Renfrew Region

Integrated Regional Resource Plan (IRRP) Appendices

December 22, 2022

Connecting Today.
Powering Tomorrow.

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Appendix A - Methodology and Assumptions for Demand Forecast

The sections that follow describe the IESO’s methodology to adjust the forecast for normal & extreme weather, LDC methodologies to forecast demand in their respective service area, and the energy efficiency assumptions used to modify the demand forecast based on expected energy efficiency savings. Appendix A concludes with tabulations of all of the relevant data pertaining to the peak load forecasts that were developed for the purposes of this IRRP.

A.1 Method for Accounting for Weather Impact on Demand

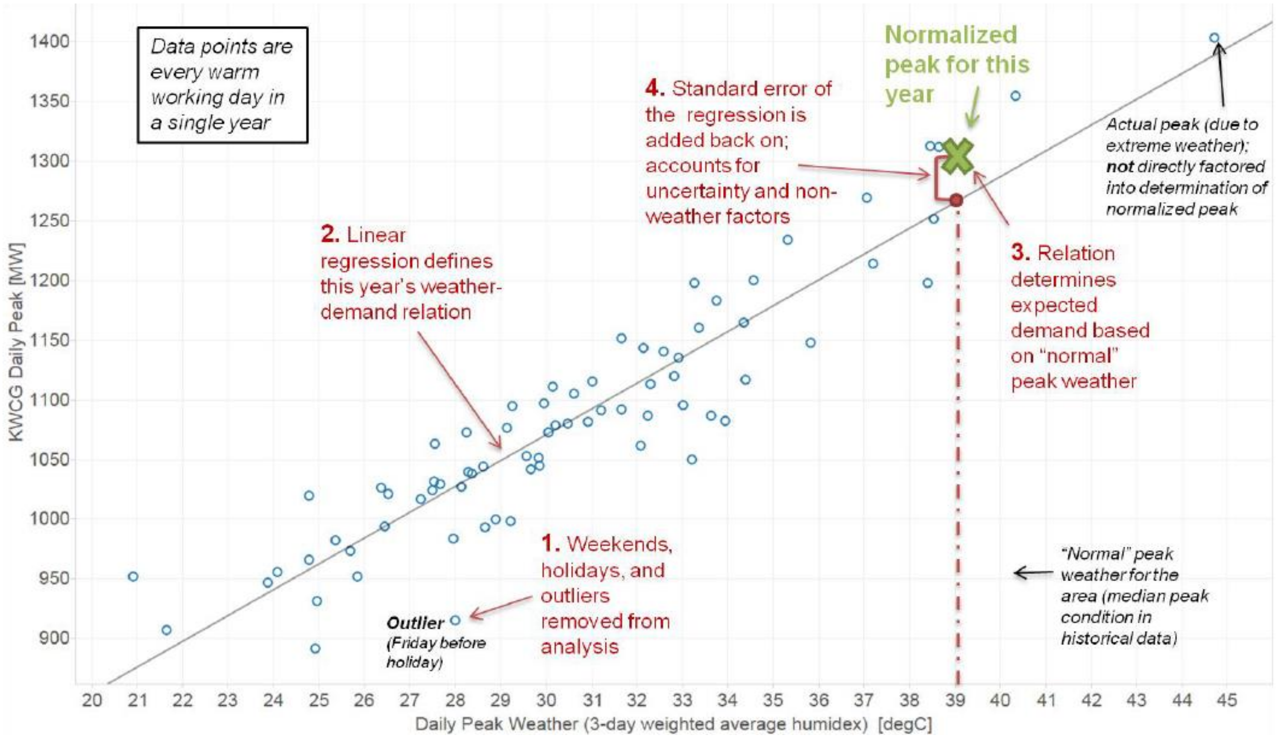
Weather has a large influence on the demand for electricity, so to develop a standardized starting point for the forecast, the historic electricity demand information is weather-normalized. This section details the weather-normalization process used to establish the starting point for regional demand forecasts.

First, the historical loads were adjusted to reflect the median peak weather conditions for each transformer station in the area for the forecast base year (in this case 2020). Median peak refers to what peak demand would be expected if the most likely, or 50th percentile, weather conditions were observed. This means that in any given year there is an estimated 50% chance of exceeding this peak, and a 50% chance of not meeting this peak. The methodological steps are described in Figure 1.

The 2020 median weather peak on a station and local distribution company (LDC) load basis was provided to each LDC. This data was used as a starting point from which to develop 20-year demand forecasts, using the LDCs forecasting methodology of choice (described in the proceeding sections).

Once the 20-year horizon, median peak demand forecasts were returned to the IESO, the normal weather forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand. Subsequently, the impacts of estimated Conservation and Demand Management (CDM) savings and Distributed Generation (DG) output were netted out of the forecast to create the final planning forecast. The studies used to assess the adequacy and reliability of the electric power system generally require studies to be based on extreme weather demand, or, expected demand under the hottest weather conditions that can be reasonably expected to occur. Peaks that occur during extreme weather (e.g. summer heat waves) are generally when the electricity system infrastructure is most stressed.

Figure 1 | Method for Determining the Weather-Normalized Peak



A.2 Hydro One Forecast Methodology

Hydro One Distribution provides service to counties and townships in the study area. Hydro One Distribution developed the forecast for all stations in the study area except for Pembroke TS which was jointly developed with the embedded LDC Ottawa River Power Corp. (ORPC). For the list of all stations in the study area and associated gross forecasts please see Tables A-7 and A-8 below.

There are about 64,000 Hydro One Distribution retail customers directly connected to Hydro One's distribution system in the Renfrew region. There is also the embedded LDC ORPC connected to Hydro One's distribution system.

A.2.1. Factors that Affect Electricity Demand

Hydro One Distribution services the areas in the Renfrew region that are not served by other LDCs through the stations included in the study area. The demand growth in the Hydro One Distribution service area is largely driven by the economic activities in the province and in the nearby large communities and is expected to be modest as the population moves from the urban centers to the rural areas.

