Kitchener-Waterloo-Cambridge-Guelph Region

Integrated Regional Resource Plan Appendicies

May 2021

Connecting Today.
Powering Tomorrow.

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List of Abbreviations

Alectra	Alectra Utilities Corp.
CDM	Conservation Demand Management
Centre Wellington Hydro	Centre Wellington Hydro Ltd.
DER	Distributed Energy Resources
DG	Distributed Generation
DSC	Distribution System Code
Energy+	Energy+ Inc.
FIT	Feed-in Tariff
GATR	Guelph Area Transmission Refurbishment
Halton Hills Hydro	Halton Hills Hydro Inc.
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
KWCG Region	Kitchener, Waterloo, Cambridge and Guelph
LAC	Local Advisory Committee
LDC	Local Distribution Company
LMC	Load Meeting Capability
LRT	Light Rail Transit
LTR	Limited Time Rating
LV	Low-voltage
Milton Hydro	Milton Hydro Distribution Inc.
MTS	Municipal Transformer Station
MW	Megawatt
NERC	North American Electric Reliability Corporation
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
TOU	Time-of-Use
TS	Transformer Station
TSC	Transmission System Code
Wellington North Power	Wellington North Power Inc.
WNH	Waterloo North Hydro Inc.
Working Group	Technical Working Group of the KWCG Region

Appendix A - Methodology and Assumptions for Demand Forecast

The sections that follow describe the IESO's methodology to adjust the forecast for extreme weather, LDC methodologies to forecast demand in their respective service area, and the energy efficiency assumptions used to modify the demand based on expected energy efficiency savings. Table A.1 on page 13, to Table A.2 on page 15 show the final non-coincident and coincident extreme demand forecast, respectively, per station used for the KWCG IRRP assessments. The coincident load forecast includes the estimated reduction due to CDM plus DG with the values shown in Table A.3 on page 17. Table A.4 on page 19 also shows the gross demand forecast per station as provided by LDCs.

A.1 Method for Accounting for Weather Impact on Demand

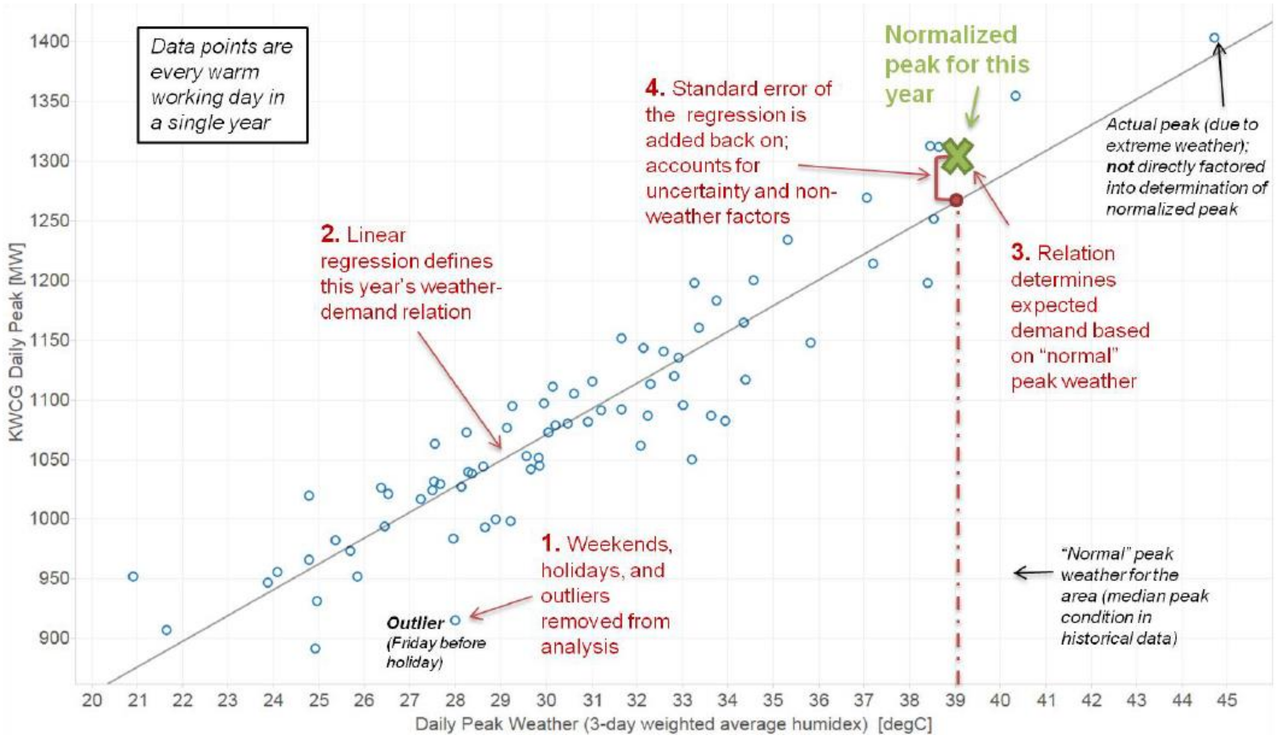
Weather has a large influence on the demand for electricity, so to develop a standardized starting point for the forecast, the historic electricity demand information is weather-normalized. This section details the weather-normalization process used to establish the starting point for regional demand 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 LDC load basis was provided to each LDC. This data was used as a start point from which to develop 20-year demand forecasts, using the LDCs preferred methodology (described in the next 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. 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 counties and townships surrounding the Region of Waterloo and Guelph area (Wellington County, and Oxford County - Blandford-Blenheim Township). Three step-down stations supply the area from the transmission system as follows:

- 230/44 kV Fergus TS supplied by 230 kV circuits D6V and D7V
- 115/27.6 kV Puslinch DS supplied by 115 kV circuits B5G and B6G
- 115/27.6 kV Wolverton DS supplied by 115 kV circuit D7F

There are about 14,000 Hydro One Distribution retail customers directly connected to Hydro One's distribution system. There are embedded LDCs connected to Hydro One's distribution system.

A.2.1. Factors that Affect Electricity Demand

Hydro One Distribution serves mostly the rural areas outside the major cities such as Kitchener, Waterloo, Guelph and Cambridge. 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.

Some of the smaller communities such as Elora, Fergus and Rockwood are in the embedded LDCs to Hydro One Distribution. The load growth in these communities is therefore factored in the Hydro One Distribution load forecast.

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 Waterloo North Hydro Forecast Methodology

Waterloo North Hydro (WNH) owns and operates the electricity distribution system in its licensed service area in the City of Waterloo and the Townships of Woolwich and Wellesley, serving approximately 58,000 customers. WNH's customer base is comprised of primarily residential (89% by customer count) and commercial/institutional loads (10% by customer count). WNH's largest loads include universities, high-tech companies and financial institutions. A small component of the WNH load base comes from the industrial/manufacturing sector (1% by customer count).

WNH is supplied through the Hydro One transmission system at primary voltages of 115 kV and 230 kV. Electricity is then distributed through WNH's service area by three MTSs and 6 municipal distribution stations. WNH's distribution system is divided into the 13.8 kV system servicing the core of the City of Waterloo, and the 27.6 kV system servicing the outskirts of the City of Waterloo as well as the township areas. WNH also has some 8.32 kV distribution throughout its rural service territory.

A.3.1. Factors that Affect Electricity Demand

There are two major factors affecting electricity demand within WNH's service territory and both are municipally driven; one by the City of Waterloo, and one by the Region of Waterloo.

