December 3, 2018

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
27th Floor/ P.O. Box 2319
2300 Yonge St.
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Incremental Capital Module Rate Application,
Halton Hills Hydro Inc.,
Board File no. TBD

Halton Hills Hydro Inc. ("HHHI") is filing its Incremental Capital Module ("ICM") Rate Application with the Ontario Energy Board ("the Board"). HHHI is submitting its ICM Rate Application in accordance with all directives and guidelines issued by the Board. HHHI is requesting an effective date of May 1, 2019 for the implementation of the Proposed Incremental Revenue Requirement Rate Riders.

The ICM Rate Application includes:

- Manager's Summary (pdf)
- 2018_Capital_Module_ACM_Model Version 4_20 (Excel)
- Off-line Rate Rider Calculations (Excel)
- Off-line Bill Impact Calculations (Excel)

Please find attached to this cover letter:

- 2 paper copies of the ICM Rate Application; and
- 1 electronic copy of the ICM Rate Application.

A copy of the Application has also been filed through the Web Portal.

In the event of any additional information, questions or concerns, please contact David Smelsky, Chief Financial Officer, at dsmelsky@haltonhillshydro.com or (519) 853-3700 extension 208, or Tracy Rehberg-Rawlingson, Regulatory Affairs Officer, at tracyr@haltonhillshydro.com or (519) 853-3700 extension 257.

Sincerely,

(Original signed)

David J. Smelsky, CPA, CMA, C. Dir.
Chief Financial Officer, HHHI

Cc: Arthur A. Skidmore, President & CEO, HHHI

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IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Halton Hills Hydro Inc. to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other charges for electricity distribution to be effective May 1, 2019.

HALTON HILLS HYDRO INC. ("HHHI") APPLICATION FOR APPROVAL OF INCREMENTAL REVENUE REQUIREMENT RECOVERY THROUGH RATES

MANAGER'S SUMMARY

Filed: December 3, 2018

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APPLICATION FOR APPROVAL OF INCREMENTAL REVENUE REQUIREMENT RECOVERY THROUGH RATES

MANAGER'S SUMMARY

Introduction

a) The Applicant is Halton Hills Hydro Inc. ("HHHI"). HHHI is a corporation incorporated pursuant to the *Ontario Business Corporations Act* and located in the Town of Halton Hills (Acton). HHHI carries on the business of distributing electricity pursuant to HHHI's Electricity Distribution Licence ED-2002-0552.

b) HHHI hereby applies to the Ontario Energy Board ("the Board") pursuant to section 78 of the *Ontario Energy Board Act, 1998* as amended (the "OEB Act") for approval of proposed incremental revenue requirement recovery, as it relates to the building of a Municipal Transformer Station, through rate riders effective May 1, 2019.

c) HHHI is applying for a rate adjustment under the Incremental Capital Module ("ICM").

d) HHHI has followed the Instructions provided in the *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (*the "July 2008 Report of the Board"*)*, the *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors - EB-2007-0673* (the "Supplemental Report"), the *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module – EB-2014-0219* and the *Supplemental Report dated January 22, 2016* (together the "September 2014 Report") in relation to the incremental capital recovery request in addition to Chapter 3 of the Filing Requirements For Electricity Distribution Rate Applications - 2017 Edition for 2018 Rate Applications ("Filing Guidelines").

e) HHHI has completed the Capital Module Applicable for ACM and ICM - Version 4.0 as revised by Board Staff for HHHI's filing. HHHI confirms the accuracy of the billing determinants entered in the models.

f) HHHI is applying for Revenue Requirement Recovery related to the ICM application for a new transformer station (the "TS") that will be commissioned in 2019.

g) HHHI is applying for and requesting that the Board deem the TS to be a distribution asset pursuant to section 84(a) of the OEB Act in order that HHHI may recover the revenue requirement related to the TS through distribution rates.

h) HHHI is applying for an exemption to the general ICM policy in order to recover incremental Operating, Maintenance and Administration ("OM&A") costs in relation to the TS.

i) HHHI is applying for recovery of annual incremental OM&A costs related to the TS.

j) 2019 will be HHHI's third (3rd) year of its five (5) year IRM period.

k) HHHI is applying for a Deferral and Variance Account to track the costs and recovery of the TS for purposes of truing up the variance at the next Cost of Service.

l) HHHI has provided additional information in this Application (the "Application") where HHHI has determined that such information may be useful to the Board.

Notice of Application

HHHI will publish the Notice of Application as per directions issued by the Board Registrar, if required.

Current Tariff of Rates and Charges

HHHI has provided in **Appendix A**, a copy of its approved Tariff of Rates and Charges, effective May 1, 2018 and issued by the Board on April 26, 2018.

Background

In 2007, HHHI's load forecasts first identified the need for a new source of transmission supply. At that time, HHHI, together with the Town of Halton Hills, worked with the planned TransCanada Energy Halton Hills Generating Station ("HHGS") to identify a parcel of land adjacent to the new HHGS for possible construction of a new HHHI TS.

The agreement with the HHGS was to build a transformer station on the land adjacent to the generating station and connect to the transmission system via HHGS's 230kV switchyard. Initial discussions with the IESO also began in 2007 to determine if the option of a unique connection arrangement with HHGS could be accommodated. Supply options, feasibility studies and alternative site studies were also completed. A Class Environmental Assessment was commenced, and corresponding Public Information Centres took place in 2008.

Due to the economic decline in late 2008, HHHI took the prudent approach and deferred work on a transformer station until such time as a revised load forecast, adjusted for the economic downturn, predicted the need.

In 2011, work recommenced on the transformer station. By that time, it became apparent to HHHI that avoiding the cost of tunneling under the King's Highway 401 (the "401") (by connecting to HHGS) represented a potentially significant capital cost saving. However, because of the unique nature of connecting to HHGS, HHHI met with the OEB and the provincial Ministry of Energy to determine the regulatory barriers to the connection.

In July 2013, Ontario Regulation 219/13 was made, exempting the HHGS from requiring an Electricity Transmission Licence. Part of this Regulation stipulated that a connection agreement was to be entered into by TransCanada (HHGS) and the distributor (HHHI). The HHGS and HHHI filed the Form of Connection Agreement with the Board in November 2013. The Board's authority under the Regulation was to reject (or not) the TransCanada – HHHI connection agreement. This arrangement, the first of its kind in Ontario, provided significant cost savings to rate payers over the other options that required the need to bring new transmission supply north, under the 401.

In February 2015, the Board issued a letter indicating that they would not reject the connection agreement. This assurance allowed HHHI to begin moving forward with the purchase of land, the design and construction of the TS. The land purchase (at the agreed upon 2007 price) was finalized in November of 2015.

In August 2015, HHHI filed its 2016 to 2020 Distribution System Plan ("DSP") as part of HHHI's 2016 Cost of Service rate application (EB-2015-0074). The DSP provided a comprehensive strategy for asset maintenance and capital expenditure over a five (5) year period covering 2016 to 2020.

HHHI's mission statement, "*To Provide Halton Hills with Electricity Distribution Excellence in a Safe and Reliable Manner*" provided the overall vision that guided the creation of the DSP. Safety and reliability are top priorities for the utility and are two key ways HHHI strives to provide distribution excellence to customers. The DSP was built on the principles of excellence, safety and reliability and takes a prudent, cost effective approach to infrastructure investment and renewal to try to serve current and future customer preferences and requirements.

The DSP provided a comprehensive strategy for asset management as well as prudent, cost effective guidance for planned capital project expenditure over the five (5) years between Cost of Service applications. HHHI developed a detailed Asset Management Strategy which informed the Asset Management Process section of the DSP and also provided a detailed capital expenditure plan which supports asset management, accommodates third party requirements and plans for significant growth and technological improvements.

The Capital Expenditure portion of the DSP provided an analysis of the historical five (5) year period as well as forecasted costs for the life of the DSP. Projects were categorized as System Access, System Renewal, System Service and General Plant. Within each category and across categories, projects were assigned a risk ranking and a priority to help HHHI with resource planning and budgeting.

The DSP did not include the request for an Advanced Capital Module for the construction of the new TS as budgetary numbers were still very preliminary and not sufficiently robust for inclusion in the DSP at that time. The DSP did provide details identifying the need for the TS in addition to the prudent investment strategy that included a number of projects that would enable supply from the new station. The DSP also clearly indicated that the capital requirement for the station would be filed as a separate ICM module.

As stated in section 1.1.6 of the DSP:

> "*As the capital requirement for this project is significant, HHH intends to file a separate Incremental Capital Module (ICM) for associated expenditures rather than including in this Distribution System Plan. Many of the projects outlined in this Distribution System Plan are required to enable the supply from this new Transformer Station. Where possible, projects will include the addition of circuits to existing poles that have already been replaced or installed as part of voltage conversion projects or regional road activities. Some voltage conversion projects may be accelerated or placed in a high priority to ensure that new circuits are available to make use of the MTS capacity as it becomes available.*"

On March 4, 2016, Board Staff submitted their comments on the Settlement Proposal in HHHI's Cost of Service application (EB-2015-0074). In their comments, Board Staff stated "OEB staff does note that the OEB retained the ICM for the IR years for projects not included in a DSP filed with the most recent cost of service application, and for projects that were included in the DSP but which did not contain sufficient information at the time of the cost of service application to address need and prudence" in response to HHHI not submitting estimated numbers for TS as part of an Advanced Capital Module in the Cost of Service application.

In June 2017, HHHI updated its load forecast to verify the required in service date for the TS and to ensure prudent and timely spending. The updated load forecast confirmed a required in-service date of 2019.
Town of Halton Hills Site Plan Approval and Building Permits were received in 2017 and site construction started in the fall of that year. Major equipment, consulting, engineering and construction services were all purchased

through a Request for Proposal process. Criteria for selecting vendor's bids were based on consultant and design engineer recommendations, prior LDC experience and industry reputation.

The completed TS will receive final commissioning and energization in the spring of 2019. The timing of energization needs to coincide with TransCanada Energy's spring maintenance outage window.

Engineering and Construction

On February 9, 2015, HHHI received a letter from the Board indicating that the Board will not make an order rejecting the Connection Agreement between HHHI and TransCanada Energy HHGS. This was the key milestone required to commence work on the station. In 2015, a project consultant was brought on board to assist HHHI in retaining appropriate engineering services and to assist with procurements of major equipment and construction services. An RFP for professional engineering services to complete station design was issued later that same year. Detailed design began in 2016 and applications for IESO System Impact Assessment (SIA) and Hydro One Customer Impact Assessments (CIA) were completed by the end of 2016.

Construction of the TS required work both on the HHHI owned property and within the switchyard of the adjacent HHGS to facilitate the connection. Work within the HHGS switchyard had to be coordinated with scheduled plant maintenance shutdown windows. As such, the first construction within the switchyard was completed in April 2017. It was critical to commence work at this time to ensure that all of the required construction within HHGS's site could be completed within the available shut down windows to ensure the in service date of spring of 2019 could be met. The work completed in April of 2017 was the installation of concrete foundations for switches and breakers to be installed during the next maintenance window.

The Site Plan Approval process with the Town of Halton Hills began with the pre-consultation process in 2016. Agencies involved in the approval process included the Town of Halton Hills, Halton Region and Conservation Halton. Final Site Plan Approval was received in August 2017 and the Building Permit for the Switchgear Building was received in November 2017.

Major equipment with long lead times was ordered in 2017. The purchase order for the two power transformers was issued in June 2017 for delivery in September 2018. The purchase order for medium voltage switchgear was issued in December 2017 for delivery in October 2018.

Eptcon Ltd. was awarded the contract for general construction at the end of August 2017. Initial site clearing and grading began that fall as permitted by the approvals received. Steel structures, switches and breakers were installed during the fall HHGS maintenance window. Construction on the TS site began in earnest in 2018. Construction on the switchgear building began in the spring of 2018.

Major equipment, consulting, engineering and construction services were all purchased through a Request for Proposal process. Criteria for selecting vendor's bids were based on consultant and design engineer recommendations, prior LDC experience and industry reputation.

During the fall maintenance window at HHGS, protection and control work was completed including the commissioning of newly installed breakers and switches, registration with the IESO and Hydro One COVER.

Construction will be completed in early 2019 with final commissioning and energization planned to coincide with HHGS's 2019 spring maintenance outage window.

Criteria

In the July 2008 Report of the Board, the Supplemental Report, and the September 2014 Report, the OEB established three tests for eligibility for an ICM application: Materiality, Need and Prudence.

<u>Materiality</u>

There are two materiality tests related to ICM applications.