A.2.2. Forecast Methodology and Assumptions

The reference level forecast is developed using both the econometric and end-use forecasting methods, which consider the growth of demographic and economic factors. The forecast corresponds to the expected weather impact on peak load under average weather conditions, known as weather normality. Furthermore, the forecast is unbiased such that there is an equal chance of the actual peak load being above or below the forecast. Assumptions included in the growth rate can be related to such factors as: Ontario GDP growth rate, housing statistics, the intensification of urban developments (i.e., MW/sq. ft); and the need for large scale electrification projects. In addition, local knowledge, information regarding the loading in the area within the next two to three years, is utilized to make minor adjustments to the forecast.

Hydro One Distribution conducts distribution area studies to examine the adequacy of the existing local supply network in the next 10 to 15 years and determine when new stations need to be built. These studies are performed on a need basis, such as:

- Load approaching the planned capacity
- Issues identified by the field and customer
- Issues discovered during our 6-year cycle studies
- Additional supply required for large-step load connections
- Poor asset condition

A.3 Ottawa River Power Corp. Forecast Methodology

Ottawa River Power provides hydro service to the City of Pembroke; serving approximately 7,500 customers of different classes (residential, commercial and industrial).

Ottawa River Power has a total of 7 municipal substations in Pembroke that are supplied from the Hydro One station (Pembroke TS) through two, 44kV sub-transmission feeders (M1 & M2). To facilitate the electricity distribution to our Pembroke customers, this sub-transmission voltage is stepped down to 4.16kV and 12.47k voltage levels at the 7 municipal substations.

A.3.1. Factors that Affect Electricity Demand

Ottawa River Power experiences a marginal system peak load during the winter months in comparison to the summer months. The residential customers in Pembroke are the main drivers for energy consumption (accounting for approximately 80% of the total peak load). Pembroke experiences an average 1% load increase annually. This is mainly due to the residential load growth (e.g., infill projects, service upgrades, EV charging stations, etc.).

Ottawa River Power has seen an increased trend of EV adoption among its customers in the last few years. It is expected that the EV adoption will continue in the same trend until 2030. It is anticipated that there will be a higher increase of EV adoption during the years (2031 to 2035) to meet the mandatory target set by the Government of Canada; having all new light-duty cars and passenger trucks to be zero-emission by 2035. Hence, Ottawa River Power forecasts an additional 0.5% load increase annually between 2031 to 2035. This percentage will increase even higher to 1% annually from 2036 to 2042.

A.3.2. Forecast Methodology and Assumptions

As per section A.1.1, the 1% annual load increase, along with the 0.5% and 1% for the EV charging stations, is included as part of the forecast.

In addition, the forecast considers data gathering from the Pembroke municipality and developers regarding future developments projects, their nature (residential, commercial, industrial), as well as project phases and timings. The loading of each new project is then estimated, based on similar existing load using their respective historical load data.

Currently, 3 new residential subdivisions with a total load of 2.4MW are expected to be developed in the Pembroke area as per the following assumption:

- Subdivision project #1: The total expected homes to be constructed is 600 homes between 2023-2033.
- Subdivision project #2: The total expected homes to be constructed is 140 homes between 2023-2029.
- Subdivision project #3: The total expected homes to be constructed is 46 homes between 2023-2024.

A.4 Energy Efficiency and Distributed Generation Assumptions in Demand Forecast

Conservation and Demand Management (CDM) measures can reduce the electricity demand and its impact can be separated into the two main categories: Building Codes and Equipment Standards, and Energy Efficiency programs. The assumptions used for the Renfrew IRRP forecast are consistent with the CDM assumptions in the IESO's 2021 Annual Planning Outlook, which was the latest provincial planning product when this IRRP was developed, the savings for each category were estimated according to the forecasted residential, commercial, and industrial gross demand. A top down approach was used to estimate peak demand savings from provincial level to the East and Essa transmission zones and then allocated to the Renfrew region. This section of the appendix describes the process and methodology used to estimate CDM savings for the Renfrew region and provides more detail on how the estimated savings were developed.

Energy efficiency (EE) is a low cost resource that offers significant benefits to individuals, businesses and the electricity system as a whole. Targeting energy efficiency in areas of the province with regional and local needs can help offset investments in new power plants and transmission lines, defer this spending to a later date and/or can compliment these investments as part of an integrated solution for the area.

To understand the scale of opportunity and associated costs for targeting energy efficiency in a local area, data and assumptions can be leveraged from provincial energy efficiency potential forecasts. In 2019, the IESO and the Ontario Energy Board completed the first integrated electricity and natural gas achievable potential study in Ontario (2019 APS). The main objective of the APS was to identify and quantify energy savings (electricity and natural gas) potential, GHG emission reductions and associated costs from demand side resources for the period from 2019-2038 under different scenarios. his achievable potential modeling is used to inform:

- future energy efficiency policy and/or frameworks;
- program design and implementation; and
- assessments of Conservation and Demand Management (CDM) non-wires potential in regional planning.
- The 2019 APS determined that both electricity and natural gas have significant cost-effective energy efficiency potential in the near and longer terms. In particular, the maximum achievable potential scenario is one scenario in the APS that estimates the available potential from all CDM measures that are cost effective from the provincial system perspective – i.e., they produce benefits from avoided energy and system capacity costs that are greater than the incremental costs of the measures. Under this scenario, the study shows that CDM measures have the potential to reduce summer electricity peak demand by up to 3,000 MW in the province over the 20-year forecast period and can produce up to 24 TWh of energy savings over the same period.

After scaling this level of forecasted maximum achievable savings potential to the local area, the committed savings that are expected to come from existing provincial and federal CDM programs as well as from codes and standards have been netted out and the remaining uncommitted achievable savings potential is presented in Tables A-9, A-10, and A-11.