As a result of recessions in the late 1980’s and early 1990’s, the City of Waterloo formulated a strategic plan to capitalize on the two very reputable local universities (University of Waterloo and Wilfrid Laurier University) and create conditions for students who attend the local universities to start new business and remain in this area. The City of Waterloo became a leader in fostering high-tech industry start-ups and full businesses, with Blackberry being an example of its global business successes as a direct result. Demand in the housing market was very strong resulting in the City of Waterloo developing to the limits of its boundaries and running out of greenfield developable land. This resulted in the city setting a new strategy of brownfield re-development, which continues to grow. Most of the brownfield re-development is in the area abutting the two local universities as well as the uptown core of the City of Waterloo. In most cases, the re-development consists of the demolition of a few single dwelling residential units being replaced with multi-unit residential complexes. It is very common to see the footprint of four houses being developed into high rise apartments with 100 dwelling units. This plan has also lead to the development of the West-side employment lands, which is a 45.2-hectare employment business park, meant to create up to 8,000 new jobs in the area and further foster innovation and high-tech industry growth in the City of Waterloo.

The second driving factor for electricity demand growth in WNH’s service territory is the Region of Waterloo’s strategy in supporting the provincial Places to Grow policy. The Region of Waterloo has limited urban sprawl by setting hard boundaries for greenfield development to coincide with existing city limits. To support the provincial policy as well as the city’s efforts to intensify the uptown and university neighbourhoods, the Region of Waterloo has installed the first phase of its light rail transit (LRT) system, connecting Waterloo and Kitchener, while planning a second phase that will ultimately connect the three local cities: Waterloo, Kitchener, and Cambridge. This initiative is meant to drive commercial and residential development along the new line, increasing electricity demand.

The regional plan also sets new areas of greenfield development, labeled as East Side Lands, to be just outside of Kitchener along Highway 7 leading toward Guelph, and extending south into Energy+ service territory all the way to Highway 401. The planned land uses involve residential, commercial, and industrial sectors and is located along the proposed new Highway 7 route, as well as a railway route identified by MetroLinx as their next major growth potential location. Electrical demand in this area is expected to be at higher densities due to the industrial component of land use as well as high-tech data centre applications of the commercial space. While residential development in this area has already begun, the timing of the railway route and new Highway 7 are expected to directly impact when the commercial and industrial development happens.

Over the last couple of years, WNH has also observed a peak demand impact as a result of further deployment of distributed energy resources, including behind-the-meter generation, and conservation efforts.

A.3.2. Forecast Methodology and Assumptions

In developing the load forecasts, WNH 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 forecast is developed for each TS that is consistent with load growth potential within the service area of that station and overall system growth. WNH uses geometric growth trend methodology (trending) to extend past growth rates of electricity demand into the future.

WNH has been trending the system peak data for the past 26 years and has analyzed this data with respect to typical rolling 3-year, 5-year, and 10-year growth rates. WNH service territory has lately experienced rolling 10-year gross load growth rates between 1-2%, sometimes reaching almost 3% (this growth excludes effects of known CDM as well as generation). The coincident peak data (September 5th, 2018 at hour 17) has been used as the base for the load forecast. Due to the fabric of the WNH customer base, the system peak for WNH is affected to a higher degree by weather and local development conditions and to a lesser degree by provincial or global factors. WNH's system peak has a tendency to rebound from recessions faster than in other Ontario jurisdictions. The historical load data from 1992 to 2018 includes a mixture of hot and cool summers, and was therefore considered an appropriate blend to be used as a basis for future trending. The rolling gross geometric growth rate since 1992 is 2.37%. The latest 10-year gross geometric growth rate is 1.91%. The gross load forecast has been prepared such that by the end of the study period in 2038, the geometric growth rate is consistent with past trends, while taking into account short and long-term development potential.

A.4 Kitchener-Wilmot Hydro Forecast Methodology

Kitchener-Wilmot Hydro owns and operates the electricity distribution system in its licensed service area in the City of Kitchener and the Township of Wilmot, serving approximately 100,000 Residential, General Service, Large Use, Street Light, Unmetered Scattered Load and Embedded Distributor rate customers.

Kitchener-Wilmot Hydro is supplied through the Hydro One transmission system at primary voltages of 115 kV and 230 kV. Electricity is then distributed through Kitchener-Wilmot Hydro's service area (411 square kilometers) by eight MTSs (27.6 kV and 13.8 kV) and seven municipal distribution stations (8.32 kV).

A.4.1. Factors that Affect Electricity Demand

There are multiple factors affecting electricity demand within the Kitchener-Wilmot Hydro service area.

The first factor driving electricity demand is population growth. In response to the Ontario's Place to Grow plan, the Region of Waterloo has published its Official Plan with forecast population growth. In Kitchener-Wilmot Hydro's service area, it is estimated that the population will increase from 232,200 in 2006 to 341,500 in 2029, and the employment will increase from 106,100 in 2006 to 139,700 in 2029. The growth in population and employment will drive the electricity demand for the next 20 years.

The second factor impacting the electricity demand is the change in the industrial sector. The City of Kitchener is experiencing a conversion from being a manufacturing-oriented economy to a more diversified and balanced economy. Kitchener-Wilmot Hydro has lost its top three load customers in the past 10 years. In the meantime, more customers with smaller demand emerge in the industrial and commercial sectors.

The third factor impacting electricity demand growth is the Region of Waterloo's Regional Official Plan. To support the provincial policy in the Places to Grow Act, as well as the city's efforts to intensify the Kitchener downtown area, the Region of Waterloo installed a LRT system between Waterloo and Kitchener, with a plan to extend the rail system to Cambridge.

The installation of the LRT is spurring development along the train route in both the residential and commercial sectors.

The fourth factor impacting the electricity demand is the rising awareness of renewable energy generation development and CDM. As directed by the OEB, Kitchener-Wilmot Hydro is currently participating in multiple provincial renewable energy programs and CDM programs, which help control and reduce the electricity demand. Time-of-Use (TOU) is also shifting demand and conserving energy as the customers manage their electricity use and control their hydro costs.

A.4.2. Forecast Methodology and Assumptions

In developing the reference forecast, Kitchener-Wilmot Hydro uses trend analysis (trending) to extend past growth rates of electricity demand into the future. A linear-trend method that uses the historical data of demand growth to forecast future growth has been applied. The coincident peak data (September 5th, 2018 at hour 17) has been used as the base for load forecast. A long-term 6.22 MW annual gross demand growth from 2011 to 2030 has been projected, with 60% of the annual load growth (3.73 MW) attributable to residential customers, and 40% (2.49 MW) attributable to commercial and industrial customers. The annual demand growth has been allocated to each transformer station based on the municipal development plan, available vacant lands and other local knowledge.

This annual demand growth rate covers both load additions of new customers and load maturation of the existing customers. The projected long-term annual demand growth is derived from the average load growth for the observed summer peaks from 1993 to 2006. The more recent data of 2007-2020 were biased and ignored due to multiple factors, like conservation and distributed generation, TOU pricing, and the economic downturn of the credit crisis and the pandemic.

A.5 Energy+ Forecast Methodology

Energy+ Inc. ("Energy+") provides electricity distribution service to the City of Cambridge, the Township of North Dumfries, part of the County of Brant, part of the City of Brantford and a number of customers along its boundary in the Township of Blanford-Blenheim and the City of Hamilton. The Energy+ Brant/Brantford distribution system is electrically separate from the Cambridge/North Dumfries distribution system so Brant/Brantford information is not included as part of this study area.

Energy+ distributes electricity to approximately 67,000 customers, of which 88% are residential, 10.7% are commercial, 0.9% are generators and 0.4% are industrial. There are also some other customers who are embedded Local Distribution Companies, street lighting and unmetered scattered load.

Energy+'s service area covers 562 square kilometres. Energy+ receives power from Hydro One Networks and delivers power to its customers in Cambridge/North Dumfries via four high voltage transformer stations. One of those stations is owned by Energy+ and the others are owned by Hydro One. Energy+'s principal primary distribution voltage is 27.6 kV.