<u>Materiality Threshold</u>

The first test is the ICM materiality threshold formula, which serves to demonstrate the level of capital expenditures that a distributor should be able to manage within current rates. The test states that: "Any incremental capital amounts approved for recovery must fit within the total eligible incremental capital amount" and "must clearly have a significant influence on the operation of the distributor". The materiality threshold is determined by the following formula:

$$Threshold\ Value\ (\%) = \left(1 + \left[\left(\frac{RB}{d}\right) \times \left(g + PCI \times (1+g)\right)\right]\right) \times \left((1+g) \times (1+PCI)\right)^{n-1} + X\%$$

where n is the number of years since the cost of service rebasing. Many of the parameters remain unchanged from the original formula except for the following:

- the growth factor g is annualized
- the dead band X has been reduced to 10%
- the stretch factor used in the PCI will be the factor assigned to the middle cohort (currently 0.3%) for all distributors

HHHI states that it has appropriately calculated a materiality threshold of $1,859,883 using the Capital Module Applicable for ACM and ICM - Version 4.0 as revised by Board Staff for HHHI's filing. The threshold calculation can be found on Tab "9. Threshold Test" on the ICM attached as **Appendix B**.

Eligible Incremental Capital

The Board adopted a second, project-specific materiality test in the Funding of Capital Report. The project-specific materiality test is as follows: "Minor expenditures in comparison to the overall capital budget should be considered ineligible for ACM or ICM treatment. A certain degree of project expenditure over and above the Board-defined threshold calculation is expected to be absorbed within the total capital budget". HHHI has provided **Table 1** to show a comparison between the summary of capital expenditures as approved in HHHI's 2016 Cost of Service Settlement Proposal (Appendix B) and actual capital expenditures as audited for 2016 and 2017 in addition to the revised budgeted capital expenditures for 2018, 2019 and 2020.

Table 1 - Capital Expenditure Comparison 2016-2020

Year	2016	2017	2018 (forecast)	2019 (budget)	2020 (DSP)	Total	Average
	($)	($)	($)	($)	($)	($)	($)
Estimated Capital Expenditure from DSP	7,708,601	7,408,324	7,788,106	7,893,817	8,149,827	38,948,675	7,789,735
Capital Expenditures	9,539,998	11,095,939	6,902,214	7,159,383	7,000,000	41,697,534	8,339,507
Sub-total - Variance	**1,831,397**	**3,687,615**	**(885,892)**	**(734,434)**	**(1,149,827)**	**2,748,859**	**549,772**

HHHI calculated the Eligible Incremental Capital using the ICM and as shown on Tab "10. Proposed ACM ICM Projects" (**Appendix B**). The eligible incremental capital calculated amount for HHHI is $28,775,942 based on total 2019 total DSP capital expenditures in the amount of $30,635,824 less a materiality threshold of $1,859,883 as shown in **Table 2**.

Table 2 - Eligible Incremental Capital

Eligible Incremenal Capital	Capital Expenditures
Forecasted 2019 Capex	7,159,383
Incremental Capital - TS	23,476,441
Total 2019 Capex	**30,635,824**
Less: Materiality Threshold	1,859,883
Maximum Eligible Incremental Capital	**28,775,942**

The incremental revenue requirement corresponding to the incremental capital amount of $23,476,441 is $1,698,085 as calculated on Tab "11. Incremental Capital Adj." and shown in **Appendix B**. The revenue requirement approved in HHHI's 2016 Cost of Service application and adjusted for depreciation in HHHI's 2018 IRM (EB-2017-0045) is $10,458,405. The OEB is guided by the words "significant influence on the operation of the distributor" and "minor expenditure in comparison to the overall capital budget" in assessing project specific materiality. The incremental revenue requirement is equivalent to an increase of 16.2% over the 2016 revised Cost of Service revenue requirement, thus, materiality is evident.

Need

As stated in the Filing Guidelines, distributors "must pass the Means Test (as defined in the September 2014 Report). Amounts must be based on discrete projects, and should be directly related to the claimed driver. The amounts must be clearly outside of the base upon which the rates were derived".

Means Test

Page 15 of the September 2014 Report states "If the regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, the funding for any incremental capital project will not be allowed" and on page 16 of the September 2014 Report it states "a threshold of 300 basis points retains some flexibility for distributors to maximize their earnings while also recognizing that funding in advance of the next rebasing is likely not required from a cash flow perspective". **Table 3,** below, shows HHHI's Historical Regulated Return for the year prior to the 2016 Cost of Service to the most recently reported. HHHI's deemed Regulated Return is 9.19%. It is highly unlikely that HHHI will exceed the 300 basis points above the deemed return on equity embedded in rates.

Table 3 - Historical Regulated Return

Year	Deemed Rate of Return	Regulated Rate of Return	Variance
2015	8.82%	6.70%	-2.12%
2016	9.19%	6.76%	-2.43%
2017	9.19%	6.98%	-2.21%

Discrete Project

On page 13 of the September 2014 Report, the Board states that ICM requests "must be discrete projects, and not part of typical annual capital programs". The building of a transformer station is not part of a typical annual capital program for HHHI. In fact, the TS is the first transformer station that HHHI has built.

As stated on page 14 of the September 2014 Report, "The use of an ACM is most appropriate for a distributor that:

- does not have multiple discrete projects for each of the four IR years for which it requires incremental capital funding;
- is not seeking funding for a series of projects that are more related to recurring capital programs for replacements or refurbishments (i.e. "business as usual" type projects); or
- is not proposing to use the entire eligible incremental capital envelope available for a particular year."

HHHI does not have other discrete projects that will require incremental capital funding. HHHI is not seeking additional funding for a series of projects that are business as usual type projects. HHHI is not proposing to use the entire eligible incremental capital envelope available for 2019. Therefore, the ICM meets the discrete project requirement.

Outside of Rate Base

In HHHI's 2016 Cost of Service Application, the only expense that had been incurred was the purchase of land for the TS. As shown on the Summary of Proposed Changes tab in Appendix E of the Settlement Proposal in EB-2015-0074, the land purchase was excluded from rate base and not included in the 2016 approved rates. Therefore, all costs associated with the ICM request are clearly outside of the base upon which the rates were derived.

<u>Prudence</u>

<u>Support of the Need for the TS</u>

The need for HHHI to build a transformer station was identified in the IESO's Northwest Greater Toronto Area Integrated Regional Resource Plan (NWGTA Region IRRP Report) (**Appendix C**) published in April 28, 2015. As shown in Section 7.1.3.1:

> *"Option 3: The Halton Hills Hydro station is required in 2018 and would be located on the north side of Highway 401, while the Milton station, required in 2020, would be located on the south side. This solution eliminates the need to run distribution feeders across Highway 401, which would otherwise present a major technical and financial barrier to integrating a single new station. A suitable location has been found in existing electrical infrastructure facilities for both proposed stations: a new station north of Highway 401 located on the grounds of the TransCanada Halton Hills Gas Generation facility and a new station on the south side located within the existing Milton SS and Halton TS grounds."*

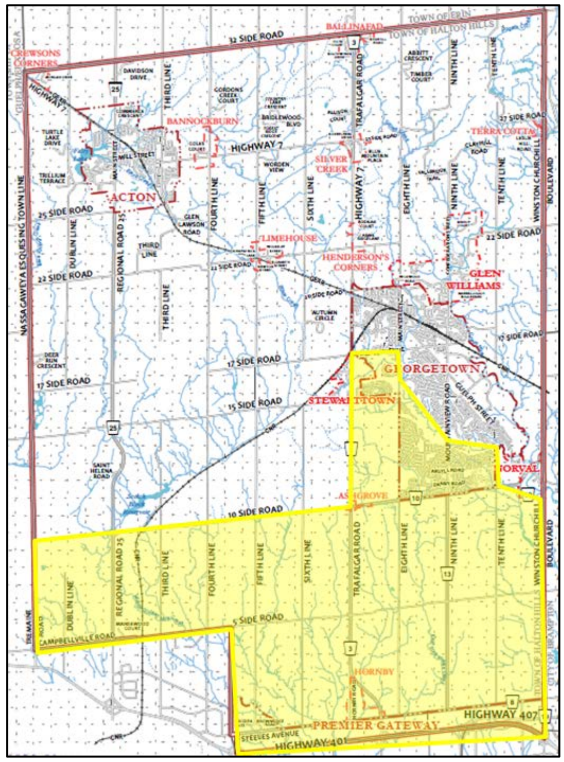
As identified through this regional planning process, the Hydro One Halton TS is nearing full capacity and there is not enough space to add new feeders.

While load forecasts as early as 2007 identified the need for a new transformer station, HHHI took the prudent step of conducting another load forecast prior to construction of the TS, to ensure the timing of station energization would coincide with load requirements. The load forecast considered historical growth, known planned growth and forecasted inclusion of the "Vision Georgetown" development. This load forecast, dated January 2017 and shown in **Appendix D**, focused on the 27.6kV distribution system and load forecast in the area of the proposed TS and supported the findings of the IESO's IRRP Report. The load forecast report identified the need for a new transformer station by the end of 2019.

The TS is required to meet near term load requirements and prepare for significant growth planned within the Town of Halton Hills. The TS will serve some existing but primarily new load in Georgetown South and the Steeles Avenue - Premier Gateway corridor to the north of Highway 401. In particular, and as a result of the "Ontario Places to Grow" legislation, the Vision Georgetown development will bring 20,000 people and 1,700 jobs to a 1,000 acre parcel in Georgetown with construction phased in between 2021 and 2031. This exceptional growth necessitates the need for new supply.

HHHI currently receives 27.6kV supply from three feeder positions at the Hydro One Halton TS. These feeders supply the Southern portion of HHHI's service territory including the Steeles Avenue Prestige Industrial Corridor, the Toronto Premium Outlets Premier Gateway corridor, Georgetown South and the surrounding rural area. Within the boundaries of this area are the lands slated for development of Vision Georgetown.

Figure 1 – Town of Halton Hills Map



As identified in the IESO's Northwest Greater Toronto Area Integrated Regional Resource Plan and supported by HHHI's load forecast, the Hydro One Halton TS and the three (3) HHHI feeders supplying HHHI in particular, are nearing capacity thus necessitating the new TS.

<u>Options</u>

HHHI determined there were three (3) possible options to increase the supply capacity to the region. The options and results are shown in **Table 4** below.

Table 4 - Study Options to Increase Supply

Option Description	Result	Reasoning
HONI expands HONI owned Halton TS	Unacceptable	Infrastructure limitation in the area does not allow additional feeders out of the HONI Halton TS into the HHHI service territory
Build a new TS	Accepted	Most prudent option to provide safe and reliable supply
Do nothing	Unacceptable	The existing supply will not meet the future increased electricity demand in the HHHI service territory

Once the decision was made to build a new transfer station, the evaluation of site options was conducted using the following criteria:

- *Technical*–Related to proximity to demand and transmission connection, available land size, availability of distribution circuits.
- *Environmental (Physical and Social)*–Related to terrestrial and aquatic ecology, existing/planned land uses, and cultural heritage.
- *Economic*–Related to total cost for completion (design and build) of TS with consideration for equipment required.

The following **Table 5** indicates the results of the site evaluations and the overall rankings.

Table 5 - Site Option Evaluation Results

Alternative Site Identification and Location	Technical	Environmental	Economic	Overall Ranking
1A North side of Steeles Avenue, near James Snow Parkway	Unacceptable	Low	Unacceptable	Unacceptable
1B South side of Steeles Avenue, near James Snow Parkway	Unacceptable	Unacceptable	Low	Unacceptable
1C South side of Steeles Avenue, near 5th Line North	Low	Low	Low	Low
2A South side of Steeles Avenue, near 5th Line South	Medium	Low	Low	Low-Medium
2B South side of Steeles Avenue, near 5th Line South (east of site 2A)	Unacceptable	Low	Low	Unacceptable
2C South side of Steeles, near 6th Line South (HHGS site)	**High**	**Medium**	**High**	**High-Medium**
2D South side of Steeles Avenue, forested area near 6th Line South (west of HHGS site)	Medium	Low	Low	Low-Medium
3A South side of Steeles Avenue, just west of Trafalgar Road	Medium	Unacceptable	Low	Unacceptable
3B South side of Steeles Avenue, just west of Trafalgar Road	Medium	Unacceptable	Low	Unacceptable
3C Trafalgar Road, south side of Highway 401	Unacceptable	Low	Low	Unacceptable
3D Trafalgar Road, Hornby Junction (ORC Lands) – South of Highway 401	Unacceptable	Medium	High	Unacceptable

High Acceptability – No effects are associated or anticipated for this site based on identified criteria.
Medium Acceptability – Few effects have been identified although the potential exists to prevent or mitigate these effects through implementation of measures and/or methodologies.
Low Acceptability - A number of effects have been identified although the potential for avoidance or mitigation is low.
Unacceptable – Effects or limitations identified are considerable (numerous) and mitigation or avoidance is not possible, therefore precluding the site consideration.

HHHI chose option 2C – HHGS Site to provide ongoing, reliable supply to serve existing customers and new growth within the Town of Halton Hills as it was the most cost effective solution that met the technical, environmental and economic criteria.

Customer Engagement

HHHI began customer engagement activities around the proposed TS in conjunction with the Class Environmental Assessment and review of alternative locations beginning in March 2008.

Customers and agencies were notified of the study commencement and invited to attend a Public Information Centre in May 2008. This Public Information Centre meeting was advertised in the local papers and customers and agencies were directly notified through letters. Customers and agencies were again notified at the completion of the study in August 2008.