A.4.1. Estimate Savings from Conservation and Demand Management Measures

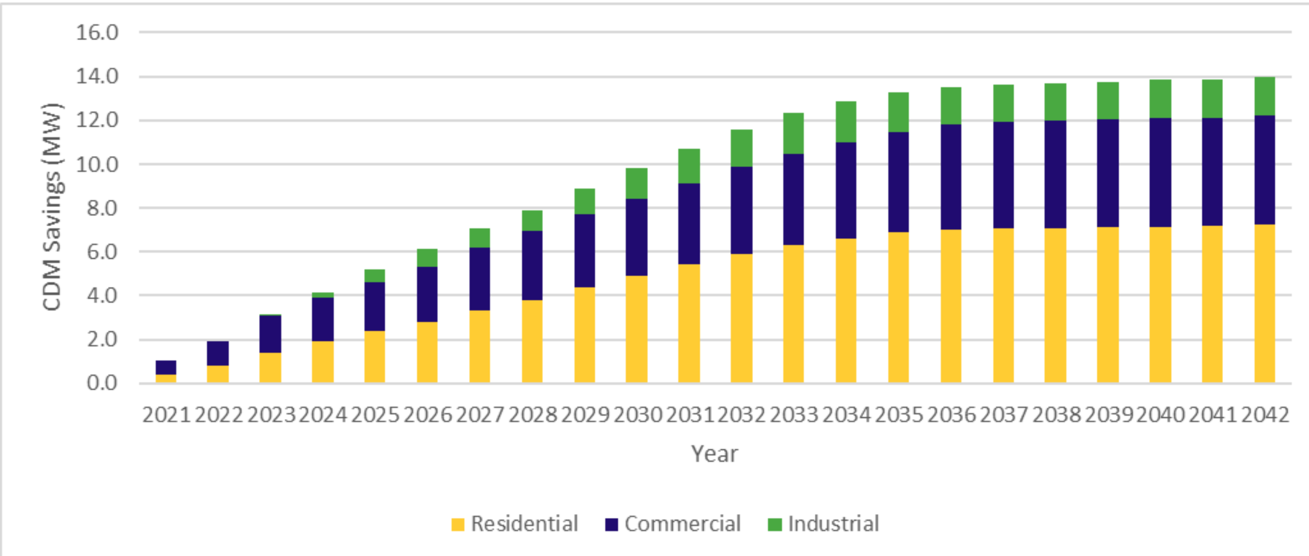
Ontario building codes and equipment standards set minimum efficiency levels through regulations and are projected to improve and further contribute to demand reduction in the future. To estimate the impact on the region, the associated peak demand savings for codes and standards by sector were estimated for the East and Essa zones and compared with the gross peak demand forecast for the zone. From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each station in the region.

In addition to codes and standards, the delivery of energy efficiency programs reduces electricity demand. The impact of existing and committed energy efficiency programs were analyzed, which include the 2021 – 2024 CDM Framework and other provincial and federal EE programs. A top down approach was used to estimate the peak demand reduction due to the delivery of EE programs, from provincial to East and Essa zones to the stations in the region. Persistence of the peak demand savings from energy efficiency programs was also considered over the forecast period.

Consistent with the gross demand forecast, 2020 was used as the base year. New peak demand savings from codes and standards were estimated from 2021 to 2042. The sectoral annual peak reduction percentages of each year were applied to the segmented demand that was forecasted at each station in order to develop an estimate of the peak demand impacts from codes and standards as well as energy efficiency. The forecasted CDM savings will decay over time as the energy efficiency measures come to the end of their effective useful lives. By 2042, the residential, commercial and industrial sectors in the region will be expected to see peak demand savings of about 9.3%, 14.1% and 2.9%, respectively for Essa zone and 9.5%, 14.6% and 2.8% for East zone.

Figure 2 shows the yearly estimate of the reduction to the demand forecast due to conservation for each of the residential, commercial and industrial consumers

Figure 2 | Reduction to Summer Demand Forecast due to Conservation



A.4.2. Distributed Generation

In the process of adjusting the gross demand forecast (as described in Section 5.1) to produce the net forecast, projected load is decremented by the expected output of the distributed generation at each station. This considers the typical peak effective contribution of the relevant generation technology.

The Renfrew region has a very small amount of installed DG and only the distribution stations Deep River, Des Joachims, Cobden, and Pembroke have any generation. Additional information on the DG forecast can be found in Appendix A.5.

A.5 Demand Forecast Data Tables

A.5.1. Reference, Non-Coincident, Planning Forecast Data Tables

Table A-1 | Final Non-Coincident, Extreme Peak, Net, Summer Demand Forecast (MW) per Station

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Cobden DS	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8
Cobden TS	22	22	22	22	23	23	23	23	23	23	23	23	23	23	23	23	24	24	24	24	24	25
Craig DS	14	14	14	14	15	15	15	15	15	15	15	15	15	16	16	16	16	16	16	17	17	17
Deep River DS	8	8	8	8	8	9	9	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Des Joachims DS	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Forest Lea DS	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Mazinaw DS	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Mountain Chute DS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pembroke TS	47	48	48	49	49	50	50	51	51	52	52	53	53	54	55	56	57	57	58	59	60	61
Petawawa DS	13	13	13	13	14	14	15	15	15	17	17	17	17	17	17	17	17	17	17	18	18	18
Chalk River CTS	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8	8
Megellan CTS	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Total	138	139	139	140	141	143	144	146	147	150	150	151	152	153	154	156	157	159	161	162	164	166

Table A-2 | Final Non-Coincident, Extreme Peak, Net, Winter Demand Forecast (MW) per Station

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Cobden DS	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8
Cobden TS	24	25	25	25	25	25	25	25	25	25	25	26	26	26	26	26	26	27	27	27	27	28
Craig DS	12	12	12	12	12	13	13	13	13	13	13	13	13	13	14	14	14	14	14	14	15	15
Deep River DS	10	10	10	10	10	11	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Des Joachims DS	3	4	4	4	4	4	4	4	4	4	4	4	3	4	4	4	4	4	4	4	4	4
Forest Lea DS	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	12	12	12
Mazinaw DS	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
Mountain Chute DS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pembroke TS	52	53	53	54	54	54	55	55	56	56	57	57	58	58	59	60	61	62	63	64	65	66
Petawawa DS	11	11	11	11	12	12	12	13	13	16	17	17	17	17	17	17	17	17	17	17	17	17
Chalk River CTS	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10
Megellan CTS	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Total	148	149	150	151	153	154	155	159	159	163	163	164	165	166	168	170	171	173	175	177	179	181

A.5.2. Conservation and Demand Management (CDM) and Distributed Generation (DG) Forecast Data Tables