A.5.1. Factors that Affect Electricity Demand

The City of Cambridge and the Township of North Dumfries are located in the Region of Waterloo. The Region of Waterloo is included in the Province of Ontario's "A Place to Grow" Plan. This Plan shows a forecasted Region of Waterloo 2051 population of 923,000. The year-end 2019 Region of Waterloo population was 612,870.

The Cambridge area continues to see increased density in the form of high rise apartment/condominium residential buildings, re-use of decommissioned industrial land for new residential development in built-up areas and residential growth in new areas.

Significant future residential growth is expected to come from planned subdivisions located in the South-East Galt area bounded by Franklin Boulevard, Main Street, Dundas Street and the East limit of the city boundary, the Cambridge West community and new residential subdivisions North of Highway 401 and East of Speedsville Road. The total number of new residential units in the City of Cambridge increased from 566 units in 2018 to 942 units in 2019 for a 66% increase.

Servicing of the first areas of the "East Side Lands" is underway. The "East Side Lands" located in the North-West part of the City of Cambridge and the adjacent municipality of the Township of Woolwich will provide significant non-residential growth over the coming years.

The connection of Distributed Energy Resources (DERs) to the Energy+ distribution system will continue to impact the level of demand/energy obtained from the transmission grid.

The level of overall economic growth always has an impact on electricity demand especially for industry.

Weather extremes continue to have a large impact of peak demand because of air conditioning load on hot summer days.

The expected larger market share for electric vehicles may have a substantial impact on local electricity demand.

A.5.2. Forecast Methodology and Assumptions

The load forecast methodology looks at the historical load patterns as well as local development and growth projections for the distribution system. The projected load growth and timing of development required consultation and some assumptions are made with respect to the timing of when load will materialize. For the 2019/2020 forecast, Energy+ assessed its growth projections by each transformer station to make an informed assessment on the projected growth.

On average, Energy+ is expecting to see a 1% growth for most parts of its distribution system with the exception of loads that are in the North West part of Cambridge which are expected to be closer to 3% up until at least 2024. The outlook beyond 2024 is less certain and therefore Energy+ reduced the growth projection to 1.5% for the forecasted period for specifically the North West part of Cambridge.

A.6 Alectra Forecast Methodology

Alectra Utilities Corp. (Alectra) owns and operates the electricity distribution system in its licensed service area in the City of Guelph and the Village of Rockwood serving approximately 52,000 customers. Alectra's customer base is represented by a mixture of residential customers (91% by customer count, 22% by load) and Commercial/Industrial /Institutional customers (9% by customer count and 78% by load). Alectra services five Large Use rate customers represented by a university and industrial/manufacturing facilities.

Alectra is supplied through the Hydro One transmission system at primary voltages of 115 kV and 230 kV within the City of Guelph. Electricity is then distributed through Alectra's service territory by three Hydro One owned transformer stations, Campbell TS, Cedar TS and Hanlon TS and the Alectra owned Arlen MTS. The Alectra distribution system in the City of Guelph is serviced at 13.8 kV. The Village of Rockwood is supplied through the Hydro One distribution system at a primary voltage of 44 kV. Electricity is then distributed through the Village of Rockwood by two Alectra owned MTSs, and one Hydro One distribution station. Alectra's distribution system in the Village of Rockwood is serviced at 8.32 kV.

A.6.1. Factors that Affect Electricity Demand

The major variables affecting electricity demand within Alectra's service territory in the City of Guelph are related to population growth rate associated with the provincial places to grow targets as well as economic development within both the current industrial/manufacturing rate class sector and future development and use of industrial parks. The rate and level of future demand increases are highly dependent on each one of these factors.

The City of Guelph has been designated as one of 25 municipalities listed in the Growth Plan as an Urban Growth Centre. The city is directed to increase its population to 175,000, which is an increase of over 50,000 people.

Another significant factor in the demand of electricity is linked to economic development within both our current and future customer base. A significant portion of the electricity demand within Alectra's service territory is associated with the manufacturing sector.

Economic development as it relates to future utilization of industrial park land represents a large portion of future increase to electricity demand within the city. The most significant development is the Hanlon Creek Business Park located in the south end of Alectra's service territory and represents a total land mass of over 370 acres. Approximately 8% of the land within the business park has been consumed to date and reflective in the current electricity demand with the remaining accounted for in the forecast.

A.6.2. Forecast Methodology and Assumptions

Alectra's methodology for developing the base load forecast consisted of a number of elements including historical loading trends, local knowledge of planned development and City of Guelph development planning information. Planning information from the City of Guelph was the starting point to formulate a maximum development forecast in order to set the parameters of the long-range load forecast for its service territory given the study period. Using this information along with 30+years of historic peak loading information, local knowledge and information regarding transformer stations service areas within Alectra's service territory, the load forecast was created for each delivery point location.

A.7 Energy Efficiency Assumptions in Demand Forecast

Energy efficiency measures can reduce the electricity demand and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and Energy Efficiency Programs. The assumptions used for the KWCG IRRP forecast are consistent with the energy efficiency assumptions in the IESO's 2019 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 forecast residential, commercial, and industrial gross demand. A top down approach was used to estimate peak demand savings from provincial level to the Southwest transmission zone and then allocated to KWCG Region. This appendix describes the process and methodology used to estimate energy efficiency savings for the KWCG Region and provides more detail on how the savings for the two categories were developed.

A.7.1. Estimate Savings from Building Codes and Equipment Standards

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 Southwest 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.

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 residential annual peak reduction percentages of each year were applied to the forecast residential demand at each station to develop an estimate of peak demand impacts from codes and standards. By 2038, the residential sector in the region is expected to see about 7.1% peak demand savings through standards. The same is done for the commercial sector, which will see about 4.9% peak-demand savings through codes and standards by 2038. The sum of the savings associated with the two sectors are the total peak demand impact from codes and standards. There are no savings from codes and standards considered to be associated with the industrial sector.

A.7.2. Estimate Savings from Energy Efficiency Programs

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 Conservation First Framework wind-down and the Interim Framework. A top down approach was used to estimate the peak demand reduction due to the delivery of 2019 and 2020 programs, from provincial to Southwest zone to the stations in the region. Persistence of the peak demand savings from energy efficiency programs were considered over the forecast period.

Similar to the estimation of peak demand savings from codes and standards, annual peak demand reduction percentages of program savings were developed by sector. The sectoral percentages were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in Southwest transmission zone. They were then applied to sectoral gross peak forecast of each station in the region. By 2020, the residential sector in the region is expected to see about 0.6% peak demand savings through programs, while commercial sector and industrial sector will see about 2.3% and 0.7% peak reduction respectively. Those savings will decay over time as the energy efficiency measures come to the end of their effective useful lives.

A.7.3. Total Energy Efficiency Savings and Impact on the Planning Forecast

As described in the above sections, peak demand savings were estimated by sector for each forecast category, and totalled for each station in the region. The analyses were conducted under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting forecast savings were applied to gross demand to determine net peak demand for further planning analyses.

