Peterborough to Kingston Region

Integrated Regional Resource Plan (IRRP) Appendices

November 4, 2021

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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

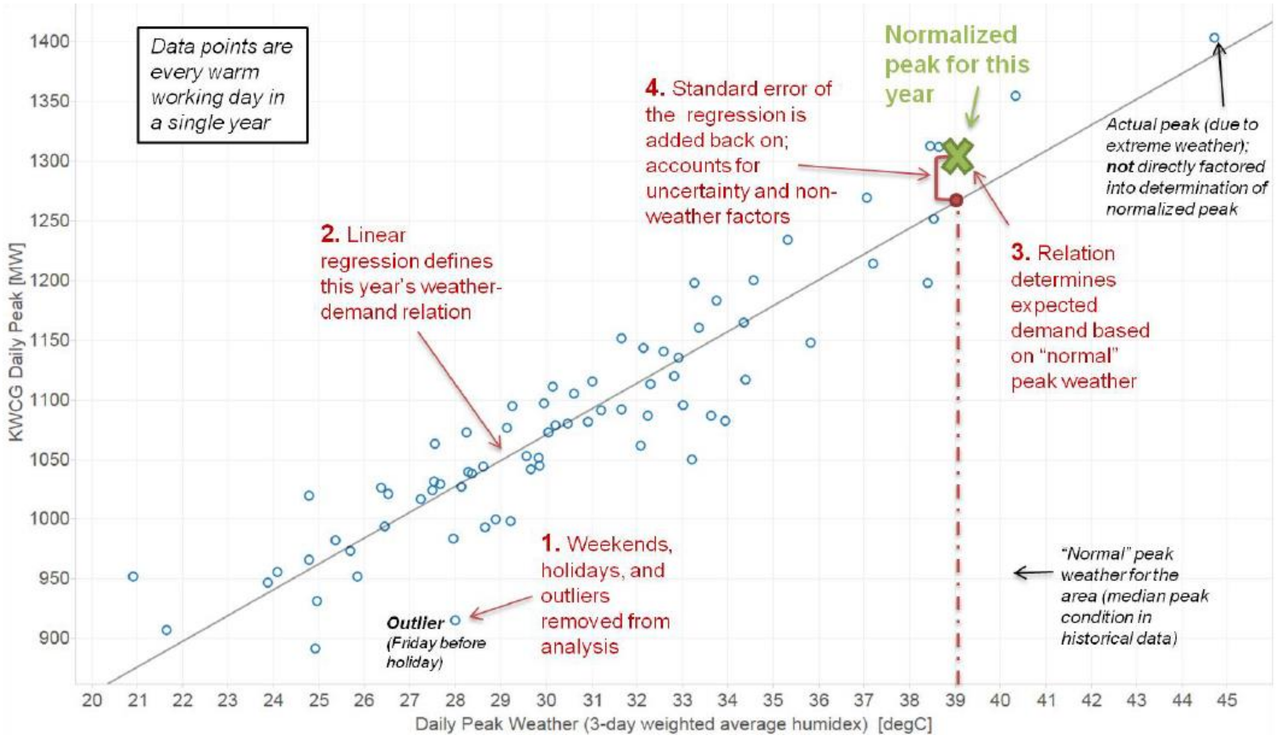
Weather has a large influence on the demand for electricity, so to develop a standardized starting point for the forecast, the historic electricity demand information is weather-normalized. This section details the weather-normalization process used to establish the starting point for regional demand 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 2018). 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 A-1.

The 2018 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 A-1 | Method for Determining the Weather-Normalized Peak



A.2 Hydro One Forecast Methodology

Hydro One Distribution provides service to part of the City of Kingston as well as counties and townships in the study area. For the list of all stations in the study area, please see Table A-8 below. In particular, the following step-down stations supply the Belleville and Kingston areas from the transmission system:

Belleville TS

Frontenac TS

Gardiner TS (T1/T2)

Gardiner TS (T3/T4)

There are about 54,000 Hydro One Distribution retail customers directly connected to Hydro One's distribution system in Belleville and Kingston areas. There are also embedded LDCs connected to Hydro One's distribution system.

A.2.1. Factors that Affect Electricity Demand

Hydro One Distribution serves part of the City of Kingston and the rural areas outside the major cities such as Belleville. The demand growth in the Hydro One Distribution service area is largely driven by the economic activities in these 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 macro-economic analysis, which takes into account 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. 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 needs 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 Utilities Kingston Forecast Methodology

As the affiliate service provider to Kingston Hydro, Utilities Kingston (UK) manages, operates and maintains the electrical distribution assets in the core area of the City of Kingston, serving approximately 28,000 customers. UK's residential customers (88.6% by customer count) accounted for 26.2% of the total annual energy consumption in 2020 whereas the remaining commercial/institutional customers (11.4% by customer count) accounted for 73.8% of the total annual energy consumption. UK's energy consumption and system demand are heavily influenced by federal institutions, municipal facilities, universities, schools and hospitals (I-MUSH Sector).

UK is supplied by the Hydro One Frontenac and Gardiner Transformer Stations (TS) through the Hydro One transmission system at primary voltages of 115 kV and 230 kV respectively. Seven 44 kV (46 kV class) feeders distribute electricity through UK's service area to large customers and 17 municipal substations (MS). The 44 kV sub-transmission voltage is stepped down to 4.16 kV (5 kV class) and now 13.8 kV (15 kV class) at UK MS facilities to facilitate distribution of electricity to small and medium size customers.

A.3.1. Factors that Affect Electricity Demand

UK has historically been a winter-peaking utility. Over the historic period of 2009 to 2019, the average residential customer count increased at an average rate of 1% while the "gross" average annual peak electricity demand declined by approximately 0.5 MW/year. This demand trend is attributed to several factors including the closure of Kingston Penitentiary in 2013, UK's success in achieving and in some instances exceeding provincial CDM targets over the 2015-2018 timeframe and provincial Time of Use (TOU) and Global Adjustment programs which came into effect around 2015. The "net" average annual peak electricity demand was another 6 to 12 MW lower than the gross demand over the same historic period due to embedded generation. This net demand reduction is attributed mainly to a 15 MW cogeneration facility operated jointly by Queen's University and Kingston General Hospital.

