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Newmarket-Tay Power Distribution Ltd.

December 22, 2020

Registrar
Ontario Energy Board
2300 Yonge Street
P.O. Box 2319
Suite 2700
Toronto, ON M4P 1E4
registrar@oeb.ca

To: Registrar

Re: Newmarket-Tay Power Distribution Ltd. ("NT Power")
Filing Consolidated Distribution System Plan ("DSP") for period 2020-2024

Pursuant to the Ontario Energy Board ("OEB") Decision and Order (EB-2017-0269) to file a consolidated DSP for the amalgamated NT Power service territory, and pursuant to the OEB Filing Requirements for Electricity Transmission and Distribution Applications Chapter 5 Consolidated Distribution System Plan Filing Requirements dated *May 14, 2020*, NT Power hereby files their consolidated DSP for the period 2020-2024.

Yours truly,

Original Signed By

G. Young
COO

GY/
Encl. NT Power's DSP

NEWMARKET-TAY POWER DISTRIBUTION LTD.

2020 – 2024 Distribution System Plan

Newmarket-Tay Power Distribution Ltd.

October 2020

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5.0 Introduction

Newmarket-Tay Power Distribution Limited (“NTPDL”) is an electricity distributor licensed by the Ontario Energy Board (“OEB”). In accordance with its Distribution License ED-2007-0624, NTPDL provides electricity distribution services in the Town of Newmarket, the Town of Midland and certain parts of the Township of Tay. This is NTPDL’s second consolidated Distribution System Plan (“DSP”) prepared in accordance with Chapter 5 of the OEB’s May 14, 2020 Filing Requirements for Electricity Distribution Rate Applications. The first plan covered the 2015 – 2019 investment period which excluded the Town of Midland service area.

NTPDL is incorporated under the Ontario Business Corporations Act and is 93% owned by Newmarket Hydro Holdings Inc which is a wholly-owned subsidiary of The Town of Newmarket, and 7 % owned by Tay Hydro Inc. which is wholly-owned by the Township of Tay. NTPDL is the result of an OEB approved merger of Newmarket Hydro Ltd. and Tay-Hydro Electric Distribution Company Inc. on May 1, 2007 and the acquisition of Midland Power Utility Corporation on September 10, 2018.

In the Town of Newmarket service area, NTPDL receives power from Hydro One Networks Inc. (“HONI”) and delivers power to its customers via two high voltage transformer stations, both of which are owned by HONI and as such is considered transmission connected.

In the Midland-Tay service area, NTPDL receives power from HONI 44kV feeders (from Waubaushene TS) and as such is considered an embedded distributor.

Revenue is earned by NTPDL by delivering electric power to the homes and businesses in its service territory. The rates charged for this and the performance standards that the energy delivery system must meet are regulated by the OEB.

NTPDL currently serves approximately 43,946 electricity distribution customers across both its service areas.

The three communities NTPDL primarily serves have distinct characteristics.

Newmarket is a dense urban utility, with some legacy large automotive manufacturing infrastructure and an expanding population and distribution system. It has been identified as an Urban Growth Centre in the Province’s Places to Grow Act.

Midland forms and functions as the centre of a broader community bounded by the Town of Penetanguishene, the Township of Tiny and the Township of Tay. It offers a regional setting which includes a mix of business, commerce, social, recreational and housing opportunities. It has been identified as a Primary Settlement Area in the Province’s Places to Grow Act.

The portion of Tay township that NTPDL serves, consists mostly of residential customers located in a mix of light urban, seasonal, and rural areas, with minimal population growth.

It should be noted that at its western and northern Newmarket service area limits, NTPDL also serves a small number of King Township and East Gwillimbury customers.

NTPDL is responsible for maintaining distribution and infrastructure assets deployed over 94 square kilometers (including 469 circuit kilometers of overhead lines and 559 circuit kilometers of underground lines) within the Newmarket and Midland-Tay service areas.

5.1 General & Administrative Matters

NTPDL's DSP documents NTPDL's asset management processes and 5-year capital expenditure plan for the 2020-2024 period. The DSP documents the practices, policies and processes that are in-place to ensure that investment decisions support NTPDL's desired outcomes in a cost-effective manner and provides value to the customer.

Purpose of filing a Distribution System Plan

NTPDL's DSP is designed to support the achievement of the four key OEB established performance outcomes:

1. **Customer Focus**: services are provided in a manner that responds to identified customer preferences;
2. **Operational Effectiveness**: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
3. **Public Policy Responsiveness**: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
4. **Financial Performance**: financial viability is maintained; and savings from operational effectiveness are sustainable.

The DSP integrates qualitative and quantitative information which results in an optimal investment plan covering:

- System expansion considerations
- System renewal considerations
- Regional planning considerations
- Renewable generation considerations
- Smart grid considerations
- Customer value considerations
- Public policy considerations

NTPDL has adopted Good Utility Practices ("GUP") of the electricity distribution industry. This has included adhering to the OEB's Distribution System Code that sets out both GUP, minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. Consistent with good practices, over the years NTPDL has maintained its equipment in safe and reliable working order and, only when economically justified, upgraded or replaced its equipment. Consistent maintenance of its equipment has permitted NTPDL to, in some circumstances, extract an extended useful working life from certain assets (i.e. painting distribution transformers, overhead switch maintenance, etc.). NTPDL has been prudent when incurring costs since customer satisfaction survey results indicate that the low price of electricity is an important factor to customers.

By prudently controlling all expenditures and therefore moderating any increases in its customers' bills, the distribution system has evolved into an array of equipment of different vintages spanning a number of technological eras. Funds were not spent on replacing functioning equipment in order to simply have more modern technologies in place. In developing the long-term DSP, NTPDL's objective is to ensure that the future distribution system is designed to deliver power at the quality and reliability levels desired by customers and to minimize the lifetime cost by balancing preventative maintenance, life-extending refurbishment, and end-of life replacement.

NTPDL has also conducted Asset Condition Assessments ("ACA") that provide input to the development of its DSPs. Although the ACAs indicate that NTPDL historically has underspent in replacing its end-of-life assets, NTPDL has been mindful of potential impacts on customers and has prudently balanced spending with a slight risk to maintaining customer service levels over the historical period. NTPDL's strategy is to gradually increase its replacement of end-of-life assets over two more DSP periods (over next ten years) rather than in one five-year period, to attain the required asset replacement levels of $10M average investment per year. As a result, this DSP has NTPDL limiting its investment in distribution assets to a total of $36M over the 5-year period 2020-2024, or an average of $7.3M per year. In terms of bill impact of this $36M investment, a residential customer would see only a $1.25 increase on their monthly bill beginning in 2028.

In short, the system will meet the customers' needs for quality and reliability of power at a reasonable and affordable cost to customers.

NTPDL considers performance-related asset information including, but not limited to, data on reliability, asset condition, loading, customer connection requirements, and system configuration, to determine investment needs of the distribution system.

NTPDL's DSP demonstrates prudence and rate mitigation consideration in the pacing and prioritizing of non-mandatory investments, specifically those related to replacement or renewal of end-of-life plant.

Timing of filing

The development of this DSP is in accordance with the OEB Decision and Order EB-2017-0269 to file a consolidated DSP for the amalgamated NTPDL service territory by December 31, 2020 and pursuant to the OEB Filing Requirements for Electricity Transmission and Distribution Applications Chapter 5 Consolidated Distribution System Plan Filing Requirements dated *May 14, 2020*.

5.2 Distribution System Plan

NTPDL's DSP has been prepared in accordance with OEB's May 14, 2020 Filing Requirements for Electricity Distribution Rate Applications – 2020 Editions for 2021 Rate Applications – Chapter 5 Consolidated Distribution System Plan..

NTPDL has organized the required information using the section headings in the Chapter 5 document. Investment projects and activities have been grouped into one of the four OEB defined investment categories listed below, based on the 'trigger' driver of the expenditure:

System access - investments are modifications (including asset relocation) to the distribution system NTPDL is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via NTPDL's distribution system

System renewal - investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of NTPDL's distribution system to provide customers with electricity services.

System service - investments are modifications to NTPDL's distribution system to ensure the distribution system continues to meet NTPDL operational objectives while addressing anticipated future customer electricity service requirements

General plant - investments are modifications, replacements or additions to NTPDL's assets that are not part of the distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities

The electric distribution system is capital intensive in nature and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network. NTPDL's DSP documents the practices, policies and processes that are in-place to ensure that decisions on capital investments and maintenance plans support NTPDL's desired outcomes in a cost-effective manner and provides value to the customer.

NTPDL's Capital investment summary for the 2020 – 2024 period is shown in Table 1 below. Amounts are net of Capital Contributions by others.

Category	2020	2021	2022	2023	2024	Average
System Access	$1,327,048	$1,795,295	$2,595,523	$2,477,641	$1,084,150	$1,855,931
System Renewal	$3,695,153	$2,861,610	$3,210,960	$3,025,360	$2,828,860	$3,124,389
System Service	$0	$920,000	$830,000	$560,000	$700,000	$602,000
General Plant	$2,089,200	$7,895,000	$1,375,000	$1,465,000	$1,725,000	$2,909,840
Total	**$7,111,401**	**$13,471,905**	**$8,011,483**	**$7,528,001**	**$6,338,010**	**$8,492,160**

Category	2020	2021	2022	2023	2024	Average
System Access	19%	13%	33%	33%	17%	23%
System Renewal	52%	21%	40%	40%	45%	40%
System Service	0%	7%	10%	7%	11%	7%
General Plant	29%	59%	17%	20%	27%	30%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Table 1 – Capital Investment Summary 2020 – 2024

As part of its planning process, NTPDL has attempted to maintain a relatively level spending pattern in the DSP period that balances the swings of annual mandatory System Access investments with non-mandatory needs in the other three investment categories through a project pacing and prioritization process with an exception in 2021 as noted below.

In 2021, NTPDL is required to pay an estimated capital contribution of $6.1 million to HONI for the construction of Holland TS. This significantly increases the 2021 capital expenditure. When the capital contribution to HONI is removed, the 2020 - 2024 annual capital budget spend is more balanced. Average annual spend reduces to $7.3M from $8.5M in the previous table

Category	2020	2021	2022	2023	2024	Average
System Access	$1,327,048	$1,795,295	$2,595,523	$2,477,641	$1,084,150	$1,855,931
System Renewal	$3,695,153	$2,861,610	$3,210,960	$3,025,360	$2,828,860	$3,124,389
System Service	$0	$920,000	$830,000	$560,000	$700,000	$602,000
General Plant	$2,089,200	$1,795,000	$1,375,000	$1,465,000	$1,725,000	$1,689,840
Total	**$7,111,401**	**$7,371,905**	**$8,011,483**	**$7,528,001**	**$6,338,010**	**$7,272,160**

Category	2020	2021	2022	2023	2024	Average
System Access	19%	25%	33%	33%	17%	26%
System Renewal	52%	39%	40%	40%	45%	43%
System Service	0%	12%	10%	7%	11%	8%
General Plant	29%	24%	17%	20%	27%	23%
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Table 2 – Modified Capital Investment Summary 2020 – 2024

Individual capital investment category variation recognizes the specific impact of System Access work schedules on the ability of NTPDL to fund/do other work at the same time while keeping rates manageable. In this sense other non-mandatory work (e.g. majority of System Renewal) is prioritized, paced and managed to provide consistent yearly overall capital spends. While individual capital categories may vary from year to year and have differing emphasis depending on service area (i.e. Newmarket emphasis on System Access, Midland-Tay emphasis on System Renewal), and with the exception of the capital contribution to HONI noted above, NTPDL's overall Capital spend has been kept consistent over the DSP plan period, averaging approximately $7.3M per year, in order to provide a steady and predictable impact on current and future rates.

This is discussed further in section 5.3 of this DSP.

5.2.1 Distribution System Plan overview

5.2.1a Key elements of the Distribution System Plan

It is expected that the operational and service requirements driving NTPDL's capital expenditures, and found within its DSP, will generally remain stable through the 2020 to 2024 planning window. NTPDL's net total capital expenditure over the planning period 2020 through 2024 is forecasted to be approximately $42.5 million, which reflects average net annual spends ranging from $6.3 million to $13.5 million from 2020 to 2024. The projected expenditures for 2020 and going forward reflect:

- System Access spending needs required to serve a slow growing customer base and mandatory plant relocation to facilitate major provincial and regional transportation plans;
- Focused System Renewal investments required to replace aging assets found in NTPDL's distribution system and maintain reliability;
- System Service investments focused primarily on substation servicing;
- General Plant spending focused on financial/customer software upgrades and staged replacement of fleet units that are reaching economic end-of-life status over the 2020 – 2024 planning window. In 2021 there is an estimated $6.1 million capital contribution 2nd true-up payment to HONI for Holland TS.

There are numerous provincial, regional, municipal and business elements that contribute to the determination of the planning investments through the period of the DSP:

Ontario Places to Grow Act (2005) / A Place to Grow plan for the Greater Golden Horseshoe (May 2019)

The A Place to Grow plan ("Grow Plan") for the Greater Golden Horseshoe replaces the Growth Plan for the Greater Golden Horseshoe (2017) and came into effect May 16, 2019. The plan provides population and employment forecasts for the Greater Golden Horseshoe to 2041.

<u>Town of Newmarket</u>

The Town of Newmarket has been identified in the Act as one of the Urban Growth Centres in the Greater Golden Horseshoe. As an urban growth centre, Newmarket is expected to be planned:

1. as a focal area for investment in regional public service facilities, as well as commercial, recreational, cultural, and entertainment uses;
2. to accommodate and support the transit network at the regional scale and provide connection points for inter- and intra-regional transit;
3. to serve as a high-density major employment centre that will attract provincially, nationally or internationally significant employment uses;
4. to accommodate a significant share of York Region population and employment growth.

The Grow Plan loosely defines the Newmarket Urban Growth Centre as the area around the intersection of Yonge Street and Davis Drive. The Grow Plan mandates that Urban Growth Centres will account for a significant amount of the municipality's future population and employment growth. The Grow Plan also mandates that the Newmarket Urban Growth Centre be planned to achieve a minimum density of 200 residents and jobs combined per gross hectare by 2031. While the Grow Plan provide general density targets, it does not provide specific residential and employment numbers for each Urban Growth Centre.

The Grow Plan also recognizes Major Transit Station Areas as areas that will be planned to achieve increased residential and employment densities. Newmarket GO Rail Station, the Newmarket Bus Terminal, and each of the transit stations on the future Yonge and Davis Rapidways are considered Major Transit Station Areas. The Grow Plan states that these locations will be planned to achieve a mix of residential, office, institutional and commercial development as appropriate to support ridership along these routes.

Infrastructure, including energy infrastructure, is expected to be planned for in an integrated manner. Of specific interest is transportation infrastructure planning. Public transit will be the first priority for transportation infrastructure planning. Collaborative local energy infrastructure planning will play an important role in assisting transit infrastructure planning in meeting provincial greenhouse gas emissions reduction targets. The Grow Plan specifically supports the fostering of collaboration between public and private sectors for joint development projects within major transit areas.

NTPDL has undertaken a collaborative project with the Town of Newmarket and York Region Transit to deploy an overhead high-power charger within a major transit area to facilitate the use of zero-emission battery buses in support of Town and Province’s efforts to reduce greenhouse gas emissions.

Town of Midland

The Town of Midland has been identified as a Primary Settlement Area in the Grow Plan. Growth will be directed to Settlement Areas to make better use of land and infrastructure. The Simcoe Sub-Area is specifically noted in the Grow Plan. It provides additional, more specific direction on how the Plan's vision will be achieved in the Simcoe Sub-area. It directs a significant portion of growth within the Simcoe Sub-area to communities where development can be most effectively serviced, and where growth improves the range of opportunities for people to live, work, and play in their communities, with a particular emphasis on Primary Settlement Areas. See Figure 1 below:

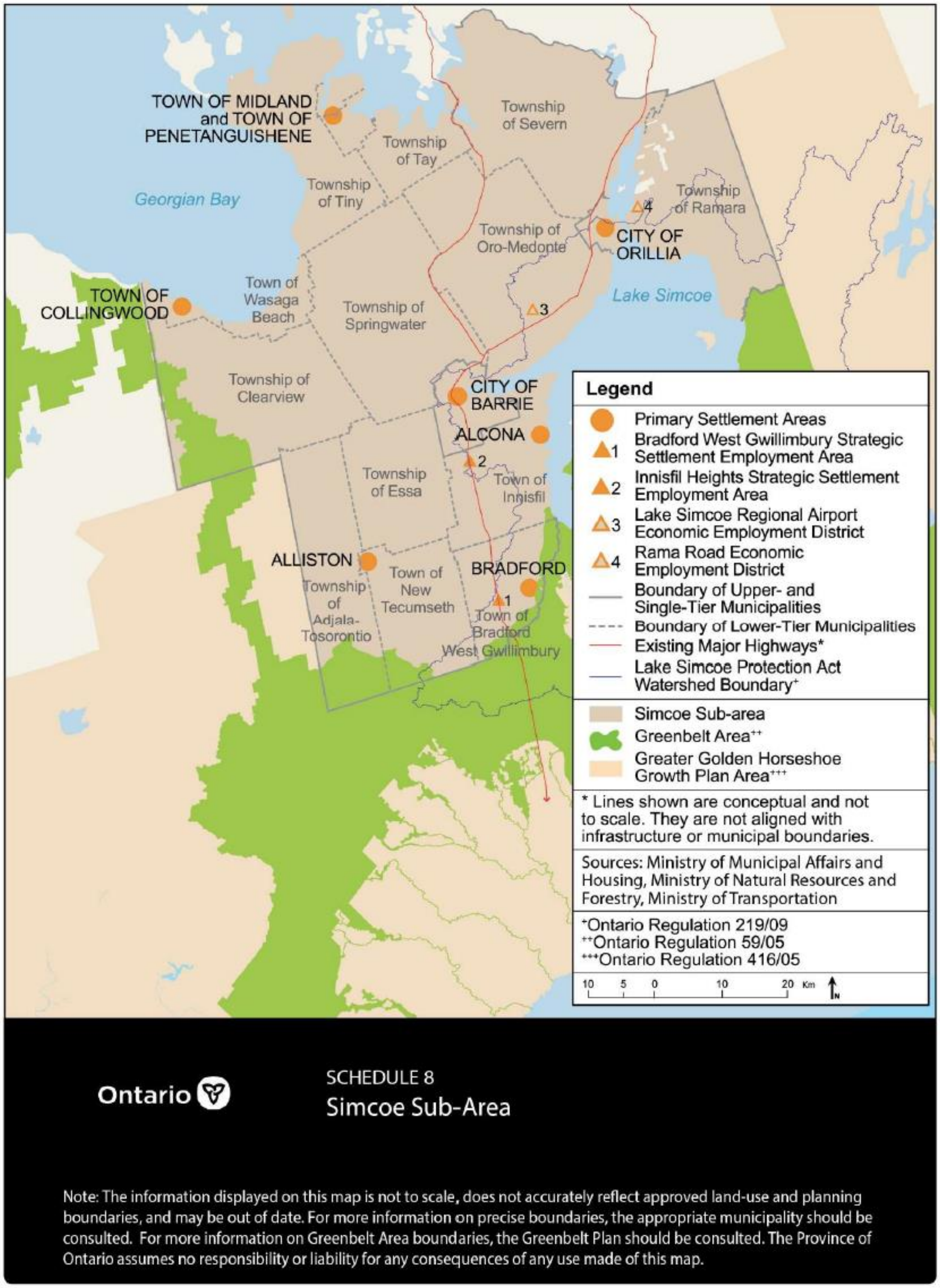


Figure 1 – Simcoe Sub-Area Primary Settlement Areas

Growth directed to Settlement Areas has been identified in the Plan. The Town of Midland is projected to grow to a population of 22,500 and employment of 13,800 by the year 2031

Distribution of Population and Employment for the City of Barrie, City of Orillia and County of Simcoe to 2031

	POPULATION	EMPLOYMENT
City of Barrie	210,000	101,000
City of Orillia	41,000	21,000
Township of Adjala-Tosorontio	13,000	1,800
Town of Bradford West Gwillimbury	50,500	18,000
Township of Clearview	19,700	5,100
Town of Collingwood	33,400	13,500
Township of Essa	21,500	9,000
Town of Innisfil	56,000	13,100
Town of Midland	22,500	13,800
Town of New Tecumseth	56,000	26,500
Township of Oro-Medonte	27,000	6,000
Town of Penetanguishene	11,000	6,000
Township of Ramara	13,000	2,200
Township of Severn	17,000	4,400
Township of Springwater	24,000	5,600
Township of Tay	11,400	1,800
Township of Tiny	12,500	1,700
Town of Wasaga Beach	27,500	3,500
TOTAL SIMCOE SUB-AREA	667,000	254,000

Ontario

PLACES TO GROW

GROWTH PLAN FOR THE GREATER GOLDEN HORSESHOE, 2017

SCHEDULE 7
Distribution of Population and Employment for the City of Barrie, City of Orillia and County of Simcoe to 2031

Growth Plan for the Greater Golden Horseshoe | 103

Figure 2 – County of Simcoe growth projections

DSP Impact:

Newmarket

The land use planning framework presented in the Grow Plan will likely require capital investment to provide for new connections and capacity including timely acquisition of property for future substation needs. This will likely require investment in the System Access and System Service categories. Specific growth scenarios details will be obtained from Region and Town Official Plans.

Midland-Tay

The population and employment growth presented in the Grow Plan will likely require capital investment to provide for new connections and capacity including timely acquisition of property for future substation needs outside of the 2020 through 2024 period of the DSP. As such there is minimal spending impact for System Access and System Service needs during the period of the DSP.

York Region Corporate Strategic Plan 2019 – 2023 (March 2019)

The York Region 2019 – 2023 Strategic Plan identifies the following Community Result Areas of focus:

1. Economic Vitality
2. Healthy Communities
3. Sustainable Environment
4. Good Government

Key activities in the plan potentially impacting future NTPDL work are:

- support business retention
- expand the VIVA bus rapid transit network
- prioritize road improvements that address areas of congestion
- update Energy Conservation and Demand Management Plan and revise Regional greenhouse gas targets

DSP impact: The plan generally does not provide for specific identified works or locations and as such there are no specific investments in the DSP directly related to the York Region Corporate Strategic Plan. However, the DSP supports the York Region Corporate Strategic Plan as follows:

1. Expand the VIVA bus rapid transit network: within this DSP, there is the Yonge St. Davis Drive to Greenlane poleline relocation project to facilitate York Region road widening and future VIVA Bus Rapid Transit ("BRT") expansion;

2. Sustainable Environment (GHG reduction): in 2020, NTPDL in collaboration with the Region & Town of Newmarket facilitated on-route EV bus charging, as well as overnight EV bus depot charging.

In general, the plan indicates that there is potential for future System Access works related to relocating plant due to road widening efforts. Continued emphasis on GHG reduction targets in the Energy Conservation and Demand Management Plan indicate that electricity will be increasingly used as a fuel substitute for transportation and heating demand. This will increase System Service needs at the distribution and transmission level. Any identified needs in these areas, that fall within the forecast period of the DSP, will be addressed accordingly.

York Region Official Plan (April 2019 Office Consolidation)

The Yonge-Davis Provincial Urban Growth Centre is one of four Regional Centres identified in the York Region Official Plan. The Regional Centre boundary is defined in the York Region Official Plan and implements the Urban Growth Centre identified in the Growth Plan, and the York Region Official Plan recognizes the Growth Plan's density target of a minimum of 200 residents and jobs per gross hectare in Regional Centres.

The York Region Official Plan also identifies both Yonge Street and Davis Drive as Regional Corridors. Regional Corridors are intended to be planned to function as urban main streets that have a compact, mixed use, well designed, pedestrian friendly and transit-oriented built form. The York Region Official Plan includes a number of other policies that are relevant to the planning of the Newmarket Urban Centres. These include policy direction with respect to the aesthetic and functional character Regional Corridors, including policy direction for undergrounding of utilities to ensure an attractive streetscape is achieved. York Region Official Plan policies in this regard include:

- requiring innovative approaches to infrastructure that support city building in Centres and Corridors by working with utility providers to ensure appropriate utility design and placement, including burying cables and structures, consistent with Transit-Oriented Design guidelines for Regional Centres and Corridors (policy 5.4.14 of the York Region Official Plan);

- requiring local official plans to identify and protect infrastructure corridors for long term servicing needs, including and in compliance with corridors identified in Provincial Plans (policy 7.5.4 of the York Region Official Plan); and

- requiring underground installation of utilities, where feasible, in new community areas and Regional Centres and Corridors, and to encourage buried utilities in the balance of the Region (policy 7.5.6 of the York Region Official Plan).

The Plan also encourages municipalities to undertake municipal-wide Community Energy Plans. These plans will detail the municipality's energy use requirements and establish a plan to reduce energy demand and consider the use of alternative and renewable energy generation options and district energy systems and will ensure that communities are designed to optimize passive solar gains thus impacting the energy requirements to be obtained from the electrical distribution grid. The plan will encourage all new buildings to include on-site renewable or alternative energy systems which produce 25 per cent of building energy use.

The York Region Official Plan forecasts that by 2031 it will reach 1.5 million residents, 780,000 jobs, and 510,000 households. A key element of the plan includes a minimum of 40 per cent residential intensification within built-up areas. According to the plan, Newmarket is expected to reach 97,100 residents and 49,400 jobs by 2031. See Table 3 below:

Municipality	2006	2016	2021	2026	2031
Aurora					
Population	49,700	63,700	68,100	69,600	70,200
Employment	20,300	29,000	32,400	33,500	34,200
East Gwillimbury					
Population	22,000	34,700	48,100	66,300	86,500
Employment	5,900	11,600	18,700	26,700	34,400
Georgina					
Population	44,600	52,800	57,900	63,900	70,300
Employment	8,000	11,000	13,900	17,400	21,200
King					
Population	20,300	27,000	29,900	32,500	34,900
Employment	7,100	9,700	11,000	11,400	11,900
Markham					
Population	273,000	337,800	370,300	398,300	421,600
Employment	144,800	200,300	221,500	231,200	240,400
Newmarket					
Population	77,600	88,700	91,900	94,500	97,100
Employment	42,100	47,600	48,700	49,000	49,400
Richmond Hill					
Population	169,800	216,900	231,400	239,100	242,200
Employment	61,100	86,100	94,300	97,400	99,400
Vaughan					
Population	249,300	329,100	360,400	388,800	416,600
Employment	162,200	226,000	248,900	257,600	266,100
Whitchurch-Stouffville					
Population	25,500	49,400	55,800	59,100	60,600
Employment	10,900	19,200	21,900	22,700	23,000
York Region					
Population	931,900	1,200,100	1,313,800	1,412,100	1,500,000
Employment	462,300	640,500	711,200	746,900	780,000

Table 3 - York Region Population and Employment Forecast by Local Municipality

Over the forecast period (2020 – 2024), customer growth is expected to average 1% annually for Residential and 0.9% for Commercial based on Municipal growth figures in Table 3 above. This presents interesting comparisons with historical growth

Historical customer growth (2015 – 2019) has averaged 1.1% annually for Residential customers. The decrease in forecast growth, even with intensification, demonstrates the decreasing land use options and availability as the Town of Newmarket becomes built out to its boundaries.

For GS>50 and GS<50 customers, business conditions continue to be a challenge and customer growth in these categories has averaged 0.2% annually over the historical period. A number of GS>50 customers have left or have transitioned to the GS<50 category in terms of electricity consumption. No significant GS>50 customer growth is forecast over the period of the DSP.

The long-term impact of the COVID-19 pandemic is unknown at this time and the growth projections exclude any considerations or adjustments for the COVID-19 pandemic.

	2015	2016	2017	2018	2019	Annual Avg
Residential	37,832	38,292	38,577	39,075	39,481	1.1%
GS<50	3,960	3,922	3,924	3,957	3,986	0.2%
GS>50	475	482	478	492	479	0.2%
Large	0	0	0	0	0	0%
Total	42,267	42,696	42,979	43,524	43,946	1.0%

Table 4 – 2015 - 2019 Customer Growth by Class

DSP impact: System Access needs for new connections are expected to remain steady over the forecast period but be less than historical levels. System Access needs for plant relocation are expected to remain near historical levels due to continued work on York Regional Corridors. Growth will not have a significant impact on System Renewal, System Service and General Plant needs over the forecast period.

Newmarket Official Plan (2008 – amended to December 2016)

The Town of Newmarket Official Plan implements the Urban Centres and Regional Corridors policies of the Provincial Growth Plan and the York Region Official Plan through the identification of two Urban Centres:

1. Newmarket Urban Centres Secondary Plan; and
2. Historic Downtown Centre

The plan predicts the Town to grow to a target population of 98,000 persons by 2026, higher than the York Region Official Plan target of 97,100 by 2031. Intensification within the Newmarket Urban Centres Secondary Plan Area forecasts a population of approximately 33,000 people by full build-out.

DSP impact: Similar to the Region Official plan, System Access needs for new connections are expected to remain steady over the forecast period but be less than historical levels. System Access needs for plant relocation are expected to remain near historical levels due to continued work on Regional Corridors. Growth is will not have a significant impact on System Renewal, System Service and General Plant needs over the forecast period.

OPA No. 10 Newmarket Urban Centres Secondary Plan (October 2016) – the Plan identifies the need to acquire property along Yonge St and Davis Dr. boulevards to accommodate future burying of overhead powerlines and other utilities. Up to an additional five metres of boulevard width are required to be dedicated to the Town or secured through an easement in favour of the Town, in accordance with Policy 13.3.4.

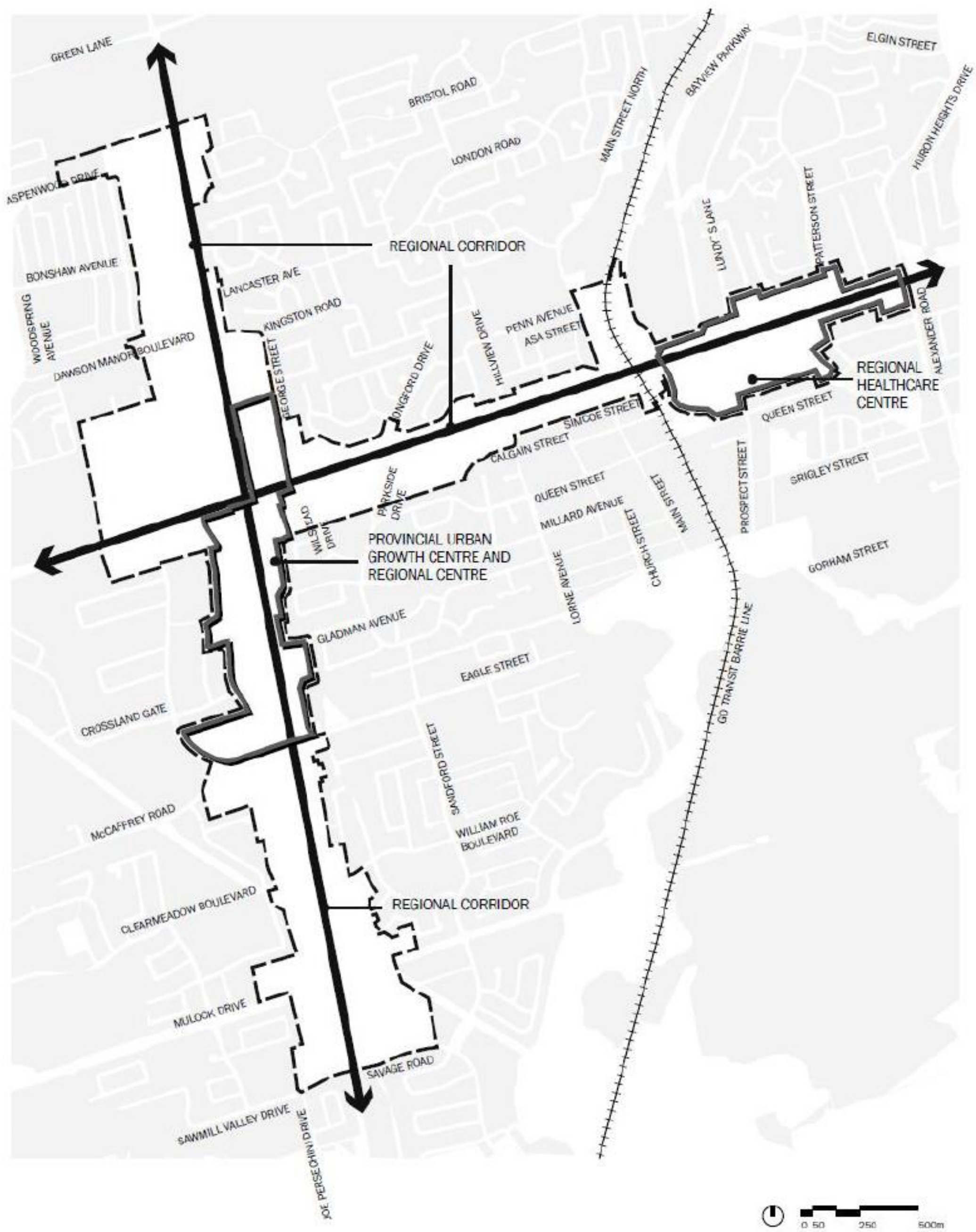


Figure 3 – Town of Newmarket Land Subject to OPA No. 10

<u>DSP impact:</u> If property is acquired and funding outside of rate base for undergrounding is obtained, then the plan could have a significant impact on System Access spending (relocation of plant). At this time there is no information that these conditions have been achieved. The DSP as written assumes no change to the existing overhead plant.

Town of Midland Strategic Plan (2016)

The Strategic Plan systematically addresses the purpose of the Town of Midland, its internal and external environment, value to stakeholders, plans for action and long-term financial planning. The plan provides high level strategic direction for the municipality and identifies key priorities to be undertaken by Council.

The plan strategic priorities focus on five (5) key areas, as follows:

- Fiscal Responsibility and Cost Containment
- Organizational Excellence
- Economic Development
- Developing Partnerships, Promoting Collaboration & Alignment
- A Healthy Sustainable Community

<u>DSP Impact</u>: Awareness of the key strategic priorities will help guide NTPDL's future work such that it will complement the Town's strategy.

Town of Midland Official Plan (2003 - updated to January 13, 2017)

The Town of Midland Official Plan establishes goals, objectives, land use, transportation, servicing and community improvement policies to direct the physical growth of the Town of Midland. The 2003 Official Plan establishes the general pattern for future growth to the year 2023.

The Town of Midland commenced a review of the Official Plan in 2015. A draft of a new plan, dated May 2017, has been posted on the Town website for public comment.

Section 6.5 of the draft plan states the Town preference for all local power and telecommunications facilities and other cable services to be located underground and be grouped into a single utility conduit, where feasible. Such activity would be subject to Municipal cost recovery mechanisms outside of utility rate base.

Section 6.6 of the draft plan states that the Town is a willing host for green energy facilities of a modest scale, including wind turbines and solar farms. New generation connections would impact System Access costs.

<u>DSP Impact</u>: The desire for undergrounding utility infrastructure is noted however as no external funding mechanisms have been established by the Municipality, no associated costs for undergrounding existing overhead plant are included in the DSP except for a former MPUC project in 2020 that facilitated the Town of Midland's King St Revitalization project (burial of the last three services). Undergrounding would have significant impacts on System Access costs. Trends in new generation connections will be monitored to determined if forecasts included in the DSP need to be adjusted.

Town of Newmarket Road Projects – The Town of Newmarket has ongoing road rehabilitation and widening projects some of which may require the relocation of NTPDL plant.

<u>DSP impact</u>: Current road project schedule has limited impact on System Access spending in the DSP. Future changes to the road schedule, within the period of the DSP, may require reallocation of resources to System Access spending from other capital investments.

York Region Road Projects – As of January 6, 2020 York Region has identified one project in the Town of Newmarket in the 2020 – 2024 timeframe - the reconstruction of Yonge St. between Davis Drive and

Green Lane beginning in 2022. NTPDL is required to relocate their plant beforehand. York Region delayed utility relocation construction start date from 2018 to beyond 2021 for NTPDL.

DSP Impact: System Access spending will be required in 2020 – 2024 to accommodate York Region road works.

Simcoe County Road Projects – The County utilizes a GIS mapping application to detail their current year road and bridge construction works. There is no information on post 2020 road works.

DSP Impact: NTPDL will be required to react to road project work that affects the distribution plant, as it occurs during the period of the DSP.

GTA Northern York Sub-Region Supply Study

NTPDL is participating in the GTA Northern York Sub-Region Supply Study for its Newmarket service area. The last York Region Integrated Regional Resource Plan (IRRP) was published in 2015, and the next planning process kicked off at the end of 2017. A new IRRP was presented and released in February 2020. The current IRRP identifies a need for a new transformer station in the medium term (~2027) for ensuring reliability of supply to Northern York Region. The IRRP recommends, given development pressures in the area, finding and preserving land now. This effort would be undertaken by Hydro One. The Hydro One Regional Integrated Plan (“RIP”) was issued in October 2020.

DSP Impact: No impact on the DSP.

Southern Georgian Bay/Muskoka Region Supply Study – NTPDL is in Group 2 - Southern Georgian Bay/Muskoka region for its Midland-Tay service area. An IRRP for the Parry Sound/Muskoka sub-region was issued in December 2016. The Hydro One RIP was issued in August 2017. The second cycle of regional planning for this area commenced in 2020. A draft South Georgian Bay/Muskoka Scoping Assessment has been discussed with the study participants.

DSP impact: The 2016 IRRP and 2017 RIP recommendations will not impact NTPDL’s 2020 – 2024 planning investments for the Midland-Tay service area. However, NTPDL may be required to react to any recommendations that come out of the current regional planning cycle for Southern Georgian Bay/Muskoka Region.

Town of East Gwillimbury Green Lane Secondary Plan – NTPDL services a small portion of the Town of East Gwillimbury south of Green Lane at the northern boundary of the Town of Newmarket. The Green Lane Secondary Plan Area is located along the Green Lane Corridor (both north and south sides) from west of Yonge Street to Leslie Street. The Town of East Gwillimbury has initiated a Secondary Plan process to create the detailed planning framework and identify land uses to guide future development of the corridor. A Secondary Plan and associated Official Plan Amendment has been prepared following public consultation. The draft OPA states that:

- New buildings are encouraged to include renewable energy sources and be designed to support net zero water and energy systems.
- New and reconstructed buildings with internal parking shall contain electric vehicle charging stations or be pre-wired to allow for future incorporation of electric vehicle charging stations.”

Green Lane is designated as a Regional Corridor in the York Region Official Plan.

DSP impact: At this time there are no specific DSP program spending impacts. It is expected that System Access and System Service investments will be required once specific development details in the portion of lands serviced by NTPDL are known.

County of Simcoe Official Plan (2008 – updated 2016) - The Simcoe Official Plan is a document designed to assist in growth management to 2031. The Official Plan establishes density targets that will ensure a greater utilization of existing settlement areas through intensification and infilling so there is less demand on settlement area expansions. Housing growth is directed to existing settlements. Land use policies provide for and encourage the multi-use expansion of settlements, the development of rural business parks and highway commercial development where appropriate.

DSP impact: At this time there are no specific DSP program spending impacts. All category spending is expected to remain at historical levels within the DSP forecast period. NTPDL will continue to monitor for any category spending changes due to Plan implementation.

Tay Official Plan (1999) –The Township of Tay has initiated an Official Plan (OP) and Zoning By-law (ZBL) Review to replace the existing official plan approved in 1999 and a new Official Plan consultation draft was prepared in March 2016. Amendments are required to address the provincial compliance requirements of the Planning Act and Places to Grow Act. The review is not expected to impact the DSP as planned. The new Official Plan reflects the Township's policies relating to the future development of the Municipality. The Plan is based on the premise that the Municipality will remain predominantly rural in nature with major (Victoria Harbour and Port McNicoll) and minor (Waubaushene) settlement areas.

DSP impact: At this time there are no specific DSP program spending impacts. All category spending is expected to remain at historical levels within the DSP forecast period. NTPDL will continue to monitor for any category spending changes due to Plan implementation.

OEB 2015 CDM Guidelines – The guidelines were issued in December 2014 and reflect the OEB's expectations with respect to coordination and integration between electricity and natural gas and putting conservation first into distribution planning. NTPDL is expected to achieve 49.27 GWh of CDM savings in the 2015 – 2020 period. As of April 30, 2019, NTPDL has achieved 40.94 GWh of savings, representing 82% of the original target.

DSP impact: CDM savings are expected to impact net load growth on the system. Targeted savings are not expected to have a significant impact on DSP category spending during the forecast period.

Business Conditions (Newmarket) – Newmarket like many communities in south-western Ontario, has been significantly exposed to the manufacturing downturn (and specifically, the automotive sector). Three large GS>50 kW class customers ceased operations in 2009 and other large customers have reduced consumption. While there have been some new entrants in the GS service classification (e.g. Celestica) commercial/industrial growth is expected to be slow over the period of the DSP.

DSP impact: Continued low growth in GS operations are expected to mitigate the need for System Service investments over the DSP forecast period. No new stations or feeder extensions are required.

Business Conditions (Midland-Tay) - Growth in the northern Simcoe County has been far less frenetic than the growth witnessed throughout the Greater Toronto Area and parts of Southern Simcoe County. The limited growth is reflected in the amount of System Access and System Service works required in the forecast period to provide for new connections.

<u>DSP impact</u>: Low growth in the Midland-Tay service area is expected to mitigate the need for System Access and System Service investments.

Substation Loading – The previous DSP indicated that a new DS would be required in the NTPDL service area in the 2015 – 2019 plan period in order to maintain reliable levels of service. Current loading levels indicate that a new station will not be required until after 2024.

Low growth and available capacity at existing DS facilities preclude the need for new station facilities in the Midland-Tay area over the 2020 – 2024 forecast period.

<u>DSP impact</u>: No impact on the 2020 – 2024 DSP.

End of life Assets – NTPDL has identified a need to proactively manage the replacement of assets that are at or near end of life. Age and deteriorating conditions are beginning to affect reliability performance. Replacement plans covering a multiyear period have been developed to begin dealing with key assets at end of life. Replacement plans ensure that planning objectives related to reliability, customer satisfaction and operating cost control are achieved.

<u>DSP Impact</u>: It is recognized that a majority of System Renewal investments are non-mandatory and annual program spending is a trade-off between the risk of outages due to equipment failure and maintaining current levels of reliability. In this DSP, System Renewal spending is paced throughout the forecast period of the DSP to accommodate annual spending variances in the other investment categories to maintain a relatively level spending pattern while continuing the progress of replacing end of life assets in a timely and cost-effective manner that NTPDL believes will maintain current levels of reliability. In general System Renewal spending is expected to increase compared to historical levels.

General Plant needs – NTPDL has identified a number of General Plant investment needs primarily in the Fleet, IT and Leasehold Improvement areas. Most needs involve the replacement of existing assets. Fleet needs will generally be timed to replace units at end of life. IT needs are expected to increase in order to replace or upgraded existing system that no longer perform required functions in an efficient and cost-effective manner as well as addressing increasing cybersecurity risks.

<u>DSP Impact</u>: An increase in spending for IT needs compared to historical levels.

Summary

Key Element	DSP areas of influence	DSP pace Impact
Places to Grow Act	System Access and System Service	Refer to details in Town/Region/County plans
York Region Corporate Strategic Plan	System Access	No impact
	System Service	More than Historical
York Region Official Plan	System Access - services	Less than Historical
	System Access - relocations	Historical
Newmarket Official Plan	System Access - services	Less than Historical
	System Access - relocations	Historical
Newmarket Urban Centres Secondary Plan	System Access - relocations	Historical
Town of Midland Strategic Plan	System Access	No impact
Town of Midland Official Plan	System Access - undergrounding	Minimal impact
Town of Newmarket Road Projects	System Access - relocations	Historical
York Region Road Projects	System Access - relocations	Historical
GTA Northern Region IRRP	System Service	No impact
Southern Georgian Bay/Muskoka Region IRRP	System Service	No impact
Town of East Gwillimbury Green Lane Secondary Plan	System Access	No impact
County of Simcoe Official Plan	System Access	Historical
Tay Official Plan	System Access	Historical
OEB 2015 CDM Guidelines	System Service	No impact
Business Conditions (Newmarket)	System Service	No impact
Business Conditions (Midland-Tay)	System Service	No impact
Substation Loading	System Service	No impact
End of life Assets	System Renewal	Increasing
General Plant	Fleet	Historical
	IT	Increasing

Table 5 – Summary of Key Elements and DSP Impacts

5.2.1b Consideration of Customer preferences and expectations

NTPDL has used information obtained through consultations with customers and other stakeholders (i.e. town government, IESO, developers, etc.) to plan and pace expenditures as evenly as possible over the forecast period, while ensuring the investments address customers preferences and expectations.

NTPDL has used customer surveys to provide a high-level assessment of customer preferences. Survey results indicate satisfaction with current service performance levels. Customer concern about the overall cost of electricity supports the need to consider rate mitigation efforts while managing risk and smoothing spending over time for non-mandatory investments necessary to maintain current service performance levels. Survey results are implicitly considered in the development of the asset management strategy, objectives and plans.

The 2015 Customer Satisfaction Survey included questions to residential and commercial customers to determine their preference with respect to maintaining reliability through proactive equipment replacement to maintain reliability. This was used to determine level of ratepayer support for NTPDL's plant investment position (System Renewal) in the 2015 – 2019 DSP that was designed to maintain existing service levels. A similar survey was conducted in 2015 that focused on NTPDL's Large Customers only to get their specific perspectives on these same issues. A majority in both surveys supported pro-active equipment replacement as opposed to "run to failure". More recent surveys (2017, 2018, 2019) continue to demonstrate customer support and desire for NTPDL to continue current levels of reliable service through maintenance and improvements to the distribution system. This level of ratepayer preference for System Renewal investment continues to be a key driver of DSP investments over the 2020 – 2024 planning period. This position has also been supported by the UtilityPulse Ontario database which has compiled responses of customer preferences that places 'Pro-actively maintaining and upgrading equipment' as a high priority planning requirement in the next five years.

Other stakeholder interests (i.e. town preference for undergrounding, regional planning recommendations, etc.) are also considered in planning and developing the DSP.

In 2018, NTPDL engaged a 3rd party consultant, Decision Partners ("DP"), to engage NTPDL's customers to understand their interests, understanding, preferences, and expectations with the goal to obtain their input for NTPDL's consideration into development and/or re-alignment of its DSP and business plan. DP employs a proprietary Mental Models research methodology including conducting 57 confidential in-depth mental model interviews (over 36 hours total) with NTPDL customers. The interviews were conducted between February and May 2018.

The demographic of the 57 interviewees consisted of residential, small commercial, Key customers and "Cluster 6" business customers, municipal councillors, and developers from both the Newmarket and Tay service areas. This focused customer research aligned with customer feedback from the general annual customer satisfaction surveys:

- Cost of electricity continues to be the top priority for all customer groups and they expect NTPDL to be prudent in managing the costs within NTPDL's control, even if NTPDL distribution costs make up only a smaller portion of customer bills;
- Reliability is an increasingly important priority for customers (40% of the interviewees), especially for the Key Commercial and Cluster 6 customers - they want investments to focus on maintaining reliability;
- System Access & System renewal investments were considered very important to over 70% of the customers;
- System Service were important to about 45% of interviewees and some expressed benefits to modernization and keeping up with technology but cautioned about ensuring investments to be "future proof"; others were concerned that new technology meant more costs on their bills or that that being the first adopter of technology usually means more costs;

It is understood that NTPDL's rate mitigation efforts will only impact less than 20% of the residential customer's bill, the other 80% being out of NTPDL's control.

<u>DSP Impact</u>: Once mandatory investments (i.e. System Access) were budgeted and scheduled within the DSP forecast period, non-mandatory investments were assessed, prioritized and scheduled within the DSP forecast period with a leading emphasis on System Renewal in order to maintain current service levels as guided by customer preference feedback.

5.2.1c Sources of cost savings

NTPDL planning and investment processes follow GUP that is executed through the DSP. GUP have inherent cost savings represented as avoided costs through sound decision making, thoughtful compromises, right timing and optimum expenditure levels. Most cost savings achieved during the forecast period are based on existing practices such as the following:

- Plant relocation related road reconstruction works will be coordinated with York Region and other utility work schedules to ensure that plant is not replaced prematurely and then replaced again shortly afterwards; if necessary proposed works will be timed to better coordinate with the reconstruction schedule. Capital contributions from York Region will offset a portion of the total relocation costs (material and labour-saving devices at 50%). York Region pays for all costs in excess of like for like and non-standard replacement. Savings (capital contributions) are built into the net forecast spend amounts. One example was to wait to install a 44kV motorized tie switch between Holland TS and Armitage TS on Yonge St. until the VIVA Y3.2 relocation project. This was a win-win for both parties in that NTPDL saved installation costs and the VIVA (York Region) saved on the relocation costs. NTPDL customers benefited from improved reliability with shorter outage time and labour costs to switch loads between stations.

- In accordance with our strategic plan for NTPDL to develop an asset registry and work towards a more real-time ACA of its distribution system, NTPDL commenced with implementation of Hexacode. The implementation of the Hexacode Asset Management Registry and Asset Condition Assessment software tool will provide a better understanding of each asset's stage in their life cycle which leads to more cost effective and timely decisions with respect to maintenance, refurbishment and replacement decisions. Savings are built into forecast spend amounts.

- Testing (i.e. oil testing of power transformers) and inspection coordinated with maintenance programs, allows for the efficient use of resources. Pole testing provides information on pole condition to help prepare multi-year replacement plans. Contractors performing tree trimming, insulator washing and infra-red testing also carry out visual inspections of adjacent plant. Exception reports are generated, as required, for follow-up remediation efforts by NTPDL crews. Savings are built into the forecast spend amounts.

- In the Midland-Tay service area, 15kV jacketed TR-XLPE cable is specified for underground subdivisions. Operations at 5kV will result in minimizing electrical insulation stresses thereby potentially achieving an extended life for this type of cable. Using terminations at equipment rather than splices will eliminate potential weak links in the cable system. Savings are built into the forecast spend amounts.

- Proactive maintenance and replacement of plant will reduce reactive maintenance costs and maintain existing customer reliability levels. This will have a beneficial impact on the cost of outages to customers. A structured program will also smooth out financial rate impacts in an effort to avoid disruptive rate spikes to address the volume of plant reaching end of life. Savings are built into the forecast spend amounts.

- Coordination of transformer replacement with the overhead line rebuild/underground cable replacement program will reduce overall installation costs through reduced mobilization costs; at the same time transformer sizing can be coordinated to accommodate forecasted renewable generation and/or EV charger deployment. Savings are built into the forecast spend amounts.

- Underground locates are contracted out through a competitive bid process. This avoids the costs of hiring staff specifically to perform day to day locate services. Savings are built into the forecast spend amounts.

- Improved use of the GIS as a consolidated Asset Register to capture/access plant attribute data (i.e. nameplate data, condition, inspection/maintenance histories, etc.) will aid in cost control through the provision of the most up to date asset information available to engineering and operations staff in their long and short-term decision making. Savings are built into the forecast spend amounts.

- Replacement of electro-mechanical relays with electronic relays at substations and utilization of fibre communication media will improve command, control and communication of the distribution grid and have a positive impact on improving outage restoration times thereby mitigating customer outage costs. Savings are built into the forecast spend amounts.

- The use of software (e.g. SPIDAcalc) to optimize plant designs will reduce overdesign and ensure that current CSA standards for non-linear design of pole loading and structural stability are adhered to. Savings are built into the forecast spend amounts.

- The use of standards developed through the Utility Standards Forum, significantly reduces unit cost for standard development and equipment approvals (i.e. hiring of staff specifically to develop construction standards). USF has 50+ Ontario electricity distribution utility members. The cooperative approach to standards development provides members with a consistent, cost effective and ESA approved set of construction standards. Common material requirements result in readily available stock and economies of scale pricing. Savings are built into the forecast spend amounts.

- Certain maintenance activities (i.e. painting transformers) help extend the life of the equipment thereby deferring replacement costs for a number of years. NTPDL has standardized on an all stainless steel padmount switchable transformer in order to reduce the need further painting and replacement of leaking transformers (and future maintenance costs), as well as increase reliability with more localized switching at the transformer.

- Certain fleet hydraulic units (aerial units, digger derricks) are refurbished after approximately 10 years of service essentially doubling the life of the unit. This is a considerable cost saving compared to the cost of purchasing a new hydraulic unit. Savings are built into the forecast spend amounts.

Activity	Cost Savings					Inherent/intangible/avoided cost/other savings
	2020	2021	2022	2023	2024	
Coordination of plant relocation	IF	IF	IF	IF	IF	Material and labour saving devices at 50%
AM software implementation	IF	IF	IF	IF	IF	Optimized asset replacement
Testing/Inspection /Mtce coordination	IF	IF	IF	IF	IF	Optimized testing/inspection/maintenance costs
15kv insulated UG cable/no splices	IF	IF	IF	IF	IF	Extended service life/minimize cable failure points
Proactive maintenance	IF	IF	IF	IF	IF	Reduced customer outage costs
Transformer/cable replacement coordination	IF	IF	IF	IF	IF	Reduced mobilization;
Underground locates	IF	IF	IF	IF	IF	Contracted services
GIS asset data repository	IF	IF	IF	IF	IF	Optimized decisions
Station relay upgrades	IF	IF	IF	IF	IF	Improved C^3
Design Software	IF	IF	IF	IF	IF	Optimized plant design
Joint Construction Standards development (50 LDCs) - USF	IF	IF	IF	IF	IF	Standards FTE not required
Equipment refurbishment	IF	IF	IF	IF	IF	Extended life of asset

Table 6 – 2020– 2024 Activity savings

IF = Included in Forecast figures

5.2.1d Period covered by the Distribution System Plan

For the purposes of this DSP, 2015 to 2019 is the historical period, and the forecast is for 2020 to 2024.

5.2.1e Vintage of the information

The information generally used throughout the DSP are based on available information established to end of 2019 and should be considered as current. Specific variances from this are as noted. NTPDL statistics based on 2019 RRR filings.

5.2.1f Important changes to NTPDL asset management process

This is the second DSP filed by NTPDL.

Since NTPDL's last DSP, NTPDL has updated the condition assessment of its key distribution assets in its Newmarket and Tay service areas. An updated ACA by Kinectrics Inc. was undertaken in 2020. The 2020 update resulted in a quantifiable evaluation of asset condition and refinement of existing asset replacement programs.

In 2017 NTPDL undertook the development of a new Strategic Framework for the organization. The Strategic Framework identified and updated NTPDL's Vision and Mission statements, Core Values, Strategic Imperatives and Key Objectives to be achieved going forward. The Asset Management objectives guiding this DSP were developed in consideration of the overall Strategic Framework for the organization and specifically the Key Objectives.

In 2018, NTPDL acquired Midland Power Utility Corporation. Asset Management processes have undergone harmonization as a result. It was determined that a more accurate and timely understanding of NTPDL's assets' condition, performance and investment needs was required to manage risk more effectively. This meant that it was necessary to migrate from the current asset registry, composed of disparate sets of records in different areas and formats, to a unified asset management registry. A centralized hub would assist in the day-to-day operation of the utility enabling lifecycle tracking of assets as well as real time health indexing for major assets.

To develop this capability, NTPDL partnered with Hexacode Solutions to implement an asset registry and asset condition assessment tool. The Hexacode software solution provides for an advanced asset health index and effective age methodology that provides accurate data for capital planning and total life cycle costing. The methodology is supported by a real-time integration platform. Implementation of this solution began in late 2018 and continued through 2019 with Poles being the initial asset being integrated.

NTPDL's asset management practice is a formalized one based on asset health indices and resulting condition-based replacement plans, modified by NTPDL to consider rate mitigation (low cost identified as a customer priority) and efficient focus of effort to optimize investment effectiveness.

5.2.1g Contingent activities/events affecting the Distribution System Plan

There are a number of ongoing and future activities in the NTPDL service areas that may/will impact on capital project prioritization and spending as outlined in the DSP.

<u>Customer Connections</u>

Customer connection forecasts are based on timing information received from Regional/County and Town Planning staff, planning reports (provincial, regional, municipal), developer submissions and inquiries, and historical connection rates. Variances in connection timing/quantity over the period of the DSP will impact on actual connections and related System Access expenses. NTPDL continues to consult regularly with municipal staff, developers and customers to update connection forecast numbers and timing.

<u>Metrolinx Rail GO Expansion</u>

Metrolinx is electrifying core areas of the GO Transit rail network including the Toronto-Barrie line which runs through Newmarket. The electrification plans will impact NTPDL and the DSP in a number of ways:

- A new station is planned for the Mulock and Bayview area. This will have servicing impacts and plant relocation impacts. Specifically, new road egress will affect NTPDL building operations due to NTPDL proximity to the new passenger station. Timing for this station is uncertain.

- A switching station is proposed in Newmarket on property adjacent to its head office and currently utilized by NTPDL for staff training purposes. The property is owned by the Town of Newmarket. This will impact some of NTPDL training operations and may require relocation of some NTPDL training facilities to a new location.

- The Transit Project Assessment Process (TPAP) was completed in late 2017. Construction began in 2019 and is scheduled to be completed by 2025.

The electrification plans require the rebuilding of rail crossings in the Town of Newmarket. NTPDL is required to relocate powerlines across 15 rail crossings; all but one needed to be relocated underground because it was not feasible to remain overhead. Originally Metrolinx had indicated that they would like all the powerline rail crossings to be relocated by end of 2020; 9 of 15 rail crossings were to be completed in 2019 (Phase 1) while 6 rail crossings are to be completed in 2020 (Phase 2). However, Metrolinx paused construction work until after 2020. All these relocation costs are expected to be covered by Metrolinx.

At this time, there are no specific details as to plant relocation and other activities that may be required to accommodate the new Mulock passenger station and the switching station and no related costs are factored into the DSP.

<u>Metrolinx Newmarket GO Mobility Hub</u>
In March 2018, Metrolinx released its report on the Newmarket GO Station Mobility Hub. The report establishes a vision for the area and provide guidance on how it should look and function. The report calls for the burial of overhead utility plant in the vicinity of the Mobility Hub. NTPDL's position is that, based on feedback from customer consultations, undergrounding of existing plant, for aesthetic reasons, should be funded outside of rate base. At this time, burial of overhead plant near the Mobility Hub is not in the DSP forecasted investment plans. This could change if funding external to rate base is provided.

Figure 4 – Newmarket GO Station Mobility Hub

Town of Newmarket Road Projects

The Town carries out road improvements and road resurfacing on an annual basis. Timing and location for these works is subject to ongoing change. NTPDL consults with the town semi-annually to determine timing and scope of road works that may impact NTPDL plant. NTPDL will be required to react to new road project proposals as they occur during the period of the DSP.

York Region/Simcoe County Road Projects

NTPDL consults with the Region/County annually to determine timing and scope of road works that may impact NTPDL plant. The Region posts future road work schedule on its website. The County posts only current year road work information on its website. System Access expenditures are required to relocate plant. NTPDL will be required to react to new road project proposals as they occur during the period of the DSP.

Municipal Approvals – UG cable replacement

The ACA program has identified the need to replace end-of-life underground distribution cable through a multi-year program of spending that has been detailed in this DSP. The timing for annual individual cable replacement projects, forming part of the UG cable replacement program, is contingent upon receiving timely municipal approvals for related excavation work. Projects will be identified and prioritized, through the budget process, in advance and communicated to the Municipality to ensure correct coordination of effort between NTPDL and the Municipality.

Meter reverification

NTPDL is required to have its residential type meters tested to ensure compliance with Measurement Canada standards. NTPDL completed its initial compliance sampling on its smart meter population for the Newmarket, Tay and Midland areas. The varying group sampling results have staggered the seal expiry dates over the next 5 years as follows:

- 2020: 545 meters
- 2021: 4,578 meters
- 2022: 2,173 meters
- 2023: 15,652 meters
- 2024: 4,350 meters

The majority of the meters listed above will be eligible for seal extension sampling the year prior its expiry date. Any meter groups not successfully sample tested at that time will have to be removed from service before their seal expires. The approximate cost to procure and install a meter prior to 2022 will be $100. Meters expiring in 2023 and 2024 will cost approximately $140 per meter.

The DSP assumes that the meters will successfully pass reverification testing.

Southern Georgian Bay/Muskoka Region Supply Study

NTPDL is in Group 2 - Southern Georgian Bay/Muskoka region for its Midland-Tay service area. An IRRP for the Parry Sound/Muskoka sub-region was issued in December 2016. The Hydro One RIP was issued in August 2017. The second cycle of regional planning for this area commenced in 2020. A draft South Georgian Bay/Muskoka Scoping Assessment has been discussed with the study participants.

NTPDL may be required to react to any recommendations that come out of the current regional planning cycle for Southern Georgian Bay/Muskoka Region. There may be an opportunity to move to a direct connection to the transmission system for the Tay and Midland areas as part of the supply study, which could lead to potential savings for customers. The outcomes of this Region supply study are contingent upon advancement of the planning requirements. NTPDL can opt to apply for an ICM rate application if required at an opportune time in this case

5.2.1h Grid modernization, DER and Climate Change investments

Cluster 6 - Local Energy Market project

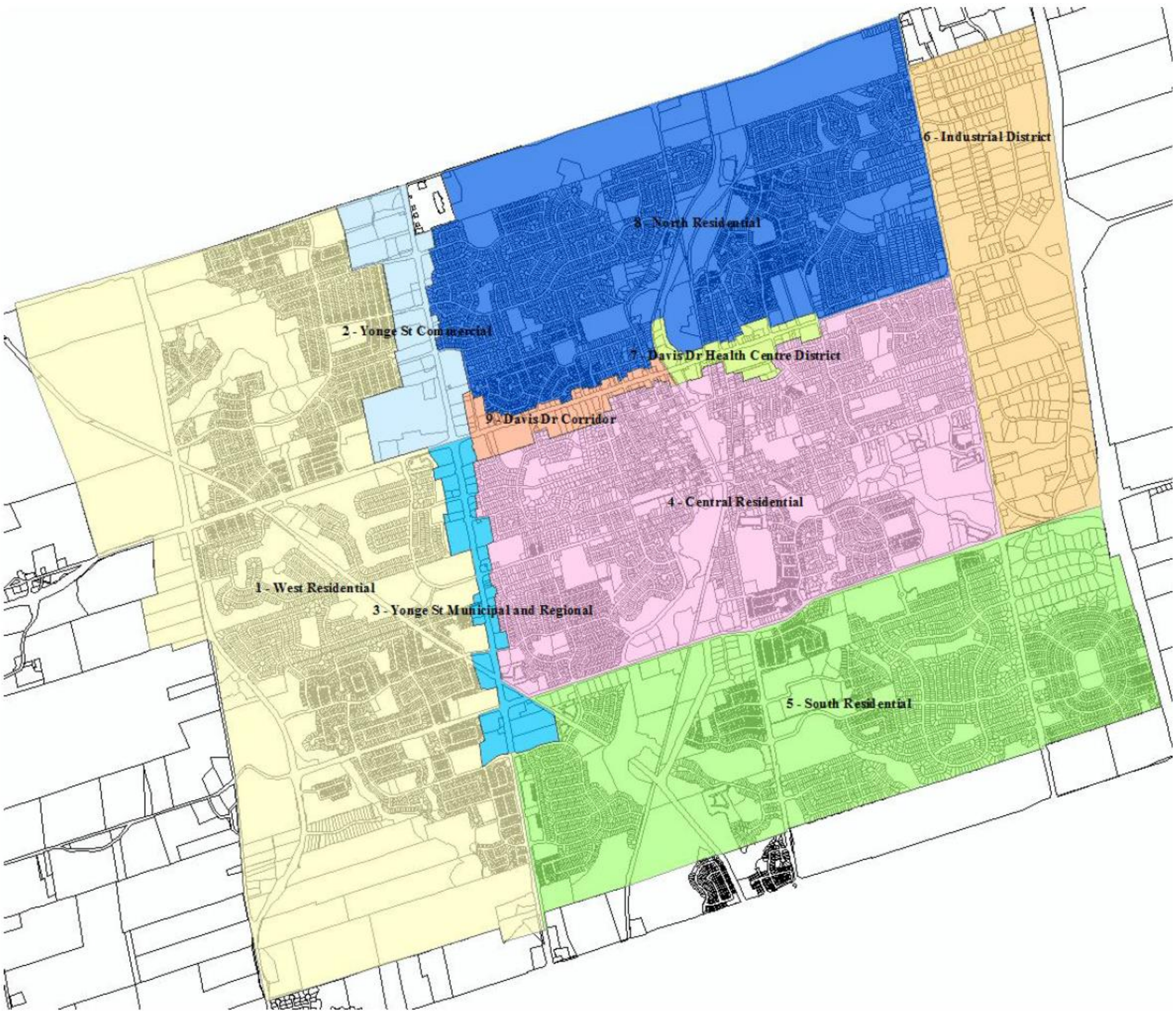


Figure 5 – Cluster 6

The project's objective is to establish effective DER integration by NTPDL facilitating customer-to-customer transactions to employ their battery energy storage and generation more cost-effectively to achieve reliability and electricity cost-savings at a lower cost than traditional pole line and transformer upgrades.

The project will engage customers to integrate DERs generally, including demand response, conservation, and the capacity and operating flexibility of assets behind the meter.

As part of the project, the project team will continue to engage with the Ontario Energy Board for guidance relating to the regulatory matters raised by the project, and to submit the necessary applications to the OEB to enable the project to proceed.

External funding is being sought for this project.

<u>New station relays and circuit breakers</u>
NTPDL is moving from licensed radio frequency to fibre for SCADA communication needs. This will result in increased data transfer, speed and reliability for control and telemetry of station and distribution assets in the field. This is primarily an operating cost. Replacement of electro-mechanical relays with electronic relays at substations and utilization of fibre communication media will improve command, control and communication of the distribution grid and have a positive impact on improving outage restoration times thereby mitigating customer outage costs.

<u>Climate Change Study</u>
In 2017, as part of their strategic planning process, NTPDL commissioned a study to determine what its Newmarket service area will experience in terms of climate change and severe weather in the future. for the Town of Newmarket in the period 2040 – 2049. Projected climate impacts in the 2040-2049 period are summarized as follows:

- Less snow and more rain in winter
- Increase in precipitation by 13% overall
- Increase in frequency of extreme storm events (>50mm precipitation)
- Average annual temperature increase of 4.5^0C
- Increase in frequency of winter storms

This information will be used to review system design needs to adapt to climate change (e.g. all rail crossings will be buried to mitigate the risk of powerlines falling on passenger train tracks as a result of the predicted increased risk of ice accretion) as well as avoid future maintenance costs for both parties.

5.2.2 Coordinated Planning with third parties

NTPDL has extensive, on-going consultations with various stakeholders regarding infrastructure planning. These consultations vary in nature from regularly scheduled meetings with senior representatives to ad-hoc / as-needed discussions with developers, electrical contractors and customers. The common purpose of all these consultations is to obtain a clear understanding of the expectations of each stakeholder regarding NTPDL's role in the success of its endeavors and to provide the stakeholders with the various solutions that may be available. Consultations provide useful information that helps NTPDL develop its investment plans for the DSP forecast period.

5.2.2a Description of the consultations

Table 7 provides a brief summary of the various consultations that NTPDL participates in during the year. Details regarding the deliverables and impact to the DSP are provided in the noted references and discussion following:

Purpose of Consultation	Initiator	Other Participants	Deliverables –Scope and Timing	Impact on DSP
Regional Planning (Newmarket)	IESO	HONI, Alectra Utilities	IRRP and HONI RIP completed in 2020	No direct impact, see Appendix E and F for details
Regional Planning (Midland-Tay)	IESO	EPCOR Electricity Distribution Ontario Inc. (Collingwood), HONI, Innpower, Lakeland Power Distribution Ltd., Orangeville Hydro Limited, Orillia Power Distribution Corporation, Parry Sound Power Corp., Alectra Utilities. (Barrie), Elexicon Energy (Gravenhurst), Wasaga Distribution Inc	IRRP completed in 2016; New Scoping Assessment completed in October 2020	No direct impact, see Appendix D for IRRP details
Determination of System Access needs for Rail electrification	Metrolinx	Town of Newmarket, York Region, HONI	Schedule and scope of rail crossing rebuilds requiring relocation of NTPDL plant	Relocations require System Access expenditures in 2019 and 2020
Customer consultations to provide advice and obtain feedback	NTPDL	Customers, HONI, Alectra	CDM, DG information provision; customer satisfaction survey; DP customer engagement mental model interviews.	Customer survey preferences are integral part of DSP
Coordination of UG plant locations	Town of Newmarket	PUCC members	Multi-year forecast of major UG projects involving most utility providers, updated yearly	No specific impact on DSP
Overhead plant locations approval on roadways	NTPDL	Town of Newmarket, Region of York, Town of Midland, Tay Township, East Gwillimbury, Simcoe County	Town or Region/County approval of proposed NTPDL overhead plant location on road allowance	No specific impact on DSP
Determination of road authority work schedules	NTPDL	Town of Newmarket, Region of York, Town of Midland, Tay Township, Simcoe County	Determination of timing and scope of road authority work that may impact existing NTPDL plant	System Access spending in 2018-19 for Yonge St. road widening in 2022. No impact on forecast period.

Table 7- Consultation Summary

<u>Regional Planning - Newmarket Service area</u>

The Newmarket service area is in Group 1 – GTA Northern York Sub Region. The other service providers in this subregion are:

- Alectra Utilities
- HONI

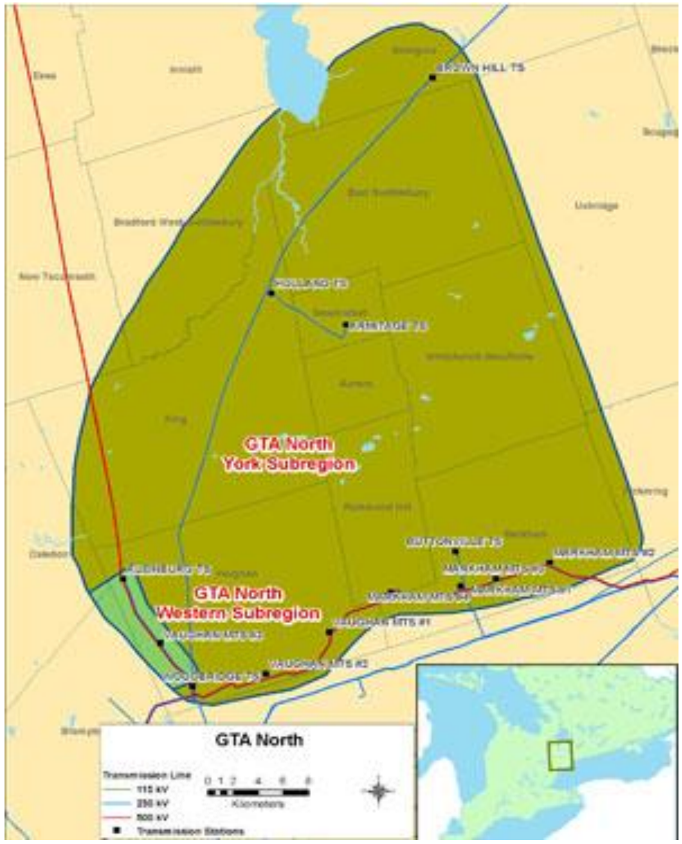


Figure 6 – GTA North Region

The last York Region Integrated Regional Resource Plan (IRRP) was published in 2015, and the next planning process kicked off at the end of 2017. A new IRRP was presented and released in February of. The current IRRP identifies a need for a new transformer station in the medium term (~2027) for ensuring reliability of supply to Northern York Region. The IRRP recommends, given development pressures in the area, finding and preserving land now. This effort would be undertaken by Hydro One. The Hydro One Regional Integrated Plan ("RIP") was issued in October 2020.

The 2020 IRRP and corresponding HONI RIP will not impact the DSP investment plans over the 2020 – 2024 forecast period.

<u>Regional Planning – Midland-Tay Service area</u>

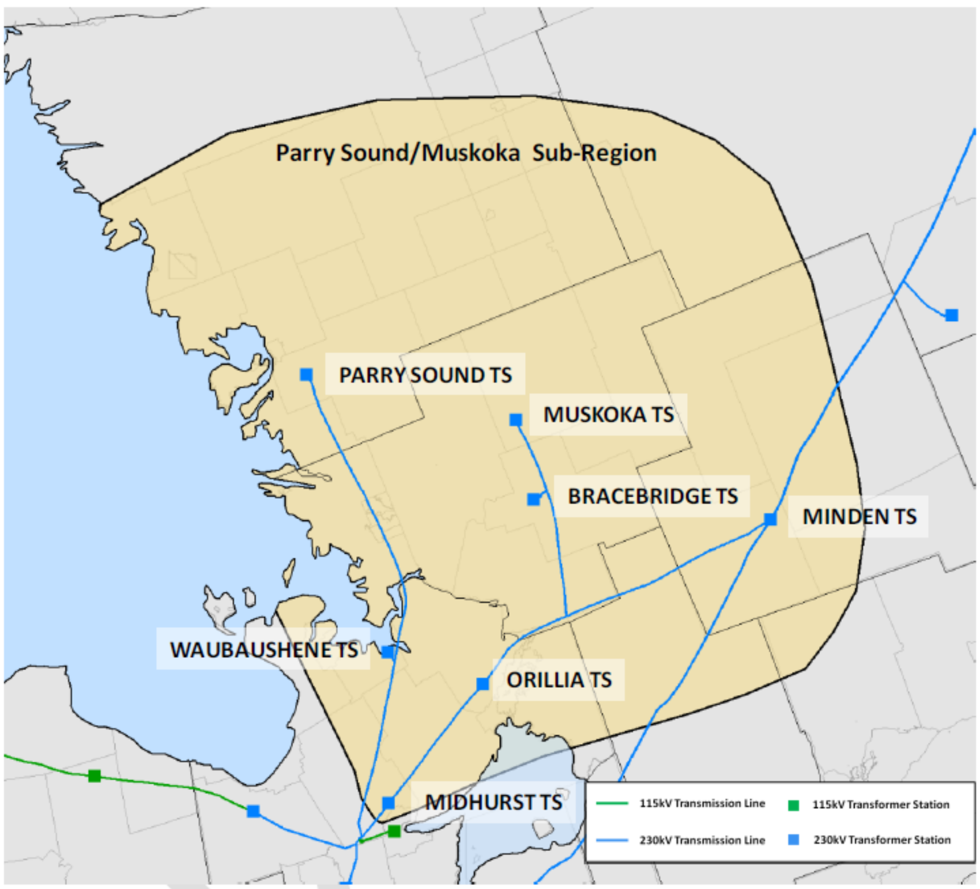
The Midland-Tay service area is in Group 2 - Southern Georgian Bay/Muskoka region. The other service providers in this Region are:

- EPCOR Electricity Distribution Ontario Inc.
- HONI
- Innpower
- Lakeland Power Distribution Ltd.
- Orangeville Hydro Limited
- Orillia Power Distribution Corporation
- Parry Sound Power Corp.
- Alectra Utilities. (Barrie)
- Elexicon Energy
- Wasaga Distribution Inc.

A South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report was published in June 2015. In the report, the Regional Participants identified two sub-regions – Barrie/Innisfil and Parry Sound/Muskoka. Two Working Groups were established to undertake Integrated Regional Resource Plans (IRRP) for each sub-region to address the needs in these areas. NTPDL is part of the Parry Sound/Muskoka sub-region. The Parry Sound/Muskoka IRRP addresses the electricity needs for the sub-region over the next 20 years from 2015 to 2034. This IRRP for this sub-region was completed in December 2016. The IRRP indicated that the electricity demand in the sub-region is expected to grow 0.9% annually, with an incremental peak demand growth of 100 MW over the planning period. The Hydro One RIP was completed in August 2017

The 2016 IRRP and 2017 RIP will not impact the DSP investment plans over the 2020 – 2024 forecast period.

The second cycle of regional planning for this area commenced in 2020. A draft South Georgian Bay/Muskoka Scoping Assessment has been discussed with the study participants.