Table A-3 | CDM Contribution (MW) Considered in Non-Coincident, Extreme Peak, Net, Summer Demand Forecast

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Cobden DS	0.1	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Cobden TS	0.2	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	1.9	2.1	2.3	2.5	2.6	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Craig DS	0.1	0.3	0.4	0.5	0.6	0.7	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.8
Deep River DS	0.1	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.7	0.7	0.8	0.8	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Des Joachims DS	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Forest Lea DS	0.1	0.1	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.1
Mazinaw DS	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Mountain Chute DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Pembroke TS	0.1	0.3	0.4	0.7	1.0	1.3	1.5	1.7	1.9	2.3	2.5	2.7	2.9	3.0	3.0	3.1	3.1	3.1	3.1	3.2	3.2	3.2
Petawawa DS	0.3	0.5	0.7	0.9	1.0	1.1	1.3	1.4	1.5	1.6	1.7	1.8	1.9	1.9	2.0	2.1	2.1	2.1	2.1	2.2	2.1	2.1
Chalk River CTS	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Megellan CTS	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	1	2	3	4	5	6	7	8	9	10	11	12	12	13	13	14	14	14	14	14	14	14

Table A-4 | CDM Contribution (MW) Considered in Non-Coincident, Extreme Peak, Net, Winter Demand Forecast

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Cobden DS	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Cobden TS	0.1	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.1	1.3	1.4	1.6	1.7	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2.0
Craig DS	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0
Deep River DS	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Des Joachims DS	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Forest Lea DS	0.0	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
Mazinaw DS	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Mountain Chute DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Pembroke TS	0.1	0.1	0.2	0.5	0.8	1.0	1.2	1.3	1.6	1.9	2.1	2.3	2.5	2.6	2.6	2.5	2.6	2.6	2.6	2.5	2.5	2.5
Petawawa DS	0.1	0.2	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0
Chalk River CTS	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2
Megellan CTS	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	1	1	2	2	3	4	4	5	6	7	7	8	9	9	9	9	9	9	9	9	9	10

Table A-1 | DG Contribution (MW) Considered in Non-Coincident, Extreme Peak, Net, Summer Demand Forecast

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Cobden DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cobden TS	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Craig DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Deep River DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Des Joachims DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forest Lea DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mazinaw DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain Chute DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pembroke TS	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Petawawa DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Chalk River CTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Megellan CTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	**1.7**	**1.7**

Table A-6 | DG Contribution (MW) Considered in Non-Coincident, Extreme Peak, Net, Winter Demand Forecast

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Cobden DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cobden TS	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Craig DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Deep River DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Des Joachims DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forest Lea DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mazinaw DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain Chute DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pembroke TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Petawawa DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Chalk River CTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Megellan CTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

A.5.3. Reference, Coincident, LDC Provided Forecast Data Tables

Table A-7 | LDC Non-Coincident, Median Peak, Gross Summer Demand Forecast (MW) per Station

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Cobden DS	7	7	7	7	7	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	9
Cobden TS	24	24	24	25	25	25	25	26	26	26	26	27	27	27	27	27	28	28	28	28	29	29
Craig DS	14	14	14	15	15	15	15	15	16	16	16	16	17	17	17	17	17	18	18	18	18	18
Deep River DS	8	8	8	8	8	8	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Des Joachims DS	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Forest Lea DS	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Mazinaw DS	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Mountain Chute DS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pembroke TS	46	47	48	48	49	50	51	51	52	53	54	54	55	56	57	58	58	59	60	61	62	63
Petawawa DS	13	14	14	14	14	14	14	14	14	15	15	15	15	15	15	15	15	15	16	16	16	16
Chalk River CTS	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8	8	8	8
Megellan CTS	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Total	138	140	141	143	144	146	148	149	151	152	154	156	157	159	160	162	164	166	167	169	171	173

Table A-8 | LDC Non-Coincident, Median Peak, Gross Winter Demand Forecast (MW) per Station

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Cobden DS	6	6	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8
Cobden TS	25	25	25	25	25	26	26	26	26	27	27	27	27	28	28	28	28	29	29	29	29	29
Craig DS	11	11	12	12	12	12	12	12	13	13	13	13	13	13	14	14	14	14	14	14	15	15
Deep River DS	9	9	9	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	11	11
Des Joachims DS	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4	4	4
Forest Lea DS	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11	11	11	11	11	12	12	12
Mazinaw DS	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
Mountain Chute DS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pembroke TS	49	49	50	50	51	52	52	53	53	54	55	55	56	57	58	58	59	60	61	62	63	64
Petawawa DS	10	11	11	11	11	11	11	11	11	11	11	11	12	12	12	12	12	12	12	12	12	12
Chalk River CTS	8	8	8	8	8	8	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Megellan CTS	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Total	140	142	143	144	146	147	149	150	152	153	155	156	158	159	161	162	164	166	168	169	171	173

A.5.4. Max Uncommitted CDM Savings Per Station Data Tables

Table A-9 | Residential Uncommitted CDM Savings (MW) per Station

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Cobden DS	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
Cobden TS	0.1	0.2	0.3	0.4	0.5	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.6	1.7	1.9	1.9	1.9	1.9	2.0
Craig DS	0.0	0.1	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9	1.0	1.0	1.0	1.0
Deep River DS	0.0	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
Des Joachims DS	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2
Forest Lea DS	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8
Mazinaw DS	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Mountain Chute DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Pembroke TS	0.1	0.3	0.4	0.6	0.8	1.0	1.2	1.4	1.6	1.8	2.0	2.2	2.4	2.5	2.7	2.9	3.1	3.3	3.4	3.4	3.5	3.6
Petawawa DS	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4
Chalk River CTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Megellan CTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.3	0.8	1.3	1.9	2.5	3.1	3.6	4.2	4.7	5.2	5.7	6.1	6.6	7.0	7.4	7.8	8.3	9.0	9.1	9.2	9.4	9.5