Moving forward, UK is anticipating significant growth in electricity demand over the next few decades due to City planning policies that encourage intensification of development and global climate change mitigation efforts which are expected to depend upon a clean Ontario electricity mix, the electrification of transportation (e.g. electric vehicles) and the electrification of heating (e.g. heat pumps, etc.). The I-MUSH sector in Kingston is expected to lead the way with net-zero energy targets ranging from 2040 to no later than 2050.

A.3.2. Forecast Methodology and Assumptions

In developing the load forecasts, UK gathers development projection data from the local municipalities and developers to determine areas and timing of planned development as well as land uses. This information is then converted to electrical demand quantities and analyzed against past trends. A "reference" forecast is then developed for each TS that is consistent with load growth potential within the service area of that station and overall system growth. UK uses a mix of historic growth trending and forward looking economic forecasting to develop the "reference forecast" growth rates of electricity demand. Despite the slight decline in the "gross" average annual peak winter electricity demand in recent years, the "gross" average annual peak summer electricity demand has increased at a rate of approximately 1 MW/year over the 2014-2019 timeframe and if this trend continues the "gross" annual peak summer demand could surpass "gross" annual peak winter demand as early as 2023. UK also considered housing unit and employment forecasts from a 2019 report entitled "Population, Housing and Employment Growth Forecast, 2016 to 2046" prepared by an economist firm for the City of Kingston.

After preparing the "reference" forecast, the theme of "electrification" began to emerge as UK customers from the I-MUSH sector shared their net-zero targets. In order to better understand the potential ramifications of electrification, UK reached out to three of its largest customers; CFB Kingston, Queen's University and the City of Kingston. All three customers provided estimates for the electrification of their heating system. A high growth winter demand scenario (Winter Growth Scenario 2) was developed by converting the rated output of existing natural gas heating appliances (BTUh) to the equivalent electric resistive heating demand (kW). A medium growth winter demand scenario (Winter Growth Scenario 1) was developed by converting the electric resistive heating demand of Winter Growth Scenario 2 to an equivalent electric heat pump demand. In order to do this conversion, UK assumed that the peak heating demand on the coldest winter days (e.g. below -15 degrees Celsius) would be supplemented by natural gas heating appliances and most of the heating demand would be met using heat pumps with a coefficient of performance (COP) of 3. The total 2021-2040 incremental demand due to electrification is summarized in the table below:

Table A-1 | 2021-2040 Incremental Electrification Forecast in MW

Description	Growth Scenario 2	Growth Scenario 1
EV Charging	13.7	6.1
I-MUSH New Facility	35.8	11.9
I-MUSH Heating Retrofit	93.4	31.1
Total	142.9	49.1

A.4 Elexicon Energy Forecast Methodology

A.4.1. Factors that Affect Electricity Demand

Population growth is the primary driver for electricity demand increase in the residential and commercial sector. As municipality develop new land for residential use, Elexicon sees a direct correlation between customer count increase and loading increase. The forecast methodology used by Elexicon is based on this core principle (see details in A.1.2)

Weather also plays an important role in system loading. In the summer-peaking areas, Elexicon uses cooling degree days as a key indicator to analyze the coloration between temperature and loading. However, the forecast provided by Elexicon assumes average temperature scenario as the IRRP process accounts for extreme temperature adjustments.

Large industrial sector load growth is more difficult to predict. Elexicon reviews the availability of suitable land for industrial development, then references past connection request and customer engagement to estimate the growth in power demand. This growth is a flat increment to be added to the forecast result from the previous steps.

Other factors not reflected in the initial data gathering include the effect of electrification. Electrification can be further broken down into electrical vehicles (EV) and heating.

A separate load forecast was conducted based on effect of electric vehicles. This forecast references "Electric vehicles, setting a course for 2030" Deloitte study, IESO Annual Planning Outlook (APO), census Canada statistics. At the end of the forecast period (2038), it was estimated EV load would increase the Elexicon Belleville region peak demand by 2%

Forecasting of heating electrification was not performed. Based on preliminary research, only limited amount of customer base such as academic institution and government agencies are considering transition to heat pumps. There are some residential developers that have proposed heat pumps for new subdivision use, however based on the growth outlook, lack of policy influence and customer demographic specific to Elexicon's service area, we did not expect heating electrification to have significant contribution to our peak demand at this time.

A.4.2. Forecast Methodology and Assumptions

General Forecast Methodology Outline

1. Gather existing loading, customer count and temperature data
2. Normalize loading data by removing outliers, weekends and holidays, etc.
3. Calculate overall demand per customer (kVA/customer) by dividing total service area load by the number of existing customers.
4. Adjust kVA/customer value based on various temperature scenarios. For IESO submission, weather normalization is not performed by LDC
5. Gather population growth data from Municipality forecast and adjust based on past forecast accuracy. Project customer growth by year for the next 10 years.
6. Apply kVA/customer to the new customer growth profile using an average temperature profile to arrive at the new forecasted load.

7. Steps above should reflect residential and commercial customers. Large industrial growth is harder to predict and will be forecasted based on customer engagement and municipal planning and development trend. This industrial load increment is added to the final forecast result.

A.5 Lakefront Utilities Forecast Methodology

Lakefront Utilities (LUI) is a licensed electricity distributor in the Town of Cobourg and the Village of Cramahe. LUI is responsible for maintaining distribution and infrastructure assets deployed over 28 square kilometres within the Cobourg and Cramahe service areas. LUI currently serves approximately 10,500 electricity distribution customers across its two service areas.

LUI is supplied power from Port Hope transformer station and three 44 kV breakers, all owned and operated at primary voltage of 115 kV to 44 kV by Hydro One Networks Inc. LUI distributes electricity to the Town of Cobourg and Village of Cramahe at primary distribution voltages of 27.6 kV and 4.16 kV (through five 4.16 kV and two 27.6 kV substations).