Source: IESO

Figure 7 – Parry Sound/Muskoka Sub-Region

<u>Metrolinx</u>

Metrolinx is electrifying core areas of the GO Transit rail network including the Toronto-Barrie line which runs through Newmarket. The electrification plans will impact NTPDL and the DSP in a number of ways:

- A new station is planned for the Mulock and Bayview area. This will have servicing impacts and plant relocation impacts. Specifically, new road egress will affect NTPDL building operations due to NTPDL proximity to the new passenger station. Timing for this station is uncertain.

- A switching station is proposed in Newmarket on property adjacent to its head office and currently utilized by NTPDL for staff training purposes. The property is owned by the Town of Newmarket. This will impact some of NTPDL training operations and may require relocation of some NTPDL training facilities to a new location.

- The Transit Project Assessment Process (TPAP) was completed in late 2017. Construction began in 2019 and is scheduled to be completed by 2025.

The electrification plans require the rebuilding of rail crossings in the Town of Newmarket. NTPDL is required to relocate powerlines across 15 rail crossings; all but one need to be relocated underground because it is not feasible to remain overhead. Originally Metrolinx had indicated that they would like all the powerline rail crossings to be relocated by end of 2020; 9 of 15 rail crossings were to be completed in 2019 (Phase 1) while 6 rail crossings are to be completed in 2020 (Phase 2). However, Metrolinx paused construction work until after 2020. All these relocation costs are expected to be covered by Metrolinx.

At this time, there are no specific details as to plant relocation and other activities that may be required to accommodate the new Mulock passenger station and the switching station and no related costs are factored into the DSP.

Customer Consultations

NTPDL keeps in contact with its customers generally through meetings and discussions that arise usually in the context of new loads anticipated, opportunities for improvement of performance or events that have occurred that affected them.

NTPDL conducts customer satisfaction surveys on a regular basis. Surveys show that the customers are very satisfied with NTPDL's service. NTPDL reviews the survey results to determine if adjustments to corporate programs and strategies are warranted.

PUCC consultation

NTPDL consults with the Town of Newmarket led Public Utilities Coordinating Committee for underground plant location. This occurs on a periodic basis. NTPDL also consults with similar Region of York led meetings held annually. PUCC discussions are initiated by the Town/Region. The PUCC meets and discusses long term capital plans with all member utilities on a quarterly schedule. PUCC membership consists of local representatives from the municipal, electricity, gas and telecom sectors.

There is no town led underground PUCC administration for the Midland-Tay service area.

These consultations may provide information that may impact System Access (request to relocate plant by third party) investments in the forecast period. Current PUCC consultations are not expected to have a material impact on the DSP investment plan.

NTPDL plant locations approval on roadways consultation

As part of the regular project planning process, NTPDL consults with the Town or Region/County to obtain approval for new pole locations on roadway related to a specific project. The Town or Region/County are the "owner" of the roadway and their approval for any works constructed on it is required. NTPDL initiates the process and provides the Town or Region/County with detailed project plans for new/replacement poleline infrastructure located on road allowance. Work is able to commence when Town or Region/County approval is obtained for the proposed project pole locations. This is a regular administrative consultation process and does have a material impact on the DSP investment plan.

Road works consultation

Major road work (i.e. widening) by the Town or the Region/County may require relocation of NTPDL infrastructure. The consultations are initiated by the Town or the Region/County and are designed to ensure proper and timely coordination of effort to complete the road project. This may involve Town or Region/County coordination with other entities such as telecommunication utilities, etc. This is a project specific consultation process and any material impacts have been incorporated into the DSP investment plan.

Utility Consultations

NTPDL consults with its neighbouring utilities, such as Alectra Utilities, on various matters such as joint use on poles, mutual assistance during severe weather incidents, LTLT resolution, etc. Consultations may be initiated by NTPDL or neighbouring utility depending on the nature of the item to be discussed. As an example, assistance consultation to recover from a severe storm is generally initiated by the utility requiring assistance. Current utility consultations are not expected to have an impact on the DSP investment plan.

5.2.2b Final deliverables of the consultation process

Newmarket Service area

The final deliverable of the Regional Planning consultation process is the development of an electricity plan to meet supply needs of the York Sub-region over a twenty-year period. The study integrates load growth projections, bulk system needs, relevant community plans (i.e. Town of Newmarket's Community Energy Plan), FIT and other generation uptake, as well as local constraints to ensure that system adequacy needs arising from assessment of projected load growth are appropriately captured.

NTPDL's role in the process is to actively participate in the study process and to provide the following information:

- Input on study Terms of Reference
- Forecast demand data
- Existing, committed and potential DG including FIT and non-FIT uptake
- Information on Green Energy and other relevant community plans
- Any Rate-based Conservation and DR programs to be included in the study
- Input to help develop options:
    - Conservation options
    - Local generation options
    - Transmission or distribution options including maximizing existing infrastructure capability
- Input into Non-Wires Alternatives solutions
- Input towards the development of implementation plans

The last York Region Integrated Regional Resource Plan (IRRP) was published in 2015, and the next planning process kicked off at the end of 2017. A new IRRP (Appendix E) was presented and released in February 2020. The current IRRP identifies a need for a new transformer station in the medium term (~2027) for ensuring reliability of supply to Northern York Region. The IRRP recommends, given development pressures in the area, finding and preserving land now. This effort would be undertaken by Hydro One.

The 2020 IRRP will not impact the DSP investment plans over the 2020 – 2024 forecast period.

As part of the next cycle of the Planning Process for York Region, NTPDL provided its updated 2020 – 2029 load forecast to HONI in 2019.

Midland-Tay service area

NTPDL is part of the Parry Sound/Muskoka sub-region. The Parry Sound/Muskoka IRRP addresses the electricity needs for the sub-region over the next 20 years from 2015 to 2034. This IRRP for the Parry Sound/Muskoka sub-region was completed in December 2016 (see Appendix D). The Hydro One RIP was completed in August 2017. The IRRP indicated that the electricity demand in the sub-region is expected to grow 0.9% annually, with an incremental peak demand growth of 100 MW over the planning period.

The IRRP will be revisited in 2021. A draft South Georgian Bay/Muskoka Scoping Assessment has been discussed with the study participants.

5.2.2c Material Documents used in the consultation process

NTPDL has provided the following documentation to the IESO as part of the consultation process:

1. Newmarket-Tay Distribution Ltd. Gross Forecast Methodology
2. Gross Median Weather and Net Extreme Weather forecasts

NMT	Gross Median Weather Station Peak Demand Forecast (MW)																			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Holland TS (44kV)	62.5	59.8	60.5	61.3	62.0	62.7	63.3	64.0	64.6	65.2	65.8	66.4	67.1	67.7	68.3	68.9	69.5	70.2	70.8	71.4
Armitage TS (44kV)	81.6	86.3	87.4	88.6	89.6	90.7	91.6	92.6	93.5	94.4	95.4	96.3	97.2	98.2	99.1	100.0	101.0	101.9	102.8	103.7

NMT	Net Extreme Weather Station Peak Demand Forecast (MW)																			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Holland TS (44kV)	65.9	62.8	63.4	64.1	64.7	67.3	69.9	72.4	72.9	72.9	72.9	72.9	72.9	72.9	72.9	72.9	72.9	72.9	72.9	72.9
Armitage TS (44kV)	85.5	89.4	89.9	90.9	91.6	91.6	91.6	91.6	91.6	91.9	93.2	94.8	96.4	97.9	99.1	100.4	101.7	103.1	104.6	106.2

Table 8 – NTPDL Load Forecasts provided to IESO

5.2.2d REG investments - IESO comment letter

NTPDL has not proposed any REG investments during the 5-year Distribution System Plan (DSP) period, and as such, no letter from the IESO is required.

5.2.3 Performance Measurement for continuous improvement

5.2.3a Metrics used to monitor distribution system planning performance

NTPDL has been and continues to be, focused on maintaining the adequacy, reliability and quality of service to its distribution customers. NTPDL reviews plan performance on an ongoing basis through various mechanisms such as:

Customer oriented performance - Annual customer survey

On a regular basis, NTPDL undertakes customer satisfaction surveys to obtain feedback on the overall value of service offered to customers. Customers (residential and commercial) are engaged to provide high level feedback on their perceptions of NTPDL performance and where they think NTPDL could improve service. This information is extremely useful to help guide future investment planning that will maintain/improve customer satisfaction. NTPDL's target is to maintain an "A" rating or better for the following survey metrics:

Customer Care
Company Image
Management Operations

NTPDL's target is to be within 5% of previous survey scores for the following survey metrics:

Customer Centric Engagement Index (CCEI)
Customer Experience Performance rating (CEPr)

Customer oriented performance - Service Reliability
Service reliability is an indicator of quality of electricity supply received by the customer.

Service reliability is monitored on a daily basis. All Trouble Reports are reviewed by Operations senior staff and executive management on a daily basis. Within 24-hours of a feeder outage, a more detailed Outage Report is circulated internally to Operations senior and executive management that also includes the President and COO. Meetings and discussions are held to review issues of an exceptional nature.

Two specific indicators are used to monitor service reliability: SAIDI and SAIFI.

SAIDI is an index of system reliability that expresses the average amount of time, per reporting period, supply to a customer is interrupted.

SAIFI is an index of system reliability that expresses the number of times per reporting period that the supply to a customer is interrupted.

SAIDI and SAIFI are defined as:

SAIDI = System Average Interruption Duration Index

$$= \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

SAIFI = System Average Interruption Frequency Index

$$= \frac{\text{Total Customer Interruptions}}{\text{Total Customers Served}}$$

The SAIDI and SAIFI targets as stated in the most recent OEB RRFE scorecard are used as default targets for reliability performance expectations in the forecast years. The most recent 5 year rolling SAIDI and SAIFI averages are compared to the default targets to determine increasing or decreasing reliability trends.

These indices provide NTPDL with an annual measure of its service performance for internal benchmarking and for comparisons with other distributors. In accordance with Section 7.3.2 of the OEB Electricity Distribution Rate Handbook, NTPDL records and reports SAIDI and SAIFI figures annually.

Outages are classified according to cause code, as per OEB reporting requirements, to provide further insight into the root cause of the outage.

Code	Cause of Interruption
0	**Unknown/Other** Customer interruptions with no apparent cause that contributed to the outage.
1	**Scheduled Outage** **Customer interruptions** due to the disconnection at a selected time for the purpose of construction or preventive maintenance.
2	**Loss of Supply** Customer interruptions due to problems associated with assets owned and/or operated by another party, and/or in the bulk electricity supply system. For this purpose, the bulk electricity supply system is distinguished from the distributor's system based on ownership demarcation.
3	**Tree Contacts** Customer interruptions caused by faults resulting from tree contact with energized circuits.
4	**Lightning** Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs.
5	**Defective Equipment** Customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.
6	**Adverse Weather** Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events).
7	**Adverse Environment** Customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing.
8	**Human Element** Customer interruptions due to the interface of distributor staff with the distribution system.
9	**Foreign Interference** Customer interruptions beyond the control of the distributor, such as those caused by animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects.

Table 9 – Causes of Interruption Codes

Tracking outage performance by cause-code provides valuable information on specific outage causes that need to be addressed to improve negative trending. As with the reliability indices, the past 5-year historical performance range is used as a target and results outside this range indicate positive or negative trending. Negative trending may indicate that NTPDL may be required to undertake specific actions to improve service reliability.

NTPDL is a member of the Canadian Electricity Association (CEA) Service Continuity Committee and utilizes its membership to discuss and understand best practices with regards to a managed approach to improving distribution system reliability and to perform peer comparisons of reliability statistics. NTPDL participates in the Annual Service Continuity Survey on Distribution System Performance in Electrical Utilities to determine how favourably NTPDL's reliability compares to the peer (Urban/Rural) group of utilities.

NTPDL plans to utilize additional customer specific measures of reliability: Customers Experiencing Multiple Interruptions (CEMI), and Customers Experiencing Long Duration Interruptions (CELDI). Implementation of a more sophisticated Outage Management System ("OMS") will support the implementation of CEMI & CELDI use to improve reliability to its customers. This investment in systems to support OMS implementation is allocated in the IT expenditures of this DSP.

<u>Customer oriented performance - Bill impacts</u>

Over 75% of a customer's bill is due to factors (i.e. generation, transmission, global uplift, etc.) outside the control of the LDC. Notwithstanding that, surveys continue to indicate that it is the overall cost of the bill, not the individual components, that are of concern to the customer.

NTPDL considers the short and long-term customer bill impacts as part of the asset management process and bill impact mitigation is a consideration in investment planning decisions. Where possible, NTPDL's forward looking asset management plans and programs are structured to smooth customer bill impacts over the years. This is especially evident from NTPDL limiting its investment to a total of $36M over this 5-year DSP period 2020-2024, or an average of $7.3M per year, instead of $10M average investment per year as informed by Asset Condition Assessments ("ACA") it conducted. In terms of bill impact of this $36M investment, a residential customer would see only a $1.25 increase on their monthly bill beginning in 2028.

NTPDL conducted Asset Condition Assessments ("ACA") that informs the development of its DSPs. Although the ACAs indicate that NTPDL historically has underspent in replacing its end-of-life assets, NTPDL has been mindful of potential impacts on customers and has prudently balanced spending with a slight risk to maintaining customer service levels over the historical period. NTPDL's strategy is to gradually increase its replacement of end-of-life assets over two more DSP periods (over next ten years) rather than in one five-year period, to attain the required asset replacement levels of $10M average investment per year as informed by Asset Condition Assessments ("ACA") it conducted.

NTPDL's smoothing of customer bill impacts is also evident in how NTPDL structures its non-mandatory programs, such as asset refurbishment/replacement, where risk and rate mitigation inputs are considerations to program scheduling. While most investment scheduling can be smoothed, certain capital expenditures are lumpy in nature and these may result in expenditure volatility in a specific year.

NTPDL's target for this measure is for rate impacts in residential and general service classes to remain within OEB rate mitigation guidelines.

Customer oriented performance - Billing accuracy

In NTPDL surveys, billing related issues have been identified as a key identifier of customer satisfaction. When billing is wrong, adjustments have to be made to provide the customer with a corrected bill. Sometimes there is a disconnect between what the customer perceives to be a billing problem and what NTPDL considers to be a billing problem. Employee training helps deal with the problems that cause the most concern with customers. Billing accuracy reduces disputed bill re-work, delayed payments and improves customer confidence. Billing is one of the principal forms of communication with the customer. NTPDL's billing accuracy measure is that reported in the annual RRR filings to the OEB.

NTPDL's target for this measure is to maintain a minimum of 98% accuracy per OEB guidelines.

Cost Efficiency and Effectiveness – Project/program variance analysis

NTPDL monitors capital projects and maintenance program spending. For material capital projects budgeted in the DSP, actual costs are to be compared to estimates and variances exceeding designated thresholds will require detailed explanation by operating staff that executed the project and engineering staff that planned the project. This will help improve the accuracy of estimate to actual spending. The performance measure is that these projects and programs are completed within the budget year unless carryover spending has been specifically identified. It is recognized that changes in externally driven project schedules can have a major impact not only on the project in question but on the entire capital spending for the period under review. Planned maintenance programs are expected to be completed within the budget and calendar year. NTPDL's target for this measure is that actual variances shall be within 20% of estimate.

Cost Efficiency and Effectiveness - DSP Spending Progress Report

NTPDL will be monitoring its execution of the projects and programs included in the DSP. On an annual basis, NTPDL will calculate for that year, and on a cumulative basis for the five years of the DSP, its actual capital spending compared to the approved capital budget. This will help identify any issues in the DSP investment planning process that need to be addressed for the next iteration of the DSP. NTPDL's target for this measure is that DSP actual spending to be within 10% of approved DSP capital budget.

Asset/System Operations Performance – Safety

Maintaining a high level of employee and public safety is a key corporate objective. Any issues, systemic or otherwise, that would compromise worker or public safety need to be identified and addressed in a timely manner.

Safety is monitored on an ongoing basis. Monthly summaries of incidents and accidents are provided to the NTPDL Executive. The NTPDL Board is verbally advised of any safety related issues arising since the previous verbal report to the Board. NTPDL has adopted the ESA Serious Electrical Incident Index (SEII) as a performance benchmark for non-occupational safety incidents involving NTPDL plant.

Asset/System Operations Performance – Level of Compliance with Ontario Reg. 22/04

As with every other Ontario distributor, NTPDL's design, construction, inspection, maintenance practices are audited on a yearly basis as required by Ontario Regulation 22/04. The utility can be deemed to be in one of three performance categories:

1. In Compliance - Substantially meeting the requirements of Regulation 22/04.
2. Needs Improvement - Continuing failure to comply with a previously identified Needs Improvement item or non-pervasive failure to comply with adequate, established procedures for complying with Regulation 22/04

3. Not in Compliance - A failure to comply with a substantial part of Regulation 22/04; or continuing failure to comply with a previously identified Needs Improvement item

NTPDL's target is to remain In Compliance in all categories being audited.

Asset/System Operations Performance –Substation loading

NTPDL's distribution substations have been identified as being single most critical asset category within its distribution system. Substation loading beyond equipment nameplate ratings can lead to loss of equipment life and reduced service reliability. NTPDL looks to maintain substation normal loading at approximately 80% of the ONAN (Oil Natural Air Natural) MVA capacity of the substation transformer. NTPDL deems this a reasonable operating philosophy in that the use of the asset is optimized and overload capacity (up to nameplate) exists for contingency situations. Substation loading information is collected and reviewed monthly. The substation loading indicates the effectiveness of NTPDL's asset utilization planning. NTPDL's target for this measure is that substation peak demand is not to exceed transformer maximum nameplate rating.

Asset/System Operations Performance – System Losses

NTPDL system losses are monitored annually. System design and operation is managed such that system losses are maintained within OEB thresholds as defined in the OEB Practices Relating to Management of System Losses. Losses are monitored to ensure that the OEB 5% threshold is not exceeded.

RRFE Performance Scorecard

The OEB RRFE performance scorecard is reviewed annually to ensure performance trending aligns with the overall corporate business strategy and objectives, as well as regulatory targets. Underperformance trending would result in measures being taken to realign performance trending with expectations.

A summary of performance targets to be referred to throughout the period of the DSP are shown in Table 10 below:

Performance Indicator	Targets				
	2020	2021	2022	2023	2024
Reliability (SAIFI)*	1.06	1.06	1.06	1.06	1.06
Reliability (SAIDI)*	1.33	1.33	1.33	1.33	1.33
Customer Care	A	A	A	A	A
Customer Image	A	A	A	A	A
Management Operations	A	A	A	A	A
Customer Centric Engagement Index (CCEI)	89%	89%	89%	89%	89%
Customer Experience Performance rating (CEPr)	89%	89%	89%	89%	89%
Billing Accuracy	98%	98%	98%	98%	98%
Billing Impact	Annual rates subject to OEB approval (within mitigation guidelines)				
Material Project variance	<=+/- 20%	<=+/- 20%	<=+/- 20%	<=+/- 20%	<=+/- 20%
DSP progress variance	<=+/- 10%	<=+/- 10%	<=+/- 10%	<=+/- 10%	<=+/- 10%
Safety	ESA SEII = 0	ESA SEII = 0	ESA SEII = 0	ESA SEII = 0	ESA SEII = 0
ESA Reg 22/04	0 Non-compliance	0 Non-compliance	0 Non-compliance	0 Non-compliance	0 Non-compliance
Substation loading (Normal)	Peak demand <=nameplate	Peak demand <=nameplate	Peak demand <=nameplate	Peak demand <=nameplate	Peak demand <=nameplate
Losses	<5%	<5%	<5%	<5%	<5%

Table 10 – DSP Performance Targets

* 2020 – 2024 SAIDI and SAIFI unadjusted targets to be based on 2015 – 2019 5-year average baseline for NTPDL/MPUC merged utility

Annual performance variances that are not within target ranges or meet minimal performance thresholds would result in senior management review of performance cause that may result in changes to immediate or future plans to direct future performance back to target levels.

5.2.3b Unit Cost Metrics

Unit cost metrics for the 2015 – 2019 period are presented below as per prescribed format of Appendix 5-A.

Metric Category	Metric	Measures	
		2019	2015-2019 Average
Cost	Total Cost per Customer[1]	$240	$363
	Total Cost per km of Line[2]	$10,242	$15,370
	Total Cost per MW[3]	$63,427	$89,235
CAPEX	Total CAPEX per Customer	$138	$271
	Total CAPEX per km of Line	$5,879	$11,458
O&M	Total O&M per Customer	$102	$92
	Total O&M per km of Line	$4,363	$3,911

Notes to the Table:

1 The Total Cost per Customer is the sum of a distributor's capital and O&M costs divided by the total number of customers that the distributor serves.

2 The Total Cost per km of Line is the sum of a distributor's capital and O&M costs divided by the total number of kilometers of line that the distributor operates to serve its customers.

3 The Total Cost per MW is the sum of the distributor's capital and O&M costs divided by the total peak MW that the distributor serves.

Explanatory Notes on Adverse Deviations
Metric Name: Cost; CAPEX; COST per MW; CAPEX per Customer; CAPEX per km of line
High average cost due to high Gross Capital costs in 2015 and 2016 for pole replacement due to Yonge Street reconstruction for VIVA bus service and high Gross Capital cost in 2018 due to acquisition of Midland PUC.
Metric Name: O&M per Customer; O&M per line km of line
Higher cost due to annual inflationary pressures as well as additional support required in the areas of human resources, IT, engineering and operations.
Metric Name:

Table 11 – Unit Cost Metrics 2015 – 2019

5.2.3c Summary of historical performance and performance trends

Customer oriented performance - Annual customer survey

The customer survey results over the historical period are shown in the tables below:

	2015*	2017*	2018	2019
Customer Care	A	B+	A	A
Company Image	A	A	A	A
Management Operations	A	A	A	A+
Customer Centric Engagement Index (CCEI)	84%	84%	86%	89%
Customer Experience Performance rating (CEPr)	86%	86%	88%	89%

* Midland service area not in 2015 and 2017 surveys

Table 12 – 2015 – 2019 Customer Survey Results – Newmarket/Tay

The survey results indicate consistent customer perception of NTPDL key performance categories of Customer Care, Company Image and Management Operations. In 2017 there was a slight drop-in Customer Care primarily due to dissatisfaction over the steep rise in electricity costs through 2017. It should be noted that over 80% of the customer's bill is out of NTPDL's control.

Over the historical period, NTPDL scored at or higher than National and Ontario benchmarks in all three performance categories.

The CCEI and CEPr indexes provide specific feedback on customer interaction perceptions and their engagement connection with the NTPDL brand. Results have generally been improving, currently averaging in the high-eighty percentile region towards the end of the historical period. NTPDL's performance in this area exceeds National and Ontario performance.

NTPDL undertook surveys specific to its Large Customers (>50 kW demand) in 2015, 2017 and 2018. Survey was performed by UtilityPULSE. Scores have been high and consistent over this period.

	2015*	2017	2018
Customer Centric Engagement Index (CCEI)	88%	90%	89%
Customer Experience Performance rating (CEPr)	92%	91%	90%

*Midland service area not included in 2015 survey

Table 13 – Customer Engagement and Experience Scores

The CCEI and CEPr indexes provide specific feedback on customer interaction perceptions and their engagement connection with the LDC brand. The combined entity's performance in this area exceeds the UtilityPULSE (UP) database performance.

In the 2018 survey, respondents were asked to identify the top 5 initiatives/projects which encompass operational aspects and/or financial commitment, that should be prioritized over the following five years:

Maintaining and upgrading equipment	97%
Investing more in the electricity grid to reduce outages	90%
Reducing response times to outages	90%
Improving power quality	83%
Coordinating infrastructure planning with commercial customers	83%

Table 14 – Top Five Initiatives/Projects

Customer oriented performance - Service Reliability

The NTPDL interruption history for all interruptions (2015 – 2019) are shown the table below:

Year	Total Outage Causes	All interruptions	All interruptions excluding loss of supply	All interruptions excluding MEDs	All interruptions excluding loss of supply & MEDs
2015	224	25,700	24,848	25,700	24,848
2016	225	50,111	45,007	30,164	25,060
2017	195	38,979	37,485	21,667	20,173
2018	232	62,360	33,914	41,139	33,914
2019	183	51,556	35,528	36,055	30,895

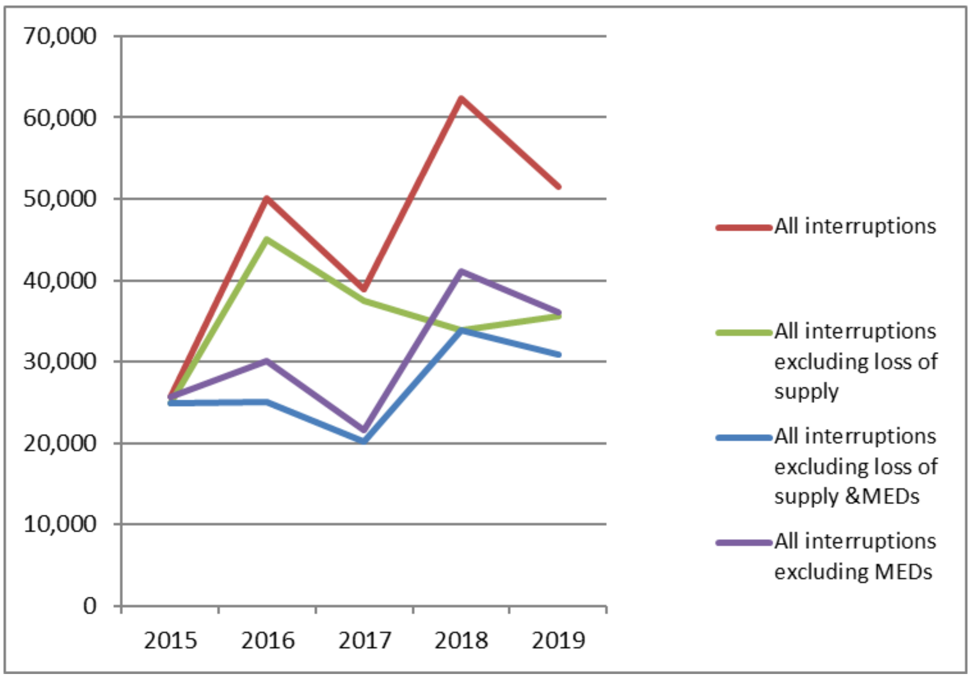


Table 15 – Interruption History 2015 – 2019

Service reliability statistics are compiled monthly and presented to the NTPDL Board quarterly (see sample reliability statistics summary in Appendix B).

In Newmarket, most interruptions occur on the 13.8kV feeder system. Total interruptions increased in 2016 compared to previous years primarily due to the need to perform numerous scheduled outages as part of the Yonge St. VIVA bus project which required replacement and relocation of NTPDL plant along

Yonge St. from south of Mulock St. to Davis Dr. In 2018 and 2019, almost half of the number of interruptions experienced by customers were due to Loss of Supply issues and MEDs.

In Midland, most interruptions occur on the 4kV feeder system. Reliability performance has been relatively high in the historical period except for 2016. In 2016, the Town experienced two major storms in August and October which resulted in outages to numerous customers from damaged overhead plant and loss of HONI supply. In 2017 performance returned to historical low levels.

44kV feeder outages impact the supply to NTPDL's municipal stations which in turn impact large numbers of customers compared to individual 13.8kV and 4kV feeder outages.

Total interruptions decreased in 2019 primarily although they still remain somewhat high due to Loss of Supply and MED issues.

MED Outage Summary

NTPDL Major Events are determined in accordance with OEB RRR definition (i.e. unpredictable and beyond the control of the distributor). NTPDL specifically uses the fixed approach methodology (i.e. criteria for 10% of total customers affected) for determining a MED. MED outages since the last Cost of Service filing are outlined in Table 16 below:

Year	Area*	Date	Cust	% of base	MED event
2010	-	-	-	-	No MEDs
2011	N	Aug 24	5,272	16	Cause was Loss of Supply (Code2)
2012	N	Dec 22	3,727	11	Cause was Tree Contacts (Code 3)
2013	N	July 8	3,806	11	Cause was Lightning (Code 4)
	N	Nov 18	28,542	82	Cause was Loss of Supply (Code2)
2014	-	-	-	-	No MEDs
2015	-	-	-	-	No MEDs
2016	N	Mar 25	4,689	13	Cause was freezing rain - Adverse Weather (Code 6)
	N	May 25	11,100	31	Cause was vehicle hitting pole – Foreign Interference (Code 9)
	M-T	Aug 17	4,158	58	Cause was high winds – Adverse Weather (Code 6)
2017	N	Apr 22	8,065	23	Cause was failure of customer-owned substation transformer and protection resulting in loss of 44kV supply feeder – Foreign Interference (Code 9)
	N	May 11	4,969	14	Cause was animal contacts resulting in multiple feeder outages – Foreign Interference (Code 9)
	N	Oct. 15	4,278	12	Cause was broken poles due to high winds - Adverse Weather (Code 6)
2018	N	May 4	15,683	44	Cause was equipment failure at HONI owned Armitage TS – Loss of Supply (Code 2)
	N	Nov 1	5,538	15	Cause was Holland TS Bus protection for a fault on a HONI owned feeder.
2019	N	Apr 11	5,434	15	M5 and M7 loads were lost due to failure of HONI M5 protection
	N	May 21	5,434	15	M5 and M7 loads were lost due to HONI protection operation
	N	Sep 13	4,633	13	M24 breaker locked out due to lightning

Table 16 – Historical MED Outage Summary

* N = Newmarket area, M-T = Midland-Tay area

SAIFI and SAIDI statistics

NTPDL's SAIFI and SAIDI statistics for the 2015– 2019 historical period are shown below:

Year	SAIFI	SAIDI	SAIFI (excl. Code 2 & MEDs)	SAIDI (excl. Code 2 & MEDs)	Ontario SAIFI (excl. Code 2 & MEDs)	Ontario SAIDI (excl. Code 2 & MEDs)
2015	0.61	0.60	0.59	0.54	1.57	2.77
2016	1.17	2.06	0.59	0.46	1.48	2.79
2017	0.91	1.05	0.47	0.38	1.44	2.85
2018	1.44	1.42	0.78	0.66	1.48	2.59
2019	1.17	1.52	0.70	0.78	1.52	2.64

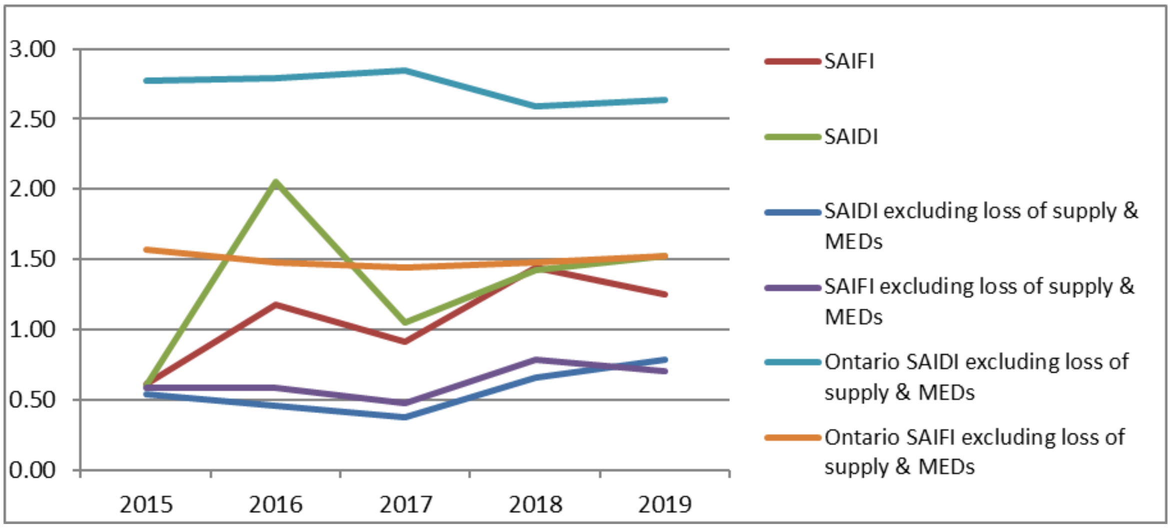


Table 17 – Reliability Statistics 2015 - 2019

The reliability statistics, excluding loss of bulk supply and MEDs, indicate good performance (SAIFI and SAIDI < 1) over the historical period, especially when compared to the Ontario average.

NTPDL participated in the CEA 2019 Annual Service Continuity Survey on Distribution System Performance in Electrical Utilities. The 2019 survey report indicates that NTPDL's reliability compares very favourably within the peer (Region 2 - Urban/Rural) group of utilities. The following numbers compare the SAIFI and SAIDI averages over a five-year period, 2015 – 2019, including MED statistics, to align with data in the CEA report.

SAIFI has been averaging approximately 0.63 over the 2015 - 2019 period. This equates to a NTPDL customer experiencing an outage once every 1.59 years. This performance compares very favourably with the 2019 CEA 5-year Canadian utility performance figures of 3.08 (Region 2) and OEB published Ontario performance figure of 1.50.

SAIDI has been averaging approximately 0.56 over the 2015 - 2019 period. This equates to a NTPDL average of 37 minutes of outages per customer per year. This performance compares very favourably with the 2019 CEA 5-year Canadian utility performance figures of 8.83 (Region 2) and OEB published Ontario performance figure of 2.73.

Historical outage causes are listed below:

Code	Primary Cause	2015	2016	2017	2018	2019	Average
0	Unknown/Other	8	17	6	14	4	10
1	Scheduled Outage	80	34	57	51	56	56
2	Loss of Supply	2	4	3	5	6	4
3	Tree Contacts	10	9	6	15	6	9
4	Lightning	0	5	1	2	1	2
5	Defective Equipment	32	49	30	61	38	42
6	Adverse Weather	9	14	7	10	13	11
7	Adverse Environment	0	0	1	0	0	0
8	Human Element	2	4	0	2	0	2
9	Foreign Interference	81	89	84	72	59	77
	Total	224	225	195	232	183	212

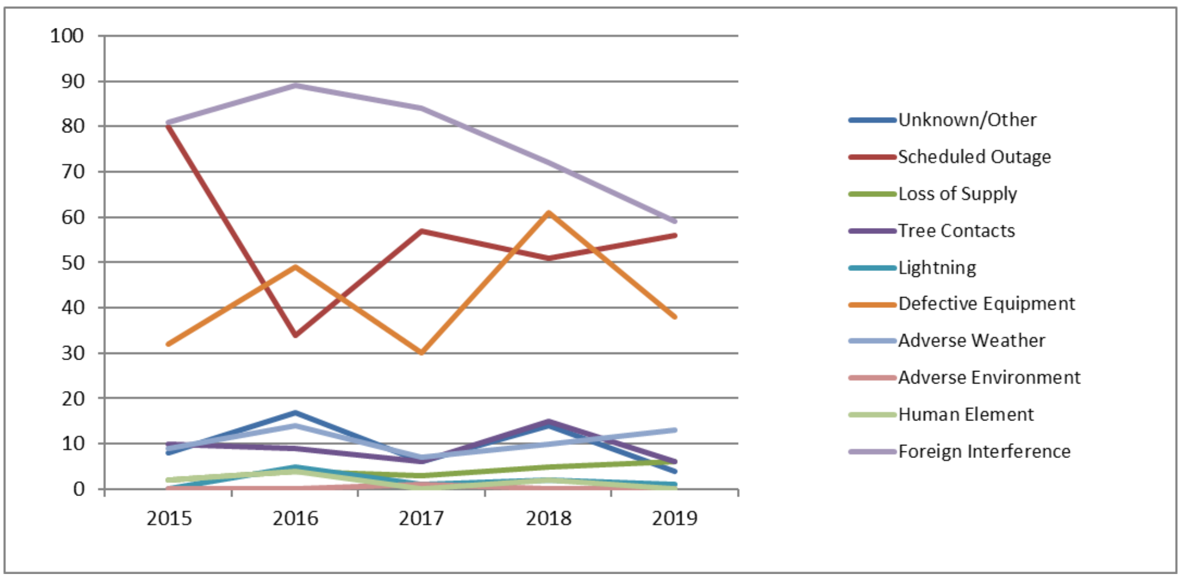


Table 18 – Outage Causes 2015 – 2019

Code 0 outages (Unknown) have been fluctuating over the historical period. Most unknown outages are suspected momentary animal or vegetation contact as power is normally successfully restored without repairs to any identified equipment.

Code 1 outages (Scheduled) show a stabilizing trend as work required for the VIVAnext Bus Rapid Transit ("BRT") project along Yonge St. in Newmarket has been substantially completed reducing the need and number of scheduled outages. The VIVAnext Bus Rapid Transit ("BRT") project required numerous scheduled outages for plant relocation along Yonge St.

Code 2 outages (Loss of Supply) show a slight increase in trending over the historical period. While frequency is low, each loss of supply event has major impacts on customer interruption and customer hours-interrupted numbers.

Code 3 outages (Tree contacts) show a relatively stable trend over the historical period. This demonstrates the effectiveness of NTPDL's vegetation management program.

Code 4 outages (Lightning) have had minimal occurrences except for a number of events in 2016.

Code 5 outages (Defective Equipment) show a fluctuating trend. The increase in 2018 is due to higher than normal number of equipment failures, of varying causes, affecting small numbers of customers each time. Code 5 outages are mitigated through effective maintenance programs and renewal programs for assets at end of useful life.

Code 6 outages (Adverse Weather) show an increasing trend. The number of customers being impacted by adverse weather has been increasing over the historical period.

Code 7 outages (Adverse Environment) show minimal impact on reliability.

Code 8 Outages (Human Error) have had low occurrences except for a slight increase in 2016.

Code 9 Outages (Foreign Interference) show a reduction in 2019. The majority of Code 9 outages have been animal related (squirrels). Since the beginning of 2017, NTPDL has been installing animal guards on select equipment (during outage response, maintenance) to mitigate future animal contact occurrences. In 2016 a key outage in this category was due to a vehicle striking and breaking a pole causing circuits to trip out resulting in numerous customer outages. In 2017 a key outage in this category was due to a Customer substation failure affecting the 44kV feeder supply to numerous other customers.

The following tables provide more detail on the outage cause impact on the number of customers interrupted by cause and number of customer-hours of interruption by cause.

Code	Primary Cause	2015	2016	2017	2018	2019	Average
0	Unknown/Other	2,010	5,252	597	10,570	1,414	3,969
1	Scheduled Outage	13,011	2,547	5,423	5,545	9,337	7,173
2	Loss of Supply	852	5,104	1,494	28,446	16,028	10,385
3	Tree Contacts	1,586	176	1,131	1,585	74	910
4	Lightning	-	204	2	302	4,633	1,028
5	Defective Equipment	4,636	5,781	7,388	8,362	9,999	7,233
6	Adverse Weather	2,297	13,497	7,774	3,181	5,318	6,413
7	Adverse Environment	-	-	10	-	-	2
8	Human Element	9	2,042	-	2,185	-	847
9	Foreign Interference	1,299	15,508	15,160	2,184	4,753	7,781
	Total	25,700	50,111	38,979	62,360	51,556	45,741

Table 19– Outage Causes – Number of Customer Interruptions 2015 – 2019

Code	Primary Cause	2015	2016	2017	2018	2019	Average
0	Unknown/Other	728	2,441	1,436	8,941	1,243	2,958
1	Scheduled Outage	10,156	388	1,164	1,052	12,373	5,027
2	Loss of Supply	2,705	27,209	2,475	32,908	26,958	18,451
3	Tree Contacts	2,194	164	892	6,728	81	2,012
4	Lightning	-	451	1	304	5,328	1,217
5	Defective Equipment	4,834	7,914	6,254	3,503	7,557	6,012
6	Adverse Weather	3,607	32,393	8,468	3,787	7,172	11,085
7	Adverse Environment	-	-	18	-	-	4
8	Human Element	9	40	-	2,444	-	499
9	Foreign Interference	1,210	16,357	24,291	1,831	1,909	9,120
	Total	25,443	87,357	44,999	61,498	62,621	56,384

Table 20– Outage Causes – Number of Customer-Hours of Interruptions 2015 – 2019

Customer oriented performance - Bill impacts

Over the historical period, Newmarket and Tay residential and GS customers have had an average annual rate increase of 0.7% (2015 – 2019) based on the Annual IR index methodology. Under this adjustment process, rates are mechanistically set at inflation (determined by OEB) less productivity (determined by OEB) and stretch factors (0.6% default for Annual IR).

	2015	2016	2017	2018	2019
Rate Filing	Annual IR	Annual IR	Annual IR	Annual IR	Annual IR
Residential	0%	1%*	1.3%	0.6%	0.6%
GS<50	0%	1%*	1.3%	0.6%	0.6%
GS>50	0%	1%*	1.3%	0.6%	0.6%

* 2015 rates effective January 1, 2016; no 2016 rate application

Table 21 – Historical Annual Rate Impacts for Newmarket and Tay Residential and General Service Classes

Over the historical period (2015 – 2019), Midland residential and GS customers have had an average annual rate increase of 1.15% based on the Price Cap IR index methodology. Under this adjustment process, rates are mechanistically set at inflation (determined by OEB) less productivity (determined by OEB) and stretch factors (0.45% for MPUC).

	2015	2016	2017	2018	2019
Rate Filing	Price Cap IR	Price Cap IR	Price Cap IR	Price Cap IR	Price Cap IR
Residential	1.15%*	1.65%	1.45%	0.75%	0.75%
GS<50	1.15%*	1.65%	1.45%	0.75%	0.75%
GS>50	1.15%*	1.65%	1.45%	0.75%	0.75%

Table 22 – Historical Annual Rate Impacts for Midland Residential and General Service Classes

In 2017, NTPDL undertook a pilot project in conjunction with BEWORKS, a consumer-centric design agency, and introduced a new bill format to improve communications on electricity costs with customers. The “Bills that Save” project is designed to improve consumer comprehension about TOU electricity pricing, especially the most expensive on-peak electricity price. The project objective is to use new bill format to motivate consumers to shift energy usage to Off-Peak periods, consistent with time-of-use pricing in Ontario using the principles of Behavioural Economics and scientific experimentation. Simplified price presentation and framing will help NTPDL’s customers better understand the costs and values associated with TOU pricing. The new bill formats were expected to have a positive effect on shifting consumer electricity consumption to off-peak periods thereby lowering their costs and bill impacts.

The project ran to the end of July 2018 in Newmarket and Tay. One of the bill formats yielded a significant overall 0.8% decrease in On-Peak consumption relative to the control bill.

Customer oriented performance - Billing Accuracy

Annual RRR statistics are shown below:

	NTPDL	OEB guidelines
2015	99.96%	98%
2016	95.85%	98%
2017	99.92%	98%
2018	99.95%	98%
2019	79.61%	98%

Table 23 - Percentage of respondents indicating a billing problem in the last 12 months

Deviations from standard are discussed below.

In 2016, the former Midland PUC achieved a billing accuracy of 75.6% due to a very small error in the billing system. The error was immediately corrected once identified. Newmarket and Tay had a billing accuracy of 99.98% during this time. The impact of this error on the overall historical performance of the combined utility is noted in the table above.

In 2019, wholesale market rates were incorrect for 3 months and the over billing was approximately $70k. Over billing was corrected in 2019.

It is expected that going forward, NTPDL will meet or exceed the OEB targets for Billing Accuracy.

Cost Efficiency and Effectiveness – Project/program variance analysis

Key Historical 2015 – 2019 Budgeted Material projects and their spending variances is shown in the table below:

Category	Project Name	Budget $'000	Actual $'000	Variance %
System Access	Residential Additions	1,575	2,718	73%
	VIVA Yonge St. Relocation	2,560	2,347	-8%
	Miscellaneous Service Upgrades	248	126	-49%
	Pole Relocation - Park Ave	95	102	8%
	Srigley Street Rebuild	98	101	4%
	VIVA Davis Dr. Relocation	142	97	-32%
	Yonge St. – Davis to Green Lane	1,240	83	-93%
	Commercial/Industrial Additions	353	246	-30%
System Renewal	Planned Transformer Replacements	1,410	1,769	25%
	Planned Pole Replacements	362	767	112%
	Unplanned Pole Replacements	309	360	16%
	Walter and Sheldon Rebuild	150	150	0%
	Poleline Rebuild - Huron Heights	214	102	-52%
	Poleline Rebuild - Lindsay	146	80	-45%
System Service	New Substation Lands – Davis Dr.	1,668	1,675	0%
General Plant	New Vehicles and Fleet	770	1,126	46%
	Financial Management System upgrade	150	222	48%
	CIS upgrade	150	145	-4%
Total		11,640	12,216	5%

Table 24 – Key Historical Material project spending variances

A number projects planned for the 2015 – 2019 period were never started due to the need to reallocate resources for projects over which NTPDL has limited control (i.e. System Access projects). Specifically, scheduling changes in the Yonge St. widening projects and other projects had major impacts on resource scheduling and resulted in redistribution of funding to other projects/investments that could move forward in that period. A number of projects/expenditures (i.e. Metrolinx Rail Electrification works) were not planned for, but circumstances necessitated their execution and completion. For those that were both planned and executed, overall project variance averaged 5%.

Cost Efficiency and Effectiveness - DSP Spending Progress Report

The 2015 – 2019 DSP budget to actual spending is shown in the table below:

Category		2015	2016	2017	2018	2019
		$'000	$'000	$'000	$'000	$'000
System Access	Plan	$1,253	$2,290	$2,423	$3,162	$1,249
	Actual	$1,146	$2,782	$2,591	$554	$617
System Renewal	Plan	$1,716	$1,026	$1,798	$1,187	$2,010
	Actual	$1,682	$858	$1,249	$1,238	$1,617
System Service	Plan	$1,884	$52	$30	$197	$1,019
	Actual	$1,948	$103	$13	$134	$133
General Plant	Plan	$584	$795	$1,034	$166	$543
	Actual	$8,746	$532	$2,300	$927	$711
Total	Plan	$5,437	$4,163	$5,285	$4,712	$4,821
	Actual	$13,522	$4,275	$6,153	$2,853	$3,078
% Spending Variance		149%	3%	16%	-39%	-36%

Table 25 – DSP Spending Program Variances

The Budget to Actual numbers include budget/actual statistics from the former MPUC even though a DSP had not been completed for MPUC during the historical period.

Over the historical 2015-2019 DSP 5-year period, a total of $29.9M was spent or an average of $6M per year. Total overall actual spending over the 5-year period was 22% over the DSP amount, mainly due to the capital contribution that NTPDL had to pay to HONI as explained below.

Note that the 2015 General Plant Actual figures include an $8.1M capital contribution (true-up) to HONI for the construction and operation of Holland TS.

Asset/System Operations Performance – Safety

During the historical period, there were "0" public Serious Electricity Incidences per ESA records.

Asset/System Operations Performance – Reg. 22/04

NTPDL has achieved compliance in this portion of the audit each year since the regulation came into effect in 2004. Any audit findings that are noted as "Needs Improvement" or "Not in Compliance" are addressed to ensure that they are "In Compliance" for the following year audit. Annual audit findings over the historical period are shown in the table below:

Audit Year	Compliance Status
2015	Compliant
2016	Compliant
2017	Compliant
2018	Compliant
2019	Compliant

Table 26– 2015 – 2019 ESA Audit Results

Asset/System Operations Performance –Substation loading

The substation loading performance metrics indicate distinct differences in the Newmarket and Midland-Tay service areas electricity consumption patterns. The Newmarket and Midland-Tay service areas are summer peaking. All MS peaks shown in the chart below are non-coincident.

DS Name	Capacity (MVA)	2015 Peak Load (MVA)	2016 Peak Load (MVA)	2017 Peak Load (MVA)	2018 Peak Load (MVA)	2019 Peak Load (MVA)	Avg % Utilization
Newmarket Area							
Cook	10	7.7	8.3	8.1	8.4	8.1	81%
Gilbert	20	12.3	17.4	16.8	18.0	13.4	78%
Andrews	20	17.9	9.8	10.3	14.0	17.1	69%
Twinney	20	15.4	19.8	16.7	18.8	15.8	87%
Thompson	20	15.7	20.4	15.2	16.0	17.6	85%
Simmons	10	9.9	12.3	5.6	11.8	11.8	103%
Broughton	10	6.1	12.3	10.4	12.2	5.5	93%
Legge	10	11.8	9.6	11.8	11.1	11.5	112%
Leadbeater	10	4.2	5.4	6	9.0	6.0	61%
Total	130	101	115.3	100.9	119.3	106.8	84%
Midland Area							
Brandon	7.5	3.2	3.5	3	3.5	3.1	43%
Dorion	5	2.1	2.2	2.1	2.5	4.3	53%
Fourth	5	2.4	2.4	2.3	3.3	2.9	53%
Montreal	10	4.1	4.4	4.2	4.7	5	45%
Queen	10	4.3	4.5	4	5.4	4.2	45%
Scott	5	3	3	2.9	3.6	3.3	63%
Firth (HONI)	5	2.8	2.8	2.6	2.9	2.5	54%
Total	47.5	21.8	22.8	21.1	25.9	25.3	49%
Tay Area							
Victoria Harbour	5	4.1	4.4	4.7	5.1	4.6	92%
Port McNicoll	5	4	3.9	3.8	4.0	4.0	79%
Waubashene	3	1.9	1.4	1.4	1.6	1.8	54%
Total	13	10	9.7	9.9	10.7	10.4	78%

Table 27– NTPDL 2015 – 2019 Substation loading

The Newmarket service area loading demonstrates the extent to which MS interconnections are utilized to provide contingency (e.g. 2 MVA of load is always moved from Legge DS to Gilbert T2 DS in the summer) for short term operational purposes.

The Midland-Tay service area loading demonstrates the relatively stable nature of a low load growth area and that there is capacity available to accommodate additional load growth over the period of the DSP.

Asset/System Operations Performance – System Losses

NTPDL system losses over the historical period are shown below:

	2015	2016	2017	2018	2019
NTPDL	3.52%	4.32%	2.87%	3.9%	3.0%

Table 28 – NTPDL System Losses

Losses are trending in the 2.9 – 4.3% range over this historical period and within the OEB 5% threshold.

RRFE Performance Scorecard

For the 2018 reporting year, NTPDL filed its first set of RRR data as an amalgamated utility (acquired MPUC in 2017). The historical data for the years 2014 – 2017 inclusive is data for NTPDL without MPUC data. 2018 data is amalgamated data.

The RRFE performance scorecard metrics indicate that NTPDL is effective in achieving RRFE performance outcomes. Most measures show historical performance is within target values. The OEB has ranked all Ontario LDCs in one of five efficiency groups (1 – 5) with Group 1 being deemed the most efficient and Group 5 being deemed the least efficient. Based on the most recent PEG report, NTPDL is ranked in Group 3 with respect to Efficiency Assessment (stretch factor = 0.30%). Group 3 consists of utilities with actual costs that are within 10% (below) of predicted costs.

5.2.3d Effect of performance information on the plan

The results of the performance measures are a contributing factor in determining the direction and investment priorities of the DSP.

Customer Survey Results

NTPDL conducts customer satisfaction surveys on a regular basis. NTPDL reviews the survey results to determine if adjustments to corporate programs and strategies are warranted. Any significant change to program/strategies would affect the DSP.

The drop in Customer Care from an “A” rating (2015 Survey) to a “B+” rating (2017 Survey) reflected a pan-Ontario dissatisfaction with the price and value of electricity services. The Customer Care rating returned to “A” in the 2018 survey. The overall ratings demonstrate that NTPDL continues to maintain high levels of customer trust and meets their expectations for service delivery.

Existing DSP investment programs have been compiled and prioritized to maintain existing performance levels which are expected to achieve similar customer satisfaction results in future surveys.

Customer oriented performance - Service Reliability

The reliability indices (lagging indicator) demonstrate the significant impact of System Access work (primarily the Yonge St. VIVA bus project) on the number of outages experienced by customers as evident in the outage statistics. These are unavoidable outages required to perform mandatory plant relocation. Where possible, NTPDL attempted to mitigate the impact of these scheduled outages through the use of temporary generation to supply customer facilities. The high levels of foreign interference related outages (Code 9 - animal contact) is being addressed through the animal guard installation program and should decrease over the forecast period. The impacts of extreme weather (Code 6) will continue to be monitored over the forecast period to determine if the rate of change of outages is increasing or stabilizes. Increasing rate of change would necessitate investigating planning/design changes to mitigate this. Equipment Failure outages (Code 5) should remain relatively stable over the forecast period due to the ongoing cable and pole replacement programs. Overall indications are that reliability levels are being maintained now and into the forecast period.

Maintaining historical reliability performance has been factored into the development of the DSP. The asset management and capital expenditure process recognize that for current reliability levels to be maintained, system renewal needs, specifically focusing on primary underground cable replacement and pole line reconstruction, need to be addressed in the forecast period.

Customer oriented performance - Bill impacts

Bill impact considerations are a key driver of NTPDL's DSP development. The investment plan reflected in the DSP contributes to smoothing customer bill impacts over the period of the plan and is reasonable (within OEB mitigation guidelines). Rate mitigation has been taken into consideration in the development of the DSP and NTPDL's asset management and capital expenditure planning process. Forecast investments are expected to result in rate increases for residential and general service classes within OEB rate mitigation guidelines.

Customer oriented performance - Billing Accuracy

The one-time 2016 billing error affecting Midland customers was resolved. Relatively high performance by NTPDL staff and systems in billing accuracy for the remainder of the historical period precludes the need for specific investment needs in the DSP.

Cost Efficiency and Effectiveness – Project/program variance analysis

As part of the asset management and capital investment planning process, projects and programs have been prepared in consideration that spending must be achievable with the resources that are available (i.e. suppliers (material), design services, municipal approvals, contract labour, vehicles, etc.) in a timely manner. DSP investment planning has been set up to design, issue and construct works that can be achieved within the forecast period.

Cost Efficiency and Effectiveness - DSP Spending Progress Report

As part of the asset management and capital investment planning process, the overall DSP program spending has been prepared in consideration that the programs must be achievable with the resources that are available (i.e. suppliers (material), design services, municipal approvals, contract labour, vehicles, etc.) in a timely manner. DSP investment planning has been set up to design, issue and construct works that can be achieved within the forecast period.

Asset/System Operations Performance – Safety

NTPDL continues to promote continued education, awareness and application of safe work practices and as such safety continues to play a key role in project prioritization. Safety is a key factor in prioritizing non-mandatory investments. It is embedded in project value and risk assessment. NTPDL's safety performance is high and no specific project was identified that needed to be factored into the DSP. In general, ensuring a safe environment for workers and the public has been taken into consideration in the development of the DSP and NTPDL's asset management and capital expenditure planning process.

Asset/System Operations Performance – Reg. 22/04

NTPDL continues to demonstrate prudent compliance with O. Reg. 22/04 and as such ESA compliance continues to play a key role in project prioritization. NTPDL historical performance is in compliance with

O. Reg. 22/04 and no specific project have been identified that need to be factored into the DSP. In general, ensuring Reg. 22/04 compliance is maintained has been taken into consideration in the development of the DSP and NTPDL's asset management and capital expenditure planning process.

Asset/System Operations Performance – Substation loading

Acceptable levels of substation loading are determined through NTPDL's asset management process which in turn would identify a need to be addressed through the capital expenditure planning process.

The previous DSP indicated that a new DS would be required in the NTPDL service area in the 2015 – 2019 plan period in order to maintain reliable levels of service. Current loading levels indicate that a new station will not be required until after 2024.

Low growth and available capacity at existing DS facilities preclude the need for new station facilities in the Midland-Tay area over the 2020 – 2024 forecast period.

Asset/System Operations Performance – System Losses

Existing performance is within OEB performance targets and as such there is no specific impact on the DSP. Performance outside OEB targets would trigger a review of asset management practices and capital investment needs to bring system performance back within loss standards.

RRFE Performance Scorecard

The RRFE Performance Scorecard supports the key plan objectives of maintaining current reliability levels and low overall cost to the customer during the forecast period.

Scorecard - Newmarket-Tay Power Distribution Ltd. 10/21/2020

Performance Outcomes	Performance Categories	Measures		2015	2016	2017	2018	2019	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	99.77%	100.00%	100.00%		90.00%	
		Scheduled Appointments Met On Time		98.00%	99.80%	99.91%	99.99%	99.90%		90.00%	
		Telephone Calls Answered On Time		84.00%	81.80%	76.64%	70.86%	68.58%		65.00%	
	Customer Satisfaction	First Contact Resolution		92%	90%	90%	93.7%	97.7%			
		Billing Accuracy		99.98%	99.99%	99.95%	99.95%	79.61%		98.00%	
		Customer Satisfaction Survey Results		94%	91%	91	A	96			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		82.00%	82.00%	81.00%	82.00%	83.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0			0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000			0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		0.58	0.42	0.42	0.66	0.78			0.83
		Average Number of Times that Power to a Customer is Interrupted [2]		0.67	0.57	0.54	0.78	0.70			0.55
	Asset Management	Distribution System Plan Implementation Progress		99%	100%	120	103	64			
	Cost Control	Efficiency Assessment		2	2	2	2	3			
		Total Cost per Customer [3]		$596	$613	$630	$657	$678			
		Total Cost per Km of Line [3]		$25,590	$26,481	$27,509	$28,067	$28,984			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]		22.68%	38.69%	64.35%	87.00%	88.00%			36.24 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	100.00%	100.00%					
		New Micro-embedded Generation Facilities Connected On Time		100.00%	100.00%	100.00%	100.00%			90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		2.70	2.74	2.35	1.41	1.37			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		0.74	0.67	0.66	1.23	1.19			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.66%	9.66%	9.66%	9.66%	9.66%			
			Achieved	8.51%	8.01%	2.41%	11.19%	6.94%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the now discontinued 2015-2020 Conservation First Framework. 2019 results include savings reported to the IESO up until the end of February 2020.

Legend: 5-year trend: up, down, flat. Current year: target met, target not met.

Table 29 – NTPDL 2019 RRFE Performance Scorecard

5.2.4 Realized efficiencies due to smart meters

NTPDL has deployed smart meters to all its residential customers. NTPDL is in the process of deploying MIST meters to all its GS>50kW. Approximately 300 MIST meters are expected to be deployed. MIST meter deployment is expected to be complete by the end of March 2021.

Smart meters communicate back to NTPDL through Advanced Metering Infrastructure (AMI) provided by Sensus. This has eliminated the need to read meters manually. All residential smart meters have "last gasp" technology ("last gasp" technology allows the meter to communicate to utility operations when power has been lost) incorporated into them.

Smart meter consumption data can be aggregated to assist in localized asset utilization studies. This will be especially useful with the continuing deployment of electric vehicles and associated home charging stations. The impact of these systems on the local distribution transformer can be determined and facilitate any decisions as to the necessity of upgrading the transformer to a higher capacity unit.

Load profile data allows NTPDL to bill TOU, allowing customers to take advantage of off-peak rates. Reduced on-peak consumption assists in deferring capacity expansion needs.

Smart meter load profile data has proven to be beneficial in resolving a number of customer issues including high bill complaints, flickering lights and low/high voltage complaints. NTPDL Customer Service representatives can review consumption history in detail with the customer and this has led to successful resolution of most billing inquiries. Consumption reviews with the customer also educates them with respect to the benefits of energy conservation.

5.3 Asset Management Process

This section of the DSP provides a high-level overview of NTPDL's asset management process.

NTPDL's asset management process is a systematic approach used to plan and optimize ongoing capital and operating and maintenance expenditures on the distribution system and general plant. Electricity distributors are capital intensive in nature and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network.

5.3.1 Asset Management Process overview

5.3.1a Asset Management objectives and relationship to corporate goals

NTPDL's asset management objectives align with NTPDL's Core Values and are implicitly summarized in NTPDL's Corporate Vision and Mission statements:

Vision

> "An independent, industry-leading LDC committed to our customer's changing needs".

Mission

> "Earning the trust of our customers by safely and reliably meeting their electricity needs."

NTPDL's key Vision and Mission outcome is maintaining a desired level of customer service at the best appropriate cost.

NTPDL's Core Values are:

- Safety first – our top priority on the job and in the communities we serve
- Respect – is how we treat each other and our customers
- Reliable – our customers depend on us to provide electricity and the services they need
- Customer Focus – serving our customers is why we exist

To deliver on the Vision, Mission and Core Values, NTPDL has identified seven Key Objectives to be achieved going forward:

- Ensure Leadership Alignment
- Empower Employees
- Deliver on Customer Needs
- Continuously Improve Operations
- Achieve Smart Control Across the Distribution System
- Run an Effective, Efficient and Financially Sustainable LDC
- Assess Emerging Needs in Context

NTPDL's Core Values and Key Objectives form the foundation for NTPDL's Asset Management Objectives which are:

- Safety - Construct, maintain and operate all assets in a safe manner;
- Reliability - Monitor and address asset condition issues in a timely manner to ensure the continued reliable supply of electricity delivery; ensure alignment with regional planning objectives

- Customer Focus - Ensure that decisions on capital investments and maintenance plans support NTPDL's desired outcomes in a cost-effective manner and provides value to the customer
- Financial Integrity - Manage investment planning to mitigate rate impacts while maintaining corporate financial stability and long-term sustainable performance.
- Regulatory Compliance - Ensure responsiveness to public policy requirements and objectives; facilitation of new renewable generation; facilitation of the smart grid

The Corporate and Asset Management objectives form the high-level philosophy framework for NTPDL's investment program and are implicitly embedded in NTPDL's capital investment planning process and maintenance program. NTPDL has identified five asset management objectives that align with the corporate objectives.

The table below shows the linkages between RRFE Outcomes, Core Values, Key Objectives and Asset Management Objectives.

RRFE Outcomes	Core Value(s)	Key Objective(s)	Asset Management Objectives	AM Objective Measure	AM Objective Target
Operational Effectiveness	Safety first; Respect	Ensure Leadership alignment; Empower Employees, Continuously Improve Operations	**Safety -** Construct, maintain and operate all assets in a safe manner;	1. ESA Non-Compliance 2. ESA SEII	1. NC = 0 2. SEII = 0
Operational Effectiveness	Reliable; Customer Focus	Deliver on Customer Needs; Achieve Smart Control; Continuously Improve Operations	**Reliability -** Monitor and address asset condition issues in a timely manner to ensure the continued reliable supply of electricity delivery; ensure alignment with regional planning objectives	1.SAIDI 2.SAIFI	1.SAIDI within range of past 5-year performance 2.SAIFI within range of past 5-year performance
Customer Focus	Respect; Customer Focus	Continuously Improve Operations; Deliver on Customer Needs;	**Customer Focus -** ensure that decisions on capital investments and maintenance plans support NTPDL's desired outcomes in a cost-effective manner and provides value to the customer	1.Customer Survey 2. DSP feedback	1. Customer survey results (+/-) or 5% than previous survey metrics scores 2. Feedback from web posting and PICs => 70% agreement with plan
Financial Performance	Respect; Customer Focus	Run an Effective, Efficient and Financially Sustainable LDC	**Financial Integrity -** Manage investment planning to mitigate rate impacts while maintaining corporate financial stability and long-term sustainable performance	1.Investment spending 2. DSP implementation	1. Material Capital expenditure +/- 20% to estimate 2. DSP annual investment category spending +/- 10% of plan
Public Policy Responsiveness	Safety; Respect;	Ensure Leadership Alignment; Empower Employees; Assess Emerging Needs in Context; Achieve Smart Control	**Regulatory Compliance -** Ensure responsiveness to public policy requirements and objectives; facilitation of new renewable generation; facilitation of the smart grid	1. New REG connected on time 2. Broadband for control and telemetry purposes	1. 90%+ 2. Upgraded digital relays and future broadband for four stations by 2024; Three distribution switches automated by 2024

Table 30 – RRFE Outcomes – Core Values and Key Objectives - Asset Management linkage

For investment review, it is necessary to identify the relative priority of each asset management objective with respect to each other. Different investments will have different alignments with respect to the asset management objectives and weighting the asset management objectives will aid in identifying those investments that best align with them. The five objectives are each assigned a relative weight of 0 - 1.0 with the total sum of the objectives equalling 1.0.

Safety – This objective has been given the highest priority by NTPDL. “Safety first” comprises organizational efforts to ensure that worker and public safety is paramount in day to day activities and is explicitly ranked this way in the corporate strategy. It is recognized that some safety issues (i.e. live conductor on ground) require emergency remedial action (mandatory) and are not “planned investment” considerations. They are acted upon immediately and level of effort may impact other non-mandatory investments that would otherwise have had the resources (labour, funds) allocated to them. Other planned investments may impact long term safety and can be paced and prioritized where safety is just one of the Asset Management Objectives that is addressed by the investment. The Safety objective is assigned a weight of 0.25

Reliability – This objective is ranked similar to safety in priority. Together with safety it is one of the two goals explicitly cited in NTPDL’s Mission Statement. In customer surveys, it has ranked high in importance of customer needs. The Reliability objective is assigned a weight of 0.25

Customer Focus – This objective is ranked high in ensuring that business outcomes meet the value needs of the customer. The Customer objective is assigned a weight of 0.2

Financial Integrity - This objective is ranked equally with the previous objective. A stable rate of return, low electricity rates and ability to sustainably invest in distribution system access, service, renewal and general plant are key to the long-term success of this objective. Balancing of stakeholder interests in this area is an ongoing exercise. In customer surveys, low electricity rates ranked first in importance of customer needs. In consideration that NTPDL’s controllable portion of the customer bill is less than 25%, the Financial Integrity objective is assigned a weight of 0.20.

Regulatory Compliance – NTPDL is required to deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Ontario Energy Board). While obligations are mandated, the LDC does exercise some control over pace and level of annual effort depending (i.e. CDM obligations) on the issues at hand that can affect investment timing. The Regulatory Compliance objective is assigned a weight of 0.1.

Objective	Weight
Safety	0.25
Reliability	0.25
Customer Focus	0.20
Financial Integrity	0.20
Regulatory Compliance	0.10
Total	**1.00**

Table 31 – Objective Weighting Summary

An integral part of achieving the asset management objectives is a maintenance program to ensure system performance is sustained during the entire asset service life. NTPDL has in place inspection and routine maintenance programs to achieve this.

NTPDL has adopted an Asset Management policy to ensure a continual and consistent focus on delivering services in a way that balances risk and long-term costs (Appendix C). The policy establishes the core asset management principles that drive NTPDL's planning framework.

5.3.1b Asset Management process components

NTPDL's Asset Management process begins with a description of how the responsibilities of Asset Management are addressed at NTPDL. NTPDL has a generic asset management model that consists of an Asset Owner, Asset Managers and Service Providers.

Asset Owner

The Asset Owner can be considered the NTPDL Board and the President. The overall responsibility for NTPDL's Asset Management System rests with the President as delegated by NTPDL's Board of Directors. NTPDL's Board of Directors is responsible for ensuring high levels of corporate performance through effective management monitoring and strategic guidance. This ensures the Asset Management System is managed effectively.

Asset Managers

The Asset Manager role encompasses responsibility for distribution plant and general plant. NTPDL is structured so that its business units (Engineering/Operations, Finance and Information Technology) provide the key support for the Asset Management System in these areas.

Heads of the business units are responsible for overseeing and ensuring that business unit assets are planned for, specified, procured, installed, operated, maintained, refurbished, renewed and disposed of as appropriate for long term sustainability.

Service Providers

The Service Providers are responsible for delivering asset investment programs, to maintain and operate the assets based on the guidelines set by the Asset Managers. Service Providers (i.e. Lines section, etc.) are groups under control of the Business Unit Asset Manager to which they report to. The Service Provider groups can include external contractors and consultants that support them as required.

NTPDL's Asset Management support structure is shown below:

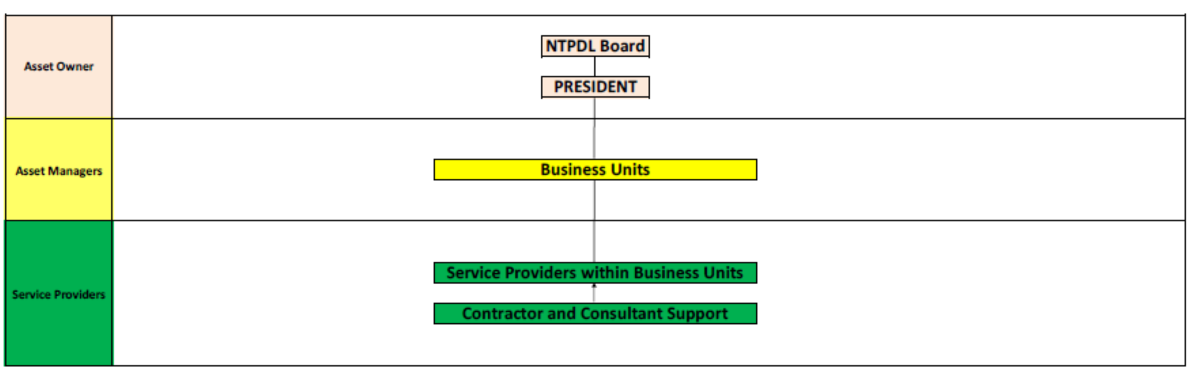


Figure 8 – NTPDL Asset Management support structure

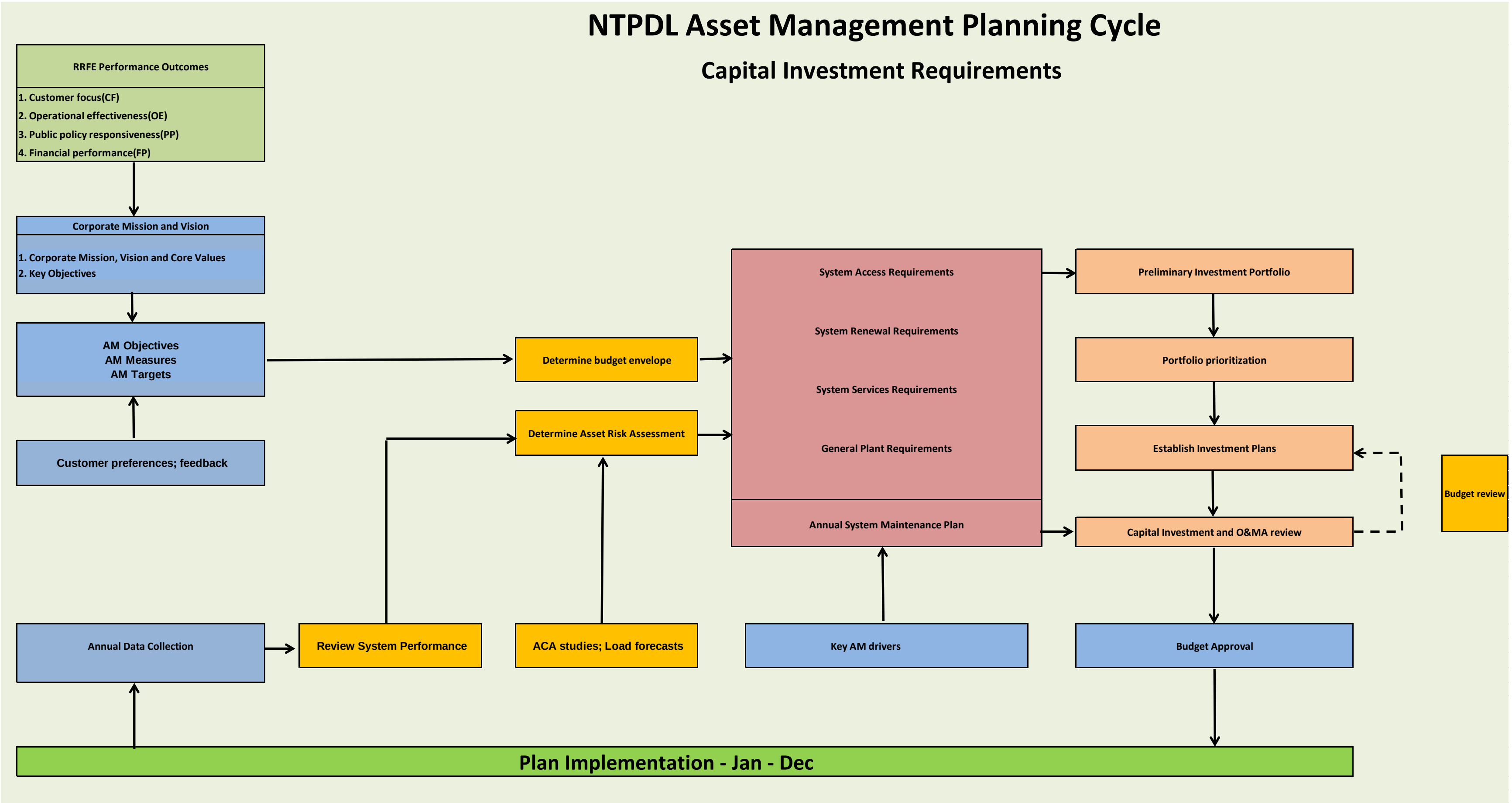


Figure 9 - NTPDL Asset Management Planning Cycle

NTPDL's Asset Management planning cycle is shown in Fig. 9 above.

The Asset Management planning cycle is a process designed to achieve NTPDL's Asset Management Objectives. The process is a cyclical one.

Asset performance information and annual asset data collection is used to update NTPDL's asset register for the investment planning part of the cycle. Performance data normally reflects the previous year's data. Data collection is ongoing as new/replaced assets are added to the system. Asset performance information collected is used to calculate annual OEB SQI and Scorecard performance metrics which tie back to RRFE outcomes. Performance information is also used to determine how well NTPDL's Asset Management objectives have been achieved in the past investment period.

One of the first steps in the planning cycle is to determine budget levels of spending. Levels will likely fluctuate over the DSP investment period around an annual average target spend. The proposed budget target consists of capital and operating investments/funds determined with due consideration to financial/capability considerations, corporate objectives, asset management objectives, customer preferences and other stakeholder interests (i.e. regulatory/government directives/policy). Budget target determination is not a simplistic formulaic approach but one that considers multiple factors and trade-offs, often competing ones. After reviewing the above considerations, a budget target is developed by NTPDL Executive Management.

For the 2020 – 2024 period of the DSP the budget target is to achieve an average annual capital spend of approximately $7.3M.

The budget target provides the required information on organizational financial capability for ranking, prioritizing and pacing of investment projects that result in the achievement of the four RRFE performance outcomes.

In parallel with budget target determination, a review of system performance is undertaken to determine whether current performance meets NTPDL's asset management objectives. Asset performance information and annual asset data collection is used to update NTPDL's asset register. The asset register is where asset information is held. Performance data normally reflects the previous year's data. Data collection is ongoing as new/replaced assets are added to the system. Load forecasts provide growth related data to determine assets at risk, constraining the ability of the system to deliver on System Access and System Service performance expectations. Inspection, maintenance feedback and periodic Asset Condition Assessment studies provide up to date information on asset condition and remaining life for System Renewal and General Plant investment determination.

Information held in the Asset Register is generally accessed at the beginning of the investment planning process to support rationale for specific project plans. Facilitated by IT investments in financial systems, NTPDL was able to merge the Midland Asset Register with its own in 2020.

There are four key components that comprise the Asset Register. They are the ESRI Geographical Information System (GIS), the Microsoft Dynamics GP ERP system, the Harris Customer Information System (CIS) and Operations Records databases/files.