Table A-10 | Commercial Uncommitted CDM Savings (MW) per Station

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Cobden DS	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Cobden TS	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Craig DS	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.6
Deep River DS	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Des Joachims DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Forest Lea DS	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Mazinaw DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Mountain Chute DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pembroke TS	0.0	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.1	1.2	1.3	1.4	1.4	1.5	1.6	1.6	1.7	1.7	1.7	1.8	1.8
Petawawa DS	0.0	0.1	0.2	0.3	0.5	0.6	0.8	0.9	1.0	1.2	1.3	1.4	1.5	1.5	1.6	1.6	1.7	1.8	1.8	1.8	1.8	1.9
Chalk River CTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Megellan CTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.3	0.6	1.0	1.5	2.0	2.4	2.8	3.2	3.6	3.9	4.1	4.3	4.6	4.7	4.8	5.0	5.2	5.3	5.4	5.5	5.6

Table A-11 | Industrial Uncommitted CDM Savings (MW) per Station

Station	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Cobden DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cobden TS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Craig DS	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Deep River DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Des Joachims DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Forest Lea DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mazinaw DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain Chute DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pembroke TS	0.1	0.2	0.3	0.2	0.1	0.1	0.1	0.3	0.2	0.1	0.2	0.2	0.2	0.2	0.4	0.5	0.6	0.7	0.7	0.7	0.7	0.7
Petawawa DS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Chalk River CTS	0.0	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6
Megellan CTS	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	0.1	0.3	0.5	0.5	0.4	0.4	0.6	0.8	0.8	0.7	0.8	0.9	0.9	1.0	1.3	1.5	1.6	1.7	1.7	1.7	1.8	1.8

Appendix B - Development of the Plan

B.1 The Regional Planning Process

In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. This comprehensive process starts with an assessment of the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in the development of a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as-needed basis in Ontario for many years. Most recently, planning activities to address regional electricity needs were the responsibility of the former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), which conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the OEB convened a Planning Process Working Group (PPWG) to develop a more structured, transparent, and systematic regional planning process. This group was composed of electricity agencies, utilities, and other stakeholders. In May 2013, the PPWG released its report to the OEB (PPWG Report), setting out the new regional planning process. Twenty-one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion of regional plans was outlined. The OEB endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, and to the former OPA's licence in October 2013. The licence changes required it to lead two out of four phases of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence became the responsibility of the IESO.

The regional planning process begins with a needs assessment process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO conducts a scoping assessment to determine what type of planning is required for a region. A scoping assessment explores the need for a comprehensive IRRP, which considers conservation, generation, transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option, in which case a transmission- and distribution-focused regional infrastructure plan (RIP) can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the scoping assessment, the IESO produces a report that includes the results of the needs assessment process and a preliminary terms of reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If a RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at a minimum of every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a public comment period prior to finalization.

The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs and RIPs are posted on the IESO's and the relevant transmitter's websites, and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, and for conservation and energy management purposes. They are also a useful source of information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning undertaken in Ontario. As shown in Figure | A-6 , three levels of electricity system planning are carried out in Ontario:

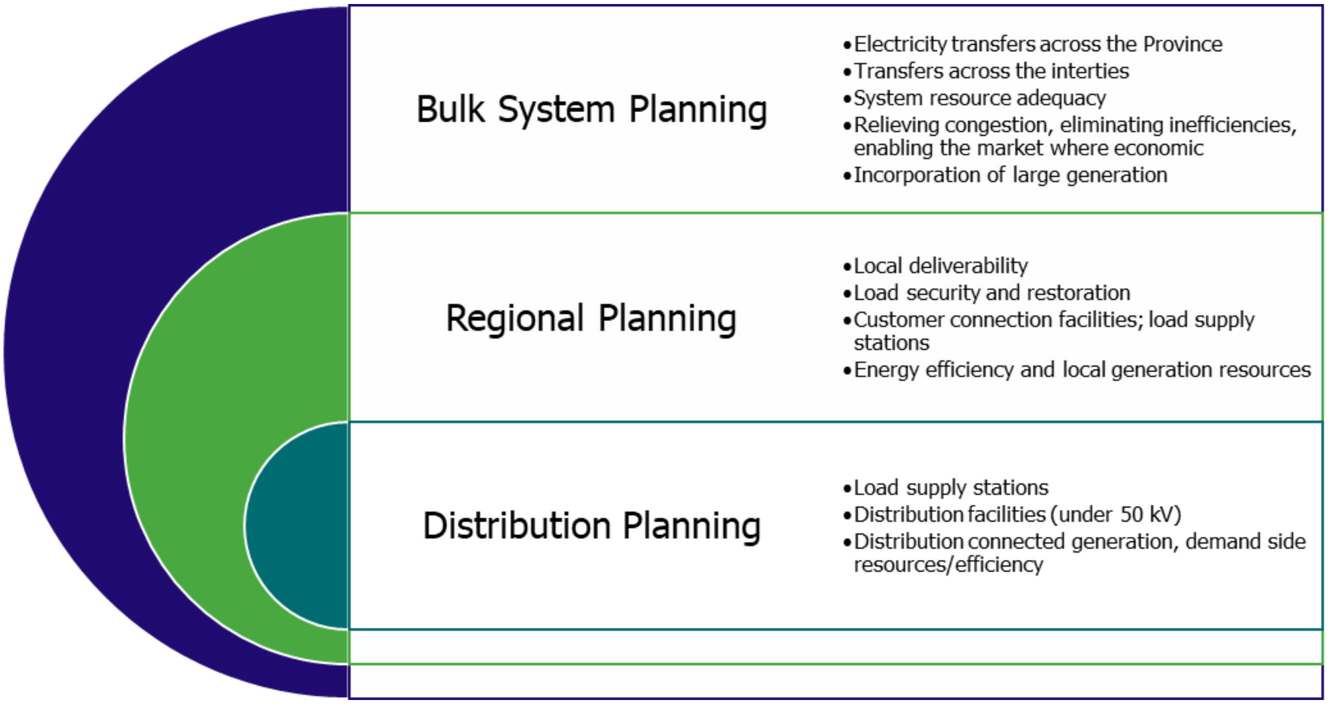
- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. In addition to considering major transmission facilities or "wires", bulk system planning assesses the resources needed to adequately supply the province. This type of planning is typically carried out by the IESO pursuant to government policy. Distribution planning, which is carried out by LDCs, considers specific investments in an LDC's territory at distribution-level voltages.

