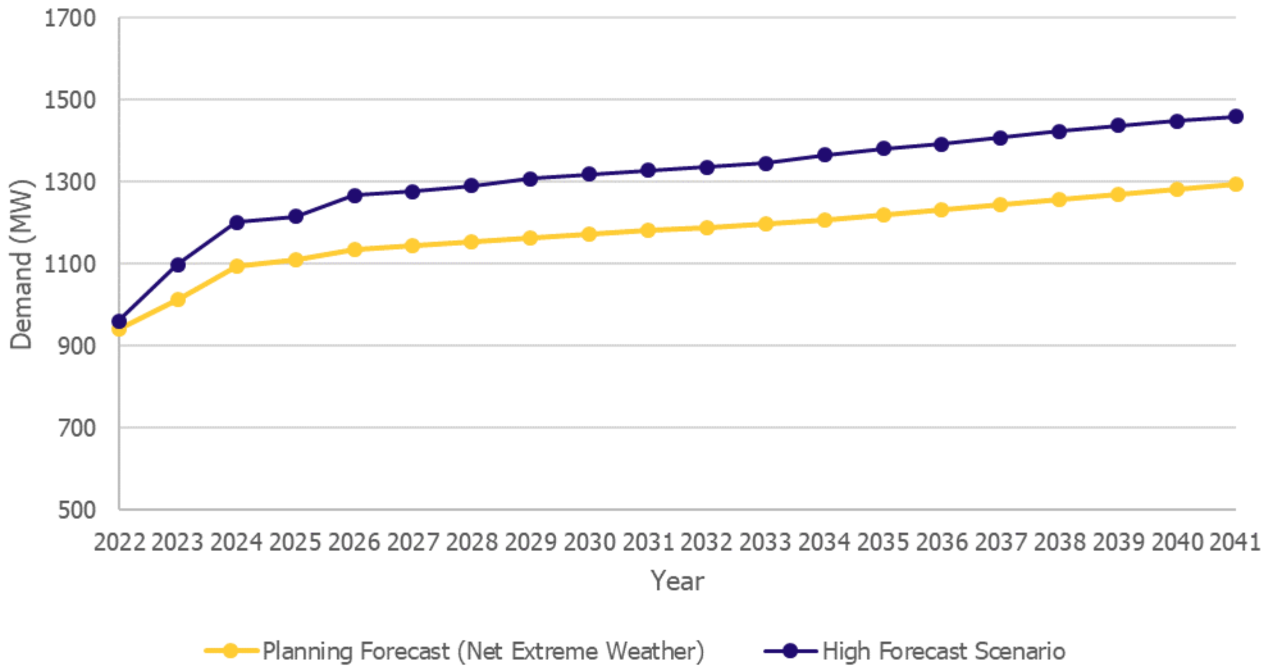

## 5.7 High Forecast Scenario

The Technical Working Group opted to develop a high forecast sensitivity scenario for the Niagara Region. This higher demand scenario is to take into account a variety of factors that could drive demand higher over the next 20 years, including but not limited to: electric vehicle charging infrastructure, electrified space heating installations, unanticipated new industrial customers, or general higher-than-expected growth. However, the Technical Working Group did not have specific end-use data available to develop the high forecast. Instead, the DG contribution to peak (as described in Section 5.5) was removed according to contract expiries, resulting in approximately 3% higher total regional load by 2041 when compared to the reference planning forecast. The impact on stations with greater contracted DG is higher.

The high forecast also included several large industrial customers whose connection was uncertain at the time of finalizing the reference forecast. These include customers that members of the Technical Working Group were aware of and liaising with, as well as customers that initiated a System Impact Assessment with the IESO during the Niagara IRRP development. In total, another 132 MW was added due to this assumption, when compared to the reference planning forecast. This is shown in Figure 9.

[3] See footnote 2.

**Figure 9 | High Forecast Scenario for the Niagara Region[4]**




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 pinch points 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 as they think about various projects in the region. Moreover, during 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.

## 5.8 Hourly Forecast Profiles

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for certain stations with identified needs were developed to characterize their needs with finer granularity. The profiles were based on historical load data, 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 generation and distributed energy resource options.

Additional load profile details including hourly heat maps for each need can be found in Appendix D. 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 the 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

[4] See footnote 2.

estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of 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, NERC TPL-001-4, and Northeast Power Coordinating Council ("NPCC") 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.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the 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-001-4, and NPCC Directory #1. LMC studies are conducted using power system simulation analyses.
- **Asset Replacement Needs** are identified by the transmitter 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 mid-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 Niagara IRRP can be found in Appendix G. The needs identified are discussed in Sections 6.2 – 6.5 below.

## 6.2 Station Capacity Needs

In the near/mid-term, there are summer station capacity needs at Beamsville TS, Murray TS, Crowland TS, and Niagara West MTS. In the longer term, there are station capacity needs at Carlton TS, Vineland DS, and Kalar MTS. Table 2 below summarizes transformer capacity limitations for the Niagara Region.

**Table 2 | Summary of Station Capacity Needs in the Niagara Region**

| Need | 10-day LTR Rating (MW)[5] | Need Date[6] | Size of Need by 2041 |
|---|---|---|---|
| Beamsville TS | 57 | 2022 | 44 |
| Murray TS (T11/T12) | 72 | 2022 | 14 |
| Crowland TS | 96 | 2022 | 25 |
| Niagara West MTS | 60 | 2026 | 22 |
| Carlton TS | 94 | 2028 | 11 |
| Kalar MTS | 68 | 2030 | 7 |
| Vineland DS | 25 | 2030 | 3 |

### 6.2.1 Beamsville TS, Niagara West MTS, and Vineland DS

The three stations supplying the Lincoln, West Lincoln, and Grimsby areas (Beamsville TS, Niagara West MTS, and Vineland DS) are forecast to reach their individual station limits, as well as their collective limit (sum of their LTRs). Beamsville TS and Vineland DS each comprise two 115 kV/27.6 kV transformers, with summer LTRs of 57 MW and 25 MW, respectively. The Beamsville TS capacity need exists today (Figure 10), whereas the Vineland DS need is forecast to start in 2030 (Figure 12). Niagara West MTS consists of two 230 kV/27.6 kV transformers, with a summer LTR of 60 MW and a need beginning in 2026 (Figure 11). Cumulatively, the capacity need at these three stations grows to 57 MW by 2041 (Figure 13).

[5] Assuming a 0.9 power factor.

[6] Based on non-coincident station forecasts, as explained in Section 5.6.