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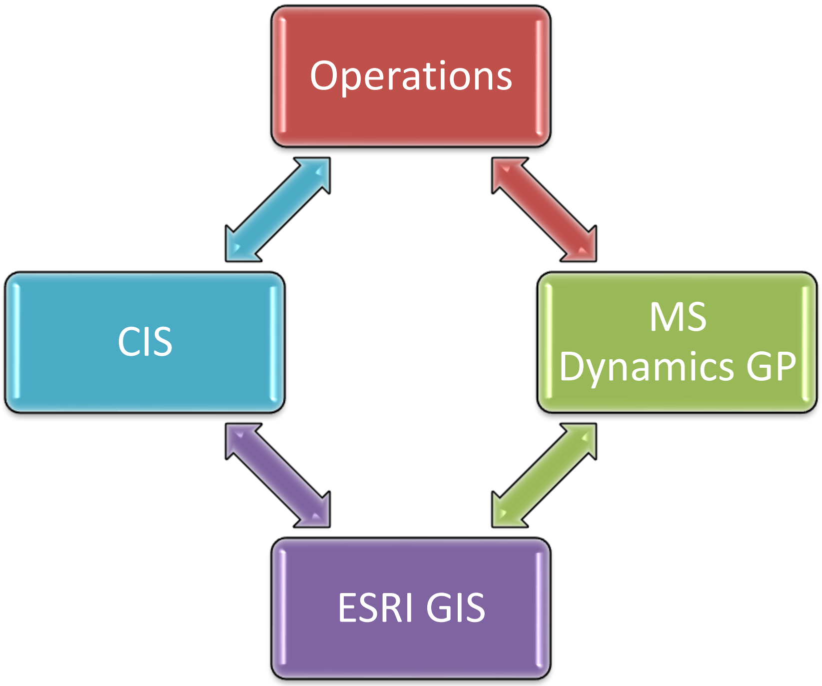

Figure 10 – NTPDL Asset Register structure

In 2017 NTPDL adopted the Microsoft Dynamics GP ERP system. It is a single integrated software environment to help automate business processes, enhance collaboration, improve efficiency, and enable better business decision making.

It facilitated the migration of the former MPUC asset databases over to the Newmarket Asset Register.

Where possible, rather than re-create existing databases, linkages between systems have been provided to allow for seamless access through existing software systems.

Asset Register			
Asset register component	**Owner/Location**	**Asset information**	**Information media**
ESRI GIS	- Operations	- Asset location (pole GPS coordinates) - Basic attributes (voltage, size, conductor length) - installation history(pole)	- electronic database composed of multiple map layers of assets
Microsoft Dynamics GP ERP system system	- Accounting	- IFRS financial asset value - asset useful life studies - contributed capital	-electronic database
	- Accounting	Distribution Plant (bulk GL) - purchase history - depreciation amounts General Plant - purchase history - depreciation amounts (land, buildings, hardware, software, fleet)	-electronic database
Harris CIS	- Customer Service	- meter information (physical attributes, consumption, etc.)	electronic database; Savage database
Operations records	- Operations	ACA reports	electronic and paper files
	- Operations	Outage history -SAIFI, SAIDI stats database, trouble reports	electronic and paper files
	-Operations	Maintenance Records -transformers, switchgear, poles, stations, meters	electronic files
	-Operations	Inspection Records - transformers, switchgear, poles, stations, circuit breakers	electronic and paper files
	-Operations	Asset utilization records -station, feeder loading	SCADA database and electronic files; Savage database(44kV)
	-Operations	Fleet history Tool, test equipment history	electronic and paper files

Table 32 – NTPDL Asset Register

With the proposed budget target as a guide and information from the Asset Register, investment planning then proceeds. A preliminary portfolio of capital investments is produced. Investment justification is compiled for projects in the portfolio along with more detailed business cases for the larger material project proposals. Capital Investments are placed in one of the four investment categories based on the “trigger” driver of the expenditure:

1. System Access
2. System Renewal
3. System Service
4. General Plant

Mandatory capital projects are automatically included as per scheduled need. In general, mandatory projects are defined as:

• New/modified customer service connections (System Access)
• Road authority required plant relocation projects (System Access)
• Mandated service obligations (System Access)
• Renewable energy projects (System Access)
• Emergency plant replacement (System Renewal - reactive)
• Safety related projects (System Service)

Mandatory investments are allocated budget funds first. Remaining budget funds are allocated to non-mandatory investments in the System Renewal, System Service and General Plant categories.

The annual asset maintenance plan (operating) is prepared. The asset maintenance plan reduces unplanned and emergency repairs as it emphasizes preventative and predictive maintenance. It determines which assets are maintained to maximize asset life-cycle benefit and which assets are simply run to failure.

Investment needs are determined by the key drivers of asset investment that lead to the achievement of the asset management objectives. NTPDL's asset management process identifies five key drivers of asset investment:

1. The current state of the assets
2. Assets critical to performance
3. NTPDL's desired level of service and mandated deliverables
4. NTPDL's asset life-cycle cost considerations
5. NTPDL's design and operating philosophies, and maintenance strategies

At this stage of the process, non-mandatory capital investment proposals are reviewed by NTPDL staff for consideration of inclusion into the budget plan. Projects that optimize system performance, costs and risks relevant to service delivery and can have sufficient resources allocated to them, are then considered for inclusion in the budget plan.

This review provides an initial triage to determine projects that can wait (be deferred to future budget periods) and those that need closer review for potential inclusion in the immediate planning period. Assessments may also indicate that to optimize system performance the capital budget may require funding adjustment. Reasons for adjustment consider factors such as:

- Project interdependencies
- Resource (labour, material, etc.) availability
- Cost and benefit uncertainties/risks
- Capital availability
- Rate impact
- Portfolio effectiveness (corporate goals)
- Portfolio effectiveness (customer value)

In this case a revised capital budget may be considered, and the capital investment portfolio would be re-evaluated to optimize system performance.

Final budget and project selection determined through NTPDL senior management discussion and review. Once this has been done, the completed budget is presented to the NTPDL Board of Directors for approval.

Following final investment plan approval, the asset management process would then proceed to the plan implementation stage. Investment plans would be executed and resulting system performance outcomes would be collected and reviewed starting the asset management planning cycle over again.

5.3.2 Overview of Assets Managed

5.3.2a. Description of the distribution service area

General

As of December 31, 2019, NTPDL served approximately 39,481 residential customers, 3,986 GS<50 customers and 479 GS>50 customers as well as several unmetered loads in three communities with a combined service area of 94 square kilometers.

Locations

The two communities NTPDL serves have distinct characteristics. Newmarket is located in the Northern Part of York Region, while Midland-Tay is located on the shores of Georgian Bay in North Simcoe County. The two service areas are not contiguous. The service areas of NTPDL are about an hour's drive from each other.

Temperature and Weather

The Newmarket service area has a humid continental climate (Köppen climate classification Dfa) with four distinct seasons featuring cold, somewhat snowy winters and hot, often humid summers. Precipitation is moderate and consistent in all seasons, although summers are a bit wetter than winter due to the moisture from the Gulf of Mexico and the Great Lakes.

The Midland-Tay service area has warm and sometimes hot summers with cold, longer winters (Köppen climate classification Dfb) with roughly equal annual precipitation as the Newmarket service area. Along the eastern shores of Georgian Bay, frequent heavy lake-effect snow squalls increase seasonal snowfall totals upwards of 3 m (120 in).

Severe weather in the summer manifests itself mostly in the form of thunderstorms that can damage overhead distribution plant. In the winter, severe weather may consist of snow squalls, high winds and the occasional episode of freezing rain.

Service Area Density

Newmarket is a dense urban town with over 90,000 residents. Employment is spread out amongst 4 business sectors: Business Services, Institutional, MWCT and Retail/Public Services. Recent business growth has been in the Health Care and Retail trade sectors. There has been a corresponding business decline in the manufacturing sector.

The Midland-Tay service area comprises the communities of the Town of Midland, Waubaushene, Port McNicoll and Victoria Harbour. The Midland-Tay service area contains mostly residential customers located in a mix of light urban, seasonal, and rural areas, with little or no population growth. Tourism is a key industry in Midland-Tay that offers four-season recreation and leisure pursuits for both residents and visitors alike. The Midland-Tay service area has approximately 1/3 of the Newmarket service area population.

The combined NTPDL urban service area comprises approximately 97% of the total NTPDL service area.

Underground and Overhead Assets

NTPDL is responsible for maintaining distribution and infrastructure assets deployed, including 469 circuit kilometers of overhead lines and 559 circuit kilometers of underground lines, within the Newmarket and Midland-Tay service areas.

Customer and Economic Growth

Newmarket's customer growth from 2015 to 2019 has increased by 3.9 %. Average annual growth over the historical period for the entire NTPDL service territory has been 1.0%.

The economic development strategy in the Town of Newmarket focuses on Innovation, Collaboration and Urbanization. Key growth enablers include the development of an ultra-high-speed broadband system, corridor intensification and stakeholder consultation. In June 2018, the Town of Newmarket launched Envi Network, a municipally-owned Internet service provider through Newmarket Hydro Holding, with a mission to build a local fibre-optic broadband network to service businesses and, eventually, residential customers.

The economic development strategy in the Midland-Tay area focuses on knowledge related business and businesses, four season tourism, geriatric healthcare services, workforce development and attraction of new agricultural based businesses.

HONI Relationship and Neighbouring Utilities

Newmarket is not embedded while Midland-Tay is embedded off HONI's Waubaushene TS.

NTPDL's Newmarket service area is bordered by the following utilities:

- HONI
- Alectra Utilities

HONI transmission assets traverse Newmarket's service area.

NTPDL's Midland-Tay service area is bordered by the following utilities:

- HONI

Maps of the Newmarket-Midland-Tay service areas are shown below.

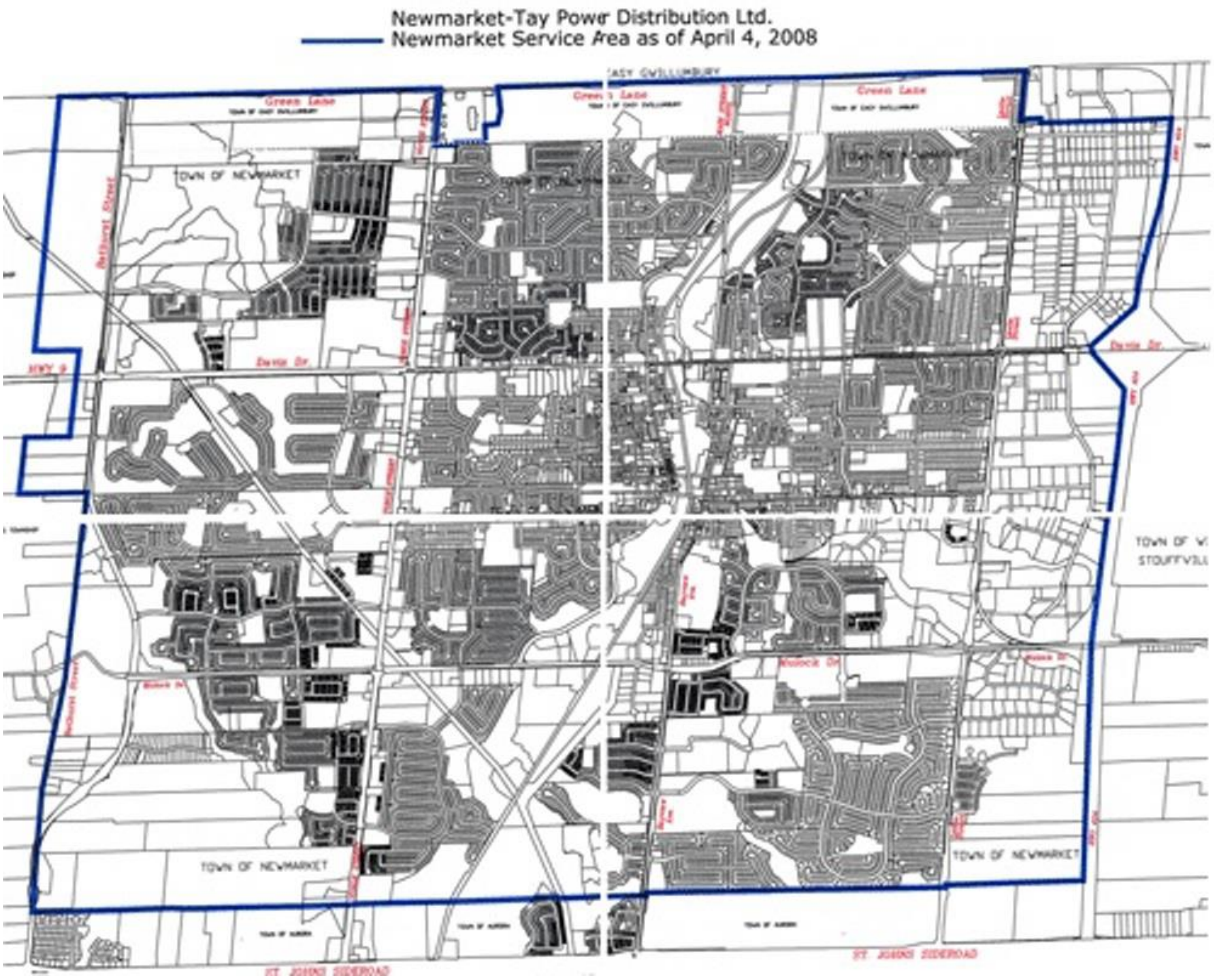

Figure 11 –Newmarket Service Territory

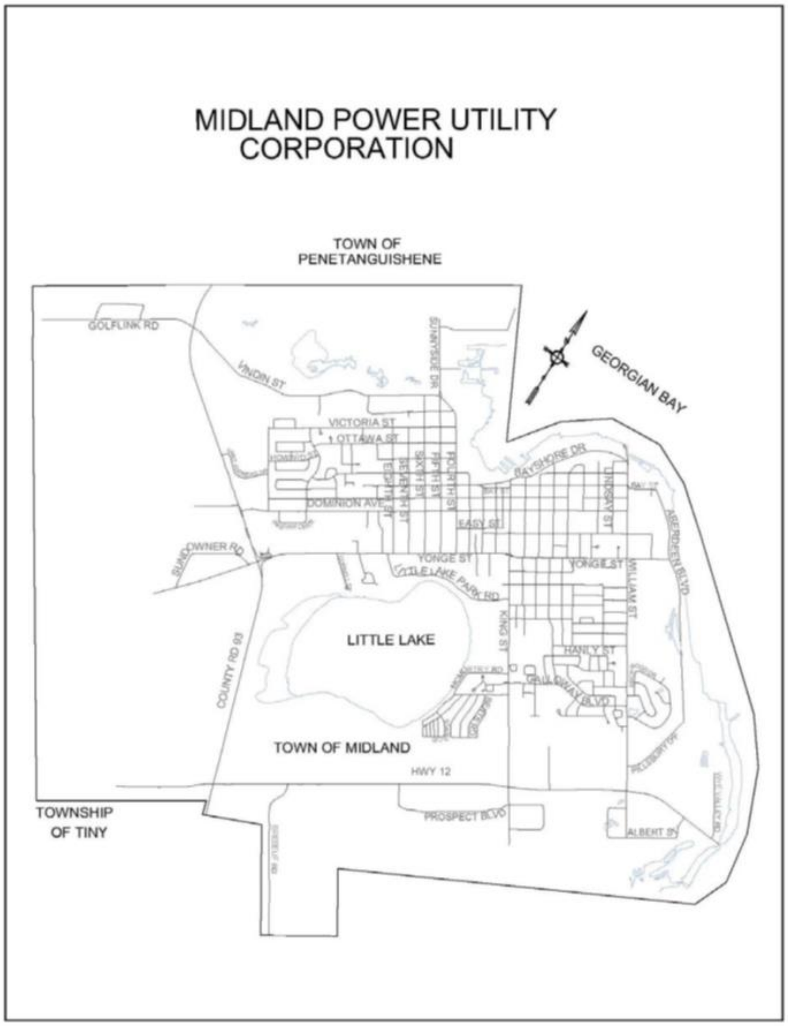

Figure 12 – Midland Service Territory

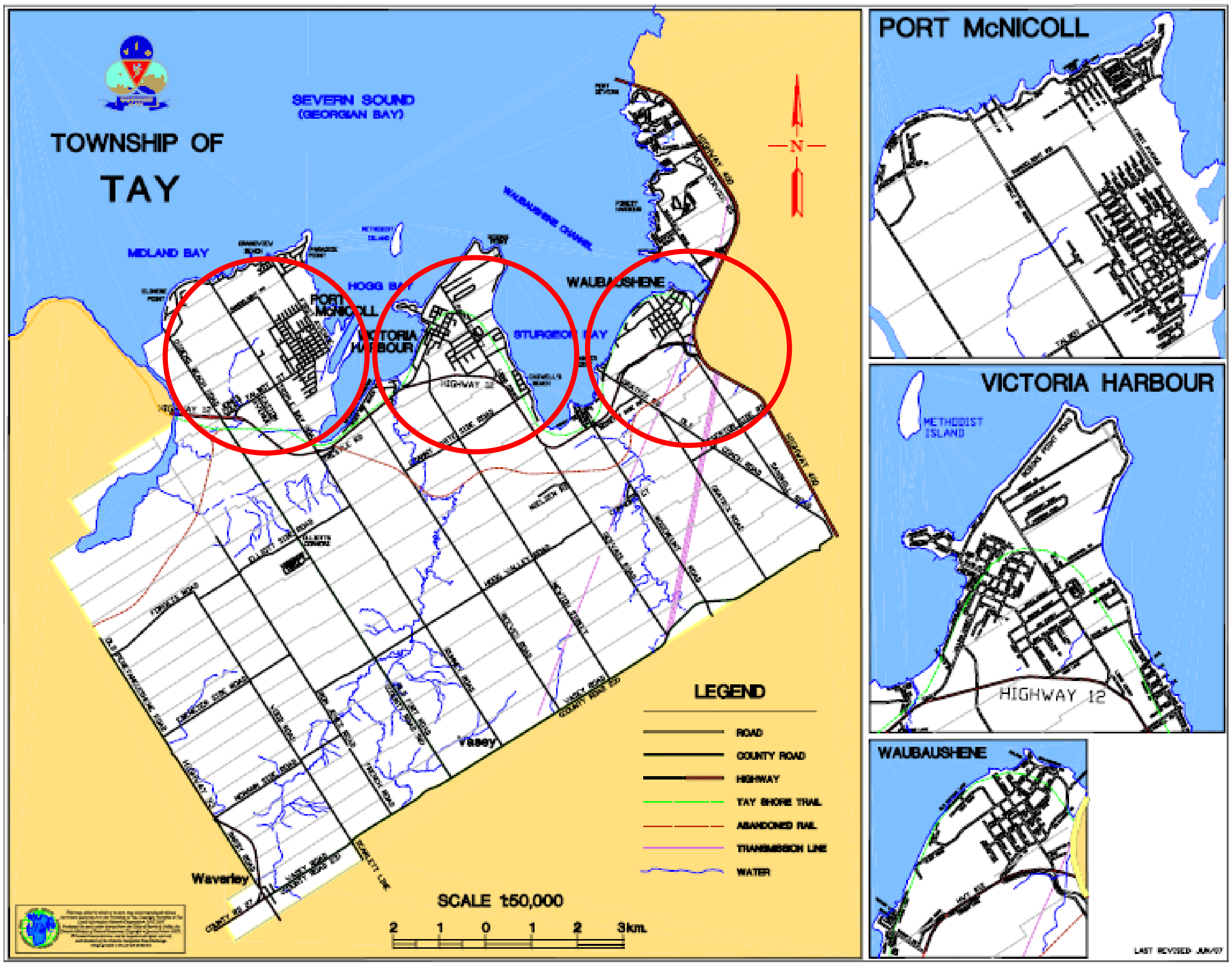

Figure 13 - Tay Service Territory

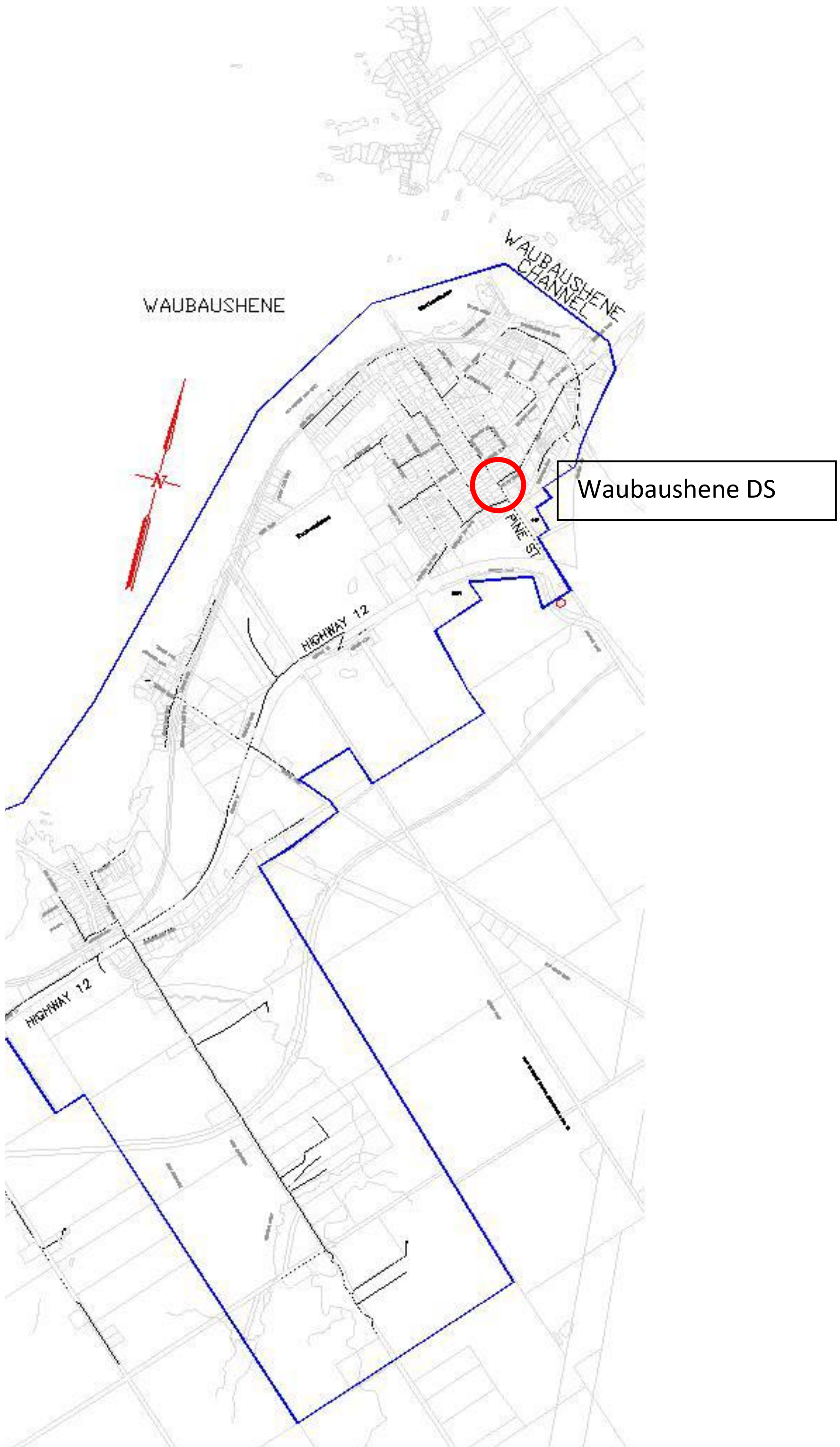

Figure 14 – Midland-Tay Service Territory – Waubaushene DS

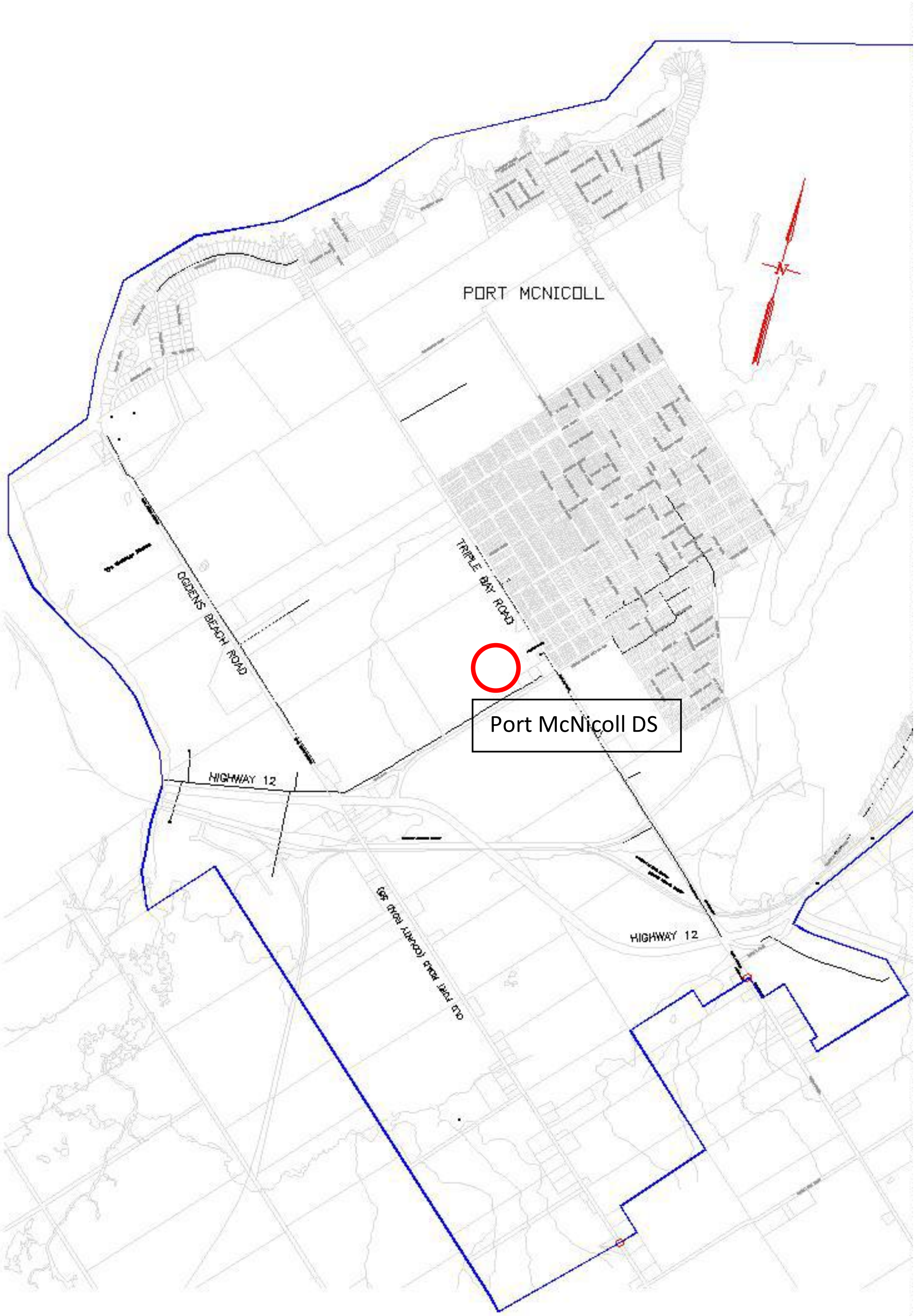

Figure 15 – Midland-Tay Service Territory - Port McNicoll DS

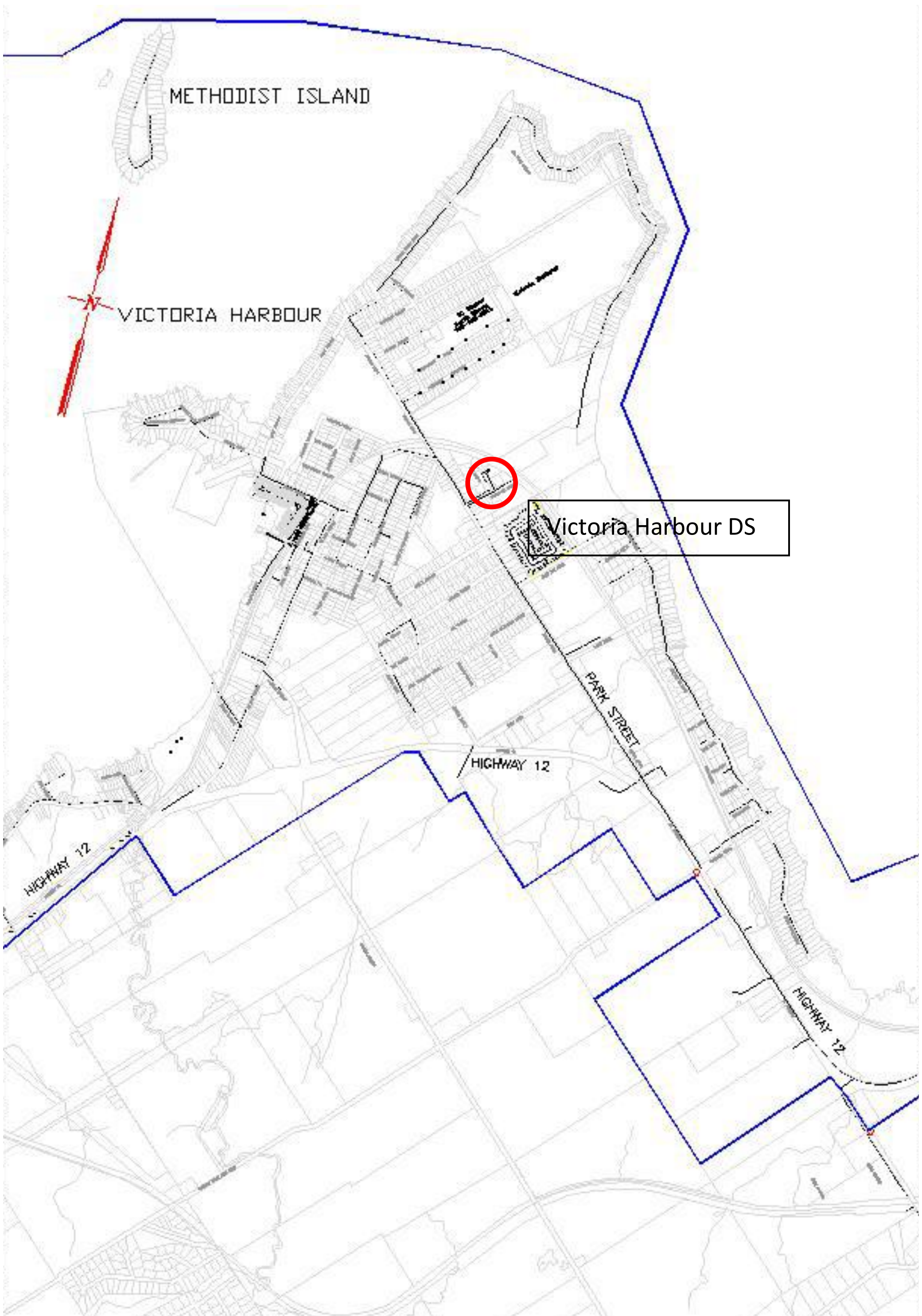

Figure 16 – Midland-Tay Service Territory - Victoria Harbour DS

5.3.2b System configuration

The Newmarket service area receives deliveries of bulk power through 4 x 44kV feeders emanating from the Holland Junction TS and 5 x 44kV feeders emanating from the Armitage TS.

The Midland-Tay service area receives deliveries of bulk power through 6 x 44kV feeders emanating from the Waubaushene TS.

While there are several large users (>500kVA service capacity) that take power directly from the 44kV feeders through customer owned substations, most customers are served from NTPDL's distribution substations. There are 9 distribution substations in Newmarket, 6 distribution substations in Midland and 3 distribution substations in Tay. A small portion of the Midland supply is provided by Hydro One through the HONI owned Firth's Corners DS.

DS Name	Details	Transformer Sizes	DS Capacity
Newmarket			
Cook	Primary 44kV; Secondary 13.8kV	T1 10/13.3/16 MVA	10MVA
Gilbert	Primary 44kV; Secondary 13.8kV	T1 10MVA T2 10/13.3/16 MVA	20 MVA
Andrews	Primary 44kV; Secondary 13.8kV	T1 10/13.3/16 MVA T2 10/13.3/16 MVA	20 MVA
Twinney	Primary 44kV; Secondary 13.8kV	T1 10/13.3/16 MVA T2 10/13.3/16 MVA	20 MVA
Thompson	Primary 44kV; Secondary 13.8kV	T1 10/13.3/16 MVA T2 10/13.3/16 MVA	20 MVA
Simmons	Primary 44kV; Secondary 13.8kV	T1 10/13.3/16 MVA	10MVA
Broughton	Primary 44kV; Secondary 13.8kV	T1 10/13.3/16 MVA	10MVA
Legge	Primary 44kV; Secondary 13.8kV	T1 10/13.3/16 MVA	10MVA
Leadbeater	Primary 44kV; Secondary 13.8kV	T1 10/13.3/16 MVA	10MVA
Midland			
Brandon	Primary 44kV; Secondary 4kV	T1 7.5 MVA	7.5 MVA
Dorion	Primary 44kV; Secondary 4kV	T1 5 MVA	5 MVA
Fourth	Primary 44kV; Secondary 4kV	T1 5 MVA	5 MVA
Montreal	Primary 44kV; Secondary 4kV	T1 10 MVA	10 MVA
Queen	Primary 44kV; Secondary 4kV	T1 5 MVA	5 MVA
Scott	Primary 44kV; Secondary 4kV	T1 5 MVA	5 MVA
Firth DS(HONI)	Primary 44kV; Secondary 8.32kV	T1 5 MVA	5 MVA
Tay			
Victoria Harbour (Tay)	Primary 44kV; Secondary 8.32kV	T1 5 MVA	5 MVA
Port McNicoll (Tay)	Primary 44kV; Secondary 8.32kV	T1 5 MVA	5 MVA
Waubaushene (Tay)	Primary 44kV; Secondary 8.32kV	T1 3 MVA	3 MVA

Table 33 – NTPDL DS summary

In the Newmarket service area, distribution stations take power at 44kV and transform it down to 13.8kV. Distribution station locations are shown in Figure 17 below:

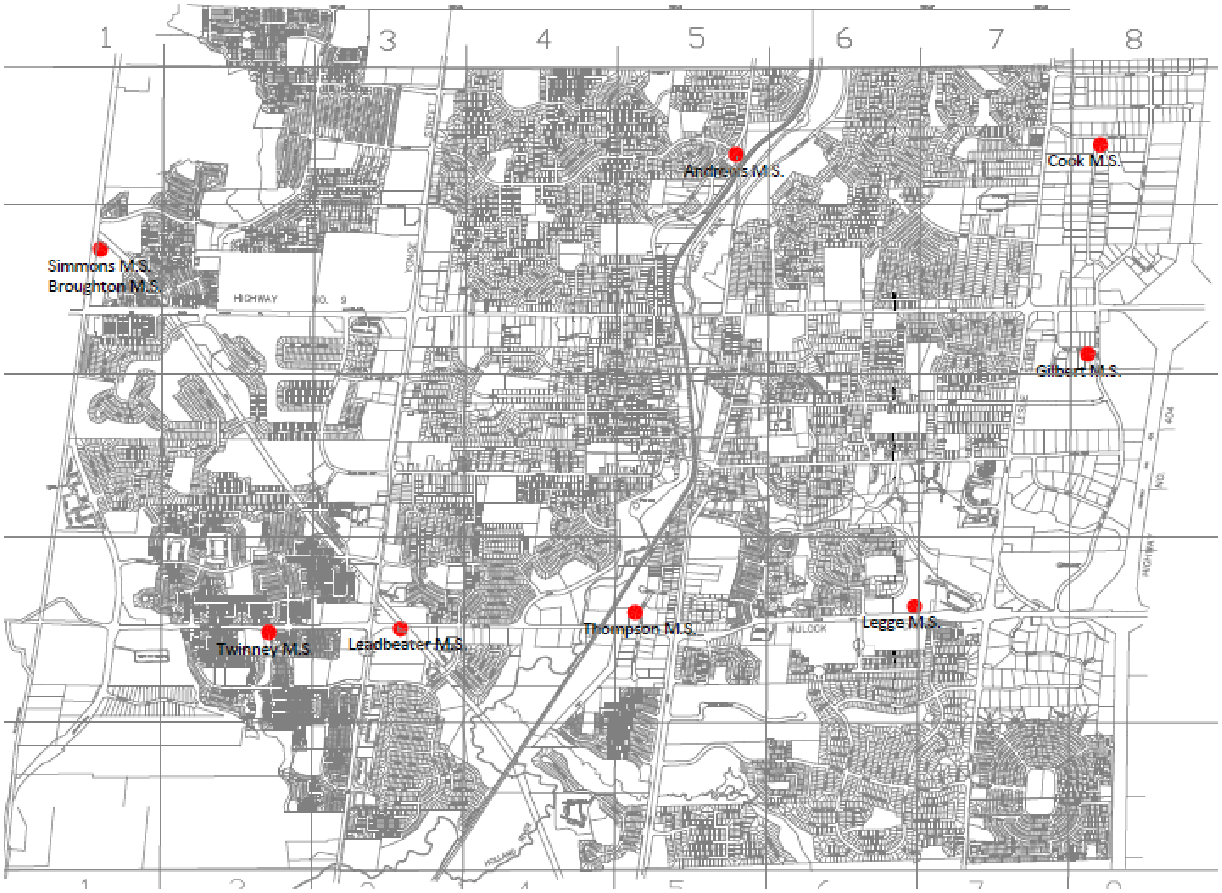

Figure 17 – Newmarket DS locations

A network of 13.8kV feeders is used to move the power to residential and small commercial neighbourhoods where it is again transformed down, through local overhead, padmount and vault transformation facilities to user utilization levels of 600/347V, 120/208V and 120/240V. There are a total of 361km of overhead and 510km of underground 13.8kV circuitry. There also are a total of 87km of overhead and 2km of underground 44kV circuitry owned by NTPDL. A significant amount of the underground 13.8kV circuitry is single phase distribution within residential subdivisions.

In the Midland-Tay service area, distribution stations take power at 44kV and transform it down to 8.32kV and 4kV. Distribution station locations are shown in Figures 18. Feeder routing is shown in Figures 19 and 20.

All distributions stations in Midland are equipped with motion activated cameras that take a 10 sec video whenever they are activated. The system emails a short video immediately and if the motion continues it will keep activating and sending video. The installation of this system has eliminated ground wire theft at the stations.

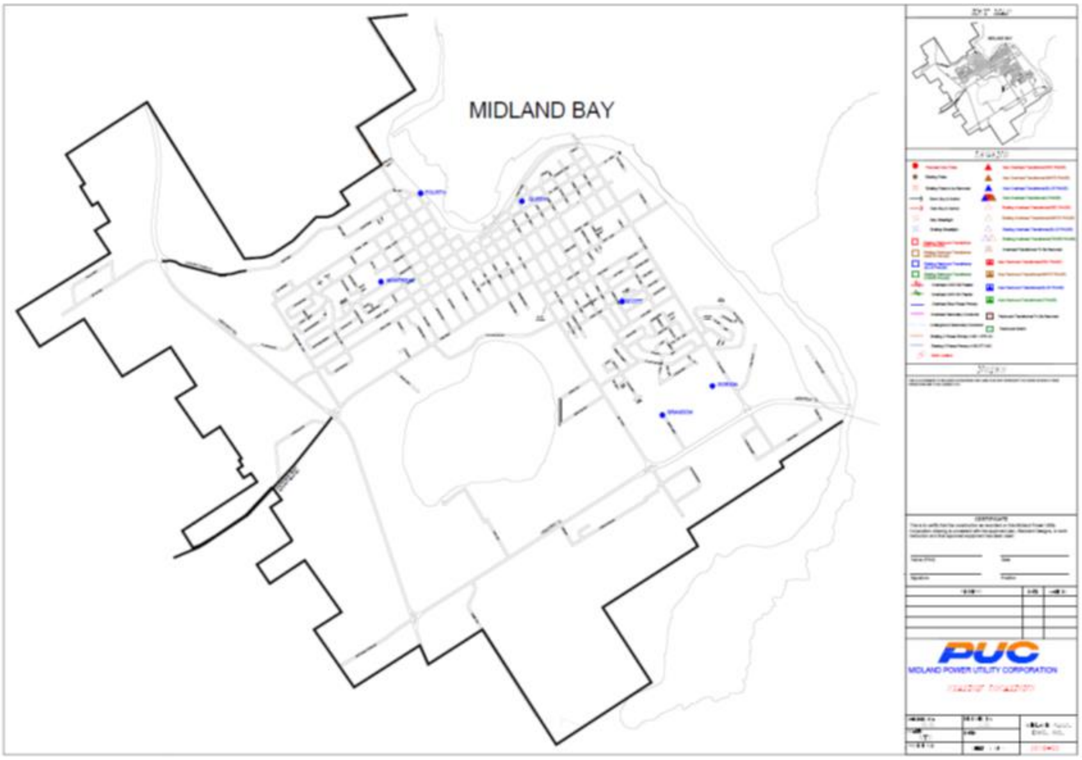

Figure 18 – Midland DS locations

A network of 8kV and 4kV feeders is used to move the power to residential and small commercial neighbourhoods where it is again transformed down, through local overhead, padmount and vault transformation facilities to user utilization levels of 600/347V and 120/208V. There is a total of 108km of overhead and 49km of underground circuitry. Approximately 95% (46.8 km) of the underground circuitry is at the 4kV level. The remaining 5% is at the 8.32kV level.

Maps of the 4kV and 8kV distribution system in Midland are shown in the figures below:

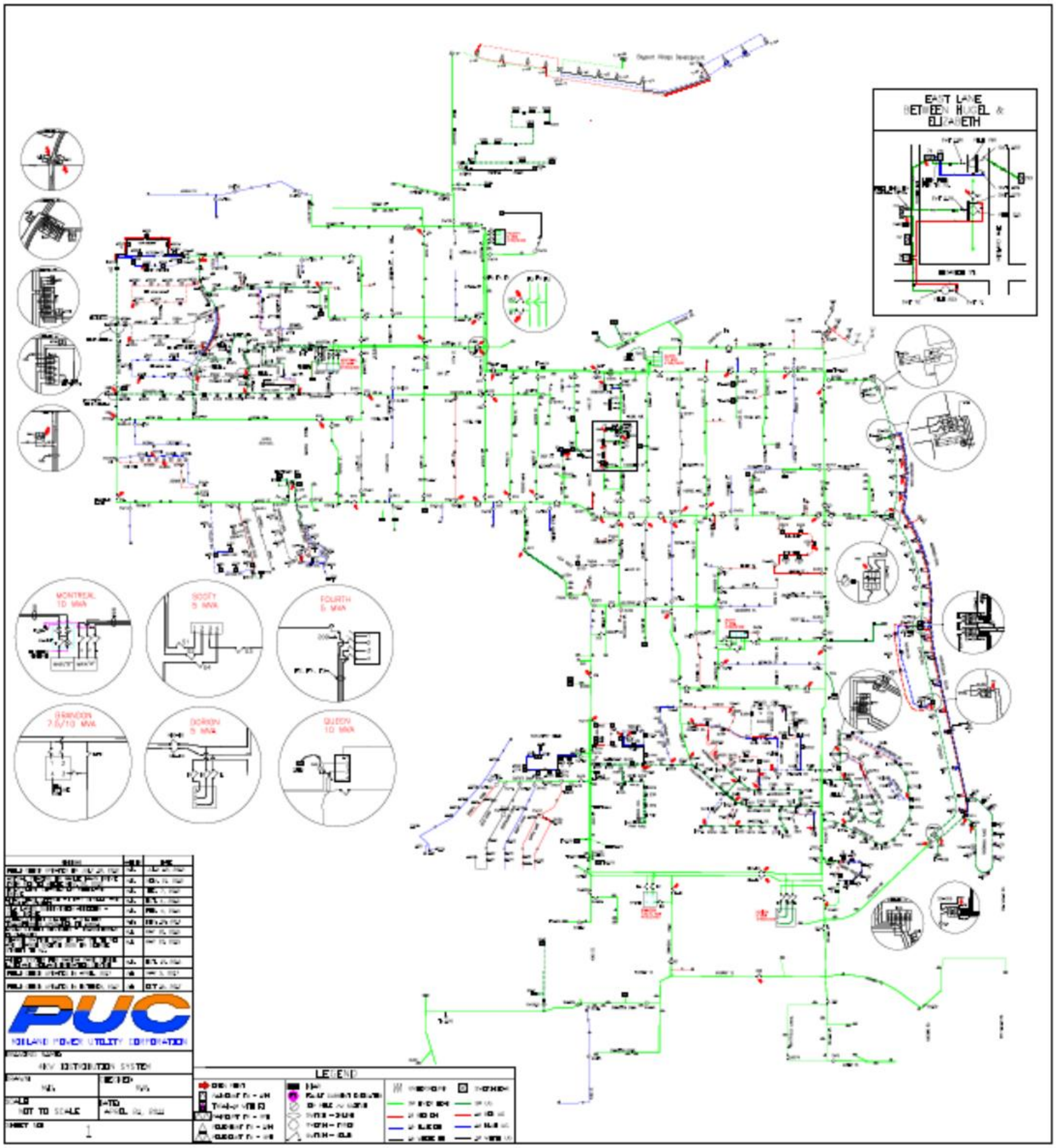

Figure 19 – Midland 4kV Distribution System

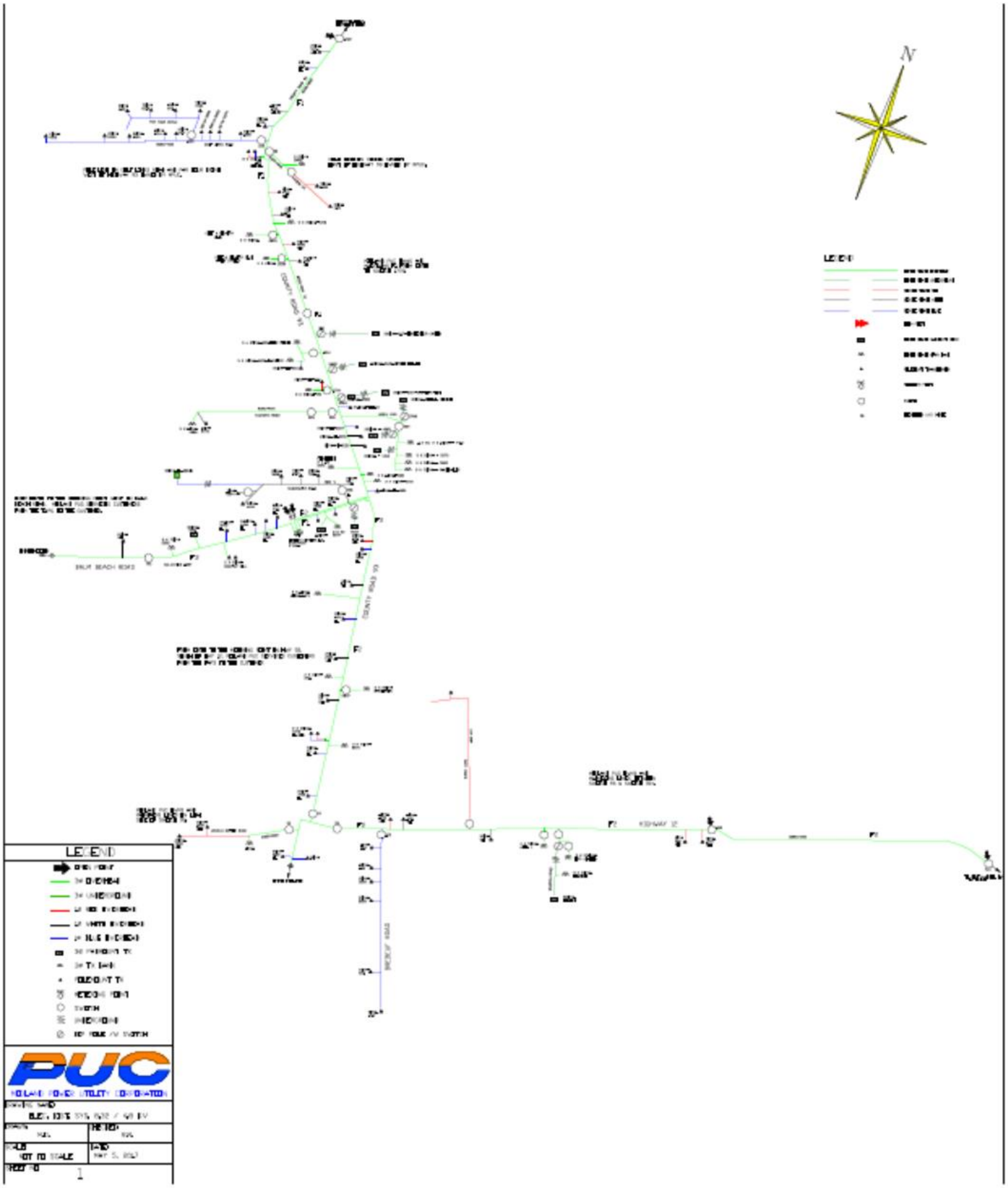

Figure 20 – Midland 8kV Distribution System

There are no submersible transformer installations, cable chambers, room vaults or other confined spaces in NTPDL's service territory.

5.3.2c Information by asset type

Information regarding NTPDL's key assets by asset type, quantity/years in service and condition is shown in the tables below:

Asset Category		Population	Health Index Distribution Very Poor < 25%	Poor 25-<50%	Fair 50-<70%	Good 70-<85%	Very Good >85%	Average Health index	Average Age	Replacement Strategy
Substation Transformers		23	13%	0%	4%	13%	70%	82%	29	Proactive
Circuit Breakers		61	0%	0%	0%	0%	100%	100%	15	Proactive
Pole Mounted Transformers		1797	3%	16%	19%	4%	58%	58%	29	Proactive
Pad Mounted Transformers		4428	5%	5%	5%	9%	75%	75%	23	Proactive
Pad Mounted Switchgear		133	< 1%	4%	20%	20%	55%	55%	19	Proactive
Poles	Wood Poles	8147	3%	3%	7%	16%	71%	71%	29	Proactive
	Concrete Poles	303	0%	0%	0%	0%	100%	100%	9	Proactive
Underground Cable	Non-TRXLPE*	412.6	11%	8%	2%	10%	69%	69%	32	Proactive
	TRXLPE*	278.5	0%	0%	0%	0%	100%	100%	18	Proactive

Table 34 – NTPDL Asset Condition Summary

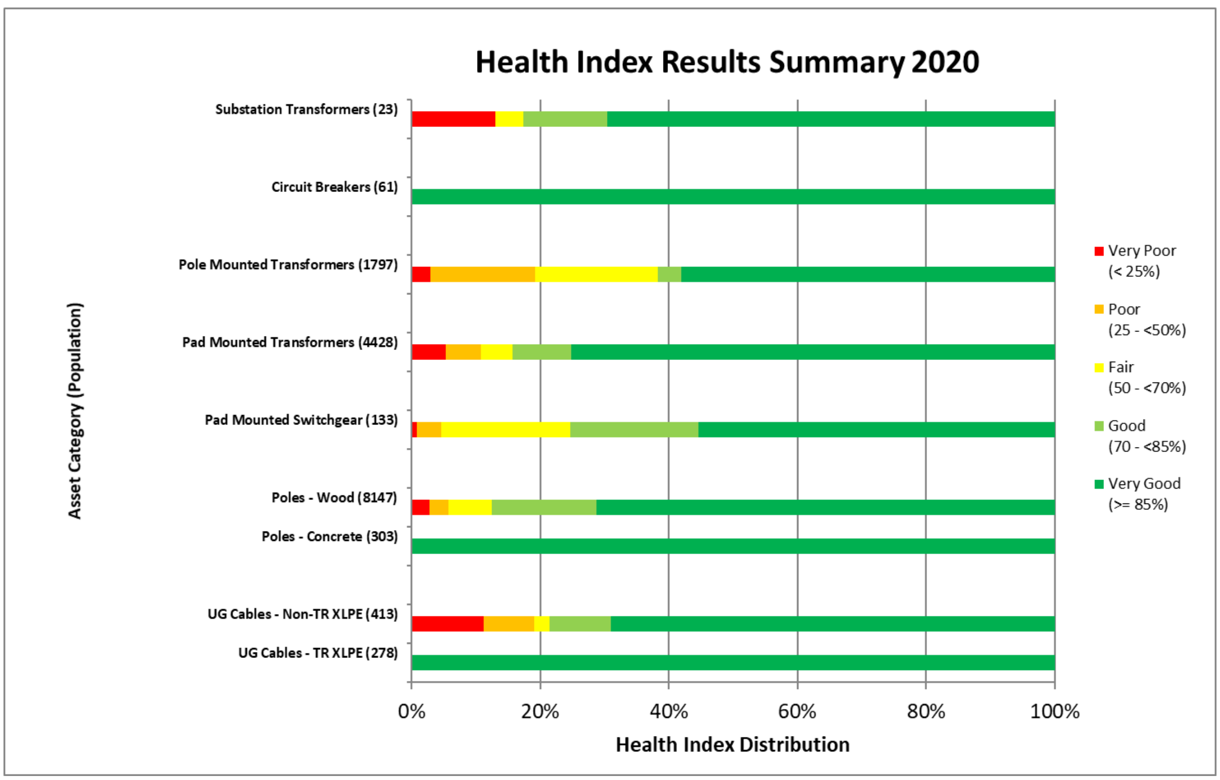

Table 35 – Newmarket Asset Health Index Summary

Newmarket asset data from the Kinectrics 2020 Asset Condition Assessment.

Non-key distribution assets (low unit cost – run to failure) or those that require no maintenance in themselves (i.e. overhead wire) are not specifically tracked for condition assessment. In general, determination of issues of immediate or future asset performance concern is augmented by staff expert knowledge and distribution system awareness.

Proactive replacement strategies have been adopted for assets listed in the table above. Asset categories where significant portions of the population were in poor or very poor condition were Substation Transformers, Non-Tree Retardant XLPE cable and Pole mounted transformers.

A multiyear long term optimized and levelized replacement plan (rate and resource mitigation) for the assets listed in the table above has been prepared using the condition assessments as a guide.

A variety of wires sizes for overhead 8.32kV and 4.16kV circuits (#2, 1/0, 3/0, 4/0 ACSR 336 ASC) in Midland. The 336 ACSR conductor has in excess of 500 Amps current carrying capacity.

Proactive replacement strategies have been adopted for overhead transformers, underground cable and poles at end of life. Other asset types (i.e. substation transformers) are being closely monitored to determine the specific replacement/refurbishment period. At this time, three (3) station replacement/ refurbishments are planned during the 2020 – 2024 period. Reactive replacement strategies have been adopted for the remainder.

5.3.2d Assessment of existing system capacity

NTPDL is a summer peaking utility. Summers are generally hot and humid influencing the use of electricity for space cooling.

<u>Station Capacity</u>

Station capacity for planning purposes is based on 80% of the normal rating of the station transformers. Short time fluctuations in demand load would not be expected to exceed the normal rating of the station transformer. When normal loading exceeds 80% of the transformer rating the excess amount would be permanently transferred to another station with capacity or if this is not possible, due to system constraints or other issues, new facilities would be planned to be constructed.

The 80% loading guide allows DS to back each other up to various degrees to handle short term system disturbances and maintenance needs. Limitations in feeder interconnectivity may result in some loading over transformer normal rating for short periods of time.

In Tay, Waubaushene DS can be partially backed up by Victoria Harbour DS.

In Midland, HONI owned Firth DS is backed up by other HONI owned DS.

The chart below indicates an average utilization rate of 84% for Newmarket area DS capacity and 55% for the Midland-Tay area DS capacity over the historical 2015 – 2019 period.

DS Name	Capacity (MVA)	2015 Peak Load (MVA)	2016 Peak Load (MVA)	2017 Peak Load (MVA)	2018 Peak Load (MVA)	2019 Peak Load (MVA)	Avg % Utilization
Newmarket Area							
Cook	10	7.7	8.3	8.1	8.4	8.1	81%
Gilbert	20	12.3	17.4	16.8	18.0	13.4	78%
Andrews	20	17.9	9.8	10.3	14.0	17.1	69%
Twinney	20	15.4	19.8	16.7	18.8	15.8	87%
Thompson	20	15.7	20.4	15.2	16.0	17.6	85%
Simmons	10	9.9	12.3	5.6	11.8	11.8	103%
Broughton	10	6.1	12.3	10.4	12.2	5.5	93%
Legge	10	11.8	9.6	11.8	11.1	11.5	112%
Leadbeater	10	4.2	5.4	6	9.0	6.0	61%
Total	130	101	115.3	100.9	119.3	106.8	84%
Midland Area							
Brandon	7.5	3.2	3.5	3	3.5	3.1	43%
Dorion	5	2.1	2.2	2.1	2.5	4.3	53%
Fourth	5	2.4	2.4	2.3	3.3	2.9	53%
Montreal	10	4.1	4.4	4.2	4.7	5	45%
Queen	10	4.3	4.5	4	5.4	4.2	45%
Scott	5	3	3	2.9	3.6	3.3	63%
Firth (HONI)	5	2.8	2.8	2.6	2.9	2.5	54%
Total	47.5	21.8	22.8	21.1	25.9	25.3	49%
Tay Area							
Victoria Harbour	5	4.1	4.4	4.7	5.1	4.6	92%
Port McNicoll	5	4	3.9	3.8	4.0	4.0	79%
Waubashene	3	1.9	1.4	1.4	1.6	1.8	54%
Total	13	10	9.7	9.9	10.7	10.4	78%

Table 36 – NTPDL 2015 – 2019 DS Utilization

NTPDL has a spare 5 MVA DS transformer (Primary 44kV; Secondary 4.16kV) that can be used for emergency replacement of any of the DS transformers based on existing loading in Midland. If loading on any of the larger DS transformers (i.e. Queen) were to grow beyond 5MVA, then replacement would be accompanied by load transfers to other DS to ensure loading on the replacement transformer does not exceed its normal rating.

There is also a spare 10MVA DS transformer for Tay.

44kV feeder capacity

NTPDL is transmission connected in the Newmarket service area via 44kV feeders from HONI-owned Armitage and Holland transformer stations. The 2019 44kV feeder utilization statistics (non-coincident peak loading day) are shown below:

Feeder	Planning Capacity (Amps)	2019 Peak Load (Amps)	% Utilization
Armitage TS			
41M13	300	204	68%
41M21	300	341	114%
41M23	300	267	89%
41M24	300	361	120%
41M33	300	246	82%
Holland TS			
153M5	300	210	70%
153M6	300	337	112%
153M7	300	108	36%
153M8	300	261	87%

Table 37 – NTPDL 44kV Feeder Utilization

The 44kV feeder loading shows how the existing circuit configuration results in normal and contingency loading situations above the normal planning loading limit on certain feeders. Improvements to 44kV feeder interconnections will improve the ability of NTPDL to distribute load more evenly. The 153M7 is intended to backup the Yonge St area but intertie connections are not complete, so has relatively low normal load. Completing the 153M7 intertie in 2021 will help address the load distribution issue.

Midland is fed from two dedicated 44 KV feeders, the 98-M2 and 98-M4, and two feeders shared with Hydro One and Alectra, the 98-M3 and 98-M7. The 2019 44kV feeder utilization statistics (non-coincident peak loading day) are shown below:

Feeder	Planning Capacity (Amps)	2019 Peak Load (Amps)	% Utilization
Waubaushene TS			
98M2	600	277	46%
98M3	720	27	4%
98M4	720	314	44%
98M7	800	33	4%

Table 38 – Midland 44kV Feeder Utilization

Feeder loading is generally within planning guidelines and as such is not a key driver of material upstream investments in the DSP or Regional Planning process for Midland.

Tay DS are supplied by HONI owned 44kV feeders (98M1 and 98M6)

Newmarket and Tay 13.8kV and 8kV feeder capacity

The 13.8kV and 8kV feeders emanate from NTPDL distribution stations located in the Newmarket and Tay service areas respectively. Newmarket is summer peaking while Tay is winter peaking.

Feeder loading is generally within planning guidelines and as such is not a key driver of material investments according to System Service needs. At time, during contingency situations, feeder load may, for a short time, exceed the planning rating but not the capacity rating of the conductor.

Midland 8.32kV and 4kV feeder capacity

The 8.32kV and 4kV feeders emanate from Midland and HONI distribution stations. Midland is summer peaking.

Feeder loading is generally within planning guidelines and as such is not a key driver of material investments according to System Service needs.

5.3.3 Asset Lifecycle Optimization Policies and Practices

This section of the DSP provides a high-level overview of NTPDL's asset lifecycle optimization policies and practices. A key component of NTPDL's asset lifecycle optimization is the determination of asset health through ACA studies.

For Newmarket and Tay, the first study was performed by Kinectrics in 2011-2012 and updated studies were performed in 2013, 2017 and 2020. The results of the studies identify plant that is at or near the end of their asset life and subject to appropriate disposition through system renewal programs. The 2020 ACA study includes assets in Midland which was acquired by NTPDL in 2018.

5.3.3a Formal policies and practices

NTPDL's policies and practices towards asset lifecycle optimization are derived from NTPDL's Asset Management Policy and Asset Management Objectives. Key asset lifecycle practices are:

Asset Register development – For the Newmarket service area, NTPDL's ESRI-based GIS is the designated asset register for Field Assets. The asset register is intended to hold/link to asset attribute information as well as linkages to historical financial and non-financial information over each asset's lifecycle. Linkages to NTPDL enterprise systems will provide financial asset information.

For the Midland-Tay service territory, the key components that comprise the Asset Register are the GIS database (Autodesk AutoCAD Maps 3D), the ACCPAC Accounting System, the Harris Customer Information System (CIS) and MS Access database. It is intended to migrate the former MPUC CIS, GIS, ACCPAC and MS Access databases over to the Newmarket area systems.

General plant asset information resides with the respective owners of the asset (i.e. fleet assets reside with Operations). The asset register will provide the relevant information for ongoing development and optimization of assets inspection, maintenance, refurbishment and replacement programs, assist with asset planning, assist in meeting regulatory/legislative compliance and IFRS accounting standards. The asset register will aid in cost control through optimization of the asset's lifecycle.

For example, subdivision cable is generally installed from a common lot of cable and if cable tests and reliability performance indicate end of life for specific cable sections, it is likely that the other cable sections may be in similar condition thereby warranting a full subdivision cable replacement program versus the "whack-a-mole" approach of repairing fault after fault after fault. The asset register (GIS) can identify common asset attributes and historical performance to develop an appropriate scope for the cable replacement program.

Asset Refurbishment /Replacement - NTPDL considers a wide range of factors when deciding whether to refurbish or replace a distribution asset, including public and employee safety, service quality, rate impacts, maintenance costs, fault frequency, asset condition, and life expectancy so that investment in replacement plant is a prudent one. Plant is replaced at the end of life when all refurbishment options have been exhausted.

When an asset has reached end of life and the cost of maintenance and/or the frequency of service disruptions have reached an unacceptable or uneconomic level, the asset is identified for refurbishment or replacement. If the malfunction of these identified assets would create a significant safety, reliability or service impact, the assets are replaced within the current year's budget. Assets that have not reached their end of life are left in service and refurbished as required based on service reliability, condition assessment and regular inspections as required under the Distribution System Code. The NTPDL inspection, testing and maintenance program, together with ACA studies, serves as a foundation for proactive and reactive replacement programs for distribution assets at or near end of life. Fleet and other general plant assets are assessed through in-house developed approaches.

Cable injection, where deemed appropriate based on cable age, condition and construction, may provide for a cost-effective refurbishment alternative to cable replacement that potentially could extend cable life by 20 years or more. At this time there is a significant portion of underground cable at end of life that needs to be replaced and is in a condition where cable injection would not be a suitable alternative.

Replacement of end of life plant with new plant will still require the allocation of resources for ongoing O&M purposes. Repair would be the most significant O&M activity impacted by new plant. Certain assets, such as poles, offer few opportunities for repair related activities and generally require replacement when deemed at end of normal life or critically damaged. Other assets such as direct buried cable offer opportunities for repair related activities (e.g. splices) up to a point where further repairs are not warranted due to end of life conditions. In a few areas cable faults will not be repaired due to cable end of life. When faulted, the faulted cable section will be replaced, normally a section between two distribution transformers. For planned cable replacement in a subdivision, new primary cable installed in duct replaces direct buried primary cable and is expected to provide higher reliability and life. This will shift response activity for a cable failure from repair (O&M) to replacement (Capital). If assets approaching end of life are replaced at a rate that maintains equipment class average condition then one would expect little or no change to O&M costs under no growth scenarios but would still see upward O&M cost pressure on positive growth scenarios (more cumulative assets to maintain each year). Replacement rates that improve equipment class average condition could result in lowering certain maintenance activities costs (e.g. pole testing, reactive repairs, etc.). Overall this is expected to put downward pressure on O&M repair related costs.

Asset Inspection and Maintenance – NTPDL maintains the efficiency and reliability of its distribution system through an active inspection, maintenance and asset management program that focuses on customer service, employee safety and cost-effective maintenance, refurbishment and replacement of assets that can no longer meet acceptable utility performance standards.

Maintenance Planning criteria are developed in consideration of the Asset Management Objectives. Maintenance planning issues are identified through various methods and sources, primarily through feedback from distribution system operations, inspections, manufacturer's maintenance recommendations, and the Kinectrics ACA report. Maintenance is performed to ensure equipment continues to provide its essential functionality in a safe manner over its lifecycle. Some assets require very frequent maintenance efforts (e.g. fleet vehicles), others require infrequent maintenance efforts (e.g. pole structures) and some are essentially maintenance free (e.g. overhead conductor). For most assets, uniform maintenance programs have been set up for the whole class. For very large and critical assets (e.g. station transformers) maintenance programs can be unit specific depending on the nature of asset issues discovered.

NTPDL has a combined inspection and maintenance practice for field assets. General patrol requirements, as outlined in the Distribution System Code, are adhered to. Asset inspection and maintenance is designed to optimize the asset lifecycle until such time that the asset has reached a condition requiring refurbishment or replacement. Inspection and maintenance program details are provided below:

Program	Field Asset	Practice	Schedule
Distribution Lines			
	44kV Loadbreak switch	Visual Inspection	Every 3 years
	44kV Insulator	Washing	2-3 times per year
	44kV Feeder circuit	Infrared inspection	Yearly
	13.8kV, 8kV, 4kV loadbreak switch	Visual inspection	Every 3 years
	13.8kV, 8kV, 4kV Insulator	Washing	2-3 times per year
	13.8kV, 8kV, 4kV Feeder circuit	Infrared inspection	Yearly
	13.8kV, 8kV, 4kV InLine switches	Rotation	Every 3 years
	13.8kV, 8kV, 4kV Padmount Switchgear	Visual inspection	Every 3 years
	13.8kV, 8kV, 4kV Padmount Transformers	Visual inspection	Every 3 years
	Overhead plant (poles, conductors, etc.)	Patrol	3 year rotation
	Transformers	Painting	Specific units annually
	Overhead lines	Tree trimming	3/4 year rotation
Stations			
	DS stations	Full visual inspection	Monthly
	Station transformers	Oil tests	Yearly
	Station equipment	Maintenance	Every 3/4 years
	Station equipment	Infrared inspection	Yearly
	Station reclosers	Oil tests	Every 5 years
General Plant			
	Fleet vehicles(large)	Hydraulic Inspection	Every 3 – 6 months
	Fleet vehicles	LOF	Every 2 – 3 months
	Fleet vehicles	Rustproofing	Annual after year 3
	Facilities	HVAC, Fire sprinkler inspection	Quarterly
	Facilities	Emergency Generator	Annual

Table 39 – Inspection and Maintenance Program

Asset investment determination - Asset replacement is considered annually as part of NTPDL's investment planning process along with the other capital projects scheduled for completion in the upcoming year. Mandatory asset replacements, due to near term significant safety or reliability issues are automatically included in the budget spend. Non-mandatory asset replacements are prioritized and scheduled as described in section 5.3.1. Non-mandatory replacements provide a degree of planning flexibility to help keep annual capital expenditures stable. The outcomes of the investment planning process will align with the proposed budget or may indicate that the budget needs revision to adequately address underinvestment risks. With increasing need to address assets at end of life, multi-year asset replacement programs have been structured to smooth out ("levelize") budget and resource impacts.

When assets are replaced as a result of system renewal investments, the new assets are incorporated into the inspection and maintenance programs. As the average health index of the group (i.e. UG cables) improves through system renewal investments, it should have a beneficial impact on how much effort is spent on reactive emergency maintenance.

Maintenance Planning Criteria

Maintenance Planning criteria are developed in consideration of the Asset Management Objectives. Maintenance planning issues are identified through various methods and sources, primarily through feedback from distribution system operations, inspections, manufacturer's maintenance recommendations, and the Kinectrics ACA report. Maintenance is performed to ensure equipment continues to provide its essential functionality in a safe manner over its lifecycle. Some assets require very frequent maintenance efforts (e.g. fleet vehicles), others require infrequent maintenance efforts (e.g. pole structures) and some are essentially maintenance free (e.g. overhead conductor). For most assets, uniform maintenance programs have been set up for the whole class. For very large and critical assets (e.g. station transformers) maintenance programs can be unit specific depending on the nature of asset issues discovered.

5.3.3b Lifecycle risk management

NTPDL has determined that ACA studies and comprehensive data collection will provide a better understanding of each distribution asset's stage in their lifecycle which will lead to more cost-effective decisions with respect to risk management. This complements the information received through the inspection and maintenance programs to assess asset risk.

Asset performance during an investment cycle is collected and utilized in the next investment planning period. Mandatory investments are automatically included in the investment plan regardless of risk. Non-mandatory asset investment is valued and scored. The scoring process considers the implicit risk of not investing in the upcoming investment cycle. For example, critical asset investments such as station transformers and 44kV plant will score relatively high on benefit compared to distribution transformer investment due to the higher widespread impact that a failure of a critical asset has. This has also led to the development of proactive replacement strategies for higher risk high cost critical assets (i.e. poles and underground cable) and reactive replacement strategies for lower risk low cost assets (distribution transformers and switchgear).

The 2015 – 2019 DSP introduced proactive non-mandatory distribution asset replacement investments for poles and underground cable. The 2020 Kinectrics ACA report continues to support the need for these programs and adds programs to address additional assets requiring proactive replacement. The investment strategies are designed to smooth out the impact of these programs on rates. The programs will continue to be structured to remain within OEB rate mitigation guidelines. There is an increased amount of risk for those assets in "very poor" and "poor" condition that await replacement towards the later years of the replacement program. In this sense risk is balanced against the reality of unsustainable rate increases that would be needed to eliminate all asset risk in a short period of time. Assets with the lowest health index in a category (i.e. poles, UG cable) are addressed first. Other assets with higher health index scores are deferred to future investment periods. Individual asset priority position in the program will be managed as more asset information is obtained through ongoing annual inspection and testing to optimize replacement risk decisions.

Multi-year renewal programs for assets in "very poor" and "poor" condition best balance risk, value and rate impact. The multi-year programs for cable and poles introduced in the 2015 – 2019 DSP will continue in the 2020 – 2024 DSP. New programs addressing additional assets are added to the 2020 – 2024 DSP based on data in the 2020 Kinectrics ACA report.

	Asset	Quantity	Program Cost
2015 - 2019 DSP	Poles	643	$8.32M
	UG Cable	30 km	$6.0M
2020 – 2024 DSP	Poles	368	$2.5M
	UG Cable	10 km	$4.0M
	Padmount Transformers	380	$3.3M
	Overhead Transformers	100	$0.6M
	Padmount Swithcgear	12	$0.4M

Table 40 – Proactive Asset Renewal Programs

Other assets in “very poor” and “poor” condition will be dealt with on a reactive basis.

Long term replacement plans have also been prepared for fleet and other general plant assets.

5.3.4 System Capability assessment for renewable energy generation

5.3.4a Applications from renewable generators > 10kW

NTPDL has connected ten renewable energy generators to date as shown in the table below:

Address	Municipality	Technology	kW	Connecting Feeder
1100 Gorham St.	Newmarket	Solar PV (rooftop)	100	41M21
17850 Yonge St.	Newmarket	Solar PV (rooftop)	450	153M6
100 Eagle St.	Newmarket	Solar PV (rooftop)	150	153M8
800 Mulock Dr.	Newmarket	Solar PV (rooftop)	500	41M21
715 Kingsmere Ave.	Newmarket	Solar PV (rooftop)	75	41M24
1155 Stellar Dr	Newmarket	Solar PV (rooftop)	200	41M24
120 Bayview Pkwy	Newmarket	Solar PV (rooftop)	40	153M6
125 Harry Walker Pkwy	Newmarket	Solar PV (rooftop)	210	41M24
1000 Wye Valley Road	Midland	Solar PV (rooftop)	500	98M4
16821 Highway #12	Midland	Solar PV (rooftop)	250	98M2

Table 41 – List of FIT connections

5.3.4b Renewable generation connections anticipated 2020 -2024

At this current time, there are no renewable generation applications in the queue to be connected. Since the discontinuation of the IESO FIT and microFIT programs, NTPDL has received minimal interest from customers regarding REG.

5.3.4c Capacity to connect REGs

In the NTPDL's three service areas, the distribution system (DS stations, feeders) has capacity in excess of the upstream HONI TAA capacity allocations. Based on common industry practices for synchronous generating units, NTPDL aims to ensure that Distributed Energy Resource aggregate capacity is less than one-third of the minimum load of the Local Electric Power System (EPS). This is a very conservative approach since NTPDL has only received solar photovoltaic REG applications, which have a lower short circuit contribution and do not actively regulate the voltage on the system. Using this high-level methodology, 16MW of REG would be available from NTPDL's eighteen substations in Newmarket, Midland and Tay.

5.3.4d REG connection constraints

NTPDL is supplied from the following HONI owned transformer stations:

1. Armitage TS
2. Holland TS
3. Waubaushene TS

Threshold Allocation Assessments have been obtained from HONI as follows:

Station	TAA (kW)	REG connected (kW)	Balance
Holland TS	2,000	640	1,360
Armitage TS	2,000	1,085	915
Waubaushene TS	1,000	750	250

Table 42 – HONI TS station capacity for DGs

There are no MPUC feeders that have REG connected and are unable to connect any additional REG.

5.3.4e Embedded distributor connection constraint impacts

There are no embedded distributors in NTPDL's service territories.

5.4 Capital Expenditure Plan

NTPDL's DSP details the program of system investment decisions developed based on information derived from NTPDL's asset management and capital expenditure planning process. Investments, whether identified by category or by specific project, are justified in whole or in part by reference to specific aspects of NTPDL's asset management and capital expenditure planning process.

NTPDL's DSP includes information on prospective investments over a five-year forward-looking period (2020 – 2024) as well as planned and actual information on investments over the historical five-year period (2015 – 2019).

5.4a Customer engagement activities to ascertain plan alignment

Customer engagement is considered essential to achieving NTPDL's Customer Focus outcomes. NTPDL uses a variety of activities to engage customers and determine their preferences for the development of NTPDL's distribution system going forward.

<u>Customer engagement to aid in DSP development</u>

NTPDL believes that customer engagement with respect to DSP outcomes should provide useful information, be cost-effective, and be able to engage as many customers as reasonably possible. The goal is to capture preferences with respect to the underlying principles guiding the development of the DSP. As stated in section 5.2.1b, NTPDL's mechanism of choice to accomplish this is through telephone-based customer surveys.

Customer surveys provide a high-level assessment of customer preferences with respect to service reliability and operational effectiveness. For accuracy purposes, survey samples should be representative of the service territory population. NTPDL has been conducting customer surveys since 2006. In 2019 NTPDL engaged UtilityPULSE to conduct a survey of its customers. UtilityPULSE uses standard public opinion research methods to obtain survey results. Survey results indicate satisfaction with current service performance levels which indicates that plan efforts to maintain historical levels are reasonable thereby supporting system renewable efforts and prudent smart grid development. Concern about the overall cost of electricity supports the need to consider rate mitigation efforts while managing risk and smoothing spending over time for non-mandatory investments. It is understood that NTPDL's rate mitigation efforts will only impact less than 20% of the customer's bill, the other 80% being out of NTPDL's control. Survey results are implicitly considered in the development of the asset management strategy, objectives and plans.