Regional planning can overlap with bulk system planning and with the distribution planning of LDCs. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue or when a distribution solution addresses the needs of the broader local area or region. As a result, it is important for regional planning to be coordinated with both bulk and distribution system planning, as it is the link between all levels of planning.

By recognizing the linkages with bulk and distribution system planning, and coordinating the multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan into perspective. Furthermore, in avoiding piecemeal planning and asset duplication, regional planning optimizes ratepayer interests, allowing them to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

Figure | A-6 | Levels of Electricity System Planning



B.2 IESO's Approach to Regional Planning

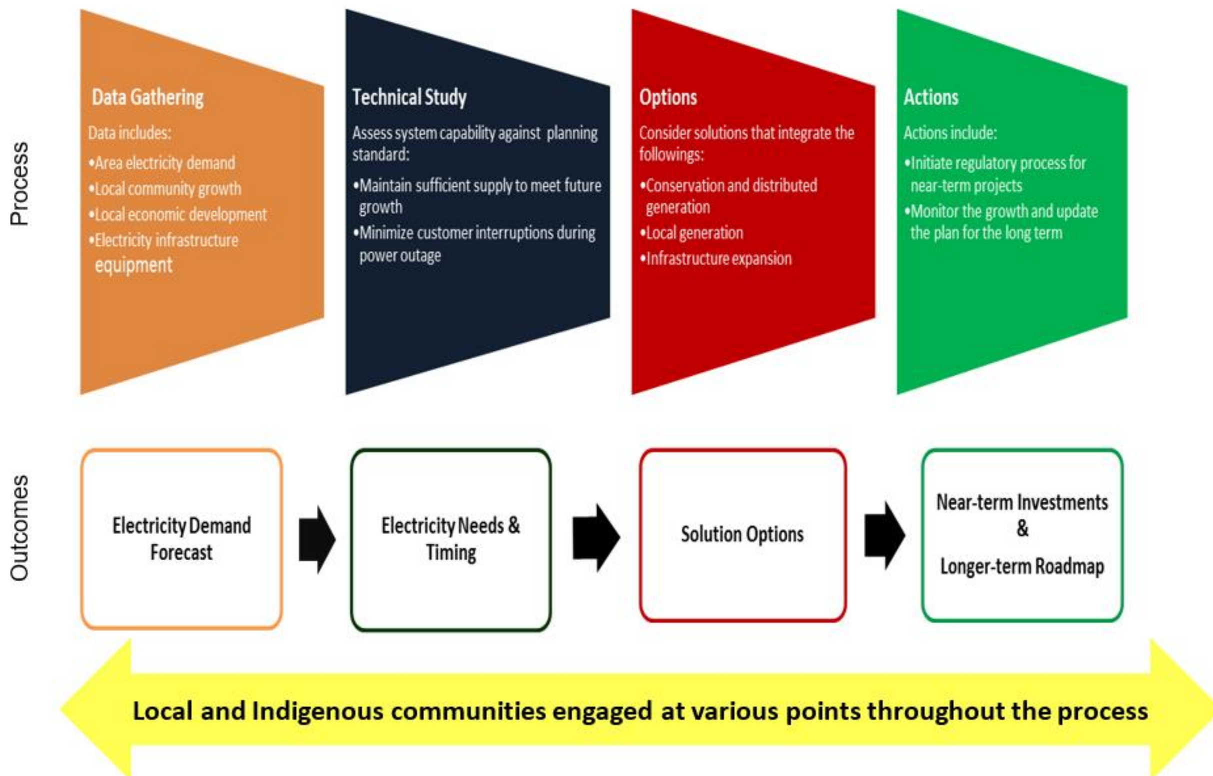
IRRPs assess electricity system needs for a region over a 20-year period, enabling near-term actions to be developed in the context of a longer-term view of trends. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

The IRRP describes the Working Group's recommendations for mitigating reliability and cost risks related to end-of-life asset replacement and demand forecast uncertainty associated with large load customers or due to any changes in the existing provincial conservation targets. The IRRP helps ensure that recommendations to address near-term needs are implemented, while maintaining the flexibility to accommodate changing long-term conditions.

In developing an IRRP, the IESO and the study team follow a process, with a clearly defined series of steps (see Figure | A-7). These includes developing electricity demand forecasts; conducting technical studies to determine electricity needs and the timing of these needs; considering potential options; and creating a plan with recommended actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and Indigenous communities who may have an interest in the area.

The IRRP report documents the inputs, findings and recommendations developed through this process, and outlines recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP triggers the initiation of the transmitter's RIP process to develop those options. Other recommendations in the IRRP may include: development of conservation, local generation, community engagement, or information gathering to support future iterations of the regional planning process in the region or sub-region.

Figure | A-7 | Steps in the IRRP Process



Appendix C - Economic Assumptions

The following is a list of the assumptions that is typically included in the IRRP appendix and/or summarized in stakeholder engagement materials:

- The NPV of the cash flows for the economic analysis is expressed in 2021 CAD.
- The USD/CAD exchange rate was assumed to be 0.76 for the study period.
- Natural gas price forecast is as per Sproule Outlook @ Dawn used in the 2021 Annual Planning Outlook (APO).
- The NPV analysis was conducted using a 4% real social discount rate. An annual inflation rate of 2% is assumed.
- The life of the station upgrades was assumed to be 45 years; and the life of the simple cycle gas turbine (SCGT) facility and storage assets was assumed to be 30 years and 15 years respectively. Cost of asset replacement were included where necessary to ensure the same NPV study period.
- Development timelines for transmission was assumed to be four years; development timelines for generation and storage were assumed to be three years.
- The size of the resource option was determined by a deterministic capacity assessment.
- A reciprocating gas engine was identified as one of the lowest-cost gas generation resource alternatives for the Renfrew region, based on escalating values from a previous study independently conducted for the IESO.1
- A battery energy storage system was identified as another low-cost resource alternative. Total battery storage system costs are composed of capacity and energy costs (I.e. energy storage devices are constrained by their energy reservoir). The battery storage capacity and energy costs are based on the 2021 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB).
- Sizing of the battery storage solution was based on meeting the peak capacity and peak energy requirements for the local reliability need, such that the reservoir size is capable of using existing resources to sufficiently charge to meet the hours of unserved energy.
- System capacity value was $144 k/MW-yr (2021 CAD) based on an estimate for the Cost of the Marginal New Resource (Net CONE), a new simple cycle gas turbine (SCGT) in Ontario.
- Production costs were determined based on energy requirements to serve the local reliability need, assuming the fixed and variable operating and maintenance costs for the resource (i.e., battery energy storage system or gas generation)