Table A.1 | Final Non-Coincident Extreme Peak Demand Forecast (MW) per Station in KWCG Region

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Arlen MTS	30	31	32	32	33	34	35	36	37	38	40	41	42	43	45	46	47	49	50
Campbell TS (T1/T2)	91	91	92	92	92	92	93	93	93	94	95	97	97	98	98	99	99	100	100
Campbell TS (T3/T4)	53	53	53	53	53	55	56	56	56	56	57	57	57	58	58	58	59	59	59
Cedar TS (T1/T2)	78	79	79	80	81	81	82	82	83	84	85	85	86	87	88	89	90	91	92
Cedar TS (T7/T8)	39	40	40	40	40	40	40	40	40	41	41	41	41	41	41	42	42	42	42
CTS	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Elmira TS	39	39	40	41	41	42	43	43	44	45	49	50	51	52	57	58	59	60	61
Energy+ MTS #1	94	95	95	96	97	98	99	100	101	103	105	106	107	109	110	112	113	115	117
Fergus TS	106	108	110	112	112	112	113	115	115	116	122	123	124	125	121	122	122	123	124
Galt TS	126	127	128	129	130	131	132	134	135	136	138	140	142	144	146	147	149	151	153
Hanlon TS	31	31	32	32	33	33	33	34	34	35	35	36	36	37	37	38	39	39	40
Kitchener MTS #1	39	40	41	42	42	43	43	44	45	46	46	47	48	48	49	50	51	51	52
Kitchener MTS #3	57	57	58	59	59	60	60	61	62	62	63	64	65	66	67	67	68	69	70
Kitchener MTS #4	66	66	67	68	68	69	69	70	70	71	72	72	73	74	74	75	76	77	77

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Kitchener MTS #5	74	75	76	76	77	77	78	78	79	80	80	81	82	82	83	84	85	86	86
Kitchener MTS #6	71	71	72	72	73	73	74	74	75	76	77	77	78	79	79	80	81	82	83
Kitchener MTS #7	48	49	49	50	50	51	52	52	53	53	55	55	56	56	57	58	59	59	60
Kitchener MTS #8	44	46	47	48	50	51	53	55	57	59	61	63	65	67	68	70	72	74	76
Kitchener MTS #9	39	40	40	41	41	41	42	49	50	51	51	52	52	53	54	55	55	57	57
Preston TS	108	114	117	119	120	122	123	125	126	128	130	132	134	136	137	139	141	143	145
Puslinch DS	33	33	34	34	34	35	35	36	36	36	37	37	38	38	39	39	40	40	41
Rush MTS	51	55	55	55	56	56	56	57	57	57	58	62	62	62	63	63	64	65	65
Scheifele MTS	153	154	155	156	157	158	159	160	161	163	165	163	164	166	167	169	171	172	174
WNH MTS #3	63	61	62	63	64	65	67	68	69	70	72	73	74	76	77	79	81	82	84
Wolverton DS	21	20	21	21	21	21	21	21	21	21	21	21	21	22	22	22	22	22	23
Total	1558	1581	1600	1615	1631	1648	1665	1689	1706	1725	1758	1781	1800	1821	1843	1867	1890	1913	1937

Table A.2 | Final Coincident Extreme Peak Demand Forecast (MW) per Station in KWCG Region

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Arlen MTS	28	29	30	31	32	32	33	34	35	36	38	39	40	41	42	43	45	46	47
Campbell TS (T1/T2)	91	91	91	92	92	92	93	93	93	94	95	96	97	97	98	99	99	100	100
Campbell TS (T3/T4)	53	53	53	53	53	55	56	56	56	56	56	57	57	58	58	58	59	59	59
Cedar TS (T1/T2)	75	75	76	76	77	77	78	79	79	80	81	81	82	83	84	85	86	87	87
Cedar TS (T7/T8)	38	38	38	38	38	38	38	38	39	39	39	39	39	39	39	40	40	40	40
CTS	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Elmira TS	39	39	40	41	41	42	43	43	44	45	49	50	51	52	57	58	59	60	61
Energy+ MTS #1	92	93	93	94	95	96	97	98	99	100	102	104	105	106	108	109	111	113	114
Fergus TS	95	98	99	101	101	101	102	104	104	104	110	111	111	112	109	110	110	111	111
Galt TS	120	121	121	122	123	125	126	127	128	129	131	133	135	136	138	140	142	144	146
Hanlon TS	30	31	31	31	32	32	33	33	34	34	35	35	36	36	37	37	38	39	39
Kitchener MTS #1	35	36	37	37	38	38	39	40	40	41	42	42	43	44	44	45	46	46	47
Kitchener MTS #3	50	50	51	51	52	52	53	54	54	55	56	56	57	58	58	59	60	61	61
Kitchener MTS #4	63	64	65	65	66	66	67	67	68	68	69	70	70	71	72	72	73	74	75

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Kitchener MTS #5	70	71	71	72	72	73	73	74	74	75	76	76	77	78	78	79	80	81	81
Kitchener MTS #6	66	67	67	68	68	69	69	70	70	71	72	72	73	74	74	75	76	77	77
Kitchener MTS #7	46	47	48	48	49	49	50	50	51	52	53	53	54	55	55	56	57	57	58
Kitchener MTS #8	37	38	39	40	42	43	45	46	48	50	51	53	54	56	58	59	61	63	64
Kitchener MTS #9	36	37	37	38	38	39	39	46	47	47	48	48	49	49	50	51	52	53	53
Preston TS	102	108	111	112	113	115	116	118	119	121	123	124	126	128	130	131	133	135	137
Puslinch DS	33	33	34	34	34	35	35	35	36	36	37	37	38	38	39	39	39	40	40
Rush MTS	48	52	52	52	53	53	53	54	54	54	55	58	59	59	60	60	61	61	62
Scheifele MTS	147	149	150	150	151	152	153	154	155	157	159	157	158	160	161	163	164	166	167
WNH MTS #3	60	58	59	60	61	62	63	64	66	67	68	69	71	72	74	75	77	78	80
Wolverton DS	18	18	18	18	18	18	18	18	19	19	19	19	19	19	19	19	20	20	20
Total	1478	1500	1517	1531	1546	1562	1578	1600	1617	1635	1665	1687	1705	1725	1746	1769	1790	1812	1835

Table A.3 | CDM and DG Contribution (MW) Considered in Coincident Extreme Peak Demand Forecast

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Arlen MTS	0.8	0.8	0.9	1.1	1.1	1.2	1.3	1.5	1.5	1.5	1.5	1.6	1.6	1.7	1.8	1.8	1.9	1.9	2.0
Campbell TS (T1/T2)	4.1	4.2	4.4	4.6	4.8	5.0	5.1	5.4	5.5	5.5	5.1	3.8	3.9	3.9	3.9	3.6	3.6	3.6	3.7
Campbell TS (T3/T4)	3.2	3.3	3.4	3.6	3.7	2.1	2.2	2.4	2.5	2.5	2.4	2.1	2.2	2.2	2.3	2.2	2.2	2.2	2.2
Cedar TS (T1/T2)	1.5	1.6	1.7	2.0	2.1	2.3	2.5	2.7	2.9	3.0	3.2	3.3	3.4	3.5	3.4	3.4	3.4	3.4	3.4
Cedar TS (T7/T8)	0.6	0.6	0.7	0.8	0.9	0.9	1.0	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.4	1.4
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
Elmira TS	4.6	4.7	4.8	5.0	5.1	5.2	5.3	5.5	5.6	5.7	2.6	2.7	2.8	2.5	2.6	2.5	2.5	2.6	2.6
Energy+ MTS #1	3.7	3.8	4.0	4.3	4.5	4.8	5.0	5.3	5.5	5.6	5.0	4.9	5.0	5.2	5.2	4.9	4.9	4.6	4.6
Fergus TS	9.5	9.7	10.1	10.5	10.8	11.2	11.5	10.5	10.7	11.0	6.5	6.2	6.4	6.1	6.0	6.0	6.1	6.1	6.0
Galt TS	4.4	4.6	5.1	5.6	6.1	6.6	7.0	7.5	7.9	8.3	8.0	8.1	8.4	8.3	8.2	8.3	8.4	8.5	8.3
Hanlon TS	0.8	0.8	0.9	1.0	1.1	1.2	1.2	1.3	1.4	1.4	1.4	1.3	1.4	1.4	1.5	1.4	1.4	1.4	1.4
Kitchener MTS #1	1.0	1.1	1.2	1.4	1.5	1.7	1.8	2.0	2.1	2.2	2.3	2.2	2.3	2.5	2.6	2.6	2.7	2.7	2.7
Kitchener MTS #3	1.8	1.9	2.1	2.3	2.5	2.7	2.9	3.1	3.3	3.4	3.2	3.2	3.3	3.5	3.4	3.4	3.5	3.5	3.5
Kitchener MTS #4	2.0	2.1	2.4	2.7	2.9	3.1	3.3	3.6	3.8	3.9	4.0	4.0	4.1	4.3	4.3	4.2	4.3	4.3	4.3