According to the most recent residential and commercial customer survey, the most important service improvements that NTPDL could undertake, from the customer's perspective, are shown in the table below:

One or two most important things 'your local utility' could do to improve service	2019
Newmarket-Tay Power Distribution Limited	**% of all suggestions**
Better prices/lower rates	43%
Better communications with customers	12%
Improve/simplify/clarify billing	9%
Better outage information	7%
Information & incentives on energy conservation	3%
Improve customer service/reliability of staff	5%
Improve power reliability	4%
Be more efficient	2%
Delivery charges	2%
Restore power faster	2%
Change Peak Usage rates	1%
Get involved with Green Energy	1%
Bury power lines	1%

Table 43 – Customer service preferences (2019 UtilityPULSE Survey)

Cumulative results from surveys over the historical period support the position that the surveys have engaged a wide group of NTPDL customers (different each year), and that key concerns and preferences are similar amongst them as shown in the table below:

	2015	2017	2018	2019	Avg.
Better prices/lower rates	41%	60%	38%	43%	46%
Better communications with customers	10%	8%	21%	12%	13%
Improve power reliability	16%	5%	2%	4%	7%
Improve/simplify/clarify billing	6%	9%	7%	9%	8%
Information & incentives on energy conservation	9%	3%	9%	3%	6%
Better maintenance	16%	0%	0%	0%	4%
Better outage information	0%	5%	9%	7%	5%
Be more efficient	8%	2%	1%	2%	3%
Better on-line presence/Pay bills online	6%	3%	0%	0%	2%
Increase service hours/availability of hydro representative	4%	0%	3%	5%	3%
Concerns about SMART meters	5%	1%	0%	0%	2%
End TOU	0%	5%	0%	1%	2%
Remove hidden costs on bills	5%	0%	0%	0%	1%
Staff related concerns	3%	2%	0%	0%	1%
Create an online APP	0%	0%	3%	0%	1%
Get involved with Green Energy	0%	0%	3%	1%	1%
Restore power faster	0%	1%	1%	2%	1%
Delivery Charges	0%	0%	0%	2%	1%
Bury Power Lines	0%	0%	0%	1%	0%

Table 44 – Top two Customer service preferences (2015 - 2019 UtilityPULSE Surveys)

Very few customers realize that NTPDL accounts for less than 20% of their electricity bill. In that context, the tables above indicate that lowering the overall cost of electricity is the key value proposition that customers believe the entire electricity industry should deliver.

In summary, the key underlying principle of the DSP, based on surveys of customer preferences, was determined to be maintaining existing service levels over the period of the plan.

Other activities to ascertain stakeholder (i.e. Town) interests have been carried out.

Council workshops (Newmarket & Tay) are undertaken at least once a year. Meetings are held so that stakeholder feedback can be incorporated into the investment planning process in a timely manner. The meetings are designed for two-way communication. NTPDL's meeting goal is to update Council, as representatives of NTPDL's customers, with respect to what is happening in their community with respect to NTPDL, regulatory and ministerial directives, key NTPDL projects to be undertaken in the upcoming year. The second goal of the meeting is to solicit Council feedback on electrical supply issues that are communicated to them from municipal residents and commercial establishments. Some information may be known through direct communication by customers to NTPDL, but Council members tend to accumulate specific consumer issues, viewpoints and overall perception of service through ongoing discussion with their constituents and this has value to NTPDL.

The Community Hydro Distribution Advisory Committee ("CHDAC"), consisting of representatives from both the Town of Midland & NTPDL, was established "to ensure the high standards of hydro electric distribution services in the Town of Midland are maintained; and the working relationship with the community in the broadest sense remain effective and responsive". Matters of interest to the Midland community and NTPDL are communicated at the CHDAC.

Local Public Information Centres (PIC) are used to engage customers on project specific issues primarily related to rehab underground work in their neighbourhoods dealing with outage scheduling and aesthetic design issues. Customers have the opportunity to provide feedback on proposed works. PIC obtained preferences are tactical in nature and executed at the implementation stage and have no significant impact on the strategic nature of the plan.

Municipal development planning consultation provides an indirect gauge of customer preferences as to the aesthetic development of NTPDL's distribution system, especially along arterial loads. As representatives of the "customer", in roadway aesthetic considerations, municipal and regional authorities have identified the undergrounding of electrical plant along key arterial streets as a key desirable planning outcome. At the present time this outcome is not aligned with the key customer preference on the most recent survey results.

Customer meetings are held generally to discuss issues that are unique to a specific customer or a small group of customers.

Meetings are held on an ongoing basis with customers to promote energy conservation and advise on connection process for distributed generation.

The corporate website and social media also provide forums for customer engagement. Information obtained from customers, as a result of continuous feedback through the year, is considered in the development of the investment portfolio and the investment prioritization process.

Review of draft DSP to ascertain alignment with customer/stakeholder preferences

To ascertain draft plan alignment, NTPDL engaged customers by posting the draft 2020 – 2024 DSP with a summary introduction to its website and social media to advise and encourage all customers to review the DSP and provide their feedback. The posting period for review and comment was November 2 to November 27 2020. Given the COVID-19 pandemic situation, NTPDL was limited to non-physical customer engagement methods.

There were only two responses during this period. While the number of responses is not statistically relevant, one respondent did not leave any comment, while the other commented that people “should not be expected to read & understand a 177 page report”. For the next DSP review, NTPDL intends to address the DSP review process. The review has resulted in no changes to the programs in this DSP

In summary, NTPDL’s customer engagement strategy and plan over the period of the DSP is as follows:

2020	2021	2022	2023	2024
Safety Survey	Customer Satisfaction Survey	Safety Survey	Customer Satisfaction Survey	Safety Survey
Council Workshops	Council Workshops	Council Workshops	Council Workshops	Council Workshops
CHDAC	CHDAC	CHDAC	CHDAC	CHDAC
Local PICs	Local PICs	Local PICs	Local PICs	Local PICs
Municipal Consultations	Municipal Consultations	Municipal Consultations	Municipal Consultations	Municipal Consultations
Customer meetings	Customer meetings	Customer meetings	Customer meetings	Customer meetings
Website and Social Media	Website and Social Media	Website and Social Media	Website and Social Media	Website and Social Media
DSP posting for comment	-	-	-	-

Table 45 – NTPDL Customer Engagement Plan

In carrying out distribution activities to support the Corporate Mission and Vision statements, stakeholder interests have to be considered and factored into the planning process. Stakeholder interests vary and at times can be either complementary or conflicting. As a part of the planning process, some basic assumptions are made about the stakeholder interests. The assumptions represent high level utility assessments of key stakeholder class attributes that the utility has observed from many years of historical interaction with each respective stakeholder group.

The assumptions and related stakeholder interests are shown in the table below:

Stakeholders	Stakeholder Needs	Stakeholder Interests	Stakeholder Perception of Planning Risks
NTPDL Corporation	Accurate external/internal information to set policy	Achieve mission vision and corporate objectives	Financial loss due to sub-optimization of operations; brand value deterioration
NTPDL Employees	Safe and stable work environment; skills development	Long term productive relationship with employer	Employment instability; unsafe work environment
Shareholders	Stable rate of return	Safe long-term investment	Financial and political pitfalls
IESO (OPA)	Accurate load forecasting; meeting CDM targets for LTEP; accurate real-time information and market rule compliance by market participants	Comprehensive utility forecasting process; LDC delivery of CDM programs; LDC adherence to technical and communication protocols	Inaccurate information contribution to Regional planning processes; CDM targets not met; inaccurate or untimely information for market operations
HONI	Information to determine short, medium and long term local and regional infrastructure needs.	Coordination of transmission and distribution growth needs; LDC participation in Regional Planning	Inaccurate forecasts affecting resource commitments; Inaccurate information contribution to Regional planning processes
Generators	Stable market and ability to connect to distribution system	Clear rules and processes for connection	Distribution congestion affecting plant location and costs
Retailers	Reliable supply to customers; efficient business processes	Maximize contract revenues; customer relationship	Loss of revenue; loss of customers
Provincial Government	Efficient, low cost and reliable market	Reliable supply to stimulate growth and political goodwill	Localized negative political impact
OEB	Efficient, low cost and reliable market; regulatory compliance	Minimization of regulatory intervention	Regulatory intervention and political impact risks
ESA	Public electrical safety	Utility construction built to Reg. 22/04	Public safety risk if plant not built/maintained to code(s)
Municipalities(non-shareholders)	Reliable supply to customers	Consultations on activities within municipal boundaries; visual aesthetics	Supply/reliability shortfalls affecting their constituents
Residential Customer	Reliable supply and low rates	Aesthetics	Supply/reliability shortfalls; price concerns
Small Commercial	Reliable supply and low rates	Rate stabilization or reduction	Supply/reliability shortfalls; price concerns affecting business plans
Large Commercial/Industrial	Reliable supply and low rates	Rate stabilization or reduction	Supply/reliability shortfalls; price concerns affecting business plans

Table 46 – Stakeholder Needs, Interests and Perceptions

5.4b System forecast development 2020-2024

Newmarket area

It is expected that the operational and service requirements driving NTPDL's capital expenditures in this area will generally increase through the 2020 to 2024 planning window. NTPDL expects moderate load and customer growth in line with development plans that directly impact this area:

1. Ontario Places to Grow Act
2. York Region Official Plan (2016 Office consolidation)
3. Town of Newmarket Official Plan – Amendment #10(October 2016)

System renewal investments (end of life replacement) will ensure that customer service levels with respect to reliability are maintained. Condition monitoring (ACA studies) and performance analytics help direct preventive maintenance to specific at-risk equipment and extend further the safe reliable useful life of all equipment.

System Access investments will provide for new overhead plant along the Yonge St. corridor due to road widening and Metrolinx Rail Electrification efforts. The undergrounding of these major arterial streets has been identified as a desirable outcome by the Region/Municipality however any such activity would be subject to Region/Municipal cost recovery mechanisms outside of rate base.

Smart grid investments will be pursued where prudent and prioritized (i.e. automation of 44kV switches).

The accommodation of renewable energy generation projects is not expected to drive any significant system developments over the next five years.

Midland-Tay area

It is expected that the operational and service requirements driving capital expenditures in this area will generally remain consistent through the 2018 to 2022 planning window. NTPDL expects low load and customer growth in line with development plans that directly impact this area:

1. Ontario Places to Grow Act
2. Town of Midland Strategic Plan (2016)
3. Town of Midland Official Plan (2017)

System Access investments will provide for new customer connections over the period of the DSP. This will be accommodated through existing infrastructure.

System Renewal investments (end of life replacement) will ensure that customer service levels with respect to reliability are maintained. Inspection and performance analytics help direct preventive maintenance to specific at-risk equipment and extend further the safe reliable useful life of all equipment.

There are no material System Access investments over the period of the DSP. Smart grid investments will be pursued where prudent and prioritized. At this time there are no plans to increase the present level of automation (i.e. overhead switch automation) in the distribution system. The accommodation of renewable energy generation projects is not expected to drive any significant system developments over the next five years.

5.4.1 Capital expenditure planning process overview

5.4.1a Analytical tools and methods used for Risk management

System Reliability

NTPDL's SCADA system and Outage Tracking data base provide information on outages and are instrumental in the preparation of outage reports that are used to aid in reliability risk management. NTPDL manages reliability risk through these reports and the investment planning process.

System Reliability - Distribution System Contingencies

Contingency Plans are required to deal with asset risk related to events that affects the proper functioning of the distribution system. Contingency planning deals with potential high-impact/low-probability (HILP) events that can have major repercussions on the distribution system and NTPDL customers. This will mostly apply to critical assets such as distribution station transformers and 44kV feeders. All other events, that are generally regular occurrences, low-impact/low-scope and have established processes to deal with them, are not detailed here. The HILP events considered here are shown in the Table 47 below:

Asset Class	Contingency Event	Contingency Plan
DS Power Transformers	Transformer failure requiring off-site servicing	1. Spare Transformer 2. Storage location for spare 3. Plans to move spare to affected DS
DS Circuit breaker or reclosers	Circuit breaker failure	1. Spares – Critical parts list 2. Contact plan for manufacturer repair support 3. Feeder emergency loading capability 4. Ties to alternate DS supplies
DS Feeder cables	Failure of one or more underground cables	1. Spare cable reel 2. Ties to alternate DS supplies
DS RTU	Failure of RTU leading to loss of station control	1. Standby staff to man station 2. Contact plan for manufacturer repair support
Station Protective Devices	Device failure leading to full/partial loss of station	1. Spare – Critical Parts list 2. Ties to alternate DS supplies
Poles/conductors	Loss of high number of pole structures through high impact event (severe weather, etc.)	1. Stock poles/conductors 2. Supplier stock 3. Neighbouring LDC stock

Table 47 – Contingency events and plans

In all cases if available contingency measures prove insufficient, load shedding may be required to ensure equipment is not loaded beyond approved tolerances.

Cyber-Security

NTPDL is committed to ensuring its systems are secure and to preserving the privacy of its customers. During the forecast period, a continued investment in hardware, software, services and training will enable NTPDL to fully comply with the requirements under the Ontario Energy Board Cyber Security Framework, as well as to further enhance its overall security posture.

In addition, on an annual basis, NTPDL undergoes 3rd party assessments of its privacy and information technology and operational technology environments. Multiple layered systems and processes are in place to identify, protect and detect cyber security and privacy events/incidents.

Climate Change Adaptation

Climate change is expected to increase the risk and frequency of severe weather events that can impact system reliability.

NTPDL's distribution system is expected to be primarily impacted by severe changing weather conditions related to:

1. Temperature
2. Heavy Rain/Flooding
3. High Wind velocity/Wind gusts
4. Tornadoes
5. Freezing Rain > 25mm

Climate change projections show primarily increased probabilities of occurrence (return times) in the categories listed above. Magnitude of events experienced may increase slightly.

There are two key concepts related to improving the performance of electrical distribution systems in severe weather situations: hardening and resiliency. Hardening deals with physical changes to make particular pieces of infrastructure less susceptible to severe weather-related damage. Resiliency deals with increasing the ability to recover quickly from damage to distribution infrastructure components or to any of the external systems on which they depend.

At this time NTPDL does not have any investments targeted to specifically address climate change. Some investments have added collateral value with respect to climate change risks. NTPDL has invested in concrete and composite poles for the Davis Drive and Yonge St. pole relocation works. These types of poles are considered to be "hardened" against severe weather events as compared to standard poles. NTPDL also ensured that all rail crossing rebuilds for the Metrolinx Rail Electrification project were made underground to mitigate the effect of severe weather (i.e. wind storms, icing, etc.)

5.4.1b Processes, tools and methods used to identify, select, prioritize and pace projects in each investment category

Project Identification

The projects that NTPDL selects for its capital budget are the ones that are required to ensure the safety, efficiency, and reliability of its distribution system to allow NTPDL to carry out its obligation to distribute electricity within its service area as defined by the Distribution System Code.

System Access projects such as development and municipal plant pole relocation projects are identified throughout the year by external proponents. Most of these projects are mandatory in nature and are budgeted and scheduled to meet the timing needs of the external proponents.

System renewal projects are mostly non-mandatory in nature and are identified through NTPDL's Asset Management process. The project needs for a particular period are supported by a combination of asset inspection, individual asset performance, and asset condition assessments.

System Service projects are non-mandatory in nature and are identified through NTPDL's Asset Management process and operational needs to ensure that any forecasted load changes that constrain the ability of the system to provide consistent service delivery are dealt with in a timely manner.

General plant projects, such as fleet vehicle acquisition or replacement, software/hardware, etc., are non-mandatory in nature and are identified internally by specific departments (engineering, finance, operations, administration, etc.) and supported through specific business cases for the particular need.

Project Selection and Prioritization

Mandatory projects are automatically selected and prioritized based on externally driven schedules and needs. Most System Access projects fall into this category and may involve multi-year investments to meet proponent needs. The Yonge St. VIVA projects are examples of this.

Non-mandatory projects are selected and reviewed by NTPDL staff for consideration of inclusion into the budget plan. Most System Renewal, System Service and General Plant projects fall into this category and some projects, such as System Renewal – Poles, may involve multi-year program investments to meet Asset Management objective needs. Projects that optimize system performance, costs and risks relevant to service delivery and can have sufficient resources allocated to them, are then considered for inclusion in the budget plan.

Reliability and safety are key considerations in project prioritization. In determining reliability priorities, NTPDL considers the following characteristics of its distribution system:

- Failure of one 44kV feeder line interrupts approximately 20 MVA of load
- Failure of a distribution station interrupts approximately 5 – 10 MVA of load
- Failure of a 13.8kV feeder line interrupts approximately 5 MVA of load
- Failure of one 8kV feeder line interrupts approximately 4 MVA of load
- Failure of one 4kV feeder line interrupts approximately 2 MVA of load
- Overhead lines take hours to repair while underground cables take days

In this sense, when prioritizing individual projects, 44 kV asset impacts will score relatively high in benefit and risk impact followed by distribution stations and 13.8 kV facilities.

Project Pace

Project pace for System Access projects is generally determined by external schedules and needs. System Service and General Plant projects tend to be lumpy in nature and most are paced to begin and complete within a particular budget year. System Renewal projects tend to be multi-year programs and are paced to balance the Asset Management objective needs of the particular program with regard to available resources and managing the program impacts on the customer's bill. In this sense program benefit and deferral risk are weighed against the ability of the customer to pay.

NTPDL's multi-year System Renewal programs have been prepared and paced based on ACA studies performed by Kinectrics and GIS data (Midland). The Kinectrics studies were used to determine discrete annual investments for the continued renewal of the distribution system. The ACA studies identify the type and quantity of assets (i.e. km of underground cable) that are expected to be proactively replaced due to end of life condition and provides a recommended and prioritized renewal investment profile. This recommended profile is used to guide multi-year capital investment requirements. In most cases NTPDL has adopted less than the annual replacement pace recommended in the ACA in order to mitigate rate impacts to customers. The multi-year programs cover the five-year period of the DSP. It is recognized that ACA replacement pace is a balance between increasing risk of asset failure and customer outage impacts/costs with the benefits of rate mitigation.

NTPDL is also considering the technical feasibility of employing life-extending techniques (i.e. cable injection) as a means of pacing renewal investments and mitigating risk and rate impacts.

All potential non-mandatory Capital projects in the System Renewal, System Service and General plant categories are reviewed by NTPDL staff for consideration of inclusion into the budget plan. Projects that optimize system performance, costs and risks relevant to service delivery and can have sufficient resources allocated to them, are then considered for inclusion in the budget plan. Project scopes, justifications and cost estimate are prepared for each project to aid in determining overall project effectiveness, benefit, and timing.

Investment selection considers how the investment aligns with NTPDL's weighted corporate and asset management goals.

Objective	Weight
Safety	0.25
Reliability	0.25
Customer Focus	0.20
Financial Integrity	0.20
Regulatory Compliance	0.10
Total	**1.00**

Table 48 – Objective weighting summary

Safety – This objective has been given the highest priority by NTPDL. "Safety first" comprises organizational efforts to ensure that worker and public safety is paramount in day to day activities and is explicitly ranked this way in the corporate strategy. It is recognized that some safety issues (i.e. live conductor on ground) require emergency remedial action (mandatory) and are not "planned investment" considerations. They are acted upon immediately and level of effort may impact other non-mandatory investments that would otherwise have had the resources (labour, funds) allocated to them. Other planned investments may impact long term safety and can be paced and prioritized where safety is just one of the Asset Management Objectives that is addressed by the investment. The Safety objective is assigned a weight of 0.25

Reliability – This objective, together with safety, is one of the two goals explicitly cited in NTPDL's Mission Statement. In customer surveys, it has ranked high in importance of customer needs. The Reliability objective is assigned a weight of 0.25

Customer Service – This objective ranks relatively high in ensuring that business outcomes meet the value needs of the customer. The Customer objective is assigned a weight of 0.2

Financial integrity - This objective is ranked equally with the previous objective. A stable rate of return, low electricity rates and ability to sustainably invest in distribution system access, service, renewal and general plant are key to the long-term success of this objective. Balancing of stakeholder interests in this area is an ongoing exercise. In customer surveys, low electricity rates ranked first in importance of customer needs. In consideration that NTPDL's controllable portion of the customer bill is less than 25%, the Financial integrity objective is assigned a weight of 0.2.

Regulatory Compliance – NTPDL is required to deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Ontario Energy Board). While obligations are mandated, the LDC does exercise some control over pace and level of annual effort depending (i.e. CDM obligations) on the issues at hand that can affect investment timing. The Regulatory Compliance objective is assigned a weight of 0.1.

5.4.1c Methods and criteria used to prioritize REG investments

The prioritization process for REG expansions is the same as for distribution system expansion projects where the REG expansion is triggered and driven by customer requirements.

When NTPDL is required to do an expansion or enhancement to the distribution system to connect an embedded generation facility, the provisions of the OEB DSC Section 3.2 will apply. NTDPL will perform an economic evaluation to determine the generator's share of the present value of the projected capital costs and ongoing maintenance costs of the expansion. NTDPL assumes that future revenue and avoided costs will be zero.

NTPDL does not plan to connect any NTPDL owned renewable generation during the period covered by the DSP.

5.4.1d NTPDL policy and procedure on incorporating non-distribution system alternatives

NTPDL does not have any specific policy or procedure related to utilizing non-distribution system alternatives for system capacity or operational constraint relief.

The amount of proposed renewable energy generation during the period of the DSP does not offer any significant capacity or operational constraint relief to NTPDL's distribution system.

NTPDL is also participating in an IESO funded project to investigate the use of battery storage on distribution grid operations. 2 x 2 MW, 4-hour "Battery Solid" energy storage systems have been connected to Newmarket Hydro's distribution grid, absorbing power during periods of excess energy supply and providing it back to the grid when energy demand is high.

NTPDL actively participates in the Regional Planning process to identify any system capacity or operational constraint relief that can be achieved through cooperative planning and program execution with regional distributors and transmitters.

NTPDL notes that non-distribution investments to relieve capacity or operational constraints need to be optimal solutions. The solution must be optimal with respect to the uncertainty of future system loading. The non-distribution system investments need to ensure that distribution system investments can deferred by a specific time period with certainty. Future uncertainties about local distribution capacity demand need to be factored into the value of the non-distribution system investment.

5.4.1e System Planning – opportunistic modernization of the distribution system

New station relays

Replacement of electro-mechanical relays with electronic relays at substations and utilization of fibre communication media will improve command, control and communication of the distribution grid and have a positive impact on improving outage restoration times thereby mitigating customer outage costs.

Fibre communications

In June 2018, the Town of Newmarket launched Envi Network, a municipally-owned Internet service provider through Newmarket Hydro Holding, with a mission to build a local fibre-optic broadband network to service businesses and, eventually, residential customers. NTPDL will be utilizing this fibre for SCADA communication with the DS stations.

Cluster 6

The project is organized into three major task areas: creating a roadmap for an LDC to become a fully integrated network operator, ensuring local market readiness, and deployment of a cloud-based platform to allow for transactions.

Powerconsumer and Newmarket-Tay Power have been engaging customers since December 2018 to socialize the concept of a local energy market and gauge interest for participation. Many industrial, commercial, and institutional customers are interested in operating in a way that is more integrated with the distribution system and have expressed interest in this project. Next key steps include quantifying the economic potential for DER integration for Newmarket-Tay Power and its customers and the development of a transaction standard between an LDC and its customers.

Rail Crossing undergrounding

Metrolinx plans to electrify core areas of the GO Transit rail network including the Toronto-Barrie line which runs through Newmarket. Most rail crossings will be rebuilt (bridges or tunnels) requiring NTPDL to remove all overhead rail crossings and relocate them underground. Cost for this will be borne by Metrolinx.

Energy Storage

The IESO Energy Storage procurement process was implemented to better understand how energy storage projects can be integrated and operated in the Ontario market. Nine energy storage projects totalling 16.75 megawatts (MW) are currently under development. One of the energy storage projects is being led by Ameresco Canada Inc.

Ameresco has built 2 x 2 MW, 4-hour “Battery Solid” energy storage system facilities and connected them to Newmarket Hydro’s distribution grid, to absorb power during periods of excess energy supply and provide it back to the grid when energy demand is high. In addition to providing this basic “peak shaving” function this system will also provide on-going grid reliability and stability as more renewable energy comes on-line in the area.

Enhanced Customer Services

NTPDL has undertaken a collaborative project with the Town of Newmarket and York Region Transit to deploy an overhead high-power charger within a major transit area to facilitate the use of zero-emission battery buses in support of Town and Province’s efforts to reduce greenhouse gas emissions. This is the first utility-transit cooperative venture in Ontario. The high-power charger allows for on-route opportunity charging of zero-emission battery buses. The project has been co-funded by NRCan to demonstrate Electric Vehicle Infrastructure deployment under the Energy Innovation Program. The charger and buses were deployed in 2020.

5.4.1f Distribution rate funded CDM programs

5.4.1.1 Rate-funded Activities to Defer Distribution Infrastructure

Proposed distribution rate funded programs may consist of:

1. CDM programs that target peak demand (kW) reductions to address a local constraint of NTPDL’s distribution system.
2. Demand response programs whose primary purpose is peak demand reduction in order to defer capital investment for specific NTPDL distribution infrastructure.
3. Programs to improve the efficiency of the distribution system and reduce distribution losses. (ie. re-conductor to larger size, voltage conversion, etc.)
4. Energy storage programs whose primary purpose is to defer specific capital spending for the NTPDL distribution system

5.4.1.1a CDM programs to target peak demand (kW) reduction

There are no rate-funded programs to target peak demand reduction.

5.4.1.1b Demand Response programs to defer distributions infrastructure

There are no rate-funded demand response programs to defer distribution infrastructure.

5.4.1.1c Programs to improve the efficiency of the distribution system

System losses and asset utilization are within guidelines. There are no specific rate-funded programs to improve the efficiency of the distribution system. Opportunistic improvements to distribution system efficiency, in conjunction with other investment needs, are considered on a case by case basis.

5.4.1.1d Energy Storage programs to defer capital spending

There are no rate-funded energy storage programs to defer capital spending

5.4.2 Capital Expenditure Summary

The Capital Expenditure Summary provides a ‘snapshot’ of NTPDL’s capital expenditures over a 10-year period, including five historical years and five forecast years.

For ‘summary’ purposes the entire costs of individual projects or activities are allocated to one of four investment categories on the basis of the primary (i.e. initial or ‘trigger’) driver of the investment. The investment categories are:

1. System Access
2. System Renewal
3. System Services
4. General Plant

For material projects, costs are allocated to the relevant investment categories.

Brief explanatory notes are provided to explain the factor(s) and/or circumstances underlying marked changes in the share of total investment represented by a given investment category over the forecast period relative to ‘actual’ spending over the historical period.

Explanatory notes for year over year ‘Plan vs. Actual’ variances for individual investment categories are provided where:

- for any given year “Total” ‘Plan’ vs. ‘Actual’ variances over the historical period are markedly positive or negative; or
- a trend for variances in a given investment category is markedly positive or negative over the historical period.

OEB Filing Requirements Chapter 2 - Appendix 2-AA
Capital Projects Table

Projects	2015	2016	2017	2018	2019 Bridge Year	2020 Test Year
Reporting Basis						
SYSTEM ACCESS						
Residential Additions	535	551	607	118	907	338
VIVA Yonge St. Relocation	80	1,945	1,013	44	-734	
Metering	154	183	276	128	58	610
Metrolinx Rail Electrification	0	0	0	0	411	0
CN Rail - Signal Light Additions	0	0	228	0	0	0
Miscellaneous Service Upgrades	54	47	19	0	6	0
Pole Relocation - Park Ave	0	0	0	102	0	0
Srigley Street Rebuild	98	3	0	0	0	0
VIVA Davis Dr. Relocation	22	74	0	0	0	0
Yonge St. – Davis to Green Lane	0	0	0	0	83	0
Commercial/Industrial Additions	128	2	75	27	14	150
Electric Bus Charger Project	0	0	0	41	-185	229
Sub-Total	1,070	2,806	2,218	460	561	1,327
SYSTEM RENEWAL						
Planned Transformer Replacements	644	264	363	201	297	1,032
Planned Pole Replacements	205	81	104	105	271	218
Unplanned Pole Replacements	122	58	80	51	49	0
Switch Replacements	46	6	26	132	127	151
Poleline Rebuild - Hwy 12	0	0	0	0	281	0
Miscellaneous O/H Upgrades	146	27	72	31	82	35
Miscellaneous U/G Upgrades	153	0	33	0	0	28
Walter and Sheldon Rebuild	150	0	0	0	0	0
Poleline Rebuild - Huron Heights	0	0	0	0	102	32
Poleline Rebuild - Lindsay	0	0	0	80	0	0
King St. Pole Line Upgrade (Elizabeth to Yonge)	0	103	0	0	0	0
King St. Pole Line Upgrade (Galloway to Robert)	0	124	0	0	0	0
Sixth Street Poleline Upgrade - Victoria to Hugel	0	0	122	0	0	0
Bayshore / Bay St. Poleline Relocation	0	0	194	0	0	0
Borsa Lane Pole Line - Bayshore to Easy St.	0	0	0	261	101	0
Bay St. Pole Line Upgrade	0	0	0	157	0	0
Thoms – primary cable replacement	0	0	0	0	0	0
William Roe – primary cable replacement	0	0	0	0	0	0
Hodgson – primary cable replacement	0	0	0	0	0	0
Sandford – primary cable replacement	0	0	0	0	0	0
Poleline Rebuild - Hillview	0	0	0	0	0	127
Poleline Rebuild - Bogart	0	0	0	0	0	75
Poleline Rebuild - Simcoe & Talbot	0	0	0	0	0	101
Glen Eagles Cres – primary cable replacement	0	0	0	0	0	330
Glen Mhor Cres – primary cable replacement	0	0	0	0	0	282
Substation Renewal/Repairs	0	0	0	0	0	307
DS Power Transformer Replacement	0	0	0	0	0	800
Sub-Total	1,468	664	994	1,017	1,310	3,518
SYSTEM SERVICE						
New Substation Lands – Davis Dr.	1,675	0	0	0	0	0
Miscellaneous Substation Upgrades	185	103	7	122	128	0
Feeder tie - Davis Dr	0	0	0	0	0	0
Sub-Total	1,859	103	7	122	128	0
GENERAL PLANT						
Holland TS 5 Year True Up	8,180	0	0	0	0	0
Leasehold Improvements	231	75	740	509	259	340
Miscellaneous Computer Software	124	78	315	101	124	300
Miscellaneous Computer Hardware	71	50	146	230	178	360
New Vehicles and Fleet	120	311	654	32	9	1,034
Financial Management System upgrade	0	0	222	0	0	0
CIS upgrade	0	0	145	0	0	0
Sub-Total	8,725	513	2,222	872	570	2,034
Miscellaneous	400	190	711	383	511	232
Total	**13,522**	**4,277**	**6,153**	**2,854**	**3,080**	**7,111**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*						
Total	**13,522**	**4,277**	**6,153**	**2,854**	**3,080**	**7,111**

Table 49 –2015 – 2020 Key Material Capital Projects

OEB Filing Requirements Chapter 2 – Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

Category	Historical (previous plan and actual)															Forecast (Planned)				
	2015			2016			2017			2018			2019			2020	2021	2022	2023	2024
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var					
	$'000	$'000	%	$'000	$'000	%	$'000	$'000	%	$'000	$'000	%	$'000	$'000	%	$'000	$'000	$'000	$'000	$'000
System Access	1253	1146	-8.5	2290	2782	21.5	2423	2591	6.9	3162	554	-82.5	1249	617	-50.5	1327	1795	2595	2477	1084
System Renewal	1716	1682	-2.0	1026	858	-16.4	1798	1249	-30.5	1188	1238	4.3	2010	1617	-19.5	3695	2861	3211	3025	2829
System Service	1884	1948	3.4	52	103	99.5	30	13	-57.5	197	134	-32.0	1019	133	-86.9	0	920	830	560	700
General Plant	584	8746	1398.1	795	532	-33.0	1034	2300	122.5	166	927	460.1	543	711	30.9	2089	7895	1375	1465	1725
Total	5437	13522	148.7	4162	4276	2.7	5285	6152	16.4	4711	2853	-39.4	4820	3079	-36.1	7111	13472	8011	7528	6338
System O&M	3220	3652	13.4	3369	3979	18.1	3374	3949	17.0	3453	4501	30.4	3496	4485	28.2	4543	4670	4511	4735	4834

Capital Expenditure Summary

Explanatory Notes on Variances

Notes on shifts in forecast vs. historical budgets by category – Increased emphasis on System Renewal in forecast to ensure existing reliability level are maintained; high General Plant expenditure in 2021 due to capital contribution to HONI for Holland TS

Notes on year over year Plan vs. Actual variances for Total Expenditures – high actual in 2015 due to capital contribution to HONI for Holland TS; higher General Plant expenditures in 2017 due to fleet and leasehold improvement; lower than expected System Access costs in 2018 and 2019

Notes on Plan vs. Actual variance trends for individual expenditure categories – System Access expenditures subject primarily to Region schedule changes for road widening; other category variances impacted (higher/lower) by annual System Access spending and available resource allocation

Table 50 – Capital Expenditure Summary

5.4.3 Justifying Capital Expenditures

NTPDL's DSP delivers value to customers by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures.

5.4.3.1 Overall Plan

NTPDL's DSP is a portfolio of investments allocated across the four investment categories.

5.4.3.1a Comparative expenditures by category 2015 – 2019

The comparative expenditures by category over the historical period are shown in Table 50 in section 5.4.2 and in the following charts as percentages.

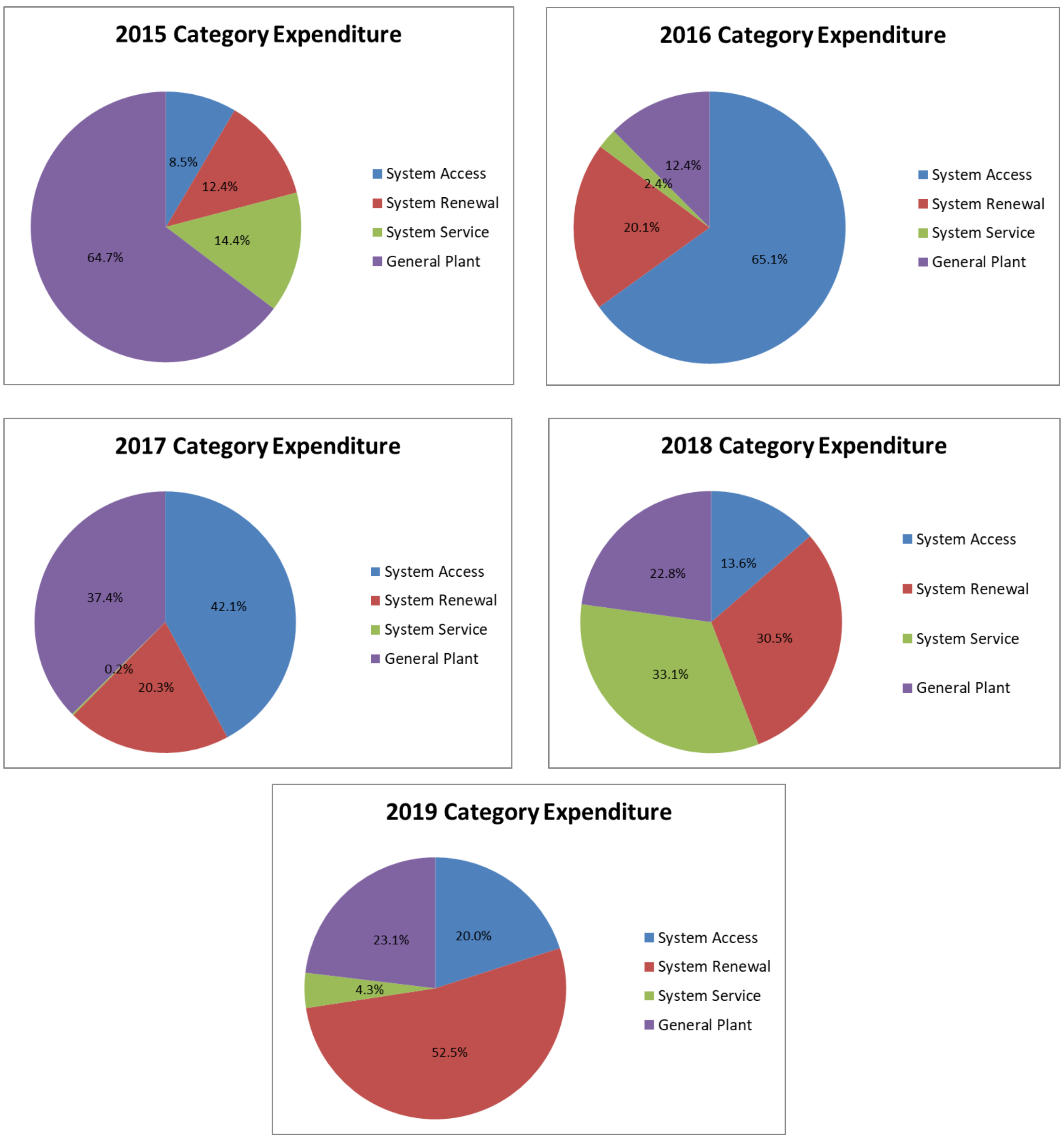

Figure 21 – 2015 – 2019 Capital Expenditure Charts

Historical spending and variance explanation by category is given below:

System Access

NTPDL's System Access investments are driven by others. NTPDL is obligated to connect new load and new renewable generation. NTPDL uses an economic evaluation methodology prescribed in the DSC to determine the level, if any, of capital contributions for each project with such levels incorporated into the annual capital budget. The scheduling of investments needs is usually coordinated to meet the needs of third parties.

NTPDL is also required to respond to the road authorities by obligations under the *Public Service Works on Highways Act.* The Act prescribes a formula for the apportionment of costs that allows for the road authority to contribute 50% of the "cost of labour and labour saving devices" towards the relocation costs.

The level of System Access expenditures in each of 2015 to 2019 historical years has varied between $0.6M and $2.8M.

- 2015 actuals were $1,146,000.
- 2016 actuals were $2,782,000. The significant increase from 2015 primarily due to poleline relocation work required for the VIVA bus rapidway along Yonge St.
- 2017 actuals were $2,591,000. The continued high level of spend in 2016 was primarily due to continued poleline relocation work required for the VIVA bus rapidway project along Yonge St.
- 2018 actuals were $554,000. The significant drop in spending was primarily due to substantial completion of the Yonge St. road reconstruction work south of Davis Dr. and scheduling delays in the commencement of the Yonge St. road widening project north of Davis Drive.
- 2019 actuals were $617,000. The increase from 2018 of $63,000 was primarily due to increased customer addition costs and the start of the Metrolinx Rail Electrification works

In 2016 through 2017, the VIVA Rapid Transit work along Yonge St. in Newmarket was a major undertaking requiring considerable relocation of NTPDL plant and allocation of associated resources.

Key material project multiyear spending is shown in the table below:

Category	Project Name	2015 $'000	2016 $'000	2017 $'000	2018 $'000	2019 $'000
System Access	Residential Additions	535	551	607	118	907
	VIVA Yonge St. Relocation	80	1,945	1,013	44	-734
	Metering	154	183	276	128	58
	Metrolinx Rail Electrification	0	0	0	0	411
	CN Rail - Signal Light Additions	0	0	228	0	0
	Pole Relocation - Park Ave	0	0	0	102	0
	Commercial/Industrial Additions	128	2	75	27	14

Table 51 – Historical spending - Key System Access Projects

System Renewal

System renewal is a mix of non-mandatory (planned end of life replacement) and mandatory (emergency replacement) investments. Non-mandatory investments are identified in the Asset Management Plan, prioritized and scheduled.

The level of system renewal expenditures in each of 2015 to 2019 historical years has varied between $0.9M and $1.7M.

- 2015 actuals were $1,682,000.
- 2016 actuals were $858,000. The decrease from 2015 was primarily due to the reallocation of resources (labour and material) to the poleline relocation work required for the VIVA bus rapidway project along Yonge St.
- 2017 actuals were $1,249,000. Similar to 2016, level of spend was less than budgeted primarily due to the continued poleline relocation work required for the VIVA bus rapidway project along Yonge St.
- 2018 actuals were $1,238,000. Level of spend was maintained at previous year spends to accommodate forecast System Access spend.
- 2019 actuals were $1,617,000. The increase from 2018 of $379,000 was primarily due to less anticipated System Access work allowing for resources to be reallocated.

Key material project multiyear spending is shown in the table below:

Category	Project Name	2015 $'000	2016 $'000	2017 $'000	2018 $'000	2019 $'000
System Renewal	Planned Transformer Replacements	644	264	363	201	297
	Planned Pole Replacements	205	81	104	105	271
	Unplanned Pole Replacements	122	58	80	51	49
	Switch Replacements	46	6	26	132	127
	Poleline Rebuild - Hwy 12	0	0	0	0	281
	Miscellaneous O/H Upgrades	146	27	72	31	82
	Miscellaneous U/G Upgrades	153	0	33	0	0
	Walter and Sheldon Rebuild	150	0	0	0	0
	Poleline Rebuild - Huron Heights	0	0	0	0	102
	King St. Pole Line Upgrade (Elizabeth to Yonge)	0	103	0	0	0
	King St. Pole Line Upgrade (Galloway to Robert)	0	124	0	0	0
	Sixth Street Poleline Upgrade - Victoria to Hugel	0	0	122	0	0
	Bayshore / Bay St. Poleline Relocation	0	0	194	0	0
	Borsa Lane Pole Line - Bayshore to Easy St.	0	0	0	261	101
	Bay St. Pole Line Upgrade	0	0	0	157	0

Table 52 – Historical spending - Key System Renewal Projects

System Service

System Service investments are non-mandatory investments to provide for consistent service delivery and to meet operational objectives. These investments are required to support the expansion, operation and reliability of the distribution system.

The level of system service expenditures in each of 2015 to 2019 historical years has varied between $0.01M and $1.9M.

- 2015 actuals were $1,948,000. Property purchase for a future substation on Davis Dr. was the significant system service expenditure.
- 2016 actuals were $103,000. The decrease from 2015 was primarily due to completion of the Davis Dr. substation land purchase.
- 2017 actuals were $13,000. The decrease from 2016 was primarily due to limited expenditures in this category limited to the SCADA system.
- 2018 actuals were $134,000. Similar to 2017, expenditures in this category were limited primarily to minor station upgrade work.
- 2019 actuals were $133,000. Similar spend and needs to 2018.

Key material project multiyear spending is shown in the table below:

Category	Project Name	2015 $'000	2016 $'000	2017 $'000	2018 $'000	2019 $'000
System Service	New Substation Lands – Davis Dr.	1,675	0	0	0	0
	Miscellaneous Substation Upgrades	185	103	7	122	128

Table 53 – Historical spending - Key System Service Projects

General Plant

General Plant investments are non-mandatory investments, not part of its distribution system (e.g. fleet, tools, land, etc.). Investments in this category are driven by operational and business needs to achieve a safe workplace, enhance employee work environments and satisfaction, increase efficiencies and productivity, and enhance customer service and value.

The level of general plant expenditures in each of 2015 to 2019 historical years has varied between $0.5M and $8.7M.

- 2015 actuals were $8,746,000. The majority of this expenditure was an $8.2M capital contribution to HONI for Holland TS.
- 2016 actuals were $532,000. Similar level of spend to 2015 (discounting the capital contribution to HONI).
- 2017 actuals were $2,300,000. The increase from 2015 and 2016 was primarily due to expenditures related to major fleet vehicles, leasehold improvements and computer hardware and software.
- 2018 actuals were $927,000. Spending in 2018 was primarily focused on leasehold improvements for the Newmarket facility.
- 2019 actuals were $711,000. The decrease from 2018 of $216,000 was primarily due to reduced leasehold improvement and computer hardware expenses.

Key material investment multiyear spending is shown in the table below:

Category	Project Name	2015 $'000	2016 $'000	2017 $'000	2018 $'000	2019 $'000
General Plant	Holland TS 5 Year True Up	8,180	0	0	0	0
	Leasehold Improvements	231	75	740	509	259
	Miscellaneous Computer Software	124	78	315	101	124
	Miscellaneous Computer Hardware	71	50	146	230	178
	New Vehicles and Fleet	120	311	654	32	9
	Financial Management System upgrade	0	0	222	0	0
	CIS upgrade	0	0	145	0	0

Table 54 – Historical spending - Key General Plant investments

5.4.3.1b Impact of system investment on O&M costs 2020 – 2024

NTPDL's operations and maintenance strategy is, to the extent possible, to minimize reactive and emergency-type work through efficient operations and an effective planned maintenance program, including predictive and preventative actions. NTPDL's customer responsiveness and system reliability are monitored continually to ensure that its maintenance strategy is effective. This effort is coordinated with NTPDL's capital project work so that where maintenance programs have identified matters which require capital investments, NTPDL may adjust its capital spending priorities to address those matters.

System investments will result in:

- the addition of incremental plant (e.g. poles, switchgear, transformers, etc.);
- the relocation/replacement of existing plant (e.g. Yonge St. road widening, Metrolinx GO electrification);
- the replacement of end of life plant with new plant (e.g. cables, poles, transformers, etc.)
- new/replacement system support expenditures (e.g. fleet, software, etc.)

In general, incremental plant additions will be integrated into the Asset Management system and will require incremental resources for ongoing O&M purposes. This is expected to put upward pressure on O&M costs.

Forecast O&M costs for the 2020 – 2024 period are:

2020	2021	2022	2023	2024
$4,543,000	$4,670,000	4,511,000	4,735,000	$4,834,999

Table 55 – 2020 – 2024 O&M projections

Relocation/replacement of existing plant normally results in an asset being replaced with a similar one, so there would be little or no change to resources for ongoing O&M purposes (i.e. inspections still need to be carried out on a periodic basis as required per the Distribution system Code). There may be some slight life advantages when a working older piece of equipment is replaced with a newer one that would impact on O&M repair related charges. Overall, the plan system investments in this category are expected to put neutral pressure on O&M costs.

Replacement of end of life plant with new plant will still require the allocation of resources for ongoing O&M purposes. Repair would be the most significant O&M activity impacted by new plant. Certain assets, such as poles, offer few opportunities for repair related activities and generally require replacement when deemed at end of normal life or critically damaged. Other assets such as direct buried cable offer opportunities for repair related activities (e.g. splices) up to a point where further repairs are not warranted due to end of life conditions. In a few areas cable faults will not be repaired due to cable end of life. When faulted, the faulted cable section will be replaced, normally a section between two distribution transformers. For planned cable replacement in a subdivision, new primary cable installed in duct replaces direct buried primary cable and is expected to provide higher reliability and life. This will shift response activity for a cable failure from repair (O&M) to replacement (Capital). If assets approaching end of life are replaced at a rate that maintains equipment class average condition, then one would expect little or no change to O&M costs under no growth scenarios but would still see upward O&M cost pressure on positive growth scenarios (more cumulative assets to maintain each year). Replacement rates that improve equipment class average condition could result in lowering certain maintenance activities costs (e.g. pole testing, reactive repairs, etc.). Overall, this is expected to put downward pressure on O&M repair related costs.

System support expenditures (e.g. GIS, ACA studies) are expected to provide a better overall understanding of NTPDL's assets that will lead to more efficient and optimized design, maintenance and investment activities going forward. ACA studies have been conducted and data gaps have been identified. To improve the quality of data used in the ACA studies, increased data collection efforts (i.e. testing program for poles) will be required which will increase pressure on O&M costs. Collected data will be input into the GIS as attribute information for each piece of plant. Improved asset information will allow existing resources to partially compensate for growth related increases in O&M activities. Fleet replacement expenditures will result in reduced O&M for new units however this will be offset by increasing O&M of remaining units as they get older.

In summary, the system investments will result in some upward growth related and support related O&M pressures, downward repair related O&M pressures. Overall, the system investments are not expected to have a significant impact on total O&M costs in the forecast period.

Item	Growth impact on O&M	Relocate impact on O&M	Replace impact on O&M	Support impact on O&M
Poles	increase	neutral	neutral	increase
Cables	increase	N/A	decrease (repairs only)	neutral
UG Transformers	increase	N/A	neutral	neutral
UG Switchgear	increase	N/A	neutral	neutral
OH Transformers	increase	neutral	neutral	neutral
MS Transformers	increase	N/A	decrease (repairs only)	decrease
MS Circuit breakers	increase	N/A	decrease (repairs only)	decrease
Meters	increase	N/A	neutral	increase
Fleet	neutral	neutral	neutral	neutral

Table 56 – O&M impacts for significant assets

NTPDL's forecast O&M increases during the plan period are predicted to be approximately 1.6% per year.

5.4.3.1c Investment drivers

During the 2020 – 2024 period, NTPDL has three key drivers of its capital investment:

1. obligation to connect a customer in accordance with Section 28 of the Electricity Act, 1998, Section 7 of NTPDL's Electricity Distribution Licence and the Distribution System Code.
2. the Region road widening north of Davis Dr. which will result in significant relocation of NTPDL plant and allocation of available resources
3. planned system renewal spending to proactively replace plant at end of life in order to meet NTPDL's commitment to maintain a safe and reliable supply of electricity at prudent cost to its customers i.e. mitigate adverse bill impacts to customers.

The specific investments drivers for each category are described below:

<u>System Access</u>

- Customer service requests - continued development of the Town of Newmarket as an Urban Growth Centre requiring new customer connections (site redevelopment; subdivisions). Historical trend has seen decreasing investments due to economic conditions and build out of the Newmarket service area. Forecasts assume increased investment needs due to urban intensification (Newmarket area) and potential new subdivision development (Skyline in Tay)
- 3rd party infrastructure – Yonge St. road widening between Davis Dr. and Green Lane for Region purposes, will require significant plant relocation. Spending in this area will follow a similar pattern to the spending on the VIVAnext project along Yonge St. south of Davis Dr. during the historical period.

In summary, due to the forecast employment and population growth in the Town of Newmarket under the Places to Grow Act, System Access needs in the 2020 – 2024 period will continue to focus on new subdivision connections, connection upgrades due to site redevelopment, and plant relocation due to urbanization and intensification of the road network.

System Renewal

- Failure risk - multiyear planned cable and pole replacement programs that address assets in "very poor" and "poor" condition. Historical trend has seen decreasing investments due to resource reallocation to mandatory System Access investments related to third party plant relocations. Forecast investments will increase to ensure service reliability and customer satisfaction is maintained.
- High Performance risks - overhead line rebuilds. Historical investments have been based on sections of line that require complete rebuild (poles, conductors, insulators, etc.) as opposed to dispersed pole replacement works. Forecast investments will continue to target specific sections of line requiring complete rebuild.
- Emergency needs - emergency reactive replacement of distribution system assets (poles, transformers, switches, switchgear, cable, conductor, insulators, guys, anchors, etc.) due to unanticipated failure, storms, motor vehicle accidents, vandalism, etc.
- NTPDL conducted Asset Condition Assessments ("ACA") that informs the development of its DSPs. Although the ACAs indicate that NTPDL historically has underspent in replacing its end-of-life assets, NTPDL has been mindful of potential impacts on customers and has prudently balanced spending with a slight risk to maintaining customer service levels over the historical period. NTPDL's strategy is to gradually increase its replacement of end-of-life assets over two more DSP periods (over next ten years) rather than in one five-year period, to attain the required asset replacement levels of $10M average investment per year as informed by Asset Condition Assessments ("ACA") it conducted. Therefore, NTPDL limited its asset replacements and overall capital expenditure to a total of $42.5M over this 5-year DSP period 2020-2024, or an average of $8.5M per year, instead of $10M average investment per year as informed by the Asset Condition Assessments ("ACA"). In terms of bill impact of this $42.5M investment, a residential customer would see only a $1.25 increase on their monthly bill beginning in 2028. Table 57 shows annual DSP System Renewal asset replacements relative to the ACA and overall DSP Capital expenditure.

In summary, system renewal spending gradually increase to levels higher to that seen in the historical period. Historical period spending was constrained due to offsetting mandatory System Access spending and NTPDL's desire to manage risk while maintaining reasonable rates and spend. Specific high-performance risk areas will be prioritized during the 2020 – 2024 period to ensure that system reliability is maintained.

		2020	2021	2022	2023	2024	DSP 2020 - 2024 Total	DSP 2020 - 2024 Avg
Total Net Capital Investment		**$7.1M**	**$13.5M**	**$8.0M**	**$7.5M**	**$6.3M**	**$42.5M**	**$8.5M**

Asset Condition Assessment Summary		**2020**	**2021**	**2022**	**2023**	**2024**	**DSP 2020 - 2024 Total**	**DSP 2020 - 2024 Average**
Wood Pole Replacements	ACA	137	125	115	106	99	582	116
	Plan	48	80	80	80	80	368	74
Pad Transformer Replacements	ACA	124	115	109	104	101	553	111
	Plan	68	78	78	78	78	380	76
Pole Transformer Replacements	ACA	65	62	59	56	53	295	59
	Plan	0	25	25	25	25	100	20
Pad Switchgear Replacements	ACA	2	2	3	2	3	12	2.4
	Plan	2	2	3	2	3	12	2.4
Underground Primary Cables (circuit km)	ACA	22.2	22	21.7	21.2	21	108.1	21.6
	Plan	1.5	0.7	2.4	2.5	2.9	10.1	2.0
Substation Transformers	ACA	0	0	1	1	1	3	0.6
	Plan	1	1	1	1	0	4	0.8

Table 57 – System Renewal based on ACA relative to Overall Capital Investment

System Service

- System operational objectives – investments to maintain system reliability and efficiency of distribution stations. Historical investment needs related to station modifications have been relatively consistent and low. Forecast investment needs related to station modifications are expected to be of similar magnitude.

In summary, system service spending will continue to focus on maintaining station operational performance.

General Plant

- System Maintenance support – replacement of rolling stock; tools. Historical investments have resulted in specific rolling stock and tool replacement as required. Replacement of major fleet units tends to be a high lumpy cost in a particular investment year when compared to the replacement costs of small fleet units.
- Business Operations efficiency – Forecast investment will focus on annual spending supporting IT hardware and software assets.
- Non-system Physical plant – leasehold improvements. Forecast investments will focus on annual spending supporting leasehold and office asset needs.
- Capital Contribution to HONI – In 2021 NTPDL is required to provide a Capital Contribution of $6.1 million to HONI towards the construction and ongoing operation of Holland TS.

In summary, general plant spending will continue to focus on ensuring fleet asset performance meets NTPDL operational and reliability needs, and annual computer hardware/software enhancements to support business operations efficiency, adherence to OEB cybersecurity framework and improved customer service.

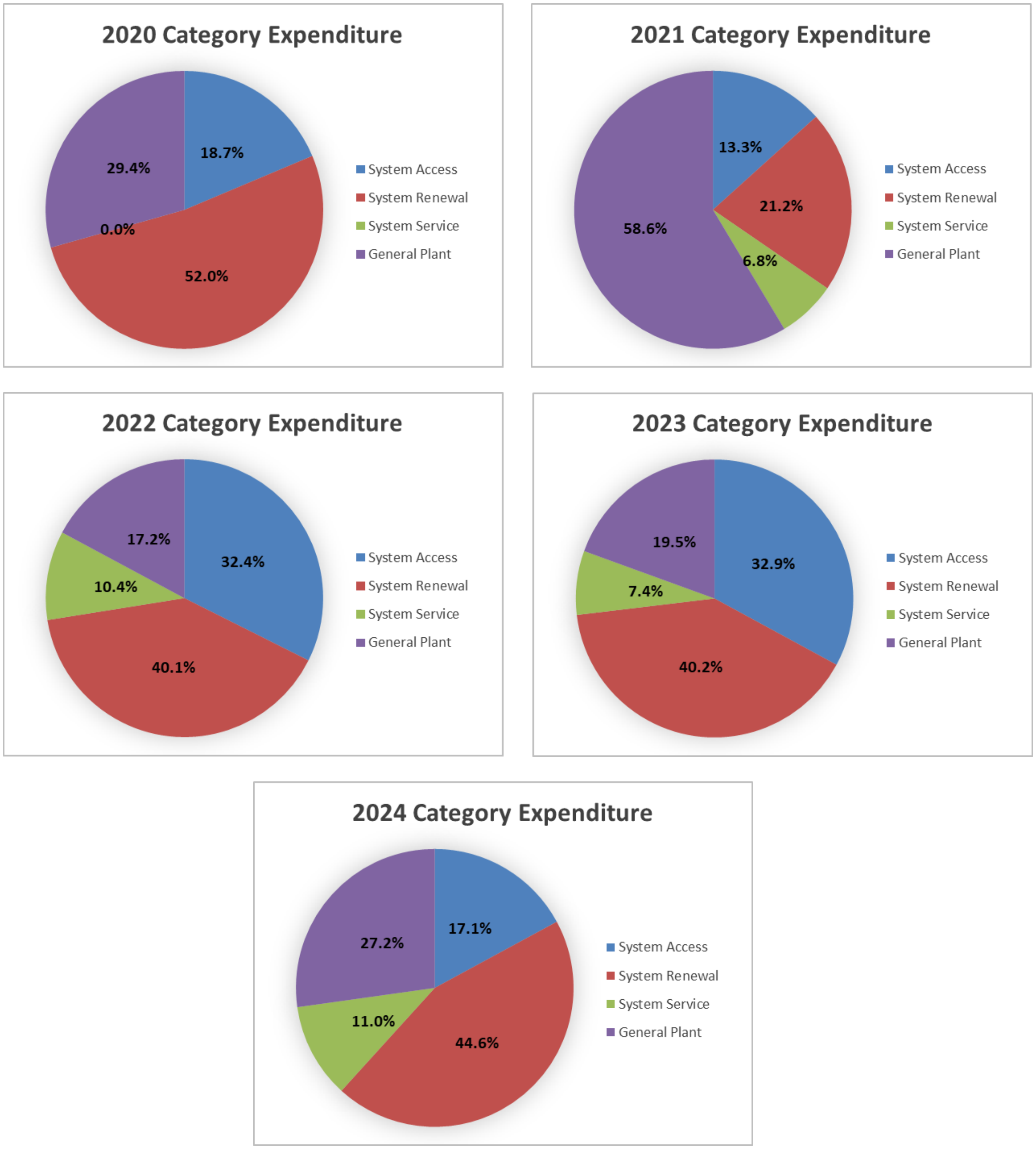

Figure 22 – 2020 – 2024 Capital Expenditure Charts

5.4.3.1d NTPDL capability assessment

There is sufficient capacity on the NTPDL distribution system to connect foreseeable DG needs over the investment period. It is not a significant driver for any of the four category expenditures.

5.4.3.2 Material Investments

This section lists the material projects by year from 2020 to 2024. The materiality threshold is calculated on the basis of 0.5% of Distribution Revenue Requirement.

The 2020 Distribution revenue requirement is $21,000,000, and as such the materiality threshold is calculated as being $105,000. NTPDL has chosen to report on all investments expected to cost $100,000 or more.

Category	Project Name	2020 $'000	2021 $'000	2022 $'000	2023 $'000	2024 $'000	TOTAL $'000
System Access	Residential Additions	338	351	351	351	351	1,742
	Commercial/Industrial Additions	379	150	150	150	150	979
	Metering	610	633	381	857	583	3,064
	Yonge St. - Davis to Green Lane Plant Relocation	0	661	1,713	1,120	0	3,494
System Renewal	Planned Pole Replacements	218	503	600	600	600	2,520
	Planned Padmount Transformer Replacements	1,032	835	473	473	473	3,285
	Planned Polemount Transformer Replacements	0	138	138	138	138	550
	Planned Padmount Switchgear Replacements	70	70	105	70	105	420
	Overhead Poleline Rebuilds	336	140	0	0	0	476
	Underground Cable Replacements	612	289	959	1,008	1,166	4,034
	Annual DS Upgrades/Repairs	308	38	148	38	38	568
	DS Power Transformer Replacements	800	500	500	500	0	2,300
System Service	Station System Service	0	650	500	500	500	2,150
	Overhead System Service	0	270	330	60	200	860
General Plant	Holland TS Capital Contribution	0	6,100	0	0	0	6,100
	Leasehold Improvements	340	350	150	150	150	1,140
	Replacement of Fleet Equipment	1,034	390	170	260	520	2,374
	IT Hardware and Software	660	1,000	1,000	1,000	1,000	4,660
Total		**6,736**	**13,066**	**7,666**	**7,273**	**5,973**	**40,714**

Table 58 – Material Capital Expenditures 2020 - 2024

All material projects have the following information provided:

A. General Information on the Project/Activity
B. Evaluation criteria for each project/activity
C. Category-specific information and analysis for each project/activity

A. General Information on the Project/Activity

1. total capital and where applicable, (non-capitalized) O&M costs proposed for recovery in rates
2. any capital contributions made or forecast to be made to a transmitter with respect to a Connection and Cost Recovery Agreement (CCRA).
3. related customer attachments and load, as applicable
4. start date, in-service date and expenditure timing over the planning horizon (2020 – 2024)
5. the risks to the completion of the project or activity as planned and the manner in which such risks will be mitigated
6. comparative information on expenditures for equivalent projects/activities over the historical period, where available
7. information on total capital and O&M costs associated with REG investment, if any, included in a project/activity; and a description of how the REG investment is expected to improve the system's ability to accommodate the connection of REG facilities

B. Evaluation criteria for each project/activity

Material investments are evaluated based on key regulatory outcomes as indicated below:

1. Efficiency, customer value and reliability
2. Safety
3. Cyber-security, privacy
4. Co-ordination, interoperability
5. Environmental benefits
6. Conservation and Demand Management

C. Category-specific information and analysis for each project/activity

1. System Access
2. System Renewal
3. System Service
4. General Plant

2020 - 2024 Material Projects

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Project Name:	**Annual Residential Customer Additions**		
Project #:	**11**		
Investment Category:	**System Access**		
Investment Type:	**Mandatory**		
Service Area:	**All**		
Start Date: January 1, 2020		**In Service Date: January 2020 – December 2024**	
Net Capital Cost: $1,741,750 (Gross – Contributed + OM&A)		**Gross Capital Cost:**	**$9,988,000**
		Contributed Capital:	**$8,246,250**
		OM&A Costs:	**$0**

Expenditure Timing: Annual	**Q1**	**Q2**	**Q3**	**Q4**
	$500,000	**$500,000**	**$500,000**	**$500,000**

A. General Information:

New residential customer additions – annual program

Year	# Units	Gross Capital	Contributed Capital	Net Capital
2020	**348**	**$1,924,000**	**$1,586,250**	**$337,750**
2021	**360**	**$2,016,000**	**$1,665,000**	**$351,000**
2022	**360**	**$2,016,000**	**$1,665,000**	**$351,000**
2023	**360**	**$2,016,000**	**$1,665,000**	**$351,000**
2024	**360**	**$2,016,000**	**$1,665,000**	**$351,000**

Risks to Completion and Risk Mitigation: Timing subject to Customer needs. Material and resources available.

Comparative Information on Equivalent Historical Projects (if any): This is an annual mandatory program.

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver**: Provide connection supply to new residential services
	Reliability Planning: N/A
	Priority: N/A – Regulatory requirement and mandatory project, driven by residential development. Connection coordinated with customer requirements.
	Investment effectiveness: Ensure compliance with Section 28 of the Electricity Act and customer satisfaction. Customers provides capital contribution amounts as per DSC.
Safety	Connection constructed according to Reg. 22/04 standards

Cyber Security, Privacy	N/A	
Co-ordination, Interoperability	N/A	
Environmental benefits	N/A	
Conservation and Demand Management	N/A	
C. Category-specific requirements: System Access		
Projects/activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system.		
Factors affecting the Timing/Priority of implementing the project		Mandatory; project timing coordinated with customer need to connect
Factors relating to Customer Preferences or input from customers and other third parties		Connection date subject to customer schedule.
Factors affecting the final cost of the project		Final cost is based upon actual number of residential services to be connected in 2020 – 2024 period.
How controllable costs have been minimized		Connection work coordinated with customer schedule; prudent cost estimates are based on standardized materials, unit rate construction contracts, and appropriate equipment sizing; residential connection quantity estimate based on historical connections and known applications for connection
Identify if other planning objectives (System Renewal, System Service, General Plant) are met by the project or have intentionally been combined into the project and if so, which objectives and why		-n/a
Project Design/Implementation Options Considered		-n/a
Option analysis (if applicable)		-project subject to economic evaluation per DSC
Results of Final Economic Valuation (if applicable)		-n/a
System Impacts (Nature, Magnitude and Costs)		-n/a
Other related information		-n/a

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Project Name:	**Annual Commercial/Industrial Customer Additions**
Category #:	**11**
Investment Category:	**System Access**
Investment Type:	**Mandatory**
Service Area:	**All**
Start Date: January 1, 2020	**In Service Date: January 2020 – December 2024**
Net Capital Cost: $979,298 (Gross – Contributed + OM&A)	**Gross Capital Cost:** $2,680,000
	Contributed Capital: $1,700,702
	OM&A Costs: $0

Expenditure Timing: Annual	**Q1**	**Q2**	**Q3**	**Q4**
	$134,000	**$134,000**	**$134,000**	**$134,000**

A. General Information:

New commercial/industrial customer additions – annual program

Year	# Units	Gross Capital	Contributed Capital	Net Capital
2020	10	$1,480,000	$1,100,702	$379,298
2021	6	$ 300,000	$ 150,000	$150,000
2022	6	$ 300,000	$ 150,000	$150,000
2023	6	$ 300,000	$ 150,000	$150,000
2024	6	$ 300,000	$ 150,000	$150,000

Risks to Completion and Risk Mitigation: Timing subject to Customer needs. Material and resources available.

Comparative Information on Equivalent Historical Projects (if any): This is an annual mandatory program.

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver**: Provide connection supply to new commercial/industrial services
	Reliability Planning: N/A
	Priority: N/A – Regulatory requirement and mandatory project, driven by commercial/industrial development. Connection coordinated with customer requirements.
	Investment effectiveness: Ensure compliance with Section 28 of the Electricity Act and customer satisfaction. Customers do not require to contribute capital based economic evaluations per DSC.
Safety	Connection constructed according to Reg. 22/04 standards

Cyber Security, Privacy	N/A	
Co-ordination, Interoperability	N/A	
Environmental benefits	N/A	
Conservation and Demand Management	N/A	
C. Category-specific requirements: System Access		
Projects/activities in this category are driven by <u>statutory, regulatory or other obligations</u> on the part of the distributor to provide customers with access to their distribution system.		
Factors affecting the Timing/Priority of implementing the project		Mandatory; project timing coordinated with customer need to connect
Factors relating to Customer Preferences or input from customers and other third parties		Connection date subject to customer schedule.
Factors affecting the final cost of the project		Final cost is based upon actual number of commercial/industrial services to be connected in 2020 - 2024
How controllable costs have been minimized		Connection work coordinated with customer schedule; prudent cost estimates are based on standardized materials, unit rate construction contracts, and appropriate equipment sizing; commercial/industrial connection quantity estimate based on historical connections and known applications for connection
Identify if other planning objectives (System Renewal, System Service, General Plant) are met by the project or have intentionally been combined into the project and if so, which objectives and why		-n/a
Project Design/Implementation Options Considered		-n/a
Option analysis (if applicable)		-project subject to economic evaluation per DSC
Results of Final Economic Valuation (if applicable)		-n/a
System Impacts (Nature, Magnitude and Costs)		-n/a
Other related information		-n/a

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Project Name:	**Annual Metering Expenditures**
Category #:	**9**
Investment Category:	**System Access**
Investment Type:	**Mandatory**
Service Area:	**All**

Start Date: **January 1, 2020**		**In Service Date: January 2020 – December 2024**	
Net Capital Cost: **$3,064,000** (Gross – Contributed + OM&A)		**Gross Capital Cost:**	**$3,064,000**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing: Annual	**Q1**	**Q2**	**Q3**	**Q4**
	$153,000	**$153,000**	**$153,000**	**$153,000**

A. General Information:

Meter reverifications and metering for customer additions – annual program

Year	Net Capital
2020	$610,000
2021	$632,750
2022	$381,450
2023	$856,650
2024	$583,150

Risks to Completion and Risk Mitigation: Timing subject to Customer needs. Material and resources available.

Comparative Information on Equivalent Historical Projects (if any): This is an annual mandatory program.

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver**: Metering hardware for new and existing customers; system needs
	Reliability Planning: N/A
	Priority: N/A – Regulatory requirement and non-discretionary project, driven by development and regulatory needs. Schedule coordinated with customer requirements as applicable.
	Investment effectiveness: Ensure compliance with Section 28 of the Electricity Act and customer satisfaction.
Safety	Equipment meets Reg. 22/04 standards
Cyber Security, Privacy	N/A
Co-ordination,	

Interoperability	N/A
Environmental benefits	N/A
Conservation and Demand Management	N/A
C. Category-specific requirements: System Access	
Projects/activities in this category are driven by <u>statutory, regulatory or other obligations</u> on the part of the distributor to provide customers with access to their distribution system.	
Factors affecting the Timing/Priority of implementing the project	Mandatory; project timing coordinated with customer need to connect; other system timing needs
Factors relating to Customer Preferences or input from customers and other third parties	Connection date subject to customer schedule; other third-party requirements
Factors affecting the final cost of the project	Final cost is based upon actual cost of the construction, factors that can affect actual costs include: unexpected changes to scope, number of customer requests (anticipated vs. actual), and customer initiated changes, weather and/or field conditions.
How controllable costs have been minimized	Project coordinated with customer/third party schedule; prudent cost estimates are based on standardized materials, unit rate construction contracts, and appropriate equipment sizing
Identify if other planning objectives (System Renewal, System Service, General Plant) are met by the project or have intentionally been combined into the project and if so, which objectives and why	-n/a
Project Design/Implementation Options Considered	-n/a
Option analysis (if applicable)	-project subject to economic evaluation per DSC if applicable
Results of Final Economic Valuation (if applicable)	-n/a
System Impacts (Nature, Magnitude and Costs)	-n/a
Other related information	-n/a

Newmarket-Tay Power Distribution Ltd.
Capital Project

2021 - 2023

Project Name:	**Yonge St. – Davis Dr. to Green lane plant relocation**		
Project #:	**10**		
Investment Category:	**System Access**		
Investment Type:	**Mandatory**		
Service Area:	**Newmarket**		
Start Date:	**January 1, 2020**	**In Service Date:**	**December 31, 2022**
Net Capital Cost: **$3,494,609** (Gross – Contributed + OM&A)		**Gross Capital Cost:**	**$8,998,990**
		Contributed Capital:	**$5,504,381**
		OM&A Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$300,000	**$300,000**	**$300,000**	**$300,000**

A. General Information:

Construction costs for pole relocation due to Region road rebuilding project. Widening Yonge St from 4 to 6 lanes.

2021 net costs = $ 661,445
2022 net costs = $1,713,073
2023 net costs = $1,119,991

Risks to Completion and Risk Mitigation: Overall project timing subject to Region schedule.

Comparative Information on Equivalent Historical Projects (if any): This is a mandatory program requiring plant relocation due to road widening. Similar to previous pole relocation projects.

Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver**: to accommodate Region road rebuilding needs
	Priority: N/A – Regulatory requirement and mandatory project, driven by third party needs. Plant relocation coordinated with York Region.
	Investment effectiveness: Complies with mandated service requirements of DSC. Region/Town provides capital contribution amounts as per Public Service Works on Highways Act. Region/Town also pay for incremental non like-for-like enhancements
Safety	Relocated plant to be installed in accordance with CSA construction standards and in compliance with ESA Reg. 22/04
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	This work will be coordinated with Region schedule and plans.
Environmental benefits	N/A

Conservation and Demand Management	N/A
C. Category-specific requirements: System Access	
Projects/activities in this category are driven by statutory, regulatory or other obligations on the part of the distributor to provide customers with access to their distribution system.	
Factors affecting the Timing/Priority of implementing the project	Mandatory; project design parameters and timing coordinated with Region schedule
Factors relating to Customer Preferences or input from customers and other third parties	Pole relocation details subject to Region consultation.
Factors affecting the final cost of the project	Project cost determined by Region road design issues affecting pole relocation and construction grade required to accommodate safe and reliable installation.
How controllable costs have been minimized	Design to meet current CSA standards and to incorporate sufficient load carrying strength to minimize guying needs and property acquisition. Construction work coordinated with Region schedule; Region to provide capital contribution amounts as per Public Service Works on Highways Act. Region to pay incremental cost for non like-for-like relocation conditions (i.e. decorative concrete vs standard wood pole)
Identify if other planning objectives (System Renewal, System Service, General Plant) are met by the project or have intentionally been combined into the project and if so, which objectives and why	There may be some indirect system renewal benefit through replacement of old poles with new plant
Project Options Considered	-n/a
Summary of business case analysis (if applicable)	-n/a
Results of Final Economic Valuation (if applicable)	-n/a
System Impacts (Nature, Magnitude and Costs)	-n/a
Other related information	-n/a

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024				
Project Name:	**Planned Pole Replacement**			
Category #:	**1**			
Investment Category:	**System Renewal**			
Investment Type:	**Non-Mandatory**			
Service Area:	**All**			
Start Date:	**January 2020**	**In Service Date:**	**January 2020 - December 2024**	
Net Capital Cost: $2,520,000		**Gross Capital Cost:**	**$2,520,000**	
		Contributed Capital:	**$0**	
		OM&A Costs:	**$0**	
Expenditure Timing: Annual	**Q1 $126,000**	**Q2 $126,000**	**Q3 $126,000**	**Q4 $126,000**

A. General Information:

This is an annual program that covers the planned replacement of individual poles when it has been determined that they have reached end-of-life. End-of-life is determined through the inspection process and NTPDL's ACA program. Poleline rebuild projects cover multiple poles requiring replacement.

Year	# Units	Gross Capital	Contributed Capital	Net Capital
2020	29	$217,500	$0	$217,500
2021	67	$502,500	$0	$502,500
2022	80	$600,000	$0	$600,000
2023	80	$600,000	$0	$600,000
2024	80	$600,000	$0	$600,000

Risks to Completion and Risk Mitigation: NTPDL material and resources available.
Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory annual program. Related spending in previous years.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** This project is driven by the need to replace assets that have reached End-Of-Life status.
	Reliability Planning: Plant is replaced like-for-like or upgraded to as per plans for the area.
	Priority: 2020 – 2024 paced – Non-mandatory project
	Investment effectiveness: Plant is replaced like-for-like or upgraded to as per plans for the area.
Safety	Poles at End-Of-Life represent a safety hazard to staff and the public. EOL status generally implies that pole structural strength has decreased to levels below the

	minimum acceptable per CSA Standard for Overhead construction. Replacement of EOL plant restores the system to safe structural and operating condition
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Environmental benefits	N/A
Conservation and Demand Management	N/A
C. Category-specific requirements: System Renewal	
Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").	

Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure 1. Condition of Asset vs. Typical Life Cycle and Performance Record 2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure 3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level) 4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level) 5. Value of Customer Impact (high, medium, low)	1. Asset at EOL have reached the end of their life cycle. Future satisfactory performance in doubt. 2. Varies – pole failure may involve an entire feeder depending on location and protective device activated (i.e. lateral fuse or circuit breaker, etc.) 3. Pole failure could result in major interruption of 6-8 hours. 4. Reduced outages will improve customer satisfaction. 5. Customer surveys show that reliability is ranked high in value to them
Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects	NTPDL has the resources and materials in order to ensure project completion on time. Locates required from others.
Consequences for system O&M costs, including the implications for system O&M of not implementing the project	N/A – EOL equipment may fail unexpectantly and result in higher replacement costs (overtime, etc.) and higher outage costs to customers due to extended duration of unplanned outage
Impact on reliability and safety factors	New poles will be installed per CSA and 22/04 standards
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	N/A – deferral increases risk of unexpected failure; other alternatives (i.e. undergrounding) more expensive.

Analysis of Project Benefits and Cost for extra cost "like for like". (System Access, System Service, General Plant benefit) (if applicable)	Pole class and loading design may be upgraded to coincide with plans for the area.
Other related information	N/A

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Project Name:	**Planned Padmount Transformer Replacement**			
Category #:	**3**			
Investment Category:	**System Renewal**			
Investment Type:	**Non-Mandatory**			
Service Area:	**All**			
Start Date: January 2020		**In Service Date:** January 2020 - December 2024		
Net Capital Cost: $3,284,500		**Gross Capital Cost:**	**$3,284,500**	
		Contributed Capital:	**$0**	
		OM&A Costs:	**$0**	
Expenditure Timing: Annual	**Q1 $165,000**	**Q2 $165,000**	**Q3 $165,000**	**Q4 $165,000**

A. General Information:

This is an annual program that covers the planned replacement of padmount transformers when it has been determined that they have reached end-of-life. End-of-life is determined through the inspection process and NTPDL's ACA program.