A.5.1. Factors that Affect Electricity Demand

LUI experiences a marginal system peak during the summer months in comparison to the winter months. Feeder conversion work remains a key focus of LUI's investment program. LUI is in the process of converting its 4.16 kV system to a 27.6 kV system. The conversion process is scheduled over a relatively long period, and approximately 80% is completed with the remaining targeted to be completed within the DSP forecast period. LUI engaged with a consultant to review the capacity of the existing 44/27.6 kV substations in the Town of Cobourg and to determine the timing of additional capacity requirements to meet forecast load growth, new developments, and the impact of 4.16 kV voltage conversions. Based on the projected load growth and planned voltage conversion program, additional 27.6 kV capacity will be required in the forecast period. As a result, LUI is planning to build and install a new 27.6 kV substation within the forecast period.

A.5.2. Forecast Methodology and Assumptions

Voltage conversions will ensure long-term reliability is maintained at current levels. Upgrading the 4.16 kV system to 27.6 kV conversions will reduce station maintenance needs and lower line losses, provide additional capacity for higher penetration of DER distributed generation connections and, in some cases, improve power quality. LUI conducted EV charging pilots to understand the impact of EVs on the distribution system. LUI designs for 200 A service for residential customers and EV charging is considered in the connection design for commercial/industrial customers. EV charging will be considered in new distribution system renewal and access projects. The use of SmartMap allows individual transformer monitoring to identify overloaded assets due in part to EV charging and to appropriately act.

A.6 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 Peterborough to Kingston IRRP forecast are consistent with the CDM assumptions in the IESO's 2020 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 transmission zone and then allocated to the Peterborough to Kingston region. This section of the appendix describes the process and methodology used to estimate CDM savings for the Peterborough to Kingston region and provides more detail on how the estimated savings were developed.

A.6.1. Estimate Savings from Conservation and Demand Management Measures

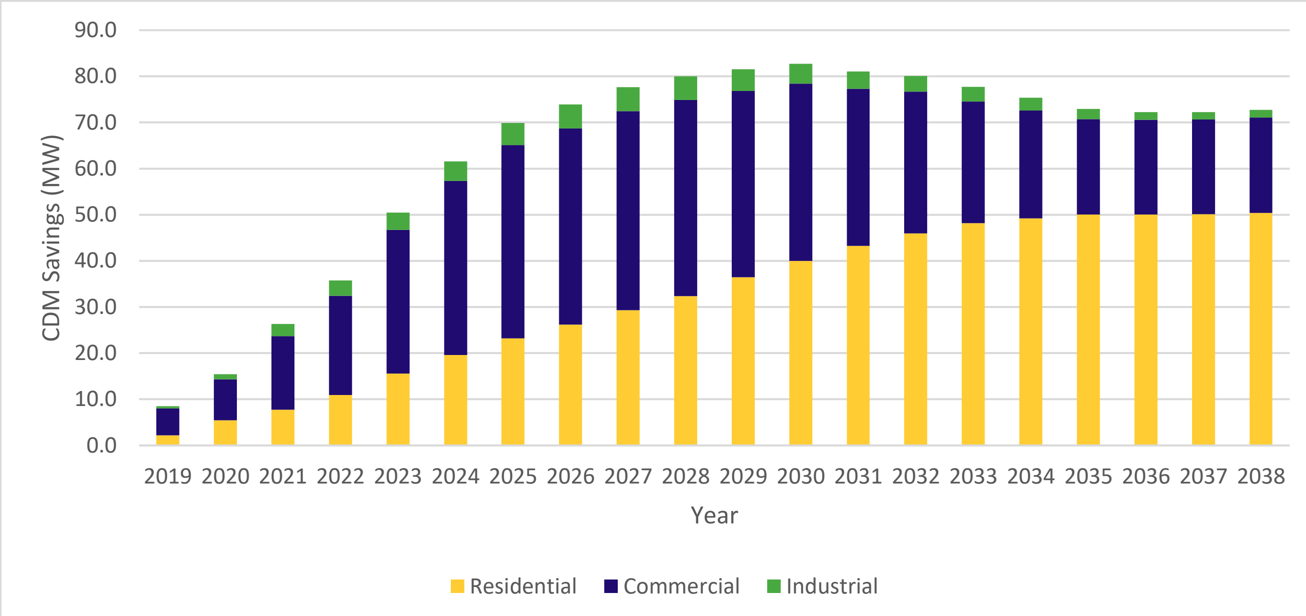
Ontario building codes and equipment standards set minimum efficiency levels through regulations and are projected to improve and further contribute to demand reduction in the future. To estimate the impact on the region, the associated peak demand savings for codes and standards by sector were estimated for the East zone 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 zone 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, 2018 was used as the base year. New peak demand savings from codes and standards were estimated from 2019 to 2038. 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 2038, the residential, commercial and industrial sectors in the region will be expected to see peak demand savings of about 6.9%, 3.8% and 1.0%, respectively.

Figure A-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 A-2 | Reduction to Summer Demand Forecast due to Conservation



A.6.2. 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.

Figure A-3 shows the DG effective output capacity per fuel type for each year of the forecast period. The total installed capacity is continually rising in this figure due to the assumption that expiring contracts will be reacquired. Additional information on the DG forecast can be found in Appendix A.7.