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Kitchener MTS #5	2.4	2.5	2.8	3.1	3.4	3.6	3.8	4.2	4.4	4.5	4.5	4.5	4.6	4.7	4.7	4.7	4.7	4.7	4.7
Kitchener MTS #6	2.5	2.6	2.9	3.2	3.4	3.7	3.9	4.2	4.4	4.4	4.2	4.3	4.4	4.5	4.6	4.6	4.6	4.6	4.5
Kitchener MTS #7	1.6	1.7	1.9	2.1	2.3	2.5	2.6	2.8	3.0	3.1	2.8	2.8	2.9	3.1	3.2	3.2	3.3	3.3	3.4
Kitchener MTS #8	1.3	1.4	1.6	1.8	1.9	2.2	2.3	2.6	2.8	2.9	3.0	3.1	3.3	3.4	3.5	3.6	3.6	3.7	3.7
Kitchener MTS #9	8.3	8.4	8.6	8.8	8.9	9.1	9.2	3.3	3.5	3.5	3.6	3.7	3.7	3.8	3.8	3.5	3.5	3.0	3.0
Preston TS	2.2	2.4	2.5	2.7	2.9	3.0	3.2	3.4	3.5	3.6	3.2	3.3	3.4	3.4	3.3	3.4	3.4	3.3	3.3
Puslinch DS	0.8	0.9	0.9	1.0	1.1	1.2	1.2	1.3	1.4	1.5	1.5	1.5	1.5	1.4	1.4	1.4	1.4	1.3	1.3
Rush MTS	1.3	1.5	1.6	1.9	2.0	2.3	2.4	2.6	2.8	2.8	2.9	3.2	3.3	3.4	3.5	3.6	3.6	3.6	3.6
Scheifele MTS	4.8	5.0	5.4	6.0	6.4	6.8	7.1	7.7	8.0	8.1	7.8	7.7	7.9	8.0	8.0	7.9	7.9	7.9	7.9
WNH MTS #3	1.9	2.0	2.1	2.4	2.6	2.8	3.0	3.3	3.5	3.6	3.7	3.7	3.9	4.1	4.1	4.1	4.1	4.2	4.1
Wolverton DS	0.5	0.7	0.8	0.9	0.9	1.0	1.1	1.1	1.2	1.3	1.3	1.4	1.4	1.4	1.3	1.3	1.4	1.4	1.2
Total	66.0	68.5	72.9	78.6	83.1	86.4	90.1	88.3	92.0	94.3	85.0	84.1	86.4	87.5	88.0	87.1	87.4	87.3	86.9

Table A.4 | LDC Coincident Gross Peak Demand Forecast (MW) per Station in KWCG Region

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Arlen MTS	27	28	29	30	30	31	32	33	34	35	36	37	39	40	41	42	43	45	46
Campbell TS (T1/T2)	88	89	89	90	90	90	91	91	92	92	93	93	94	94	95	95	96	96	97
Campbell TS (T3/T4)	52	52	53	53	53	53	54	54	54	55	55	55	55	56	56	56	56	57	57
Cedar TS (T1/T2)	71	71	72	73	73	74	75	76	76	77	78	79	80	80	81	82	83	84	84
Cedar TS (T7/T8)	35	36	36	36	36	36	36	37	37	37	37	37	38	38	38	38	38	39	39
CTS	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Elmira TS	40	41	42	43	43	44	45	46	47	47	48	49	50	51	55	56	57	58	59
Energy+ MTS #1	89	90	90	92	93	94	95	96	97	99	100	101	102	104	105	106	108	109	110
Fergus TS	98	100	102	104	104	105	106	106	107	108	108	109	110	110	107	108	108	109	109
Galt TS	115	116	118	119	121	122	124	125	127	128	130	131	133	135	136	138	140	142	143
Hanlon TS	29	29	30	30	31	31	32	32	33	33	34	34	35	35	36	36	37	37	38
Kitchener MTS #1	33	34	35	36	37	37	38	39	39	40	41	41	42	43	44	44	45	46	46
Kitchener MTS #3	48	49	49	50	51	51	52	53	53	54	55	55	56	57	58	58	59	60	60
Kitchener MTS #4	61	61	62	63	64	64	65	66	67	67	68	69	69	70	71	71	72	73	73

Station	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Kitchener MTS #5	67	68	69	70	71	71	72	73	73	74	75	75	76	77	77	78	79	79	80
Kitchener MTS #6	64	65	65	66	67	67	68	69	69	70	71	71	72	73	73	74	75	75	76
Kitchener MTS #7	45	45	46	47	47	48	49	50	50	51	52	52	53	54	54	55	56	56	57
Kitchener MTS #8	36	37	38	39	41	42	44	46	47	49	50	52	54	55	57	59	60	62	63
Kitchener MTS #9	42	43	43	44	44	45	46	46	47	47	48	48	49	50	50	51	51	52	53
Preston TS	97	102	105	106	108	109	111	112	114	115	117	119	120	122	123	125	127	129	130
Puslinch DS	31	32	32	33	33	33	34	34	35	35	35	36	36	37	37	38	38	38	39
Rush MTS	46	50	50	50	51	51	52	52	53	53	54	57	58	58	59	59	60	60	61
Scheifele MTS	142	143	144	145	147	148	149	151	152	153	155	153	155	156	157	159	160	162	163
WNH MTS #3	58	56	57	58	59	61	62	63	64	65	67	68	70	71	72	74	75	77	78
Wolverton DS	17	18	18	18	18	18	18	18	18	19	19	19	19	19	19	19	19	20	20
Total	1436	1459	1479	1498	1516	1535	1553	1572	1591	1610	1629	1648	1667	1687	1707	1727	1747	1767	1788

Appendix B - Solution Options to Load Restoration Need in the Cambridge Area

Table B.1 | Maximum 30-Minute/Fast 4-Hours Load Restoration Capability in the Cambridge Area for Faults on Galt-Preston Section of M20D & M21D

Option	Description	Load Restoration Capability (MW)*	Total Cost	Cost per Additional MW of Restored Load
-	Status Quo	180**	$0	$0
1	Add capacitor banks at Preston 230 kV TS for a total of 200 Mvar	300***	$7M	$58k
2	Add second Preston autotransformer plus capacitor banks at Preston 230 kV TS for a total of 300 Mvar	500***	$27M	$84k

* Preston 230 kV terminals on both M20D and M21D were closed for restoration. Operational measures on the 115 kV system, e.g., open low voltage bus-tie breakers/switches at 115 kV connected stations, may be required to secure the transmission system to handle a subsequent contingency.