Year	# of Pad Tx Purchases	# of Pad Tx Replacements	Net Capital
2020	184	68	$1,032,000
2021	68	78	$835,000
2022	53	78	$472,500
2023	53	78	$472,500
2024	53	78	$472,500

Risks to Completion and Risk Mitigation: NTPDL material and resources available.
Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory annual program. Related spending in previous years.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** This project is driven by the need to replace assets that have reached End-Of-Life status.
	Reliability Planning: Plant is replaced like-for-like or upgraded to as per plans for the area. Replaced plant may be resized to accommodate EV uptake in area.
	Priority: 2020 – 2024 paced – Non-mandatory project
	Investment effectiveness: Plant is replaced like-for-like or upgraded to as per plans for the area.
Safety	Padmount transformers at End-Of-Life represent a safety hazard to staff and the public. Replacement of EOL plant restores the system to safe operating condition

Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Environmental benefits	Proactive replacement eliminates potential impact of oil spill on the environment
Conservation and Demand Management	N/A
C. Category-specific requirements: System Renewal	
Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").	
Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure 1. Condition of Asset vs. Typical Life Cycle and Performance Record 2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure 3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level) 4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level) 5. Value of Customer Impact (high, med, low)	1. Asset at EOL have reached the end of their life cycle. Future satisfactory performance in doubt. 2. Varies – typically 6 – 8 customers per transformer 3. Transformer failure could result in customer interruption of 6-8 hours (remove, clean up, replace, restore). 4. Reduced outages will improve customer satisfaction. 5. Customer surveys show that reliability is ranked high in value to them
Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects	NTPDL has the resources and materials in order to ensure project completion on time.
Consequences for system O&M costs, including the implications for system O&M of not implementing the project	N/A – EOL equipment may fail unexpectantly and result in higher replacement costs (overtime, etc.) and higher outage costs to customers due to extended duration of unplanned outage
Impact on reliability and safety factors	New transformers built and installed per CSA and 22/04 standards
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	N/A – deferral increases risk of unexpected failure.
Analysis of Project Benefits and Cost for extra cost "like for like". (System Access, System Service, General Plant benefit) (if applicable)	Replaced plant may be resized to accommodate EV uptake in area.
Other related information	N/A

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 – 2024

Project Name:	**Planned Polemount Transformer Replacement**		
Category #:	**3**		
Investment Category:	**System Renewal**		
Investment Type:	**Non-Mandatory**		
Service Area:	**All**		
Start Date:	**January 2020**	**In Service Date:**	**January 2020 – December 2024**
Net Capital Cost: $550,000		**Gross Capital Cost:**	**$550,000**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing: Annual	**Q1**	**Q2**	**Q3**	**Q4**
	$27,500	**$27,500**	**$27,500**	**$27,500**

A. General Information:

This is an annual program that covers the planned replacement of polemount transformers when it has been determined that they have reached end-of-life. End-of-life is determined through the inspection process and NTPDL's ACA program.

Year	# of Pole Tx Purchases	# of Pole Tx Replacements	Net Capital
2020	0	0	$0
2021	25	25	$137,500
2022	25	25	$137,500
2023	25	25	$137,500
2024	25	25	$137,500

Risks to Completion and Risk Mitigation: NTPDL material and resources available.
Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory annual program. Related spending in previous years.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** This project is driven by the need to replace assets that have reached End-Of-Life status.
	Reliability Planning: Plant is replaced like-for-like or upgraded to as per plans for the area. Replaced plant may be resized to accommodate EV uptake in area.
	Priority: 2021 – 2024 paced – Non-mandatory project
	Investment effectiveness: Plant is replaced like-for-like or upgraded to as per plans for the area.
Safety	Polemount transformers at End-Of-Life represent a safety hazard to staff and the public. Replacement of EOL plant restores the system to safe operating condition

Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Environmental benefits	Proactive replacement eliminates potential impact of oil spill on the environment
Conservation and Demand Management	N/A
C. Category-specific requirements: System Renewal	
Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").	
Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure 1. Condition of Asset vs. Typical Life Cycle and Performance Record 2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure 3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level) 4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level) 5. Value of Customer Impact (high, med, low)	1. Asset at EOL have reached the end of their life cycle. Future satisfactory performance in doubt. 2. Varies – typically 6 – 8 customers per transformer 3. Transformer failure could result in customer interruption of 6-8 hours (remove, clean up, replace, restore). 4. Reduced outages will improve customer satisfaction. 5. Customer surveys show that reliability is ranked high in value to them
Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects	NTPDL has the resources and materials in order to ensure project completion on time.
Consequences for system O&M costs, including the implications for system O&M of not implementing the project	N/A – EOL equipment may fail unexpectantly and result in higher replacement costs (overtime, etc.) and higher outage costs to customers due to extended duration of unplanned outage
Impact on reliability and safety factors	New transformers built and installed per CSA and 22/04 standards
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	N/A – deferral increases risk of unexpected failure.
Analysis of Project Benefits and Cost for extra cost "like for like". (System Access, System Service, General Plant benefit) (if applicable)	Replaced plant may be resized to accommodate EV uptake in area.
Other related information	N/A

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Project Name:	**Planned Padmount Switchgear Replacement**		
Category #:	**3**		
Investment Category:	**System Renewal**		
Investment Type:	**Non-Mandatory**		
Service Area:	**Newmarket**		
Start Date:	**January 2020**	**In Service Date:**	**January 2020 - December 2024**
Net Capital Cost: $420,000		**Gross Capital Cost:**	**$420,000**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing: Annual	**Q1**	**Q2**	**Q3**	**Q4**
	$0	**$42,000**	**$42,000**	**$0**

A. General Information:

This is an annual program that covers the planned replacement of padmount switchgear when it has been determined that they have reached end-of-life. End-of-life is determined through the inspection process and NTPDL's ACA program.

Year	# Units	Net Capital
2020	2	$70,000
2021	2	$70,000
2022	3	$105,000
2023	2	$70,000
2024	3	$105,000

Risks to Completion and Risk Mitigation: NTPDL material and resources available.
Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory annual program. Related spending in previous years.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** This project is driven by the need to replace assets that have reached End-Of-Life status.
	Reliability Planning: Plant is replaced like-for-like.
	Priority: 2020 – 2024 paced – Non-mandatory project
	Investment effectiveness: Plant is replaced like-for-like.
Safety	Padmount switchgear at End-Of-Life represent a safety hazard to staff and the public. Replacement of EOL plant restores the system to safe operating condition
Cyber Security, Privacy	N/A
Co-ordination,	N/A

<table>
<tr><td>Interoperability</td><td colspan="2"></td></tr>
<tr><td>Environmental benefits</td><td colspan="2">Proactive replacement eliminates potential impact of oil spill (for oil filled switchgear) on the environment</td></tr>
<tr><td>Conservation and Demand Management</td><td colspan="2">N/A</td></tr>
<tr><td colspan="3">C. Category-specific requirements: System Renewal</td></tr>
<tr><td colspan="3">Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. “failure”).</td></tr>
<tr><td colspan="2">Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure
1. Condition of Asset vs. Typical Life Cycle and Performance Record
2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure
3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)
4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)
5. Value of Customer Impact (high, med, low)</td><td>1. Asset at EOL have reached the end of their life cycle. Future satisfactory performance in doubt.
2. Varies – switchgear failure may involve an entire feeder depending on location and protective device activated (i.e. lateral fuse or circuit breaker, etc.)
3. Switchgear failure could result in major interruption of 6-8 hours.
4. Reduced outages will improve customer satisfaction.
5. Customer surveys show that reliability is ranked high in value to them</td></tr>
<tr><td colspan="2">Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects</td><td>NTPDL has the resources and materials in order to ensure project completion on time.</td></tr>
<tr><td colspan="2">Consequences for system O&M costs, including the implications for system O&M of not implementing the project</td><td>N/A – EOL equipment may fail unexpectantly and result in higher replacement costs (overtime, etc.) and higher outage costs to customers due to extended duration of unplanned outage</td></tr>
<tr><td colspan="2">Impact on reliability and safety factors</td><td>New switchgear built and installed per CSA and 22/04 standards</td></tr>
<tr><td colspan="2">Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons</td><td>N/A – deferral increases risk of unexpected failure.</td></tr>
<tr><td colspan="2">Analysis of Project Benefits and Cost for extra cost “like for like”. (System Access, System Service, General Plant benefit) (if applicable)</td><td>N/A</td></tr>
<tr><td colspan="2">Other related information</td><td>N/A</td></tr>
</table>

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Project Name:	**Overhead poleline rebuilds – Annual Program**		
Category #:	**1**		
Investment Category:	**System Renewal**		
Investment Type:	**Non-mandatory**		
Service Area:	**All**		
Start Date: January 1, 2020		**In Service Date:**	**January 2020 – December 2021**
Net Capital Cost: $475,500		**Gross Capital Cost:**	**$475,500**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing: Annual	Q1	Q2	Q3	Q4
	$84,000	$84,000	$84,000	$84,000

A. General Information:

This program addresses the planned rebuild of the existing overhead polelines which has reached end-of-life. End-of-life is determined through the inspection process and NTPDL's ACA program.

Year	Poleline Rebuild Project	Poles replaced	Gross Capital
2020	Hillview	10	$127,000
	Bogart	6	$75,000
	Simcoe & Talbot	3	$101,500
	Huron Hts Dr (carryover costs from 2019)	0	$ 32,000
2021	Old Fort Road	14	$140,000
2022	N/A	N/A	N/A
2023	N/A	N/A	N/A
2024	N/A	N/A	N/A

Risks to Completion and Risk Mitigation: locates required. Process in place for this.
Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory program. Related spending in previous years.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** This program is driven by the need to replace assets that have reached End-Of-Life status.
	Reliability Planning: rebuild to current standards for overhead and underground construction
	Priority: 2020 – 2022 paced – Non-mandatory project
	Investment effectiveness: Plant is replaced like-for-like or upgraded to as per plans for the area.

Safety	Poles at End-Of-Life represents a safety hazard to staff and the public. EOL status generally implies that pole structural strength has decreased to levels below the minimum acceptable per CSA Standard for Overhead construction. Replacement of EOL plant restores the system to safe structural and operating condition
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Environmental benefits	N/A
Conservation and Demand Management	N/A

C. Category-specific requirements: System Renewal	
Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").	
Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure 1. Condition of Asset vs. Typical Life Cycle and Performance Record 2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure 3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level) 4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level) 5. Value of Customer Impact (high, medium, low)	1. Asset at EOL have reached the end of their life cycle. Future satisfactory performance in doubt. 2. Varies – pole failure may involve an entire feeder depending on location and protective device activated (i.e. lateral fuse or circuit breaker, etc. 3. Pole failure (multiple) could result in major interruption of 12-18 hours. 4. Reduced outages will improve customer satisfaction. 5. Customer surveys show that reliability is ranked high in value to them
Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects	NTPDL have the resources and materials in order to ensure project completion on time. Locates required from others.
Consequences for system O&M costs, including the implications for system O&M of not implementing the project	EOL equipment may fail unexpectantly and result in higher replacement costs (overtime, etc.) and outage costs to customers
Impact on reliability and safety factors	New poles will be installed per CSA and 22/04 standards
Analysis of Project Benefits and Costs with	Deferral increases risk of unexpected failure; other

alternative timing, expenditure, mitigation comparisons	alternatives (i.e. undergrounding) more expensive.
Analysis of Project Benefits and Cost for extra cost “like for like”. (System Access, System Service, General Plant benefit) (if applicable)	Pole class and loading design may be upgraded to coincide with plans for the area.
Other related information	Multi-year program to replace entire sections of pole line that have been assessed to be in “very poor”/”poor” condition. Complements the individual pole replacement program

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Project Name:	**Underground Cable Replacement – Annual Program**			
Category #:	**2**			
Investment Category:	**System Renewal**			
Investment Type:	**Non-mandatory**			
Service Area:	**Newmarket and Midland**			
Start Date:	**January 1, 2020**	**In Service Date: January 2020 - December 2024**		
Net Capital Cost: $4,033,500		**Gross Capital Cost:**	**$4,033,500**	
		Capital Contributions:	**$0**	
		OM&A Costs:	**$0**	
Expenditure Timing:	**Q1 $215,000**	**Q2 $215,000**	**Q3 $215,000**	**Q4 $215,000**

A. General Information:

This program involves the replacement of underground primary cable in the Newmarket and Midland-Tay service areas. Through NTPDL's ACA program, the underground cable has been determined to be at end-of-life. The cable is direct buried and will be replaced by cable in duct.

Year	Project	Cable (m)	Gross Capital
2020	Glen Eagles Cres - Midland	725	$329,900
	Glen Mhor Cres - Midland	900	$282,100
2021	Glen Bogie Cres - Midland	720	$288,700
2022	Glen Bogie Cres - Midland	80	$31,300
	Quaker Hills Ph 1 (Currey, Lloyd and Robinson) - NMKT	1,270	$528,000
	Dominion Ave - Midland	500	$179,000
	Playfair Rd - Midland	550	$220,000
2023	Dominion Ave - Midland	24	$30,300
	Penetanguishene Rd (Victoria to Hugel) - Midland	770	$308,000
	Quaker Hills Ph 2 (William Roe, Hodgson, Thoms, Talbot and Sandford) - NMKT	1790	$669,600
2024	Quaker Hills Ph 3 (Sandford, Handley, Borden and Beswick) - NMKT	1850	$720,000
	Quaker Hills Ph 2 (William Roe, Hodgson, Thoms, Talbot and Sandford) - NMKT	1000	$446,400

Risks to Completion and Risk Mitigation: Municipal approval timing. Material and resources available
Comparative Information on Equivalent Historical Projects (if any): This program is part of NTPDL's ongoing asset renewal efforts.
Renewable Energy Generation linkage: N/A

Non-distribution system options: N/A	
B. Investment Evaluation Criteria	
Efficiency, Customer Value, Reliability	**Main Driver:** This project is driven primarily by the need to replace assets that are aging and in poor condition and that pose a reliability risk to the distribution system
	Reliability Planning: all cable will be replaced with 15kV jacketed TR-XLPE cable. Operations at lower voltages (i.e. Midland) will result in minimizing electrical insulation stresses thereby potentially achieving an extended life for this type of cable**.**
	Priority: 2020 – 2024 paced – Non-mandatory project priority determined through the NTPDL capital prioritization process
	Investment effectiveness: The underground cables are aging and assessed at end of life which makes them more prone to failure requiring frequent emergency repairs. Investment will result in reduced customer outages and emergency repair activity.
Safety	Elimination of faults will reduce stress and asset degradation on circuit components from the transformer station to the customer.
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Environmental benefits	N/A
Conservation and Demand Management	N/A
C. Category-specific requirements: System Renewal	
Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").	
Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure 1. Condition of Asset vs. Typical Life Cycle and Performance Record 2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure 3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level) 4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level) 5. Value of Customer Impact (high, medium, low)	1. Underground cable is in poor to very poor condition. Underground cables are not installed in ducts and are not TR-XLPE. 2. The proposed projects directly affect hundreds of customers. 3. Estimated local outage frequency impact = 2 interruptions per year per customer; Estimated local outage duration impact = 240 minutes per year per customer. 4. Reduced outages will improve customer satisfaction. 5. Ranked high in safety value and reliability to customer
Other factors that may affect the timing of	NTPDL has the resources and materials in order to

the proposed project such as the pacing of investments and the priority relative to other projects	ensure project completion on time.
Consequences for system O&M costs, including the implications for system O&M of not implementing the project	Cable failures will require contractors to dig splice pits, and crew hours to repair cables.
Impact on reliability and safety factors	New cable will be installed per 22/04 standards
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	Rate of expenditure balances rate mitigation needs with decreasing asset reliability. Decreasing rate of expenditure will result in higher frequency risk of outages to customers as asset replacement is delayed.
Analysis of Project Benefits and Cost for extra cost “like for like”. (System Access, System Service, General Plant benefit) (if applicable)	N/A
Other related information	Ongoing program to replace underground primary cable in “very poor”/”poor” condition.

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Project Name:	**Annual DS Upgrades/Repairs**		
Category #:	**4**		
Investment Category:	**System renewal**		
Investment Type:	**Non-mandatory**		
Service Area:	**All**		
Start Date:	**January 1, 2020**	**In Service Date:**	**January 2020 – December 2024**
Net Capital Cost: $567,500		**Gross Capital Cost:**	**$567,500**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing: Annual	**Q1**	**Q2**	**Q3**	**Q4**
	$0	**$37,500**	**$0**	**$0**

A. General Information:

This program addresses the planned annual upgrade and repair of various Distribution Station assets which have reached end-of-life. End-of-life is determined through the inspection process and NTPDL's ACA program.

Year	**Net Capital**
2020	**$307,500**
2021	**$37,500**
2022	**$147,500**
2023	**$37,500**
2024	**$37,500**

Risks to Completion and Risk Mitigation: NTPDL material and resources available.
Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory annual program. Related spending in previous years.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** This project is driven by the need to replace assets that have reached End-Of-Life status.
	Reliability Planning: DS performance has largest impact on system reliability.
	Priority: 2020 – 2024 paced – Non-mandatory project
	Investment effectiveness: Plant is replaced like-for-like.
Safety	DS assets at End-Of-Life represent a safety hazard to staff. Replacement of EOL plant restores the system to safe operating condition
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A

Environmental benefits	Proactive replacement eliminates potential impact of oil spill (for oil filled transformer) on the environment
Conservation and Demand Management	N/A
C. Category-specific requirements: System Renewal	
Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. "failure").	
Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure 1. Condition of Asset vs. Typical Life Cycle and Performance Record 2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure 3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level) 4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level) 5. Value of Customer Impact (high, medium, low)	1. Asset at EOL have reached the end of their life cycle. Future satisfactory performance in doubt. 2. Varies – DS asset failure may involve several DS feeders or even the entire station depending on nature of failure. Impact could affect hundreds to thousands of customers 3. Failure could result in major interruption of 2-3 hours while customers are switched to alternate supplies. Major component failure could present ongoing long-term risk to system reliability. 4. Reduced outages will improve customer satisfaction. 5. Customer surveys show that reliability is ranked high in value to them
Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects	NTPDL has the resources and materials in order to ensure annual program completion.
Consequences for system O&M costs, including the implications for system O&M of not implementing the project	N/A – EOL equipment may fail unexpectantly and result in higher replacement costs (overtime, etc.) and higher outage costs to customers due to extended duration of unplanned outage
Impact on reliability and safety factors	DS assets built and installed per current standards for performance and reliability
Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons	N/A – deferral increases risk of unexpected failure.
Analysis of Project Benefits and Cost for extra cost "like for like". (System Access, System Service, General Plant benefit) (if applicable)	N/A
Other related information	N/A

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Project Name:	**DS Power Transformer Replacement**		
Category #:	**4**		
Investment Category:	**System renewal**		
Investment Type:	**Non-mandatory**		
Service Area:	**Newmarket and Tay**		
Start Date:	**January 1, 2020**	**In Service Date:**	**January 2020 – December 2024**
Net Capital Cost: $2,300,000		**Gross Capital Cost:**	**$2,300,000**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing: Annual	**Q1**	**Q2**	**Q3**	**Q4**
	$0	**$0**	**$0**	**$500,000**

A. General Information:

This program addresses the planned replacement of specific Distribution Station Power Transformer assets which are expected to reach end-of-life during the 2020 – 2024 period. End-of-life is determined through the inspection process and NTPDL's ACA program.

Year	Station	Net Capital
2020	Waubaushene	$800,000
2021	Thompson T1	$500,000
2022	Thompson T2	$500,000
2023	Port McNicoll	$500,000
2024	N/A	$0

Risks to Completion and Risk Mitigation: NTPDL material and resources available.
Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory annual program. Related spending in previous years.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** This project is driven by the need to replace assets that have reached End-Of-Life status.
	Reliability Planning: DS Transformer has large impact on system reliability.
	Priority: 2020 – 2024 paced – Non-mandatory project
	Investment effectiveness: Plant is replaced like-for-like.
Safety	DS assets at End-Of-Life represent a safety hazard to staff. Replacement of EOL plant restores the system to safe operating condition
Cyber Security, Privacy	N/A
Co-ordination,	N/A

<table>
<tr><td>Interoperability</td><td colspan="2"></td></tr>
<tr><td>Environmental benefits</td><td colspan="2">Proactive replacement eliminates potential impact of oil spill (for oil filled transformer) on the environment</td></tr>
<tr><td>Conservation and Demand Management</td><td colspan="2">N/A</td></tr>
<tr><td colspan="3">C. Category-specific requirements: System Renewal</td></tr>
<tr><td colspan="3">Projects/activities in this category are driven by the relationship between the ability of an asset or asset system to continue to perform at an acceptable standard on a predictable basis on one hand and on the other, the consequences for customers served by the asset(s) of a deterioration of this ability (i.e. “failure”).</td></tr>
<tr><td colspan="2">Description of the Relationship between the Asset Characteristics and Consequences of Asset Performance Deterioration or Failure
1. Condition of Asset vs. Typical Life Cycle and Performance Record
2. Number of Customers in Each Customer Class Potentially Affected by Asset Failure
3. Quantitative Customer Impacts (frequency or duration of interruptions and associated risk level)
4. Qualitative Customer Impacts (customer satisfaction, customer migration and associated risk level)
5. Value of Customer Impact (high, med, low)</td><td>1. Asset at EOL have reached the end of their life cycle. Future satisfactory performance in doubt.
2. Varies – DS transformer failure involves the entire station. Impact will affect thousands of customers
3. Failure could result in major interruption of 2-3 hours while customers are switched to alternate supplies. Transformer failure presents ongoing long-term risk to system reliability until replaced.
4. Minimizing asset EOL related outages will improve customer satisfaction.
5. Customer surveys show that reliability is ranked high in value to them</td></tr>
<tr><td colspan="2">Other factors that may affect the timing of the proposed project such as the pacing of investments and the priority relative to other projects</td><td>NTPDL has the resources and materials in order to ensure annual program completion.</td></tr>
<tr><td colspan="2">Consequences for system O&M costs, including the implications for system O&M of not implementing the project</td><td>N/A – EOL equipment may fail unexpectantly and result in higher replacement costs (overtime, etc.) and higher outage costs to customers due to extended duration of unplanned outage</td></tr>
<tr><td colspan="2">Impact on reliability and safety factors</td><td>DS assets built and installed per current standards for performance and reliability</td></tr>
<tr><td colspan="2">Analysis of Project Benefits and Costs with alternative timing, expenditure, mitigation comparisons</td><td>N/A – deferral increases risk of unexpected failure.</td></tr>
<tr><td colspan="2">Analysis of Project Benefits and Cost for extra cost “like for like”. (System Access, System Service, General Plant benefit) (if applicable)</td><td>N/A</td></tr>
<tr><td colspan="2">Other related information</td><td>N/A</td></tr>
</table>

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Program Name:	**Station System Service**		
Category #:	**6**		
Investment Category:	**System Service**		
Investment Type:	**Non-mandatory**		
Service Area:	**Newmarket and Tay**		
Start Date:	**January 2020**	**In Service Date:**	**January 2020 – December 2024**
Net Capital Cost: **$2,150,000** (Gross – Contributed + OM&A)		**Gross Capital Cost:**	**$2,150,000**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$107,500	**$107,500**	**$107,500**	**$107,500**

A. General Information:

This program addresses a number of Station System Service projects planned for the 2020 – 2024 forecast period. These projects address system capacity issues and support NTPDL's system operational objectives relating to safety, reliability, power quality, and system efficiency

Year	Project	Net Capital
2020	N/A	$0
2021	Station Relay Upgrades	$500,000
	Remote Operable Switch	$150,000
2022	Station Relay Upgrades	$500,000
2023	Station Relay Upgrades	$500,000
2024	Station Relay Upgrades	$500,000

Risks to Completion and Risk Mitigation: NTPDL material and resources available.
Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory program. Related spending in previous years.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver**: to improve protection and control assets in various NTPDL stations
	Reliability Planning: supports grid modernization and resiliency
	Priority: 2021 – 2024 paced – Non-mandatory project priority determined through the NTPDL capital prioritization process.
	Investment effectiveness: will improve NTPDL operational effectiveness; maintain current standards of reliability; positive efficiency improvement impact on field operations
Safety	N/A
Cyber Security,	N/A

Privacy	
Co-ordination, Interoperability	N/A
Environmental benefits	N/A
Conservation and Demand Management	N/A
C. Category-specific requirements: System Service	
Projects/activities in this category are driven by the distributor's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives.	
Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable: -avoided costs	Improved protection and control capability in normal and emergency field operations
Regional Electricity Infrastructure Requirements which affected Project, if applicable	N/A
Description of how advanced technology (ie Smart Grid) has been incorporated into the project (if applicable) and including how standards relating to interoperability and cybersecurity have been met.	Station relays will have smart grid capability built into their design and function
Reliability, efficiency, safety and coordination benefits or effects the project will have on the distributor's system	Improved system configuration capability; improved outage response
Factors affecting implementation timing/priority	Project prioritization and timing subject to NTPDL capital prioritization process
Project Analysis - Value Assessment -include monetary benefit, if applicable -technically feasible alternatives	Value assessed for 2020 - 2024 expenditure
Project Analysis - Risk Assessment -impact of "do nothing" scenario -technically feasible alternatives -include monetary consequence, if applicable	Risk assessed for 2020 - 2024 expenditure
Other related information	N/A

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Program Name:	**Overhead System Service**		
Category #:	**6**		
Investment Category:	**System Service**		
Investment Type:	**Non-mandatory**		
Service Area:	**All**		
Start Date: January 2020		**In Service Date: January 2020 – December 2024**	
Net Capital Cost: $860,000 (Gross – Contributed + OM&A)		**Gross Capital Cost:**	**$860,000**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing:	**Q1**	**Q2**	**Q3**	**Q4**
	$215,000	**$215,000**	**$215,000**	**$215,000**

A. General Information:

This program addresses a number of Overhead System Service projects planned for the 2020 – 2024 forecast period. These projects address system capacity issues and support NTPDL's system operational objectives relating to safety, reliability, power quality, and system efficiency

Year	Project	Net Capital
2020	N/A	$0
2021	M7 Feeder Tie - Davis Dr (HJ to Armitage)	$270,000
2022	William St Rebuild (ties PM to VH)	$120,000
	Waubaushene DS feeder extension (W of Tanner)	$150,000
	SCADA Switches	$60,000
2023	SCADA Switches	$60,000
2024	SCADA Switches	$60,000
	Backup resiliency (Lorne Ave, Queen to Park)	$80,000
	Triple Bay - finish connection to station	$60,000

Risks to Completion and Risk Mitigation: NTPDL material and resources available.
Comparative Information on Equivalent Historical Projects (if any): This is a non-mandatory annual program. Related spending in previous years.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver**: to improve load switching capability between various NTPDL stations and other facilities that supply the NTPDL service territory
	Reliability Planning: supports grid modernization and resiliency
	Priority: 2021 – 2024 paced – Non-mandatory project priority determined through the NTPDL capital prioritization process.
	Investment effectiveness: will improve capacity contingency capability allowing

	NTPDL to maintain current standards of reliability; positive efficiency improvement impact on field operations
Safety	N/A
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Environmental benefits	N/A
Conservation and Demand Management	N/A

C. Category-specific requirements: System Service	
Projects/activities in this category are driven by the distributor's expectations that evolving customer use of the system may occasion the creation of system capacity constraints or otherwise adversely impact operations in a manner that challenges the distributor's service delivery standards or objectives.	
Benefits to Customers of Project Expressed in terms of Cost Impact, where practicable: -avoided costs	Improved contingency capability in normal and emergency field operations
Regional Electricity Infrastructure Requirements which affected Project, if applicable	N/A
Description of how advanced technology (ie Smart Grid) has been incorporated into the project (if applicable) and including how standards relating to interoperability and cybersecurity have been met.	SCADA switches will have remote control capability reducing switching time and improving outage restoration efforts
Reliability, efficiency, safety and coordination benefits or effects the project will have on the distributor's system	Improved system configuration capability; improved outage response
Factors affecting implementation timing/priority	Project prioritization and timing subject to NTPDL capital prioritization process
Project Analysis - Value Assessment -include monetary benefit, if applicable -technically feasible alternatives	Value assessed for 2020 - 2024 expenditure
Project Analysis - Risk Assessment -impact of "do nothing" scenario -technically feasible alternatives -include monetary consequence, if applicable	Risk assessed for 2020 - 2024 expenditure
Other related information	N/A

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Project Name:	**Replacement of Fleet Equipment**		
Program #:	**12**		
Investment Category:	**General Plant**		
Investment Type:	**Non-Mandatory**		
Service Area:	**All**		
Start Date:	**January 2020**	**In Service Date:**	**January 2020 – December 2024**
Net Capital Cost: $2,374,200		**Gross Capital Cost:**	**$2,374,200**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing: Annual	**Q1**	**Q2**	**Q3**	**Q4**
	$0	**$0**	**$0**	**$474,800**

A. General Information:

New fleet units are to be procured to replace existing fleet units which has been assessed at economic end-of –life. Repairs and maintenance costs of existing units are expected to remain high with continued operation. New fleet units will have reduced repair and maintenance costs.

Year	Description	Net Capital
2020	Small Fleet Vehicles and Trailers	$204,200
	60ft Radial Boom Truck	$430,000
	55ft Double Bucket Truck	$400,000
2021	Small Fleet Vehicles and Trailers	$40,000
	42ft Single Bucket Truck	$350,000
2022	Small Fleet Vehicles and Trailers	$170,000
2023	Small Fleet Vehicles and Trailers	$260,000
2024	Digger Derrick	$520,000

Risks to Completion and Risk Mitigation: Delivery subject to manufacturer schedule. Price subject to competitive bid process.
Comparative Information on Equivalent Historical Projects (if any): Variability in unit cost subject to unit complexity and currency exchange rates for units procured outside Canada
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Replacement of aging fleet assets.
	Reliability Planning: N/A
	Priority – 2020 – 2024 paced - Non-Mandatory project priority determined through the NTPDL capital prioritization process
	Investment effectiveness: The proposed fleet units for replacement have reached the end of economic useful life. Reduced operating and maintenance expenses are

	expected.	
Safety	The replaced units will be matched to the work requirements and will reduce the risk of improper work methods. The timing for fleet replacement ensures that units are replaced before they deteriorate to a degree that represents an operational safety hazard.	
Cyber Security, Privacy	N/A	
Co-ordination, Interoperability	N/A	
Environmental benefits	New large fleet units (i.e. bucket trucks) will be capable of using biodiesel fuel as applicable	
Conservation and Demand Management		
C. Category-specific requirements: General Plant		
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.		
Project Analysis - Value Assessment -include monetary benefit, if applicable		Based on vehicle condition assessment
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable		Potential for increased maintenance and fuel costs; reduced reliability
High cost material projects business case details (>$250k)		Replacement need - equipment assessments completed
Other related information		N/A

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Project Name:	**IT Hardware and Software**		
Program #:	**14**		
Investment Category:	**General Plant**		
Investment Type:	**Non-Mandatory**		
Service Area:	**All**		
Start Date:	**January 2020**	**In Service Date:**	**January 2020 – December 2024**
Net Capital Cost: $4,660,000		**Gross Capital Cost:**	**$4,660,000**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing: Annual	**Q1**	**Q2**	**Q3**	**Q4**
	$233,000	**$233,000**	**$233,000**	**$233,000**

A. General Information:

Annual hardware and software expenditures to support ongoing operational processes. While overall program is material, majority of individual annual expenditures (i.e. replacement laptops, etc.) below material levels.

Year	Net Capital
2020	$ 660,000
2021	$1,000,000
2022	$1,000,000
2023	$1,000,000
2024	$1,000,000

Risks to Completion and Risk Mitigation: IT resources are available to ensure program completion
Comparative Information on Equivalent Historical Projects (if any): Similar to annual IT spending in historical period.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Replacement of obsolete or underperforming IT assets.
	Reliability Planning: N/A
	Priority: 2020 – 2024 paced - Non-Mandatory project priority determined through the NTPDL capital prioritization process
	Investment effectiveness: Annual expenditures will ensure that equipment is operating at top efficiency and supportive of ongoing operational process needs.
Safety	N/A
Cyber Security, Privacy	All IT infrastructure subject to NTPDL cybersecurity measures.
Co-ordination,	N/A

Interoperability		
Environmental benefits	N/A	
Conservation and Demand Management		
C. Category-specific requirements: General Plant		
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.		
Project Analysis - Value Assessment -include monetary benefit, if applicable		Value assessed for 2020 - 2024 expenditure
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable		Risk assessed for 2020 - 2024 expenditure Potential negative impact on ongoing operational processes and resultant decrease in overall customer satisfaction
High cost material projects business case details (>$250k)		Individual expenditures not material
Other related information		N/A

Newmarket-Tay Power Distribution Ltd.
Capital Project

2020 - 2024

Project Name:	**Leasehold and Office Annual Expenditures**		
Program #:	**15**		
Investment Category:	**General Plant**		
Investment Type:	**Non-Mandatory**		
Service Area:	**All**		
Start Date:	**January 2020**	**In Service Date:**	**January 2020 – December 2024**
Net Capital Cost: $1,140,000		**Gross Capital Cost:**	**$1,140,000**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing: Annual	**Q1**	**Q2**	**Q3**	**Q4**
	$57,000	**$57,000**	**$57,000**	**$57,000**

A. General Information:

Annual leasehold and office expenditures to support ongoing operational processes.

Year	Net Capital
2020	$ 340,000
2021	$ 350,000
2022	$ 150,000
2023	$ 150,000
2024	$ 150,000

Risks to Completion and Risk Mitigation: Resources are available to ensure program completion
Comparative Information on Equivalent Historical Projects (if any): Similar to annual spending in historical period.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Improvements to building and office accessories to support ongoing operational processes.
	Reliability Planning: N/A
	Priority: 2020 – 2024 paced - Non-Mandatory project priority determined through the NTPDL capital prioritization process
	Investment effectiveness: Annual expenditures will ensure that facility condition is supportive of ongoing operational process needs.
Safety	Expenditures will address existing safety issues (if any)
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A

Environmental benefits	N/A
Conservation and Demand Management	N/A
C. Category-specific requirements: General Plant	
Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.	
Project Analysis - Value Assessment -include monetary benefit, if applicable	Value assessed for 2020 - 2024 expenditure
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable	Risk assessed for 2020 - 2024 expenditure Potential negative impact on ongoing operational processes and resultant decrease in overall customer satisfaction
High cost material projects business case details (>$250k)	Individual expenditures not material
Other related information	N/A

Newmarket-Tay Power Distribution Ltd.
Capital Project

2021

Project Name:	**Holland TS Capital Contribution**		
Program #:	**16**		
Investment Category:	**General Plant**		
Investment Type:	**Mandatory**		
Service Area:	**Newmarket**		
Start Date:	**January 2021**	**In Service Date:**	**December 2021**
Net Capital Cost $6,100,000		**Gross Capital Cost:**	**$6,100,000**
		Contributed Capital:	**$0**
		OM&A Costs:	**$0**

Expenditure Timing: Annual	**Q1**	**Q2**	**Q3**	**Q4**
	$0	**$6,100,000**	**$0**	**$0**

A. General Information:

In 2021, NTPDL will make a Capital Contribution to HONI towards the construction and operation of Holland TS as per its Connection and Cost Recovery Agreement (CCRA) with HONI. This contribution covers year 6 – 10 of the CCRA load commitments.

Risks to Completion and Risk Mitigation: N/A
Comparative Information on Equivalent Historical Projects (if any): Similar to previous capital contribution (true-up) for Holland TS that covered years 1 – 5 of the CCRA load commitments.
Renewable Energy Generation linkage: N/A
Non-distribution system options: N/A

B. Investment Evaluation Criteria

Efficiency, Customer Value, Reliability	**Main Driver:** Legal requirement to compensate HONI for ongoing operation of Holland TS per the terms of the CCRA.
	Reliability Planning: N/A
	Priority: N/A - Mandatory expenditure through the terms of the CCRA with HONI.
	Investment effectiveness: Holland TS supplies approximately 45% of the Newmarket service territory.
Safety	N/A
Cyber Security, Privacy	N/A
Co-ordination, Interoperability	N/A
Environmental benefits	N/A
Conservation and Demand Management	

C. Category-specific requirements: General Plant

Projects/activities in this category are driven by the distributor's evolving requirements for capital to support day to day business and operations activities.	
Project Analysis - Value Assessment -include monetary benefit, if applicable	N/A – legal requirement
Project Analysis - Risk Assessment -impact of "do nothing" scenario -include monetary consequence, if applicable	N/A – legal requirement
High cost material projects business case details (>$250k)	N/A – legal requirement
Other related information	N/A

Appendices

Appendix A

Town of Newmarket Official Plan Amendment #10 (September 2013) excerpt

13.3.4 Energy and Utilities

i. The Town will work with utility providers in the coordination and planning of utility services, including common or joint trenches, where feasible, in order to minimize disruption and the land requirements for underground utilities.

ii. Appropriate locations for utility equipment may be determined and consideration shall be given to the locational requirements within the right of way as well as on private property where access by the utility is provided from the exterior of buildings/structures.

iii. Utility equipment will be encouraged to be clustered where possible to minimize the physical space requirements and visual impact. Innovative methods are encouraged to integrate utility structures within streetscape features, including gateways, lamp posts, and transit shelters.

iv. The Town will work with the Region to require, where feasible the burying of the existing overhead hydro lines and associated utilities along Yonge Street and Davis Drive consistent with the direction set forth in Section 7.5.5 of the Region of York Official Plan.

v. The Town will encourage York Region to amend its Official Plan to include up to an additional five metres of boulevard width on each side of both Yonge Street and Davis Drive in order to accommodate the undergrounding of the overhead hydro lines and associated utilities.

vi. Prior to York Region amending its Official Plan to incorporate an expanded right-of-way for Yonge Street and Davis Drive to accommodate the undergrounding of the hydro lines and associated utilities, the following policies will apply in the Urban Centres:

a) With new development or redevelopment, all new buildings and above- and below-ground structures, including underground parking structures, fronting on Yonge Street or Davis Drive will be required to be setback a minimum of four metres from the Regional right-of-way existing as of October 31, 2013 to ensure space is available to underground overhead hydro and associated utilities in the future. The final determination of the setback will be subject to a detailed analysis conducted by the proponent, in consultation with the Town, Newmarket Tay Hydro Distribution Ltd. and York Region. The actual setback may be greater or less than four metres if the detailed analysis demonstrates that an alternative setback is sufficient to accommodate the undergrounding of hydro and associated utilities across the frontage of the property.

b) Encroachment agreements may be entered into at the Region's discretion to allow uses on the lands dedicated and/or subject to easements in accordance with Policy 13.3.4(iii)(b). Encroachments may include below-ground parking or surface uses associated with the primary use of the adjacent development such as outdoor patios or the display or sale of goods.

c) Where phased development or redevelopment is delayed and the lands have been conveyed to the Region, existing above-ground parking may be permitted to continue until such time as development or redevelopment occurs.

d) The Town may provide incentives where land has been dedicated to the Region to accommodate the undergrounding of the hydro lines, including but not limited to provision for zero setbacks for development from the expanded right-of-way, or reduced parkland dedication in accordance with the Parkland Dedication By-law.

vii. The following policies will apply in the Urban Centres following the adoption of an amendment to the York Region Official Plan incorporating an expanded right-of-way for Yonge Street and Davis Drive to accommodate the undergrounding of the hydro lines:

a) At the time of development or redevelopment the land required to accommodate the undergrounding of hydro and associated utilities along Yonge Street and Davis Drive not already conveyed through Policy 13.3.4(iii) and as defined through the right-of-way widths in the York Region Official Plan shall be conveyed to the Region.

Appendix B

NTPDL - 2020 Q2 Reliability (April 1 to June 30, 2020)			
Primary Cause Code	**Interruption Count**	**Customer Interruptions**	**Customer Hours**
0 - Unknown	1	3	2.6
1 - Scheduled Outage	1	1,990	1,736.6
2 - Loss of Supply	1	4,042	9,700.8
3 - Tree Contacts	7	86	234.4
4 - Lightning	1	2	1.7
5 - Defective Equipment	10	1,726	2,291.5
6 - Adverse Weather	1	5	5.8
7 - Adverse Environment	1	1	5.3
8 - Human Element	0	0	0.0
9 - Foreign Interference	24	1,821	2,158.6
TOTAL	**47**	**9,676**	**16,137.3**

Major Event Days	Cause	Duration (hr)	Customer Interruptions	Customer Hours
n/a				
n/a				
n/a				

Customer Count	Description	SAIDI	SAIFI	CAIDI
44,111	**All Events**	0.3658	0.2194	1.6678
	Adjusted (excluding MED)	0.3658	0.2194	1.6678
	Adjusted (excluding MED & LOS)	0.3265	0.1742	1.8736

Appendix C

Newmarket-Tay Power Distribution Ltd. POLICY	SI NUMBER: POL100-006 ISSUE DATE: November 3, 2015
TITLE Asset Management Policy	LAST REVIEW DATE: November 3, 2015 NEXT REVIEW DATE: November, 2016 ORIGINATED BY: President

PREAMBLE

Newmarket-Tay Power Distribution Ltd. (NT Power) is committed to delivering safe and reliable services to its customers in a financially and operationally effective manner. NT Power utilizes its distribution system assets to deliver services in its Newmarket and Tay service areas. The distribution system assets are capital-intensive and have very long lives. Providing good quality, valued, reliable and sustainable services depends on having the distribution system assets in good condition. NT Power has developed an asset management policy to ensure a continual and consistent focus on delivering services in a way that balances risk and long-term costs. The policy establishes the core asset management principles that drive NT Power's planning framework.

POLICY

It is NT Power policy that the distribution system shall be designed, procured, constructed, operated, maintained, renewed and retired in an efficient manner that:

- Supports NT Power's strategic goals and asset management objectives;
- Supports the OEB's RRFE outcomes;
- Implements NT Power's business plan as documented in the Distribution System Planning Report;
- Complies with regulatory and statutory requirements
  - Health and safety of workers and the public;
  - Electricity supply quality and reliability;
  - Environmental Protection;

- GUP;
- Financial and IFRS accounting practice; and

• Effectively controls and balances service levels with asset lifecycle costs and risks as well as reconciles with NT Power's investment strategies and financing capabilities.

It is the responsibility of the NT Power Board to ensure there are established roles, responsibilities, authorities and controls to achieve the asset management policy, strategy, objectives and plans.

The President has overall responsibility for developing NT Power's Asset Management System and reporting on the status and effectiveness of NT Power's Asset Management System.

This Policy will be reviewed annually.

____________________________ ____________________________

P. D. Ferguson, P. Eng. Date Signed
President

Appendix D

Parry Sound/Muskoka Sub-Region Integrated Regional Resource Plan

PARRY SOUND / MUSKOKA SUB-REGION
INTEGRATED REGIONAL RESOURCE PLAN

Part of the South Georgian Bay/Muskoka Planning Region | December 16, 2016

ieso
Connecting Today. Powering Tomorrow.

Integrated Regional Resource Plan

Parry Sound/Muskoka

This Integrated Regional Resource Plan ("IRRP") was prepared by the Independent Electricity System Operator ("IESO") pursuant to the terms of its Ontario Energy Board electricity licence, EI-2013-0066.

This IRRP was prepared on behalf of the Parry Sound/Muskoka Sub-region Working Group (the "Working Group"), which included the following members:

- Independent Electricity System Operator
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Lakeland Power Distribution Ltd.
- Midland Power Utility Corporation
- Newmarket-Tay Power Distribution Ltd.
- Orillia Power Distribution Corporation
- PowerStream Inc.
- Veridian Connections Inc.

The Working Group assessed the reliability of electricity supply to customers in the Parry Sound/Muskoka Sub-region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth scenarios and varying supply conditions in the Parry Sound/Muskoka Sub-region; and developed recommended actions, while maintaining flexibility in order to accommodate changes in key assumptions over time.

The Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations.

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List of Abbreviations

Abbreviations	Descriptions
CCAP	Climate Change Action Plan
CDM or Conservation	Conservation and Demand Management
CEP	Community Energy Plans
CFF	Conservation First Framework
CHP	Combined Heat and Power
DG	Distributed Generation
DR	Demand Response
FIT	Feed-in Tariff
GHG	Greenhouse Gas
Hydro One	Hydro One Networks Inc. (Distribution and Transmission)
IAP	Industrial Accelerator Program
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LAC	Local Advisory Committee
Lakeland Power	Lakeland Power Distribution Ltd.
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTEP	(2013) Long-Term Energy Plan
LTR	Limited Time Rating
Midland PUC	Midland Power Utility Corporation
MW	Megawatt
Newmarket-Tay Power	Newmarket-Tay Power Distribution Ltd.
OEB or Board	Ontario Energy Board
OPA	Ontario Power Authority
Orillia Power	Orillia Power Distribution Corporation

Abbreviations	Descriptions
ORTAC	Ontario Resource and Transmission Assessment Criteria
OWA	Ontario Waterpower Association
PowerStream	PowerStream Inc.
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group Report to the Board
RIP	Regional Infrastructure Plan
TOU	Time-of-Use
TS	Transformer Station
TWh	Terawatt-Hours
Veridian Connections	Veridian Connections Inc.
Working Group	Technical Working Group for Parry Sound/Muskoka Sub-region IRRP

1. Introduction

This Integrated Regional Resource Plan ("IRRP") for the Parry Sound/Muskoka Sub-region addresses the electricity needs for the sub-region over the next 20 years from 2015 to 2034 ("study period"). The IRRP was prepared by the Independent Electricity System Operator ("IESO") on behalf of the Technical Working Group (the "Working Group") for the Parry Sound/Muskoka Sub-region composed of the IESO, Hydro One Distribution and Hydro One Transmission[1], Lakeland Power Distribution Ltd. ("Lakeland Power"), Midland Power Utility Corporation ("Midland PUC"), Newmarket-Tay Power Distribution Ltd. ("Newmarket-Tay Power"), Orillia Power Distribution Corporation ("Orillia Power"), PowerStream Inc. ("PowerStream") and Veridian Connections Inc. ("Veridian Connections").

The area covered by the Parry Sound/Muskoka IRRP is a Sub-region of the South Georgian Bay/ Muskoka Region identified through the Ontario Energy Board ("OEB" or "Board") regional planning process. This sub-region roughly encompasses the Districts of Muskoka and Parry Sound and the northern part of Simcoe County. This sub-region is characterized by:

- **Diverse communities**: In addition to the "unorganized areas"[2] in the Parry Sound District, there are eight First Nation communities and 35 municipalities located in this sub-region, all of which are listed in Section 4.1. The communities have different local priorities and electricity needs. Some communities are engaging in community energy planning activities.

- **Large geographical area:** A mix of long and expansive 230 kilovolt ("kV") transmission, 44 kV sub-transmission and low-voltage distribution infrastructure are required to deliver electricity supply to the various communities and customers across this sub-region. The geography and sparsely populated areas make it challenging and costly to develop and maintain infrastructure.

- **Use of Electric Space and Water Heating:** Due to limited access to natural gas infrastructure in this sub-region, many communities rely on electric space and water heating, especially during the winter season. In addition to electricity, some customers also rely on other fuel types, such as wood, to meet their heating requirements.

[1] For the purpose of this report, "Hydro One Transmission" and "Hydro One Distribution" are used to differentiate the transmission and distribution accountabilities of Hydro One Networks Inc. ("Hydro One"), respectively.
[2] Unorganized areas are parts of the province where there is no municipal level of government. Services in these unorganized districts are typically administered by local services boards.

- **Modest Growth:** While relatively slower growth is expected in the manufacturing sector, growing First Nation communities, developments in the tourism and retail sector, and potential local economic development could contribute to higher electricity demand in the sub-region. Seasonal population driven by tourism and recreational activities may also increase electricity requirements over the longer term.

This IRRP fulfills the requirements for the sub-region as required by the IESO's OEB electricity licence. IRRPs are required to be reviewed on a 5-year cycle so that plans can be updated to reflect the changing electricity outlook. This IRRP will be revisited in 2021, or earlier if significant changes occur relative to the current forecast.

This IRRP report is organized as follows:

- A summary of the recommended plan for the Parry Sound/Muskoka Sub-region is provided in Section 2;
- The process used to develop the plan is discussed in Section 3;
- The context for electricity planning in the Parry Sound/Muskoka Sub-region and the study scope are discussed in Section 4;
- Demand forecast and conservation and demand management ("CDM" or "conservation") and distributed generation ("DG") assumptions are described in Section 5;
- Needs in the Parry Sound/Muskoka Sub-region are presented in Section 6;
- Options to address regional and local needs are addressed in Section 7;
- Recommended actions are set out in Section 8;
- A summary of community, Indigenous and stakeholder engagement to date is provided in Section 9; and
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

The Parry Sound/Muskoka IRRP addresses the sub-region's electricity needs over the next 20 years, based on application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP was developed in consideration of a number of factors, including reliability, cost, technical feasibility, flexibility and also the diverse needs and unique characteristics of the sub-region.

The needs and recommended actions are summarized below.

2.1 Need to Minimize the Frequency and Duration of Power Outages

Customers and communities in the Parry Sound/Muskoka Sub-region experience more frequent and prolonged power outages relative to other communities and electricity customers in the province. Any outage along the 230 kV transmission, 44 kV sub-transmission and low-voltage distribution lines can interrupt the electricity supply to the communities and customers. Results from the service reliability performance assessment show that a number of 44 kV sub-transmission systems in this sub-region are performing below provincial average[3] in terms of frequency and duration of outages. Long 44 kV sub-transmission lines and off-road facilities are the main causes for frequent and prolonged outages for this sub-region. Lengthy distribution lines also typically exhibit lower levels of reliability because of increased exposure to trees and wildlife, and they sustain more damage from poor weather. Limited access to off-road facilities makes it difficult for repair crews to detect early signs of equipment failures, do preventative maintenance and restore power in a timely manner.

While major 230 kV transmission outages have been relatively infrequent in the Parry Sound/Muskoka Sub-region, the existing 230 kV transmission system has limited ability to restore power in a timely manner and minimize the number of customers impacted in the event of a major 230 kV transmission outage and does meet Ontario's planning criteria.

The Working Group has recommended a set of actions to minimize the frequency and duration of 44 kV related power outages and to bring the 230 kV transmission system in compliance with Ontario's planning standards.

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[3] On average, customers being supplied from a typical 44 kV sub-transmission line in Ontario experience outages about two times a year with outages typically lasting 5 hours or less.

Recommended Actions

1. **Inform communities and Local Advisory Committee ("LAC")[4] members of the 44 kV sub-transmission system service reliability performance and the on-going maintenance and improvement initiatives in the Parry Sound/Muskoka Sub-region.**

   Hydro One Distribution will examine options to improve the reliability performance on the 44 kV sub-transmission system as part of their planning process. Hydro One Distribution will provide an update on measures to improve 44 kV sub-transmission system service reliability performance including any proposed capital plans. This update will be provided by end of 2017.

   The ability to implement any proposed capital investment plans will be contingent on the outcome of Hydro One Distribution's 2018-2022 rate filing application with the OEB.

2. **Examine the cost benefit and cost responsibility of options to resupply customers in Bracebridge, Gravenhurst, Muskoka Lakes and surrounding areas from alternate transformer station**

   Hydro One Distribution, Lakeland Power and Veridian Connections will examine various options to improve service reliability performance of the 44 kV sub-transmission system supplying the Bracebridge/Gravenhurst/Muskoka Lakes and surrounding areas, including the option to resupply customers in Bracebridge, Gravenhurst, Muskoka Lakes and surrounding areas from an alternate transformer station. The cost-benefit and cost responsibility of these options will be considered. The affected LDCs will discuss their assessment and decision with the Working Group through the regional planning process. This action is expected to be completed by the end of 2017. The results will be shared with LAC members and affected communities.

[4] A LAC for the Parry Sound/Muskoka Sub-region was established to allow community representatives to provide input on the status of local growth and developments, local planning priorities, energy planning activities (e.g., community energy planning), and opportunities to implement community-based energy solutions.

3. **Install two 230 kV motorized switches at Orillia TS**

   To restore power to customers in a timely manner in the event of a major outage on the Muskoka-Orillia 230 kV sub-system, the Working Group recommends proceeding with the installation of two 230 kV motorized switches at the Orillia Transformer Station ("TS"). The IESO will provide a letter to Hydro One Transmission to initiate project development work for the two 230 kV motorized switches at Orillia TS in 2017. Based on typical development timeline of switching facilities, the project is expected to be in-service by the end of 2020.

4. **Explore opportunities to improve resilience and service reliability at the community level**

   Some communities are engaged in community energy planning activities and interested in developing distributed energy resources. The IESO can facilitate discussions with First Nation communities, municipalities and LAC members on the opportunities to improve system resilience and service reliability through community energy planning and distributed energy resources and the cost-benefit of these opportunities.

2.2 Need to Provide Adequate Supply to Support Growth

Despite the relatively slow growth in this sub-region, the transformers supplying the Parry Sound and Waubaushene areas are approaching their maximum capacity in the near term. Additionally, the electricity demand on the 230 kV transmission system supplying the Orillia and Muskoka area may exceed capacity over the longer term.

Actions need to be taken to ensure that the regional electricity system has adequate supply to support growth in this sub-region over the planning period.

Recommended Actions

1. **Resupply some customers in the Parry Sound and Waubaushene areas from neighbouring transformer stations using existing and new distribution facilities to maximize the use of the existing system**

   The electricity demand at the Parry Sound TS has already exceeded the transformers' capacity. To manage the near-term demand growth in the area, about 6 Megawatts ("MW") at Parry Sound TS will be resupplied from Muskoka TS. To facilitate the transfer of load from Parry Sound TS to Muskoka TS, it is recommended that Hydro One Distribution seek approval to construct 44 kV feeder tie between the Muskoka TS M5 and M1 feeders. The siting and routing of these facilities will be determined as part of the project development process. Based on the typical project development timeline for 44 kV sub-transmission reinforcements, the project is expected to be in-service by 2020.

The electricity demand at Waubaushene TS is approaching it's transformer's capacity limits. To manage the near-term demand growth in the area, about 4 MW at Waubaushene TS will be resupplied from Orillia TS by 2020. If required, another 7 MW at Waubaushene TS can be resupplied from Midhurst TS upon completion of Barrie Area Transmission Reinforcement in the early 2020s. This can be done using existing distribution system and no new facilities will be required.

Midhurst TS is a major transformer station supplying the Barrie/Innisfil Sub-region. Resupplying some of the customers in the Waubaushene area from Midhurst TS could impact the timing and need for a new transformer station in the Barrie/Innisfil Sub-region over the longer term. As such, the Working Group will need to coordinate with the Barrie/Innisfil IRRP Working Group to monitor and manage the demand growth in the Waubaushene and Barrie/Innisfil Sub-region.

2. **Determine the cost and feasibility of using distributed energy resources and local conservation and demand management options to defer major capital investments in the Parry Sound/Muskoka Sub-region**

   With the relatively slow electricity demand growth forecast for this sub-region, there is an opportunity to use targeted local conservation and demand management, distribution-connected generation and/or other distributed energy resources to defer major capital investments that might otherwise be required (e.g., transformer upgrades at Parry Sound TS and Waubaushene TS, reinforcements on the Muskoka-Orillia Sub-system).

   The Working Group will initiate a local achievable potential study in the Parry Sound/Muskoka Sub-region to determine the cost and feasibility of using distributed energy resources and local demand management options to defer those major capital investments. A range of distributed energy resources and local demand management options may be suitable, including focused marketing and/or incentive adders to existing conservation programs, new conservation and demand management programs, local demand response, behind-the-meter generation and energy storage. These options will be considered as part of the study. This study will be initiated in early 2017 by the LDCs. The IESO will assist and provide funding for the study.

The Working Group will also work closely with communities to leverage local knowledge and community energy planning activities and to identify opportunities for targeted conservation and energy efficiency programs in First Nation communities and municipalities.

3. **Determine whether it is cost effective to advance the end-of-life replacement and to replace the aging assets with upgraded/upsized facilities at Parry Sound TS and Waubaushene TS**

   The transformers at Parry Sound TS and Waubaushene TS were installed in the early 1970's and therefore these transformers could be reaching end-of-life in the early 2030s. On an annual basis, Hydro One Transmission will provide updated information on the condition of aging equipment at the Parry Sound TS and Waubaushene TS. This information will be shared with the LAC and the Working Group. The IESO will continue to monitor the demand growth at Parry Sound TS and Waubaushene TS to determine whether it is cost effective to advance the end-of-life replacement and to replace aging assets with upgraded/upsized facilities. This need will be revisited in the next iteration of the plan.

4. **Monitor electricity demand growth closely to determine the timing of any investment decisions relating to the Muskoka-Orillia 230 kV sub-system**

   On an annual basis, the IESO will review electricity demand growth on the Muskoka-Orillia 230 kV sub-system with the Working Group and members of the LAC. This information will be used to determine if and when an investment decision for the Muskoka-Orillia 230 kV is required. This need will be revisited in the next iteration of the plan.

3. Development of the Integrated Regional Resource Plan

3.1 The Regional Planning Process

In Ontario, planning to meet the electricity needs of customers at a regional level is done through regional planning. Regional planning assesses the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and develops 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, the former Ontario Power Authority ("OPA") carried out planning activities to address regional electricity supply needs. The OPA 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 Board convened a Planning Process Working Group ("PPWG") to develop a more structured, transparent, and systematic regional planning process. This group was composed of industry stakeholders including electricity agencies, utilities, and stakeholders, and in May 2013, the PPWG released its report to the Board[5] ("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 was outlined. The Board endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, as well as through changes to the OPA's licence in October 2013. The OPA's licence changes required it to lead a number of aspects 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 were to become the responsibility of the new IESO.

The regional planning process begins with a Needs Screening performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO then conducts a Scoping Assessment to determine whether a comprehensive IRRP is required, which considers conservation, generation, transmission, and

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[5] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

distribution solutions, or whether a more limited "wires" solution is the only option such that a transmission and distribution focused Regional Infrastructure Plan ("RIP") can be undertaken instead. The Scoping Assessment assesses what type of planning is required for each region. There may also be regions where infrastructure investments do not require regional coordination and so 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 Screening 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 an RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. It should be noted that a RIP may be initiated after the Scoping Assessment or after the completion of all IRRPs within a planning region; the transmitter may also initiate and produce a RIP report for every region. 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 2-week comment period prior to finalization.

The final IRRPs and RIPs are posted on the IESO's and relevant transmitter's websites, and may be referenced and submitted to the Board 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 for planning, conservation and energy management purposes, as 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 that is undertaken in Ontario. As shown in Figure 3-1, there are three levels of planning that are carried out for the electricity system 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. Bulk system planning considers not only the major transmission facilities or "wires", but it also 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 Local Distribution Companies ("LDCs"), considers specific investments in an LDC's territory at distribution level voltages.

Regional planning can overlap with bulk system planning. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. For example, overlaps can occur when a distribution solution addresses the needs of the broader local area or region. Therefore, 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.

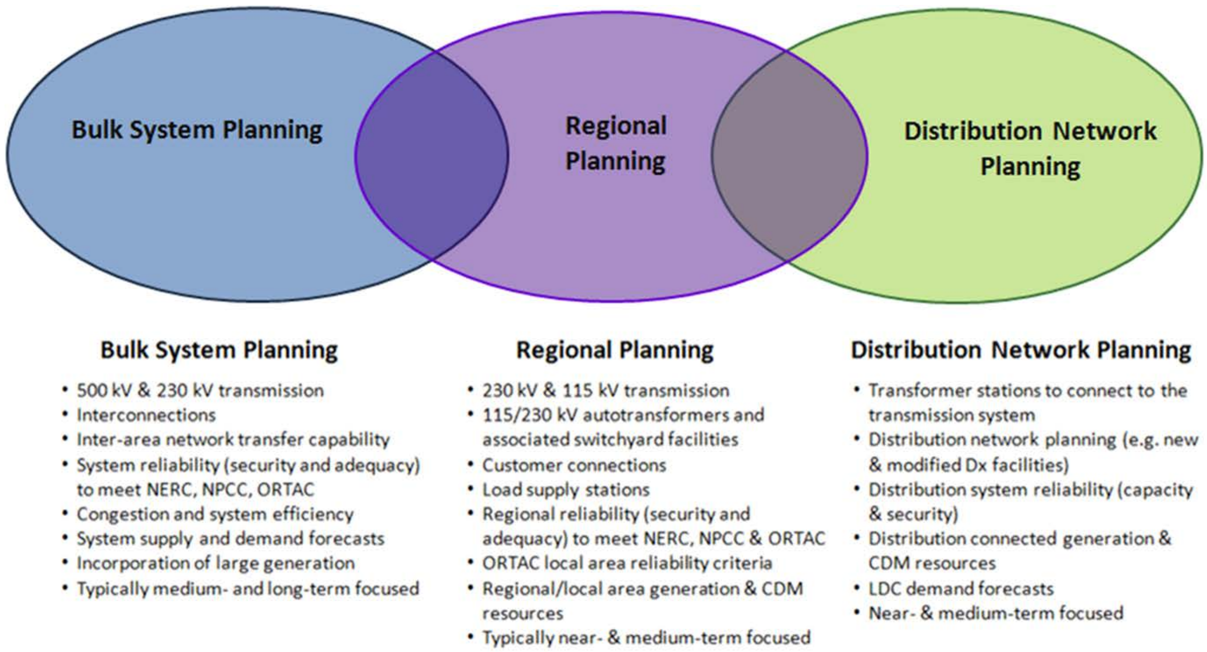


Figure 3-1: Levels of Electricity System Planning

By recognizing the linkages with bulk and distribution system planning, and coordinating 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 in perspective. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication, and allows Ontario ratepayer interests 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.

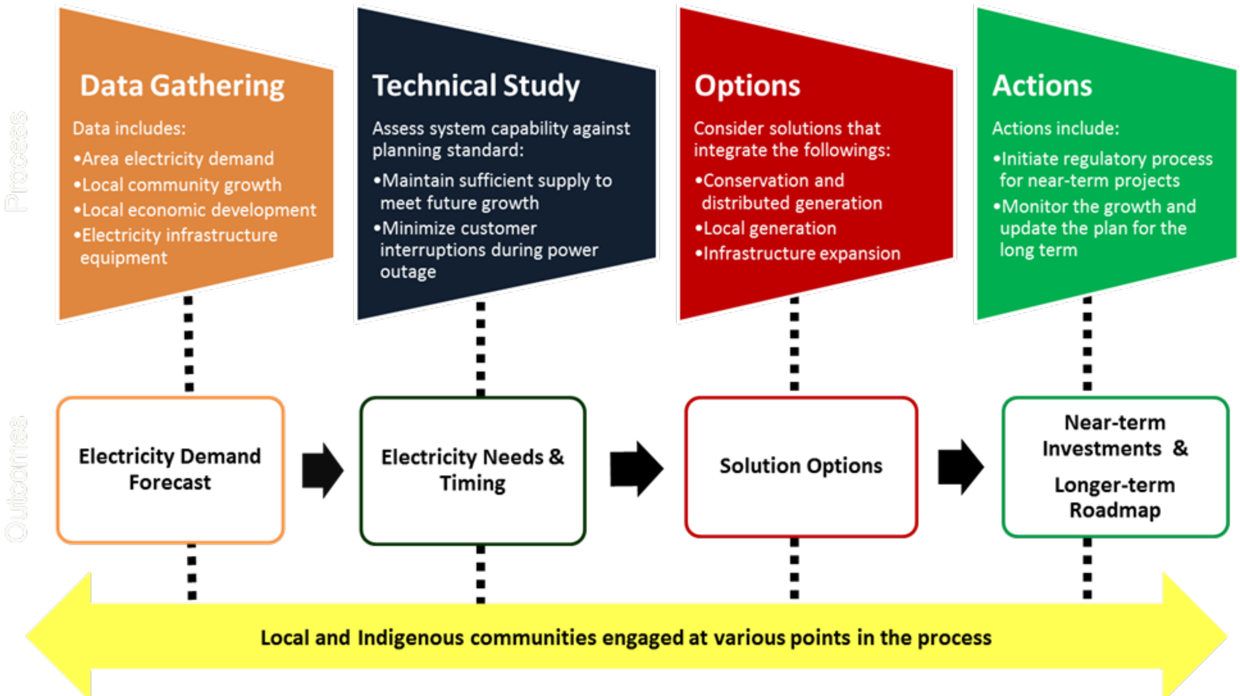
3.2 The IESO's Approach to Integrated Regional Resource Planning

IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends in a region, so that near-term actions are developed within the context of a longer-term vision. 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 system enhancements based on different scenarios. The Working Group also recommends staging options to mitigate reliability and cost risks related to demand forecast uncertainty associated with large individual customers. The IRRP seeks to ensure flexibility is maintained such that changing long-term conditions may be accommodated.

In developing this IRRP, the Working Group followed a number of steps. These steps included: data gathering, including development of electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and, preparation of a recommended plan including actions for the near and longer term. Throughout this process, engagement was carried out with local municipalities, First Nation communities, Métis community councils and local stakeholders. These steps are illustrated in Figure 3-2 below.

Figure 3-2: Steps in the IRRP Process



This IRRP documents the inputs, findings, and recommendations developed through the process described above, and provides recommended actions for the various entities responsible for plan implementation.

3.3 Parry Sound / Muskoka Sub-region Working Group and IRRP Development

In 2014, the lead transmitter – Hydro One Transmission – initiated a Needs Screening process for the South Georgian Bay/Muskoka planning region. The South Georgian Bay/Muskoka Needs Screening study team determined that there was a need for coordinated regional planning, resulting in the initiation of the Scoping Assessment process.

The South Georgian Bay/Muskoka Scoping Assessment Outcome Report [6] was finalized on June 22, 2015 and identified two sub-regions for coordinated regional planning: Parry Sound/Muskoka and Barrie/Innisfil. The two sub-regions are shown in Figure 3-3.

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[6] South Georgian Bay/Muskoka Region Scoping Assessment Outcomes report (see IESO website: whttp://www.iemo.com/Documents/Regional-Planning/South-Georgian-Bay-Muskoka/SGBM-Scoping-Process-Outcome-Report-Final-20150622.pdf)

Figure 3-3: South Georgian Bay/Muskoka Region and Sub-regions

Subsequently, the Working Groups were formed to carry out the IRRP for the Parry Sound/Muskoka and Barrie/Innisfil Sub-regions. According to the OEB regional planning process, the Working Groups had 18 months to develop the IRRP.

In addition to the formation of the Working Groups, a LAC for the Parry Sound/Muskoka was established to allow community representatives to provide input on the status of local growth and developments, local planning priorities, energy planning activities (e.g., community energy planning), and opportunities to implement community-based energy solutions. Further detail regarding community and stakeholder engagement activities is provided in Section 9.

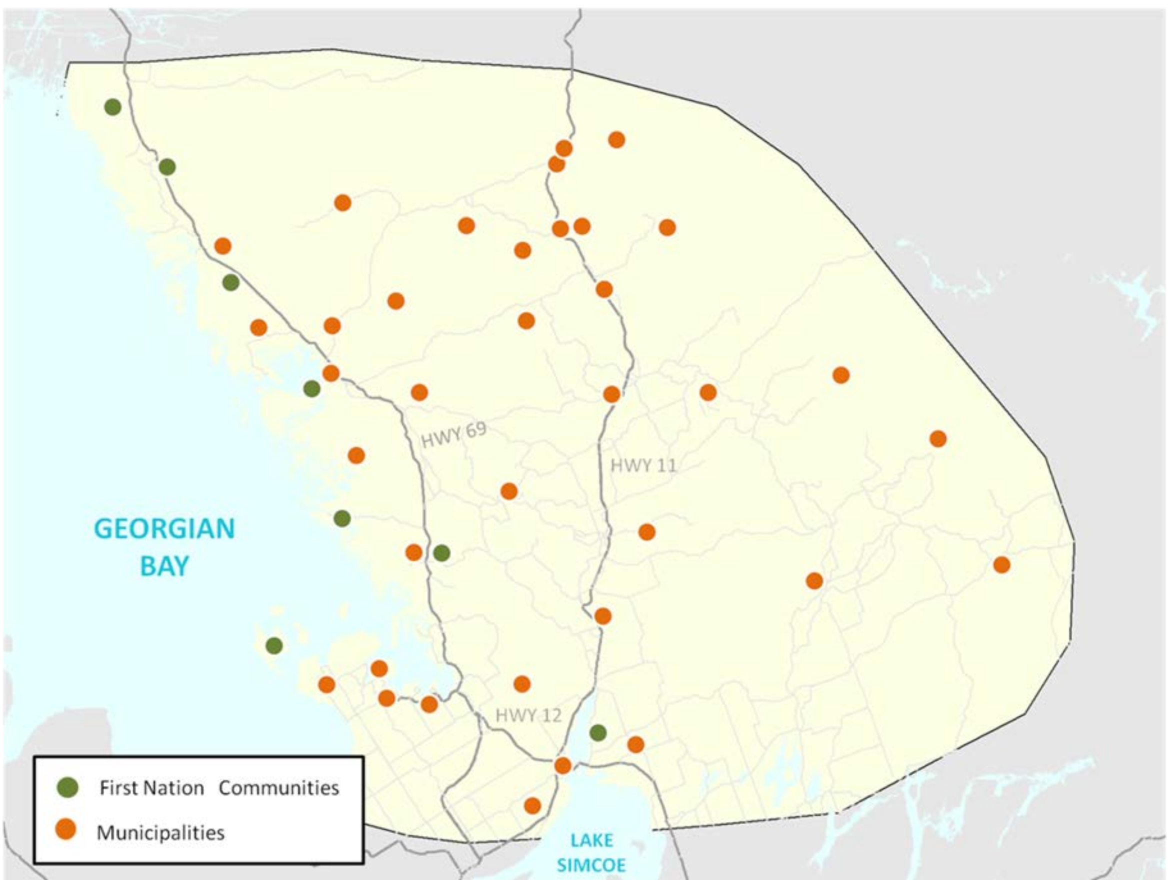
4. Background and Study Scope

The study scope of the IRRP is described in Section 4.1. Section 4.2 describes the electricity system supplying the Parry Sound/Muskoka Sub-region.

4.1 Parry Sound / Muskoka - Study Scope

The Parry Sound/Muskoka Sub-region roughly encompasses the Districts of Muskoka and Parry Sound and the northern part of Simcoe County. The approximate geographical boundaries of the sub-region are shown in Figure 4-1.

Figure 4-1: Geographical Boundaries of the Parry Sound/Muskoka Sub-region



The Parry Sound/Muskoka Sub-region includes the following First Nation communities:

- Henvey Inlet
- Magnetawan
- Shawanaga
- Wasauksing
- Moose Deer Point
- Beausoleil
- Wahta Mohawks
- Chippewas of Rama

The sub-region also includes the following municipalities:

- City of Orillia
- Municipality of Highlands East
- Municipality of Magnetawan
- Municipality of McDougall
- Municipality of Whitestone
- Town of Bracebridge
- Town of Gravenhurst
- Town of Huntsville
- Town of Kearney
- Town of Midland
- Town of Parry Sound
- Town of Penetanguishene
- Township of Algonquin Highlands
- Township of Armour
- Township of Carling
- Township of Georgian Bay
- Township of Joly
- Township of Lake of Bays
- Township of McKellar
- Township of McMurrich-Monteith
- Township of Minden Hills
- Township of Muskoka Lakes
- Township of Oro-Medonte
- Township of Perry
- Township of Ramara
- Township of Ryerson
- Township of Seguin

- Township of Severn
- Township of Strong
- Township of Tay
- Township of the Archipelago
- Township of Tiny
- United Townships of Dysart, Dudley, Harcourt, Guilford, Harburn, Bruton, Havelock, Eyre and Clyde
- Village of Burk's Falls
- Village of Sundridge

In addition, there are a number of unorganized areas in the District of Parry Sound.

The Parry Sound/Muskoka IRRP assesses the reliability and adequacy of the regional electricity system supplying the Parry Sound/Muskoka Sub-region and identifies integrated solutions for the 20-year period from 2015 to 2034. The electricity system supplying the Parry Sound/Muskoka Sub-region is described in more detail in Section 4.2.

It is important to note that connection assessments of generation resources procured under programs, such as the Feed-in-Tariff, are beyond the scope of this IRRP. Generation projects participating in procurement programs will be assessed according to the rules and specifications of those programs. However, the peak demand contribution from generation resources already contracted through such programs are taken into account in the demand forecast as described in Section 5.3.3.

4.2 Electricity System Supplying Parry Sound/Muskoka Sub-region

The electricity system supplying the Parry Sound/Muskoka Sub-region consists of local generation resources, 230 kV regional transmission, 44 kV sub-transmission and low voltage distribution networks. Local generation resources provide important sources of electricity supply to the communities and customers in this sub-region. However, local generation sources are not sufficient and are supplemented with power delivered to the sub-region from the rest of the province through the 230 kV transmission system. From the 230 kV transmission system power is delivered to communities and customers through the 44 kV sub-transmission and low-voltage distribution networks. The following sub-sections discuss these components in more detail.

4.2.1 Local Generation Resources

Local generation in the Parry Sound/Muskoka Sub-region is primarily hydroelectric and solar. The total installed capacity of local generation is approximately 126 MW comprised of approximately 28 MW hydroelectric, 97 MW solar, and 1 MW combined heat and power ("CHP").

In Ontario, the electricity system is designed to meet regional coincident peak demand – i.e., the one-hour period each year when total demand for electricity in the region is the highest. While hydroelectric and solar resources are potential sources of energy, only a portion of their generation capacity can be relied upon at the time of peak due to the variable nature of these resources. In the Parry Sound/Muskoka Sub-region, electricity demand typically peaks during the evening in the winter season. For the purpose of infrastructure planning, the installed capacity of distributed and variable generation is accordingly adjusted to reflect the reliable power output at the time of the local winter peak.

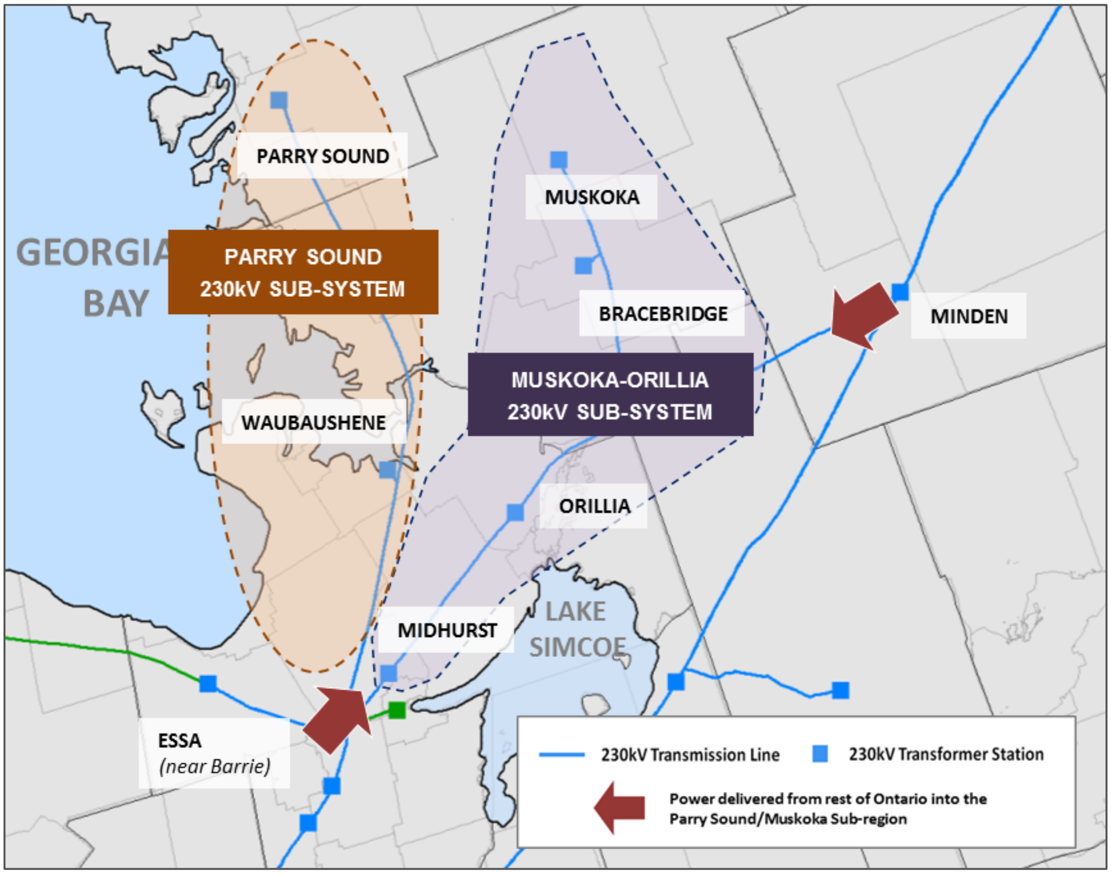
Hydroelectric facilities in the area are relatively small, generally less than 2 MW, however there are a couple facilities as large as 10 MW. The output of these facilities also depends on the availability of water resources and the operation of the facilities. To determine the dependable level of output at the time of peak, historical performance data of the hydroelectric generation facilities in the sub-region were used. The results are an assumed 34% capacity contribution from these resources.