- Carbon pricing assumptions are based on the proposed Federal carbon price increase of a carbon price that escalates to \$170/tCO2e by 2030. Thereafter, the \$170/tCO2e assumption is held constant in real dollars for the forecast period. The benchmark (tCO2e/GWh) for new gas facilities is assumed to be eliminated by 2030.
- The assessment was performed from an electricity consumer perspective and included all costs incurred by project developers, which were assumed to be passed on to consumers.

Appendix D – Hourly Demand Forecast

D.1 General Methodology

An hourly demand forecast consists of a series of year-long hourly profiles ("8760 profile", based on the number of hours in a year), which have been scaled to the appropriate annual peak demand. These profiles are developed to help determine which non-wires options may be best suited to meet regional needs.

For the Renfrew IRRP, hourly load forecasting was conducted on a station-level, using a multiple linear regression with approximately five years' worth of historical hourly load data. Firstly, a density-based clustering algorithm was used for filtering the historical data for outliers (including fluctuations possibly caused load transfers, outages, or infrastructure changes). Subsequently, the historical hourly data was combined with select predictor variables to perform a multiple linear regression and model the station's hourly load profile. The following predictor variables were used:

- Calendar factors (such as holidays and days of the week);
- Weather factors (including temperature, dew point, wind speed, cloud cover, and fraction of dark; both weekday and weekend heating, cooling, and dead band splines were modelled);
- Demographic factors (population data[1]); and
- Economic factors (employment data[2]).

Model diagnostics (training mean absolute error, testing mean absolute error) were used to gauge the effectiveness of the selected predictor variables and to avoid an over-fitted model. While future values for calendar, demographic, and economic variables were incorporated in a relatively straightforward manner, the unreliability of long-term weather forecasts necessitated a different approach for predicting the impact of future weather.

Each future date was first modelled using historical weather data from the equivalent day of year throughout the past 31 years. Additionally, to fully assess the impact of different weather sequences against the other non-weather variables, the historical weather for each of the 31 previous years was shifted both ahead and behind up to seven days, resulting in 15 daily variations. This approach ultimately led to 465 possible hourly load forecasts for each future year being forecast. For example: 31 years of historical weather data × 15 weather sequence shifts = 465 weather scenarios for each year being forecast. June 2nd 2025 was forecast assuming the historical weather from every May 26th to June 9th period that occurred between 1991 and 2021.

Subsequently, the list of 465 forecasts were ranked in ascending order based on their median energy values. Load duration curves which illustrate this ranking can be seen in Figure 3.

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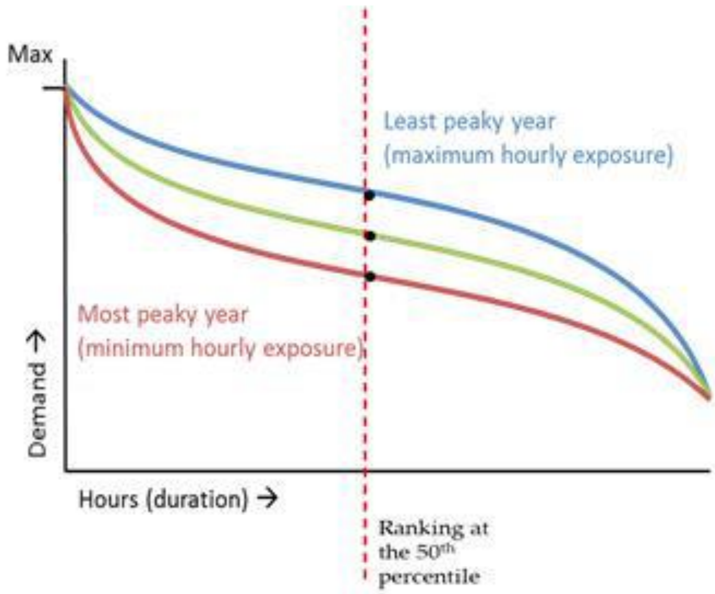
[1] Sourced from the Ministry of Finance and Statistics Canada.

[2] Sourced from the Centre for Spatial Economics, IHS Markit Ltd., and the Conference Board of Canada.

Figure 3 | Illustrative Example: Ranking Hourly Load Profiles by Energy



The forecast in the 3rd percentile was considered the “Extreme Peak” (extreme profile, red curve) and the forecast in the 50th percentile was chosen was the “Median Peak” (median profile, green curve). For the Niagara IRRP, the median profiles were scaled to their respective maximums from the peak demand forecast.

Sections D.2, D.3, and D.4 contain additional examples of the forecast hourly profiles for Pembroke TS, Forest Lea DS, and Petawawa DS. Heat maps are also provided to illustrate some of the station capacity need characteristics.

D.2 Pembroke TS Capacity Need

See Table 9 in the Renfrew IRRP Appendix Excel file for the station’s forecast hourly load profile and need in 2042.