The Public Information Centre provided the following information to customers, agencies and stakeholders:

i. Introduction of the MTS and the Class Environmental Assessment process
ii. Evaluation of alternative sites & reason for site selection
iii. Provide opportunity for public to become informed and to comment

A page dedicated to the TS is situated on HHHI's website. This page was launched in 2008 and includes information about where and why the TS is being constructed and includes copies of the Environmental Assessment report and the Public Information Centre materials.

In the 2016 Cost of Service (EB-2015-0074) Interrogatory Responses, Appendix B, HHHI included a letter from the Chief Administrative Officer, Town of Halton Hills, indicating that the Town of Halton Hills expected that HHHI would "be able to provide the necessary energy needs to Vision Georgetown prior to 2021". The letter is included in this Application as **Appendix E**.

Benefits

HHHI chose Option 2C as the least cost option that ensures reliability of supply for its customers. This option takes advantage of an innovative partnership with TransCanada Energy, the first of its kind in Ontario – enabled via a regulation passed by the provincial government. By utilizing an existing connection to Hydro One rather than building a new connection, several benefits are realized:

- Cost savings compared to building a new transmission connection crossing the 401.
- Cost savings related to land purchase and egress

- Reduced transformation costs for customers
- Reliable supply for new growth along Steeles Avenue and for the new Vision Georgetown subdivision which will add 20,000 customers to Georgetown South over a ten (10) year period.

By connecting to the transmission system through a new supply point rather than taking additional feeders from an existing point of supply, HHHI can provide improved reliability of service through additional switching options.

<u>Planning and Cost Savings / Efficiencies / Avoidance</u>

In planning for the new TS coming on line, HHHI ensured its distribution system would be ready to take advantage of the new supply through a number of projects that were identified in the 2016 DSP. Where possible, projects involving the addition of circuits to existing poles that were already replaced or installed as part of voltage conversion projects or regional road activities/projects were augmented rather than building new pole lines. Some voltage conversion projects were accelerated or given a higher priority to ensure that new circuits will be available to make use of the TS capacity as it becomes available.

HHHI has taken steps throughout the design and construction of the TS to create cost efficiencies. The site selection and unique connection to the transmission system through HHGS's switchyard provided significant cost savings over the option of connecting directly to Hydro One and requiring new transmission connections underneath the 401. The land purchase price for the site location was locked in at 2007 prices and resulted in considerable cost savings compared to the cost of land in the Steeles Avenue Prestige Industrial Corridor today.

Major equipment, consulting, engineering and construction services were all purchased through a Request for Proposal process. Vendors were invited to bid based on consultant and design engineer recommendations, prior LDC experience and industry reputation. Proposals were evaluated based on a scoring matrix that included relevant experience, ability to meet the technical requirements, reputation and price. Major equipment bids were evaluated by HHHI staff, design engineer and project consultant, with final approval by HHHI Executives and the HHHI Board of Directors. Each successful proponent was asked to find cost efficiencies wherever possible.

In an effort to maximize cost savings, the two largest pieces of equipment (power transformers and gas insulated switchgear) were purchased through a joint purchase agreement with another LDC also constructing a transformer station. Savings on the switchgear was 3% of the total cost and savings achieved on the cost of the power transformers was 1%. The combined cost savings was $74,504.32. Another cost saving opportunity was realized in the purchase of the 230kV primary cable required for the transmission connection. Typically, this specialized cable has a minimum purchase requirement. Through working directly with cable manufacturers, HHHI was able to save $22,000 through sourcing a cable length to meet our requirements.

Through diligent procurement and project management, overall costs have remained under budget.

<u>Conclusion of Prudence</u>

HHHI's mission statement is "*To Provide Halton Hills with Electricity Distribution Excellence in a Safe and Reliable Manner*". Safety and reliability are top priorities for HHHI and are two key ways HHHI strives to provide distribution excellence to customers. Capital expenditure decisions are built on the principles of excellence, safety and reliability and take a prudent, cost effective approach to infrastructure investment and renewal to try to serve current and future customer preferences and requirements. As evidenced above, HHHI needed to fill the need for the TS to ensure capacity and reliability to customers. In building the TS, HHHI used every means available to make cost effective decisions in order to limit the impacts to customers and rates. Thus, HHHI has proven its prudence in the incurring of the ICM costs.

Incremental Operating, Maintenance and Administration Costs

The July 2008 Report of the Board, the Supplemental Report and the September 2014 Report address only incremental capital expenditures. In many cases, incremental capital projects consist of only capitalized assets and the associated burdens and labour. However, in some cases, additional incremental operating, maintenance and administrative ("OM&A") costs are also incurred in the current year of the project and every year going forward.

The TS is an example of a capital expenditure that requires incremental OM&A costs each year going forward. Operating costs for the TS have been projected as an incremental cost driver for the period April 2019 to December 31, 2019 in the amount of $120,250 and then $131,515 annually in 2020. The costs considered include 24/7 monitoring by a third party control room, weekly and monthly inspections and preventable maintenance, property taxes and increase insurance costs. The incremental OM&A costs are shown in **Table 6** below.

Table 6 - Incremental OM&A Costs related to the TS

Description	April 2019 to December 31, 2019	January 1, 2020 to December 31, 2020
Training Costs[1]	$ 35,000	$ 5,000
TS Monitoring Costs TS Communication Costs[2]	18,750	25,000
Property taxes	27,750	38,110
Insurance & property protection	15,000	18,405
SCADA maintenance	3,750	5,000
Station maintenance[3]	20,000	40,000
Total	**$ 120,250**	**$ 131,515**

Notes:
[1] Training Costs - include initial training on Equipment operation, Protection and Control
[2] TS Monitoring Costs TS Communication Costs - Third Party Control Room, Fibre communications
[3] Station maintenance -$20,000 prior to expiry of warranty period

While the operating costs relating to the TS are direct increases to OM&A spending, it should be noted that customers will realize savings in monthly transformation connection costs as HHHI will be able to transfer some of the existing load to the new TS. In addition, customers will avoid additional transformation connection costs going forward as a result of HHHI supplying all new loads from the new TS. Both of these will mitigate the impact of the increased OM&A expenditure relating to the TS.

In its 2018 IRM application, HHHI requested additional rate riders to help off-set the cost of increased labour costs related to a pay-equity adjustment to wages. This request was denied, thus putting a strain on HHHI's OM&A envelope spending. For HHHI to further absorb $131,515 in additional and incremental OM&A costs, other programs may need to be reduced with a risk of decreased reliability.

ICM Model

HHHI has completed the 2018 Capital Module Applicable to ACM and ICM - Version 4.0, as revised by Board Staff and sent to HHHI on September 10, 2018 and has provided both a hard copy (see **Appendix B**) and a live Excel file of the model.

HHHI confirms the consumption and demands entered in the model are consistent with the Reporting and Record Keeping Requirements filed with the Board. The data entered into Tab "6. Rev_Req_Check" is consistent with the revenue requirement workform submitted as part of the depreciation adjustment in EB-2018-0045 – 2018 IRM application.

The TS capital costs are separated into five (5) categories and are shown below in **Table 7** with the amortization expense and CCA calculations. The projected TS capital costs are $23,476,441.

Table 7 - TS Capital Cost Categories

Cost Category	Capital Cost	Amortization Expense	Capital Cost Allowance (CCA)		
			Class	Rate	Amount
TS Switchgear - Gas, Transformer	6,789,816	196,505	47	8%	543,185
Substation Equipment, U/G Cables, Meters, Capital Contribution	9,060,154	243,061	47	8%	724,812
Duct & Civil, Building	6,408,952	153,855	47	8%	512,716
SCADA & DC System	230,519	15,368	45	45%	103,734
Land	987,000	-	n/a	n/a	-
Total Costs	**23,476,441**	**608,789**			**1,884,447**

Where applicable, HHHI has used the HHHI specific Kinetrics report (Kinetrics Inc. Report No: K-418022-RA-0001-R003 dated December 10, 2009) to determine useful lives and calculate amortization expense. Where a specific asset is not included in this report, HHHI has used the Board Kinetrics Report, dated July 2010, for recommended useful lives. The HHHI specific and Board Kinetrics reports are include in **Appendices F and G** respectively.

HHHI has no outstanding Connection Cost Recovery Agreements with Hydro One and therefore, there are no true-ups required to be included with the ICM.

Revenue Requirement

The revenue requirement calculation for the incremental capital costs can be found on Tab "11. Incremental Capital Adj." in **Appendix B**. The incremental capital revenue requirement calculated by the model is $1,698,085 and shown in **Table 8** below.

Table 8 - Incremental Capital Revenue Requirement

Current Revenue Requirement			
Current Revenue Requirement - Total		$ 10,458,405	A
Eligible Incremental Capital for ACM/ICM Recovery	**Total Claim**	**Eligible for ACM / ICM**	
Incremental Capital	23,476,441	$ 23,476,441	B
Depreciation Expense	608,789	$ 608,789	C
CCA	1,884,447	$ 1,884,447	V
Return on Rate Base			
Incremental Capital		$ 23,476,441	B
Depreciation Expense		$ 608,789	C
Incremental Capital to be included in Rate Base		$ 23,172,047	D = B - C/2
Deemed ShortTerm Debt %	4% E	$ 926,882	G = D * E
Deemed Long Term Debt %	56% F	$ 12,976,346	H = D * F
Short Term Interest	1.65% I	$ 15,294	K = G * I
Long Term Interest	2.89% J	$ 375,016	L = H * J
Return on Rate Base - Interest		$ 390,310	M = K + L
Deemed Equity %	40.00% N	$ 9,268,819	P = D * N
Return on Rate Base -Equity	9.19% O	$ 851,804	Q = P * O
Return on Rate Base - Total		$ 1,242,114	R = M + Q
Amortization Expense			
Amortization Expense - Incremental	C	$ 608,789	S
Grossed up PIL's			
Regulatory Taxable Income	O	$ 851,804	T
Add Back Amortization Expense	S	$ 608,789	U
Deduct CCA		$ 1,884,447	V
Incremental Taxable Income		$ (423,854)	W = T + U - V
Current Tax Rate	26.5% X		
PIL's Before Gross Up		$ (112,321)	Y = W * X
Incremental Grossed Up PIL's		$ (152,818)	Z = Y / (1 - X)
Incremental Revenue Requirement			
Return on Rate Base - Total	Q	$ 1,242,114	AA
Amortization Expense - Total	S	$ 608,789	AB
Incremental Grossed Up PIL's	Z	$ (152,818)	AC
Incremental Revenue Requirement		**$ 1,698,085**	**AD = AA + AB + AC**

The Working Capital Allowance used in the ICM is 7.5%, and the Cost of Capital used is 1.65% for Short Term Debt, 2.89% for Long Term Debt, a 9.19% Deemed Return on Rate Base and calculated Incremental Grossed up PILs is a credit of $152,818. As per the September 2014 Report and Filing Guidelines, the Board decided that the half-year rule would apply only in the final year (4^{th}) of the Price Cap IR plan term. HHHI is in the 3^{rd} year of the IRM and notes that the half-year rule was not applied in the calculation of incremental depreciation.

While HHHI has built the TS on the basis of planned significant future growth, the greatest growth period will begin in 2021, the same year as HHHI expects to file the next Cost of Service. Prior to 2021, customer revenues from new customer growth facilitated by the TS will be modest. As typical trending growth is expected to occur between this Application and the next Cost of Service application, HHHI has not included any revenue off-sets to the incremental capital revenue requirement.

In addition to the incremental capital revenue requirement, HHHI is also requesting $131,515 in incremental OM&A costs as detailed above.

HHHI is requesting $1,829,600 in total incremental cost recovery, as shown in **Table 9** immediately below.

Table 9 - Total Incremental Cost Recovery Request

Incremental Costs	Amount
Revenue Requirement - Capital	1,698,085
Revenue Requirement - OM&A	131,515
Total	**1,829,600**

Rate Riders

Due to the incremental OM&A request and the fixed to variable ratio adjustment for Residential customers, HHHI has calculated the Rate Riders outside the ICM Excel file. The calculations will be submitted with the Application in Excel format and are shown in **Appendix H** (pdf). **Table 10** below provides a summary of the calculations. As per Board policy, Residential rate riders are fully fixed.

Table 10 - Proposed Incremental Revenue Requirement Rate Riders

Rate Class	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
		From Sheet 4	From Sheet 4	From Sheet 4	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	$ 1,124,339	20,188	193,694,443	-	$ 4.64	$ -	$ -
GENERAL SERVICE LESS THAN 50 KW	$ 200,461	1,810	50,527,239	-	$ 5.03	$ 0.0018	$ -
GENERAL SERVICE 50 TO 999 KW	$ 304,149	186	135,373,696	394,783	$ 15.38	$ -	$ 0.6835
GENERAL SERVICE 1,000 TO 4,999 KW	$ 165,500	11	99,309,703	262,132	$ 32.87	$ -	$ 0.6148
UNMETERED SCATTERED LOAD	$ 3,469	152	934,714	-	$ 1.41	$ 0.0010	$ -
SENTINEL LIGHTING	$ 7,961	173	260,238	704	$ 1.68	$ -	$ 6.3607
STREET LIGHTING	$ 23,721	4,674	1,128,400	3,155	$ 0.41	$ -	$ 0.2750
Total	$ 1,829,600	27,194	481,228,433	660,774			

Deferral and Variance Account

HHHI requests Board approval to create a deferral and variance account to track the costs and recovery of costs related to the TS with the intention of truing up the balance at HHHI's next Cost of Service. HHHI will follow the accounting treatment for deferral and variance accounts as described in the Accounting Procedures Handbook and the ACM Report.