Figure A-3 | Distributed Generation Effective Output Capacity

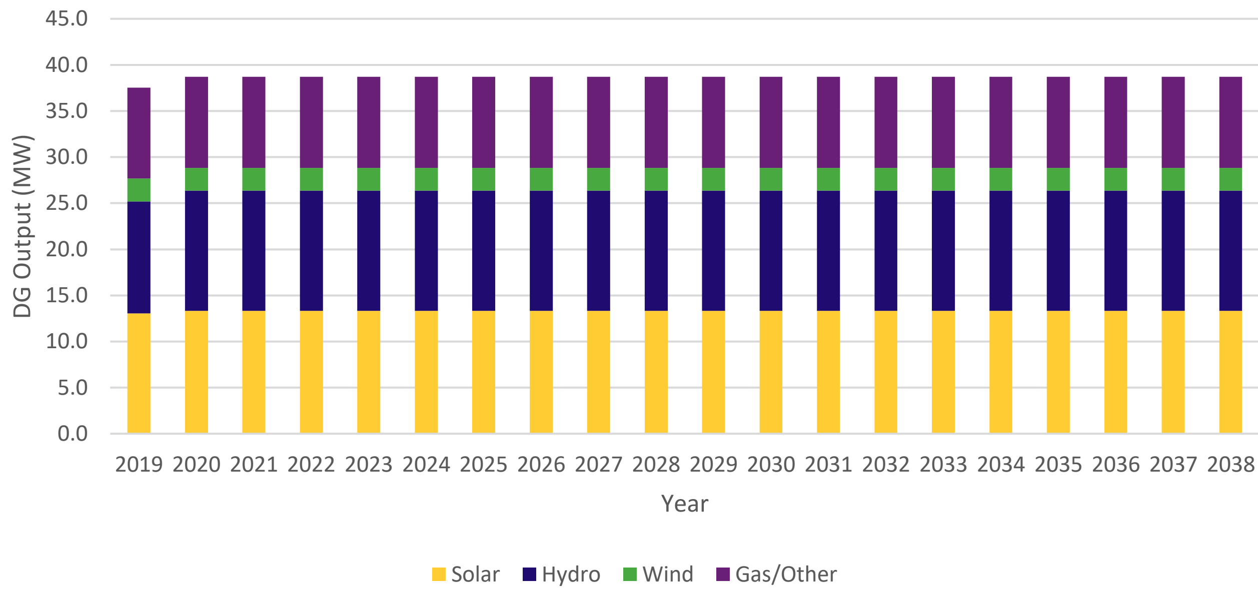
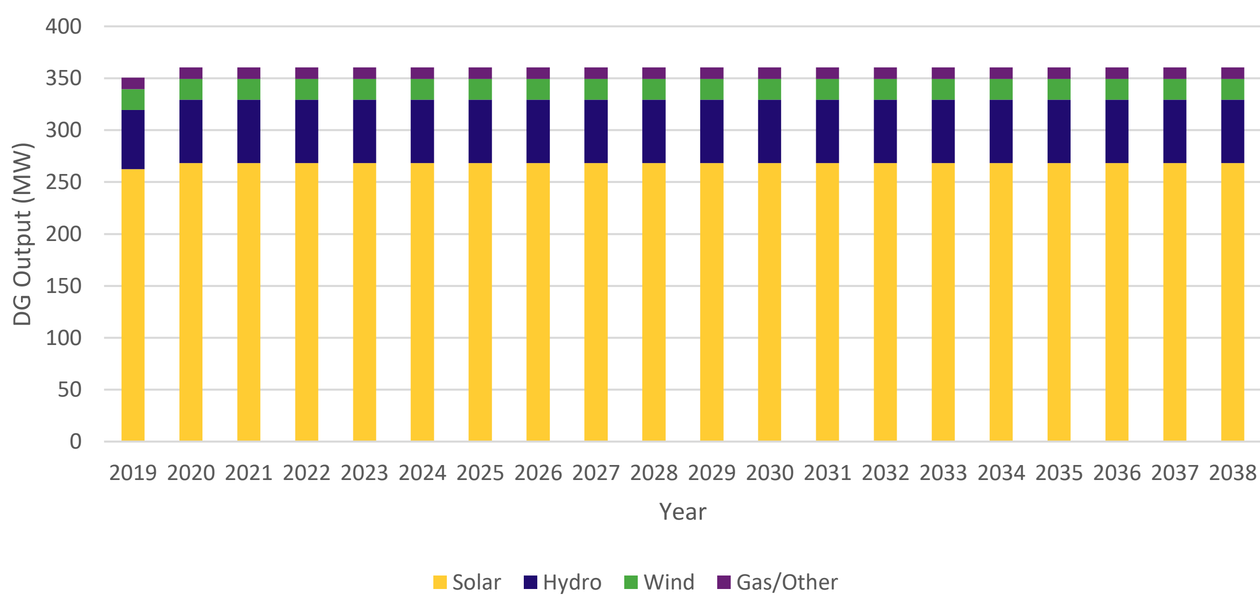


Figure A-4 shows the DG installed capacity per fuel type for each year of the forecast period. Additional information on the DG forecast can be found in Appendix A.7 which includes an additional 11MW from Queen's University co-gen, that is not captured in figure A-3.

Figure A-4 | | Distributed Generation Installed Capacity



With the assumption that expired contracts will retire, it was seen that DG output began to decrease rapidly post-2030. In terms of impact to the reference forecast, this would mean that later years of the forecast period would see higher net load due to the waning capacity of DG not being able to output as much generation during peak hours.

Figure A-5 | Summer Planning Demand Forecast including the Effects of DG Retirement