** Preston autotransformer was locked to its pre-contingency tap position.

*** Load restoration capability may be reduced by the limited transfer capability of 115 kV path; requires further study in future planning activities/regional planning cycles

Appendix C - Development of the Plan

C.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 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 least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a two-week 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 C.1, three levels of electricity system planning are carried out in Ontario:

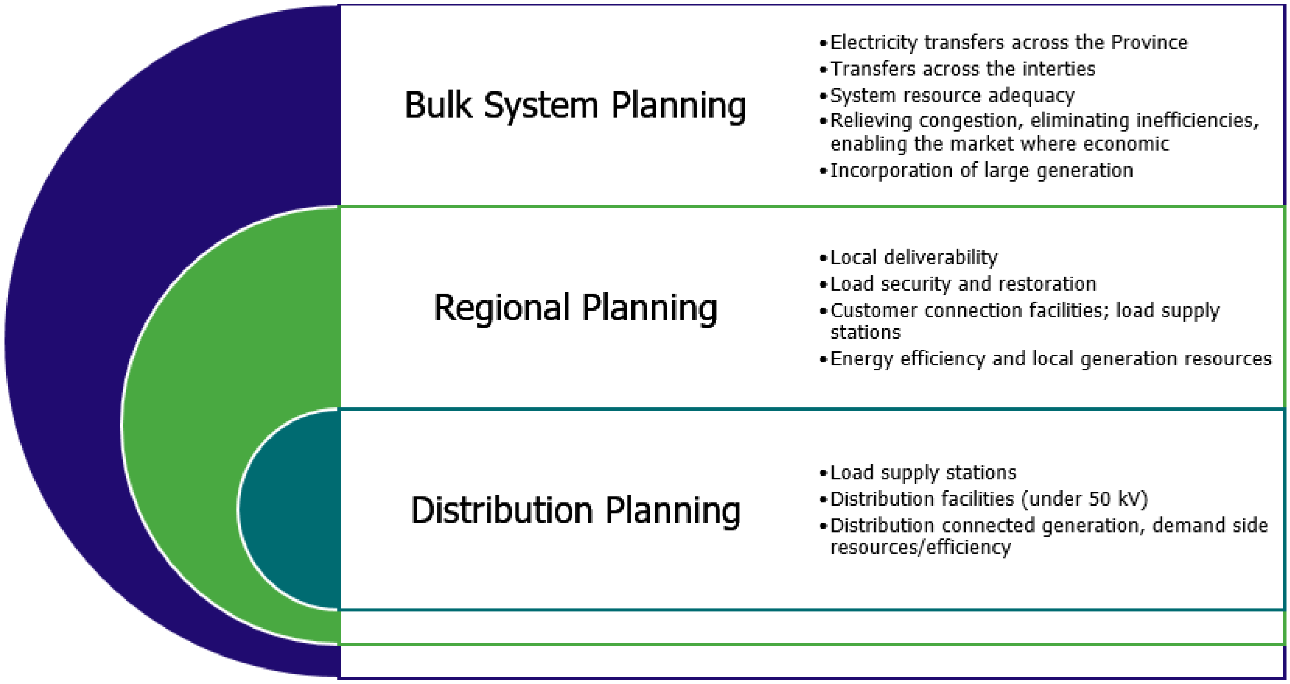
- Bulk system planning
- Regional system planning
- Distribution system planning

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 C.1 | Levels of Electricity System Planning



C.2 IESO's Approach to Regional Planning

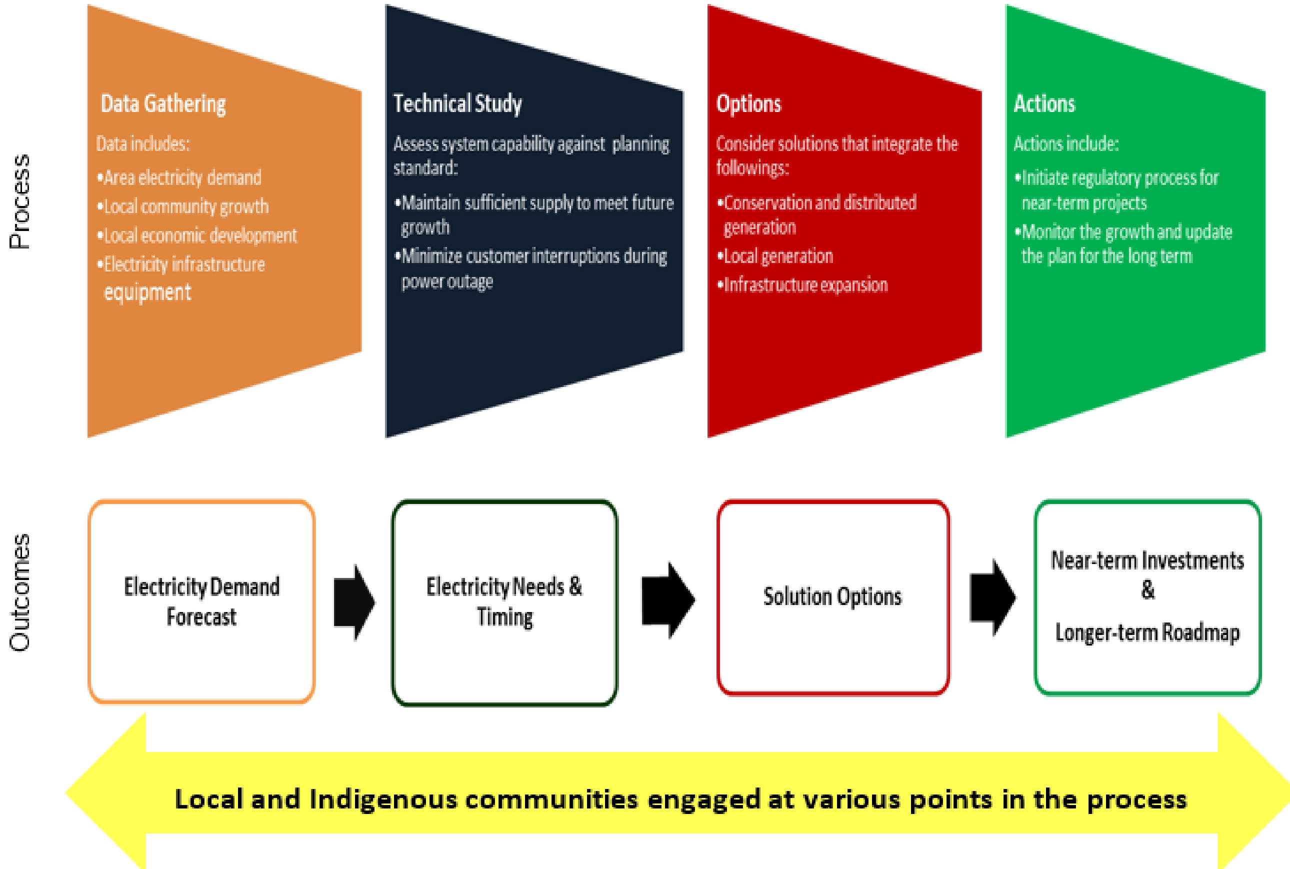
IRRPs assess electricity system needs for a region over a 20-year period, enabling near-term actions to be developed in the context of a longer-term view of trends. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

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 C.2). 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 C.2 | Steps in the IRRP Process



Appendix D – Short Circuit Assessment

Distribution system short circuit levels, as measured at the low-voltage (LV) bus of transmission connected transformer stations, are subject to change due to two main driving factors: changes in upstream impedance and changes in amount and type of DERs connected to the station. Changes in upstream impedance typically result from transmission system changes, such as transformer replacement or network expansion or reconfiguration.

The upstream impedance generally has minimal impact on the station LV actual short circuit and vice versa because of the dominant effect of the station transformers impedance. However, changes in the amount and type of DERs connected to a LV bus of a station have a significant and direct impact on the station LV short circuit level.

While equipment which limits the available short circuit capacity on the LV side of a transformer station may potentially be upgraded with higher rated equipment, the Working Group is cognizant that there is an effective practical limit to this rating as established in Appendix 2 of the Transmission System Code (TSC). Distribution systems components, including equipment owned by end-use customers, in Ontario, is designed, manufactured, and applied to this standard with the following short circuit capacities:

- 500 MVA @ 13.8 kV
- 800 MVA @ 27.6 kV
- 1500 MVA @ 44 kV

The aforementioned short circuit capacities are used for evaluating the amount of DER that can be connected to a station LV bus. Some stations may have a smaller value due to pre-existing legacy equipment which was adequate and is deemed to be grandfathered.