Bill Impacts

The proposed rate impacts reflect HHHI's 2018 distribution rates, adjusted for a Price Cap Index of 1.20%; this includes a Productivity Factor of 0.00% based on the assignment of HHHI to Stretch Factor Group I (PEG Report dated August 2018, Table 5) and the calculated Incremental Revenue Requirement Rate Rider related to the recovery of revenue requirement as it pertains to the new TS for all impacts that include the IRM. Additional bill impacts are shown in **Appendix I.**

Table 11 –Proposed Total Bill Impacts by Rate Class for Incremental Revenue Requirement

Rate Class	Volumes		% Change (IRM Only)	% Change (ICM Only)	% Change (IRM & ICM)
	kWhs	kWs			
Residential - Time of Use	750	-	-2.50%	4.40%	1.90%
General Service Less Than 50 kW	2,000	-	-3.24%	3.37%	0.12%
General Service 50 to 999 kW	328,500	500	9.59%	0.82%	10.41%
General Service 1,000 to 4,999 kW - Interval Meters	1,600,000	2,500	9.64%	0.74%	10.38%
Unmetered Scattered Load	150	-	-2.36%	6.33%	3.97%
Sentinel Lighting	650	1	-1.00%	7.42%	6.42%
Street Lighting	94,033	251	9.04%	0.56%	9.60%

In **Table 11**, HHHI has included the proposed percentage change resulting from HHHI's 2019 IRM application (EB-2018-0037) alone, the bill impact of the ICM application alone and the combined bill impact. As shown in the table, the IRM mitigates the ICM bill impacts in all classes that normally bill Regulated Price Plan ("RPP"). It should be noted that the General Service 50-999 kW, General Service 1,000 to 4,999 kW and Street Lighting classes, all classes that normally bill hourly prices and the Global Adjustment Rate Rider, see a substantial increase to their bills as a result of the IRM application and, in particular, the Global Adjustment rate rider changing from a credit in 2018 rates to a debit in the proposed 2019 rates. If the effects of the Global Adjustment Rate Rider were removed, the proposed bill impacts would be those shown in **Table 12**. This equates to an approximately 11% bill impact solely related to the Global Adjustment Rate Rider.

Table 12 –Proposed Total Bill Impacts by Rate Class (excluding Global Adjustment Rate Rider Impact)

Rate Class	Volumes		% Change (IRM excluding GA Rate Rider)	% Change (ICM Only)	% Change (IRM- excluding GA Rate Riders & ICM)	% Change - GA Rate Rider Only	% Change (IRM & ICM)
	kWhs	kWs					
Residential - Time of Use	750	-	-2.50%	4.40%	1.90%	0.00%	1.90%
General Service Less Than 50 kW	2,000	-	-3.24%	3.37%	0.12%	0.00%	0.12%
General Service 50 to 999 kW	328,500	500	-1.42%	0.82%	-0.61%	11.02%	10.41%
General Service 1,000 to 4,999 kW - Interval Meters	1,600,000	2,500	-1.44%	0.74%	-0.70%	11.09%	10.38%
Unmetered Scattered Load	150	-	-2.36%	6.33%	3.97%	0.00%	3.97%
Sentinel Lighting	650	1	-1.00%	7.42%	6.42%	0.00%	6.42%
Street Lighting	94,033	251	-2.08%	0.56%	-1.52%	11.14%	9.60%

Setting aside the impact of the Global Adjustment Rate Rider which is mechanistic and outside the control of HHHI, HHHI is not suggesting any rate mitigation as the overall bill impact is mitigated by the proposed IRM application.

Conclusion

HHHI respectfully submits that it has complied with the Board's Chapter 3 of the Filing Requirements for Transmission and Distribution Applications issued July 12, 2018 and all ACM/ICM Reports and Supplemental Reports.

The ICM is intended to address the treatment of a distributor's capital investment needs that arise during the rate-setting plan that are incremental to a materiality threshold. The ICM is a funding mechanism for significant, incremental and discrete capital projects for which a utility is granted rate recovery in advance of its next rebasing application. In the application above, HHHI submits that it has shown the materiality, need and prudence for the incremental capital expenditure as required.

The proposed rate impacts reflect HHHI's 2018 distribution rates, adjusted for a Price Cap Index of 1.20%; this includes a Productivity Factor of 0.00% based on the assignment of HHHI to Stretch Factor Group I and the calculated Incremental Revenue Requirement Rate Rider as it pertains to costs associated with the new TS.

Consequences of Non-Approval of ICM

If the approval for incremental revenue requirement is not granted, HHHI will be faced with a significant negative cash flow in the short term and financial hardship during the incentive regulation term. HHHI will be forced to consider early rebasing if it fails to secure incremental revenues through this Application.

Relief Sought

HHHI is making an Application for an Order or Orders approving the following:

- The proposed Rate Riders for recovery of Incremental Revenue Requirement as it relates to the new TS and set out in **Appendix H** to the Application as just and reasonable rates and charges pursuant to Section 78 of the OEB Act, to be effective May 1, 2019.
- HHHI is requesting that the Board deem the TS to be a distribution asset pursuant to section 84(a) of the OEB Act in order that it may recover the revenue requirement related to the TS through distribution rates.
- HHHI is requesting an exemption to the general ICM policy in order to recover incremental Operating, Maintenance and Administration ("OM&A") costs in relation to the TS.

- HHHI is requesting recovery of annual incremental OM&A costs related to the TS commencing May 1, 2019.
- An accounting order for the creation of a USofA 1508 Deferral and Variance sub-account to record costs and recoveries related to the Incremental Revenue Requirement application.

Form of Hearing Requested

HHHI requests that this Application be disposed of by way of a written hearing.

Respectfully submitted this 3rd day of December, 2018.

(Original signed)

David J. Smelsky, CPA, CMA, C.Dir.
Chief Financial Officer
Halton Hills Hydro Inc.

Attachments

Appendix A	2018 Tariff of Rates and Charges
Appendix B	2019_Capital_Module_ACM_Model Version 4_20_20181203
Appendix C	2015-Northwest-GTA-IRRP-Report-1
Appendix D	Stantec HHH Load Forecast - January 2017
Appendix E	2015 Town CAO Letter
Appendix F	HHHI Specific Kinetrics Report
Appendix G	Kinetrics-OEB Asset Amortization
Appendix H	2019 Proposed Incremental Revenue Requirement Rate Rider Calculation to be effective May 1, 2019 – Offline Calculation
Appendix I	Proposed Bill Impacts – Offline Calculation

Appendix A

2018 Tariff of Rates and Charges

(Intentionally Blank)

Halton Hills Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0045

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separate metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers. The customer will be supplied at one service entrance only. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	23.48
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0034
Low Voltage Service Rate	$/kWh	0.0026
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kWh	(0.0014)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0068
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0056

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0045

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non-residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	28.37
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0102
Low Voltage Service Rate	$/kWh	0.0024
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kWh	(0.0014)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0060
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0053

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
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EB-2017-0045

GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION

This classification applies to a non-residential customer with an average peak demand equal to or greater than 50 kW over the past twelve months, or is forecast to be equal to or greater than 50 kW, but less than 1,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the proposed capacity or installed transformer. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts with the exception of the Retail Transmission Rate-Network Service Rate, which is billed on a $/kW basis only.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	86.83
Distribution Volumetric Rate	$/kW	3.8580
Low Voltage Service Rate	$/kW	1.0483
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019 Applicable only for Non-Wholesale Market Participants	$/kW	(1.2172)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kW	0.5107
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kW	(0.0276)
Retail Transmission Rate - Network Service Rate	$/kW	2.6217
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2146

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
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EB-2017-0045

GENERAL SERVICE 1,000 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non-residential customer with an average peak demand equal to or greater than 1,000 kW over the past twelve months, or is forecast to be equal to or greater than 1,000 kW, but less than 5,000 kW. For a new customer without prior billing history, the peak demand will be based on 90% of the installed transformer. Class A and Class B consumers are defined in accordance with O.Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

The rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

The rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Billing demands are established at the greater of 100% of the kW, or 90% of the kVA amounts with the exception of the Retail Transmission Rate-Network Service Rate, which is billed on a $/kW basis only.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	185.55
Distribution Volumetric Rate	$/kW	3.4705
Low Voltage Service Rate	$/kW	1.0483
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kW	(0.9398)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kW	(0.0341)
Retail Transmission Rate - Network Service Rate	$/kW	2.6217
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	2.2146

Halton Hills Hydro Inc.
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MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2017-0045

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, pedestrian X-Walk signals/beacons, railway crossings, etc. The level of the consumption will be agreed to by the distributor and the customer, based on detailed manufacturer information/documentation with regard to electrical consumption of the unmetered load or periodic monitoring of actual consumption. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	7.97
Distribution Volumetric Rate	$/kWh	0.0054
Low Voltage Service Rate	$/kWh	0.0024
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kWh	(0.0012)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kWh	(0.0001)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0060
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kWh	0.0053

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
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EB-2017-0045

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	9.47
Distribution Volumetric Rate	$/kW	35.9050
Low Voltage Service Rate	$/kW	0.7547
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kW	(0.4711)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kW	(0.0298)
Retail Transmission Rate - Network Service Rate	$/kW	1.8704
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5942

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
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EB-2017-0045

STREET LIGHTING SERVICE CLASSIFICATION

All services supplied to street lighting equipment owned by or operated for the Municipality, the Region or the Province of Ontario shall be classified as Street Lighting Service. Street Lighting plant, facilities, or equipment owned by the customer are subject to the Electrical Safety Authority (ESA) requirements and Halton Hills Hydro specifications. Class B consumers are defined in accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	2.30
Distribution Volumetric Rate	$/kW	1.5523
Low Voltage Service Rate	$/kW	0.7393
Rate Rider for Disposition of Global Adjustment Account (2018) - effective until April 30, 2019 Applicable only for Non-RPP Customers	$/kWh	(0.0010)
Rate Rider for Disposition of Deferral/Variance Accounts (2018) - effective until April 30, 2019	$/kW	(0.9785)
Rate Rider for Disposition of Capacity Based Recovery Account (2018) - effective until April 30, 2019 Applicable only for Class B Customers	$/kW	(0.0285)
Retail Transmission Rate - Network Service Rate	$/kW	1.8617
Retail Transmission Rate - Line and Transformation Connection Service Rate	$/kW	1.5617

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0032
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0003
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2018
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EB-2017-0045

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator’s microFIT program and connected to the distributor’s distribution system. Further servicing details are available in the distributor’s Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

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MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	5.40

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for Transformer Losses - applied to measured demand & energy	%	(1.00)

Halton Hills Hydro Inc.
TARIFF OF RATES AND CHARGES
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EB-2017-0045

SPECIFIC SERVICE CHARGES

APPLICATION

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No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Customer Administration

Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge - no disconnection	$	30.00
Collection of account charge - no disconnection - after regular hours	$	165.00
Disconnect/Reconnect at Meter - during regular hours	$	65.00
Disconnect/Reconnect at Meter - after regular hours	$	185.00
Disconnect/Reconnect at Pole - during regular hours	$	185.00
Disconnect/Reconnect at Pole - after regular hours	$	415.00
Install/Remove Load Control Device - during regular hours	$	65.00
Install/Remove Load Control Device - after regular hours	$	185.00

Other

Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service install & remove - overhead - no transformer	$	500.00
Temporary service install & remove - underground - no transformer	$	300.00
Temporary service install & remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	22.35
Interval meter charge	$	20.00

Halton Hills Hydro Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2018

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EB-2017-0045

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Debt Retirement Charge, the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0560
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0455

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Appendix B

2018_Capital_Module_ACM_Model Version 4_20_20181203

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Note: Depending on the selections made below, certain worksheets in this workbook will be hidden. **Version** **4.20**

Utility Name	Halton Hills Hydro Inc.
Assigned EB Number	
Name of Contact and Title	David Smelsky, Chief Financial Officer
Phone Number	519-853-3700 x 208
Email Address	dsmelsky@haltonhillshydro.com
Is this Capital Module being filed in a CoS or Price-Cap IR Application?	**Price-Cap IR** — **Rate Year** **2019**
Indicate the Price-Cap IR Year (1, 2, 3, 4, etc) in which Halton Hills Hydro Inc. is applying:	**3**
Halton Hills Hydro Inc. is applying for:	**ICM Approval**
Last Rebasing Year:	**2016**
The most recent complete year for which actual billing and load data exists	**2017**
Current IPI	**1.20%**
Strech Factor Assigned to Middle Cohort	**III**
Stretch Factor Value	**0.30%**
Price Cap Index	**0.90%**

Based on the inputs above, the growth factor utilized in the Materiality Threshold Calculation will be determined by:

$$\frac{\text{Revenues Based on 2017 Actual Distribution Demand}}{\text{Revenues Based on 2016 Board-Approved Distribution Demand}}$$

Notes

Pale green cells represent input cells.