Similarly, the solar facilities in the sub-region are also relatively small, with most being less than 0.5 MW, however there are a couple facilities as large as 10 MW. While the installed capacity of solar is high in the region, there is limited availability of solar power during the time of local peak, which occurs during the evening in the winter. It is assumed that solar would not provide any capacity at the time of local peak.

4.2.2 230 kV Transmission System

Power is delivered from the rest of the province into the Sub-region through the 230 kV transmission system at Essa (near Barrie) and Minden. As shown in Figure 4-2, the 230 kV transmission system supplies seven customers and utility-owned transformer stations. For the purpose of regional planning, the sub-region is further sub-divided into two regional 230 kV sub-systems: Muskoka-Orillia 230 kV sub-system and Parry Sound 230 kV sub-system.

Figure 4-2: Parry Sound/Muskoka Sub-region – 230 kV Transmission System

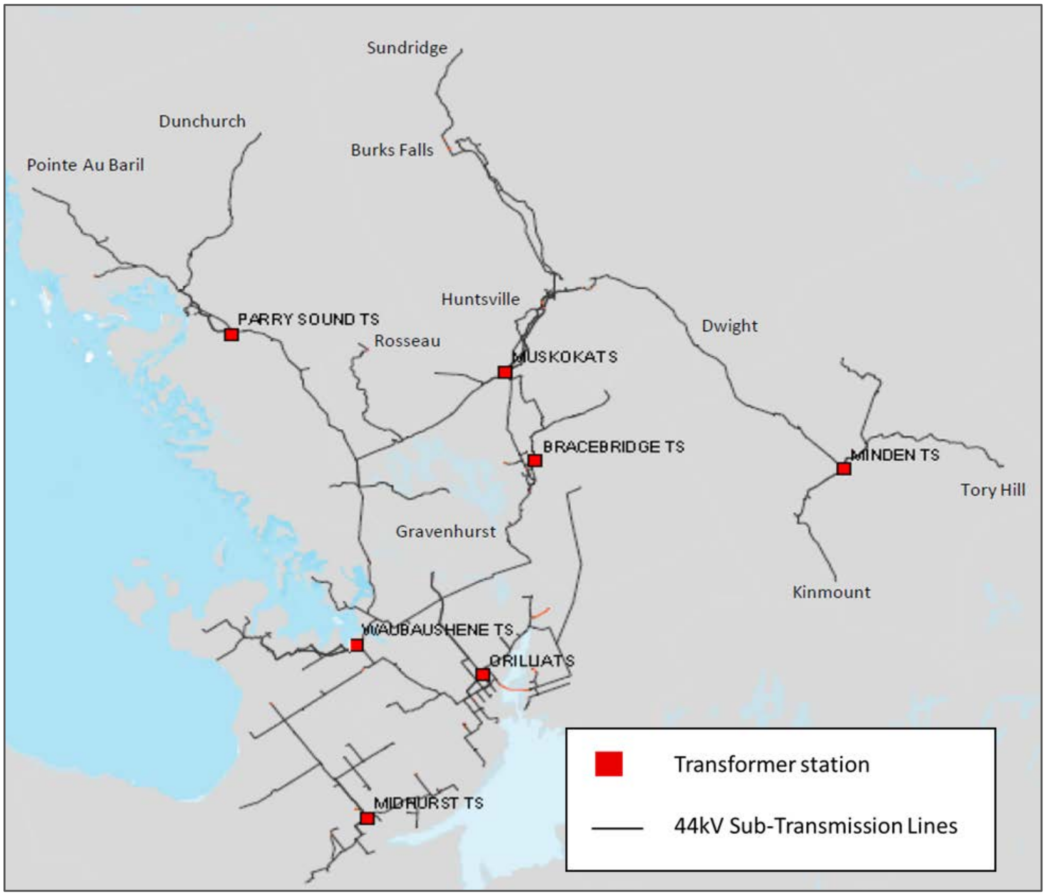


Since Midhurst TS primarily supplies the customers in the Barrie/Innisfil Sub-region, it is considered within the scope of the Barrie/Innisfil IRRP. However, Midhurst TS is supplied by the Muskoka-Orillia 230 kV sub-system and could impact the electricity supply to the Parry Sound/Muskoka Sub-region. Therefore, when assessing the reliability and adequacy of the Muskoka-Orillia 230 kV sub-system, the electricity demand growth at Midhurst TS needs to be considered in this IRRP.

4.2.3 44 kV Sub-transmission and Low-Voltage Distribution System

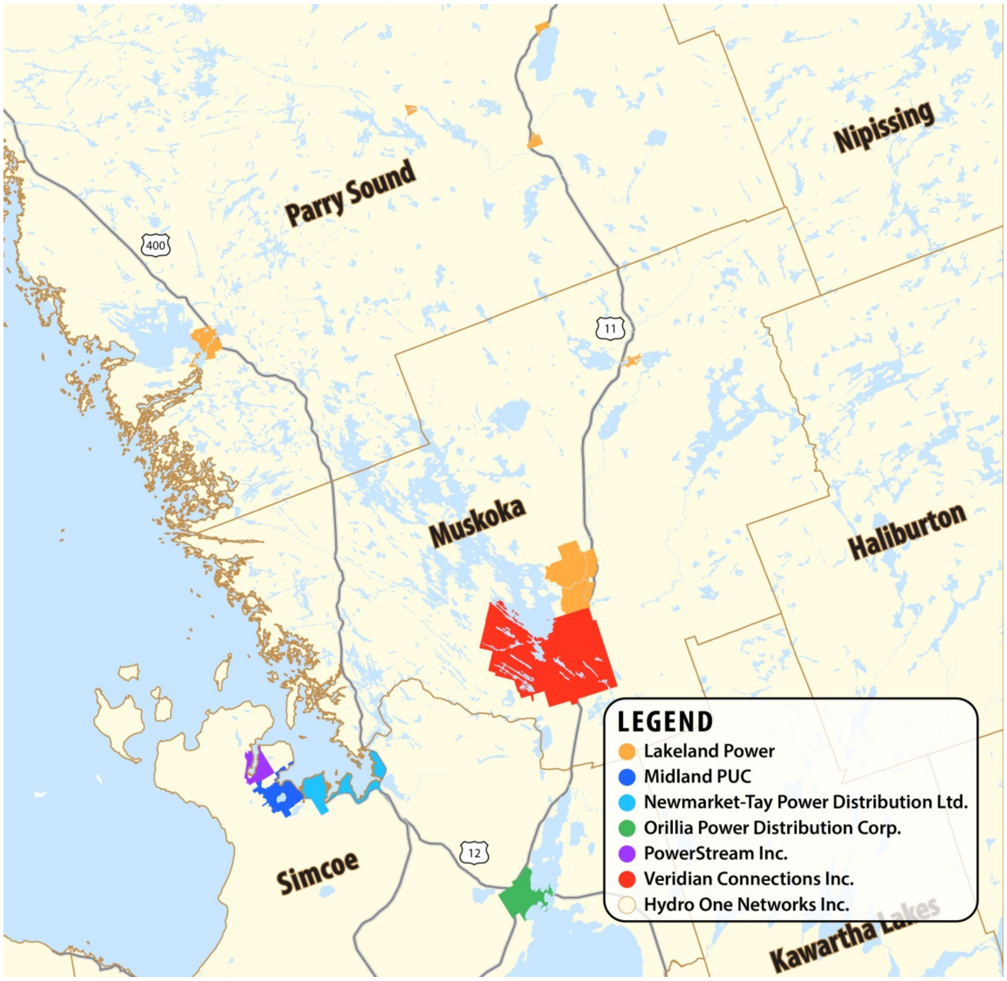
From the 230 kV sub-systems, power is delivered through transformer stations to the 44 kV sub-transmission system majority of which is operated by Hydro One Distribution in the Parry Sound/Muskoka Sub-region. As illustrated in Figure 4-3, given the large geography and sparsely populated areas, many communities and customers in this Sub-region are supplied by long 44 kV sub-transmission lines and a single source of supply.

Figure 4-3: 44 kV Sub-transmission System in the Parry Sound/Muskoka Sub-region



From the 44 kV sub-transmission system, power is delivered to the low voltage distribution network, which supplies various communities across the sub-region. The low-voltage distribution system is managed and operated by seven LDCs: Lakeland Power, Midland PUC, Newmarket-Tay Power, Orillia Power, PowerStream, Veridian Connections, and Hydro One Distribution, as shown in Figure 4-4.

Figure 4-4: Local Distribution Companies Service Areas



Distribution system planning is beyond the scope of the regional planning process. Issues related to the distribution system may be discussed in this IRRP for context, but will be addressed through the local distribution planning process led by the Local Distribution Companies ("LDCs").

Details regarding the characteristics of the LDC service areas can be found in Appendix A.

5. Demand Forecast

Regional electricity systems in Ontario are designed to meet regional coincident peak demand – the one-hour period each year when total regional demand for electricity is the highest.

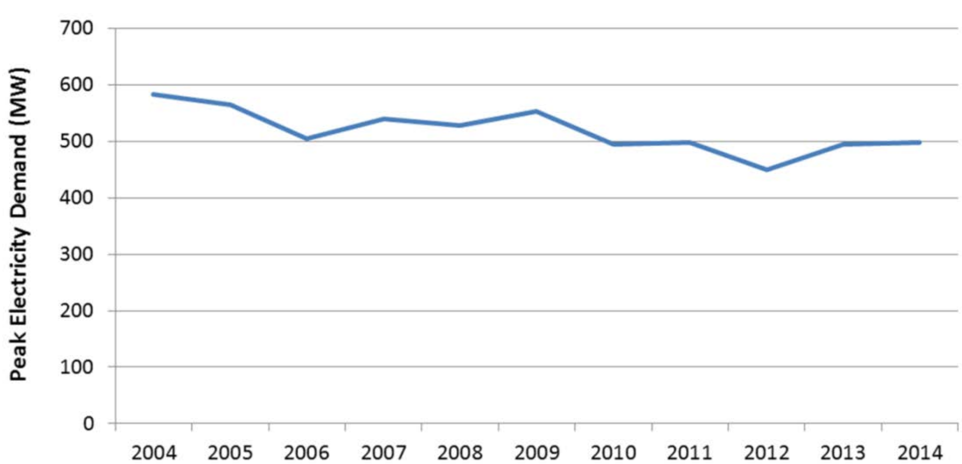
This section describes the development of the regional electricity demand forecast for the Parry Sound/Muskoka Sub-region. Section 5.1 describes historical electricity demand trends in the sub-region from 2004 to 2014. Section 5.2 provides an overview of the demand forecast methodology used in this study, and Section 5.3 summarizes the planning forecast for the sub-region.

5.1 Historical Electricity Demand 2004-2014

Electricity demand in this sub-region is primarily driven by residential and commercial customers. Due to limited access to natural gas infrastructure in this sub-region, many communities rely on electric space and water heating, especially during the winter season. As such, the electricity demand in this sub-region typically peaks during the winter months. This sub-region also supports a mix of economic activities including tourism, retail, healthcare and manufacturing industries. Seasonal population driven by tourism and recreation activities also contributes to the electricity demand requirements in this sub-region.

Demand has declined slightly between 2004 and 2010 but has been relatively stable since then at around 500 MW, as shown in Figure 5-1. The historical demand shown below was adjusted to account for weather-related impacts.

Figure 5-1: Historical Peak Demand - Parry Sound/Muskoka Sub-region (2004-2014)



5.2 Methodology for Establishing Planning Forecast

A planning forecast was developed to assess reliability of the Parry Sound/Muskoka Sub-region electricity system over the planning period (2015 to 2034). For the purpose of regional planning, the planning forecast considers the following components:

- Gross winter demand forecast scenarios for distribution-connected and transmission-connected customers,
- Estimated peak demand savings from meeting provincial energy conservation targets, and
- Expected peak demand capacity contribution from DG.

The gross demand forecast was developed based on the expected peak demand projections for distribution-connected and transmission-connected customers in the Parry Sound/Muskoka Sub-region. To develop the planning forecast, the gross demand forecast was modified to reflect the estimated peak demand savings from meeting provincial energy conservation targets and from existing and contracted DG.

Using a planning forecast that is net of provincial conservation targets is consistent with the province's Conservation First policy. However, this assumes that the targets will be met and that the targets, which are energy-based, will produce the expected local peak demand impacts. An important aspect of plan implementation will be monitoring the actual peak demand impacts of conservation programs delivered by the LDCs and, adapting the plan accordingly.

The methodology and assumptions used for the development of the planning forecast are described in detail in Appendix A.

5.3 Development of Planning Forecast

5.3.1 Gross Demand Forecast

The gross demand forecast was provided by the seven LDCs in this sub-region, based on customer connection requests, local economic development and growth assumptions outlined in Ontario's *Places to Grow Act, 2005*, which are reflected in municipal and regional plans.

A modest increase in electricity demand is forecast in this sub-region over the next 20 years. While slower growth is expected in the sub-region's manufacturing sector, growing Indigenous communities, new residential and commercial developments, seasonal population and potential local economic development such as the Parry Sound Airport Development and

Rama Road Corridor Economic Employment District, will contribute to growing electricity demand in the sub-region. Electric space and water heating requirements from communities, and aforementioned new residential and commercial developments will continue to be a major driver of peak electricity demand in this sub-region. Based on the information provided by the LDCs, gross demand is expected to grow 1.1% annually over the planning period.

Given the diverse communities and geography of this sub-region, electricity demand growth is not uniformly distributed across the sub-region. Only a small increase in electricity demand is expected in the northern Simcoe County, Minden and Parry Sound. Most of the electricity growth is forecast to be concentrated in Muskoka, Orillia and surrounding areas. For example, in Orillia, additional planned developments, including condominium and waterfront development and new retail, commercial, industrial and institutional customers may materialize within the 20-year planning period resulting in as much as an additional 20-22 MW of peak demand. For the purpose of regional planning, this potential load was considered as part of the sensitivity analysis.

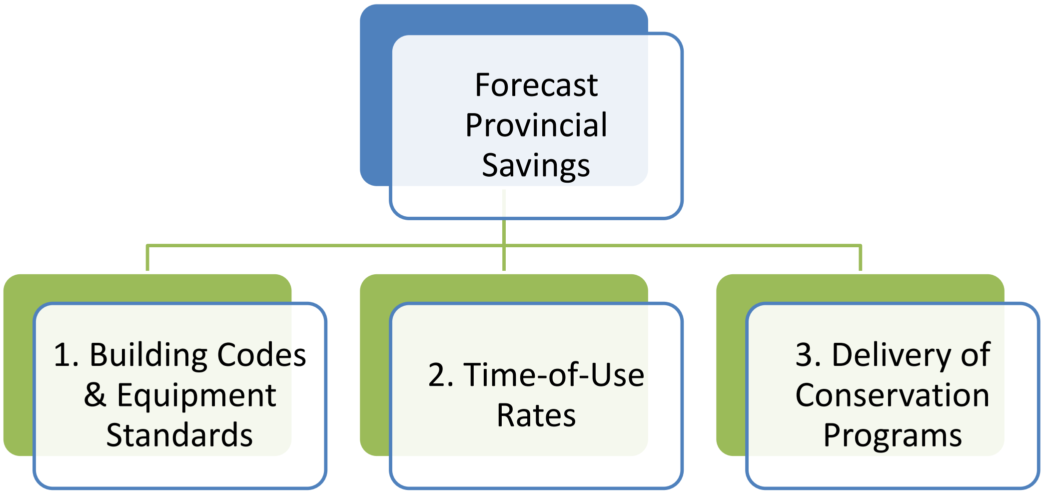
The specific forecasting methodology and assumptions for the gross demand forecast can be found in Appendix A.

5.3.2 Expected Peak Demand Savings from Provincial Conservation Targets

Conservation is incented and achieved through a mix of program-related activities, rate structures, and mandated efficiencies from building codes and equipment standards. Conservation plays a key role in maximizing the utilization of existing infrastructure and maintaining reliable supply by keeping demand within equipment capability. The conservation savings forecast for the Parry Sound/Muskoka Sub-region have been applied to the gross peak demand forecast, along with DG resources (described in Section 5.2), to determine the planning forecast in this sub-region.

In December 2013 the Ministry of Energy released a revised Long-Term Energy Plan ("LTEP") that outlined a provincial conservation target of 30 terawatt-hours ("TWh") of energy savings by 2032. The expected peak demand savings from meeting this target were estimated for the Parry Sound/Muskoka Sub-region. To estimate the impact of the conservation savings in the sub-region, the forecast provincial savings were divided into three main categories, as illustrated in Figure 5-2.

Figure 5-2: Categories of Conservation Savings



1. *Savings due to Building Codes & Equipment Standards*
2. *Savings due to Time-of-Use Rate structures*
3. *Savings due to the delivery of Conservation Programs*

The impact of estimated savings for each category was further broken down for the Parry Sound/Muskoka Sub-region by the residential, commercial and industrial customer sectors. The IESO worked together with the LDCs to establish a methodology to estimate the electrical demand impacts of the energy targets by the three customer sectors. This provides a better resolution of forecast conservation, as conservation potential estimates vary by sector due to different energy consumption characteristics and applicable measures.

For the Parry Sound/Muskoka Sub-region, LDCs were requested to provide breakdowns of their gross demand forecast, and electrical demand by sector for the forecast at each transformer station. For each transformer station where the LDC could not provide gross load segmentation, the IESO and the LDC worked together using best available information and assumptions to derive sectoral gross demand. For example, LDC information found in the OEB's Yearbook of Electricity Distributors was used to help estimate the breakdown of demand. Once sectoral gross demand at each transformer station was estimated, the next step was to estimate peak demand savings for each conservation category: building codes and equipment standards, time-of-use rates, and delivery of conservation programs. The estimates for each of the three savings groups were done separately due to their unique characteristics and available data. The final estimated conservation peak demand reduction, 35 MW by 2034, was then applied to the gross demand to create the planning forecast.

Additional conservation forecast details are provided in Appendix A.

5.3.3 Expected Peak Demand Contribution of Existing and Contracted Distributed Generation

As of 2015, about 123 MW of DG was contracted and/or existing in the Parry Sound/Muskoka Sub-region. The majority of the contracted and installed capacity is solar projects. The sub-region also has several hydroelectric power facilities and one CHP facility.

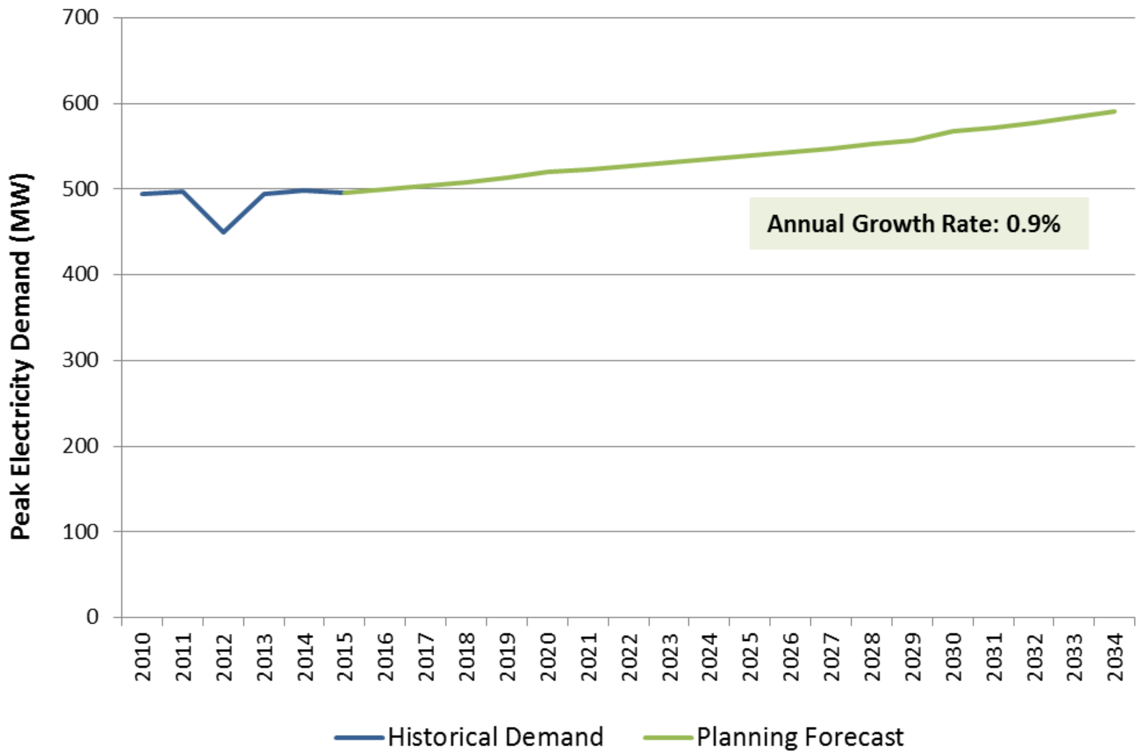
As the peak for the sub-region tends to occur during the winter evening hours, solar resources do not provide capacity contribution, however the other DG resources do have an impact on the peak. For the purpose of developing the planning forecast, contracted DG is expected to reduce the regional peak demand by as much as 11 MW over the next 20 years. Future DG uptake was, as noted, not included in the planning forecast and is instead considered as an option for meeting identified needs.

The expected annual peak demand contribution of contracted DG in the Parry Sound/Muskoka Sub-region can be found in Appendix A.

5.3.4 Planning Forecast

Figure 5-3 shows the planning forecast for the Parry Sound/Muskoka Sub-region for the planning period from 2015 to 2034 (using a base year of 2014). The planning forecast takes into consideration the gross demand forecast scenarios, estimated peak demand savings from provincial energy conservation targets, and existing and contracted DG. Based on the planning forecast, the electricity demand in the sub-region is expected to grow 0.9% annually, with an incremental peak demand growth of 100 MW over the planning period.

Figure 5-3: Parry Sound/Muskoka Sub-region Planning Forecast (2015-2034)



As discussed in Section 4.2.2, Midhurst TS primarily supplies the customers in the Barrie/Innisfil Sub-region. As a result, the Parry Sound/Muskoka Sub-region demand forecast shown above does not include electricity demand from Midhurst TS.

Further details related to the demand forecast scenarios can be found in Appendix A.

6. Needs

This section outlines the needs assessment methodology and identifies regional electricity supply and reliability needs over the 20-year planning period.

6.1 Needs Assessment Methodology

The IESO's ORTAC,[7] the provincial standard for assessing the reliability of the transmission system, was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of the bulk transmission system, as well as the assessment of local or regional reliability (see Appendix B for more details).

Through the application of these criteria, three broad categories of needs can be identified:

- **Transformer Station Capacity** is the electricity system's ability to deliver power to the local distribution network through the regional transformer stations. This is limited by the load meeting capability ("LMC") of the step-down transformer stations in the local area, which is the maximum demand that can be supplied from the transformer stations based on equipment rating and outage conditions.
- **Supply Capacity** is the electricity system's ability to provide continuous supply to a local area. This is limited by the LMC of the transmission line or sub-system, which is the maximum demand that can be supplied on a transmission line or sub-system under applicable transmission and generation outage scenarios as prescribed by ORTAC; it is determined through power system simulations analysis (See Appendix B for more details). Supply capacity needs are identified when peak demand on a transmission line or sub-system exceeds its LMC.
- **Load Security and Restoration** is the electricity system's ability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements prescribed by ORTAC are described in Appendix B.

[7] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

In addition, the needs assessment may also identify needs related to service reliability performance, equipment end-of-life and planned sustainment activities. Service reliability and performance is measured based on customers' exposure to power outages on the distribution and transmission system, and is expressed in terms of frequency (i.e., number of outages a year) and duration (e.g., length of time before the power is restored). Equipment reaching the end of its life and planned sustainment activities may impact the needs assessment and options development. Transmission assets reaching end-of-life are typically replaced with assets of equivalent capacity and specification. The need to replace aging transmission assets may present opportunities to better align investments with evolving power system priorities. This may involve up-sizing equipment in areas with capacity needs, or downsizing or even removing equipment that is no longer considered useful. Such instances may also present opportunities to enhance or reconfigure assets for infrastructure hardening to improve system resilience.

6.2 Regional and Local Electricity Reliability Needs

Through the needs assessments, the Working Group has identified the need: (1) to minimize the frequency and duration of power outages and (2) to provide adequate supply to support growth in the Parry Sound/Muskoka Sub-region. The following sections further describe these needs.

6.2.1 Need to Minimize the Frequency and Duration of Power Outages

As discussed in Section 4.2, while there is local generation in this sub-region, communities and customers primarily rely on the 230 kV transmission, 44 kV sub-transmission and low-voltage distribution lines to deliver power from the rest of the province into the Parry Sound/Muskoka Sub-region. Outages along any of these lines (i.e., 230 kV, 44 kV, low voltage distribution lines) could interrupt the electricity supply to communities and customers in the Parry Sound/Muskoka Sub-region.

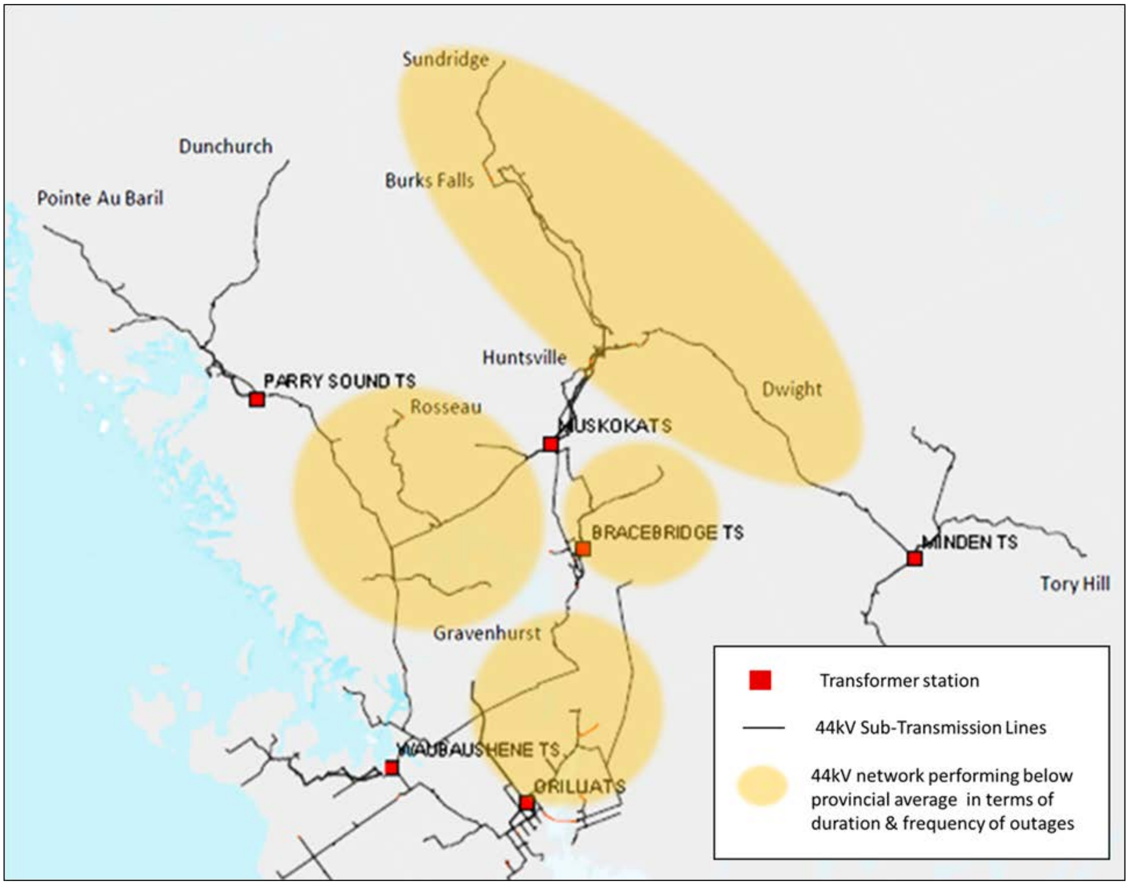
In this sub-region, customers and communities experience more frequent and prolonged power outages in comparison to customers and communities in other areas of the province. The consequences of extended power outages can have impacts for customers and society at large. For example, the Working Group has heard from communities and customers in this sub-region that below-average reliability is an impediment to economic development.

To better understand the causes of these power outages, the Working Group examined the service reliability and performance of the 44 kV sub-transmission system, and the load restoration capability and security of the 230 kV transmission line supplying the Parry Sound/Muskoka Sub-region. The results from the needs assessments are summarized below.

44 kV Sub-Transmission Service Reliability and Performance

In response to community and customers' concerns regarding power outages in this sub-region, the Working Group examined historical service reliability and performance of the 44 kV sub-transmission system over the last five years. Results from the assessment show that a number of 44 kV sub-transmission systems in this sub-region are performing below average in terms of frequency and duration of outages (as shown in Figure 6-1). On average, customers being supplied from a typical 44 kV sub-transmission line in Ontario experience outages about two times a year with outages typically lasting 5 hours or less. Based on the historical service reliability and performance data over the last five years, the outages for many of the 44 kV sub-transmission system in the Parry Sound/Muskoka Sub-region are almost double the provincial average in terms of frequency and duration.

Figure 6-1: 44 kV sub-transmission systems that are performing below provincial average in terms of frequency and duration of outages in the Parry Sound/Muskoka Sub-region



The service reliability and performance of the 44 kV sub-transmission system is impacted by a number of factors, including a facility's exposure to various elements, age and maintenance of equipment, length and configuration of the network, and the repair crew's accessibility to facilities. Lengthy 44 kV sub-transmission lines and off-road facilities are the main reasons for frequent and prolonged outages in the Parry Sound/Muskoka Sub-region.

- **Lengthy 44 kV sub-transmission lines:** As a large and sparsely populated geographical area, this sub-region is supplied by 44 kV sub-transmission lines that are typically longer than other 44 kV sub-transmission lines in Ontario. The average length of a 44 kV sub-transmission line in Ontario is about 45 km. Most of the 44 kV sub-transmission systems in the Parry Sound/Muskoka Sub-region range from 40 to 100 km in length. Long sub-transmission lines typically exhibit lower levels of reliability because of increased exposure to trees and wildlife. Tree contact has been identified as one of the major causes of 44 kV sub-transmission outages in this sub-region. Furthermore, with longer

44 kV sub-transmission lines, repair crews require additional time to identify and isolate causes of any outages.

- **Off-Road Facilities:** Many of the 44 kV sub-transmission systems are located off-roads. Due to limited access to off-road facilities, repair crews have difficulty detecting early signs of equipment failure, performing preventative maintenance and restoring power in a timely manner.

The detailed summary of the reliability performances of these 44 kV sub-transmission systems can be found in Appendix C.

<u>Load Restoration and Security on the 230 kV Transmission System</u>

Outage statistics from Hydro One Transmission indicate that have been three major outages involving the loss of both 230 kV transmission circuits in the sub-region since 1990. These outages lasted no more than 2-3 hours. While major 230 kV transmission outages have been relatively infrequent and short in duration in the Parry Sound/Muskoka Sub-region, the existing 230 kV transmission system supplying the Orillia and Muskoka area has limited ability to restore power in a timely manner and minimize the number of customers interrupted in the event of a major 230 kV transmission outage. As discussed in Section 6.1, the 230 kV transmission system should be designed in accordance with the load restoration and security criteria outlined in ORTAC (see Appendix B).

Based on the needs assessment, the Muskoka-Orillia 230 kV sub-system does not meet the ORTAC load restoration criteria and may violate the load security criteria over the longer term depending on the electricity demand growth in the area. The Muskoka-Orillia 230 kV sub-system is a 171 km double-circuit 230 kV transmission line (M6/7E) between Barrie and Minden. This system currently supplies four transformer stations and supplies about 465 MW of peak demand.[8] In the event of a major outage involving the loss of both transmission circuits on the Muskoka-Orillia 230 kV sub-system, all customers supplied by this transmission line would be interrupted. The existing system cannot restore any power to customers within 30 minutes. As

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[8] Muskoka-Orillia 230 kV sub-system includes the electricity demand at Orillia TS, Muskoka TS, Midhurst TS, and Bracebridge TS. Although Midhurst is part of Barrie/Innisfil IRRP, it is supplied by the Muskoka-Orillia 230 kV sub-system and could have an impact on the electricity supply to the Parry Sound/Muskoka Sub-region.

a result, the Muskoka-Orillia 230 kV sub-system does not meet the ORTAC 30 minute load restoration criteria.

Based on the planning forecast, the winter demand on the Muskoka-Orillia 230 kV sub-system is expected to increase to 621 MW by 2034. According to ORTAC load security criteria, no more than 600 MW of electricity supply can be interrupted following a major outage. Depending on the electricity demand growth, the Muskoka-Orillia 230 kV sub-system may violate the load security criteria over the longer term.

Action is required to improve the load restoration and security for the Muskoka-Orillia 230 kV sub-system and to bring the 230 kV transmission system in compliance with Ontario's planning standards.

6.2.2 Need to Provide Adequate Supply to Support Growth

To ensure there is an adequate and reliable source of electricity supply for the customers and communities in the Parry Sound/Muskoka Sub-region, the electricity system will need to have sufficient supply to support forecast electricity demand growth and to comply with ORTAC. Results from the needs assessment indicate that transformers at Waubaushene TS and Parry Sound TS are at, or nearing capacity and will be in violation of ORTAC in the near term. Over the longer term, electricity demand growth could also exceed the supply capability of the Muskoka-Orillia 230 kV sub-system. The following sections further discuss these near- and longer-term supply capacity needs.

<u>Demand Exceeds Capability at Parry Sound TS and Waubaushene TS in the Near-Term</u>

The transformers supplying the Town of Parry Sound and surrounding areas can supply up to 52 MW at the time of local peak (Parry Sound TS LMC = 52 MW). The electricity demand in the area has already exceeded the capability of these transformers over the last couple of years. For example, during the winter of 2015, these transformers supplied up to 61 MW at the time of local peak, exceeding the LMC of Parry Sound TS by about 9 MW. Near-term action is required to ensure that the electricity system in the area has adequate supply to support growth. Over the planning period, the electricity demand supplied by Parry Sound TS is forecast to grow less than 1 MW per year so that by 2034 Parry Sound TS would need to supply about 74 MW.

Similarly, Waubaushene TS, supplying Waubaushene and the surrounding area can supply up to 99 MW at the time of local peak (Waubaushene TS LMC = 99 MW). Today, Waubaushene TS supplies about 96 MW of electricity demand. The transformers at this station are nearing capacity and electricity demand growth is expected to exceed capability by 2017. Near-term action is required to ensure that the electricity system has adequate supply to support future growth. The electricity demand supplied by Waubaushene TS is expected grow modestly at less than 1 MW per year. Based on the planning forecast, Waubaushene TS is expected to supply about 111 MW of electricity demand by 2034.

Demand may exceed the capability of Muskoka-Orillia 230 kV sub-system over the longer term

The Muskoka-Orillia 230 kV sub-system can supply up to 600 MW at the time of peak (Muskoka-Orillia 230 kV sub-system LMC = 600 MW). Today, the Muskoka-Orillia 230 kV sub-system supplies up to 454 MW.[9] Given the modest electricity demand growth in this area, electricity demand is not expected to exceed its capability until the early 2030s based on the planning forecast.

Given the uncertainty associated with the long-term electricity demand forecast, it is sufficient to monitor demand growth before proceeding with an investment decision. Section 7.2.2 provides a high-level discussion of options to address this potential need over the longer term.

6.3 Other Electricity Needs and Considerations

In addition to the regional and local electricity reliability needs outlined in Section 6.2, the Working Group identified other electricity needs and considerations that could impact the regional electricity supply. These issues are discussed in more detail below.

6.3.1 End-of-Life Replacements and Sustainment Activities

The Minden 230/44 kV transformers are scheduled for end-of-life replacements within the next five years. Hydro One is preparing a plan to replace all the aging equipment at Minden TS in the next few years. The aging 25/42 MVA transformers are to be replaced with 50/83 MVA transformers to address the capacity needs at the station. This sustainment decision was made prior to the initiation of this IRRP.

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[9] Muskoka-Orillia 230 kV sub-system includes the electricity demand at Orillia TS, Muskoka TS, Midhurst TS, and Bracebridge TS. Although Midhurst TS is considered as part of Barrie/Innisfil IRRP, it is supplied by the Muskoka-Orillia 230 kV sub-system and has an impact on the electricity supply to the Parry Sound/Muskoka Sub-region.

In addition to the near-term sustainment activities, the Working Group also identified potential assets that could be reaching end-of-life over the planning period. The expected service life of a transformer is about 60 years. The transformers at Parry Sound TS and Waubaushene TS were installed in the early 1970s and therefore these transformers could be reaching end-of-life in the early 2030s. There may be opportunities to align end-of-life facility replacements with solutions to address longer-term needs in the sub-region.

6.3.2 Community Energy Planning

A number of communities in the sub-region are in the process of developing community energy plans ("CEP(s)"). At the time of this report, seven of the eight First Nation communities have received funding from the IESO through the Aboriginal Community Energy Plan program to develop CEPs. The Municipal Energy Plan Program[10] administrated by the provincial government supports municipalities in their efforts to develop CEPs.

Through community energy planning activities, communities will have a better understanding of their local energy needs and emissions footprint, be able to identify opportunities for energy efficiency and emissions reduction, and develop plans to meet their goals in consideration of local economic development. These CEPs examine broader energy needs, such as transportation, natural gas and electricity, and consider other objectives including net zero energy, electrification, and emissions reductions.

On June 8, 2016, the Ontario government released Ontario's Climate Change Action Plan ("CCAP"), which outlines policy to reduce the use of fossil fuel and to encourage the move toward a low carbon economy. In response to this policy direction, a CEP may include recommendations to promote electrification and other forms of fuel switching, such as shifting from natural gas to electric-power heat pumps and from gasoline to electric vehicles, to achieve a goal of reducing greenhouse gas ("GHG") emissions. As such, the outcomes from CEPs may drive additional requirements on the electricity system and should be monitored closely through the regional planning process. Furthermore, with the increased access to distributed energy resources, CEPs may identify opportunities for community-based energy solutions, such as district energy, CHP, or microgrids. Depending on the timing, location and magnitude of the

[10] For more information on the Ministry of Energy MEP Program: http://www.energy.gov.on.ca/en/municipal-energy/

needs, community-based energy solutions can be considered as potential options to address regional electricity needs.

6.3.3 Power Quality

A large customer in the sub-region is experiencing issues related to power quality. Power quality issues are defined as disturbances to the customer's electricity supply as a result of voltage. Voltage issues can be caused by customers' equipment and/or system voltage performance. The solutions and cost responsibility of investments to address power quality issues may vary depending on the root causes of the problem. The Working Group agreed that power quality issues need to be better understood and should be examined on a case-by-case basis by the area LDCs, transmitter and customers.

6.4 Needs Summary

Table 6-1 provides a summary of the regional supply and reliability needs in the Parry Sound/Muskoka Sub-region.

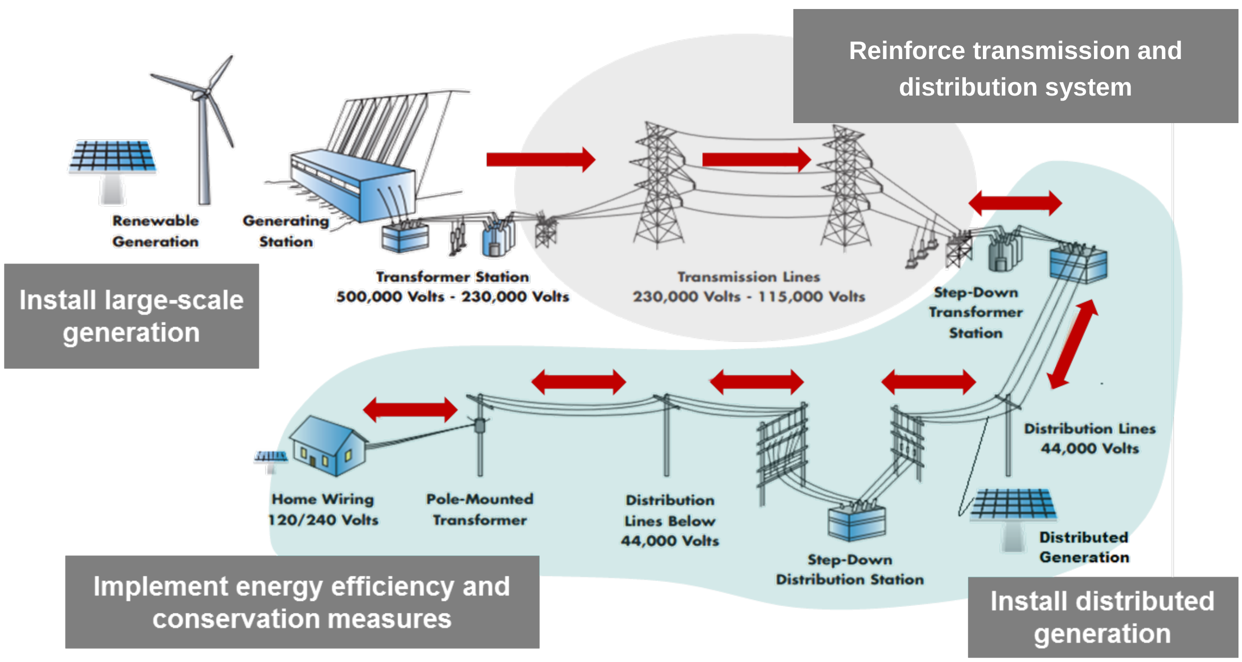
Table 6-1: Summary of Regional and Local Reliability Needs

Local and Regional Electricity Reliability Needs	Components	Status
Need to Minimize the Frequency and Duration of Power Outages	44 kV sub-transmission systems	Performing below provincial average in terms of frequency and duration of 44 kV sub-transmission outages
	Muskoka-Orillia 230 kV sub-system	Limited ability to restore power to customers in a timely manner in the event of a 230 kV transmission outage involving the loss of both transmission circuits. The sub-system does not meet the ORTAC load restoration criteria
		Electricity demand growth may exceed 600 MW and could violate the ORTAC load security criteria in the early 2030s
Provide Adequate Supply to Support Growth	Parry Sound TS	Electricity demand growth already exceeds system capability today
	Waubaushene TS	Electricity demand growth forecast to exceed system capability in 2017
	Muskoka-Orillia 230 kV sub-system	Electricity demand growth could exceed system capability in the early 2030s

7. Options to Address Regional and Local Electricity Needs

As shown in Figure 7-1, traditionally power has been generated from large, centralized generation sources. To provide electricity supply to the various communities across Ontario, power has been delivered through transmission and distribution infrastructure. To address regional and local electricity needs, one approach is therefore to reinforce the transmission and distribution infrastructure supplying the local area. However, in recent years, communities and customers have been exploring opportunities to reduce their reliance on the provincial electricity system by meeting their electricity needs with local, distributed energy resources and community-based solutions. This approach includes a combination of emerging technologies and conservation programs, such as targeted DR and conservation programs, DG and advanced storage technologies, micro-grid and smart-grid technologies, and more efficient and integrated process systems combining heat and power.

Figure 7-1: Options to Address Electricity Needs



__Options Evaluation__

When evaluating alternatives, the Working Group considered a number of factors, including technical feasibility, cost, flexibility, alignment with planning policies and priorities and consistency with long-term needs and options. Solutions that maximized the use of existing infrastructure were given priority.

Investing in new electricity infrastructure, such as a new transmission line or a generation facility requires substantial capital investment, has environmental/land-use impacts and has a long-service life. As such, it is important to take into the consideration the longer-term cost implications, value and potential risks (e.g., stranded or underutilized assets) when recommending an investment. Furthermore, these facilities typically require long lead times to obtain approvals and complete construction. For these reasons, decisions on new facilities must take into account these considerations and be made with sufficient lead time to ensure they are available when needed.

When assessing the need for infrastructure investments, it is important to strike a balance between overbuilding infrastructure (e.g., committing to infrastructure when there is insufficient demand to justify the investment) and under-investing (e.g., avoiding or deferring investment despite insufficient infrastructure to support growth in the region). Typically, demand management and energy efficiency programs can be implemented within six months, or up to two years for larger projects, whereas transmission and distribution facilities can take five to seven years to come into service. The lead time for generation development is typically two to three years, but could be longer depending on the size and technology type.

Finally, the issue of how much is appropriate to invest and who pays needs to be addressed. In regional planning, depending on the type and classification of assets, the costs may be shared by all provincial ratepayers or recovered only by the specific customers they serve (e.g., LDC, industrial customers). In some cases, a combination of cost-sharing may occur when there are both provincial and local benefits. Notably, the Working Group has heard concerns from communities about affordability. Given the high cost of electricity, it is important consider how investments impact local ratepayers.

<u>Near-Term Actions and Long-Term Planning Considerations</u>

For the near and medium term, the IRRP identifies specific actions and investments for immediate implementation. This ensures that necessary resources will be in-service in time to address more pressing needs. For the long term, the IRRP identifies potential options to meet needs that may arise in 10-20 years. It is not necessary to recommend specific projects at this time (nor would it be prudent given forecast uncertainty and the potential for technological change). Instead, the long-term plan focuses on developing and maintaining the viability of long-term options, engaging with communities, and gathering information to lay the groundwork for making decisions on future options.

As discussed in Section 6, actions need to be taken to (1) minimize the frequency and duration of power outages, and (2) ensure that the regional electricity system has adequate supply to support growth. In developing the 20-year plan, the Working Group examined a wide range of integrated solutions to address these local and regional needs. These options are discussed in the following section.

7.1 Minimize the Frequency and Duration of Power Outages

To minimize the frequency and duration of power outages, the Working Group examined options to improve service reliability and performance on the 44 kV sub-transmission system and to address load restoration and security needs on the 230 kV transmission system.

7.1.1 Options to Improve Service Reliability and Performance on the 44 kV Sub-transmission System

44 kV Sub-Transmission Maintenance and Outage Mitigation Initiatives

Hydro One Distribution owns and operates the 44 kV sub-transmission system in the Parry Sound/Muskoka Sub-region. Currently, Hydro One Distribution has a number of on-going maintenance and outage mitigation initiatives, including vegetation management, line patrols and grid modernization, to help reduce the frequency and duration of outages on the 44 kV sub-transmission system. These initiatives are summarized in Table 7-1.

Table 7-1: Status of Current Maintenance and Outage Mitigation Initiatives in the Parry Sound/Muskoka Sub-region

Initiatives	Status
Vegetation Management Program	▪ Vegetation management was last completed in these areas in 2015/2016 ▪ Full clearing for these areas is planned for 2021/2022 ▪ Hydro One has committed $20 million in 2016 in the districts of Muskoka and Parry Sound to reduce tree-related outages for its customers
Line Patrols	▪ Data is collected to help identify and prioritize the need to replace distribution poles and/or potentially defective equipment ▪ Last line patrolling cycle for these priorities areas occurred between 2010-2012 ▪ The next line patrolling cycle is scheduled for 2016 to 2021

Mid-cycle Hazard Tree Program	▪ Visual inspection to identify potential risk of tree-related contact ▪ This program will be conducted in this sub-region in 2018/2019
Distribution Management System & Grid Modernization	▪ Distribution management system will be implemented in this sub-region by the end of 2016 and will enable operators to have greater grid visibility and to respond to outages in a timely manner ▪ A broader grid modernization initiative is underway to identify opportunities for distribution automation (e.g., remote fault indicators, automated switches), which can help operators diagnose the sources of the outages and respond in a timely manner

In addition to these on-going maintenance programs and initiatives, Hydro One Distribution may take additional measures to further improve service reliability and performance on the 44 kV sub-transmission systems. These include:

- Install distribution automation and fast-acting switching devices to restore power in a timely manner
- Relocate "Off-Road" 44 kV sub-transmission system lines to roadside to facilitate access for maintenance crews
- Strengthen ties within the 44 kV sub-transmission system to allow adjacent 44 kV lines to serve as a back-up supply in the event of an outage

The cost, feasibility and effectiveness of these measures depend on the solution type, geography and nature of the 44 kV sub-transmission system and will need to be examined on a case-by-case basis. Hydro One Distribution will assess these options through the distribution planning process and will provide an update to the communities and LACs on plans to improve 44 kV sub-transmission system service reliability performance, including any proposed capital plans, by the end of 2017. The ability to implement any proposed capital investment plans will be contingent on the outcome of Hydro One Distribution's 2018-2022 rate filing application with the OEB.

Option to Resupply Customers from Bracebridge TS

Currently, the Town of Bracebridge, the Town of Gravenhurst, the Township of Muskoka Lakes, and the Township of Seguin are supplied by lengthy 44 kV sub-transmission system lines (60-100 km in length) from Muskoka TS and Orillia TS. To reduce 44 kV sub-transmission line exposure, new 44 kV sub-transmission lines can be built (~ up to 15 km) to resupply these areas from Bracebridge TS. These new 44 kV sub-transmission lines to Bracebridge TS cost about $3 to $6 million.

Today, Bracebridge TS supplies one industrial customer. The electricity demand from this industrial customer has decreased significantly over several years. Over the longer term, there should be sufficient capacity at Bracebridge TS to supply some of the customers in the Town of Bracebridge, the Town of Gravenhurst, the Township of Muskoka Lakes, and surrounding areas.

As discussed in Section 6.2.1, outages on the transmission system or transformer stations are relatively infrequent in this sub-region. However, due to the current system configuration at Bracebridge TS,[11] all power being supplied by the Bracebridge TS will be interrupted in the event of an outage at the TS or on the 230 kV transmission line.

Operational measures could help mitigate customers' exposure to outages on the 230 kV transmission system supplying Bracebridge TS. In the event of an outage on the 230 kV system, customers could rely on the Muskoka TS or Orillia TS as a backup supply and vice versa. In addition, a second TS and/or a combination of switching facilities could be installed to minimize the impact of potential 230 kV transmission system outages. The cost of these transmission reinforcements could range from $5 to $30 million.

Going forward, Hydro One Transmission, Hydro One Distribution, Lakeland Power and Veridian Connections will examine the cost-benefit and cost-responsibility of options to improve the service reliability performance of the 44 kV sub-transmission system supplying the Bracebridge/Gravenhurst/Muskoka Lakes and surrounding areas and will discuss these findings with the Working Group through the regional planning process. This action is expected to be completed by the end of 2017. The results from these discussions will be shared with LAC members and affected communities.

[11] In Ontario, most transformer stations are designed to have two transformers to provide redundancy during outages on the transmission system. In the event that one transformer is out-of-service, the remaining TS could still provide a continuous supply to the customers. Because Bracebridge TS was originally designed to serve the needs of the specific industrial customer, the station only has a single transformer.

7.1.2 Options to Improve Load Restoration and Security on the Muskoka-Orillia 230 kV Transmission System

Distribution Option

One option to restore electricity supply to customers following a major outage on the Muskoka-Orillia 230 kV sub-system is to resupply these customers from neighbouring 230 kV transmission system (e.g., Parry Sound 230 kV sub-system) using the distribution network. The extent to which these customers can be resupplied through the distribution network is highly variable and depends on various factors such as load level at neighbouring stations, distance between stations, voltage of neighbouring distribution systems, time of day and operating procedures in place on the distribution system. Based on information provided by the LDCs, only about 20 to 30 MW can be resupplied from neighbouring stations within 30 minutes following a major outage on the Muskoka-Orillia 230 kV sub-system. In order to meet the ORTAC load restoration at today's demand level, the system will need to restore at least 200 MW within 30 minutes following the transmission outage. As such, this option is not sufficient to meet the ORTAC load restoration criteria.

Transmission Option

In the event of a 230 kV transmission outage, fast-acting isolating devices can be installed to minimize the impact of supply interruption to customers. There are two types of fast-acting isolating devices: (1) motorized switches and (2) breakers.

Motorized switches can be used to isolate sections of the transmission line within 30 minutes following a major transmission outage and would enable power to be restored to customers in a timely manner. This is particularly important in remote areas, where repair crew may have limited access to the infrastructure. Grid operators can operate these switches remotely to isolate sections affected by an outage in a timely manner. The cost of these switches ranges from $5 to $7 million.

As an alternative solution, breakers can immediately isolate sections of the transmission line that are not directly impacted by the outage. Since breakers can reduce the total number of customers that would be affected by a transmission outage, it can be an effective solution to address the longer-term load security needs on Muskoka-Orillia 230 kV sub-system. Since additional infrastructure and protection and control systems are required for breakers, the cost of breakers is usually 3-4 times more than for motorized switches ($20 to $25 million). Given the uncertainty of the demand forecast over the longer term and the substantial cost of installing breakers, the Working Group agreed that installing breakers on the Muskoka-Orillia 230 kV sub-system is not required at this time. A summary of options to improve load restoration and load security on Muskoka-Orillia 230 kV sub-system can be found in Appendix E.

In consideration of the cost-benefit of these options, the Working Group recommends proceeding with the installation of two 230 kV motorized switches at Orillia TS. With these switches, about 50% of the electricity supply to customers on the Muskoka-Orillia 230 kV sub-system could be restored within 30 minutes in the event of an outage on the 230 kV transmission system, meeting the ORTAC 30 minute load restoration criteria.

To bring the 230 kV transmission system in compliance with Ontario's planning standard, the IESO will provide a letter to Hydro One Transmission to initiate project development work for the two 230 kV motorized switches at Orillia TS. Based on project development timeline for switching facilities, the project is expected to be in-service by the end of 2020.

7.1.3 Opportunities to Use Community-Based Solutions to Improve Resilience and Service Reliability

In addition to the transmission and distribution options discussed above, there may be opportunities to improve system resilience and service reliability at the community level using distributed energy resources and emerging technologies, such as residential solar-storage technology, micro-grids and on-site generation. Many of the community-based solutions are still in the early stages of development. The Working Group needs to better understand the cost and feasibility of these options. Depending on the interest from First Nation communities, municipalities and the LAC, the Working Group can facilitate discussions on the cost-benefit of opportunities to improve system resilience and the service reliability through community-based solutions. A good opportunity for these discussions may be through community energy planning activities.

7.2 Provide Adequate Supply to Support Growth

To ensure that the regional electricity system has adequate supply to support growth, the Working Group examined options to address the near-term needs at Parry Sound TS and Waubaushene TS and the longer-term supply capacity needs on the Muskoka-Orillia 230 kV sub-system.

The following section discusses these options in more detail.

7.2.1 Options to Provide Additional Transformer Station Capacity at Parry Sound TS and Waubaushene TS

Distribution Option

To free up supply capacity at Parry Sound TS and Waubaushene TS, some customers in the Parry Sound and Waubaushene areas can be resupplied from neighbouring transformer stations using existing and/or new 44 kV sub-transmission facilities.

To manage the near-term demand growth in the area, about 4 MW at Waubaushene TS can be resupplied from Orillia TS using the existing 44 kV sub-transmission infrastructure by 2020. If required, another 7 MW at Waubaushene TS can be resupplied from Midhurst TS upon completion of Barrie Area Transmission Reinforcement in the early 2020s. This can be done using existing distribution system and no new facilities will be required. This option would address the needs at Waubaushene TS over the planning period at minimal cost and would maximize the use of existing facilities. Midhurst TS is a major transformer station supplying the Barrie/Innisfil Sub-region. Resupplying some of the customers in Waubaushene from Midhurst TS could have an impact on the timing and need for a new TS in the Barrie/Innisfil Sub-region over the longer term. As such, the Working Group will need to coordinate with the Barrie/Innisfil IRRP Working Group to monitor and manage the demand growth in the Waubaushene and Barrie/Innisfil areas.

Similarly, to manage the near-term growth in the area, about 6 MW at the Parry Sound TS can be resupplied from Muskoka TS. There is sufficient capacity at Muskoka TS to supply these customers over the planning period. To facilitate the transfer of load from Parry Sound TS to Muskoka TS, Hydro One will need to seek approval to construct 44 kV feeder tie between the Muskoka TS M5 and M1 feeders (estimated cost of about $7 million). The siting and routing of these facilities will be determined as part of the project development process. Based on the typical project development timeline for 44 kV sub-transmission reinforcements, the project is expected to be in-service by 2020. These reinforcements would substantially address the near-term supply needs at Parry Sound TS and would also improve service reliability for the Townships of Muskoka Lakes and Seguin.

In the near term, the Working Group recommends resupplying some customers in the Parry Sound and Waubaushene areas from neighbouring transformer stations. This option will fully address the supply needs at Waubaushene TS over the planning period and will help manage near-term demand at Parry Sound TS at a minimal cost. Even after implementing these near-term measures, about 16 MW of additional supply will still be required to address the supply needs at Parry Sound TS over the planning period. As such, other options will need to be considered to address the supply needs at Parry Sound TS over the planning period.

Transmission Option

Transformers at the existing Parry Sound TS and Waubaushene TS can be upgraded to enable more power to be delivered to the Parry Sound and Waubaushene areas. This option costs about $25 to $30 million for each transformer station upgrade.

Transmission-Connected Generation Facilities

Since the need is at the transformer station level, transmission-connected generation facilities would not address the need. The Working Group therefore did not consider it.

Community-Based Solution: Local Demand Management and Distributed Energy Resources

With the relatively slow electricity demand growth forecast for this sub-region, there is an opportunity to use targeted conservation and local demand management, distribution-connected generation and/or other distributed energy resources to defer the transformer upgrade at Parry Sound TS and Waubaushene TS. In order to defer the transformer upgrades, LDCs would need to reduce the electricity demand by about 1 MW annually at each of these transformer stations. Based on economic analysis, the LDCs can save about $2 million for every year of deferred capital. More details related to the capital deferral analysis can be found in Appendix D.

Through discussions with the LDCs and communities, the Working Group has identified a number of potential community-based solutions to address supply needs in the Parry Sound and Waubaushene areas. For example:

- **Heating efficiency:** As discussed in Section 5.1, the electricity demand peak in this sub-region is driven by electric space and water heating. There may be opportunities to reduce the peak demand by improving heating efficiency in the area.

  While a large portion of the communities in this sub-region rely on electric heating, some customers also rely on other fuel types, such as wood, to meet their heating requirements. In some cases, communities may have some access to natural gas infrastructure. Through initiatives, such as home energy audits, retrofit programs and community energy planning activities, the Working Group can work with communities to better understand the heating requirements and energy baseline (e.g., heating fuel, housing insulation) and identify opportunities to improve heating efficiencies in the Parry Sound/Muskoka Sub-region.

- **Local hydroelectric potential:** Based on information provided by the Ontario Waterpower Association ("OWA"), there is about 38 MW of hydroelectric potential in the Parry Sound District. As discussed in Section 4.2.1, many of the hydroelectric resources are run-of-the-river facilities with limited storage capability. As such, only a portion of their installed capacity can be relied upon at the time of local peak. Furthermore, much of these potential hydroelectric resources are located far from existing transmission and distribution infrastructure. To access this potential, additional transmission and distribution infrastructure may be required. More details related to these hydroelectric potential can be found in Appendix F.

- **Pilots and emerging technologies:** Many LDCs are engaging in pilots and studies to better understand the costs and feasibility of community based solutions and **e**merging technologies, such as residential solar-storage technology, microgrids, and thermal energy storage. These emerging technologies can potentially help reduce a community's reliance on the provincial grid during the time of local peak.

At this time, the Working Group has limited information on the cost and feasibility of distributed energy resources and local demand management. More work is needed to determine whether it is cost effective and feasible to rely on these solutions to address the local need. To better understand the cost and feasibility of implementing distributed energy solutions and demand management in the Parry Sound/Muskoka Sub-region, the Working Group recommends initiating a local achievable potential ("LAP") study for the Parry Sound/Muskoka Sub-region in early 2017. The study will examine the cost and feasibility of a range of distributed energy resources and local demand management options including incentive adders to existing conservation programs, new conservation and demand management programs, local demand response, behind-the-meter generation and energy storage. The study may also examine options to manage new demand from increased electrification that may result from Ontario's CCAP. This study will be initiated in early 2017 by the LDCs. The IESO will assist and provide funding for the LAP study.

As well, the Working Group will work closely with communities to leverage local knowledge and community energy planning activities and to identify opportunities for targeted conservation and energy efficiency opportunities in First Nation communities and municipalities.

End-of-Life Replacement Considerations

As discussed in Section 6.3.1, transformers at Parry Sound TS and Waubaushene TS could be reaching their end-of-life in the early 2030s. Depending on the electricity demand growth, it may be cost effective to advance the end-of-life replacement of these aging assets with upgraded/upsized facilities.

To determine if there is an opportunity to align the end-of-life facility replacement with solutions to address supply need at Parry Sound TS and Waubaushene TS, the Working Group will actively monitor and assess the conditions of these transformers and electricity demand growth. The Working Group will revisit this need in the next iteration of the plan.

7.2.2 Options to Provide Additional Supply Capacity on Muskoka-Orillia 230 kV sub-system over the Longer Term

As discussed in Section 6.2.2, about 20 MW of additional supply capacity will be required on the Muskoka-Orillia 230 kV sub-system in the early 2030s. Given the uncertainty with the demand growth and the fact that the need does not arise until late in the planning period, early development work for major electricity infrastructure projects is not required at this time. However, it is important to continue to monitor demand closely to determine if and when an investment decision for the Muskoka-Orillia 230 kV sub-system is required. To lay the ground work for the next planning cycle, the Working Group has explored potential options to address the longer-term needs on Muskoka-Orillia 230 kV sub-system.

Distribution Option

To free up supply capacity on the Muskoka-Orillia 230 kV sub-system, one option is to supply some of customers on the Muskoka-Orillia 230 kV sub-system from the transformer stations on the Parry Sound 230 kV sub-system using existing and/or new 44 kV sub-transmission facilities. However, as discussed in Section 6.2.2 , electricity demand at Parry Sound TS and Waubaushene TS has already exceeded the TS capacity and would not have sufficient capacity to supply additional customers. This option was therefore ruled out by the Working Group.

Transmission Options

Installing switching facilities or upgrading sections of the transmission lines can enable more power to be delivered into the Muskoka-Orillia 230 kV sub-system. These enhancements may be subject to regulatory approvals, such as a Class Environmental Assessment and utilities' rate filings. The lead time to develop these facilities is typically three to five years.

The costs of these transmission reinforcements range from $20 to $30 million depending on the reinforcements requirements. Cost responsibility for the transmission reinforcements would be determined as part of the regulatory application review process.

This option should be considered and revisited in the next iteration of the plan.

Transmission-Connected Generation Option

Siting transmission-connected generation facilities can be effective for addressing supply capacity on Muskoka-Orillia 230 kV sub-system. A 20 MW generation facility connected to Muskoka-Orillia 230 kV sub-system can address the potential supply capacity needs arising in the early 2030s.

There are a number of factors that need to be considered when siting localized generation, and any decisions would need to align with the recommendations found in the August 2013 report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum"[12] prepared for the Minister of Energy by the former OPA and the IESO.

As the requirements in the Parry Sound/Muskoka Sub-region are for additional capacity during times of peak demand, a large, transmission-connected generation solution would need to be capable of being dispatched when needed, and operate at an appropriate capacity factor. In some cases, additional transmission reinforcements may also be required.

The cost of a large, localized generation resource depends on the size, fuel type, technology and the degree to which it can contribute to the local and provincial system capacity or energy needs. The fuel availability will also need to be taken into consideration. The lead time for generation development is typically two to three years, but it could be longer depending on the size and technology type.

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[12] http://www.ieso.ca/Pages/Participate/Regional-Planning/Local-Advisory-Committees.aspx

This option should be considered and revisited in the next iteration of the plan.

<u>Community-Based Solutions: Local Demand Management and Distributed Energy Resources</u>

With the modest electricity demand growth in this sub-region, there is an opportunity to use targeted local demand management, distribution-connected generation and/or other distributed energy resources to manage demand on the Muskoka-Orillia 230 kV sub-system and to defer major capital investments and infrastructure development over the longer term. As discussed in Section 7.2.1, the Working Group will initiate a LAP study to determine the cost and feasibility of using distributed energy resources and local demand management options to defer major capital investments (e.g., transmission reinforcements). In conjunction with the study, the Working Group will continue to work closely with communities to coordinate community-energy planning activities and to identify opportunities for targeted CDM opportunities in First Nation communities and municipalities.

This option should be considered and revisited in the next iteration of the plan.

8. Recommended Actions

The recommended actions to minimize the frequency and duration of power outages and to provide adequate supply to support growth in the Parry Sound/Muskoka Sub-region over the planning period are outlined in Tables 8-1 and 8-2, along with the proposed timing and the parties that will lead the implementation.

The Working Group will continue to meet regularly during the implementation phase of this IRRP to monitor developments in the sub-region and to track progress toward these deliverables and this information will be shared and discussed with the LAC.

Table 8-1: Recommended Actions to Minimize Frequency and Duration of Power Outages

	Recommendations	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1	**Inform communities and LAC members of the 44 kV sub-transmission service reliability performance and the on-going maintenance and improvement initiatives in the Parry Sound/Muskoka Sub-region**	Provide an update to communities and LAC members on the 44 kV sub-transmission service reliability performance improvements including any proposed capital plans The ability to implement any proposed capital investment plans will be contingent on the outcome of Hydro One Distribution's 2018-2022 rate filing application with the OEB.	Hydro One Distribution	End of year 2017
2	**Examine the cost benefit and cost responsibility of options to resupply customers in Bracebridge, Gravenhurst, Muskoka Lakes and surrounding areas from alternate transformer station**	Discuss findings and decision with the Working Group through the regional planning process Share the results with LAC members and affected communities	Hydro One Distribution, Lakeland Power and Veridian Connections	To be completed by Q4 2017

3	**Install two 230 kV motorized switches at Orillia TS to restore power to customers in timely manner in the event of a major outage on the Muskoka-Orillia 230 kV sub-system**	Prepare a letter to Hydro One Transmission to initiate project development work	IESO	Early 2017
		Design, develop and construct two 230 kV motorized switches	Hydro One Transmission	In-service by end of 2020
4	**Explore opportunities to improve resilience and service reliability at the community level**	Facilitate discussions with First Nation communities, municipalities and LAC members on the cost-benefit and opportunities to improve system resilience and service reliability through community energy planning	IESO	On-going

Table 8-2: Recommended Actions to Provide Adequate Supply to Support Growth

Recommendations		Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1	**Resupply some customers in the Parry Sound and Waubaushene areas from neighbouring transformer stations using existing and new distribution facilities to maximize the use of the existing system**	Seek approval to construct 44 kV feeder tie between the Muskoka TS M5 and M1 feeders to facilitate the transfer of load from Parry Sound TS to Muskoka TS	Hydro One Distribution	In-service by 2020
		Transfer up to 4 MW from Waubaushene TS to Orillia TS Transfer up to 6 MW from Parry Sound TS to Muskoka TS	Hydro One Distribution	Prior to 2020
		Transfer up to 7 MW from Waubaushene TS to Midhurst TS (if required)	Hydro One Distribution	Early 2020s upon completion of

				Barrie Area Transmission Reinforcement
		Coordinate with the Barrie/Innisfil IRRP Working Group to monitor and manage demand growth in the Waubaushene and Barrie/Innisfil areas	IESO	On-going
2	**Determine the cost and feasibility of using distributed energy resources and local CDM options to defer major capital investments in the Parry Sound/Muskoka Sub-region**	Initiate a LAP study to determine the cost and feasibility of using distributed energy resources and local conservation and demand management options to defer major capital investments (e.g., transmission reinforcements)	IESO to assist and provide funding LDCs to carry out the study	Initiate study in early 2017
		Work closely with communities to leverage local knowledge and community energy planning activities and to identify opportunities for targeted conservation and demand management opportunities in First Nation communities and municipalities.	IESO	On-going
3	**Determine whether it is cost effective to advance the end-of-life replacement and to replace the aging assets with upgraded/upsized facilities at Parry Sound TS and Waubaushene TS**	Review electricity demand growth at Parry Sound TS and Waubaushene TS with LAC members	IESO	Annually
		Monitor and provide updated information on the condition of aging equipment at Waubaushene TS and Parry Sound TS to the LAC and the Working Group	Hydro One Transmission	Annually

		Determine whether it is cost effective to advance the end-of-life replacement and to replace the aging assets with upgraded/upsized facilities.	IESO	Annually
4	**Monitor electricity demand growth closely to determine if and when an investment decision on the Muskoka-Orillia 230 kV sub-system is required**	Review electricity demand growth on the Muskoka-Orillia 230 kV sub-system with LAC members	IESO	Annually

9. Community and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in the regional planning process enables the views and preferences of the community to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the engagement activities undertaken to date and next steps for the Parry Sound/Muskoka IRRP.

A phased community engagement approach was undertaken for the Parry Sound/Muskoka IRRP based on the core principles of creating transparency, engaging early and often, and bringing communities to the table. These principles were established as a result of the IESO's outreach with Ontarians in 2013 to determine how to improve the regional planning and siting process, and they now guide IRRP outreach with communities and will ensure this dialogue continues as the plan moves forward.

Figure 9-1: Summary of the Parry Sound/Muskoka Community Engagement Process

Creating Transparency:

Creation of Parry Sound/Muskoka IRRP Information Resources

- Dedicated Parry Sound/Muskoka IRRP web page created on IESO website providing background information, the IRRP Terms of Reference and listing of the Working Group members
- Dedicated web page created on Hydro One website
- Self-subscription service established for the South Georgian Bay/Muskoka planning region for subscribers to receive regional planning updates
- Status: complete

Engaging Early and Often:

Municipal and Indigenous Outreach

- Early engagement on regional planning and the South Georgian Bay/Muskoka Scoping Assessment Report (September 2015)
- Group meetings held with municipalities from across the planning region held in Huntsville and Parry Sound (September 2015)
- Meetings held with First Nation communities in Rama (September 2015)
- Status: initial outreach complete; dialogue continues

Bringing Communities to the Table:

Broader Community Outreach

- Parry Sound/Muskoka LAC formed in spring 2016; dedicated Parry Sound/Muskoka engagement web page added to IESO website
- Two LAC meetings held in June and September 2016 to discuss and obtain feedback on the development of the IRRP and draft recommendations
- LAC meetings are open to the public; materials are posted to the engagement webpage
- Status: begun in spring 2016; on-going

9.1 Creating Transparency

To start the dialogue on the Parry Sound/Muskoka IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated web page was created on the IESO website including a map of the regional planning area, information on why an IRRP was being developed for the Parry Sound/Muskoka Sub-region, the IRRP terms of reference and a listing of the organizations involved. A dedicated email subscription service was also established for the broader South Georgian Bay/Muskoka planning region where communities and stakeholders could subscribe to receive email updates about the IRRP.

9.2 Engage Early and Often

Early communication and engagement activities for the Parry Sound/Muskoka IRRP were initiated in September 2015 as part of a series of meetings with communities and stakeholders to discuss electricity planning initiatives across the Parry Sound/Muskoka Sub-region. The main objective of the meetings from a regional planning perspective was to introduce attendees to the regional planning process. This included the South Georgian Bay/Muskoka Scoping Assessment process for the regional planning studies being initiated in the area, as well as discussions of upcoming engagement activities. Various meetings were held with a broad range of attendees including municipal representatives, First Nation community members, and local industrial customers.

9.2.1 South Georgian Bay/Muskoka Region Scoping Assessment Outcome Report

The draft South Georgian Bay/Muskoka Region Scoping Report was posted to the IESO website in May 2015 for comment, and a final version was posted on June, 22, 2015. The report was led by the IESO, and developed in collaboration with regional participants, including Hydro One Networks, Lakeland Power, Midland PUC, Newmarket-Tay Power, Orillia Power, PowerStream, and Veridian Connections.

9.2.2 First Nation Community Meetings

On September 24, 2015 the IESO met with Chief Denise Restoule and Councillor Roger Restoule of Dokis First Nation, Chief Barron King of Moose Deer Point First Nation, Chief Warren Tabobondung of Wasauksing First Nation and community representatives. The feedback received focused on the concern that any necessary future infrastructure be planned so that environmental disturbance is minimized and traditional land and space considerations for each community be respected during the planning process. Community members also expressed the preference to have meetings with communities and municipalities at the same time to ensure that everyone is engaged in the same dialogue. Feedback was also shared that communities would like distributed generation proponents to have the same strong relationship with First Nation communities as they do with municipalities to provide communities with a firsthand opportunity to present and protect their needs.

The IESO remains open to additional meetings to support further engagement of the IRRP.

9.2.3 Municipal Meetings

Meetings with area municipalities are one of the first steps in engagement for all regional plans. In September 2015, the Working Group held municipal meetings in Huntsville and Parry Sound to discuss findings for the South Georgian Bay/Muskoka Region and next steps in the process, including identifying potential options to strengthen reliability in the area, increase supply capacity and replaced aging electricity infrastructure nearing end-of-life. Attendees provided insight on population forecasting, challenges with reliability in the area, and the importance of public and community engagement as the planning process develops. It was also indicated that there was a preference for a LAC for each of the two sub-regions instead of one committee for the larger South Georgian Bay/Muskoka Region.

9.3 Bringing Communities to the Table

To continue the dialogue on regional planning, a LAC was established for the Parry Sound/Muskoka Sub-region in spring 2016. The role of the LAC is to provide advice and recommendations on the development of the regional plan as well as to provide input on broader community engagement. LACs are comprised of municipal, Indigenous, environmental, business, sustainability and community representatives. There is currently one general LAC in the planning area, which includes First Nation and Métis representation. The possibility of also forming a First Nation LAC, comprised of representatives from the First Nation communities in the planning area remains, should First Nation communities request an additional forum for community discussions. All general LAC meetings are open to the public and meeting information is posted on the dedicated engagement webpage, which in this case is the IESO's Parry Sound/Muskoka engagement webpage.[13]

Development of the Parry Sound/Muskoka LAC was completed through a request for nominations process promoted by the following activities: advertisements in nine local newspapers across the planning area; digital (website) advertising in communities throughout the planning area; emails sent to municipal representatives across the region; letters to the Chiefs of the First Nation communities in the area inviting them to appoint a representative to the LAC, and an e-blast sent to the IESO's South Georgian Bay/Muskoka subscribers list.

On June 20, 2016, the Working Group held the inaugural LAC meeting in the Town of Gravenhurst. The focus of the meeting was to introduce the regional planning process to the newly formed LAC, provide an overview of the electricity infrastructure supplying the area, and touch upon key electricity needs and issues in the Parry Sound/ Muskoka Sub-region to be discussed in greater detail at subsequent LAC meetings.