**Figure 10 | Beamsville TS Capacity Need**

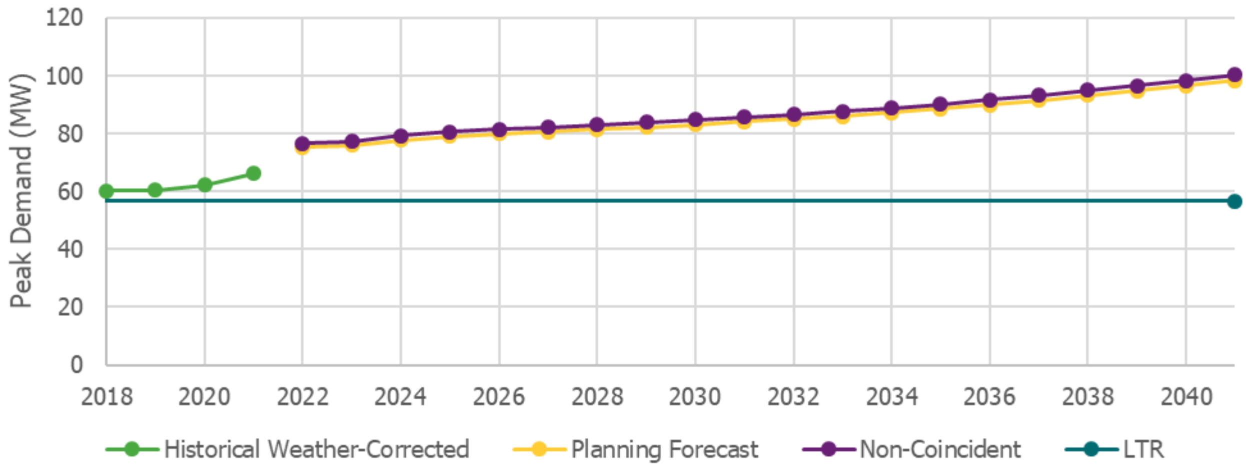



**Figure 11 | Niagara West MTS Capacity Need**

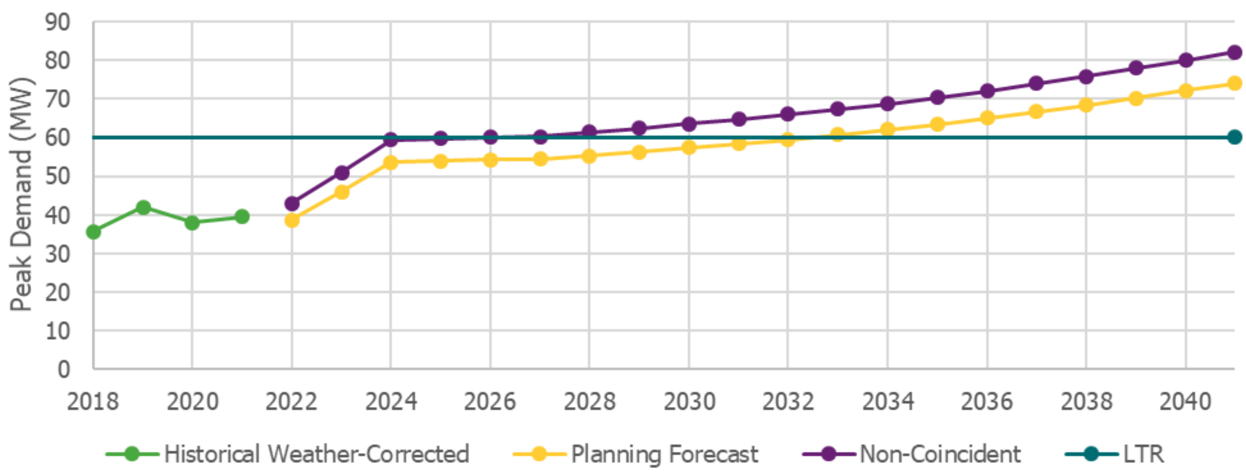



**Figure 12 | Vineland DS Capacity Need**

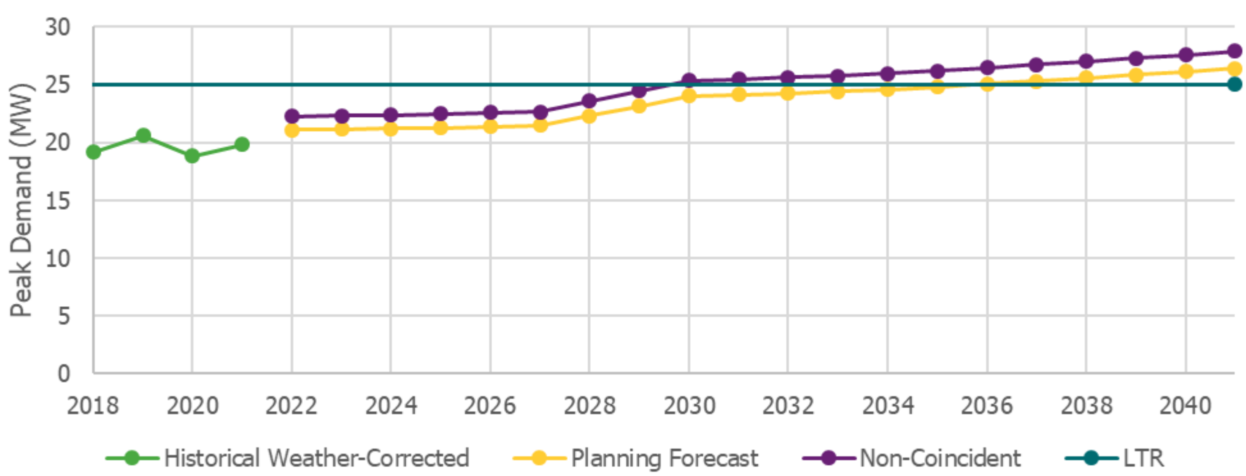
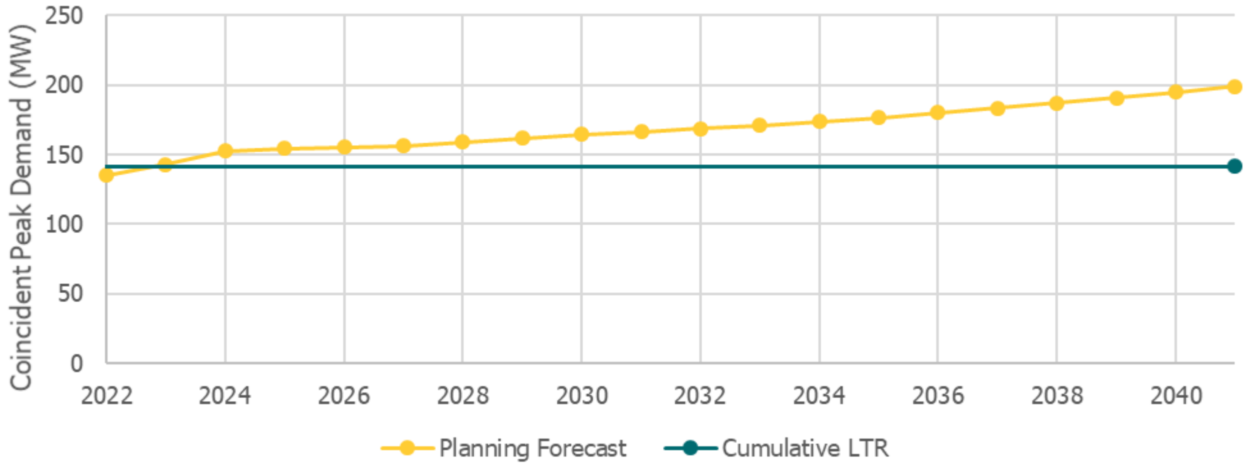


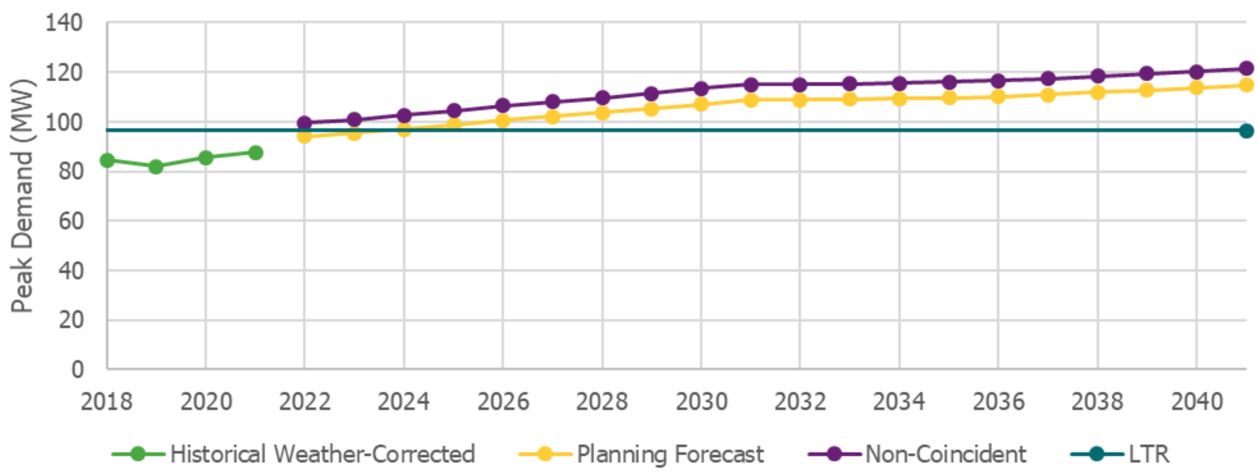
**Figure 13 | Beamsville TS, Vineland DS, and Niagara West MTS Cumulative Coincident Capacity Need**




### 6.2.2 Crowland TS

Supplying Welland, Crowland TS is forecast to reach its summer station capacity limit in 2022 and grow to a 25 MW need by 2041. This station comprises two 115 kV/27.6 kV transformers with an LTR of 96 MW.

**Figure 14 | Crowland TS Capacity Need**




### 6.2.3 Carlton TS, Kalar MTS, and Murray TS (T11/T12)

Carlton TS and Kalar MTS each comprise two 115 kV/13.8 kV transformers, with summer LTRs of 94 MW and 68 MW, respectively. Carlton TS is forecast to reach capacity starting in 2028 (Figure 15) while the Kalar MTS need arises in 2030 (Figure 16). Each need will increase to 11 MW and 7 MW, respectively, by 2041. Murray TS consists of four 230 kV/13.8 kV transformers; T11 and T12 have a summer LTR of 72 MW, whereas T13 and T14 are rated to 77 MW. The T11/T12 capacity need exists today, growing to 14 MW by 2041 (Figure 17).