Table D.1 lists all stations in the KWCG Region where new DER connection is restricted because the LV short circuit level is extremely high, that is approximately equal to or greater than 90% of the capacity. The information presented in this table is obtained with consideration of known generation connections as of March 2021 and is subject to change primarily due to new DER connections.

The appropriate LDC should be consulted for up-to-date short circuit information and feasibility of connecting new DER. In particular, Hydro One List of Station Capacity[1], which is updated periodically, provides the estimated thermal and short circuit capacities of its stations for generation connections. A capacity calculator[2] is also available to help customers evaluate their connection.

[1] Available at https://www.hydroone.com/businessservices_/generators_/Documents/honi_lsc.pdf

[2] Available at https://www.hydroone.com/business-services/generators/station-capacity-calculator

Table D.1 | Stations with Extremely High Short Circuit Level*

Station	Bus	Owner	Nominal Voltage (kV)	Short Circuit Capacity** (MVA)	Short Circuit Level (MVA)
Campbell	EZ	Hydro One	13.8	443	437
Kitchener #1	B1B2	Kitchener-Wilmot Hydro	13.8	468	447
Kitchener #3	B51B61	Kitchener-Wilmot Hydro	13.8	468	436
Kitchener #3	B52B62	Kitchener-Wilmot Hydro	13.8	468	474***
Kitchener #4	B71B81	Kitchener-Wilmot Hydro	13.8	468	466
Kitchener #4	B72B82	Kitchener-Wilmot Hydro	13.8	468	467
Kitchener #5	B91B101	Kitchener-Wilmot Hydro	13.8	468	415
Kitchener #5	B92B102	Kitchener-Wilmot Hydro	13.8	468	415
Kitchener #6	B111B121	Kitchener-Wilmot Hydro	13.8	468	459
Kitchener #6	B112B122	Kitchener-Wilmot Hydro	13.8	468	459
Kitchener #7	B13B14	Kitchener-Wilmot Hydro	13.8	468	446
Rush	B1B2	Waterloo North Hydro	13.8	467	441
Scheifele A	BY	Waterloo North Hydro	13.8	500	455
Scheifele B	QT	Waterloo North Hydro	13.8	500	454

* Data provided in this table are valid as of March 2021. For up-to-date information, contact LDCs.
** Capacities smaller than TSC requirement are due to pre-existing legacy equipment which was adequate and is deemed to be grandfathered.
*** Affected feeder breakers are to be replaced.

Appendix E – East Side Lands

This appendix is provided by Waterloo North Hydro Inc. (WNH) and Energy+ Inc. (Energy+) to document the current state of their studies for future capacity needs in their respected territories and to help inform participants in the next cycle of regional planning.

E.1 Background

WNH and Energy+ are in discussions to establish the optimal planning outcome to meet the future load growth needs of each utility. This involves coordinating efforts as part of the IRRP process to assess the timing and needs for potential future transformer stations.

This review will look at the opportunity to meet the needs of both Energy+ and WNH from a single station in an effort to maximize efficiencies. Additionally, Hydro One Transmission replaces the transformers at Preston TS in 2025-2026 with like-for-like due to end-of-life. The new transformers would have higher LTRs sufficient to meet the needs. There is also physical space at Preston TS to add four new breaker positions.

Energy+ also has the option of moving the replacement date forward for an advancement fee, should the extra capacity be needed prior to 2025. This extra capacity was also considered during this analysis. This study also examined if there were any interim capacity needs required that may not necessitate the construction of a new station by sharing of feeders.

E.2 Executive Summary

The WNH and Energy+ joint study is summarized as follows:

- The uncertainty around both the timing and the types of loads in the East Side Lands for both WNH and Energy+ make forecasting the needed in service date difficult.
- Energy+ expects that in 2022 there may be more clarity around the load growth and load density in the East Side Lands to be able to more accurately forecast a needed in service date for Energy+ MTS #2.
- Energy+ plans to receive additional capacity from Hydro One Preston TS when the transformers are replaced in 2025-2026 and there will be an opportunity to add four new breaker position to take advantage of this capacity.
- Energy+ is building its distribution infrastructure in the East Side Lands for multiple load growth scenarios which includes up to four circuits.
- WNH can feed 27.6 kV load in City of Waterloo, currently fed by WNH Scheifele TS using WNH MTS #4 or Energy+ MTS #2 or Hydro One Preston TS, provided they are express feeders.
- Energy+ feeders from MTS #2 or Hydro One Preston TS are not considered candidates to pick up significant load in Elmira due to the reliability concerns that accompany the feeder length.

E.3 Discussion

The possible future sites of WNH MTS #4 and Energy+ MTS #2 are strategically located to service the areas where the most concentrated load growth is expected to occur. Figure E.1 to Figure E.3 show the areas of load growth as depicted by the Region of Waterloo, while Figure E.4 shows the location of stations mentioned in this IRRP. WNH also has a smaller geographical load growth centre identified for commercial/industrial development in the south-east part of the town of Elmira. The WNH MTS #4 lands are located in the town of Winterbourne and the Energy+ MTS #2 lands are located on Boychuk Drive in the City of Cambridge.

At this point in time, both WNH and Energy+ have difficulty in accurately quantifying the demand that these areas will require given the current status of development. For WNH, much of the non-residential load growth in WNH's East Side Lands is expected to be tied to the new Provincial Highway 7 corridor between Kitchener and Guelph. This is expected to attract industrial and commercial businesses in the Township of Woolwich, for which the lands have been appropriately zoned. However, given the uncertainty and delays associated with this project, WNH is unable to predict the timing of this new load and the expected load growth.

Energy+ expects development of its part of the East Side Lands to begin in 2021-2022 after which the amount of load growth in this area will become clearer. Presently, while Energy+ has received site plan applications, the potential uses of these sites are so diverse (e.g. data centre, manufacturing, warehouse storage) that accurately estimating the load growth is extremely challenging. Energy+ is building its distribution infrastructure with multiple demand scenarios in mind to be able to accommodate a range of applications. Since the location of Energy+ MTS #2 is within these East Side Lands, if the load growth in this area is higher or more rapid than anticipated, exceeding capacity at existing stations, Energy+ MTS #2 is well situated to add capacity to the Energy+ system. Energy+ MTS #2 would be connected to the Hydro One F11C/F12C 115 kV transmission lines and would be able to take advantage of much of the existing distribution infrastructure to supply its intended load.

In WNH's long-term system plan, all of WNH Scheifele TS is expected to be required to supply 13.8 kV loads within the City of Waterloo as density increases in the uptown core which would require the existing 27.6 kV loads to be supplied from another source. WNH has completed a study and determined that this area could be fed by WNH's future MTS #4 or from two Energy+ express feeders from either Energy+ MTS #2 or Hydro One Preston TS. Either solution would sufficiently supply the existing load with its inherent natural growth, without concern from a capacity or voltage perspective. WNH also has spare capacity at Hydro One Elmira TS to backup either Waterloo or Breslau. However, WNH requires clarification from the IESO and Hydro One on how much spare capacity can be used from Hydro One Elmira TS based on contingency analysis of the D10H transmission line radially feeding Elmira TS. Energy+ feeders, even if built as express feeders, are not considered suitable candidates for future load growth in this area as the feeder length would be above 30 km, raising reliability and voltage concerns for what is anticipated to be an industrial area.

WNH continues to monitor 13.8 kV load growth in Waterloo, however based on the pace of new developments does not see a near-term need where this capacity would be needed from WNH Scheifele TS.