The second LAC meeting was held on September 26, 2016 in the Town of Dwight. LAC members were presented with the draft IRRP recommendations, and had the opportunity to provide their feedback following the meeting to help inform the final report. Materials from both meetings can be accessed online on the IESO's website.[14]

Copies of the meeting summaries from the Parry Sound/Muskoka LAC meetings can be found in Appendix G.

At the September 2016 meeting, the members of the Parry Sound/Muskoka LAC expressed their interest in continuing to meet on a regular basis following the posting of the IRRP. As a result, the LAC will continue to meet until the start of the next planning cycle in 2018. Information about LAC meetings will continue to be posted on the IESO Parry Sound/Muskoka Sub-region engagement webpage and email notifications of meetings will continue to be sent to the broader South Georgian Bay/Muskoka email subscriber list.

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[13] http://www.ieso.ca/Pages/Participate/Regional-Planning/South-Georgian-Bay-Muskoka/Parry-Sound-Muskoka-sub-region.aspx

[14] http://www.ieso.ca/Pages/Participate/Regional-Planning/South-Georgian-Bay-Muskoka/Parry-Sound-Muskoka-sub-region.aspx

10. Conclusion

This report documents the regional planning process that has been carried out for the Parry Sound/Muskoka Sub-region and fulfills the OEB's regional planning requirement for the sub-region. The IRRP identifies electricity needs in this sub-region over the 20-year period from 2015 to 2034 and recommends a set of actions to minimize the frequency and duration of power outages and to ensure that the regional electricity system has adequate supply to support growth.

The Parry Sound/Muskoka Sub-region Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the sub-region, and will produce annual updates that will be posted on the IESO website[15]. To support development of the plan, a number of actions have been identified to develop alternatives, engage with communities, and monitor growth in the area. Responsibility has been assigned to appropriate members of the Working Group for these actions. Information gathered and lessons learned from these activities will inform development of the next iteration of the IRRP for the Parry Sound/Muskoka Sub-region. The plan will be revisited according to the OEB-mandated 5-year schedule.

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[15] IESO website (http://www.iemo.com/Pages/Ontario%27s-Power-System/Regional-Planning/South-Georgian-Bay-Muskoka/default.aspx)

Appendix E

York Region Integrated Regional Resource Plan

York Region:

Integrated Regional Resource Plan

February 28, 2020

Connecting Today.
Powering Tomorrow.

York Region
Integrated Regional Resource Plan

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator (IESO) pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

The IESO prepared this IRRP on behalf of the York Region Technical Working Group (Working Group), which included the following members:

- Independent Electricity System Operator
- Alectra Utilities Corporation (Alectra)
- Newmarket-Tay Power Distribution Ltd. (NT Power)
- Hydro One Networks Inc. (Hydro One Distribution)
- Hydro One Networks Inc. (Hydro One Transmission)

The Working Group developed a plan that considers the potential for long-term electricity demand growth and varying supply conditions in the York Region, and maintains the flexibility to accommodate changes to key conditions over time.

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List of Acronyms and Alternatives

Acronym/ Alternative	Description
2019 APS	Achievable Potential Study
Alectra	Alectra Utilities Corporation
APO	Annual Planning Outlook
CDM	Conservation and Demand Management
CFF	Conservation First Framework
CHP	Combined Heat and Power
DER	Distributed Energy Resource
DESN	Dual Element Spot Network
DG	Distributed Generation
DR	Demand Response
EE	Energy Efficiency
FIT	Feed-in Tariff
GHG	Greenhouse Gas
GTA	Greater Toronto Area
Hydro One Distribution	Hydro One Networks Inc. (Distribution)
Hydro One Transmission or Hydro One	Hydro One Networks Inc. (Transmission)
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LTR	Limited-time Rating
MTS	Municipal Transformer Station
MW	Megawatt
NPV	Net Present Value
NT Power	Newmarket-Tay Power Distribution Ltd.

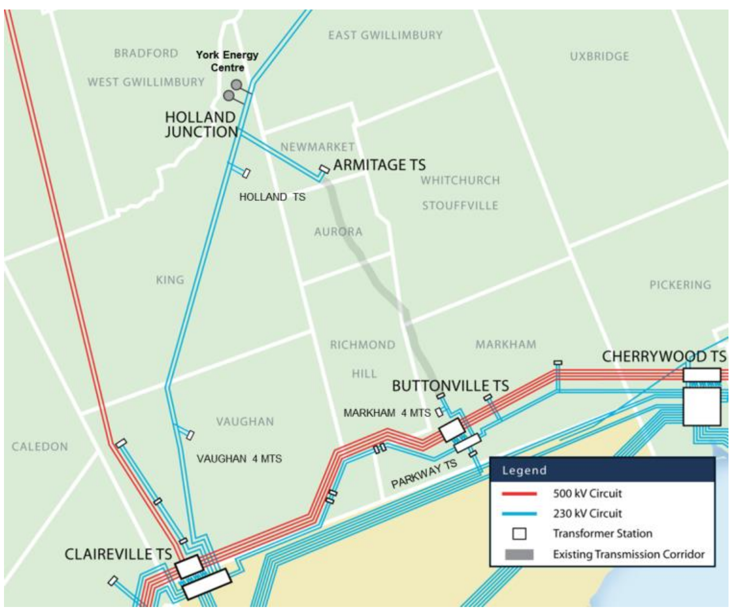
Acronym/ Alternative	Description
NWA	Non-wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
PPWG Report	Planning Process Working Group to the OEB
PV	Photovoltaic (Solar)
RIP	Regional Infrastructure Plan
SCGT	Simple Cycle Gas Turbine
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transmission Station or Transformer Station
Working Group	Technical Working Group for York Region IRRP
York Energy Centre	York Energy Centre

1. Introduction

This Integrated Regional Resource Plan (IRRP) addresses electricity needs for the Regional Municipality of York ("York Region" or "GTA North") between 2020 and 2037.[1] This report was prepared by the Independent Electricity System Operator (IESO) on behalf of the York Region Technical Working Group comprising the IESO, Alectra Utilities Corporation (Alectra), Newmarket-Tay Power Distribution Ltd. (NT Power), Hydro One Networks Inc. (Hydro One Distribution), and Hydro One Networks Inc. (Hydro One Transmission).

In Ontario, planning to meet the electrical supply and reliability needs of a local area or region is carried out through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for 21 electricity planning regions across Ontario, at least once every five years. The GTA North Region, shown in Figure 1-1, roughly corresponds with the municipal boundaries of York Region. For the purposes of this plan, GTA North and York Regions can be used interchangeably.

Figure 1-1: GTA North (York) Region



[1] The 20-year load forecast covers the period from 2018 to 2037. Consideration for 20+ year demand growth is provided, where relevant.

This IRRP reaffirms the near- to medium-term needs identified in previous electricity system plans for the area, including the 2015 IRRP, 2016 Regional Infrastructure Plan, 2018 Needs Assessment, and 2018 Scoping Assessment. This includes the anticipated need for additional step-down transformation capacity in York Region over the medium term, though need dates have been deferred since the last regional planning cycle.

In the longer term (2030+), the plan reaffirms the need for additional system supply capability. Since the long-term needs are subject to uncertainty related to future electricity demand and technological change, and because of the lead time available, this IRRP does not recommend specific investments to address them at this point. Instead, some viable options are introduced, with a goal of undertaking additional engagement over time to ensure that any final decision is informed by local preferences. At the same time, this strategy maintains flexibility for responding to changes in demand for electricity, and consideration of new solutions, such as non-wires alternatives (including energy efficiency and distributed energy resources).

The plan identifies some near-term actions to monitor demand growth, perform minor transmission system upgrades, continue to pursue information on the feasibility and economics of non-wires alternatives, engage with the community, and develop or maintain viability of long-term supply capacity options. The near-term actions recommended are intended to be completed before the next regional planning cycle, scheduled for 2024 or sooner, depending on demand growth or other factors that could trigger early initiation of the next planning cycle.

This report is organized as follows:

- A summary of the recommended plan for York Region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for regional electricity planning in York Region and the study scope are discussed in Section 4;
- The demand outlook scenarios, and energy efficiency (EE) and distributed energy resource (DER) assumptions, are described in Section 5;
- Electricity needs in York Region are presented in Section 6;
- Options and recommendations for addressing the needs are described in Section 7;
- A summary of engagement activities to date, and moving forward, is provided in Section 8; and
- A conclusion is provided in Section 9.

2. Summary of the Recommended Plan

The near-term recommendations in this IRRP are focused on meeting capacity needs at both the step-down station and regional transmission level, while exploring and preserving options to address the capacity needs expected to emerge in the longer term. Implementation of the recommended actions summarized below is expected to ensure the region's electricity needs are met until at least the late 2020s, and assist in developing recommendations to address needs into the late 2030s.

2.1 Plan for Near-Term Needs (2020-2024)

The recommendations set forth in this plan are summarized below. This IRRP recommends these activities take place within the next five years, either to address a near-term need, or to explore and preserve longer-term options.

Collect Information on Future Non-Wires Alternatives and Opportunities in York Region to inform the next IRRP

Activities are currently underway to inform long-term non-wires potential in York Region, and address some of the operational challenges associated with relying on these technologies to address transmission needs. These activities include an interoperability pilot described further in Section 7.2. The IESO is currently working with government and stakeholders to consider opportunities for EE in Ontario beyond 2020. Consideration of the value of deferring wires infrastructure, in addition to the value of avoided system energy and capacity, should be leveraged and included when determining the feasibility and cost-effectiveness of a program. Many of the municipalities in York Region have developed municipal energy plans that include goals and measures to manage energy use and reduce greenhouse gas (GHG) emissions. Some of these measures have the potential to reduce peak electricity demand, the main driver for capacity needs. In some cases, the positive impact of EE or DERs such as small-scale renewable generation projects may be offset, in the long-term, by a greater reliance on electricity due to end-use fuel switching from fossil sources to electricity.

As part of ongoing engagement with municipalities and stakeholders, the IESO will actively seek new opportunities to target peak electricity demand. In particular, opportunities to align local municipal and stakeholder activities that may help defer the medium-term need for step-down station capacity and long-term need for major system capacity upgrades will be explored and evaluated to determine feasibility and cost-effectiveness. The purpose of this information gathering is to inform the assessment of possible solutions and decisions required in the next IRRP (currently anticipated to be completed in 2025).

Reconfigure York Energy Centre Station Service Supply

The station service supply for York Energy Centre may cause the station to shut off automatically following certain contingencies affecting the transmission system, triggering voltage needs on the regional transmission system. While this risk is currently being addressed by arming automatic load rejection through a Special Protection Scheme (SPS), this measure will no longer be sufficient by approximately 2035, at which point supply security needs will be triggered. Additionally, restoration needs may begin to emerge in the near-term as a result of the temporary generation outage while York Energy Centre returns to service. Given that advancing this work would have immediate benefits for local customer reliability, improve resource availability for the grid, and address the near-term restoration need, this IRRP recommends that the IESO and York Energy Centre's owners and operator proceed with a more detailed investigation to identify and consider options for a preferred long-term station service supply configuration. Any new configuration should allow for continuous York Energy Centre operation following standard design contingencies[2]. Specifically, this includes the simultaneous loss of circuits H82/83V (causing total loss of distribution supply from Holland TS) or the loss of B88H (loss of transmission supply point).

Develop/Preserve Viability of Long-term Capacity Options

As summarized in Section 2.3, a long-term need for additional capacity to supply demand growth is anticipated in York Region. This need could be met through new large-scale dispatchable generation resources, or new transmission.

Two possible transmission options have been identified. One would require the redevelopment of an existing 20-km transmission corridor (Buttonville to Armitage), while the other requires the development of a new transmission right of way (GTA West corridor, Kleinburg to Kirby section), estimated to be around 6 km. A recommendation on the preferred plan to address this capacity needs is not required at this time, but actions should be taken in the near-term to further define, preserve and engage on these options in advance of the requirement for a final decision.

[2] This measure was recommended in the 2016 System Impact Assessment (SIA) for the Holland Breakers.

The Buttonville to Armitage corridor land is already identified and protected in various official plans. Options for reducing the impact on communities could include evaluating land-use conversions adjacent to the corridor for suitability/compatibility with the potential transmission upgrade (approximately one-third of the corridor is already built-up).

Ongoing work is also underway to identify and preserve space suitable for possible future high voltage transmission adjacent to the proposed GTA West transportation corridor. This new corridor is undergoing an environmental assessment for a new 400 series highway roughly linking Milton to Vaughan. For more information on this initiative, visit the Ministry of Transportation's GTA West Transportation Corridor website. The IESO is currently working with the Ministry of Energy, Northern Development and Mines to assess and preserve options for adjacent land for new transmission capable of meeting long-term capacity needs through the regions of Peel, Halton and York, if and when required. Additional detail on the joint study is available on the IESO's regional planning page for GTA West. Co-location of linear infrastructure is consistent with the Provincial Policy Statement and good planning practice, as it has the potential to lower total land use, reduce the impact on the community and result in cost savings. The section of this corridor with the potential to address long-term York Region capacity needs runs through northern Vaughan, roughly from the Kleinburg TS at the western edge of Vaughan near Bolton, to just north of Vaughan #4 Municipal Transformer Station (MTS) near Kipling Avenue and Kirby Road. This is often referred to as the "Kleinburg to Kirby link." This IRRP recommends that work continue to assess long-term transmission rights adjacent to the GTA West corridor.

2.2 Plan for Medium-Term Needs (2025-2029)

The recommendations described below are intended to address medium-term needs (five to 10 years out). Although actions are not required immediately, some may be initiated before the next round of regional planning is undertaken. Anticipated need dates, and triggering events, are described as required.

Reconductor Circuit P45/46 from Parkway to Markham #4 MTS

The Working Group recommends that Hydro One proceed with reconductoring a limiting circuit segment to a higher ampacity. This upgrade will enable an additional 180 MW to be served in the Markham area without exceeding thermal limits of the regional transmission system. The upgrade is recommended to be complete by the time the new Markham #5 MTS comes into service (currently forecast for 2025), to ensure full station loading is available. Based on a high-level assessment of costs, this upgrade is expected to cost approximately $2 million.

Address the Potential for High Voltages on M80/81B

A potential voltage rise need may emerge on the M80/81B circuits and connected step-down stations beginning in 2025. The need is triggered under high-load conditions following the loss of B88/89H, and is worsened by the use of capacitor banks at Lindsay TS and Beaverton TS (required to prevent voltage drop under different contingencies). This need can be addressed in a number of ways, including operational measures. This would not require new infrastructure. It is recommended that Hydro One TX investigate this need, identify a preferred solution through the RIP process, and implement that solution no later than 2025.

New Step-down Stations to Supply Growing Demand in Markham, Northern York and Vaughan

Step-down stations are points along the transmission network where electricity is converted, through step-down transformers, to lower voltages for distribution customers. Based on the anticipated growth forecast, up to three new step-down stations will be required in York Region in the medium term. The first anticipated need is for a Markham #5 MTS in 2025, followed by a Northern York TS (notionally 2027) and Vaughan #5 MTS (notionally 2030). The need dates for all three step-down stations could be deferred by NWAs that target peak demand electricity use, with the longer-term need dates more candidates for deferral. Because of the meshed nature of Alectra’s distribution grid in southern York, any non-wires initiative targeting peak demand within the municipalities of Vaughan, Richmond Hill or Markham could help defer the need dates for Markham #5 MTS as well as Vaughan #5 MTS. In order to defer a new Northern York TS, measures targeting the higher-growth northern municipalities of Newmarket, East Gwillimbury and Aurora would likely be the most effective.

Three technically feasible sites for the first station (Markham #5 MTS) were assessed in this IRRP based on overall project cost (transmission and distribution); both the central and northern candidate sites were found to be similar in terms of cost. For this reason, the Working Group recommends that Alectra select a preferred site after engagement with the community, as local preferences may depend on weighting various criteria such as land use or another potential impacts.

Although other locations are possible, at this time it is assumed that the future Northern York TS will be located in the vicinity of East Gwillimbury based on its high-growth rate and the lack of nearby step-down stations[3]. This IRRP recommends that Hydro One undertake a review of suitable locations to accommodate a potential in-service date as early as 2027. A preferred location for Vaughan #5 MTS has already been identified, by Alectra, and land set aside at the site of the existing Vaughan #4 MTS. This location is well suited to serving growth in northern Vaughan, and could be required as early as 2030.

Sufficient capacity exists along the existing Claireville to Minden 230 kV circuits to accommodate one additional station over the forecast period. However, two new stations, such as Northern York TS and Vaughan #5 MTS, are anticipated to be required in the medium to long term. As the incremental demand of these two stations is expected to trigger long-term capacity needs on the Claireville to Minden circuits by the early to mid-2030s (see Section 2.3, below), a preferred option to address the overloading of these circuits must be identified before committing to the connection of the second station.

2.3 Plan for Long-Term Needs (2030+)

No actions are required at this time to address long-term needs. However, given the potential cost, impact, and community interest in these potential long-term solutions, engagement should continue between planning cycles. The information below is provided to help inform discussions and highlight key issues when comparing feasible solutions.

Increase Supply Meeting Capability for Claireville to Minden Circuits

Continued load growth in York Region is expected to trigger the need for new capacity on the Claireville to Minden circuits, with a current anticipated need date of 2033[4]. While this need has the potential to be deferred through NWAs, actions are required in the near term to ensure long-term wires solutions remain viable.

Both new transmission and large-scale, dispatchable resources have the potential to address this long-term need. A recommendation on the final preferred option to address these capacity needs is not required at this time, and is not expected to be needed until at least 2025. The actual need date will depend on the amount of peak demand being supplied along the limiting circuit

[3] This is subject to change based on land availability and further assessments by Hydro One TX

[4] Based on the demand forecast developed for this IRRP

section between Claireville TS and Vaughan #4 MTS. Based on the load forecast, this will likely occur shortly after Vaughan #5 MTS comes into service. As a result, work to identify a preferred alternative, including engagement with affected communities, should continue to ensure that a preferred option can be identified before committing to the connection of Vaughan #5 MTS. These discussions should reflect new information as soon as it becomes available, including the annual review of actual load growth (net impact of new growth minus efficiency gains and the impact of NWAs), the status of and recommendations from the neighbouring GTA West IRRP, long-term anticipated provincial capacity needs, and the status of initiatives to preserve long-term transmission corridor options.

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, planning to meet an area's electricity needs at a regional level is completed through the regional planning process, which assesses regional needs over the near, medium, and long term, and develops a plan to ensure cost-effective, reliable electricity supply. A regional plan considers the existing transmission electricity infrastructure, local supply resources, forecast growth and area reliability; evaluates options for addressing needs; and recommends actions to be undertaken.

The current regional planning process was formalized by the OEB in 2013, and is conducted for each of the province's 21 electricity planning regions by the IESO, transmitters and local distribution companies (LDCs) on a five-year cycle.

The process consists of four main components:

1) A needs assessment, led by the transmitter, which completes an initial screening of a region's electricity needs;
2) A scoping assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3) An IRRP, led by the IESO, which identifies recommendations to meet needs requiring coordinated planning; and/or
4) An RIP led by the transmitter, which provides further details on recommended wires solutions.

More information on the regional planning process and the IESO's approach to regional planning can be found in Appendix A: Overview of the Regional Planning Process.

3.2 York Region Technical Working Group and IRRP Development

In accordance the OEB's regional planning process, Hydro One kicked off the current cycle of the regional planning process with the Needs Assessment for GTA North (York Region) in 2018. The Needs Assessment identified needs requiring further assessment and coordinated regional planning, resulting in the initiation of the Scoping Assessment process.

Based on the findings of the Needs Assessment, the Scoping Assessment process concluded that an IRRP was the appropriate planning approach for the GTA North (York Region).

In August 2018, a Technical Working Group (Working Group) began gathering data, conducting assessments to define near to long term needs, identify possible solution options, and recommend actions to address York Region's electricity system needs.

Specifically, the IRRP was initiated to:

- Explore innovative wires and/or non-wires solutions and determine the extent to which these could be leveraged to address or defer regional transmission needs in York Region;
- Determine whether development work or commitments to infrastructure investments (wires or non-wires) are needed in this planning cycle;
- Assess potential risks over the longer term and identify near-term actions to manage or mitigate these risks, where applicable.

4. Background and Study Scope

The GTA North Region (York Region), as shown in Figure 4-1, comprises the municipalities in York Region, including Vaughan, Richmond Hill, Markham, Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville, Georgina, and Chippewas of Georgina Island. Its electrical infrastructure also serves parts of the City of Toronto, Brampton, and Mississauga.

Figure 4-1: Geographical Boundaries of GTA North (York Region)

York Region is one of the fastest-growing regions in Ontario. Provincial policies, including the *Places to Grow Act, 2005* and the *Greenbelt Act*, 2005 have played a key role in facilitating and driving local development. While a large portion of the land in this region is part of the Greenbelt, a permanently protected area of green space, farmland, forests, wetlands and watersheds, the *Places to Grow Act, 2005* promoted rapid intensification and development in designated urban areas surrounding the Greenbelt. Extensive urbanization in these areas over the past decade has resulted in continued growth in the demand for electricity. In 2017, York Region had an electricity summer peak demand of over 2,000 MW. Following the province's updated *Growth Plan for the Greater Golden Horseshoe, 2019*, significant population growth and urban intensification are expected to continue in the region in the coming decades.

At the same time, many communities in York Region, including the City of Markham, City of Vaughan, Town of Newmarket, Region of York and Chippewas of Georgina Island First Nations, are actively engaged in local energy planning activities and are exploring opportunities to better manage their energy use using community-based energy solutions, such as energy storage, combined heat and power (CHP) and renewable energy resources.

4.1 Recent History of Electricity System Planning in York Region

Regional electricity planning in York Region has been underway for a number of years. Below is a summary of key products and planning decisions which have shaped York Region's current electricity system.

2005 Northern York Region Electricity Planning Study

In 2005, in response to a letter of direction from the OEB, the IESO (then the Ontario Power Authority or OPA) led the development of an integrated electricity planning study for Northern York Region. At the time, the electricity supply infrastructure to this area had reached its limits, resulting in an urgent need to address risks to customer reliability resulting from strong electricity demand growth. The planning study considered transmission, distribution, generation, and conservation options, and was developed with input from local stakeholders.

The resulting 2005 Northern York Region plan recommended a number of actions, most notably the addition of a simple cycle gas-fired peaking generation station, which was later procured, in the form of the York Energy Centre. York Energy Centre came into service in 2012. This solution enabled the communities in Northern York Region to continue to grow, while maximizing use of the existing transmission in the area.

2016 Regional Plan

The first cycle of the regional planning process for York Region was completed in 2016, with the focus on ensuring adequate supply to support near-term growth in the Vaughan area and minimizing the impact of supply interruptions under outage conditions. Through this newly formalized regional planning process, a number of projects were recommended to support near-term growth and further maximize the use of the existing system, including a new transformer station in Vaughan, new switching equipment at Holland TS, and on the parkway belt/Highway 407 transmission corridor. All of these projects have since come into service. Even with the implementation of these near-term projects and the ongoing conservation efforts identified and underway at the time, electricity demand growth was forecast to exceed system capability in the Markham-Richmond Hill area in the early 2020s and Northern York-Vaughan in the mid to late 2020s.

Work since last regional planning cycle

Since the completion of the first cycle of the regional planning process in GTA North (York Region), the Working Group has taken steps to better understand the extent to which non-wires solutions can be used to help manage growth in electricity demand in the medium to longer term. Specifically, in 2016, Alectra and the IESO conducted a study to examine the feasibility of implementing residential solar-storage technology in Markham, Richmond Hill and Vaughan. Information on the POWER.HOUSE initiative and its conclusions are available in the final study. Given the timing and magnitude of electricity demand growth in the Markham-Richmond Hill area, the study confirmed that it was not feasible to solely rely on residential solar-storage technology to defer the near-term supply need in this area. The IESO, on behalf of the Technical Working Group, confirmed the need for a new transformer station and associated lines in the Markham-Richmond Hill area by 2023, and provided a letter to Hydro One and Alectra to initiate the development work for this project. The need date for this station has since been deferred to 2025 (as described in this IRRP).

Over the last couple of years, the IESO and the local utilities have continued to engage with municipalities and Indigenous communities in York Region to confirm the projected growth, inform them of the state of electricity system needs and associated distribution and/or transmission in the area.

4.2 Study Scope

This IRRP, prepared by the IESO on behalf of the Technical Working Group, recommends options to meet the electricity needs of York region over the 2020-2037 timeline. Guided by the principle of maintaining an adequate level of reliability performance as per the *Ontario Resource and Transmission Assessment Criteria* (ORTAC), this IRRP reviews needs identified and discussed as part of the Scoping Assessment, with the focus on:

- Providing an adequate, reliable supply to support community growth
- Minimizing the impact of supply interruptions
- Coordinating and aligning end-of-life asset replacements with evolving needs

Given that the York Region 230 kV networks also serve as major pathways for the flow of power between northern and southern Ontario and across the GTA, the IRRP also assesses the York Region 230 kV networks under various bulk system conditions. However, a detailed assessment of the bulk electricity system is typically addressed through separate planning processes and is beyond the scope of this IRRP.

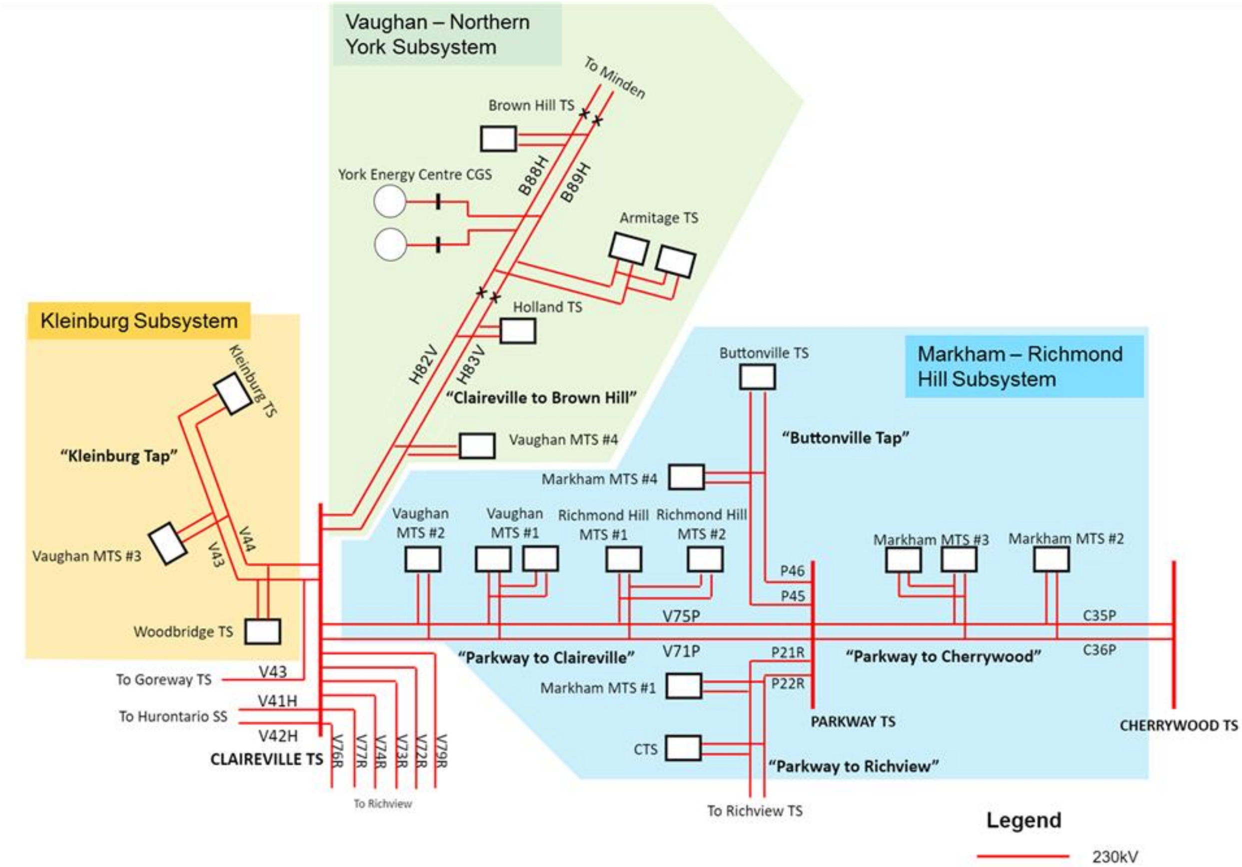
York Region 230 kV networks

Today, as shown in Figure 4-2, power is delivered from the rest of the province into this region through a 230 kV transmission network that also serves as a pathway for power to flow between northern and southern Ontario and across the GTA.

Through these 230 kV subsystems, power is delivered to various communities and customers through 20 customer and utility owned step-down transformer stations through lower voltage distribution networks. The distribution system is managed and operated by five LDCs: Alectra, NT Power, Toronto Hydro Electric System Ltd., Veridian Connections Inc., and Hydro One Distribution. All LDCs are directly connected to the transmission system, with the exception of Veridian which is embedded within Hydro One's system.

In addition to the transmission network, electricity supply to the area is also provided by York Energy Centre, a 393 MW simple cycle gas-fired generation facility that came into service in 2012.

Figure 4-2: Single Line Diagram of GTA North (York Region)



For the purpose of regional planning, this 230 kV network can be broken down into three 230 kV subsystems, as shown in Figure 4-2:

- **Kleinburg 230 kV Subsystem (V44/43)** – This radial subsystem consists of three step-down transformer stations that primarily supply rural and urban communities in Vaughan and Caledon and, to a lesser degree, Brampton, Mississauga and Toronto. Power is delivered into this subsystem from Claireville TS via the 230 kV transmission circuits V44 and V43.

- **Vaughan-Northern York 230 kV Subsystem (B82/83H, H82/83V)** – This subsystem consists of five step-down transformer stations that supply northern Vaughan and communities in Northern York Region (Aurora, Newmarket, King, East Gwillimbury, Whitchurch-Stouffville and Georgina and Chippewas of Georgina Island). York Energy Centre is connected to these 230 kV circuits. This subsystem also serves as a pathway for power flows between northern and southern Ontario.

- **Markham-Richmond Hill 230 kV Subsystem (P45/46, C35/36P, V75/71P, P21/22R) –** This subsystem consists of 12 step-down transformer stations located in urban communities in the Markham, Richmond Hill and Vaughan areas. This subsystem, which also serves as a major pathway for power to flow east-west across the GTA, is further broken down into four sub components:

  (1) Buttonville Tap - P45/46
  (2) Parkway to Cherrywood - C35/36P
  (3) Parkway to Claireville - V71/75P
  (4) Parkway to Richview - P21/22R

Completing the York Region IRRP involved:

- Preparing a long-term electricity peak demand forecast;
- Examining the load-meeting capability and reliability of the transmission system supplying the region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities (such as reactive power devices);
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid as described in Section 7 of ORTAC;
- Confirming identified end-of-life asset replacement needs and timing with Hydro One;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible EE, generation, transmission and/or distribution, and other approaches such as non-wires alternatives (NWAs);
- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5. Peak Demand Forecast

A fundamental consideration in any electricity supply study is how much electricity will be required in the region over the study period. This section outlines the electricity demand forecast within York Region over the 20-year study period, highlighting the assumptions made for peak demand load forecasts, and the expected contributions of EE and DERs to reducing or offsetting peak demand. When combined, these factors produce the net demand forecast used to assess the electricity needs of the area over the planning horizon.

For the purpose of evaluating the adequacy of the electricity system, regional planning is concerned with the coincident peak demand for a given area, or the demand observed at each station for the time of year when overall demand in the study area is expected to be at its highest. This represents the moment when assets are at their most stressed, and resources generally the most constrained. This is different from non-coincident peak, which is the sum of the individual peaks at each station, regardless of whether these peaks occur at different times. Within York Region, the peak loading hour for each year typically occurs in late afternoon during summer (4 p.m. to 6 p.m.), usually on the hottest weekday, or after consecutive hot days. Peak load is weather sensitive, and generally driven by air conditioning loads of residential and commercial customers. This typically occurs on the same day as the overall provincial peak, but may occur at a different hour in the day.

5.1 Methodology for Preparing the Forecast

The peak demand forecast used to identify needs in this IRRP was developed in the following stages:

1. The IESO weather-corrected the most recent year's demand data to create a forecast "start" point based on expected peak demand under median (or "most likely") weather conditions. This is done to ensure that LDC forecasts begin at a common data point. The demand forecast was normalized to a 2017 start point, broken down by transformer station, LDC, and step-down voltage (where applicable).
2. Each LDC developed its own demand forecast by transformer station starting from the start point data provided by the IESO. Since LDCs have the closest relationship to customers, connection applicants, and the municipalities, they tend to have a better understanding of future load growth and local drivers than the IESO. The IESO typically carries out load forecasts at the provincial level.
3. The IESO aggregated the LDC forecasts by transformer station, and subtracted the estimated impact of codes and standards, historic EE and committed future EE

programs from the future demand. These estimates were based on provincial policy and informed by the customer mix served by each station.

4. Finally, station-level forecasts were adjusted to account for the predicted impact of extreme weather conditions.

The result was a station-by-station outlook of annual peak demand from 2018 through to 2037. Actual observed peak demand in 2018 was used to validate the forecast, and assessments were performed on forecast years beginning in 2020.

More details on these assumptions, including station-level forecasts, may be found in Appendix B: Peak Demand Forecast.

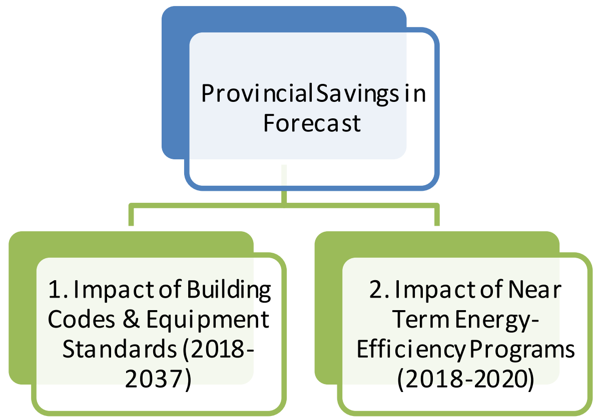
5.2 Existing or Committed Energy-Efficiency Assumptions in Forecast

Energy efficiency (EE) is achieved through a mix of program-related activities, and mandated efficiencies from building codes and equipment standards. It plays a key role in maximizing the use of existing assets and maintaining reliable supply by offsetting a portion of a region's growth in electricity demand, and helping to ensure it does not exceed equipment capability. The estimated impact of existing or committed EE programs and codes and standards for York Region have been applied to the gross peak-demand forecast for median weather, along with DERs (described in Section 5.3), to determine the net peak demand for the region.

Future EE savings for York Region have been applied to the gross peak-demand forecast to take into account both policy-driven and funded EE through the provincial Interim Framework (estimated peak demand impacts due to program delivery to the end of 2020), as well as expected peak demand impacts due to building codes and equipment standards for the duration of the forecast. As policies related to future provincial EE activities change, the forecast assumptions will be updated accordingly.

To estimate the peak-demand impact of existing and committed EE savings in the region, the forecast for provincial savings were divided into two main categories, as shown in Figure 5-1.

Figure 5-1: Existing or Committed Energy-Efficiency Savings Categories



1. *Savings due to building codes & equipment standards*
2. *Savings due to the delivery of energy-efficiency programs*

For York Region, the IESO worked with LDCs to establish a methodology to assess the estimated savings for each category, which were further subdivided by customer sector: residential, commercial, and industrial. This approach reflects the differing energy consumption characteristics and efficiency measures.

LDCs provided both their gross-demand forecast and a breakdown of electrical demand by sector for each TS. Once sectoral gross-demand at each TS was estimated, peak-demand savings were assessed for each energy-efficiency category: codes and standards, and EE programs. Due to the unique characteristics and available data associated with each group, estimated savings were determined separately. The final estimated EE peak-demand reduction, 146 MW by 2037, was applied to the gross demand to create the planning forecast.

Table 5-1Table 5.1 shows the total peak demand savings attributable to existing and committed EE and codes and standards for York Region, for selected years within the planning horizon.

Table 5-1: Forecast Peak Demand Savings from existing and committed Energy Efficiency

Year	2020	2025	2030	2037
Estimated savings (MW)	66	98	111	144

Source: IESO

A more detailed methodology on the outlook for EE, including assumptions and a breakdown by station and year, is provided in 1.1.1Appendix B: .

5.3 Distributed Energy Resources Assumptions

In addition to EE, DERs in York Region are expected to continue to offset peak demand. Previous procurements, including the Feed-in Tariff (FIT) Program, have led to an increase in the amount of renewable DERs in York. Other competitive generation procurements have also resulted in additional DER projects, such as combined heat and power. As of November 2019, more than 1,300 DERs in York Region were under contract with the IESO. The vast majority of these are small-scale (under 10 kW) solar photovoltaic (PV) systems.

Further to these, the IESO conducted competitive procurement pilots to acquire energy storage resources and support efforts to better understand barriers related to the integration of energy storage into Ontario's wholesale electricity markets. One of these, in the Newmarket area, is a 4 MW (16 MWh) battery project intended primarily to support capacity needs on the distribution system. However, with the close alignment between local and system peak, the project is likely to provide some transmission system capacity benefit as well.

Table 5-2 shows the predicted impact of existing DERs within York Region. Capacity contribution assumptions were taken from the most recent IESO Methodology to Perform the Reliability Outlook.[5]

[5] See the December 19, 2019 version of Methodology to Perform the Reliability Outlook, with associated Reliability Outlook – Tables.

Table 5-2: Active DER Contracts in York Region as of November 2019

	# of Contracts	Total Contract Capacity (MW)	Effective Capacity (MW)
Markham and Richmond Hill stations *(Markham MTS #1-4, Richmond Hill MTS #1-2, Buttonville TS)*	306	25.94	13.77
Vaughan and Kleinburg stations *(Vaughan MTS #1-4, Kleinburg TS)*	344	20.69	5.81
Northern York stations *(Armitage TS, Holland TS, Brown Hill TS)*	692	50.92	7.93
Total	**1,342**	**97.55**	**27.51**

The impact of existing DERs is already accounted for in the load forecast, as their effect on electrical demand shaped the historical data used to create the forecast start point. As a result, no additional modelling or analysis was required. The one exception was three 10 MW solar PV facilities connected at Brown Hill TS, as large variations in output over summer peak hours made it challenging to observe "typical" summer demand behaviour. For this station, the hourly output from these generation facilities was added back to the hourly meter readings to determine what load would have been in the absence of 30 MW of solar PV. This allowed for a more realistic customer demand start point to use in the forecast. The expected future impact of this PV facility was then subtracted from the gross forecast based on the capacity contribution of solar PV resources during peak periods in summer months.

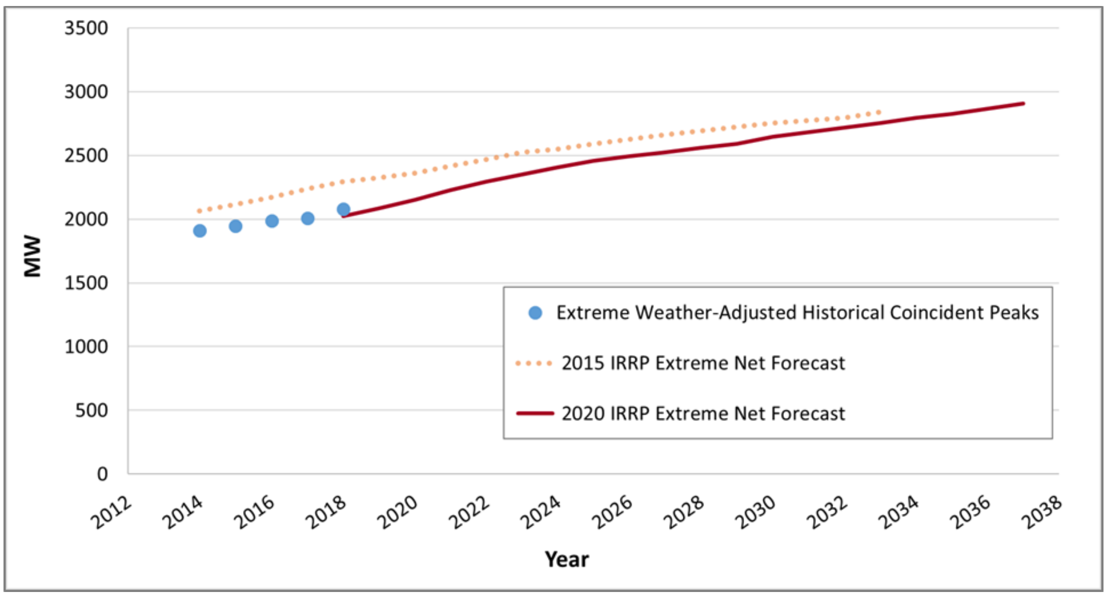
Given the difficulty of predicting where future DERs may be located, and uncertainty around future DER uptake, no further assumptions have been made regarding future DER growth. Instead of assuming DER growth implicitly as a load modifier in the demand outlook, the potential of future DERs is considered as a possible solution option. This is discussed further in Section 7.2.

5.4 Final Peak Demand Forecast

The final peak demand forecast was used to carry out system studies, and was the primary input for identifying potential needs. It was prepared by taking the gross median weather forecasts prepared by LDCs, and accounting for the impacts of EE and large DERs, as described in the preceding sections. The methodologies used by the LDCs to prepare their gross forecasts are available in Appendix B: Peak Demand Forecast. The forecast was further adjusted to account for the expected impact of extreme weather conditions, and typical station loading and operational practices (e.g., load transfers).

Figure 5-2 shows the final peak demand forecast, aggregated for the entire study area. For comparison, the figure also shows the most recent five years of historical peaks, adjusted for extreme weather, and the corresponding forecast used in the 2015 IRRP. Note that the forecast was finalized before 2018 peak demand data was available. As a result, the 2018 peak does not influence the start point of the forecast; instead, it is shown to validate the initial year of the forecast.

Figure 5-2: Peak Demand Forecast



The electricity demand growth rate fluctuates between 1.1% and 3.5% annually, averaging 1.9% over the 20-year study period. The growth is consistently higher in the near and medium term periods, with an average annual growth of 2.5% to 2027. The average growth rate is 1.4% from 2028 to 2037.

The continued high growth shown in this forecast is consistent with the A Place to Grow: Growth Plan for the Greater Golden Horseshoe (2017) and the York Region Official Plan (2019), which project an increase in population from 1,109,909[6] to 1,790,000, and employment growth from 595,200[7] to 900,000 jobs in York Region between 2016 and 2041. This represents an average

[6] York Region, 2016 Census

[7] York Region Employment and Industry Report 2016

annual population and employment increase of 2.45% and 2.05% per year, respectively. Although population and employment growth cannot be directly correlated to growth in power demand, more people and more jobs will result in upward pressure in electricity demand. Other factors, such EE or DERs, the density of development, and end-use electrification can also impact the demand for electricity.

The York Region Official Plan focuses on intensification, which is expected to drive new development. Consistent with the load growth seen in the final forecast, the municipalities of Newmarket, Vaughan, Richmond Hill and Markham, listed as the region's four centres, are expected to have the most intensification.

Between 2018 and 2037, stations located within the Vaughan sub-region (Vaughan 1-4 MTS, Kleinburg TS) show the largest average growth rate at 2.4% per annum. Within the same time period, the Markham sub-region (Markham 1-4 MTS, Richmond Hill TS, Buttonville TS) is expected to have a slightly lower average growth rate, at 2.0% per annum. Finally, the smallest average growth rate, at 1.2% per annum, is seen in the Northern York sub-region (Armitage TS, Brown Hill TS, Holland TS).

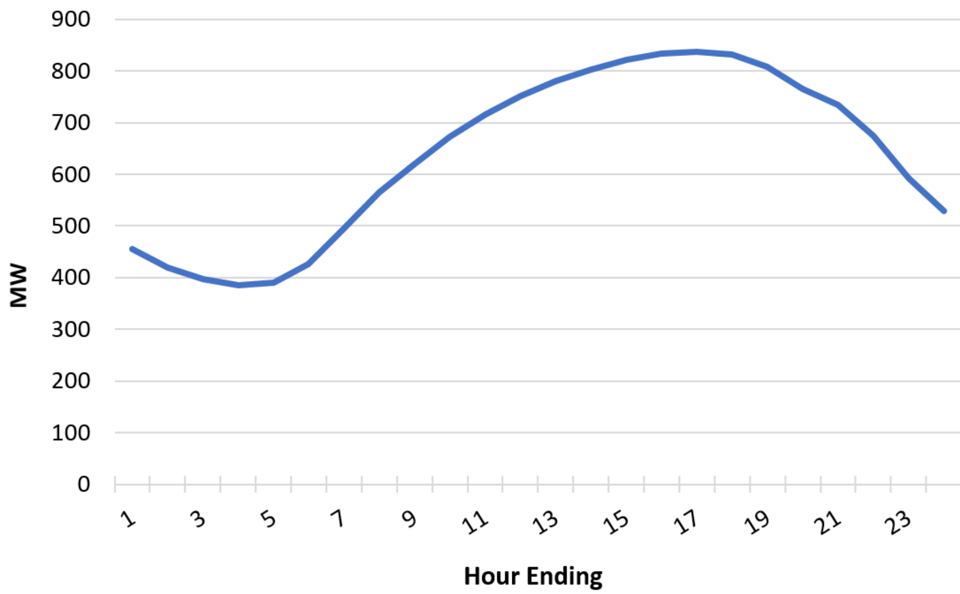
5.5 Load Duration Forecast (Load Profile)

While the final peak demand forecast is the primary input used to identify system needs, including timing and magnitude, it is only concerned with the single point of highest demand in the year (i.e., peak hour). This does not provide information related to the frequency of needs, the time of day, or the duration in which the electricity system assets are stressed during peak demand events. This information is especially important for evaluating the potential for NWAs, which may perform better at certain times of day, or for only fixed amounts of time, to defer needs.

For this type of option screening, an hourly forecast, known as a load duration forecast, was developed to predict the suitability of certain solution types to meet an area's demand, and to aid with cost estimations. Using historical hourly duration information, a sample 8,760-hour profile was created and scaled such that the peak hour would align with the peak demand forecast in a given year. Two separate profiles were created for each year of the peak forecast -- one to represent the combined loadings of all stations served by the Claireville to Brown Hill circuits (B88/89H and H82/83V); and the second to represent the sum of all stations serving load in Markham (Markham MTS #1-4). These area profiles represent the needs expected to trigger wires solutions over the 20-year study period. A sample of a typical peak-day profile for the Claireville to Brown Hill circuits is shown in Figure 5.3.

Figure 5-3

Figure 5-3: Sample Duration Profile for Claireville to Brown Hill Stations (July 15, 2032)



Additional details on how forecast profiles were created are available in Appendix B: Peak Demand Forecast.

Due to the higher level of uncertainty associated with predicting hour-by-hour demand for electricity, the results should be considered as qualitative (providing more information on needs already identified using the peak demand forecast) rather than quantitative (identifying needs). Profiles were also used to predict the suitability of certain NWA solutions to address specific needs, and to estimate feasibility and cost.

6. Electricity System Needs

Based on the demand forecast, system assumptions and application of provincial planning criteria, the Technical Working Group identified electricity needs in the near, medium, and long term. This section describes these needs, which are grouped into three categories: step-down station capacity, system capacity, and supply security and restoration. Each section begins with a brief description of the type of need, including how needs are identified, and details on each need identified through the technical assessments.

6.1 Step-Down Station Capacity Needs

Step-down transformer stations convert high-voltage electricity from the transmission system into lower-voltage electricity for delivery through the distribution system to end-use customers. Each station is capable of converting a maximum amount of power at a time, which is referred to as its Limited-time Rating (LTR). Loading a station beyond this amount is not permissible except in emergency conditions, as it lowers the life expectancy of facility equipment and can impact reliability for customers.

Step-down station capacity needs are determined by comparing the station peak demand forecast to the facility's LTR. In many cases, need dates can be deferred by transferring load at a station expected to exceed its LTR to a nearby station with available capacity. Feasible load transfers are already assumed in the demand forecast based on conversations with LDCs regarding the transfer capabilities and typical loading practices. Load transfers assumed include the following.

- **Holland-Armitage TS transfers**. Once Armitage TS reaches its full LTR, incremental load is assumed to be supplied from Holland TS.
- **Vaughan-Richmond Hill-Markham MTS transfers**. Due to the meshed distribution network design for the southern municipalities of Vaughan, Richmond Hill, and Markham, most Alectra load can be shifted between stations in the area. This is represented in the load forecast by flat (maximum LTR) demand at all but the newest step-down station in the area. Since new stations are planned to alternate between a Vaughan and Markham location, this also means that demand in one municipality appears "flat" while the other grows, and vice versa.

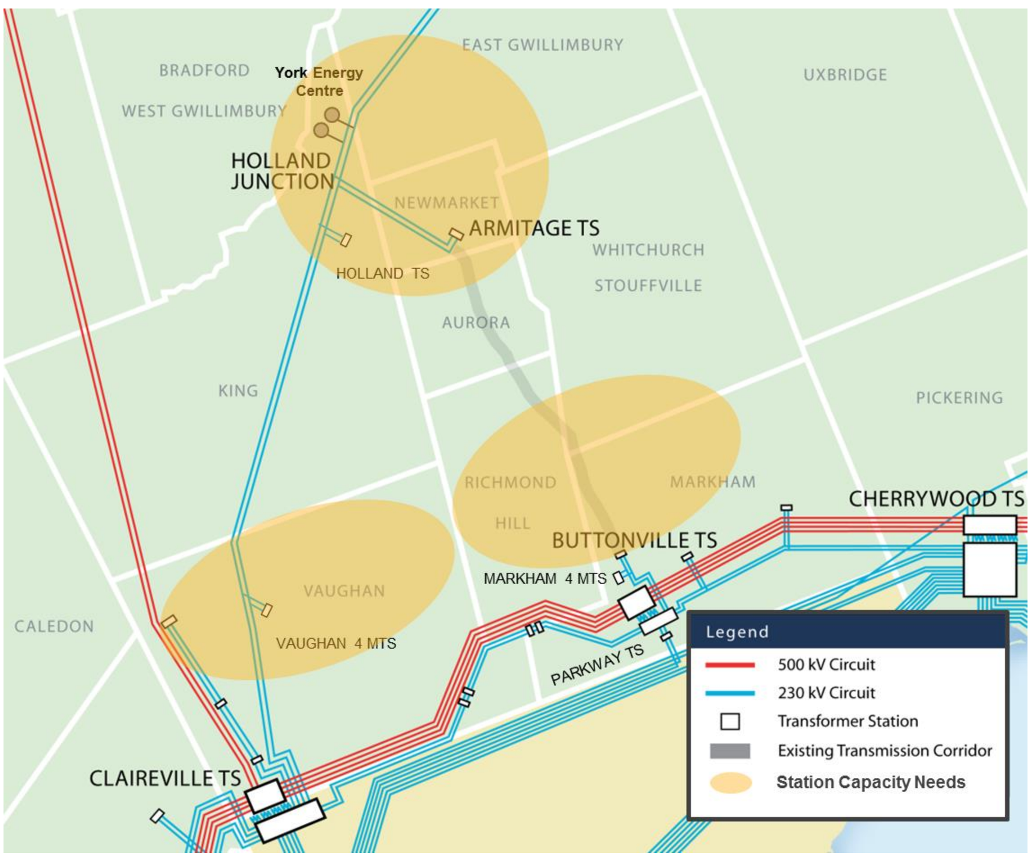
When a step-down station's capacity is reached, and feasible transfers are accounted for, options for addressing the need include reducing peak demand in the supply area (e.g., through EE or DERs), or building new step-down transformer capacity to serve incremental growth.

Typically, where there is sustained new urban growth and development in an area, measures to reduce peak demand growth are not able to defer the need for a new station indefinitely. The cost of these measures are compared to the value of deferring construction of a new station. These options are described in greater detail in Sections 7.1 and 7.2.

In order to build a new step-down station, a suitable location must be identified. Stations must be connected to a part of the transmission system with enough incremental capacity available to reliably supply the station load (See System Capacity Needs, Section 6.2). The station must also be located close enough to the anticipated customer demand to ensure that the distribution network is capable of supplying customers reliably.

Figure 6-1 shows the general areas of anticipated step-down station needs based on the load forecast, system assumptions, and growth patterns through the region.

Figure 6-1: Areas of Anticipated Step-down Station Capacity Need



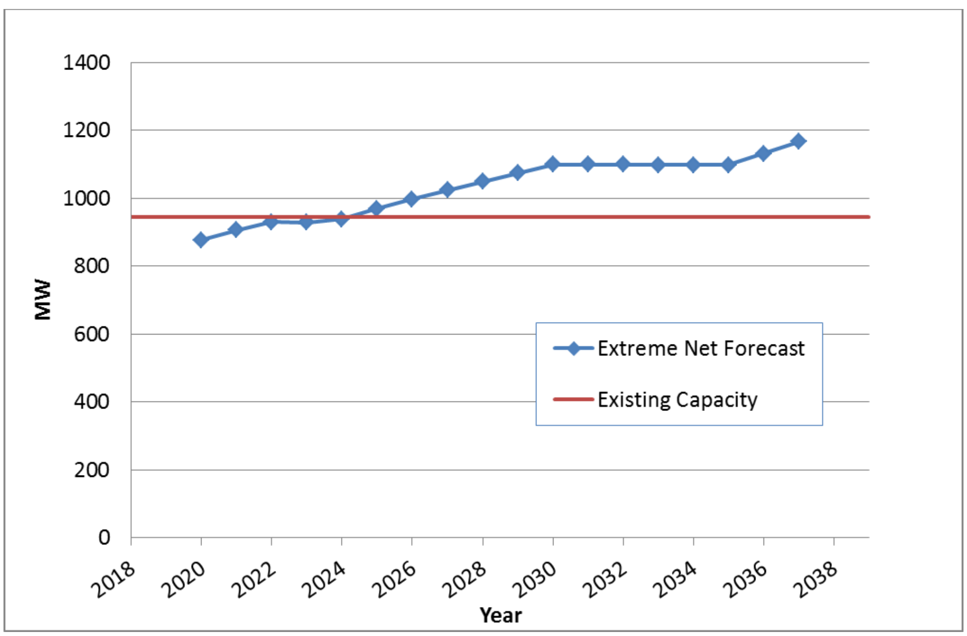
Additional information on station capacity needs for the identified areas is provided in the sections below.

6.1.1 Markham

The population of Markham is currently more than 340,000, and is projected to increase to over 420,000 by the year 2031.[8] Like the other southern York municipalities of Vaughan and Richmond Hill, most of the built up areas are in the south and central parts of the city, while the new growth over the coming decades is mostly expected to advance northward.[9] This has implications for locating future step-down stations, as transmission supply is currently only available along the Parkway transmission corridor in the south (adjacent to Highway 407), and along the Buttonville tap, which extends north roughly halfway into Markham. For the purpose of transmission planning, growth in Richmond Hill is considered also, as this area relies on the same supply infrastructure. Richmond Hill and Markham both have similar challenges in supplying northern growth increasingly further removed from the existing grid. Richmond Hill is roughly a third smaller than Markham with a current population of around 220,000, which is projected to increase to just over 240,000 by 2031.

The combined load forecasts of stations within Richmond Hill and Markham is shown in Figure 6-2.

Figure 6-2: Peak Demand and Existing Capacity in Markham and Richmond Hill



[8] All population projections taken from York official plan, January 2019 consolidation.
[9] Markham Municipal Energy Plan

Note that during the relatively flat load growth years to 2024 shown in Figure 6-2, incremental load growth in Richmond Hill and Markham is being supplied through a series of load transfers that end up at the recently built Vaughan #4 MTS (see Section 6.1.3, below). Likewise, the anticipated growth from 2025 to 2030 is comparatively high as it assumes a future Markham #5 MTS will begin to supply new in Vaughan, Richmond Hill, and Markham. This means that any measures to reduce peak demand in order to defer a new Markham area station would need to consider the total growth across Markham, Vaughan, and Richmond Hill.

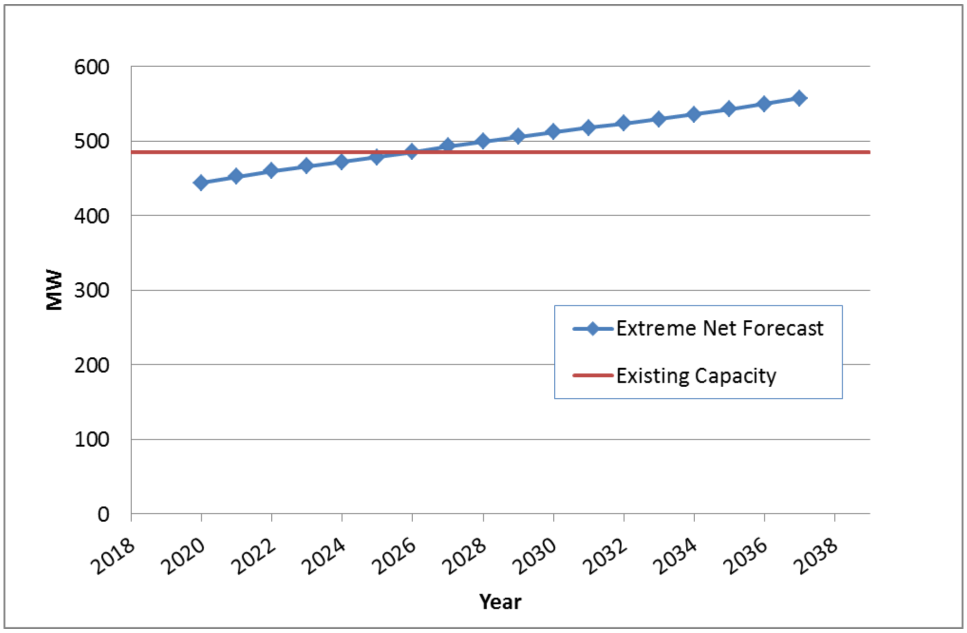
6.1.2 Northern York Region

Northern York Region is used in this IRRP to refer to customer loads currently supplied by Holland TS, Armitage TS, and Brown Hill TS. Similar to other parts of the region, it is difficult to compare municipal boundaries and electrical service boundaries. For example, a customer in eastern King township is likely to be served from Holland TS, while a customer in western King is more likely to be supplied from Kleinburg TS (which is part of a different electrical subsystem). In general terms, customers in the rapidly growing municipalities of Newmarket, Aurora, and East Gwillimbury are part of the Northern York electrical sub-region, while customers in King, Georgina and Chippewas of Georgina Island, and Whitchurch-Stouffville may be split between northern York and other electrical regions' sub-systems. Due to the long distances involved, it may not be feasible to transfer supply to some customers to infrastructure in other electrical sub-regions as a means of relieving facilities within York Region.

Out of the northern municipalities, East Gwillimbury is expected to see the highest growth over the next 20 years, with its population expected to increase from approximately 25,000 to over 85,000 by 2031. This is a significant increase, and would make East Gwillimbury similar in size by 2031 to Newmarket today.

The combined load forecasts of Holland TS and Armitage TS are shown in Figure 6-3, and roughly correspond to Newmarket, Aurora, East Gwillimbury, and parts of King and Whitchurch-Stouffville demand. Brown Hill TS is excluded from Figure 6-3.

Figure 6-3: Peak Demand and Existing Capacity in Northern York Stations



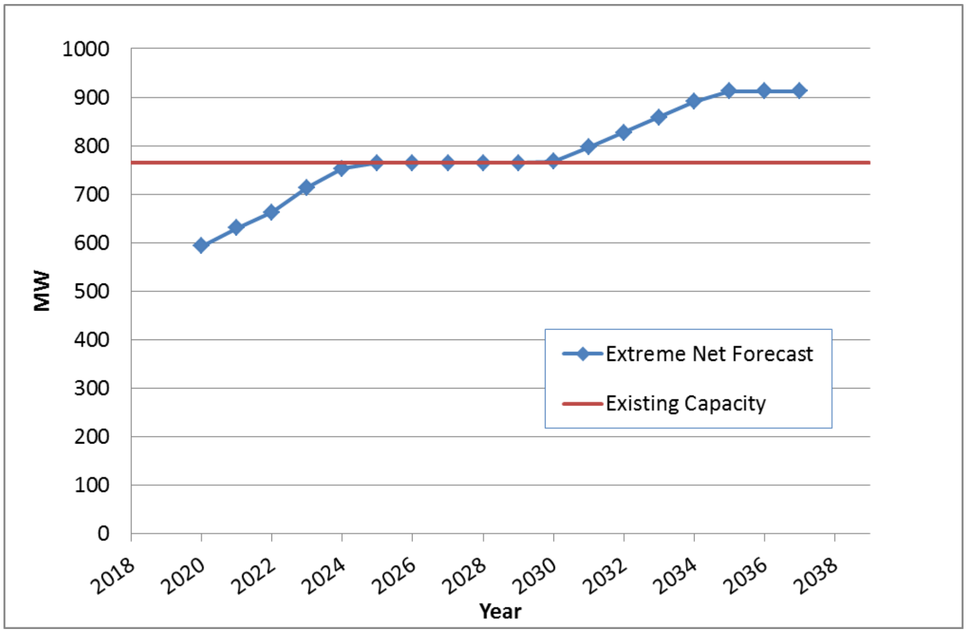
Although Brown Hill TS is part of this subsystem, at more than 20 km from Holland TS and Armitage TS, it is not close enough for load transfers. The station load is modelled in system studies to determine its impact on the grid, but it is not expected to reach its supply limit or otherwise impact needs in this study.

6.1.3 Vaughan

Similar to the situation in Markham and Richmond Hall, new growth in the city of Vaughan is increasingly being pushed further north as available land in the southern and central areas is already built up. Unlike Markham and Richmond Hill, however, Vaughan has an active transmission corridor running north through the area, which makes siting a new station close to anticipated growth centres easier.

With the addition of the new Vaughan #4 MTS in 2018, the municipality of Vaughan is the most recent to have a new step-down station come into service. Vaughan #4 MTS is located near the northernmost boundary of new growth, making this station well positioned to reliably supply the new demand. The combined load forecasts of the Vaughan stations is shown in Table 6-4.

Figure 6-4: Peak Demand and Existing Capacity of Vaughan Stations



As with the Markham forecast, demand appears flat in years where new growth is managed through transfers to a station elsewhere in southern York. For example, from 2025 to 2030, the assumption is that a new Markham station is being loaded up with new demand including Vaughan. New step-down capacity is anticipated to be required in Vaughan by 2030; however, this could be deferred through non wires measures that target peak demand growth in the area.

6.2 System Capacity Needs

System capacity refers to the amount of power that can be supplied by the regional transmission network, either by bringing power in from other parts of the province, or by generating it locally.

System capacity is evaluated by modelling power flows throughout the local grid under anticipated peak demand conditions, and applying a series of standard contingencies (outage events) as prescribed by ORTAC. Performance standards and criteria dictate how well the system must be able to operate following these contingencies. Standards at risk of not being met are identified as a system need. Since all identified system needs in York Region relate to capacity growth, they are described here as system capacity needs, for clarity.

As with station capacity needs, system capacity needs can be addressed by upgrading the system to increase load-meeting capability, or addressed or deferred by reducing peak demand.

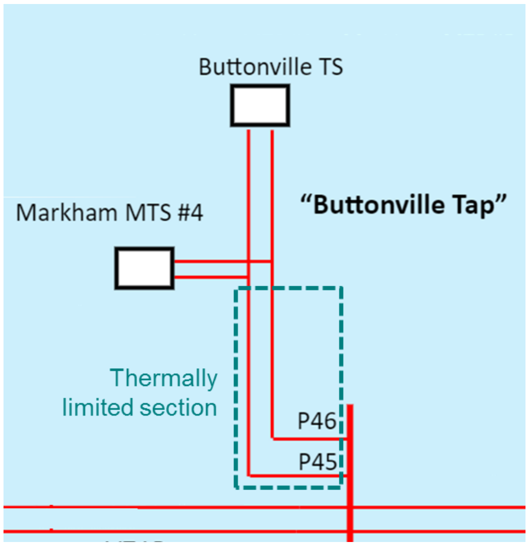
Because system assets tend to supply much larger pools of customers than any individual station, there may be more opportunities for non-wires options, but the magnitude of the need is often larger, meaning greater uptake is required over time to successfully defer system capacity needs.

Details on identified system capacity needs are described in the following sections.

6.2.1 P45/46 Supply to Markham #4 MTS

As previously identified in the Needs Assessment and Scoping Assessment, a 1.1 km section of circuit P45/46 is at risk of exceeding its thermal limit in the medium term. The P45/46 circuits extend radially north of the Parkway transformer station into Markham, where they supply the step-down stations Buttonville TS and Markham #4 MTS. These circuits are shown in Figure 6-5.

Figure 6-5: Limiting Section of P45/46, Buttonville Tap



This need is triggered when the total peak demand of Buttonville TS, Markham #4 MTS, and the future Markham #5 MTS (see Section 6.1.1) exceeds approximately 420 MW. This is forecast to occur soon after Markham #5 MTS comes into service. Note that 420 MW is an approximation as the actual loading limit can vary depending on the distribution of load between stations, for example. Power flows north of Markham #4 MTS only supply customers at Buttonville TS and possibly a future Markham #5 MTS, which means the northern section of P45/46 is not expected to hit a thermal limit unless a fourth station is connected to these circuits. This is notionally identified at the end of the 20-year forecast, but the actual need date cannot be predicted this far in advance. These dates are summarized in Table 6-1.

Table 6-1: Loading on Buttonville Tap Circuits P45 and P46

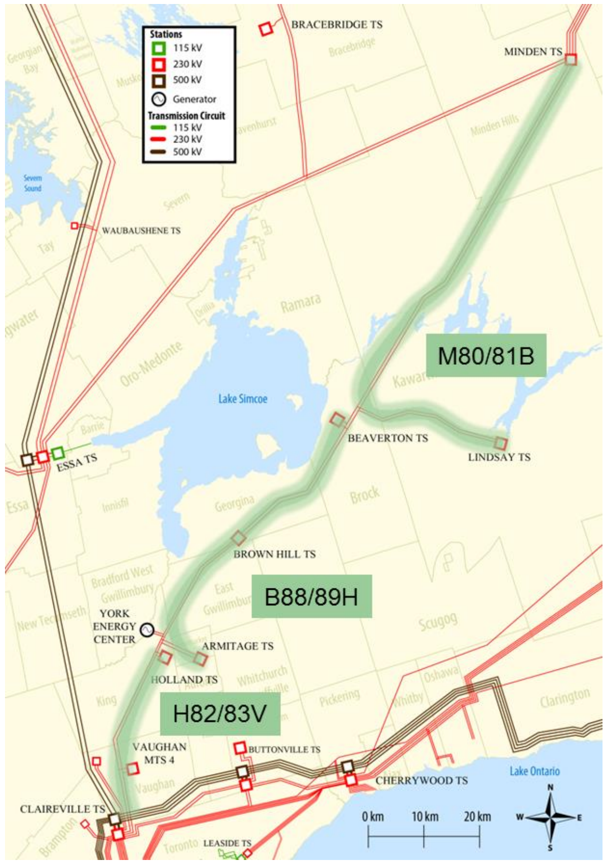
	Approx. Limit (MW)	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037
Markham #4 MTS		93	128	153	153	153	153	153	153	153	153
Buttonville TS		149	148	147	156	156	157	155	155	154	154
Markham #5 MTS		0	0	0	26	77	128	153	153	153	221
TOTAL	**420**	241	276	300	335	386	437	461	461	460	528

These needs have the potential to be deferred through non-wires measures that target peak demand in Markham (See Sections 7.1 and 7.2). Due to the meshed distribution network across Alectra's service territory in southern York, reducing peak demand across neighbouring Vaughan and Richmond Hill, combined with typical operational load transfers, can also assist in deferring this need. A relatively low-cost, low-impact wires solution has also been identified and is described in Section 7.3.1.

6.2.2 H82/83V Claireville TS to Holland TS

In the long term, continued load growth throughout York Region is expected to trigger a capacity need on the H82/83V circuits running north from Claireville TS to just south of Holland TS. These circuits are the most southerly section the transmission line that runs between Claireville TS and Minden TS. There are two sets of sectionalization devices (breakers) that divide this line into three distinct sections. The middle section, B88/89H, runs between Holland TS and Brown Hill TS and connects York Energy Centre, a critical source of supply to the area. The northernmost section, M80/81B, connects Brown Hill TS to Minden TS. The three sections are shown in Figure 6-6.

Figure 6-6: Claireville to Minden Circuits



Note that prior to 2017 there were only two sections along this corridor, with the southern section connecting Claireville TS to Brown Hill TS and referred to as B82/83V. The installation of breakers north of Holland TS was recommended in the 2015 IRRP to increase the load-meeting capability and supply security in the area, as described in Section 4.1.

Although needs emerge along different sections of this corridor at different times, it is helpful to consider the overall Claireville to Minden corridor as a single asset. Because there is no branching or redundancy along this corridor, there are limited options for alternative supply paths when a transmission outage occurs. Additionally, this corridor provides the only transmission supply path into northern York (including northern Vaughan), which means any incremental demand growth in these areas must make use of capacity on these circuits. Flows along this corridor are primarily northward from Claireville TS, which is a major bulk transmission supply point for the entire GTA. As described in Section 4.1, capacity-related needs were anticipated on this corridor during the 2005 Northern York Region Electricity Planning Study. At the time, continued growth in northern York was expected to cause northward flows from Claireville TS to exceed thermal ratings of the circuits. The recommended outcome was the addition of new dispatchable generation in northern York to reduce the amount of power that had to be transferred into the area. The resulting York Energy Centre has helped enable growth in York Region over the past decade, and is expected to continue to support local demand growth until the early 2030s.

The sections below summarize anticipated needs along this corridor over the 20-year study period.

Thermal Needs

Given the load forecast and system assumptions used in this study, thermal capacity needs have the potential to emerge in 2033 along the southernmost section of H82/83V, between Claireville TS and Vaughan #4 MTS. By 2033, the total combined load of Vaughan #4 MTS, Holland TS, Armitage TS, Brown Hill TS,[10] and possible future stations will exceed 850 MW. While the distribution of loads between stations, the eventual location of new stations and other factors influencing the actual loading limit of the Claireville to Minden circuits, make an exact loading limit difficult to predict this far in advance, an 850 MW limit is a reasonable assumption. The total combined load for these stations is shown in Table 6-2, with loads in excess of the assumed thermal limit highlighted.

Table 6-2: Loading on Claireville to Minden Circuits (Claireville TS to Brown Hill TS)

	Approx. Limit (MW)	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037
Vaughan #4 MTS		49	63	108	153	153	152	153	153	153	153
Holland TS		139	145	154	166	168	168	168	168	168	168
Armitage TS		297	307	312	312	317	317	317	317	317	317
Brown Hill TS		93	95	95	96	97	98	99	99	100	101
Northern York TS		0	0	0	0	8	21	33	45	58	72
Vaughan #5 MTS		0	0	0	0	0	0	32	94	147	147
TOTAL	850	578	610	670	727	742	756	801	875	943	959

The most limiting contingency observed in the assessment is the failure of either breaker north of Holland TS: L82L88 or L83L89. These contingencies cause either H82V and B88H, or H83V

[10] Although this corridor also serves Beaverton TS and Lindsay TS, these step-down stations are typically supplied by primarily southward flows from Minden TS. They are also not expected to see the type of demand increase anticipated for the stations included in this study, and therefore have limited impact on this system limit.

and B89H, respectively, to be removed from service. Following this outage, a single circuit remains available for supplying all stations between Claireville TS and Brown Hill TS, roughly twice the usual load level carried by each circuit when the companion is available. As peak demand increases across the area, thermal limits risk being exceeded under a wider range of outage contingencies, and will impact more customers.

Voltage Drop

In addition to thermal needs, a risk of post-contingency voltage drop in excess of 10% is also observed beginning in 2035 following the double circuit loss of H82/83V. Sudden voltage drops of this magnitude negatively impact power quality, especially for some voltage-sensitive industrial loads. In extreme cases, they can cause a “cascading” outage, where the voltage drop causes protection equipment to activate, disconnecting sections of the grid, and, in turn, producing additional voltage drops. These scenarios are more common on radial networks (connection at only one end of a circuit), especially over long distances and under heavy load conditions. This is the case following the loss of H82/83V, which provides the southern link to Claireville TS, as a significant portion of northern York customers would be left supplied by a 130 km radial link from Minden TS. This would be exacerbated by the simultaneous loss of generation support from York Energy Centre, whose station service is normally supplied via the distribution network fed from H82/83V. Under this contingency, in which this generation resource could be beneficial to supporting the system voltage, it would be left unavailable as currently configured.

Voltage Rise

A voltage rise phenomenon is also forecast beginning in year 2025 following the double circuit loss of B88/89H. Under high load conditions, the sudden loss of the major load centres supplied by Armitage TS and Brown Hill TS cause voltage on the remaining lightly loaded circuits of M80/81B to exceed 250 kV. This is above acceptable voltage levels for a 230 kV circuit. Part of the cause of this phenomenon is the use of capacitor banks at Lindsay TS and Beaverton TS to keep voltage on B88/89H from dropping after the double loss of H82/83V or the single loss of either B88H or B89H. If, however, a double circuit contingency occurs for B88/89H instead, the capacitor banks intended to keep voltage from dropping will instead contribute to excess voltage rise.

Summary of Needs

Three other considerations are important for understanding the capacity-related needs described in this section.

1) Multiple capacity-related needs are triggered in short succession. Although the need date (2033) is based on thermal limits following a specific contingency, other criteria would likely be violated shortly thereafter, including voltage drop and security of supply in 2035 (see Section 6.3.2, below). Restoration needs are also forecast to emerge as soon as 2020, meaning that solutions should be evaluated based on their ability to meet all identified needs, instead of just the most limiting or first to appear.

2) Although thermal needs do not emerge until 2033, this requires making use of a Special Protection Scheme (e.g., Load Rejection) in the interim. Under high load conditions, a predetermined set of automatic control actions will disconnect customer load following specific combinations of transmission outages and generation operation assumptions to ensure post-contingency thermal and voltage limits can be respected. This is in addition to customers who lose power due to loss of supply to their station (referred to as loss by configuration). Although load rejection is an acceptable control action under ORTAC criteria, where low-cost options exist to reduce the risk of exposure to customer outages, they should be investigated to determine if the expected benefit exceeds the upgrade cost. Other concerns with the Special Protection Scheme (SPS) operation include the frequency with which it must be manually armed by operators, estimated at hundreds of times per year by the time security needs are triggered.[11] This operational risk, in addition to thermal, voltage, and security criteria, is described in greater detail in the Holland TS 230 kV breaker System Impact Assessment, completed in 2016.

3) Once triggered, the magnitude of this capacity need increases very quickly. This happens because both the future Northern York and Vaughan stations are expected to be connected to the Claireville to Brown Hill circuits, as they provide the only transmission supply to northern Vaughan and northern York. When load transfers from Markham and Richmond Hill to Vaughan are accounted for, virtually all incremental load growth in York Region is being supplied from this same transmission line by the early to mid-2030s. This has implications for how long NWAs will be a feasible or cost-effective measure to defer new infrastructure, and the degree to which they can form part of the solution.

4) Additional potential needs exist outside of those covered by planning criteria. The needs identified in this section are based on the application of standard criteria as described in ORTAC. However, the transmitter has expressed additional concerns regarding the challenge of

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[11] SIA assessment was performed using the load forecast from the 2015 IRRP. Conclusions should be read based on MW loading rather than year, given updates to the forecast in the current IRRP.

planning for circuit outages to perform routine maintenance. These outages are typically planned during periods of low expected demand, out of consideration for the remaining assets which must supply a larger share of power during the outage period. As loads continue to increase on this corridor, the available window for securing outages will be reduced, potentially risking deferral of routine maintenance activities, or requiring York Energy Centre to dispatch more frequently to reduce transmission flows. The IESO will continue to work with Hydro One to identify appropriate maintenance periods and ensure system reliability during these times.