**Figure 15 | Carlton TS Capacity Need**

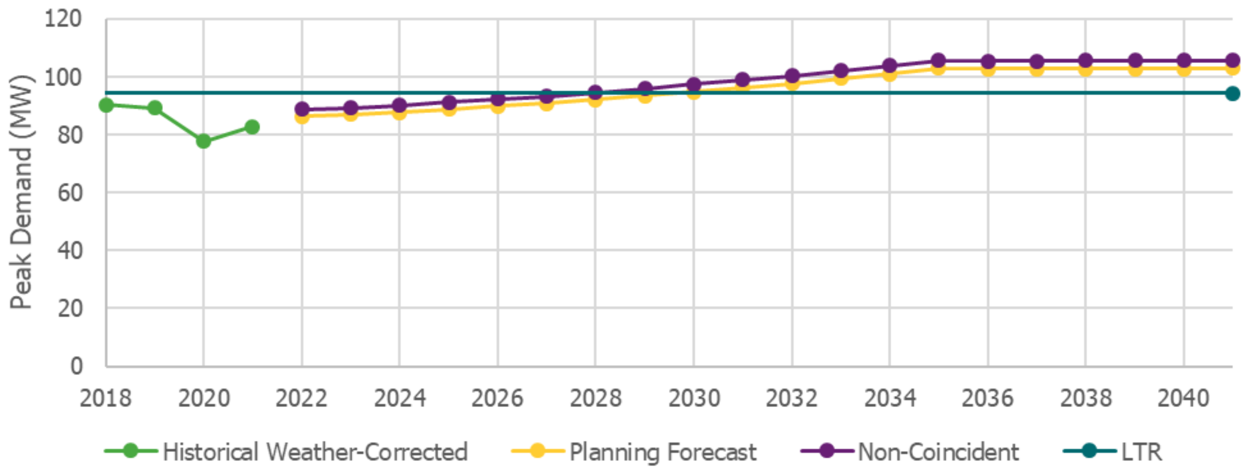



**Figure 16 | Kalar MTS Capacity Need**

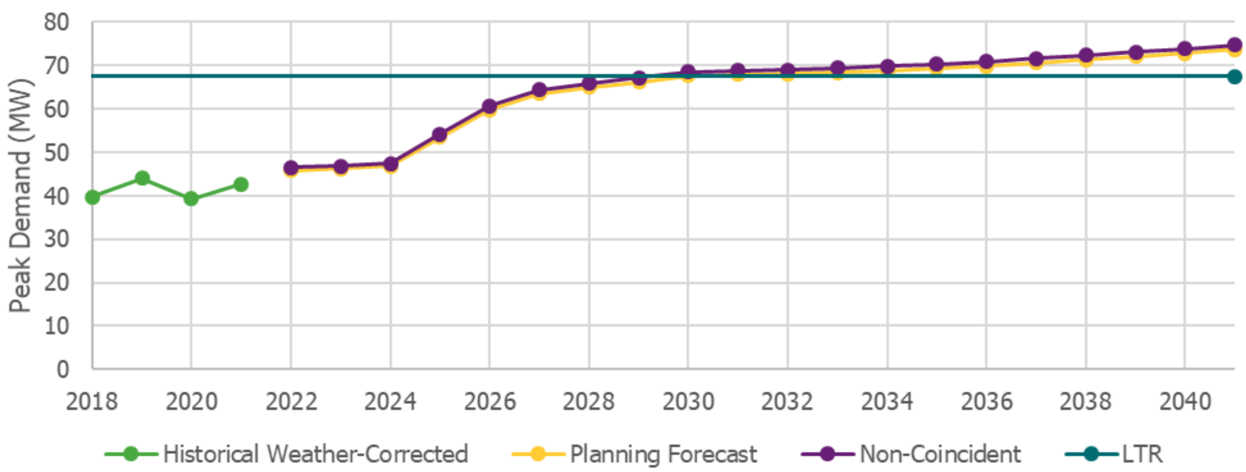



**Figure 17 | Murray TS (T11/T12) Capacity Need**

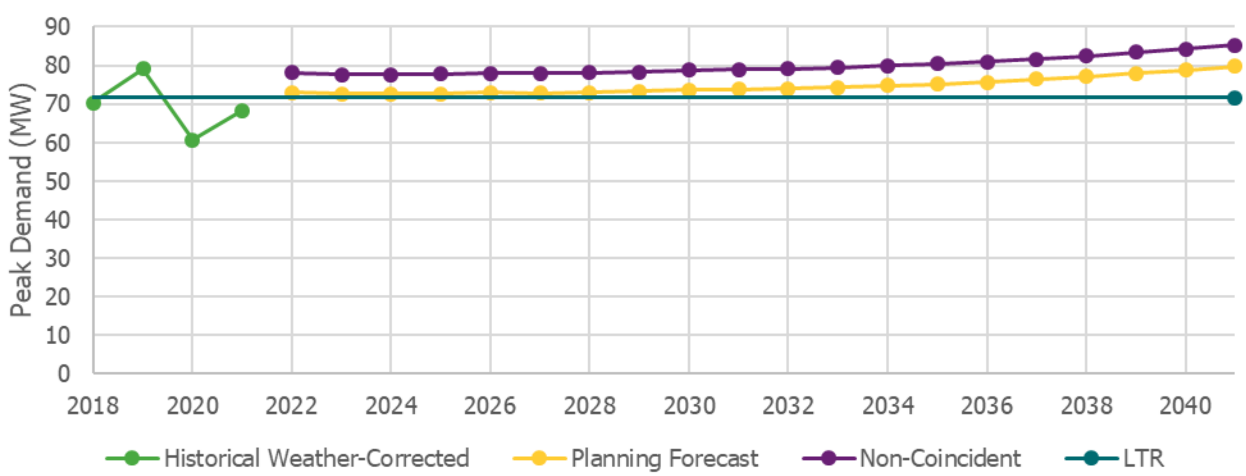
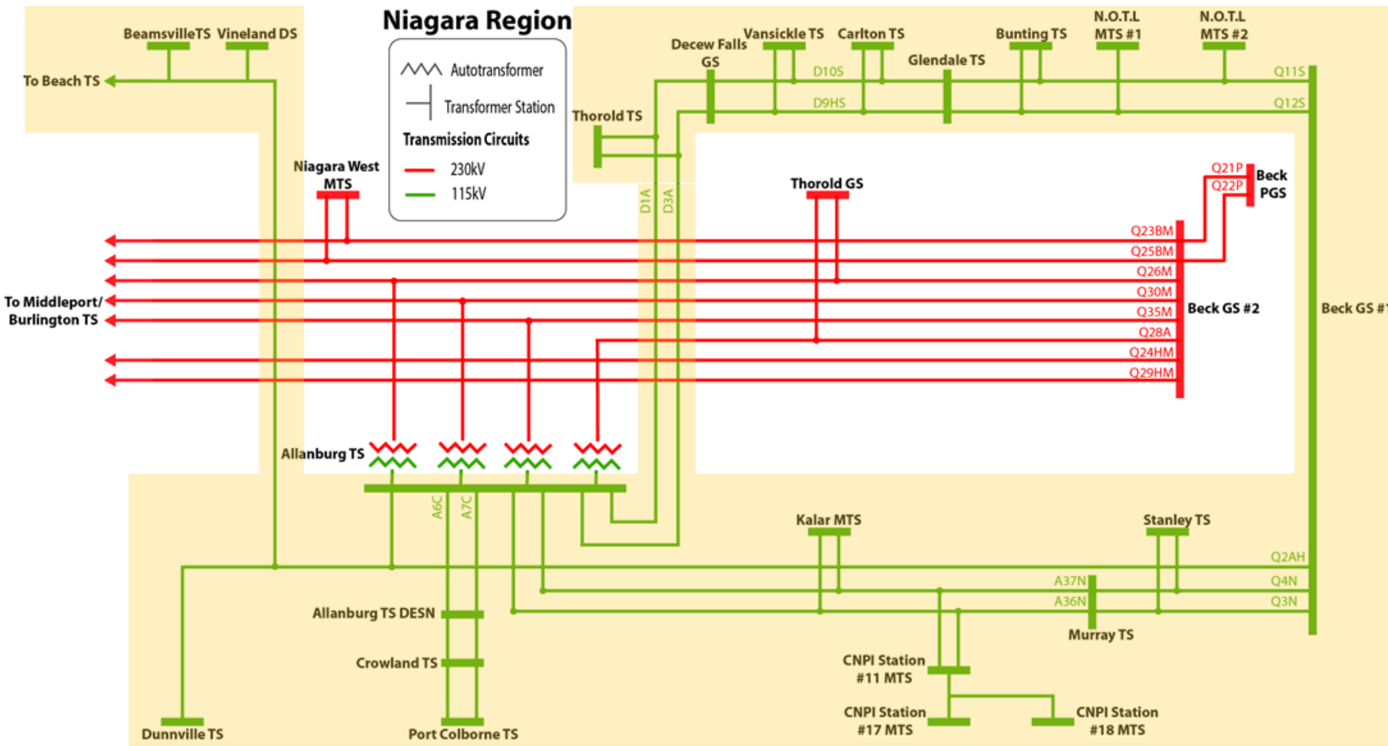



Figure 15 to Figure 17 demonstrate the non-coincident peak demand forecasts at these stations compared to their individual LTRs. Note that these station capacity needs have been presented together in this sub-section, since this IRRP is not yet recommending infrastructure reinforcements to address them. Section 7.2.1.3 describes this in more detail.

## 6.3 Supply Capacity Needs

The majority of load in the Niagara Region is supplied through its 115 kV transmission sub-system, which in turn is supplied from the 230/115 kV autotransformers at Allanburg TS, Sir Adam Beck GS #1, and Decew Falls GS. The LMC of the 115 kV sub-system is therefore limited by the capability at Allanburg TS under the various planning scenarios and applicable contingencies. The sub-system is demonstrated in Figure 18.