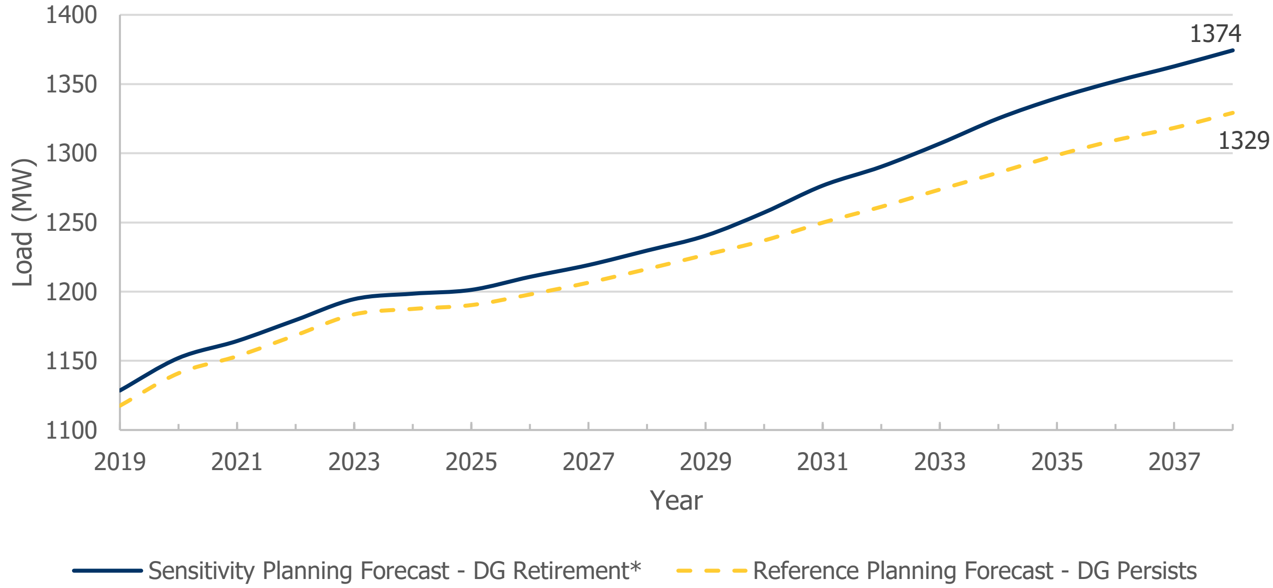


Figure A-5 shows the summer planning demand forecast, aggregated for the entire Peterborough to Kingston region, now with the DG forecast tapering off at the end of the forecast period. For comparison, the reference planning forecast.

A.7 Demand Forecast Data Tables

A.7.1. Reference, Coincident, Planning Forecast Data Tables

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

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Ardoch DS	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Battersea DS	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Belleville TS	176	182	187	192	196	200	200	201	202	202	203	204	206	207	208	210	212	213	214	215
Dobbin DS	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7
Dobbin TS	109	111	111	117	122	123	123	125	126	127	129	131	132	134	137	138	141	143	144	146
Frontenac TS	96	97	96	100	102	104	104	105	107	108	109	111	112	114	115	116	117	118	119	119
Gardiner TS (T1/T2)	150	154	156	159	161	162	163	164	166	168	169	171	173	174	176	177	179	180	181	182
Gardiner TS (T3/T4)	21	25	28	28	28	28	28	28	28	28	28	28	28	29	29	29	29	29	29	30
Harrowsmith DS	16	16	16	16	16	16	16	16	16	16	16	17	17	17	17	17	17	17	17	17
Havelock TS	73	74	74	74	75	74	74	75	75	76	76	76	77	77	78	79	79	80	80	81
Hinchinbrooke DS	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Lodgeroom DS	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	10	10	10
Napanee TS	60	61	62	62	63	63	64	64	65	66	66	67	68	69	70	71	72	73	73	74
Northbrook DS	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7
Otonabee TS	122	123	124	119	119	115	115	116	118	119	120	122	124	126	127	129	131	133	134	137
Picton TS	42	43	43	44	44	44	45	45	45	46	46	47	47	48	49	49	50	50	51	52
Port Hope TS	119	121	121	122	122	122	122	123	123	124	124	125	126	126	127	128	129	130	131	131
Sharbot DS	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Sidney TS	78	79	79	79	79	79	79	79	80	80	81	81	82	83	84	84	85	85	86	86
CTS	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Total	1118	1141	1153	1169	1184	1188	1190	1198	1207	1216	1227	1237	1250	1261	1274	1286	1299	1309	1318	1329

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Table A-3 | Final Coincident, Extreme Peak, Net, Winter Demand Forecast (MW) per Station

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Ardoch DS	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Battersea DS	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Belleville TS	162	167	170	174	178	181	181	182	183	184	185	186	187	188	189	191	192	193	194	195
Dobbin DS	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7
Dobbin TS	86	87	87	93	98	99	100	101	102	104	105	106	107	109	111	112	114	115	117	119
Frontenac TS	100	101	101	104	106	109	109	111	112	113	115	116	118	119	120	121	122	123	124	125
Gardiner TS (T1/T2)	135	138	140	142	144	146	147	149	150	152	154	155	157	158	160	161	162	163	164	164
Gardiner TS (T3/T4)	26	29	32	32	32	32	32	32	33	33	33	33	33	33	34	34	34	34	34	34
Harrowsmith DS	18	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	20	20	20	20
Havelock TS	70	69	69	69	69	70	70	70	71	71	72	72	73	73	74	74	75	75	76	76
Hinchinbrooke DS	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Lodgeroom DS	10	10	10	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11	11	11
Napanee TS	68	70	70	71	71	72	72	73	74	75	75	76	77	78	79	80	81	82	82	83
Northbrook DS	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8	8

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Otonabee TS	144	145	146	146	142	138	139	140	142	143	146	147	149	150	153	156	157	160	162	164
Picton TS	47	48	49	49	50	50	50	51	51	52	52	53	53	54	54	55	56	56	57	58
Port Hope TS	125	127	128	128	129	130	130	130	131	132	132	133	134	134	135	136	137	138	139	139
Sharbot DS	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Sidney TS	68	69	69	68	68	68	68	69	70	70	71	71	72	73	74	74	75	75	76	76
CTS	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Total	1122	1142	1153	1169	1182	1187	1193	1202	1213	1224	1234	1243	1255	1265	1277	1290	1302	1312	1323	1332

A.7.2. Conservation and Demand Management (CDM) and Distributed Generation (DG) Forecast Data Tables

Table A-4 | CDM and DG Contribution (MW) Considered in Coincident, Extreme Peak, Net, Summer Demand Forecast

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Ardoch DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Battersea DS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Belleville TS	5	6	7	9	11	12	14	14	15	15	16	16	16	16	15	15	15	14	14	15
Dobbin DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dobbin TS	6	6	7	9	10	12	13	13	13	14	14	14	14	14	13	13	13	13	13	13
Frontenac TS	13	14	15	16	18	19	20	20	21	21	21	21	20	20	19	19	19	19	19	19
Gardiner TS (T1/T2)	5	6	7	9	11	12	14	14	15	15	15	15	15	15	14	14	13	13	13	13
Gardiner TS (T3/T4)	0	0	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Harrowsmith DS	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Havelock TS	5	6	7	8	9	9	10	10	10	11	11	11	11	11	11	11	11	11	11	11
Hinchinbrooke DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lodgeroom DS	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1
Napanee TS	4	4	5	5	6	7	7	7	7	8	8	8	8	8	7	7	7	7	7	7