Pale blue cells represent drop-down lists. The applicant should select the appropriate item from the drop-down list.

White cells contain fixed values, automatically generated values or formulae.

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and the results.

OEB policies regarding rate-setting and rebasing following distributor consolidations could allow a distributor to not rebase rates for up to ten years. A distributor could also apply for and receive OEB approval to defer rebasing. If a distributor is under Price Cap IR for more than four years after rebasing and applies for an ICM, this spreadsheet will need to be adapted to accommodate those circumstances. The distributor should contact OEB staff to discuss the circumstances so that a customized model can be provided.

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Halton Hills Hydro Inc.

Select the appropriate rate classes as they appear on your most recent Board-Approved Tariff of Rates and Charges, excluding the MicroFit Class.

How many classes are on your most recent Board-Approved Tariff of Rates and Charges? **7**

Select Your Rate Classes from the **Blue Cells** below. Please ensure that a rate class is assigned to **each shaded cell.**

	Rate Class Classification
1	RESIDENTIAL
2	GENERAL SERVICE LESS THAN 50 kW
3	GENERAL SERVICE 50 TO 999 kW
4	GENERAL SERVICE 1,000 TO 4,999 kW
5	UNMETERED SCATTERED LOAD
6	SENTINEL LIGHTING
7	STREET LIGHTING

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Halton Hills Hydro Inc.

Input the billing determinants associated with Halton Hills Hydro Inc.'s Revenues Based on 2017 Actual Distribution Demand. Input the current approved distribution rates. Sheets 4 & 5 calculate the NUMERATOR portion of the growth factor calculation.

		2017 Actual Distribution Demand			Current Approved Distribution Rates		
Rate Class	**Units**	**Billed Customers or Connections**	**Billed kWh**	**Billed kW (if applicable)**	**Monthly Service Charge**	**Distribution Volumetric Rate kWh**	**Distribution Volumetric Rate kW**
RESIDENTIAL	$/kWh	20,188	193,694,443		23.48	0.0034	0.0000
GENERAL SERVICE LESS THAN 50 kW	$/kWh	1,810	50,527,239		28.37	0.0102	0.0000
GENERAL SERVICE 50 TO 999 kW	$/kW	186	135,373,696	394,783	86.83	0.0000	3.8580
GENERAL SERVICE 1,000 TO 4,999 kW	$/kW	11	99,309,703	262,132	185.55	0.0000	3.4705
UNMETERED SCATTERED LOAD	$/kWh	152	934,714		7.97	0.0054	0.0000
SENTINEL LIGHTING	$/kW	173	260,238	704	9.47	0.0000	35.9050
STREET LIGHTING	$/kW	4,674	1,128,400	3,155	2.30	0.0000	1.5523

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Halton Hills Hydro Inc.

Calculation of pro forma 2016 Revenues. No input required.

Rate Class	2017 Actual Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW (if applicable)	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Revenues from Rates	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
Total	0	0	0	D	E	F	0	0	0	0	K = G / J	L = H / J	M = I / J	0.0%
RESIDENTIAL	20,188	193,694,443		23.48	0.0034	0.0000	5,688,171	658,561	0	6,346,732	89.6%	10.4%	0.0%	61.5%
GENERAL SERVICE LESS THAN 50 kW	1,810	50,527,239		28.37	0.0102	0.0000	616,196	515,378	0	1,131,574	54.5%	45.5%	0.0%	11.0%
GENERAL SERVICE 50 TO 999 kW	186	135,373,696	394,783	86.83	0.0000	3.8580	193,805	0	1,523,077	1,716,881	11.3%	0.0%	88.7%	16.6%
GENERAL SERVICE 1,000 TO 4,999 kW	11	99,309,703	262,132	185.55	0.0000	3.4705	24,493	0	909,729	934,222	2.6%	0.0%	97.4%	9.0%
UNMETERED SCATTERED LOAD	152	934,714		7.97	0.0054	0.0000	14,537	5,047	0	19,585	74.2%	25.8%	0.0%	0.2%
SENTINEL LIGHTING	173	260,238	704	9.47	0.0000	35.9050	19,660	0	25,277	44,937	43.7%	0.0%	56.3%	0.4%
STREET LIGHTING	4,674	1,128,400	3,155	2.30	0.0000	1.5523	129,002	0	4,898	133,900	96.3%	0.0%	3.7%	1.3%
Total	**27,194**	**481,228,433**	**660,774**				**6,685,864**	**1,178,986**	**2,462,980**	**10,327,831**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

Applicants Rate Base

Last COS Rebasing: 2016

Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	81,716,296	A			
Add: CWIP Re-based Opening	$	4,516,245	B			
Re-based Capital Additions	$	7,708,601	C			
Re-based Capital Disposals	$	-	D			
Re-based Capital Retirements	$	-	E			
Deduct: CWIP Re-based Closing	-$	4,516,245	F			
Gross Fixed Assets - Re-based Closing	$	89,424,897	G			
Average Gross Fixed Assets				$	85,570,597	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	28,972,192	I			
Re-based Depreciation Expense	$	2,022,154	J			
Re-based Disposals	$	-	K			
Re-based Retirements	$	-	L			
Accumulated Depreciation - Re-based Closing	$	30,994,346	M			
Average Accumulated Depreciation				$	29,983,269	N = (I + M) / 2
Average Net Fixed Assets				**$**	**55,587,328**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	75,531,774	P			
Working Capital Allowance Rate		7.5%	Q			
Working Capital Allowance				**$**	**5,664,883**	R = P * Q
Rate Base				**$**	**61,252,211**	S = O + R
Return on Rate Base						
Deemed ShortTerm Debt %		4.00%	T	$	2,450,088	W = S * T
Deemed Long Term Debt %		56.00%	U	$	34,301,238	X = S * U
Deemed Equity %		40.00%	V	$	24,500,884	Y = S * V
Short Term Interest		1.65%	Z	$	40,426	AC = W * Z
Long Term Interest		2.89%	AA	$	991,306	AD = X * AA
Return on Equity		9.19%	AB	$	2,251,631	AE = Y * AB
Return on Rate Base				**$**	**3,283,363**	AF = AC + AD + AE
Distribution Expenses						
OM&A Expenses	$	6,007,592	AG			
Amortization	$	2,022,154	AH			
Ontario Capital Tax	$	-	AI			
Grossed Up Taxes/PILs	$	-	AJ			
Low Voltage			AK			
Transformer Allowance			AL			
Property Tax	$	104,440	AM			
			AN			
			AO			
				$	**8,134,186**	AP = SUM (AG : AO)
Revenue Offsets						
Specific Service Charges	-$	375,470	AQ			
Late Payment Charges	-$	120,000	AR			
Other Distribution Income	-$	252,074	AS			
Other Income and Deductions	-$	211,600	AT	**-$**	**959,144**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**10,458,405**	AV = AF + AP + AU
Rate Classes Revenue						
Rate Classes Revenue - Total (Sheet 5)				$	10,327,831	AW
Difference				$	130,575	AZ = AV - AW
Difference (Percentage - should be less than ±1%)					1.26%	BA = AZ / AW

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Halton Hills Hydro Inc.

Input the billing determinants associated with Halton Hills Hydro Inc.'s Revenues Based on 2016 Board-Approved Distribution Demand. This sheet calculates the DENOMINATOR portion of the growth factor calculation.
Pro forma Revenue Calculation.

Rate Class	2016 Board-Approved Distribution Demand			Current Approved Distribution Rates										
	Billed Customers or Connections	Billed kWh	Billed kW	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue By Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Total % Revenue
Total	**0**	**0**	**0**	**D**	**E**	**F**	**0**	**0**	**0**	**0**	**$K = G / J_{total}$**	**$L = H / J_{total}$**	**$M = I / J_{total}$**	**0.0%**
RESIDENTIAL	19,971	205,578,737		23.48	0.0034	0.0000	5,627,029	698,968	0	6,325,997	53.7%	6.7%	0.0%	60.3%
GENERAL SERVICE LESS THAN 50 kW	1,967	58,991,538		28.37	0.0102	0.0000	669,645	601,714	0	1,271,359	6.4%	5.7%	0.0%	12.1%
GENERAL SERVICE 50 TO 999 kW	206	136,566,740	362,031	86.83	0.0000	3.8580	214,644	0	1,396,719	1,611,363	2.0%	0.0%	13.3%	15.4%
GENERAL SERVICE 1,000 TO 4,999 kW	13	112,173,675	302,644	185.55	0.0000	3.4705	28,946	0	1,050,326	1,079,272	0.3%	0.0%	10.0%	10.3%
UNMETERED SCATTERED LOAD	144	895,971		7.97	0.0054	0.0000	13,772	4,838	0	18,610	0.1%	0.0%	0.0%	0.2%
SENTINEL LIGHTING	175	461,109	628	9.47	0.0000	35.9050	19,830	0	22,548	42,379	0.2%	0.0%	0.2%	0.4%
STREET LIGHTING	4,649	1,535,681	4,282	2.30	0.0000	1.5523	128,299	0	6,647	134,946	1.2%	0.0%	0.1%	1.3%
Total	**27,124**	**516,203,452**	**669,585**				**6,702,165**	**1,305,520**	**2,476,241**	**10,483,925**				**100.0%**

Ontario Energy Board

Capital Module

Applicable to ACM and ICM

Halton Hills Hydro Inc.

Current Revenue from Rates

This sheet is used to determine the applicant's most current allocation of revenues (after the most recent revenue to cost ratio adjustment, if applicable) to appropriately allocate the incremental revenue requirement to the classes.

Rate Class	Current OEB-Approved Base Rates			2017 Actual Distribution Demand										
	Monthly Service Charge	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kW	Re-based Billed Customers or Connections	Re-based Billed kWh	Re-based Billed kW	Current Base Service Charge Revenue	Current Base Distribution Volumetric Rate kWh Revenue	Current Base Distribution Volumetric Rate kW Revenue	Total Current Base Revenue	Service Charge % Total Revenue	Distribution Volumetric Rate % Total Revenue	Distribution Volumetric Rate % Total Revenue	Total % Revenue
Total	A	B	C	D	E	F	0	0	0	0	$L = G / J_{total}$	$M = H / J_{total}$	$N = I / J_{total}$	0.0%
RESIDENTIAL	23.48	0.0034	0.0000	20,188	193,694,443		5,688,171	658,561	0	6,346,732	55.08%	6.38%	0.00%	61.5%
GENERAL SERVICE LESS THAN 50 kW	28.37	0.0102	0.0000	1,810	50,527,239		616,196	515,378	0	1,131,574	5.97%	4.99%	0.00%	11.0%
GENERAL SERVICE 50 TO 999 kW	86.83	0.0000	3.8580	186	135,373,696	394,783	193,805	0	1,523,073	1,716,877	1.88%	0.00%	14.75%	16.6%
GENERAL SERVICE 1,000 TO 4,999 kW	185.55	0.0000	3.4705	11	99,309,703	262,132	24,493	0	909,729	934,222	0.24%	0.00%	8.81%	9.0%
UNMETERED SCATTERED LOAD	7.97	0.0054	0.0000	152	934,714		14,537	5,047	0	19,585	0.14%	0.05%	0.00%	0.2%
SENTINEL LIGHTING	9.47	0.0000	35.9050	173	260,238	704	19,660	0	25,277	44,937	0.19%	0.00%	0.24%	0.4%
STREET LIGHTING	2.30	0.0000	1.5523	4,674	1,128,400	3,155	129,002	0	4,898	133,900	1.25%	0.00%	0.05%	1.3%
Total							**6,685,864**	**1,178,986**	**2,462,977**	**10,327,827**				**100.0%**

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Halton Hills Hydro Inc.

No Input Required.