**Figure 18 | Niagara Region's 115 kV Sub-System (Highlighted Yellow)**

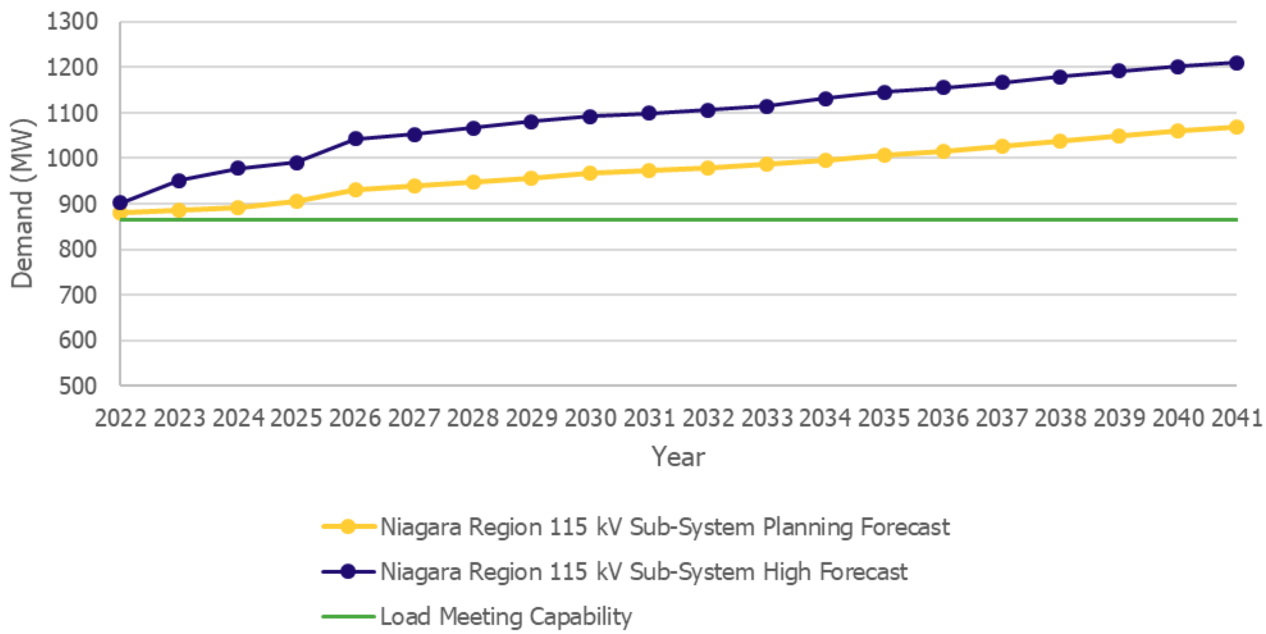



The LMC of the Niagara 115 kV sub-system, presented in Figure 19 against the forecast load, reflects limitations of the existing transmission system. Under certain outage and contingency conditions (such as contingencies impacting two circuits between Beck GS #2 and Middleport/Burlington, or Beck GS #1), the lowest-rated Allanburg autotransformer is overloaded and is the first limiting phenomenon that restricts total reliable supply into the 115 kV sub-system. However, the LMC for this area can also be restricted by other phenomena, including the thermal capability of a section of Q28A during other contingency events and specific generation outage conditions. There are further, more local restrictions within this sub-system too – such as thermal constraints limiting the supply to loads between Allanburg TS and Beck GS #1 through the 115 kV circuits.[7] All of these transmission limits are described in Appendix G.

[7] This particular need, which occurs under outage conditions, could be addressed through permissible operational control actions and would be impacted by a customer's System Impact Assessment that is ongoing at the time of regional planning.

Between 2018 – 2021, the 115 kV sub-system has had a peak coincident weather-corrected load of up to approximately 830 MW. With the reference planning forecast, the 115 kV sub-system load increases such that the supply capacity need grows to approximately 200 MW by 2041; under the high scenario, it is about 340 MW.

**Figure 19 | Niagara Region 115 kV Supply Capacity Need**




## 6.4 Asset Replacement Needs

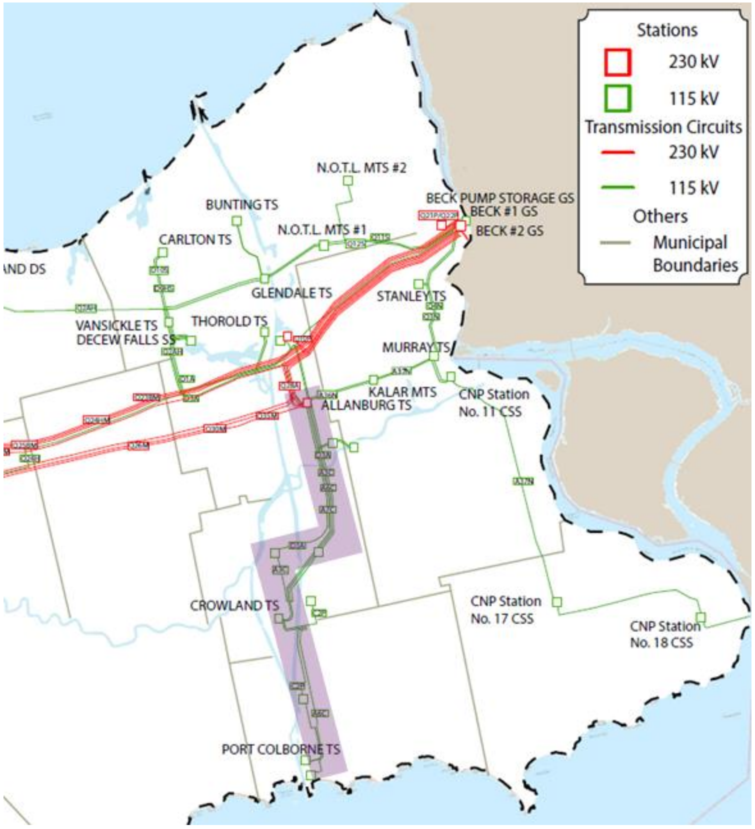
At the time of the Niagara Region Needs Assessment, Hydro One identified a number of assets requiring replacement in the next 10 years. This included Crowland TS, whose transformers were originally scheduled to be replaced with like-for-like 115/27.6 kV 83 megavolt ampere ("MVA") units before 2026. As described in the Niagara Region Scoping Assessment, the Technical Working Group agreed that sustainment plans identified by Hydro One would be assumed to proceed as described in the Needs Assessment – unless an opportunity arose for "right-sizing".

Through the development of the IRRP, during which a more comprehensive demand forecast was created and extended to a 20-year planning horizon, and additional needs were identified or refined, the Crowland TS like-for-like replacement plan was reconsidered. This need and its relevance to the other regional needs are described further in Section 7.4.

## 6.5 Load Security Needs

The circuits designated as A6C/A7C form a 115 kV double-circuit line from Allanburg TS to Crowland TS, before supplying Port Colborne TS as A6C and C2P. These circuits also serve a number of transmission-connected industrial customers that are south of Allanburg TS, primarily east of the Welland Canal. Figure 20 provides an overview of this portion of the transmission system in the Niagara Region.

**Figure 20 | Niagara Region Transmission System: A6C/A7C (Highlighted Purple)**




The aforementioned stations and transmission-connected customers on the A6C/A7C circuits are included in the Allanburg Load Rejection Scheme; operational actions are taken to disconnect these loads in the event of certain contingencies to prevent voltage decline upon the coincidental loss of Allanburg T1 and T2. At the 2022 expected load levels on the A6C/A7C circuits, a double contingency on the Q26M and Q28A circuits will trigger over 180 MW of load being disconnected from the system. This is a violation of Section 7.1 of the ORTAC, which specifies that only up to 150 MW of planned load curtailment is permissible under these conditions. The load supplied by A6C/A7C is also expected to grow throughout the study period (i.e., up to 2041). By 2041, it is expected that the load security need will grow to approximately 75 MW in excess of the permissible amount. More details regarding this load security need are provided in Appendix G.

## 6.6 Summary of Identified Needs

Below is an overview of all needs identified in this Niagara IRRP.

**Table 3 | Summary of Needs in the Niagara Region**

| Need | Need Date |
|---|---|
| Beamsville TS Station Capacity | 2022 |
| Murray TS (T11/T12) Station Capacity | 2022 |
| A6C/A7C Load Security Need | 2022 |

| Need | Need Date |
|---|---|
| Niagara 115 kV Sub-System Supply Capacity | 2022 |
| Crowland TS Station Capacity | 2022 |
| Crowland TS Asset Replacement | 2026 |
| Niagara West MTS Station Capacity | 2026 |
| Carlton TS Station Capacity | 2028 |
| Kalar MTS Station Capacity | 2030 |
| Vineland DS Station Capacity | 2030 |

# 7. Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in the Niagara Region. In 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, feasibility, cost, and consistency with longer-term needs in the area.

Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new infrastructure to increase the LMC of the area. These are commonly referred to as "wires" options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, or upgrades to existing infrastructure. Wires 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 LMC. These are commonly referred to as "non-wires" options and can include things like local utility-scale generation, distributed energy resources (including distribution-connected generation and demand response), or CDM.