Figure E.1 | East Side Lands in Region of Waterloo

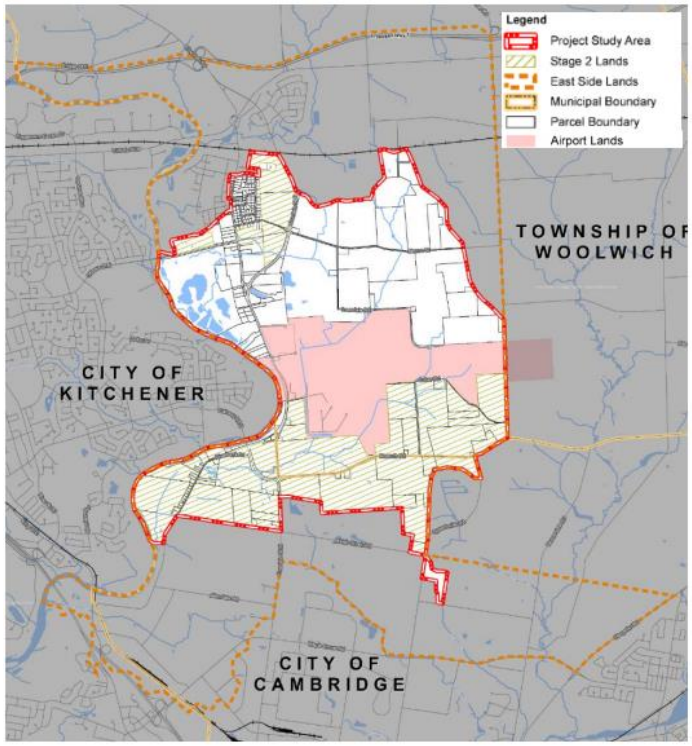


Figure E.2 | East Side Lands within Cambridge/North Dumfries (Including location of Energy+ MTS #2)

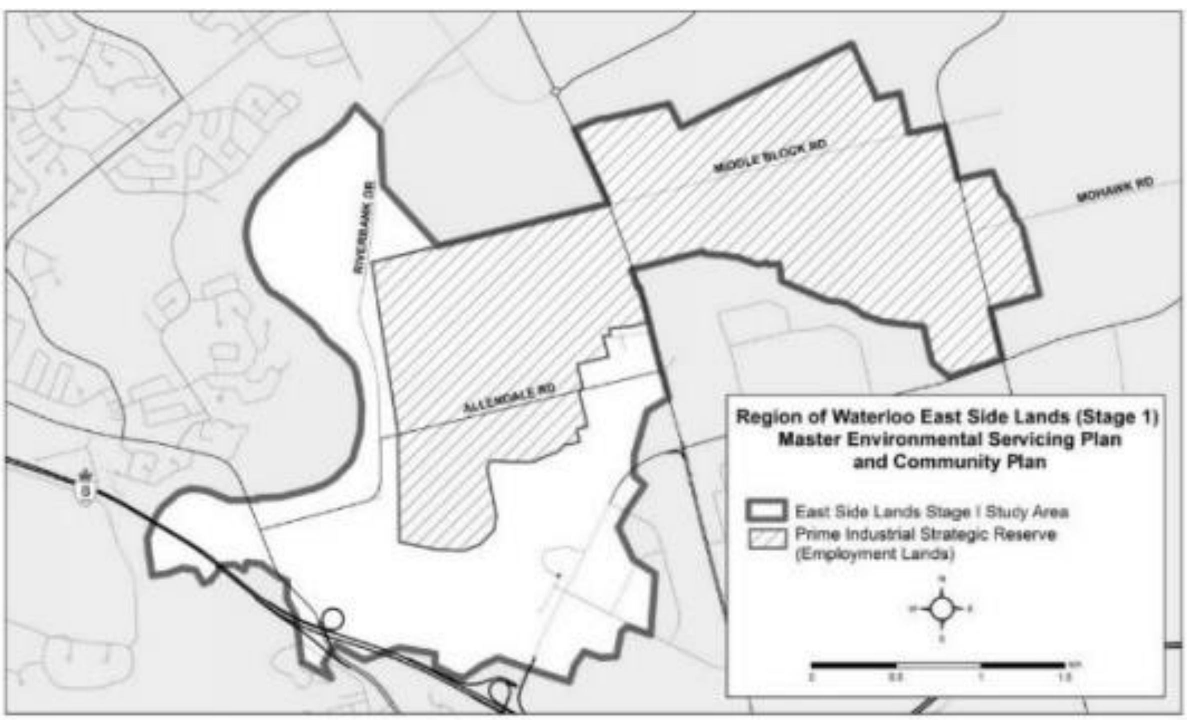


Figure E.3 | Elmira Load Growth Areas

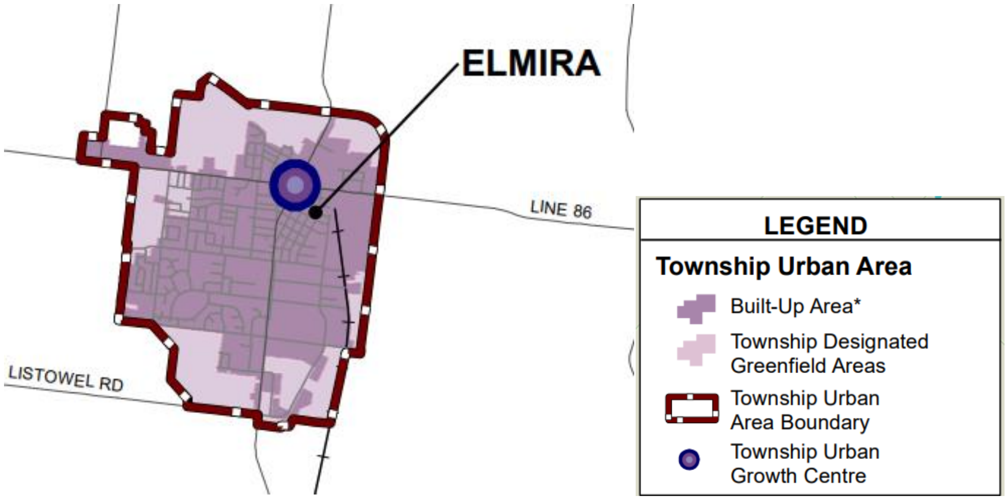
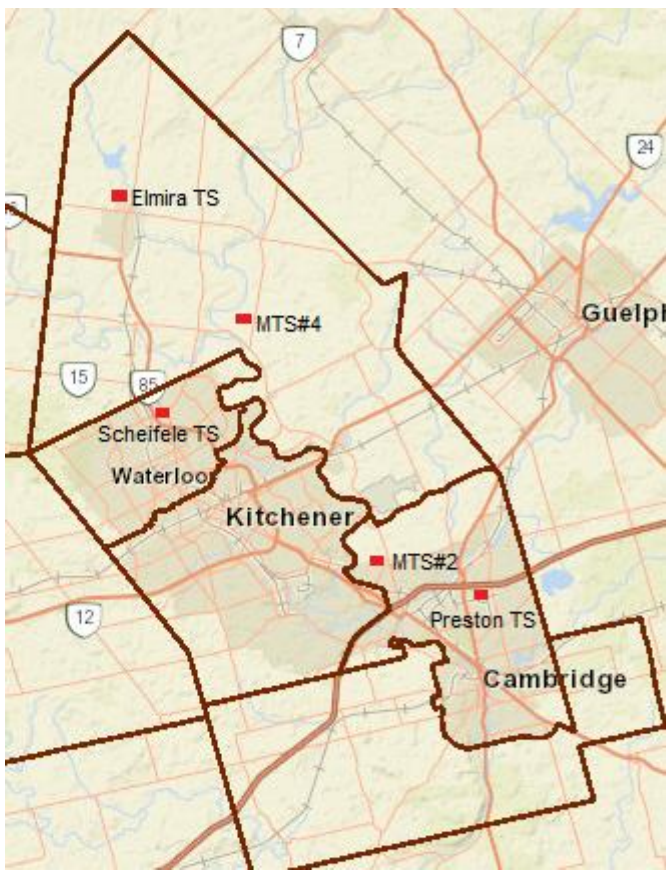


Figure E.4 | Station Locations in WNH and Energy+ Territory



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