Final Materiality Threshold Calculation

$$Threshold\ Value\ (\%) = 1 + \left[\left(\frac{RB}{d}\right) \times (g + PCI \times (1+g))\right] \times \left((1+g) \times (1+PCI)\right)^{n-1} + 10\%$$

Cost of Service Rebasing Year		**2016**	
Price Cap IR Year in which Application is made		**3**	n
Price Cap Index		**0.90%**	PCI
Growth Factor Calculation			
Revenues Based on 2017 Actual Distribution Demand		**$10,327,831**	
Revenues Based on 2016 Board-Approved Distribution Demand		**$10,483,925**	
Growth Factor		**-1.49%**	g (Note 1)
Dead Band		**10%**	
Average Net Fixed Assets			
Gross Fixed Assets Opening	$	81,716,296	
Add: CWIP Opening	$	4,516,245	
Capital Additions	$	7,708,601	
Capital Disposals	$	-	
Capital Retirements	$	-	
Deduct: CWIP Closing	-$	4,516,245	
Gross Fixed Assets - Closing	$	89,424,897	
Average Gross Fixed Assets	$	85,570,597	
Accumulated Depreciation - Opening	$	28,972,192	
Depreciation Expense	$	2,022,154	
Disposals	$	-	
Retirements	$	-	
Accumulated Depreciation - Closing	$	30,994,346	
Average Accumulated Depreciation	$	29,983,269	
Average Net Fixed Assets	$	55,587,328	
Working Capital Allowance			
Working Capital Allowance Base	$	75,531,774	
Working Capital Allowance Rate		8%	
Working Capital Allowance	$	5,664,883	
Rate Base	**$**	**61,252,211**	RB
Depreciation	**$**	**2,022,154**	d

Threshold Value (varies by Price Cap IR Year subsequent to CoS rebasing)

Price Cap IR Year 2017	**92%**
Price Cap IR Year 2018	**92%**
Price Cap IR Year 2019	**92%**
Price Cap IR Year 2020	**92%**
Price Cap IR Year 2021	**92%**
Price Cap IR Year 2022	**92%**
Price Cap IR Year 2023	**92%**
Price Cap IR Year 2024	**93%**
Price Cap IR Year 2025	**93%**
Price Cap IR Year 2026	**93%**

Threshold CAPEX $Threshold\ Value \times d$

Price Cap IR Year 2017	**$**	**1,855,452**
Price Cap IR Year 2018	**$**	**1,857,674**
Price Cap IR Year 2019	**$**	**1,859,883**
Price Cap IR Year 2020	**$**	**1,862,078**
Price Cap IR Year 2021	**$**	**1,864,260**
Price Cap IR Year 2022	**$**	**1,866,429**
Price Cap IR Year 2023	**$**	**1,868,585**
Price Cap IR Year 2024	**$**	**1,870,728**
Price Cap IR Year 2025	**$**	**1,872,857**
Price Cap IR Year 2026	**$**	**1,874,975**

Note 1: The growth factor g is annualized, depending on the number of years between the numerator and denominator for the calculation. Typically, for ACM review in a cost of service and in the fourth year of Price Cap IR, the ratio is divided by 2 to annualize it. No division is normally required for the first three years under Price Cap IR.

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Applicable to ACM and ICM
Halton Hills Hydro Inc.

Identify ALL Proposed ACM projects and related CAPEX costs in the relevant years

	Cost of Service	*Price Cap IR*				*Price Cap IR (Deferred Rebasing)*					
	***Test Year* 2016**	**Year 1 2017**	**Year 2 2018**	**Year 3 2019**	**Year 4 2020**	**Year 5 2021**	**Year 6 2022**	**Year 7 2023**	**Year 8 2024**	**Year 9 2025**	**Year 10 2026**
Distribution System Plan CAPEX	$ 9,539,998	$ 11,095,939	$ 6,902,214	$ 30,635,824	$ 8,149,827						
Materiality Threshold		$ 1,855,452	$ 1,857,674	$ 1,859,883	$ 1,862,078	$ 1,864,260	$ 1,866,429	$ 1,868,585	$ 1,870,728	$ 1,870,728	$ 1,870,728
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ 9,240,487	$ 5,044,540	$ 28,775,942	$ 6,287,749	$ -	$ -	$ -	$ -	$ -	$ -

Project Descriptions:	**Type**	**Test Year 2016**	**Year 1 2017**	**Year 2 2018**	**Year 3 2019**	**Year 4 2020**	**Year 5 2021**	**Year 6 2022**	**Year 7 2023**	**Year 8 2024**	**Year 9 2025**	**Year 10 2026**	**Total**
TS Switchgear - Gas, Transformer	**New ICM**				$ 6,789,816								**$ 6,789,816**
Substation Equipment, U/G Cables, Meters, Capital Contribution	**New ICM**				$ 9,060,154								**$ 9,060,154**
Duct & Civil, Building	**New ICM**				$ 6,408,952								**$ 6,408,952**
SCADA & DC System	**New ICM**				$ 230,519								**$ 230,519**
Land	**New ICM**				$ 987,000								**$ 987,000**
													$ -
													$ -
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													$ -
Total Cost of ACM/ICM Projects		$ -	$ -	$ -	$ 23,476,441	$ -	$ -	$ -	$ -	$ -	$ -	$ -	**$ 23,476,441**
Maximum Allowed Incremental Capital			$ -	$ -	$ 23,476,441	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23,476,441

		Price Cap IR			
	Test Year 2016	**Year 1 2017**	**Year 2 2018**	**Year 3 2019**	**Year 4 2020**
Distribution System Plan CAPEX	$ 9,539,998	$ 11,095,939	$ 6,902,214	$ 30,635,824	$ 8,149,827
Materiality Threshold		$ 1,855,452	$ 1,857,674	$ 1,859,883	$ 1,862,078
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ 9,240,487	$ 5,044,540	$ 28,775,942	$ 6,287,749

		Test Year 2016	**Year 1 2017**			**Year 2 2018**			**Year 3 2019**			**Year 4 2020**		
Project Descriptions:	**Type**		**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**
TS Switchgear - Gas, Transformer	**New ICM**		$ -	$ -	$ -	$ -			**$ 6,789,816**	$ 196,505	$ 543,185	$ -		
Substation Equipment, U/G Cables, Meters, Capital Contribution	**New ICM**		$ -	$ -		$ -			**$ 9,060,154**	$ 243,061	$ 724,812	$ -		
Duct & Civil, Building	**New ICM**		$ -			$ -			**$ 6,408,952**	$ 153,855	$ 512,716	$ -		
SCADA & DC System	**New ICM**		$ -			$ -			**$ 230,519**	$ 15,368	$ 103,734	$ -		
Land	**New ICM**		$ -			$ -			**$ 987,000**	$ -	$ -	$ -		
			$ -			$ -			$ -			$ -		
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			$ -			$ -			$ -			$ -		
Total Cost of ACM/ICM Projects			$ -	$ -	$ -	$ -	$ -	$ -	$ 23,476,441	$ 608,789	$ 1,884,447	$ -	$ -	$ -

Price Cap IR (Deferred Rebasing) (if necessary)

		Price Cap IR			
		Year 5 2021	Year 6 2022	Year 7 2023	Year 8 2024
Distribution System Plan CAPEX		$ -	$ -	$ -	$ -
Materiality Threshold		$ 1,864,260	$ 1,866,429	$ 1,868,585	$ 1,870,728
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -	$ -	$ -

		Year 5 2021			Year 6 2022			Year 7 2023			Year 8 2024		
Project Descriptions:	**Type**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**
TS Switchgear - Gas, Transformer	New ICM	$ -			$ -	$ -		$ -			$ -		
Substation Equipment, U/G Cables, Meters, Capital Contribution	New ICM	$ -			$ -	$ -		$ -			$ -		
Duct & Civil, Building	New ICM	$ -			$ -			$ -			$ -		
SCADA & DC System	New ICM	$ -			$ -			$ -			$ -		
Land	New ICM	$ -			$ -			$ -			$ -		
		$ -			$ -			$ -			$ -		
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		$ -			$ -			$ -			$ -		
Total Cost of ACM/ICM Projects		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Price Cap IR (Deferred Rebasing) (if necessary)

		Price Cap IR	
		Year 9 2025	Year 10 2026
Distribution System Plan CAPEX		$ -	$ -
Materiality Threshold		$ 1,870,728	$ 1,870,728
Maximum Eligible Incremental Capital (Forecasted Capex less Threshold)	$ -	$ -	$ -

		Year 9 2025			Year 10 2026		
Project Descriptions:	**Type**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**	**Proposed ACM/ICM**	**Amortization Expense**	**CCA**
TS Switchgear - Gas, Transformer	New ICM	$ -			$ -		
Substation Equipment, U/G Cables, Meters, Capital Contribution	New ICM	$ -			$ -		
Duct & Civil, Building	New ICM	$ -			$ -		
SCADA & DC System	New ICM	$ -			$ -		
Land	New ICM	$ -			$ -		
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		$ -			$ -		
Total Cost ofACM/ICM Projects		$ -	$ -	$ -	$ -	$ -	$ -

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Halton Hills Hydro Inc.

Incremental Capital Adjustment **Rate Year:** 2019

Current Revenue Requirement

Current Revenue Requirement - Total	$	10,458,405	A

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim	Eligible for ACM/ICM (Prorated Amount) *(from Sheet 10b)*	
Amount of Capital Projects Claimed	$23,476,441	$ 23,476,441	B
Depreciation Expense	$ 608,789	$ 608,789	C
CCA	$ 1,884,447	$ 1,884,447	V

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$	23,476,441	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$	608,789	C
Incremental Capital to be included in Rate Base (average NBV in year)			$	23,172,047	D = B - C/2
	% of capital structure				
Deemed Short-Term Debt	4.0%	E	$	926,882	G = D * E
Deemed Long-Term Debt	56.0%	F	$	12,976,346	H = D * F
	Rate (%)				
Short-Term Interest	1.65%	I	$	15,294	K = G * I
Long-Term Interest	2.89%	J	$	375,016	L = H * J
Return on Rate Base - Interest			$	390,310	M = K + L
	% of capital structure				
Deemed Equity %	40.00%	N	$	9,268,819	P = D * N
	Rate (%)				
Return on Rate Base -Equity	9.19%	O	$	851,804	Q = P * O
Return on Rate Base - Total			$	1,242,114	R = M + Q

Amortization Expense

Amortization Expense - Incremental	C	$	608,789	S

Grossed up Taxes/PILs

Regulatory Taxable Income		O	$	851,804	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$	608,789	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$	1,884,447	V
Incremental Taxable Income			-$	423,854	W = T + U - V
Current Tax Rate	26.5%	X			
Taxes/PILs Before Gross Up			-$	112,321	Y = W * X
Grossed-Up Taxes/PILs			-$	152,818	Z = Y / (1 - X)

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$	1,242,114	AA
Amortization Expense - Total	S	$	608,789	AB
Grossed-Up Taxes/PILs	Z	-$	152,818	AC
Incremental Revenue Requirement		$	1,698,085	AD = AA + AB + AC

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
Halton Hills Hydro Inc.

Calculation of incremental rate rider. Choose one of the 3 options:

Rate Class	Service Charge % Revenue	Distribution Volumetric Rate % Revenue kWh	Distribution Volumetric Rate % Revenue kW	Service Charge Revenue	Distribution Volumetric Rate Revenue kWh	Distribution Volumetric Rate Revenue kW	Total Revenue by Rate Class	Billed Customers or Connections	Billed kWh	Billed kW	Service Charge Rate Rider	Distribution Volumetric Rate kWh Rate Rider	Distribution Volumetric Rate kW Rate Rider
	From Sheet 8	*From Sheet 8*	*From Sheet 8*	Col C * Col I_{total}	Col D* Col I_{total}	Col E* Col I_{total}	*Col I_{total}*	*From Sheet 4*	*From Sheet 4*	*From Sheet 4*	Col F / Col K / 12	Col G / Col L	Col H / Col M
RESIDENTIAL	55.08%	6.38%	0.00%	935,240	108,280	0	1,043,520	20,188	193,694,443		4.31	0.0000	0.0000
GENERAL SERVICE LESS THAN 50 kW	5.97%	4.99%	0.00%	101,314	84,738	0	186,052	1,810	50,527,239		4.66	0.0017	0.0000
GENERAL SERVICE 50 TO 999 kW	1.88%	0.00%	14.75%	31,865	0	250,421	282,286	186	135,373,696	394,783	14.28	0.0000	0.6343
GENERAL SERVICE 1,000 TO 4,999 kW	0.24%	0.00%	8.81%	4,027	0	149,576	153,603	11	99,309,703	262,132	30.51	0.0000	0.5706
UNMETERED SCATTERED LOAD	0.14%	0.05%	0.00%	2,390	830	0	3,220	152	934,714		1.31	0.0009	0.0000
SENTINEL LIGHTING	0.19%	0.00%	0.24%	3,232	0	4,156	7,388	173	260,238	704	1.56	0.0000	5.9034
STREET LIGHTING	1.25%	0.00%	0.05%	21,210	0	805	22,016	4,674	1,128,400	3,155	0.38	0.0000	0.2552
Total	**64.74%**	**11.42%**	**23.85%**	**1,099,279**	**193,847**	**404,959**	**1,698,085**	**27,194**	**481,228,433**	**660,774**			
							1,698,085						
							From Sheet 11, E93						

Appendix C

2015-Northwest-GTA-IRRP-Report-1

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NORTHWEST GREATER TORONTO AREA INTEGRATED REGIONAL RESOURCE PLAN

Part of the GTA West Planning Region | April 28, 2015

ieso
Independent Electricity System Operator

Integrated Regional Resource Plan

Northwest Greater Toronto Area Sub-Region

This Integrated Regional Resource Plan ("IRRP") was prepared by the IESO pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the Northwest Greater Toronto Area Working Group, which included the following members:

- Independent Electricity System Operator
- Hydro One Brampton
- Milton Hydro
- Halton Hills Hydro
- Hydro One Networks Inc. (Distribution) and
- Hydro One Networks Inc. (Transmission)

The Northwest Greater Toronto Area Working Group assessed the adequacy of electricity supply to customers in the Northwest Greater Toronto Area 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 Northwest Greater Toronto Area Sub-Region; and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key assumptions over time.