Section 7.1 begins with a more in-depth overview of all option types considered in IRRPs. Section 7.2 describes the screening approach used to assess which needs would be best suited for a more detailed assessment for non-wires options. Subsequently, Section 7.3 to Section 7.5 present the options that were ultimately developed and evaluated (including a cost comparison) before the Technical Working Group made a recommendation.

## 7.1 Options Considered in IRRPs

Wires options are always considered in regional planning, and are developed by designing transmission reinforcements or control actions that are appropriate for the specific limiting phenomenon (voltage, thermal, stability, etc) of each need. These are identified through discussions with the Technical Working Group.

While traditional wires infrastructure is always a viable option for regional needs, some non-wires options are more suitable for specific need types and characteristics. Hence, to select and size suitable generation and other non-wires options, additional work is required – including 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 LMC. The profile indicates the duration, frequency, magnitude, and total energy associated with each need. Some of these characteristics are shown visually in Appendix D for the Niagara Region needs.

High-level cost estimates for wires options are usually provided by the transmitter. In contrast, cost estimates for generation and other non-wires options are based on benchmark capital and operating cost characteristics for each resource type and size. Generally speaking, the most cost-effective transmission-connected options for meeting local needs in the Niagara Region are resources with a performance and costs on par with simple cycle gas turbines. New natural gas-fired generation was considered in the economic analysis for illustrative purposes, as it was representative of the lowest cost generation option. Energy storage, such as lithium nickel manganese cobalt oxide batteries, are also becoming cost-competitive due to declining technology costs and the expectation of carbon prices increasing in line with federal policy. Other energy resources (which are typically distribution-connected) are also considered.

CDM measures can also help decrease the net electricity demand. Centrally delivered energy efficiency measures under the 2021-2024 CDM Framework and Save on Energy brand are already included in the load forecast, as discussed in the Section 5.4. As part of this current Framework, the IESO was directed to deliver a new program to address regional and/or local system needs. The Local Initiative Program is now one tool that is available to target the delivery of additional CDM savings at specific areas of the province with identified system needs. LDCs can also use the Ontario Energy Board's CDM Guidelines to leverage distribution rates to help address distribution and transmission system needs using non-wires alternatives.[8] Generally, incremental CDM measures are 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 percent per year). These considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

For both wires and non-wires options, the upfront capital and operating are compiled to generate levelized annual capacity costs ($/kW-year). A cash flow of the levelized costs for the options are compared over the lifespan of the wires option (typically 70 years for transmission infrastructure). The non-wires options also include any system capacity benefit that they could contribute to provincial resource adequacy needs, ensuring that they are both sized to address the local need and are comparable to the wires options. The net present value (in 2021 CAD dollars) of these levelized costs are the primary basis through which feasible options are compared.

It is important to recognize that there is a significant error margin around costs estimates at the planning stage, as they are only intended to enable comparison between options during the IRRP. The RIP (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine wires cost estimates before implementation work begins. The IESO continues to participate in the Technical Working Group during the RIP and revisits these recommendations if costs estimates differ significantly. Furthermore, in cases where other barriers downstream of the regional planning process (i.e., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints) impede the adoption of some of these cost-effective options, pilot or demonstration projects can be explored.[9]

The list of assumptions made in the economic analysis can be found in Appendix F.

## 7.2 Screening Options

As explained in Section 7.1, an array of options can be developed to meet local needs during an IRRP, but options are ultimately evaluated to recommend the most cost-effective and technically

[8] More information about the CDM Guidelines is available on the Ontario Energy Board's website.

[9] Barriers to non-wires alternatives and recommendations to address them were a part of the Regional Planning Process Review.

feasible solution. This process is complemented by considerations for stakeholder preferences and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed non-wires analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 21, and the results of its application to the Niagara IRRP needs are summarized in Table 4 and then further described in the sections below. More details on the steps and inputs used in the screening mechanism can be found in Appendix C.

**Figure 21 | IRRP Screening Mechanism**

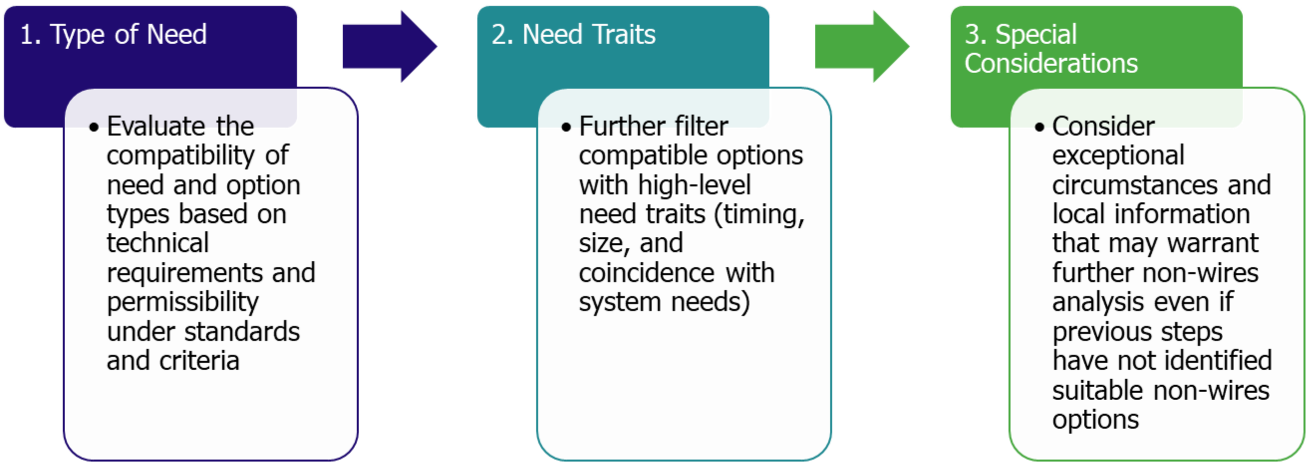



**Table 4 | Results of Niagara IRRP Screening**

| Need Type | Impacted Element | Options Screened In | Options Screened Out |
|---|---|---|---|
| Station capacity | Beamsville TS | Wires, demand response ("DR"), DG, CDM | Transmission-connected generation |
| Station capacity | Vineland DS | Wires, CDM | Transmission-connected generation, DR, DG |
| Station capacity | Crowland TS | Wires, DR, DG, CDM | Transmission-connected generation |
| Station capacity | Kalar MTS | Wires, CDM | Transmission-connected generation, DR, DG |
| Station capacity | Carlton TS | Wires | All non-wires |

| Need Type | Impacted Element | Options Screened In | Options Screened Out |
|---|---|---|---|
| Station capacity | Murray TS (T11/T12) | Wires | All non-wires |
| Supply capacity | Niagara 115 kV sub-system | Wires, transmission-connected generation, CDM | DR, DG |
| Asset replacement | Crowland TS | Coordinated with the Crowland TS station capacity need | Coordinated with the Crowland TS station capacity need |
| Load security | Load supplied by A6C/A7C circuits | Wires | All non-wires |

### 7.2.1 Non-Wires Options for the Capacity Needs

Based on the nature of the need, Step 1 of the screening mechanism identifies that in general, non-wires options can resolve supply and station capacity needs by reducing net load in the affected area. For station capacity needs specifically, these options must be resources that are connected downstream of the limiting step-down transformer. The following sections outline when Steps 2 and 3 of the screening resulted in further analysis of non-wires options.

#### 7.2.1.1 Beamsville TS, Niagara West MTS, and Vineland DS

As described previously in Section 6.2.1, there are forecast station capacity needs at Beamsville TS, Niagara West MTS, and Vineland DS, as well as a collective capacity shortfall in the area supplied by the three stations. Though eventually considered together given their geographic proximity, Beamsville TS and Vineland DS were screened independently. For Beamsville TS, with its large near-term capacity need, all applicable non-wires options were considered. Conversely, for the small long-term need at Vineland DS, the focus (in terms of a non-wires option) was on incremental CDM.

At the time of screening, the Technical Working Group did not identify a station capacity need at Niagara West MTS; this occurred later in the IRRP development when the forecast was updated by Grimsby Power. Hence, formal screening was not conducted for Niagara West MTS – but this IRRP does ultimately include recommendations that address its need (see Section 7.3).

#### 7.2.1.2 Crowland TS

For Crowland TS, all applicable non-wires options were developed in further detail. Initially, at the time of the screening, the Crowland TS and Kalar MTS station needs were approached together given their perceived geographic proximity. However, recommendations were eventually made for these stations separately after considering factors that made an integrated approach impractical. These factors include distribution voltage level differences, distance to supply forecast growth areas, and misaligned capacity need timing between the two stations.

#### 7.2.1.3 Carlton TS, Kalar MTS, and Murray TS (T11/T12)

For some needs, further analysis of non-wires is not warranted if there is the high potential for an inexpensive and simple wires alternative that maximizes the use of existing infrastructure. This can include load transfers or control actions that are sufficient to meet the need.