6.3 Supply Security and Restoration

Supply security and restoration refer to the electricity transmission system's ability to minimize the impact of potential supply interruptions in the event of a contingency, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the maximum limit of load interruption that is permissible in the event of a transmission outage considered for planning. Based on past planning practices in Ontario, the supply security limit is 600 MW for two transmission elements out of service. Load restoration describes the electricity system's ability to restore power to a customer affected by a transmission outage within specified time frames. Both transmission and distribution (transfer) measures are considered when evaluating restoration capability.

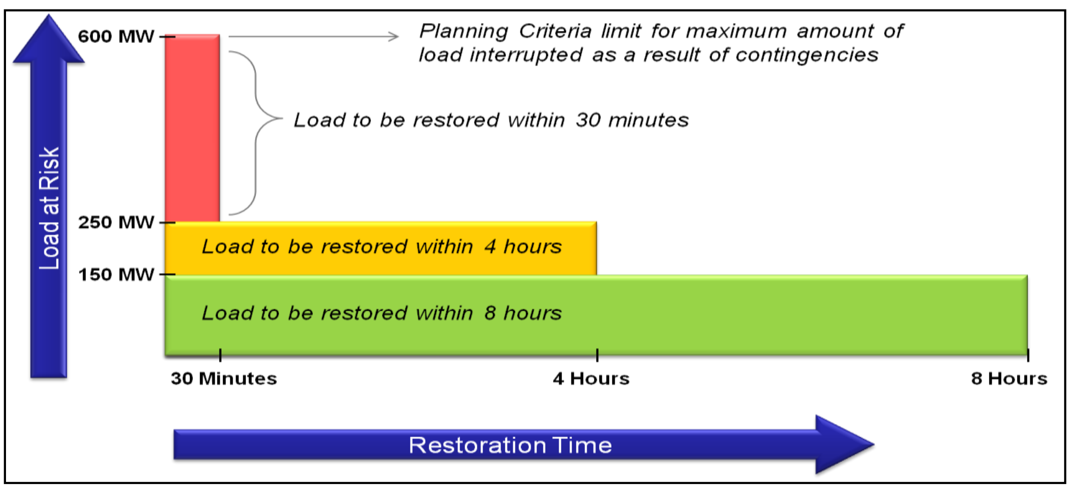
Specific requirements can be found in ORTAC, Section 7, Load Security and Restoration Criteria. The load security criteria can be found in Section 7.1 of ORTAC, and a summary of the load security criteria can be found in Table 6-3. All transformer stations in York Region have at least a dual transmission supply, which allows the load served at the station to remain uninterrupted in the event of a single-element contingency. As a result, there are no risks associated with the loss of a single transmission element. Supply interruptions may occur after multiple-element contingencies, but under all possible interruption scenarios, the amount of load interrupted was found in the assessment to remain within the limits prescribed in ORTAC.

Table 6-3: Load Security Criteria

Number of transmission elements out of service	Local generation outage?	Amount of load allowed to be interrupted by configuration	Amount of load allowed to be interrupted by load rejection or curtailment	Total amount of load allowed to be interrupted by configuration, load rejection, and/or curtailment
One	No	≤ 150 MW	None	≤ 150 MW
	Yes	≤ 150 MW	≤ 150 MW [12]	≤ 150 MW
Two	No	≤ 600 MW	≤ 150 MW	≤ 600 MW
	Yes	≤ 600 MW	≤ 600 MW[12]	≤ 600 MW

Described in Section 7.2 of the ORTAC, load restoration criteria specify that the transmission system must be planned such that, following design criteria contingencies, all interrupted load must be restored within approximately eight hours. When the load interrupted is greater than 150 MW, the amount of load in excess of 150 MW must be restored within approximately four hours. When the load interrupted is greater than 250 MW, the amount of load in excess of 250 MW must be restored within 30 minutes. A visual representation of the load restoration criteria is shown in Figure 6-7.

Figure 6-7: Load Restoration Criteria



Technically feasible solutions to address restoration or supply security needs usually consist of wires-type investments to sectionalize or introduce greater redundancy in the existing system. Sectionalization measures, such as adding switches or breakers, can reduce the area exposed to

[12] Up to the local generation outage amount, which in this area is 187 MW.

an outage, or allow for parts of the affected circuit to be restored more quickly. Greater redundancy, through new links on the transmission or distribution network, provides additional paths that can limit exposure to outages, and improve supply-meeting capability for the local system.

Due to the meshed distribution network, southern parts of York Region (roughly the municipalities of Vaughan, Markham, and Richmond Hill) generally perform well for restoration assessments, as significant transfer capability exists between adjacent station service territories by utilizing capability of the distribution network. The areas of risk for restoration-related issues are generally the northern part of York Region, including the service territories of Kleinburg TS, Holland TS, Armitage TS, and Brown Hill TS. Additionally, a security risk was identified in Northern York.

Given the proximity to repair crew and equipment, it is assumed that a transmission outage in this area can generally be restored within eight hours. As a result, restoration assessments for York Region focus on the 30-minute and four-hour milestones. Restoration capability was determined based on discussions with LDCs, which provided expected transfer capabilities and times following a total loss of station supply.

6.3.1 Kleinburg Radial Tap (V43/44)

As identified in the Needs Assessment and Scoping Assessment, the loads supplied by the V43/44 radial circuits extending north from Claireville along the western edge of Vaughan are at risk of not meeting restoration guidelines defined by ORTAC. Following the loss of these two circuits, supply is interrupted to the step-down stations of Woodbridge TS, Vaughan #3 MTS, and Kleinburg TS. In addition to supplying customers from the municipalities of Vaughan, King, and Caledon, these three stations also supply some load from Brampton, Toronto, and Mississauga. Table 6-4 shows the maximum interrupted load (total peak demand), as well as the amount at risk of not being restored within 30 minutes and four hours.

Table 6-4: Loss of V43/44, MW

	Limit	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037
Interrupted	600	418	434	446	447	452	454	473	473	473	475
Remaining after 30 minutes	250	290	299	306	308	310	312	331	331	332	334
Remaining after 4 hours	150	93	95	96	97	98	99	119	119	120	122

6.3.2 Northern York (H82/83V and B88/89H)

Both the B88/89H and H82/83V circuits supply load in northern York, where the longer distances often make restoration through the distribution network more challenging. The addition of breakers and switching devices at Holland TS in 2017 mean that following a double outage of either B88/89H or H82/83V, supply can be restored to either Holland TS or Armitage TS, respectively. However, supplying Holland TS from B88/89H during peak demand periods would require York Energy Centre to be operational to maintain voltage support in the area. Since it may take over an hour for York Energy Centre station service to shift from Holland TS to B88H and return to service after the total loss of H82/83V, restoration of Holland TS is assumed by the four-hour mark. Restoration of Armitage TS is possible within 30 minutes.

Following a loss of the northern section, B88/89H, all load at Armitage TS, Brown Hill TS, and the future Northern York TS would be lost. However, since Armitage TS can be restored within 30 minutes, load loss does not exceed ORTAC standards within the study period.

Following a loss of the southern section, H82/83V, all load at Vaughan #4 MTS, Holland TS, and the future Vaughan #5 MTS would be lost. Additionally, as mentioned in Section 6.2.2, this outage may trigger operation of an SPS, which would automatically disconnect customer load at Armitage TS and Brown Hill TS during peak load periods to ensure voltage remains within acceptable limits. This action is not permitted to interrupt more than 150 MW of customer load. Restoring Holland TS by shifting supply to B88/89H is assumed to occur at the four-hour mark, as York Energy Centre must be operable to ensure sufficient voltage support. The delay from 30 minutes (typical switching operation time) to four hours may trigger restoration needs beginning in 2020. Table 6-6 shows the maximum interrupted load (total peak demand), as well as the amount at risk of not being restored within 30 minutes and four-hour time frames.

Table 6-5: Loss of H82/83V (MW)

	Limit	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037
Loss by configuration		188	208	262	319	321	320	353	415	468	468
Estimated loss by SPS		86	96	101	101	113	126	138	150	>150	>150
TOTAL Interrupted	600	274	304	363	420	434	447	491	565	>600	>600
Remaining after 30 minutes	250	249	272	309	343	358	370	399	441	468	468
Remaining after four hours	150	0	0	0	0	0	0	0	0	0	0

The table also highlights the expected customer exposure to load rejection due to the SPS. This was estimated by taking the maximum load supplied on B88/89H when the maximum 150 MW load rejection is required to keep voltage drop within acceptable limits following the loss of H82/83V. This occurs in 2033. For earlier years, the 150 MW load rejection is reduced to keep post-contingency demand on B88/89H flat at 2033 levels. However, by 2035 the 150 MW load rejection cannot be relied upon, as it would push total interrupted load (by configuration and SPS) to more than 600 MW, exceeding maximum supply security limits. This means that by 2035 either supply security limits will be exceeded by rejecting more load than is permitted, or voltage drop limits will be reached. In either case, a system need is triggered in 2035.

6.4 Summary of Identified Needs

Table 6-7 outlines the needs identified in this IRRP, according to whether they are expected to emerge in the near, medium, or long term. The next section of the report will consider the types of solutions considered to address needs in general terms, and describe the evaluation of alternatives.

Table 6-6: Summary of Identified Needs

Need	Details	Expected Timing
Near-Term Needs		
Restoration and supply security needs	Supply security needs have previously been identified for the V71/75P Parkway corridor. Restoration needs also exist on the Kleinburg radial pocket (V43/44), and may emerge shortly (2020) in Northern York (H82/83V)	Existing
Medium-Term Needs		
H82/83V Claireville TS to Holland TS	Voltage rise on stations along M80/81B following loss of B88/89H	2025
Markham area step-down station capacity need	Loading at existing Markham area stations exceeded under basecase forecast. Need for new Markham #5 MTS triggered	2025

Northern York area step-down station capacity need	Loading at existing Armitage TS and Holland TS exceeded under basecase forecast. Need for new Northern York TS triggered	2027
P45/46 (Parkway TS to Markham #4 MTS)	System capacity need. Thermal limits are exceeded on the circuits between Parkway MTS and Markham #4 MTS, a 1.5 km section of the Buttonville Tap	2029
Vaughan area step-down station capacity need	Loading at existing Vaughan area stations exceeded under basecase forecast. Need for new Vaughan #5 MTS triggered	2030
Long-Term Needs		
H82/83V Claireville TS to Holland TS	System capacity need. Thermal, voltage drop, and supply security needs triggered in quick succession	2033

7. Plan Options and Recommendations

This section outlines the options considered to address transmission needs in York Region, including how these options were evaluated and the recommendations for action in the near-term.

There are generally two types of approaches for addressing the types of growth-related capacity needs observed in this area:

1. Target measures to reduce peak demand to maintain loading within the system's existing limits
2. Build new infrastructure to increase the load-meeting capability of the area

Distributed energy resources, including demand response, EE measures, or energy storage are well suited to the first approach, and are considered first.

Even if not being pursued to address specific system capacity needs, there are other potential benefits to non-wires investments, such as customer cost savings, and reducing GHG emissions. Some of these other objectives have been identified in municipal energy plans. The information in this IRRP may be a useful source of input for identifying the potential for projects and strategies at the local level, while identifying where electrical system benefits and infrastructure deferral value may also exist. Information on avoided costs from a provincial grid perspective (e.g., avoided energy and capacity) is presented in the Annual Planning Outlook (APO), released in January 2020. System avoided cost values are updated periodically by the IESO.

Where reducing peak demand is not technically or economically feasible, the other strategy is to upgrade the infrastructure to increase the load-meeting capacity of the area. The types of upgrades that are viable can depend on the nature of the need. In cases where a step-down station exceeds its maximum capacity, a station can be expanded or built if the transmission has sufficient capability to supply it. If the transmission system is at its capacity, generally the options are to build new local generation (to reduce the amount of power that needs to be brought in from elsewhere), or to build new or upgrade the transmission to increase transfer capability. New transmission also has the potential to improve security and restoration by adding redundant supply paths, as additional redundancy reduces exposure to outages when a transmission element is out of service.

7.1 Energy-Efficiency Opportunities and Options

Since the 2019-2020 Interim Framework took effect on April 1, 2019, the IESO has been mandated to centrally deliver province-wide EE programs that target businesses, Indigenous communities and low-income consumers. Through the Framework, the IESO offers EE incentives and rebates to electricity customers through a suite of Save on Energy programs, which provide a valuable and cost-effective system resource that helps customers better manage their energy costs.

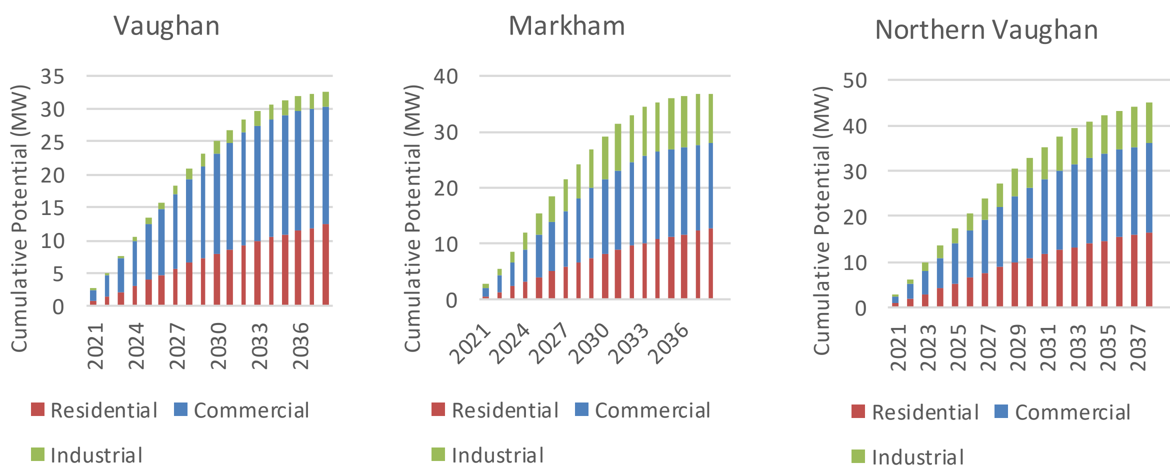
The IESO is currently working with government and stakeholders to consider opportunities for EE in Ontario beyond 2020. In 2019, the IESO completed an integrated electricity and natural gas conservation achievable potential study (2019 APS) in partnership with the Ontario Energy Board. The 2019 APS identified significant and sustained potential for EE across all customer sectors throughout the study period.

EE investment decisions are typically determined by assessing the cost-effectiveness of the initiative (i.e., whether the incentive costs are outweighed by the benefits to the electricity system). Some value is attributed to non-energy benefits, such as customer comfort or improved business productivity. The 2019 APS results were used to estimate EE opportunities within York Region that are cost effective from the system perspective.

Figure 7-1 shows the total estimated potential for cost-effective EE to reduce summer peak demand[13] in the Vaughan, Markham and Northern Vaughan areas.

[13] The 2019 APS defined the summer peak period as June-August between the hours of 1 p.m. and 7 p.m., which for the purposes of this analysis are considered to be reasonably aligned with York Region system needs.

Figure 7-1: Cumulative System Energy-Efficiency Potential to Reduce Peak Summer Demand



As described in Section 6.1, growth forecasts show a potential mid-term need for up to three new step-down stations in York Region, including a Markham #5 MTS in 2025, a Northern York TS in approximately 2027, and a Vaughan #5 MTS in approximately 2030. Additionally, an anticipated long-term need for additional system capacity along the Claireville-Minden circuits is expected in 2033 or later. As noted above, the dates for capacity-related needs (station or system) could be deferred by NWAs, such as EE, that target peak demand electricity use.

In particular, energy-efficiency initiatives targeting peak demand within the municipalities of Vaughan, Richmond Hill, and Markham have the potential to defer the need dates for Markham #5 MTS and Vaughan #5 MTS. Measures targeting the higher-growth northern municipalities of Newmarket, East Gwillimbury and Aurora would likely be the most effective at deferring the Northern York TS. Any measure introduced within York Region has the potential to defer the long-term system capacity need.

Table 7-1 shows the estimated impact on the need date for medium and long-term capacity needs in the area, assuming 50% achievement of the economic EE potential, and 100% achievement.

Table 7-1: Impact of Energy Efficiency Achievement on Capacity Need Dates

Capacity Need	Existing need date (current forecast)	Estimated deferred need date	
		50% Economic EE	100% Economic EE
Markham #5 MTS	2025	2025	2026
Northern York TS	2027	2029	2033
Vaughan #5 MTS	2030	2031	2032
H82/83V Claireville TS to Holland TS	2033	2034	2036

While the rapid growth in this region may limit the potential for EE to fully meet forecast needs, the medium to longer-term nature of the needs present an opportunity to target as much of the system cost-effective EE potential as possible in the near term. The time available still allows for evaluation and monitoring the impact on load growth between regional planning cycles and into the next planning cycle. See 1.1.1Appendix C: Options and Assumptions**Error! Reference source not found.** for more information about the methodology used to calculate EE potential.

7.2 Distributed Energy Resource Opportunities and Options

DERs, as well as other NWAs, were considered to address the long-term needs identified in the IRRP. Potential resource solutions consisted of distribution-connected technologies, taking into account the nature, magnitude and profile of the need. In terms of the resource solution, options considered included: lithium battery energy storage, solar PV generation, a combination of solar and lithium battery energy storage. Larger resource options were also considered, including natural gas-fired SCGT. The cost trends and projections associated with these technologies were assessed.

Consistent with previous IRRPs, an economic analysis of the alternatives and the lowest-cost option and combination of options were compared based on net present value (NPV). Lithium battery energy storage was ruled out as a viable option due to the significant size of the need. The capacity contribution of solar resources for peak demand reduction is estimated to range between 13.8% and 30% (refer to Figure 4.2 in the December 2019 Reliability Outlook tables); therefore, the cost of solar PV would increase significantly to install the effective capacity required. Based on the prevailing technology costs, SCGT would be the least cost resource alternative.[14]

One of the traditional barriers to developing DERs at a large enough scale to address transmission system constraints is the challenge in predicting how well resource availability will match the time of day and duration of system needs. In order to better understand the ability of DERs to target peak demand periods, and defer new transmission infrastructure, the IESO has launched a two-year local electricity market demonstration project in southern York Region.

The local electricity market demonstration will allow DERs like solar PV, energy storage, and consumer demand response, to compete to provide local solutions when they are needed. This project is expected to provide data to demonstrate how these types of resources can offset peak demand periods, and the associated costs, reliability, and operation. The capacity target is proposed to be 10 MW in a 2020 auction and 20 MW in a 2021 auction. The 2021 auction will be subject to revision after the first auction. Further design elements and considerations are available on the IESO's website.

Funding for the pilot comes from the IESO's Grid Innovation Fund and Natural Resources Canada (NRCan)'s Smart Grid Fund. Alectra, the local distribution company for the region, will help deliver the pilot program, which is expected to get underway in Q2 of 2020.

7.3 Wires Options

The term "wires" option refers to any conventional transmission or large-scale resource solution used to increase the load-meeting capability of an area.

In the near term, a relatively minor need related to the P45/46 circuits can be addressed through reconductoring of an existing line. In the medium to long term, more significant wires upgrades may be required, including up to three new step-down stations, and a system capacity upgrade for the Claireville to Minden circuits. An opportunity has also been identified to improve system reliability, operability, and resource availability by advancing the reconfiguration of

[14] The estimated overnight cost of capital assumed is about $1,445/kW (2019 $CAD), based on escalating values from a previous study independently conducted for the IESO.

York Energy Centre's station service supply point. This work would otherwise be required in the long term to address supply security.

7.3.1 Reconductor P45/46

Hydro One has previously indicated that the existing transmission towers serving this area are capable of supporting higher-rated conductors, which will raise the load-meeting capability from approximately 420 to 600 MW. The new limit would be based on supply security for the loss of both circuits. This measure is expected to cost approximately $2 million, and can be implemented with a three-year lead time. Alternatives to reconductoring would include building a new supply path to remove Markham #4 MTS from the limited P45/46 circuits, and instead provide supply from the C35/36P (Parkway) circuits. Since this alternative would be more costly (minimum $5 million), take longer, and be more disruptive to the local community, the lower-cost, less intrusive alternative is recommended.

Based on the peak demand forecast, reconductoring of the limiting transmission section is required to be complete in 2029, or a few years after Markham #5 MTS comes into service. However, since newly commissioned stations often receive large transfers to assist in load balancing, the Technical Working Group recommends that the need date be based on the Markham #5 MTS in-service date, and that Hydro One proceed with design work following the completion of this IRRP to ensure the upgrade can be in place before Markham #5 MTS comes into service (currently forecast for 2025).

In addition to the near-term need identified above, a similar long-term need may arise along the remaining Markham #4 MTS to Buttonville TS section of the same P45/46 circuit, beginning if and when a second new step-down station is required in the Markham area (notionally Markham #6 MTS). Based on the current load forecast, this is not expected to occur until the late 2030s, and has the potential to be deferred through EE and other non-wires measures targeting peak demand throughout the southern York municipalities. Given the uncertainty surrounding the longer-term need for reconductoring the remaining 2.7 km of these circuits, there is little benefit from advancing the need dates and performing the upgrades on the entire circuit at this time.

7.3.2 Address the Potential for High Voltages on M80/81B

The voltage rise described in Section 6.2.2 is forecast to trigger a need at the stations connected to the M80/81B circuits beginning in 2025. There are many relatively straightforward ways this need can be addressed. For example, a Special Protection Scheme (or Remedial Action Scheme) could automatically remove capacitor banks at Lindsay TS and Beaverton TS under high load conditions following the double circuit loss of B88/89H. The Working Group recommends that Hydro One investigate this need, identify a preferred solution through the RIP process, and implement that solution no later than 2025.

7.3.3 Reconfiguration of Station Service Supply for York Energy Centre

The York Energy Centre supplies power to the B88/89H circuits through a connection north of the Holland breakers. However, the station service (necessary for operating station equipment) is fed under normal conditions from the distribution network via Holland TS, which is located south of the Holland breakers. This means that following the loss of H82/83V south of Holland TS, which leaves Brown Hill TS, Armitage TS, and the future Northern York Region TS supplied radially from the north, York Energy Centre would also be removed from service. This outage, described in Section 6.2.2, causes risks associated with restoration in the near term, and voltage drop and supply security risks in the medium to long term.

If York Energy Centre could remain in service throughout this outage, voltage drop would be addressed without the need for load rejection, and the supply security risk would be avoided. Additionally, Holland TS could be transferred to B88/89H within 30 minutes, also addressing the near-term restoration need (load >250 MW restored within 30 minutes). This could be accomplished by ensuring normal station service supply is provided at a point north of the Holland breakers. An alternate station service supply point does exist, and is fed via the B88H circuit. However, normal operation from B88H would create a new risk for loss of York Energy Centre following a single B88H contingency. This would create similar thermal and voltage issues in Northern York beginning in 2025, and also require operation of load rejection through a Special Protection Scheme. In order to address both sets of needs, future York Energy Centre station service supply would need to ensure continuous operation following the loss of both H82/83V circuits, or the loss of either B88H or B89H.

Upgrading York Energy Centre station service to ensure operation following the loss of both H82/83V circuits, or the loss of either B88H or B89H, could be accomplished several different ways. One option is to make use of the two existing supply paths, but connected through an

Automatic Transfer Scheme, which automatically switches from one source to another immediately after a supply interruption is detected, without impacting station operation. Another option would be to add a second transmission supply point off of the B89H circuit. Alternatively, technologies such as battery storage could enable the instantaneous transfer of station service supply at the facility, with the added benefit of improving voltage stability in off-peak hours, and regulation service for the system.

Estimating the cost of these types of upgrades would require a more detailed review of York Energy Centre's existing station service configuration, including spatial layout and protections operation. Transmission alternatives could include converting Holland Junction into a full switching station (SS), or advancing the construction and specifically siting the future Northern York TS in a location suitable for supplying normal station service. The latter alternative, while addressing the simultaneous H82/83V contingency, would still expose York Energy Centre to interruption following a distribution-level outage (unless implemented in addition to an Automatic Transfer Scheme).

Under the peak demand forecast, reconfiguration of York Energy Centre station service is required no later than 2035 to address supply security and voltage drop needs. However, advancing this upgrade would benefit local customers immediately by lowering exposure to supply interruption or power quality issues under specific outage conditions. This includes eliminating the risk of a restoration need beginning in 2020. Additionally, increasing the availability of system resources under a greater range of outage conditions, including the loss of H82/83V, B88H, or distribution supply, would benefit a wider range of customers. As a result, this IRRP recommends that the IESO and Capital Power (York Energy Centre's operator and 50% owner) proceed with a more detailed investigation to identify and consider options for a preferred long-term station service supply configuration, including estimated cost impact. These discussions may include Hydro One, as necessary.

7.3.4 New Step-down Transformer Stations

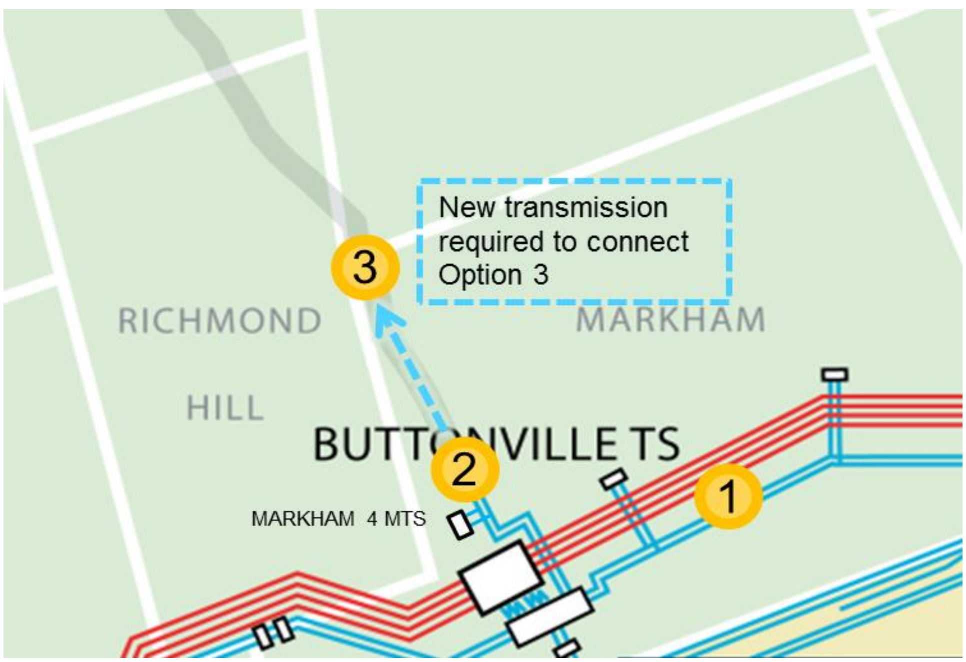
Based on the demand outlook, three areas in York Region may require new step-down station capacity in the medium term. Due to the timelines associated with these needs, and typical station construction (around three years), action is not required at this point to advance a wires solution. Instead, station loadings continue to be monitored to determine the pace of growth, net of EE and DER impacts. Options are described below to assist in identifying suitable locations for this infrastructure, and preserve long-term options.

Markham Area Transformer Station

Due to the meshed configuration of Alectra's southern York Region service territory, new step-down transformer stations are generally alternated between the western (Vaughan), and eastern (Markham) sides of the system. The last step-down station built to serve this area was Vaughan #4 MTS in 2018. This station is expected to be sufficient to meet growing load in southern York until approximately 2025. This means that the next step-down station should be built in Markham to keep distribution system loads balanced. Choosing a Markham location instead of Vaughan is also preferable as it does not contribute to the long-term Claireville to Minden system capacity needs.

Alectra began investigating possible candidate locations for Markham #5 MTS during the previous IRRP, and identified three technically feasible locations, shown conceptually in Figure 7-2.

Figure 7-2: Candidate Locations of Markham #5 MTS



The primary criterion used to determine a preferred station location is generally the cost of new infrastructure required to incorporate the station to the grid and connect customers. The technical feasibility can also be used to evaluate options, and community preferences can be a factor, especially where costs of different options are otherwise similar. Because the cost of building the station is roughly the same for all three locations (around $30 million), only those costs related to incremental transmission (where required) and distribution connections that vary by location are considered. Details on these alternatives, and associated costs, are provided as follows (numbers correspond to the locations in Figure 7-2).

1. **Southeast option, connection along the Parkway**. This site is the furthest removed from the areas of anticipated growth, significantly increasing the long-term cost of distribution infrastructure to connect new customers (approximately $69 million). There is also a risk that capacity at this station could become stranded if it becomes technically infeasible to supply load concentrated along Markham's northern border, even after accounting for transfers to and from a more northern station, such as Buttonville TS. The transmission circuits along the Parkway are capable of supplying the anticipated capacity of a station at this site, and would not require any upgrades.

2. **Central option, connection at the existing Buttonville TS**. This option involves using available space at this facility to build a second step-down station adjacent to the existing Buttonville TS. Because this location is closer to the growth areas in northern Markham, distribution costs are less that the first option (estimated at $27 - $43 million). As described in Section 6.2.1, the incremental load of a new Markham #5 MTS would trigger the need to upgrade the P45/46 circuits from Parkway to Markham #4 MTS, at a cost of approximately $2 million. No further transmission work would be required to accommodate this station location.

3. **Northern option, connection via new transmission supply from Buttonville TS.** This possible location is near the northern edge of Markham, is closer to the anticipated area of highest new growth. Associated distribution costs are estimated at $17 million. Because this site is located north of the existing grid, approximately 6 km of new, double-circuit transmission line would be required. Parts of an existing transmission corridor containing an idle 115 kV line could be leveraged, but this would require replacing the existing towers with larger, 230 kV-rated towers. Additionally, most of the required 6 km of this corridor is adjacent to residential built up areas. Previous plans considered rebuilding this corridor as an option to improve supply capacity to the area, but this resulted in community opposition (see Section 4.1). As with option 2, locating Markham #5 MTS north of Buttonville TS would also trigger the $2 million upgrade of conductors on the P45/46 circuits between Parkway and Markham #4 MTS.

Of these three options, the southeast alternative was rejected, as it performs much worse in terms of distribution costs than the central site, while introducing a risk of stranding assets in the long run. Selecting a preferred site between the central and northern options is more challenging. Both rely on capacity from the Parkway to Buttonville circuits to supply new customers in northern Markham, but one relies on transmission to access new customers, and the other distribution. In order to identify the least-cost outcome, these two sets of incremental costs are compared in Table 7-2. Since both options require the upgrading of the P45/46 circuits between Parkway TS to Markham #4 MTS, this cost is omitted from the analysis.

Table 7-2: Distribution Costs Associated with Candidate Markham #5 MTS Locations

Location	Approximate cost of distribution infrastructure ($million)
1. Southeast Option (rejected)	$69
2. Central Option (Buttonville TS)	$27 - $43
3. Northern Option	$17
Difference between Central and Northern	**$10 - $26**

The distribution costs reflect the uncertainty associated with the location and type of new connections that may be required. For example, distribution cost associated with the Central station may range from $10 million to $26 million more than the Northern station.

Predicting the transmission cost of extending the Buttonville radial tap an additional 6 km into northern Markham requires making assumptions about the type of technology being used:

1. Overhead towers. These are the most common, least-cost type of transmission technology. Costs can vary depending on site topology and tower design, but are estimated for this extension to be around $21 - 27 million. Suitability of the terrain and community preference will determine what type of tower design can be accommodated.

2. Underground cables. The use of underground cables is typically reserved for cases where overhead transmission is not technically feasible, such as when insufficient right-of-way space exists. Costs are significantly higher for this extension at approximately $102 million. Cables also typically have a shorter lifespan, requiring replacement after about 40 years, while most overhead circuits can last 60 years or longer. Additionally, although the likelihood of outages for cables is lower than overhead transmission (less risk from weather or animal contact), when they occur, these outages generally last longer before they can be isolated and repaired.

If this transmission extension were being considered as a stand-alone solution to enable the Northern Markham #5 MTS location, the costs above could be compared directly to the incremental distribution costs associated with the Central location. However, as described in

Section 6.2.2, there is also a long-term need to increase the load-meeting capability of the Claireville to Minden circuits. One identified option (described in greater detail in Section 7.3.5), is to rebuild the entire Buttonville to Armitage right of way to 230 kV, which includes the section needed for accessing the Northern Markham #5 MTS location. The Buttonville to Armitage option is one possible alternative. If it is ultimately selected as the preferred long-term solution, then the actual cost attributable to the Northern Markham step-down station is only the cost of advancing the southern portion of the line from 2033 up to 2025. This advancement is the difference between the estimated need date for system capacity, versus the date for Markham #5 MTS. This creates four transmission cost scenarios: one of two technology types (overhead or cable), and one of two cost types (total cost or the advancement cost only). Because the costs are triggered in different time frames, the scenarios are expressed in NPV to assist in the comparison in Table 7-3.

Table 7-3: NPV Comparison of Markham #5 MTS Options

	Buttonville to Armitage is NOT chosen as preferred long-term capacity solution (NPV in $2019 CAD)		**Buttonville to Armitage is chosen as preferred long-term capacity solution (NPV in $2019 CAD)**	
	Overhead tower, total cost	Cable, total cost	Overhead tower, advancement cost	Cable, advancement cost
Incremental cost of Central Markham #5 MTS[15]	$6 M - $17 M	$6 M - $17 M	$6 M - $17 M	$6 M - $17 M
Incremental cost of Northern Markham #5 MTS	$30 M	$111 M	$8 M	$30 M

The NPV comparison shows that the least-cost option depends on the assumptions made about the corridor itself, and whether it is being triggered in the long term regardless of where Markham #5 MTS is located. In general, the high cost of cables mean that it is difficult to make a

[15] NPV of $10-$26 million spend at a constant annual amount between 2025 and 2036. No extension of transmission line included in costs.

case for advancing them, regardless of future outcomes. If overhead lines are considered, the cost of transmission is within the range of incremental distribution. When the uncertainty of planning level estimates for future transmission is considered (historically in the order of +/- 50%), the Central or Northern Markham #5 MTS options become comparable.

Where costs are this similar, community input should play a stronger role in selecting the preferred outcome. The ultimate decision should, therefore, be made between Alectra and the customer, as this IRRP recognizes no strong difference in cost between the Central and Northern Markham #5 MTS locations. To date the community has been clear that the preference is to defer the need for additional transmission in Markham for as long as possible or opt for undergrounding of the transmission line along the corridor, which would suggest the Central Markham #5 MTS is preferred. At the same time, since the station is not required until the mid-to-late 2020s, this decision can be revisited once additional engagement on the long-term supply capacity solution has taken place. If the Buttonville-Armitage solution is preferred, the cost benefit of advancing an overhead transmission line may shift the preference to the Northern site.

Northern York Area Transformer Station

The existing Northern York step-down stations of Armitage and Holland TS are located within the municipalities of Newmarket and King, in close proximity to Aurora. In determining an appropriate location for a future Northern York TS, consideration is given to where new customer growth is expected to materialize. Locating a step-down station closer to new customer demand reduces the amount of distribution infrastructure required, which can reduce cost as well as the risk of distribution-related outages.

Of the six municipalities which roughly make up the Northern York sub region, the municipality of East Gwillimbury is forecast to see the highest increase in population and employment over the next few decades. There is also currently no step-down station within the community, and power is supplied via feeders from either Newmarket or King. East Gwillimbury is also able to support a new step-down station without the construction of new transmission, as the B88/89H circuits cross through its territory. Although the final decision on a suitable location, including all associated environmental assessment work, rests with the LDC and transmitter, the York Region IRRP recognizes that East Gwillimbury is likely best suited to accommodate a future Northern York TS.

New step-down stations of this type, including real estate, typically cost around $35 million. The need for this step-down station can be deferred through non-wires measures that target peak demand. The focus would need to be in Northern York Region, particularly in higher-growth areas such as Newmarket, Aurora, and East Gwillimbury. Under the load forecast, a new northern station is currently expected to be required in 2027. Given development pressures in the area, the Working Group recommends that work be undertaken to identify and secure a suitable step-down location, regardless of the final in-service date. Once suitable land is secured, the need to begin development work would not be required until at least 2024. Actual load growth at Armitage TS and Holland TS should continue to be monitored on an annual basis to advance or defer this date, as required.

Vaughan Area Transformer Station

The most recent step-down transformer station in Vaughan, the Vaughan #4 MTS, was constructed near the intersection of Kipling Avenue and Kirby Road. This location was chosen because it is close to the area of growth in Vaughan, making it well placed to supply new customers. At the time the site was being acquired, enough land was purchased to locate two step-down transformer stations: Vaughan #4 MTS, and a future Vaughan #5 MTS. It is therefore assumed that Vaughan #5 MTS can be built at this location. With land already available, the incremental cost of building this new station is approximately $25 million.

The need for this step-down station can be deferred through non-wires measures that target peak demand in southern York, namely Vaughan, Richmond Hill, and Markham. The exact need date will coincide with when the next most recently built station, in this case the future Markham #5 MTS, is loaded to its maximum. This is not currently forecast to occur until 2030 at the earliest, and the date is sensitive to measures designed to defer both the Vaughan #5 MTS, and the earlier Markham #5 MTS. With the land for this future station already secure, and the need date over 10 years away, no further action on this option is recommended at this time.

7.3.5 Increase Supply Capacity on Claireville to Brown Hill Circuits

The assessment found in the long term, the limits of the Claireville TS to Brown Hill TS 230 kV circuits will be reached. The need emerging in the early to mid-2030s is a thermal need driven by the projected demand growth in the region. Section 7.3.3 describes a proposed solution that will address other issues identified affecting these circuits, including load restoration needs (in the near-term) and voltage issues (near the end of the planning horizon).

If a transmission is preferred, given the lead time required, a decision does not have to be made until 2025 at the earliest. Other decisions needed sooner, such as the location of a future Markham step-down station, have potential to be informed by the long-term outcome. In other words, the location of the step-down station could influence the best choice for transmission, if and when a decision on transmission is needed. As a result, this IRRP recommends that additional engagement with communities, stakeholders, and the LDCs continue between regional planning cycles to better inform decision-making.

Additionally, DERs or other non-wires options have the potential to defer both the medium-term step-down station needs, and consequently, they may help to defer the longer term transmission need. The aforementioned work that is recommended between regional planning cycles can also inform approaches that are intended to address the demand side in York Region, and potentially defer future transmission requirements, and/or the need to decide on a transmission solution.

Details on identified solutions are provided below. This list should not be considered exhaustive, and new options may be added where technically and economically feasible.

DERs

A DER solution to address supply capacity needs could consist of a number of smaller resources connected to the distribution network supplied by stations along the Claireville to Brown Hill circuits. In order to be successful, the network of resources would need to, collectively, offset any peak demand in excess of the existing load meeting capability of these lines. As described in Section 6.2.2, this is roughly 850 MW, but the exact number would need to be reevaluated closer to when the need is triggered to account for updated assumptions related to customer composition and the location of new step-down stations. Based on the current forecast, the DERs would have to be sized to reliably provide at least 120 MW, in order to meet the 2037 need. Based on the duration profile estimated for the area, a peaking event could require 770 MWh of energy over the course of 10 hours. Several additional peaking events, typically of lower duration, could also be expected throughout the year. Given the need for reliable, dispatchable operation, some storage technology would likely need to be part of a DER solution. However, current battery technologies are expensive, and cannot easily be scaled up to these magnitudes. Given that technology's current characteristics, battery energy storage would also need to be oversized. Building additional local resources to power the batteries, such as solar, would also add to the cost of this type of solution. Using existing costs, as well as cost trends and projections associated with solar PV and battery storage, an installation capable of up to 120 MW of demand, and 770 MWh of energy output, would not be cost feasible, and would likely introduce operational issues as well. However, these estimates should be revised as technologies continue to develop. In particular, smaller scale initiatives could have the potential to cost effectively defer the need for a conventional solution, especially when paired with other measures such as EE.

Other Resource Solutions

Larger scale resource solutions (e.g., generation) provide capacity locally, reducing the amount of electricity that needs to be transported into the region along transmission assets. Transmission-connected generation resources can be sized large enough to address most capacity-related needs caused by the high rates of forecasted urban growth in York Region. To be a viable standalone solution, approximately 120 MW of new, dispatchable, generation would be required by the end of the study period. Such a facility would need to be connected to the Claireville to Minden circuits (H82/83V or B88/89H) north of Vaughan #4 MTS. This also assumes that the existing 393 MW YEC remains operational throughout the plan horizon.

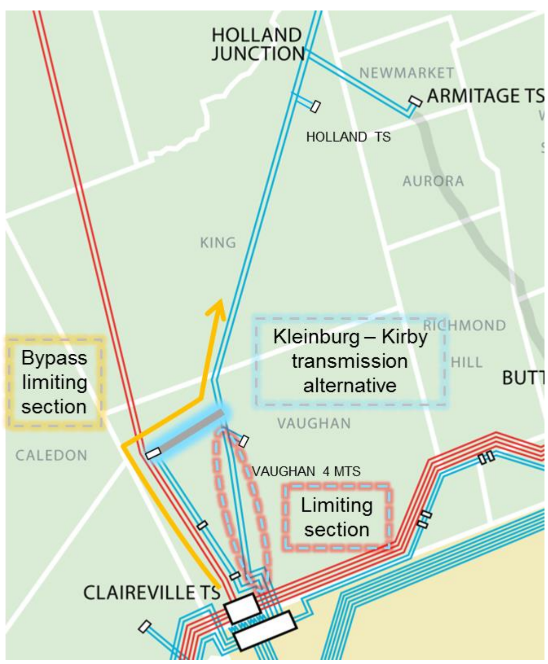
Predicting the cost of a resource solution this far in advance is challenging, as most of a resource's value comes from its contribution to system capacity, rather than local capacity needs. A purely cost-based analysis of the local generation option potentially overestimates the generation cost, since it does not credit the resource for its contribution to meeting provincial demand. If it is assumed that a simple cycle gas peaking facility were installed to address the local need only, the cost is estimated at around $270 - $300 million. However, if there is a need for (provincial) system capacity over the same time period, then the incremental cost of siting it in York Region (as opposed to elsewhere in the province) could be much less. It is not possible at this time to predict what the system value of a new resource will be in the mid-2030s. Instead, this IRRP recommends that the potential value of new capacity in this area be considered when long-term resource adequacy assessments are prepared for the 2030s. The local value of siting resources in this area can be expressed in terms of deferral value of the transmission alternatives described in the sub-sections that follow.

Compared to transmission solutions, the land use impact of the generation option is minimal, if located along the existing corridor. At the same time, the most suitable resource type for these needs at present is a gas-fired facility, as battery technology cannot be cost-effectively scaled up to the necessary size, and renewable resources are not controllable. This assumption may change over time as energy storage and other technologies improve or are introduced to the marketplace. Many municipalities in York Region have also indicated that they wish to reduce greenhouse gas emissions, which may introduce other challenges for siting gas generation and gaining community support.

Transmission Solution – New Kleinburg to Kirby Corridor

One technically feasible transmission alternative involves sectionalizing the Claireville to Brown Hill circuits with a new transmission link connected westward to the Kleinburg TS. This option would work by providing a redundant path for power flowing from Claireville TS northward into northern York, and bypass the heavily loaded and thermally limiting section of H82/83V between Claireville TS and Vaughan #4 MTS (and a future Vaughan #5 MTS location). Depending on the configuration, this alternative could reduce the load being supplied by the constrained Claireville to Brown Hill circuits by the equivalent of up to two transformer stations. In order to be effective, the point of interconnection of the new line to the Claireville to Brown Hill circuits would have to be north of Vaughan #4 MTS. This is located near Kipling Avenue and Kirby Road. This alternative is often referred to as the Kleinburg to Kirby corridor, and is highlighted in the Figure 7-3.

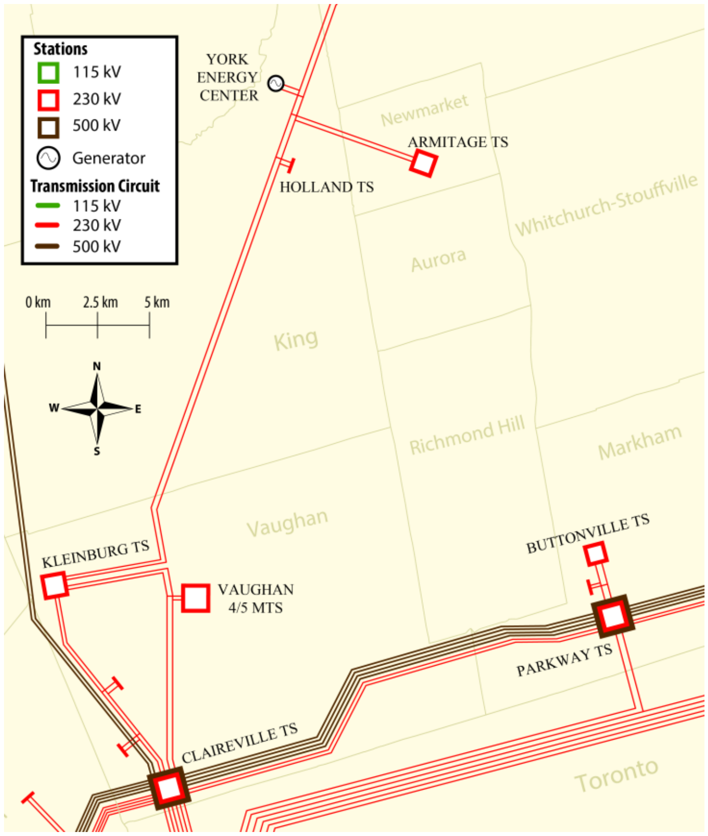
Figure 7-3: Kleinburg to Kirby Alternative



This transmission upgrade can be configured multiple ways, depending on the desired outcome for both local and provincial (bulk) system benefit. When the Kleinburg TS was originally developed, its access to both the regional 230 kV and bulk 500 kV transmission network meant it could be leveraged as a future bulk supply point, similar to Claireville TS. The station was purchased with enough land to accommodate additional switching and autotransformer facilities. If the Kleinburg to Kirby transmission upgrade is selected as the preferred option to meet York capacity needs, the ultimate configuration of Kleinburg TS should be informed by anticipated bulk system needs across the GTA at that time.

For the purpose of this study, this transmission option was modelled assuming a full switching station was built at Kleinburg, but with no autotransformers added. This was done under the assumption that the GTA West Region could have a similar capacity-related needs in the same time frame as York Region, potentially requiring additional transmission links into Kleinburg from the west. Full switching would, therefore, provide the best supply reliability for interconnecting multiple new circuits into Kleinburg from the east and west. A switching station would also need to accommodate new autotransformers, should these be required in future. For the new transmission, two double-circuit lines along the same corridor were modelled, with one terminating on the section south of Kirby Road, and the other to the north of Kirby Road. This configuration would provide significant capacity improvements for the northern section of the Claireville to Brown Hill circuits, as well as the Kleinburg radial pocket (as shown in Figure 7-4).

Figure 7-4: Possible Kleinburg TS to "Kirby Road" Configuration



Alternative configurations of the Kleinburg to Kirby transmission link which rely on one double-circuit line are feasible, but would likely require the addition of a new supply source (generation or autotransformers) at Kleinburg TS or in Northern York.

This two double circuit line alternative from Kleinburg to Kirby was found during system studies to meet all identified thermal and voltage needs over the long term. Estimating the cost of this alternative is challenging, since it requires assumptions about the eventual configuration and future bulk system needs. These are difficult to predict this far in advance. At a minimum, the cost should account for the new transmission link between Kleinburg and Kirby Road. Two conceptual double-circuit lines approximately 6 km long is estimated to cost in the range of $42 million to $54 million at the present time. While costs can vary significantly, a new switching station could cost in the range of about $110 million.

In addition to meeting thermal capacity needs, two double circuit Kleinburg to Kirby lines have the added benefits of lowering exposure to outages and improving reliability for loads served by Vaughan #4 MTS, Vaughan #5 MTS, Holland TS, and the Kleinburg radial pocket.

Specifically, with the addition of sectionalization devices, this solution could be leveraged to address restoration needs on the Kleinburg radial tap discussed in Section 6.3.1. It is also a flexible option, as new switching can be leveraged to assist other regions and the overall bulk system, and new facilities added later if required. Building the Kleinburg to Kirby transmission link may also provide valuable load-meeting capability for the neighbouring GTA West Region, which is also expected to have a step-down capacity need in the medium to long term. In terms of land use, this option would have a larger impact than the resource option described above, as it requires the development of a new, 6 km transmission corridor. The width of two double-circuit lines can vary depending on site-specific features and the technology type chosen, but 60 m is a typical assumption.

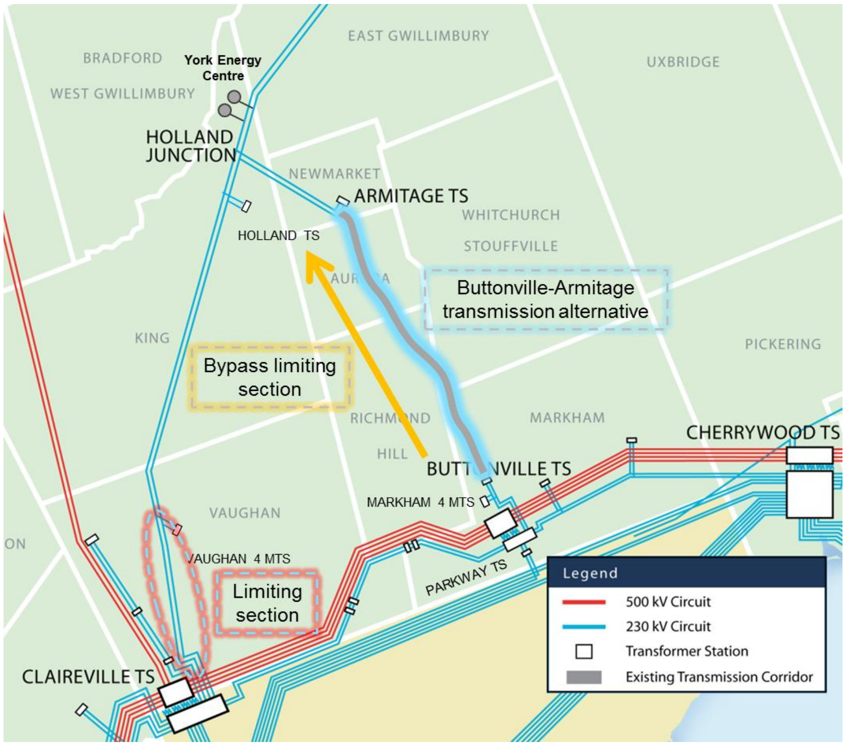
The development of a new transmission corridor along this route that has a lower impact on the land and community is currently being explored through the Northwest GTA Transmission Corridor Identification Study, a joint study being undertaken by the IESO and Ministry of Energy, Northern Development and Mines. This opportunity has emerged as a result of a separate initiative underway by the Ministry of Transportation (MTO) to develop a new 400 series highway, roughly linking Vaughan to Milton. The section of the corridor in Vaughan is ideally located to provide a potential Kleinburg to Kirby transmission link. More information on this MTO initiative is available on the website for the GTA West Transportation Corridor Route Planning and Environmental Assessment Study. In accordance with the provincial Policy Statement and good planning practice, opportunities to co-locate linear infrastructure should be pursued where feasible to do so. Co-location reduces land use impact and associated costs when planning infrastructure.

Even if the Kleinburg to Kirby supply option is not selected as the preferred approach in the long term, work to secure land for transmission will still be pursued to preserve long-term supply options in York, Peel, and Halton regions. More information on the transmission corridor initiative is available on the IESO's GTA West planning page.

Transmission Solution – Rebuild Buttonville to Armitage Corridor

This transmission solution consists of rebuilding an idle single-circuit, 115 kV transmission corridor between Buttonville TS and Armitage TS as a double-circuit 230 kV line. The total length of the rebuilt line would be approximately 20 km, and cross through sections of the municipalities of Markham, Whitchurch-Stouffville, Richmond Hill, Aurora, and Newmarket (shown in Figure 7-5).

Figure 7-5: Buttonville to Armitage Alternative



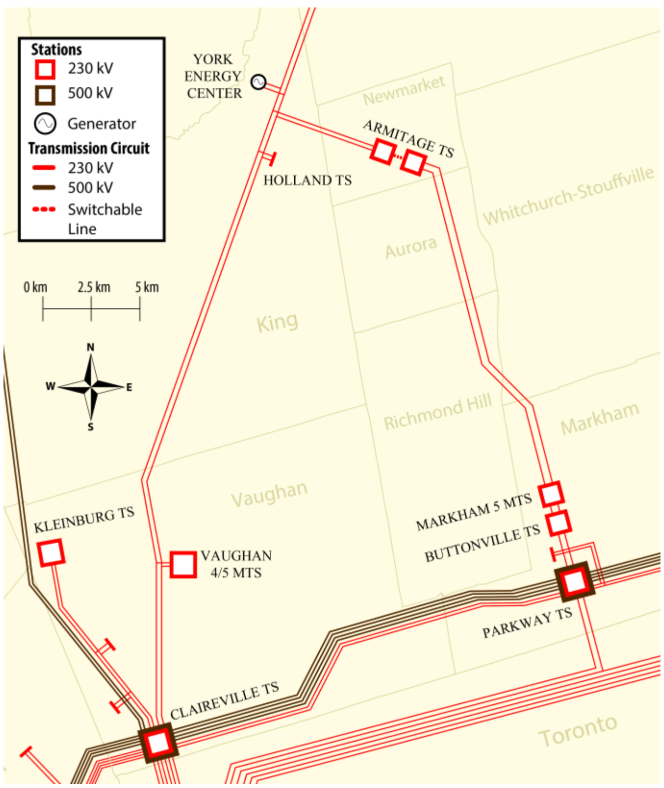
This is the same option that was considered for addressing similar capacity related needs in 2005, but was ultimately rejected in favour of a local resource-based solution. Two major factors drove this decision in 2005: opposition from the local community to redevelopment of the transmission corridor and the requirement for new generation resources to meet overall provincial electricity needs. Since these resources were to be built within Ontario anyway, the incremental cost of siting this facility in York Region was lower than the cost of this transmission upgrade.

This alternative was found during system studies to meet all identified thermal and voltage needs over the long term. It would work by creating a redundant supply path to reduce the amount of demand that needs to be served by the Claireville to Brown Hill corridor under normal operating conditions. This new circuit could also be leveraged to deliver additional restoration capability by providing alternate supply paths when faced when a transmission outage.

Similar to the Kleinburg to Kirby solution, this option could be configured to serve different system needs. At a minimum, a new double-circuit line would be required from the existing junction at Buttonville TS to Armitage TS, in central Newmarket. A full switching station is not assumed under this scenario, as there are fewer bulk system benefits of adding this type of facility in the area. Instead, two in-line switches are assumed at Armitage to assist with restoration. This means that under normal operating conditions, half of Armitage TS's load would be fed radially from Parkway TS, and half from the Claireville to Brown Hill circuits. This configuration was selected to avoid a parallel path between York Energy Centre and Claireville TS, out of consideration for existing short-circuit limitations at Claireville TS.

This alternative is shown in Figure 7-6.

Figure 7-6: Sample Buttonville to Armitage Configuration



The cost of this upgrade depends on the type of transmission technology used (overhead or underground). Assuming overhead transmission is selected for the full 20 km, the estimated cost today would be approximately $90 million. If a cable is used for the 6 km, which runs adjacent to the built up areas in Markham, and overhead towers are used for the remainder, an additional $75 million would likely be added to the total corridor cost.

Aside from new transmission, some smaller system upgrades would also be required to accommodate new sectionalization requirements and other constraints. Many options are possible and should be evaluated closer to when they are needed, but the sample configuration evaluated in this study would also require:

- Two new switches at Armitage TS
- Reconductoring of 2.7 km section of P45/46 between Markham #4 MTS and Buttonville TS
- Retapping Markham #4 MTS from Parkway corridor to prevent thermal and supply security needs

These smaller system upgrades are expected to cost approximately $13-15 million based on typical unit costs. Retapping Markham #4 MTS was considered as an alternative to reconductoring a 1.1 km section of P45/46 (see Section 7.3.1). This would require building a new 1.5 km supply path to remove Markham #4 MTS from the limited P45/46 circuits, and instead provide supply from the C35/36P (Parkway) circuits. Although this was not recommended to address the medium-term P45/46 thermal needs due to greater cost and impact ($5 million compared to $2 million), this new supply path would be required in the long term if total load on the circuits running north from Parkway exceeds 600 MW (roughly four fully loaded stations). Under the sample configuration shown, Markham #4-6 MTS, Buttonville TS, and half of Armitage TS could potentially be supplied by the extended P45/46 circuits. Note that under different configurations, such as a normally closed Buttonville to Armitage section, retapping may not be required; however, other, costlier upgrades may be possible. Final configuration decisions, and associated system upgrades, would be determined closer to the actual in-service date, when other system assumptions are better known.

In addition to meeting thermal needs on the Claireville to Brown Hill circuits, this alternative would also improve restoration capability at Armitage TS under a range of possible outage scenarios.

Comparison of Transmission Alternatives

Compared to the Kleinburg to Kirby transmission option, the Buttonville to Armitage alternative would impact more land (20 km vs. ~6 km). However, the corridor for the Buttonville to Armitage alternative already exists, which may have less of a land use impact than developing a new right of way. On the other hand, the new Kleinburg to Kirby corridor could be sited adjacent to a planned 400-series highway, which may lessen the incremental land use impact. Ultimately the determination of which transmission alternative has a lower impact should be made with community input, as they are different enough to make direct comparison difficult without clear criteria.

Comparison of costs is also challenging. Although the base cost of the Kleinburg to Kirby option is higher than Buttonville to Armitage ($152 million vs. $104 million if overhead), the majority of this is due to a switching station at Kleinburg, which could also provide capacity to the nearby GTA West Region, and could provide bulk system benefits as well. In fact, some expansion of Kleinburg TS may be required regardless of the choice of York capacity solution, just to enable capacity growth in GTA West. The needs and options associated with this area will be studied in the GTA West IRRP, details of which can be found on the IESO's GTA West planning webpage. If a new switching station at Kleinburg forms part of the long-term GTA West plan, and the $110 million cost can be shared between these two areas, then the cost of the Kleinburg to Kirby solution that can is attributable to York Region would be just under $100 million, comparable to or even less than the cost of the Buttonville to Armitage alternative. A better sense of the GTA West needs, related timing, and available solutions will be available when that IRRP – currently scheduled for Q1 2021 – is complete. Selecting the Buttonville to Armitage transmission alternative could also have an impact on the cost of step-down station alternatives for Markham in the medium term, as the northern station location would become more cost-effective under some scenarios if the required transmission expansion were to be triggered in the long term regardless of the chosen location of Markham #5 MTS. More details on considerations associated with the Markham #5 MTS location are provided in Section 7.3.4.

Because of the need for greater community engagement, and due to the uncertainty associated with long-term costs, this IRRP recommends that no decision be made at this time to select a preferred solution to long-term York capacity needs. Instead, ongoing engagement should continue to inform decision-making, and updates on the status of GTA West plans, the Northwest GTA Corridor Identification Study, and long-term system capacity needs should be provided regularly to stakeholders.

7.4 The Recommended Plan

After evaluating the needs and identified options, the Working Group recommends the actions described below to address near-term needs and preserve longer term options. All longer-term recommendations are subject to further review and amendments, as system conditions change and assumptions evolve.

Collect Information on future NWAs and Opportunities in York Region to inform the next IRRP

Actual need dates for medium- and long-term needs are dependent on peak demand, which can be deferred through non-wires solutions, such as EE and DERs. Activities are currently underway to inform non-wires potential in York Region, and address some of the operational challenges associated with relying on these technologies to address transmission needs. These activities include an interoperability pilot described further in Section 7.2. The IESO is currently working with government and stakeholders to consider opportunities for EE in Ontario beyond 2020. Consideration of the deferral value of wires infrastructure, in addition to the value of avoided system energy and capacity, should be leveraged and included when determining the feasibility and cost-effectiveness of a program.

The Working Group should monitor the impacts of EE programs, as well as other initiatives in the region, such as the interoperability pilot. to inform long-term recommendations required in the next IRRP (currently anticipated for 2025 completion). Additionally, as part of ongoing engagement with municipalities and stakeholders, the IESO will actively seek new opportunities to target peak electricity demand. In particular, opportunities to defer the medium-term need for step-down station capacity and long-term need for major system capacity upgrades will be evaluated to determine feasibility and cost-effectiveness.

Actual annual peak demand growth will also continue to be monitored to better inform actual need dates, and may potentially defer or advance further study or implementation of preferred solutions.

Reconfigure York Energy Centre Station Service Supply

The station service supply for York Energy Centre may cause the station to shut off automatically following certain contingencies, triggering thermal and voltage needs on the local transmission system. At the moment, this is being addressed by arming automatic load rejection through an SPS, but this measure will no longer be sufficient to meet needs by approximately 2033. Given that advancing this work would have immediate benefits for local customer reliability, improve resource availability, and facilitate operational functions, such as outage management, the Technical Working Group recommends that the IESO and Capital Power (York Energy Centre's operator and 50% owner) proceed to identify and consider options for a new station service supply arrangement. Any new configuration should allow for continuous

York Energy Centre operation following the simultaneous loss of H82/83V (total loss of distribution supply from Holland TS) or the loss of B88H (loss of transmission supply point).

Develop Markham #5 MTS

To address the need for additional step-down station capacity in Markham, the Technical Working Group recommends development of a new step-down transformer station. Named "Markham #5 MTS", this new station is to be developed by Alectra, with a targeted in-service date of 2025. Two candidate locations (Buttonville TS and northern Markham) have been studied and were found to have similar long-term costs, assuming overhead transmission and no preferred solution to address long-term capacity needs has been identified. In the event that the Buttonville to Armitage transmission solution is identified as a preferred alternative to meet long-term capacity needs, the northern Markham location would be economically preferable. Given the uncertainty associated with choosing a preferred outcome for a system capacity need not anticipated until the early- to mid-2030s, this IRRP recommends that Alectra select a preferred location for the Markham #5 MTS based on engagement with the local community. A hand-off letter for initiating work on Markham #5 MTS was sent to Alectra by the IESO in 2017.

Reconductor Circuit P45/46 from Parkway to Markham #4 MTS

The Technical Working Group recommends that Hydro One proceed with reconductoring of a limiting circuit segment to a higher ampacity. This upgrade will enable an additional 180 MW to be served in the Markham area without exceeding thermal limits of the system. This IRRP recommends the upgrade be complete by the time the Markham #5 MTS comes into service (currently forecast for 2025), to ensure full station loading is available. Based on a high-level assessment using typical unit costs, this upgrade is expected to cost approximately $2 million.

Develop Northern York TS

Following the need for step-down station capacity in the Markham area in 2025, additional station capacity needs are anticipated in Northern York in 2027 and Vaughan in 2030. Although development work is not yet required, and dates are subject to deferral through non-wires measures, the Technical Working Group recommends that a suitable location be identified and preserved for the future Northern York station at this time. Given development pressures in the area, deferring the search may make finding a suitable location difficult or costlier. While other locations are still possible, at this time the future Northern York TS will likely be located in East

Gwillimbury, based on the area's high growth rate and lack of existing step-down stations. This IRRP recommends that Hydro One undertake a review of suitable locations to accommodate a potential in-service date as early as 2027 and that Hydro One begin development when actual peak demand and/or updated load forecasts suggest that the new Northern York TS needs to be operational within three years.

A suitable location already exists for Vaughan #5 MTS, at the site of the existing Vaughan #4 MTS. No additional work is required at this time.

Develop/Preserve Viability of Long-term Capacity Options

A long-term need for additional supply capacity to serve demand growth in York Region is currently anticipated as early as 2033, but subject to deferral. This need could be met through new large-scale dispatchable resources, or new transmission. Two viable transmission-based options have been identified. One would require the redevelopment of an existing transmission corridor (Buttonville to Armitage), while the other requires the development of a new transmission right of way (GTA West corridor, Kleinburg to Kirby section). A recommendation on the final preferred option to address these capacity needs is not required at this time, but actions should be taken today to preserve these options for when a decision is required, including continued engagement with the local community to assist in identifying a preferred option.

Additionally, ongoing work to preserve transmission rights adjacent to the proposed GTA West highway corridor should continue. Co-location of linear infrastructure is consistent with the Provincial Policy Statement and good planning practice, and should be pursued for the GTA West corridor regardless of which long-term system capacity solution is eventually selected for York Region. Long-term development of transmission along the GTA West corridor could have benefits for supply capacity in both the York and GTA West regions, and could potentially be leveraged to address future bulk system needs for the GTA as a whole.

No Additional Action Required on Specific Restoration or Supply Security Needs

Although three areas have been identified as being at risk for restoration or supply security needs over the 20-year planning horizon, no further action beyond the recommendations included above is required at this time:

1. **Kleinburg Radial Tap (V43/44).** One of the solutions to address long-term capacity needs in the area (the Kleinburg to Kirby transmission link) has the potential to address restoration needs along these circuits. Until a preferred long-term capacity solution has been selected, there is no need to pursue other potential solutions, as these costs may end up stranded.
2. **Parkway Corridor (V75/71P).** This need has been studied through the 2015 IRRP, and a recommendation has already been implemented.

3. **Northern York (B82/83V and B88/89H).** Both the identified near-term restoration need and longer-term supply security need would be addressed through the recommendation to reconfigure York Energy Centre station service supply. No further action is required.

7.4.2 Implementation of Recommended Plan

To ensure that the near-term electricity needs of York Region are addressed, and longer-term options preserved, some plan recommendations will need to be implemented soon. These specific actions and deliverables are outlined in Table 7-4, along with the recommended timing.

Table 7-4: Summary of Needs and Recommended Actions in York Region

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Time frame/ Need Date
Collect information on future NWAs and opportunities in York Region to inform the next IRRP	Continue to monitor progress of pilots and programs to inform potential and barriers to further non-wires implementation Actively seek new opportunities from municipalities and stakeholders to target peak electricity demand Track actual summer peak demand, net of the impact of NWAs	IESO/LDCs	Annually
Reconfigure York Energy Centre station service supply	IESO to work with Capital Power to identify and consider options for a preferred station service arrangement	IESO	Ongoing
Address the potential for high voltages on M80/81B	Hydro One to identify a preferred solution through the RIP, and implement no later than 2025	Hydro One	2025
Develop Markham #5 MTS	Design, develop and construct new station in Markham	Alectra	In service 2025
Reconductor circuit P45/46 from Parkway to Markham #4 MTS	Design, develop, and carry out reconductoring of limiting section of P45/46 in time for planned Markham #5 MTS in-service date	Hydro One	In service 2025 (unless Markham 5 deferred)
Develop Northern York TS	Identify and secure preferred location for new Northern York step-down station Hydro One to begin development as required to ensure facility is in service when needed	Hydro One	Tentatively In service 2027

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Time frame/ Need Date
Develop/preserve viability of long-term capacity options	Continue working to preserve transmission right adjacent to proposed GTA West highway corridor Continue to engage with community on preferred long-term supply options and considerations	IESO	Ongoing

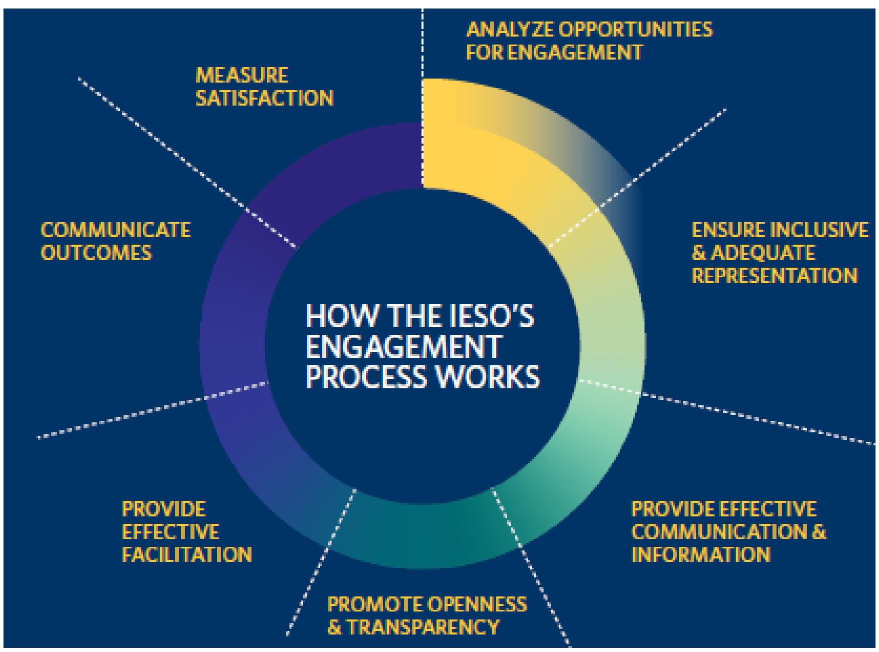
8. Community and Stakeholder Engagement

Engaging with communities and interested parties is an integral component of the regional planning process. Providing opportunities for input in regional planning enables the views and preferences of the community to be considered in the development of an IRRP and helps lay the foundation for successful implementation. This section outlines the engagement principles and activities undertaken to inform the creation of this IRRP.

8.1 Engagement Principles

The IESO's Engagement Principles[16] guide the process to help ensure that all interested parties were aware of, and could contribute to, the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, and to support its efforts to build trusted relationships.

Figure 8-1: IESO Engagement Principles



[16] http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Overview/Engagement-Principles

8.2 Creating an Engagement Approach for GTA North

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

Creating the engagement plan for this IRRP involved:
- Discussions to help inform the engagement approach for the planning cycle
- Developing and implementing engagement tactics to allow for the widest communication of the IESO's planning messages, using multiple channels to reach audiences
- Identifying specific stakeholders and communities that should be targeted for one-on-one consultation, based on identified and specific needs

As a result, the engagement plan for this IRRP included:
- A dedicated webpage on the IESO website
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin
- Public webinars
- Face-to-face meetings
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (See section 1.4 Outreach with Municipalities)

The IESO leveraged a dedicated engagement webpage to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process.

8.3 Engage early and often

Leveraging existing relationships built through the previous planning cycle, the IESO held preliminary discussions to help inform the engagement approach for this new round of planning. This started with an invitation to targeted communities and those with an identified interest in regional issues to learn more about how to provide comments on the GTA North Scoping Assessment Report[17] before it was finalized.

[17] The Scoping Assessment Report identified the need for an IRRP and included the terms of reference to guide the development of the plan. Following a window for comments, the final report was published in August 2018. No comments were received.

To ensure openness and transparency in the engagement process, the IESO created a dedicated webpage on the IESO site that provided information on all engagement activities, including background information, presentations, and the details and recordings of all public webinars.

The IESO also regularly provided updates through its weekly Bulletin and emails to interested stakeholders.

Three webinars were held throughout the engagement initiative to give interested parties an opportunity to hear about progress and provide input on key components of the IRRP. The topics were:

- Draft electricity demand forecast, preliminary needs and community engagement
- Defined needs and range of potential solutions to be examined
- Results of the options evaluated, draft recommendations and next steps

Webinar materials that included questions for input were provided in advance to help participants prepare to provide feedback.

The webinars were well attended participants including municipal representatives, sustainability and environment organizations, generators, energy service providers and consultants, gas companies, planning consultants and local resident associations. While interest was high, very few questions and comments were received during the written feedback windows.

8.4 Outreach with Municipalities

At milestones in the IRRP process, meetings with the upper- and lower-tier municipalities in the region were also held to discuss: key issues of concern, including forecast regional electricity needs; options for meeting the region's future needs; and, broader community engagement.

The IESO engaged directly with municipal staff with responsibility for planning, sustainability, asset management, energy and climate change. These meetings yielded great discussions and valuable insights in a few critical areas that are addressed in the IRRP, including:

- Drivers of growth in the northern portions of the GTA North region

- Issues and community feedback around potential solutions to address the long-term transmission supply capacity need
- Community preferences to pursue non-wires solutions to defer infrastructure investments and meet municipal climate change mitigation objectives
- Alignment of electricity planning with local planning activities particularly with respect to the York Region Municipal Comprehensive Review and subsequent municipal Official Plan updates

In addition to helping participants better understand the region's electricity needs, these meetings also strengthened relationships to enable ongoing dialogue beyond this IRRP, such as follow-up presentations to local Councils and workshop meetings with sustainability and planning staff.

8.5 Engagement Conclusions

Based on these discussions, following the publication of this IRRP, ongoing engagement will be required to monitor and inform regional characteristics for the next planning cycle when critical decisions will need to be made.

Although the anticipated growth in the region is medium- to long-term in nature and there is strong community interest in NWAs to defer electricity infrastructure, the magnitude of the growth is expected to require other solutions. Local growth, planning initiatives and energy projects will be closely monitored, and community engagement will continue through the IESO's GTA and Central Ontario Regional Electricity Network to ensure interested parties are kept informed and given opportunities to help shape the region's electricity future.

9. Conclusion

This IRRP has been developed for York Region, based on the electrical boundaries defined by the OEB's GTA North (York) planning region. The IRRP identifies electricity needs in the region over the 20-year period from 2018 to 2037, recommends a plan to address near-term needs, and lays out actions to monitor, defer, and address long- term needs.

To support the development of the near-term plan, this IRRP recommends actions to address near-term capacity needs, and identify and evaluate non-wires options to offset peak demand growth and defer the long-term need for system upgrades. Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group. Wires infrastructure projects identified to address near term needs will become part of a Regional Infrastructure Plan (RIP) to be conducted by Hydro One as an outcome of this IRRP.

To support the development of a long-term plan, a number of actions have been identified to preserve long-term options, engage with the community to determine local preferences, and monitor growth in the region. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the regional planning process for York Region, and any additional measures required as a result of faster-than-anticipated load growth in the interim.

The York Region Technical Working Group will continue to meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

Appendix F

HONI GTA North RIP summary

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE RIP STUDY TEAM IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE GTA NORTH REGION.

The participants of the Regional Infrastructure Plan ("RIP") Study Team included members from the following organizations:

- Alectra Utilities
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator
- Newmarket-Tay Power Distribution Ltd.
- Toronto Hydro-Electric System Limited
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the second cycle of GTA North regional planning process, which follows the completion of the GTA North Integrated Regional Resource Plan ("IRRP") in February 2020 and the GTA North Region Needs Assessment ("NA") in March 2018. This RIP provides a consolidated summary of the needs and recommended plans for GTA North Region over the planning horizon (1 – 10 years) based on available information.

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment and IRRP reports for this cycle, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, the following projects have been completed:

- Vaughan #4 MTS (completed in 2017)
- Holland breakers, disconnect switches and special protection scheme (completed in 2017)
- Parkway belt switches at Grainger Jct. (completed in 2018)

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in the Table 1 below, along with their planned in-service date and budgetary estimates for planning purposes.

Table 1. Recommended Plans in GTA North Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate
1	Markham Area: Step-down Transformation Capacity	Build new Markham #5 MTS	2025	$30M
2	Increase Capability of 230kV Circuits P45+P46 (these supply Buttonville TS, Markham #4 MTS, and future Markham #5 MTS)	Reconductor circuits P45/46 from Parkway to Markham #4 MTS, and connect Markham #5 MTS – 2025	2025	$2-3M
3	High voltages on 230kV circuits M80B/M81B	No action required	---	---
4	Northern York Area: Step-down Transformation Capacity	Build new Northern York Station	2027	$35-40M
5	Woodbridge TS: End-of-life of transformer T5	Replace the end-of-life transformer with similar type and size equipment as per current standard	2027	$13
6	Vaughan Area: Step-down Transformation Capacity	Build new Vaughan #5 MTS	2030	$30M

Note: LDC distribution network costs are not included in the above Table.

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 1 while keeping the Study Team apprised of project status;
- All the other long term needs/options identified in Section 6.4 will be further reviewed by the Study Team in the next regional planning cycle.