Northwest Greater Toronto Area Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions. Northwest Greater Toronto Area Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

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List of Abbreviations

Abbreviation	Description
CDM	Conservation Demand Management
DESN	Dual Element Spot Network
DG	Distributed Generation
DR	Demand Response
EA	Environmental Assessment
FIT	Feed-in Tariff
GS	Generating Station
IESO	Independent Electricity System Operator
IPSP	2007 Integrated Power System Plan
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LTEP	2013 Long-Term Energy Plan
MTO	Ministry of Transportation
MTS	Municipal Transformer Station
MVA	Megavolt ampere
MW	Megawatt
OEB	Ontario Energy Board
OPA	Ontario Power Authority (merged with IESO as of January 1st 2015)
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPS	Provincial Policy Statement
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
TS	Transformer Station
Working Group	

1. Introduction

This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Northern sub-region of the West Greater Toronto Area Region ("NW GTA" or "Northwest GTA") over the next 20 years. The report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group composed of the IESO, Hydro One Brampton, Milton Hydro, Halton Hills Hydro, Hydro One Distribution and Hydro One Transmission ("Working Group").

The NW GTA sub-region includes the municipalities of Brampton, Milton, Halton and the southern portion of Caledon. The other sub-region within the West Greater Toronto Area Region – Southwest GTA – underwent a Needs Screening and Scoping Assessment, which determined that needs in the area existed, but that they would be best addressed by the applicable distributors and transmitter for local capacity needs and through a bulk planning study for local restoration needs, rather than through an IRRP process.

Over the last 10 years, electrical demand in this sub-region has grown on average by 2.2% per year. Increasing electrical demand in densely populated urban areas and high growth rates in greenfield residential and commercial/industrial subdivisions have made this sub-region's growth rate one of the highest in Ontario. The official plans issued by the sub-region's municipalities indicate that this growth is expected to continue over the next 20 years in accordance with the province's "Places to Grow" policy.[1] There is a strong need for integrated regional electricity planning to ensure that the electricity system can support the pace of development in the long term.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is done through regional electricity planning, a process that was formalized by the Ontario Energy Board ("OEB" or "Board") in 2013. In accordance with the OEB regional planning process, transmitters, distributers and the IESO are required to carry out regional planning activities for the 21 electricity planning regions at least once every five years.

This IRRP identifies and co -ordinates the options to meet customer needs in the sub-region over the next twenty years. Specifically, this IRRP identifies investments for immediate implementation to meet near- and medium-term needs in the region, respecting the lead time

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[1] Growth Plan for the Greater Golden Horseshoe, June 2013 Consolidated, https://www.placestogrow.ca/index.php?option=com_content&task=view&id=359&Itemid=14

for development. This IRRP also identifies options to meet long-term needs, but given forecast uncertainty, the potential for technological change and the longer development lead-time, the plan maintains flexibility for long-term options and does not commit specific projects at this time. Instead, the long-term plan identifies near-term actions to develop alternatives and engage with the community, to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle, scheduled for 2020 or sooner, depending on demand growth, so that the results can inform a decision should one be needed at that time.

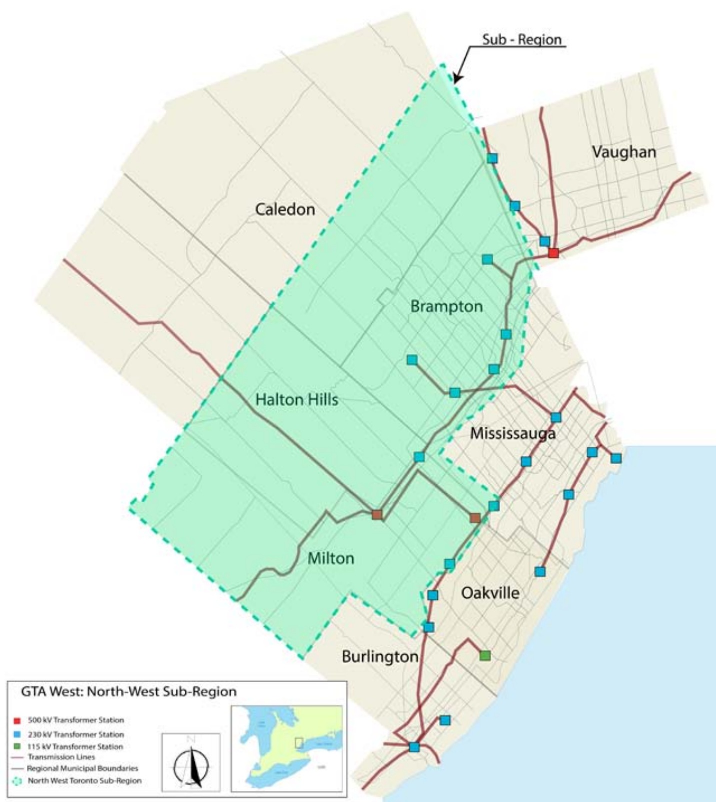
This report is organized as follows:

- A summary of the recommended plan for NW GTA is provided in Section 2
- The process and methodology used to develop the plan are discussed in Section 3
- The context for electricity planning in NW GTA and the study scope are discussed in Section 4
- Demand forecast scenarios, as well as conservation and distributed generation assumptions, are described in Section 5
- Near- and long-term electricity needs in NW GTA are presented in Section 6
- Alternatives and recommendations for meeting near- and medium-term needs are addressed in Section 7
- Options for meeting long-term needs are discussed and near-term actions to support development of the long-term plan are provided in Section 8
- A summary of community, aboriginal and stakeholder engagement to date in developing this IRRP and moving forward is provided in Section 9
- A conclusion is provided in Section 10.

2. The Integrated Regional Resource Plan

The Northwest GTA IRRP addresses the region's electricity needs over the next 20 years based on the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). The IRRP identifies needs that are forecast to arise in the near and medium term (0-10 years) and in the longer term (10-20 years). These two planning horizons are distinguished in the IRRP to reflect the level of commitment required over these time horizons. Plans for both timeframes are coordinated to ensure consistency. The IRRP was developed based on consideration of planning criteria, including reliability, cost and feasibility, and, in the near-term, it seeks to maximize the use of the existing electricity system where it is economic to do so. The NW GTA sub-region is highlighted in green in Figure 2-1, below.

Figure 2-1: West GTA Northern Sub-region (NW GTA)

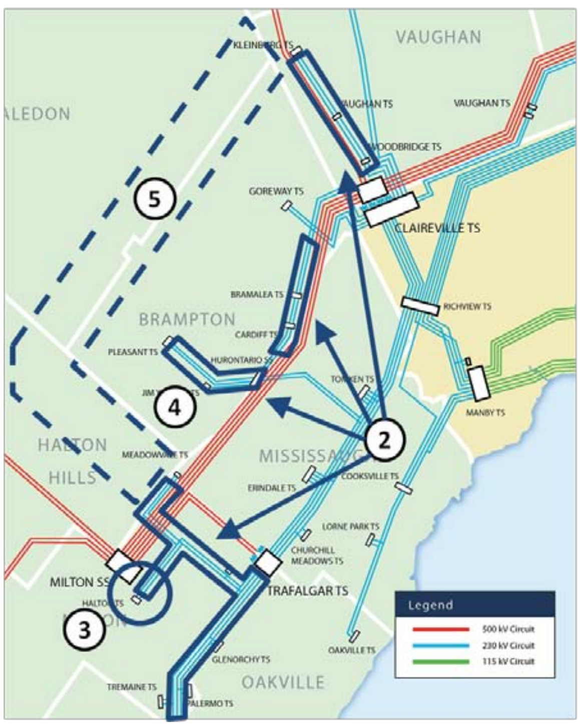


For the near and medium term, the IRRP identifies specific investments to be implemented. This is necessary to ensure that they are in service in time to address the region's more urgent needs, respecting the lead time for their development.

For the long term, the IRRP identifies a number of alternatives to meet needs. However, as these needs are forecast to rise further in the future, it is not necessary (nor would it be prudent given forecast uncertainty and the potential for technological change) to commit to specific projects at this time. Instead, near-term actions are identified to develop alternatives, keep key options open and engage with the communities, to gather information and lay the groundwork for future options. These actions are intended to be completed before the next IRRP cycle so that their results can inform a decision at that time.

The needs or recommended actions comprising the near- to medium-term and long-term plans are summarized below and shown in Figure 2-2 below.

Figure 2-2: Summary of Plan Elements



Near/ Medium Term
1. Conservation achievement (entire region)
2. Restoration needs *(left to right)*
    - Halton radial pocket
    - Pleasant TS
    - Cardiff/ Bramalea supply
    - Kleinburg radial pocket
3. Halton TS (capacity needs)
4. Supply to Pleasant TS (capacity needs)

Long Term

5. Secure long term transmission corridor rights

The sections below provide more details on plan elements shown in the map. They have been sorted according to near/medium term and long term.

2.1 Near- / Medium-Term Plan

There are a number of elements that comprise the near- and medium-term plan. The first element of the plan is to maximize achievement of conservation targets. The plan also identifies several pockets in the study area that are currently at risk for not meeting targeted load restoration levels and recommends a course of action for addressing these needs. Two new step-down transmission facilities are recommended in the near term to ensure new customer connections can be accommodated in the Halton Hills and Milton service territories. Over the medium term, a transmission line upgrade is recommended to address emerging capacity needs in the Pleasant TS service area. The recommendations that comprise the near- and medium-term plan are described in further detail below.

Near-/Medium-Term Needs

- Load restoration criteria exceeded in Northwest GTA—**2015**
- Provide additional transformer station supply capability within the Halton TS service territory—**2018 for Halton Hills Hydro and 2020 for Milton Hydro**
- Increase supply meeting capability of H29/30 circuits (supply to Pleasant TS) — **early-to-mid 2020s**
- Address overloads on T38/39B (supply to Halton TS, Meadowvale TS, Trafalgar TS and Tremaine TS) — **early-to-mid 2020s**

Recommended Actions:

1. Implement conservation and distributed generation

Meeting the provincial conservation targets established in the 2013 Long-Term Energy Plan ("LTEP") is a key component of the near-term plan. Peak-demand impacts associated with the provincial targets were assumed before identifying any residual needs, when developing the demand forecast. This is consistent with the provincial Conversation First Policy. These peak-demand impacts amount to approximately 130 megawatts ("MW") or 33% of the forecast demand growth during the first 10 years of the study. To ensure that these savings materialize, the local distribution companies' ("LDCs") conservation efforts should focus on measures that will balance the needs for energy savings to meet the Conservation First policy, while maximizing peak-demand reductions.

Monitoring conservation success, including measuring peak-demand savings, will be an important element of the near-term plan. This will lay the foundation for the long-term plan by reviewing the actual performance of specific conservation measures in the region and assessing potential for further conservation efforts.

Provincial programs that encourage the development of distributed generation ("DG"), such as the Feed-in Tariff ("FIT"), microFIT and Combined Heat and Power Standard Offer programs, can also contribute to reducing peak demand in the region. This will depend in part on local interest and opportunities for development. The LDCs and the IESO will continue their activities to support these initiatives and monitor their impacts.

2. Address restoration and T38/39B needs through bulk system study

A bulk system study is underway in the West GTA Region to address anticipated overloads on the bulk transmission system resulting from changes in provincial generation patterns and overall growth across the GTA in general and the West GTA Region in particular. Options considered as part of the bulk system study have the potential to provide benefits related to improving local restoration capabilities throughout the area as well as the medium-term T38/39B capacity needs. As a result, the Working Group agreed that these regional needs should be considered as part of the bulk system study. If these needs are not adequately addressed through the bulk system study and a bulk system plan, they will be revisited as part of the regional planning process.

3. Develop two new step-down stations to relieve Halton TS overloads

Action is required to provide additional supply capacity in the area served by Halton TS. This station is located on the south side of Highway 401 in the Town of Milton and supplies 27.6 kilovolt ("kV") power throughout Milton and southern Halton Hills. Based on current forecasts, additional 27.6 kV supply is required in the general vicinity of Halton TS by approximately 2018 for Halton Hills Hydro's service area and 2020 for Milton Hydro's service area.

Following the analysis included as Appendix E and summarized in Section 7.1.3, the most economic course of action is to construct two stations: one at the site of the current Halton Hills Generating Station ("GS") to supply Halton Hills Hydro by 2018 and one at the existing Halton TS to supply Milton Hydro loads by 2020. Based on the anticipated needs and assuming a three-year lead time for development and construction, it is recommended that Halton Hills Hydro begin development of the Halton Hills MTS at this time. Commencement of development and construction of Halton TS #2 (for supply to Milton Hydro) does not need to be initiated until 2017.