This was the case for the station capacity needs at Carlton TS and Murray TS (T11/T12). At the time of screening, Alectra Utilities indicated plans to reallocate some forecast demand at Carlton TS to a nearby station with additional capacity (Bunting TS). At Murray TS, NPEI is supplied by both T11/T12 and T13/T14. While forecast demand for T11/T12 exceeds its LTR, there is sufficient remaining capacity at T13/T14.[10] Managing the load distribution between the four transformers at Murray TS is expected to address the need at T11/T12.

For the small long-term need at Kalar MTS, incremental CDM was screened in for additional analysis.

#### 7.2.1.4 Niagara 115 kV Sub-System Supply

Due to the nature of supply capacity needs, most non-wires options can be potential solutions – either alone or as a part of an integrated package of recommendations. However, for the Niagara 115 kV sub-system, the magnitude of the capacity need was large enough that the option development focused on transmission-connected generation or storage, with some consideration for additional locally targeted CDM.

Other non-wires options such as DR and DG were screened out from further analysis for a number of reasons. For instance, the connection of DG (regardless of fuel type) is subject to equipment limitations such as minimum loading, feeder capacity, station thermal capacity, and short circuit requirements. With an approximately 200 MW supply capacity need, the amount of incremental DG required would not be able to connect to a single transformer station in the Niagara Region, and would be unlikely to be accommodated, coordinated, and operated across multiple stations to meet the local supply constraint.[11] Recall that existing contracted DG output at peak was already accounted for during the development of the net demand forecast.

Similarly, DR was screened out due to the magnitude of the Niagara 115 kV supply capacity need. Though DR can be considered as a potential option to the extent that loads in the area can be curtailed during peak hours, the amount of DR that has historically been acquired for system capacity needs can help indicate this option's feasibility. For the 2021 summer obligation period in the capacity auction, approximately 20 MW of total capacity cleared for the Niagara zone. These past auction results provide context as to the scale of demand response that would be required to address the Niagara supply capacity need; this is unlikely to be achievable in the near-term. It is also worth noting that the Capacity Auction acquires resources designed to meet provincial adequacy rather than specific local or regional needs.

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[10] Approximately 50 MW of remaining capacity is available at Murray TS (T13/T14) according to the IRRP reference planning forecast.

[11] For existing station DG connection availability, consider Hydro One's capacity evaluation tool for generation applicants.

### 7.2.2 Non-Wires Options for the Asset Replacement Needs

Outcomes of screening non-wires options for the Crowland TS asset replacement need were aligned with the screening outcomes for the Crowland TS incremental station capacity need (i.e., the capacity need that persists even if the station is replaced like-for-like).

### 7.2.3 Non-Wires Options for the Load Security Needs

Due to the nature of planning criteria outlined in ORTAC 7.2, non-wires options such as CDM and DG cannot be applied to load security needs because they usually do not enable uninterruptable power supply to customers in the event of transmission contingencies. While voluntary load loss such as DR could help address the intent of load security planning criteria, it is an option type currently procured through the provincial capacity auction. This implementation mechanism is not the optimal approach, as its current design does not include the monitoring of local adequacy nor permit immediate responses after specific local contingencies. For these reasons, non-wires options are typically screened out for load security needs unless there are exceptional circumstances identified during the IRRP development.

## 7.3 Options and Recommendations for Meeting the Beamsville TS, Niagara West MTS, and Vineland DS Needs

### 7.3.1 Transmission Options

Due to the geographic proximity of Beamsville TS, Niagara West MTS, and Vineland DS, integrated transmission options were developed to address the station capacity needs in a coordinated manner. Three options for additional station capacity for the area were considered:

1. The replacement of existing Niagara West MTS with new 2 x 75/125 MVA transformers;
2. The expansion of Niagara West MTS with two new 67 MVA transformer units; or
3. A new, separate 230 kV station supplied from Q23BM and Q25BM.

Option 1 was ruled out, given that there was no indication of asset replacement needs at the existing Niagara West MTS (resulting in stranded asset costs), plus the risk of reduced reliability expected when implementing the replacement. Option 2 was estimated to cost as little as $17M and require three years from the commitment date, whereas Option 3 was estimated to cost up to $40M (depending on the size of the transformers and implementer) and would take three to four years.[12]

Given the immediate need at Beamsville TS, the Technical Working Group also considered load transfer capabilities in the near-term. Beamsville TS and Niagara West MTS both supply Grimsby Power, NPEI, and Hydro One Distribution, while Vineland DS supplies only NPEI. At the time of this IRRP, Grimsby Power estimated the ability to transfer approximately 7 MW of NPEI's forecast load at Beamsville TS to Niagara West MTS. Beyond this amount, the Niagara West MTS station capacity need would arise sooner than already forecast. There is also some remaining capacity (approximately 4 MW) expected at Vineland DS.

[12] All cost estimates, unless otherwise specified, are net present values based on a levelized cash flow analysis rather than capital costs – see Appendix F. In this case, a capital cost estimate of $19M (+/-15%) was provided for Option 2 and $25M - $40M for Option 3.

### 7.3.2 Non-Wires Options

As explained in Section 7.2.1.1, non-wires options were screened in for additional evaluation for the Beamsville TS and Vineland DS needs.

For Beamsville TS, a number of measures were assessed – such as combinations of incremental targeted CDM with battery storage or gas generation.[13] The most cost-effective non-wires solution portfolio included incremental CDM (approximately 6 MW of additional savings by 2041), plus battery storage assumed to be installed in two phases (2025 and 2038) to match the need profile.[14] For Vineland DS, the incremental CDM potential was also calculated: approximately 2 MW of additional demand savings by 2041.

The net present value ("NPV") of the portfolio of non-wires options for both Beamsville TS and Vineland TS was calculated to be $30M - $57M. The lower cost assumed that the incremental CDM is already system cost-effective based on provincial resource adequacy, whereas the higher cost assumed that the demand savings targeted to these stations would be incremental to the provincial CDM framework. More details on the CDM potential methodology and results are provided in Appendix E.

### 7.3.3 Recommendation

During the development of the IRRP, the forecasts at Beamsville TS and Niagara West MTS were updated by the impacted LDCs as growth trended higher and new potential customers were identified. By the conclusion of the IRRP, this reinforced the preference for the integrated wires options due to their cost-effectiveness and ability to address the capacity needs at all three stations.

The original scope of the non-wires options that were developed only addressed the Beamsville TS and Vineland DS needs, but were collectively $13M – $40M more expensive than the least expensive wires option. The increased forecast for Niagara West MTS did not impact the wires option of a new 230 kV station in the area – it only increased its cost-effectiveness. Another portfolio of non-wires options sized for Niagara West MTS' final reference forecast capacity need would have increased the non-wires costs further. Reallocating the load forecast on the 115 kV stations to 230 kV supply also helps alleviate the broader Niagara 115 kV sub-system capacity need.

Therefore, due to the cost-effectiveness and ability to meet the multiple needs, the Technical Working Group recommends near-term load transfers to offload Beamsville TS, plus a new 230 kV station supplied from Q23BM and Q25BM. This could be accomplished by expanding the existing Niagara West MTS. The station should be in-service as soon as possible and accommodate at least 57 MW of pre-contingency load in the area by 2041.

It is recommended that after the IRRP, the impacted LDCs coordinate the magnitude and timing of load transfers between the three stations to manage and monitor the Beamsville TS capacity need until the new station is in-service. Moreover, the LDCs and Hydro One should coordinate during the RIP to establish the lead implementer of the new station. Timing, siting, and size of the new

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[13] Based on the unserved energy profile forecast at Beamsville TS, the gas generator option was assumed to be a simple cycle gas turbine facility.

[14] This included an 18 MW, 144 MWh battery storage facility. The Beamsville TS forecast was updated and increased near the end of the IRRP forecast; cost range estimate would only increase with larger battery storage.

transformers should be factored into the decision – in addition to a comprehensive economic comparison that accounts for both the cost of the transformer station and the distribution-level costs that could incur if the station is sited farther west and away from the service territories that are expected to grow.

## 7.4 Options and Recommendations for Meeting the Crowland TS, Load Security, and Niagara 115 kV Sub-System Needs

The Crowland station capacity and asset replacement needs, as well as the A6C/A7C load security and Niagara 115 kV sub-system capacity needs, share common transmission elements and impact each other. As such, both wires and non-wires options were developed to address these four needs in an integrated fashion.

### 7.4.1 Transmission Options

Two sets of transmission options were identified – one that largely involves the continued buildout of the 115 kV system in the Niagara Region, and another that expands the 230 kV supply.

Option Set 1 includes:

- New 115 kV station in Welland, supplied by the existing A6C/A7C circuits (to address the Crowland TS capacity need);
- New 230 kV Allanburg bus (to improve supply to the 115 kV sub-system and mitigate the A6C/A7C load security need); and
- Re-building of 115 kV Crowland TS like-for-like (to address the asset replacement need).

Option Set 2 includes:

- Replacement of sections of 115 kV D3A/A3C circuits with approximately 18 km of new 230 kV double-circuit supply lines tapping off Q24HM and Q29HM; and
- The replacement of Crowland TS with a 230 kV station (to address its asset replacement and capacity needs, offload the Niagara 115 kV sub-system, and mitigate the A6C/A7C load security need).