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Northbrook DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Otonabee TS	5	6	7	8	10	11	12	12	13	13	13	13	13	13	12	12	12	12	12	12
Picton TS	2	2	2	3	3	3	4	4	4	4	4	5	5	5	5	5	5	5	5	5
Port Hope TS	3	3	4	5	7	7	8	9	9	9	9	9	9	9	9	9	9	9	9	9
Sharbot DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sidney TS	9	9	10	11	12	13	14	14	14	14	14	14	14	14	13	13	13	13	13	13
CTS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	57	65	76	85	100	111	119	123	127	130	131	132	131	130	127	125	123	122	122	122

Table A-5 | CDM and DG Contribution (MW) Considered in Coincident, Extreme Peak, Net, Winter Demand Forecast

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Ardoch DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Battersea DS	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Belleville TS	2	3	4	6	7	8	9	9	9	9	10	10	10	10	10	10	9	9	9	9
Dobbin DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dobbin TS	11	11	12	13	14	15	15	15	16	16	16	16	16	16	16	15	15	15	15	15
Frontenac TS	12	13	14	15	17	18	18	18	18	18	18	18	18	18	17	17	16	16	16	16
Gardiner TS (T1/T2)	4	4	6	7	9	10	11	11	11	11	11	11	11	10	10	9	9	9	9	9
Gardiner TS (T3/T4)	0	0	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	1	1
Harrowsmith DS	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1
Havelock TS	11	14	14	15	16	16	17	17	17	17	17	17	17	18	18	17	17	17	17	17
Hinchinbrooke DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Lodgeroom DS	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1
Napanee TS	1	1	2	2	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Northbrook DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Otonabee TS	9	9	11	12	13	14	15	15	15	15	15	16	15	15	15	15	14	14	14	14
Picton TS	0	0	1	1	1	2	2	2	2	2	2	3	3	3	3	3	3	3	3	3
Port Hope TS	1	1	2	3	4	5	5	6	6	6	6	6	6	6	6	6	6	6	6	6
Sharbot DS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sidney TS	11	12	13	13	14	15	15	15	15	15	15	15	15	14	14	14	13	13	13	13
CTS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	64	71	80	91	101	109	114	116	118	118	120	122	121	121	119	116	114	113	113	113

A.7.3. Reference, Coincident, LDC Provided Forecast Data Tables

Table A-6 | LDC Coincident, Median Peak, Gross Summer Demand Forecast (MW) per Station

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Ardoch DS	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Battersea DS	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	10	10	10	10	10
Belleville TS	169	175	181	187	193	199	200	201	202	203	204	206	207	208	209	210	211	212	213	215
Dobbin DS	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7
Dobbin TS	107	109	111	117	124	125	127	128	130	132	133	135	137	138	140	142	143	145	147	149
Frontenac TS	102	103	104	108	111	115	116	117	119	120	121	122	124	125	125	126	127	127	128	129
Gardiner TS (T1/T2)	145	149	153	156	160	163	165	167	169	170	172	174	176	177	177	178	179	180	181	182
Gardiner TS (T3/T4)	20	23	27	27	27	27	27	28	28	28	28	28	28	28	29	29	29	29	29	29
Harrowsmith DS	15	15	15	15	16	16	16	16	16	16	16	16	17	17	17	17	17	17	17	17
Havelock TS	73	75	76	77	78	78	79	79	80	80	81	82	82	82	83	83	84	84	85	85
Hinchinbrooke DS	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7
Lodgeroom DS	8	8	8	9	9	9	9	9	9	9	9	9	9	9	9	9	10	10	10	10
Napanee TS	60	61	62	63	64	65	66	67	67	68	69	70	71	71	72	73	74	74	75	76

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Northbrook DS	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7
Otonabee TS	119	121	123	119	121	117	119	120	122	123	125	126	128	129	131	132	134	135	137	139
Picton TS	41	42	43	43	44	45	45	46	46	47	47	48	49	49	50	50	51	51	52	52
Port Hope TS	114	116	117	118	120	121	122	122	123	124	125	125	126	127	127	128	129	129	130	131
Sharbot DS	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Sidney TS	81	82	83	84	85	86	86	87	87	88	89	89	90	90	90	91	91	92	92	92
CTS	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Total	1097	1127	1148	1171	1199	1213	1224	1234	1246	1257	1268	1279	1290	1299	1309	1318	1327	1337	1345	1356

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

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Ardoch DS	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	3	3	3
Battersea DS	11	11	11	11	11	11	11	11	11	11	12	12	12	12	12	12	12	12	12	12
Belleville TS	155	160	165	170	174	179	180	181	182	183	184	185	186	187	188	189	190	191	192	193
Dobbin DS	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7
Dobbin TS	91	93	94	100	106	107	109	110	111	113	114	115	117	118	119	121	122	124	125	127
Frontenac TS	107	108	109	113	116	119	121	122	123	124	126	127	128	129	130	130	131	132	132	133
Gardiner TS (T1/T2)	132	135	138	141	145	148	149	151	152	154	156	157	159	159	160	161	162	162	163	164
Gardiner TS (T3/T4)	24	28	31	31	32	32	32	32	32	32	33	33	33	33	33	33	34	34	34	34
Harrowsmith DS	17	18	18	18	18	18	18	18	19	19	19	19	19	19	19	19	19	20	20	20
Havelock TS	77	78	79	80	81	81	82	82	83	84	84	85	85	86	86	87	87	88	88	89
Hinchinbrooke DS	6	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Lodgeroom DS	10	10	10	10	10	10	10	10	10	10	11	11	11	11	11	11	11	11	11	11
Napanee TS	65	67	68	69	70	71	72	72	73	74	75	76	77	78	78	79	80	81	82	83
Northbrook DS	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Otonabee TS	144	146	148	150	147	143	145	147	148	150	152	153	156	157	159	161	162	165	167	168
Picton TS	45	46	47	47	48	49	49	50	51	51	52	53	53	54	54	55	56	56	57	57
Port Hope TS	119	121	123	124	126	127	128	129	129	130	131	132	133	133	134	135	135	136	137	137
Sharbot DS	4	4	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5
Sidney TS	75	76	77	77	78	79	79	80	80	81	81	82	82	82	83	83	84	84	84	85
CTS	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
Total	1122	1148	1168	1193	1214	1227	1237	1248	1259	1271	1282	1292	1303	1312	1321	1331	1340	1349	1359	1367