Figure 4 | Heat Map Showing Possible Frequency of Pembroke TS Capacity Need in 2042 by MW and Month

MW Range												
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14.22222	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
12.44444	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%
10.66667	0%	1%	0%	0%	0%	0%	2%	0%	0%	0%	0%	0%
8.888889	0%	2%	0%	0%	0%	1%	4%	0%	0%	0%	0%	0%
7.111111	0%	4%	0%	0%	0%	2%	6%	1%	0%	0%	0%	0%
5.333333	0%	7%	0%	0%	0%	5%	9%	3%	0%	0%	0%	1%
3.555556	3%	12%	1%	0%	0%	7%	11%	5%	1%	0%	0%	2%
1.777778	6%	21%	2%	0%	0%	10%	13%	9%	3%	0%	1%	4%
0	10%	28%	4%	2%	2%	12%	17%	13%	4%	0%	2%	7%
Month	1	2	3	4	5	6	7	8	9	10	11	12

Figure 5 | Heat Map Showing Possible Frequency of Pembroke TS Capacity Need in 2042 by MW and Hour

MW Range	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
16	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
14.22222	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12.44444	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
10.66667	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	0%	0%	0%	0%	0%	0%	0%
8.888889	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	0%	0%	0%	0%	0%	0%
7.111111	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	1%	1%	2%	2%	3%	1%	0%	0%	0%	0%	0%	0%
5.333333	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	3%	5%	4%	4%	2%	1%	0%	0%	0%	0%	0%
3.555556	0%	0%	0%	0%	0%	1%	3%	2%	2%	2%	2%	2%	3%	4%	5%	5%	6%	4%	1%	1%	0%	0%	0%	0%
1.777778	0%	0%	0%	0%	1%	2%	4%	4%	5%	5%	3%	3%	4%	5%	8%	8%	9%	7%	3%	1%	0%	0%	0%	0%
0	0%	0%	0%	0%	1%	3%	5%	5%	6%	6%	4%	5%	5%	7%	10%	11%	13%	10%	6%	2%	1%	0%	0%	0%
	Hour																							

Each cell in the heat map indicates the expected frequency of a load level at Pembroke TS, according to the month or hour. For instance, it is estimated that in roughly 1% of total hours in 2042, loading at Pembroke TS exceeds 14 MW and occurs in July, as indicated in Figure 4. Conversely, load levels are estimated to infrequently exceed 5 MW in shoulder season months such as March and April. From an hourly perspective (Figure 5), a sustained need is estimated across day hours (roughly 6 AM – 11 PM). High magnitude needs greater than for instance, 10 MW, will likely occur during early evening hours like 5 PM – 6 PM during the summer.

D.3 Forest Lea DS Capacity Need

See Table 9 in the Renfrew IRRP Appendix Excel file for the station's forecast hourly load profile and need in 2042.

Figure 6 | Heat Map Showing Possible Frequency of Forest Lea DS Capacity Need in 2042 by MW and Month

MW Range	1	2	3	4	5	6	7	8	9	10	11	12
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.888889	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.777778	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.666667	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.555556	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.444444	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.333333	0%	0%	0%	0%	0%	0%	13%	0%	0%	0%	0%	0%
0.222222	0%	0%	0%	0%	0%	0%	25%	0%	0%	0%	0%	0%
0.111111	0%	0%	0%	0%	0%	0%	25%	25%	0%	0%	0%	0%
0	0%	0%	0%	0%	0%	0%	75%	25%	0%	0%	0%	0%
	Month											

Figure 7 | Heat Map Showing Possible Frequency of Forest Lea DS Capacity Need in 2042 by MW and Hour

MW Range \ Hour	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.888889	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.777778	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.666667	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.555556	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.444444	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0.333333	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	13%	0%	0%	0%	0%	0%	0%	0%
0.222222	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	13%	13%	0%	0%	0%	0%	0%	0%	0%
0.111111	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	25%	25%	0%	0%	0%	0%	0%	0%	0%
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	50%	50%	0%	0%	0%	0%	0%	0%	0%

It can be seen that the capacity need at Forest Lea DS is localized to two summer months during the hours of 4PM – 5PM. As discussed in the body of the report this is a smaller scale capacity need and as such the options considered focus on solutions that match this profile.

D.4 Petawawa DS Capacity Need

See Table 9 in the Renfrew IRRP Appendix Excel file for the station's forecast hourly load profile and need in 2042.

Figure 8 | Heat Map Showing Possible Frequency of Petawawa DS Capacity Need in 2042 by MW and Month

MW Range \ Month	1	2	3	4	5	6	7	8	9	10	11	12
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1.777778	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%
1.555556	0%	0%	0%	0%	0%	0%	5%	0%	0%	0%	0%	0%
1.333333	0%	0%	0%	0%	0%	0%	8%	0%	0%	0%	0%	0%
1.111111	0%	0%	0%	0%	0%	0%	13%	3%	0%	0%	0%	0%
0.888889	0%	0%	0%	0%	0%	0%	15%	5%	0%	0%	0%	0%
0.666667	0%	0%	0%	0%	0%	0%	20%	13%	0%	0%	0%	0%
0.444444	0%	0%	0%	0%	0%	0%	38%	13%	0%	0%	0%	0%
0.222222	0%	0%	0%	0%	0%	0%	58%	30%	0%	0%	0%	0%
0	0%	0%	0%	0%	0%	0%	63%	38%	0%	0%	0%	0%

Figure 9 |Heat Map Showing Possible Frequency of Petawawa DS Capacity Need in 2042 by MW and Hour

MW Range	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1.777778	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1.555556	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%	3%	0%	0%	0%
1.333333	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	0%	0%	3%	0%	0%	0%	0%	0%	3%	0%	0%	0%
1.111111	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	3%	5%	3%	0%	0%	0%	0%	0%	3%	0%	0%	0%
0.888889	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	3%	3%	5%	5%	0%	0%	0%	0%	0%	3%	0%	0%	0%
0.666667	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	8%	3%	5%	10%	0%	0%	0%	0%	0%	5%	0%	0%	0%
0.444444	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	5%	8%	3%	10%	15%	0%	0%	3%	0%	0%	8%	0%	0%	0%
0.222222	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	5%	10%	13%	18%	20%	3%	0%	3%	3%	3%	10%	0%	0%	0%
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	8%	15%	13%	18%	20%	3%	0%	3%	3%	3%	15%	0%	0%	0%
	Hour																							

Each cell in the heat map indicates the expected frequency of a load level at Petawawa DS, according to the month or hour. For instance, it is estimated that in roughly 3% of total hours in 2042, loading at Pembroke TS exceeds 2 MW and occurs in July, as indicated in Figure 8. From an hourly perspective (Figure 9), a sustained need is estimated across day hours (roughly 10 AM – 11 PM). 1 MW needs will likely occur during afternoon and evening hours during the summer.

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