In terms of preliminary capital costs, Option Set 1 was estimated to be approximately $253M - $353M[15] in total, whereas Option Set 2 may cost $128M.[16] Option Set 1 will require a minimum of three years; Option Set 2 will need six years.

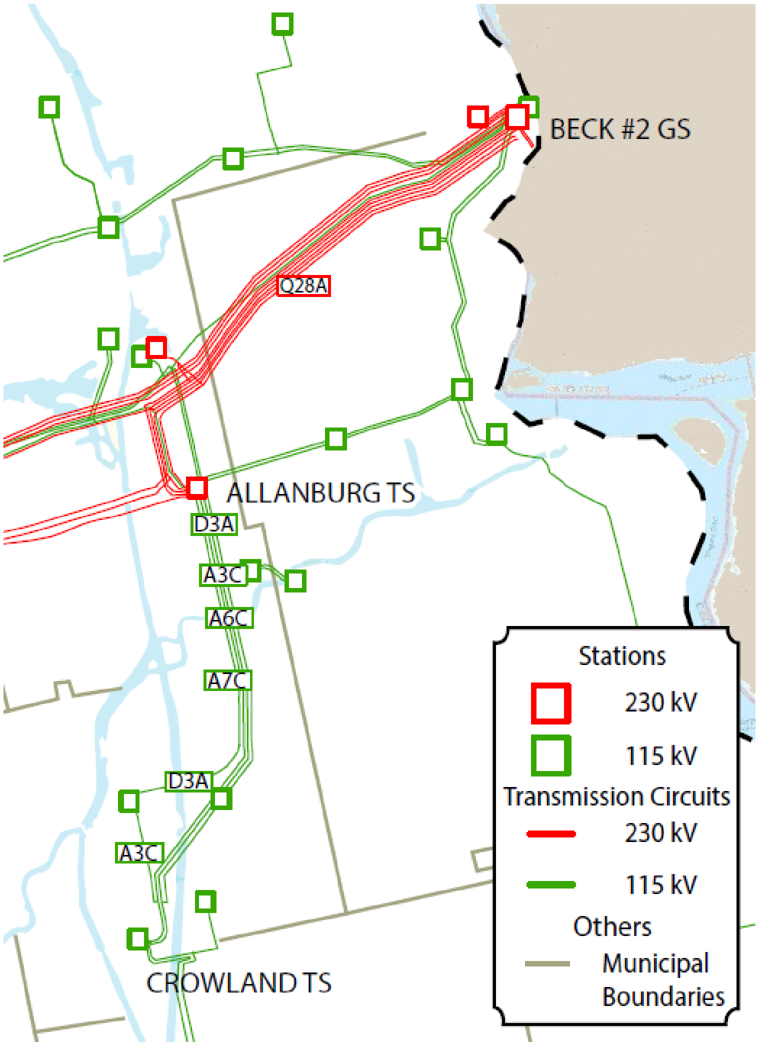
[15] The high end of the cost estimate range for Option Set 1 includes the potential for new 115 kV circuits and other reinforcements if the existing A6C/A7C circuits cannot accommodate the new 115 kV station in Welland.

[16] Capital cost estimates provided by Hydro One during the IRRP were prepared based on preliminary information and intended to provide a ballpark figure to be used strictly for initial options comparison. No engineering or field work was completed as part of the development of these cost allowances and as such, these cost allowances provide no cost guarantee or accuracy range. Costs allocations were derived from previous historical costs/unit costs and were to be used strictly for options comparison; Hydro One may refine and update cost estimates as part of the RIP.

To accommodate the planning forecast, the uprating of an existing 230 kV circuit, Q28A, is also required in addition to either Option Set. The cost and feasibility of this reinforcement is currently being assessed by Hydro One and is estimated to require until at least 2024 to be in-service.

The components of these Option Sets are identified conceptually on the map of Niagara Region's existing transmission system in Figure 22.

**Figure 22 | Impacted Areas by the Transmission Options**




Under some of the contingencies and conditions expected to limit the 115 kV sub-system LMC, operational measures such as load rejection are permissible according to ORTAC. Therefore, the benefit of a new load rejection scheme was also factored in when assessing the supply capability with each of the wires options described above. It was assumed that this scheme, developed and implemented by Hydro One for the Niagara 115 kV sub-system, could be installed in 2024 or later.[17]

[17] The ultimate in-service date will depend on the complexity of the scheme's design and NPCC approval timelines.

### 7.4.2 Non-Wires Options

As explained in Section 7.2.1.2 and 7.2.1.4, non-wires options were screened in for additional evaluation for the Crowland TS and 115 kV sub-system supply needs.

For the Crowland TS capacity need alone, incremental targeted CDM, battery storage, and gas generation were all considered either as standalone or integrated options.[18] The most cost-effective non-wires solution portfolio for the Crowland capacity need included incremental CDM (approximately 10 MW of additional savings by 2041), plus a 10 MW/40 MWh battery storage facility installed in two phases (2025 and 2038) to match the need profile. The NPV of this portfolio was calculated to be in the range of $17M - $53M. Similar to what was described for the Beamsville TS non-wires options, this cost range is attributed to the provincial CDM assumptions.[19]

As the Niagara IRRP progressed and the interplay between the Crowland TS needs and the broader Niagara 115 kV supply capability became clearer, a non-wires option was also considered at a high level. An all-generation, 240 MW alternative was sized to compare to the lowest cost transmission option set; 240 MW is the expected increase in the 115 kV sub-system supply capability enabled by Option Set 2 described previously. However, this non-wires option is not a feasible solution due to various factors. While an all-generation option was identified to compare to the wires option on a MW basis, there are significant challenges to implementing and operating a resource to address the multiple, layered, and local needs. For instance, for 240 MW of generation to address both the Crowland TS capacity and replacement needs, as well as the broader 115 kV supply needs, a portion of the generation must be sited on the distribution system to supply customers currently served by Crowland TS and the remaining must be targeted to the region's 115 kV system. There may also be thermal or short circuit limitations to connecting this amount of generation on the distribution system. Moreover, as described in Section 7.2.3, generation is typically not considered a feasible option to solve load security needs.

### 7.4.3 Recommendation

When comparing the two wires option sets, Option Set 2 is preferred for a number of reasons. It is the more cost-effective option, evaluated at more than $100M less expensive than Option Set 1 (based on capital cost estimates), even though both offer similar 115 kV sub-system supply capability and are sufficient according to the reference planning forecast. Qualitatively, by expanding the 230 kV transmission system, Option Set 2 also offers long-term flexibility to accommodate more load growth in the southern portion of the Niagara Region – particularly along the industrial and commercial hub around the Welland Canal. Option Set 1 provides limited growth options in the area in comparison to Option Set 2, without extensive station expansion at Allanburg TS. Meanwhile, converting the existing 115 kV Crowland TS to 230 kV in Option Set 2 allows the other 115 kV stations in the Niagara Region to accommodate new growth and maximizes the use of existing infrastructure with the available capacity normally utilized by the 115 kV Crowland TS. Triggering the

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[18] Based on the unserved energy profile forecast at Crowland TS, the gas generator option was assumed to be a simple cycle gas turbine facility.

[19] Another sensitivity was conducted for the battery storage sizing, resulting in a higher cost range of $25M - $61M. See Appendix D.3 for more details.

reconfiguration is also a time-sensitive opportunity, since Crowland TS is expected to require asset replacement in the near term.[20]

Long-term flexibility can also be considered by comparing the options and their ability to accommodate the high IRRP forecast scenario. According to the reference forecast, approximately 200 MW of extra 115 kV supply capability is required by 2041. As shown in Section 6.3, the high scenario increased this requirement to 340 MW. Both Option Sets 1 and 2 enable the increased capability required for the reference forecast, and neither Option Set precludes a further wires or non-wires option in the long-term. These future actions can include new generation resources or additional 230/115 kV auto-transformation. In contrast, a non-wires option sized precisely to meet the reference need would have less flexibility to accommodate growth that exceeds today's expectations.

Regardless, none of the non-wires options described in Section 7.4.2 can sufficiently address the multiple needs at once. Wires Option Set 2 would cost-effectively resolve the Crowland capacity and replacement needs, the A6C/A7C security issue, and enable other load growth on the 115 kV sub-system. For these reasons, the Technical Working Group recommends the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM/Q29HM, as well as the uprating of Q28A. A new load rejection scheme should also be developed to manage the Niagara 115 kV sub-system need. The load forecast should be monitored between regional planning cycles, and there are benefits to targeting incremental CDM to the 115 kV sub-system in order to manage load growth beyond the reference scenario. The technical feasibility and costs of the wires recommendations should be further analyzed in the RIP; the IESO will continue to participate in the RIP Working Group to provide advice and input on this matter.

## 7.5 Summary of Recommended Actions and Next Steps

The Technical Working Group recommends the actions summarized in Table 5 to meet identified needs in the Niagara IRRP.