A.7.4. Non-Coincident Demand Forecast Data Tables

Table A-8 | Final Reference, Non-Coincident, Extreme Peak, Net, Summer Demand Forecast (MW)

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Belleville TS	166	170	174	179	183	186	186	187	187	188	189	190	191	192	194	195	196	198	199	200
Frontenac TS	100	101	101	108	107	107	107	108	109	110	111	112	114	115	116	117	118	119	119	120
Gardiner TS (T1/T2)	144	146	148	151	152	153	154	155	156	158	159	161	163	164	165	166	168	169	169	170

Table A-9 | Final Growth Scenario 1, Non-Coincident, Extreme Peak, Net, Summer Demand Forecast (MW)

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Belleville TS	167	170	174	179	183	187	187	187	188	189	190	191	192	194	195	197	199	200	201	202
Frontenac TS	100	101	102	109	110	111	113	117	121	125	129	133	137	140	142	144	147	149	151	153
Gardiner TS (T1/T2)	144	146	148	151	153	155	156	158	159	161	163	165	168	169	171	173	175	176	177	179

Table A-10 | Final Reference Non-Coincident, Extreme Peak, Net, Winter Demand Forecast (MW)

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Belleville TS	163	167	171	175	179	179	180	181	182	182	183	184	185	187	188	189	191	192	193
Frontenac TS	110	111	113	117	117	117	118	119	120	121	122	123	125	126	127	128	129	130	130
Gardiner TS (T1/T2)	129	132	133	135	137	139	140	141	143	144	146	147	149	150	151	152	154	154	155

Table A-11 | Final Growth Scenario 1, Non-Coincident, Extreme Peak, Net, Winter Demand Forecast (MW)

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Belleville TS	163	164	168	172	176	180	180	181	182	183	184	185	186	187	189	190	192	193	195	196
Frontenac TS	110	111	114	119	120	121	124	128	132	136	140	144	148	151	153	156	158	160	162	164
Gardiner TS (T1/T2)	129	132	134	136	138	141	142	144	146	148	150	152	155	156	158	160	161	163	164	165

Table A-12 | Final Growth Scenario 2, Non-Coincident, Extreme Peak, Net, Winter Demand Forecast (MW)

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Belleville TS	163	164	168	172	176	180	180	181	182	183	184	185	186	187	189	190	192	193	195	196
Frontenac TS	110	111	116	124	126	130	136	145	155	165	174	183	193	199	204	210	215	220	225	230

Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Gardiner TS (T1/T2)	129	132	135	138	142	145	148	151	154	157	160	163	167	170	172	175	178	181	183	185

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:

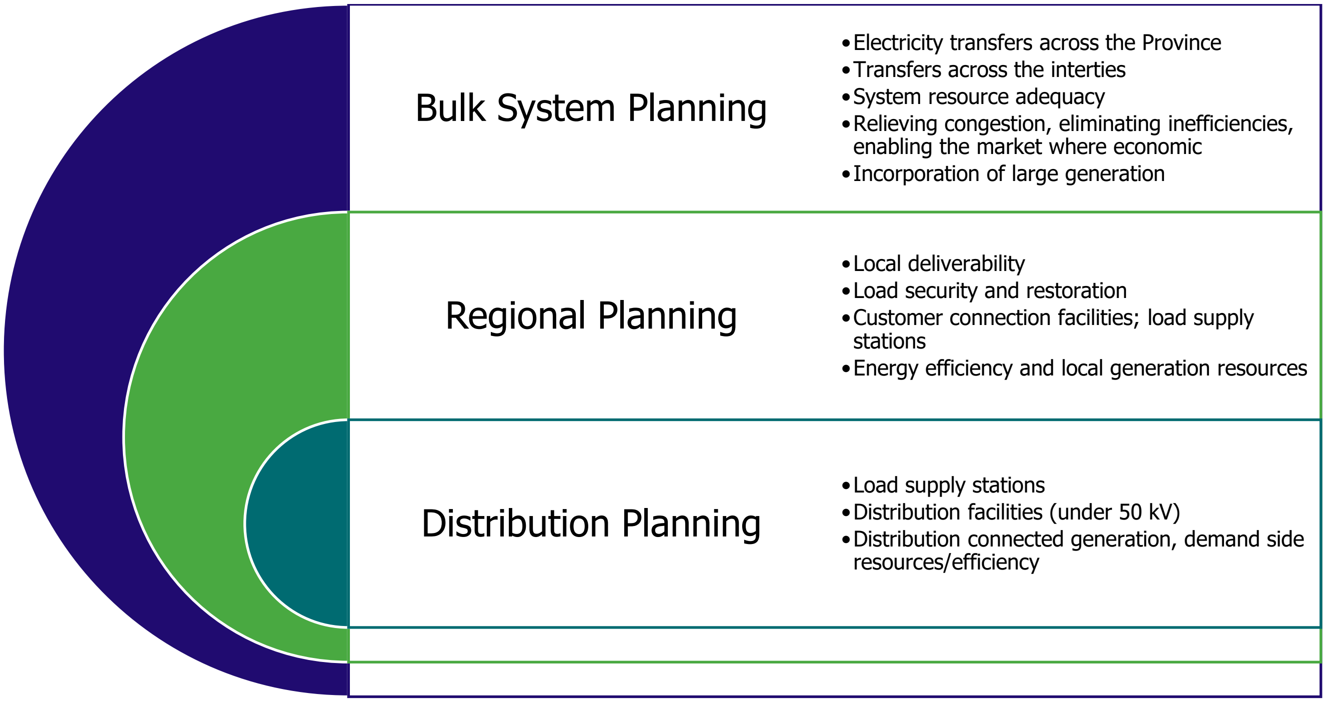
- Bulk system planning
- Regional system planning
- Distribution system planning