**Table 5 | Summary of Needs and Recommended Actions**

| Need(s) | Lead Responsibility | Technical Working Group Recommendation | Expected In-Service Date |
|---|---|---|---|
| • Beamsville TS station capacity | • Grimsby Power<br>• NPEI<br>• Hydro One Distribution | • Coordinate load transfers to offload Beamsville TS to Niagara West MTS in the near-term | • 2023 |

[20] All final cost estimates have accounted for the asset replacement value for Crowland TS.

| Need(s) | Lead Responsibility | Technical Working Group Recommendation | Expected In-Service Date |
|---|---|---|---|
| • Beamsville TS, Niagara West MTS, and Vineland DS station capacity<br>• Niagara 115 kV sub-system supply capacity | • Grimsby Power<br>• NPEI<br>• Hydro One Distribution<br>• Hydro One Transmission | • Initiate development for a new 230 kV station supplied from Q23BM and Q25BM, or an expansion of Niagara West MTS | • 2026-2027 |
| • Beamsville TS, Niagara West MTS, and Vineland DS station capacity | • Grimsby Power<br>• NPEI<br>• Hydro One Distribution | • Monitor load growth between regional planning cycles | • Ongoing |
| • Beamsville TS and Vineland DS station capacity | • Technical Working Group | • Investigate opportunities to target incremental CDM to Beamsville TS and Vineland DS | • Ongoing |
| • Crowland TS station capacity and asset replacement<br>• A6C/A7C load security<br>• Niagara 115 kV sub-system supply capacity | • Hydro One Transmission | • Initiate development for the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM and Q29HM | • 2028 |
| • Niagara 115 kV sub-system supply capacity | • Hydro One Transmission | • Develop and implement a new 115 kV sub-system load rejection scheme | • 2024 |
| • Niagara 115 kV sub-system supply capacity | • Hydro One Transmission | • Uprate Q28A | • 2024 |
| • Niagara 115 kV sub-system supply capacity | • Technical Working Group | • Monitor load growth between regional planning cycles | • Ongoing |

| Need(s) | Lead Responsibility | Technical Working Group Recommendation | Expected In-Service Date |
|---|---|---|---|
| • Niagara 115 kV sub-system supply capacity | • Technical Working Group | • Investigate opportunities to target incremental CDM to the 115 kV sub-system | • Ongoing |
| • Murray TS (T11/T12) station capacity | • NPEI<br>• Hydro One Transmission | • Transfer load in excess of the station limit to Murray TS T13/T14 | • 2023 |
| • Carlton TS station capacity | • Alectra | • Monitor load growth between regional planning cycles<br>• Transfer load in excess of the station limit to Bunting TS | • 2028 |
| • Kalar MTS station capacity | • NPEI | • Monitor load growth between regional planning cycles and consider future opportunities for incremental CDM | • 2030 |

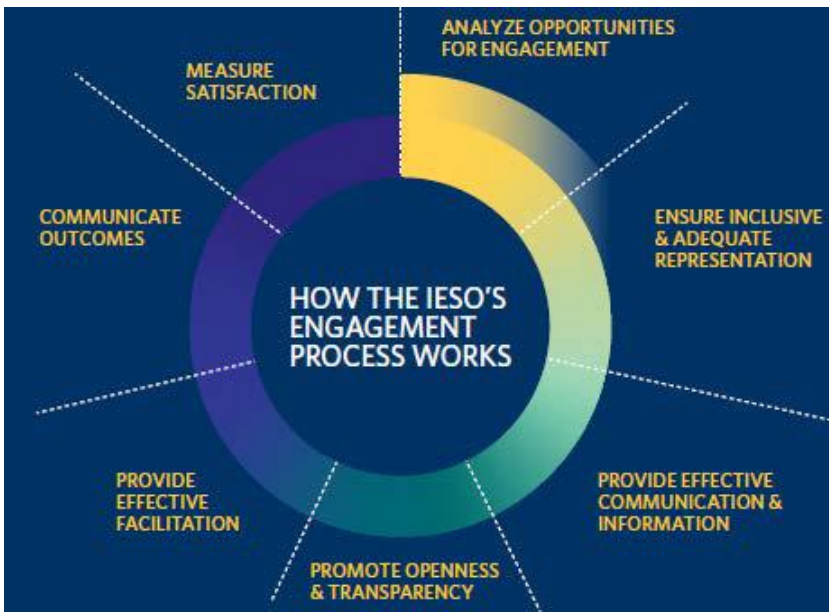
# 8. Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Niagara IRRP.

## 8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect, and fairness in its engagements, striving to build trusting relationships as a result.

**Figure 23 | The IESO's Engagement Principles**




## 8.2 Creating an Engagement Approach for Niagara Region

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

Creating the engagement plan for this IRRP involved:

- Targeted discussions to help inform the engagement approach for this planning cycle;
- Communications and other engagement tactics to enable a broad participation, using multiple channels to reach audiences; and

- Identifying specific stakeholders and communities who may have a direct impact in this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars; and
- Targeted one-on-one outreach with specific communities and stakeholders to ensure that their identified needs are addressed (see Section 8.4).

## 8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this second round of planning, and to establish new relationships and dialogue in this region where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report for the Niagara Region. An invitation was sent 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 Niagara Region Scoping Assessment Report finalization. A public webinar was held in August 2021 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach. The final Scoping Assessment was posted later in August 2021, identifying the need for a coordinated regional planning approach and an IRRP.

Following finalizing the Scoping Assessment, targeted outreach then began with municipalities in the region to inform early discussions for development of the IRRP, including the IESO's approach to engagement. The launch of a broader engagement initiative followed, with an invitation to IESO subscribers of the Niagara Region to ensure that all interested parties were made aware of this opportunity for input. Three 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 over a 21-day comment period after each webinar.

The three stages of engagement at which input was invited:

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

Comments received during this engagement were primarily focused on:

- Ensuring key areas of growth in specific pockets in the Niagara Region (including the City of Niagara Falls and Town of Fort Erie), have been considered and accounted for in the IRRP work;
- Ensuring there are procedures to alter the implementation of plan recommendations should changes occur in the region; and
- Keeping lines of communication following the plan completion to share information and updates.

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.

All interested parties were kept informed throughout this engagement initiative via email to Niagara Region subscribers, municipalities, and Indigenous and Métis communities.

Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP and recommended actions aligned with strong forecast growth and development both within specific municipalities and the region more broadly (e.g. future urban expansion and employment areas as outlined in the updated Niagara Region Official Plan). This insight has been valuable to the IESO – it 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. To that end, ongoing discussions will continue through the IESO's Southwest Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and initiatives to prepare for the next planning cycle.

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

## 8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their 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 the upper- and lower-tier municipalities in the region to discuss key issues of concern, including forecast regional electricity needs, options for meeting the region's future needs, and broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities, establish new relationships, and provided opportunities for ongoing dialogue beyond this IRRP process.

Through these discussions valuable feedback was received around strong anticipated growth in major growth centres in the region:

- Strong population growth across the Niagara Region based on 2051 growth projections and in some areas above and beyond the regional forecast (i.e. even higher growth expected in the City of Welland);
- Notable growth in the Town of Lincoln (greenhouses, Secondary Plan areas, potential GO Transit development), along the QEW corridor in Grimsby, and in Thorold;

- Strong economic development around the Welland Canal (e.g. Thorold Multimodal Hub "Niagara Ports");
- Key areas of growth in the City of Niagara Falls within intensification nodes and corridors, projects around the GO Transit Station and the new Niagara South Hospital, wastewater treatment plant, and residential new construction;
- Industrial, commercial, institutional, and residential development in the Town of Fort Erie and Secondary Plan areas; and
- Potential urban boundary expansion in the region totaling 130 hectares of residential and 150 hectares of employment lands.

## 8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Niagara Region throughout the development of the plan. This includes the communities of the Mississaugas of the New Credit, Oneida Nation of the Thames and Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council) and Métis Nation of Ontario Niagara Region Métis Council.

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions all across Ontario.

# 9. Conclusion

The Niagara IRRP identifies electricity needs in the region over the 20-year period from 2022 to 2041, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. The IESO will continue to participate in the Technical Working Group during the next phase of regional planning, the RIP, to provide input and ensure a coordinated approach.

In the near term, the IRRP recommends load transfers off Beamsville TS and a new or expanded 230 kV station supplied by Q23BM and Q25BM. The IRRP also recommends the implementation of control actions on the Niagara 115 kV sub-system to manage overloads during outage conditions, plus the replacement of Crowland TS with a new 230 kV station supplied by new 230 kV lines from Q24HM and Q29HM. Q28A should be uprated, and a portion of the load at Murray TS (T11/T12) should be transferred to Murray TS (T13/T14). Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

In the long term, the IRRP recommends that the Technical Working Group monitor growth in the Niagara 115 kV sub-system, Carlton TS, and Kalar MTS to determine if or when further reinforcements will be needed. This includes monitoring any future community energy planning or electrification trends. Additionally, there are benefits to investigating opportunities to target incremental CDM to the region – particularly to the Beamsville TS/Vineland DS/Niagara West MTS areas and 115 kV sub-system in the near-term, and Kalar MTS in the long-term.

The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that 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.