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

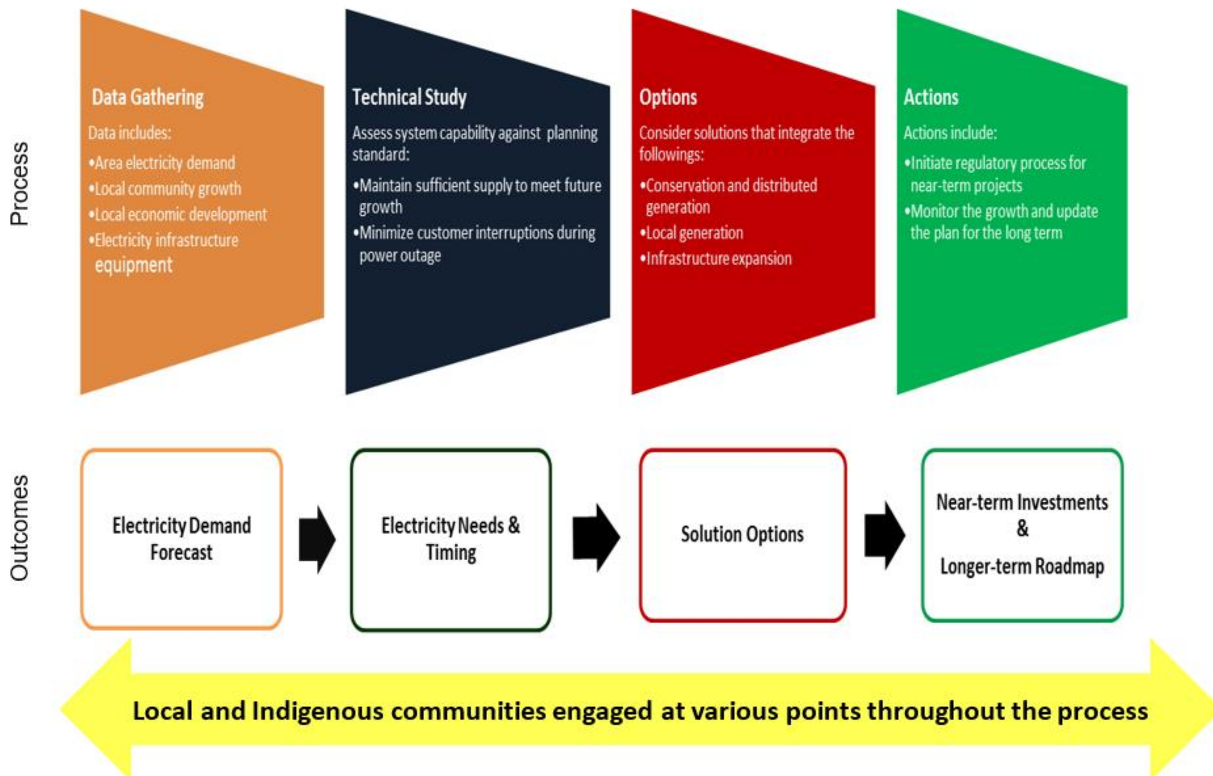
IRRPs assess electricity system needs for a region over a 20-year period, enabling near-term actions to be developed in the context of a longer-term view of trends. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

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 is expressed in 2021 CAD.
- The USD/CAD exchange rate was assumed to be 0.78 for the study period.
- Natural gas prices were assumed to be an average of $4/MMBtu throughout the study period.
- 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; the life of the line was assumed to be 70 years; and the life of the SCGT generation and storage assets was assumed to be 30 years and 10 years respectively. The life of the storage asset was based 3600 cycles, which is assumed to be used to serve the local need first, and then global energy and ancillary services for the rest of the year. Cost of asset replacement were included where necessary to ensure the same NPV study period.
- Development timelines for transmission was assumed to be seven years; development timelines for generation and storage were assumed to be three years.
- A SCGT was identified as one of the lowest-cost resource alternatives. The estimated overnight cost of capital assumed is about $2000-$2500/kW (2021 CAD) depending on the unit size, based on escalating values from a previous study independently conducted for the IESO.[1]
- An energy storage facility was identified as another low-cost resource alternative. Total energy storage system costs are composed of capacity and energy costs (I.e. energy storage devices are constrained by their energy reservoir). The estimated overnight cost of capital assumed is about $900-$2300/kW (2021 CAD) depending on the storage capacity to energy requirement, based on escalating Ontario-specific values from a previous study independently conducted for a collection of entities including the IESO.
- Sizing of the 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 gas resources to sufficiently charge to meet the hours of unserved energy.

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[1] Generally speaking, the most cost-effective transmission-connected options for meeting local needs in the Peterborough to Kingston area are resources with performance and costs on par with SCGT or CCGT generators depending on the relative size of the capacity versus energy requirements. New natural gas-fired generation was considered in the economic analysis for illustrative purposes to represent the cost of new generation.

- System capacity value was $130k/MW-yr (2021 CAD) based on an estimate for the Cost of the Marginal New Resource (Net CONE), a new SCGT in southwestern Ontario, with a sensitivity of +/- 25% assessed.

- Production costs were determined based on energy requirements to serve the local reliability need, assuming fixed operating and maintenance costs of $28-$41/kW-yr for natural gas-fired resources and $11-$14/kW-yr for storage, and variable operating and maintenance costs of $6/MWh.

- Carbon pricing assumptions are based on the proposed Federal carbon price increase, from $50/t in 2022 to $170/t by 2030, and applied to a facility's production.

- 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.

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