4. Upgrade H29/30 circuits (supply to Pleasant TS) to a higher rating

When load at Pleasant TS exceeds approximately 417 MW and one of the H29/30 circuits that supplies Pleasant TS is out of service, there is a potential for overloads on the companion circuit. Under the Expected Growth forecast, relief is anticipated to be required by about 2026, or as early as 2023 under the Higher Growth forecast. Hydro One has indicated that this line can be upgraded to accommodate over 500 MW of electrical demand at Pleasant TS, enough to accommodate the full rating of the station's step-down facilities, and deferring need until the long term. Assuming a two-year lead time for the replacement of these conductors, action is not expected to be required until the early 2020s.

Peak load should continue to be monitored at Pleasant TS and action pursued when actual demand increases from the current level of approximately 375 MW to approximately 400 MW. Assuming five to ten megawatts of demand growth per year, peak load is expected to occur approximately two years before the need date of 2026.

2.2 Long-Term Plan

> **Long-Term Needs**
>
> • Provide additional transformer and transmission line capacity in northern Brampton/southern Caledon to meet forecast demand growth

The long term plan assumes near-/medium-term needs are addressed as recommended in Section 2.1, above. If that is not done, the long-term plan will likely have to be modified. In the long term, continued load growth is expected to be significant, increasing peak summer demand in Northwest GTA from 1,220 MW to 1,580 MW during the study period. This is expected to trigger capacity needs in the northern Brampton/southern Caledon area. In broad terms, capacity needs refer to the ability of the power system to meet the peak electricity demands of end use customers. In this area, there are two main drivers that could trigger this capacity need:

- Overloads on the transformers at Pleasant TS and/or Kleinburg TS due to load growth beyond the step-down stations' capacity.
- An inability for the distribution system to deliver the required service quality as a result of limitations on the distribution network due to distances between transmission supply points (i.e., transformer stations) and new end-use customers located in northern Brampton and southern Caledon.

When new capacity is necessary in the northern Brampton/southern Caledon area, step-down transformer stations will be required in the general vicinity of the anticipated growth to supply new customer loads. Due to a lack of available transmission supply in the area, a new transmission corridor will also be required to provide supply to any future stations.

Recommended Actions:

5. Continue Ongoing Work to Establish a New Transmission Corridor through Peel, Halton Hills and Northern Vaughan

The Ministry of Transportation ("MTO") recently began Phase 2 of an environmental assessment ("EA") to establish a new 400-series highway corridor running from the Highway 401/407 junction near Milton, north along the Halton Hills/Brampton border, through southern Caledon and northern Vaughan, terminating at Highway 400. The IESO and Hydro One have been working with MTO and municipal government staff to consider the establishment of a future transmission corridor in the general vicinity of this highway, consistent with government policy on coordinated and efficient use of land, resources, infrastructure and public service facilities in Ontario communities, outlined in the Provincial Policy Statement ("PPS"). This transmission corridor would provide supply capacity for northern Halton, northern Peel, and York Region in the long term and also enhance the capability of the West GTA bulk supply system.

To ensure the future viability of this option, the IESO and Hydro One will continue working with the Ministries of Energy, Transportation, Infrastructure and Municipal Affairs and Housing and related regional and municipal government staff.

6. Monitor Demand Growth, CDM Achievement and Distributed Generation Uptake

On an annual basis, the IESO will coordinate a review of conservation and demand management ("CDM") achievement, the uptake of provincial distributed generation projects and actual demand growth within the Northwest GTA sub-region. This review will be used to track the expected timing of the following needs to determine when a decision on implementation is required:

- Construction of Halton TS #2
- Upgrade of H29/30 circuits (supply to Pleasant TS) to a higher rating
- A new NW GTA electricity corridor

3. Development of the IRRP

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 Ontario Power Authority ("OPA") carried out regional 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 2012, the Ontario Energy Board convened the 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. In May 2013, the PPWG released the Working Group Report to the Board, setting out the new regional planning process. Twenty-one electricity planning regions in the province were identified in the Working Group Report and a phased schedule for completion was outlined. The Board endorsed the Working Group 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 licence changes required it to lead a number of aspects of regional planning, including the completion of comprehensive IRRPs. Following the merger of the IESO and the OPA on January 1, 2015, the regional planning responsibilities identified in the OPA's licence were transferred to the IESO.

The regional planning process begins with a Needs Screening process 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 distribution solutions, or whether a straightforward "wires" solution is the best option. If the latter applies, then a transmission- and distribution-focused Regional

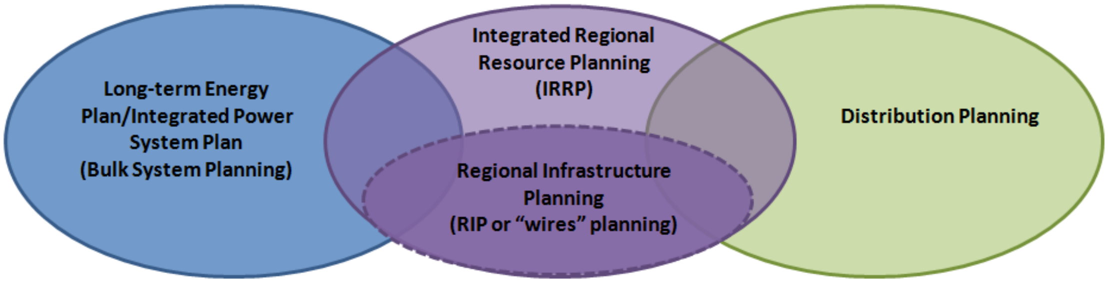
Infrastructure Plan ("RIP") is developed. The scoping assessment process also identifies any sub-regions that require assessment. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter, outside of the regional planning process. At the conclusion of the scoping assessment, the IESO produces a report that includes the results of the Needs Screening process – identifying whether an IRRP, RIP or no regional coordination is required – and a preliminary Terms of Reference. If an IRRP is the identified outcome, then the IESO is required to complete the IRRP within 18 months. If a RIP is required, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years.

The final IRRPs and RIPs are to be posted on the IESO and relevant transmitter websites and can be used as supporting evidence in a rate hearing or leave to construct application for specific infrastructure investments. These documents may also be used by municipalities for planning purposes and by other parties to better understand local electricity growth and infrastructure requirements.

Regional planning, as shown in Figure 3-1, is just one form of electricity planning that is undertaken in Ontario. There are three types of electricity planning in Ontario:

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

Figure 3-1: Levels of Electricity System Planning



Bulk System Planning

- 500 kV & 230 kV transmission
- Interconnections
- Inter-area network transfer capability
- System reliability (security and adequacy) to meet NERC, NPCC, ORTAC
- Congestion and system efficiency
- System supply and demand forecasts
- Incorporation of large generation
- Typically medium- and long-term focused

Regional Planning

- 230 kV & 115 kV transmission
- 115/230 kV autotransformers and associated switchyard facilities
- Customer connections
- Load supply stations
- Regional reliability (security and adequacy) to meet NERC, NPCC & ORTAC
- ORTAC local area reliability criteria
- Regional/local area generation & CDM resources
- Typically near- & medium-term focused

Distribution Network Planning

- Transformer stations to connect to the transmission system
- Distribution network planning (e.g. new & modified Dx facilities)
- Distribution system reliability (capacity & security)
- Distribution connected generation & CDM resources
- LDC demand forecasts
- Near- & medium-term focused

Planning at the bulk system level typically considers the 230 kV and 500 kV network. Bulk system planning considers the major transmission facilities and assesses the resources needed to adequately supply the province. Bulk system planning is typically carried out by the IESO in accordance with government policy. Distribution planning, which is carried out by local distribution companies, looks at specific investments on the low voltage, distribution system.

Regional planning can overlap with bulk system planning. For example, overlap can occur at interface points where regional resource options may also address a bulk system issue. Similarly, regional planning can overlap with the distribution planning of LDCs. An example of this is when a distribution solution addresses the needs of the broader local area or region. Therefore, to ensure efficiency and cost effectiveness, it is important for regional planning to be coordinated with both bulk and distribution system planning.

By recognizing the linkages with bulk and distribution system planning and coordinating multiple needs identified within a given region over the long term, the regional planning process provides an integrated assessment of needs. Regional planning aligns near and long-term solutions and allows specific investments recommended in the plan to be understood as part of a larger context. Furthermore, regional planning optimizes ratepayer interests by avoiding piecemeal planning and asset duplication and allows Ontario ratepayers' interests to be represented along with the interests of LDC ratepayers. Where IRRPs are undertaken, they allow an evaluation of the multiple options available to meet 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 Regional Planning

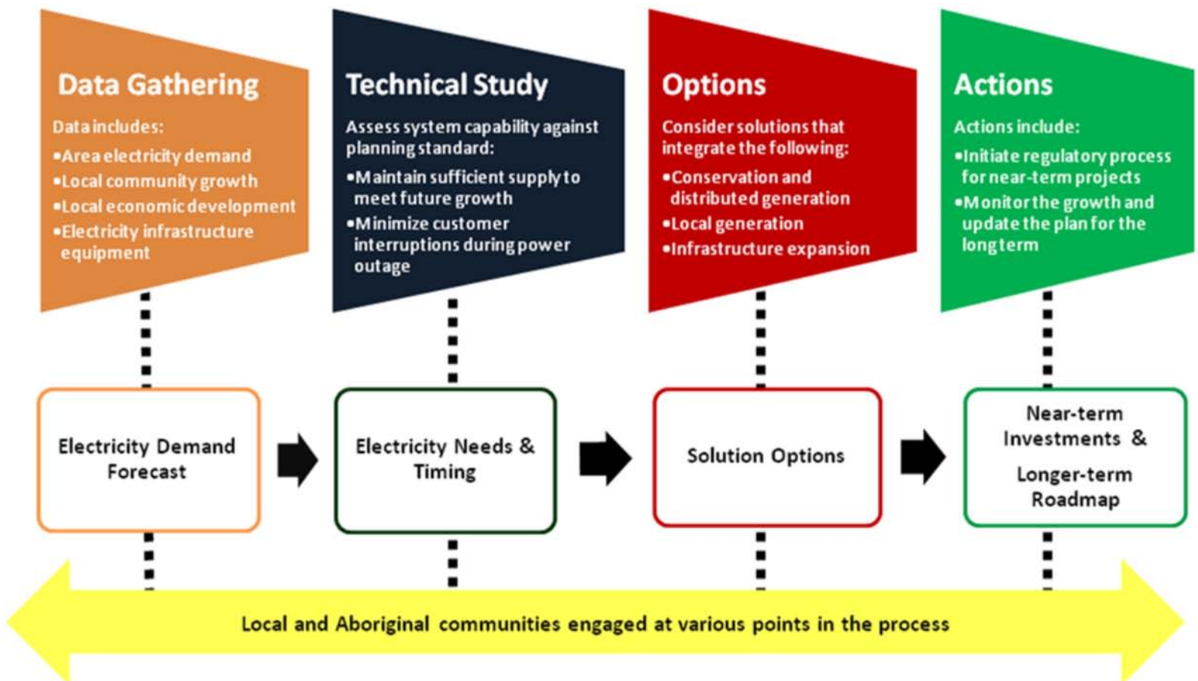
IRRPs assess electricity system needs for a region over a 20-year period. The 20-year outlook anticipates long-term trends so that near-term actions are developed within the context of a longer-term view. This enables coordination and consistency with the long-term plan, rather than simply reacting to immediate needs.

In developing an IRRP, a different approach is taken to developing the plan for the first 10 years of the plan—the near- and medium-term—than for the longer-term period of 10-20 years. The plan for the first 10 years is developed based on best available information on demand, conservation and other local developments. Given the long lead time to develop electricity infrastructure, near-term electricity needs require prompt action to enable the specified solutions in a timely manner. By contrast, the long-term plan is characterized by greater forecast uncertainty and longer development lead time, as such solutions do not need to be committed to immediately. Given the potential for changing conditions and technological development, the IRRP for the long term is more directional, focusing on developing and maintaining the viability of options for the future and continuing to monitor demand forecast scenarios.

In developing an IRRP, the IESO and regional working group (see Figure 3-2 below) carry out a number of steps. These steps include electricity demand forecasts; technical studies to determine electricity needs and the timing of these needs; the development of potential options; and a recommended plan including actions for the near and long term. Throughout this process, engagement is carried out with stakeholders and First Nation and Métis communities who may have an interest in the region. The steps of an IRRP are illustrated in Figure 3-2 below.

The IRRP report documents the inputs, findings and recommendations developed through the process described above and provides recommended actions for the various entities responsible for plan implementation. Where "wires" solutions are included in the plan recommendations, the completion of the IRRP report is the trigger for the transmitter to initiate an RIP process to develop those options. Other actions may involve: development of conservation, local generation, or other solutions; community engagement; or information gathering to support future iterations of the regional planning process in the region.

Figure 3-2: Steps in the IRRP Process



3.3 Northwest GTA Working Group and IRRP Development

Through 2012, the IESO and area LDCs discussed local conditions, recent and expected customer growth trends and anticipated challenges. The participants for this planning process were:

- IESO
- Hydro One Brampton
- Milton Hydro
- Halton Hills Hydro
- Hydro One Distribution
- Hydro One Transmission

Based on these discussions, the IESO and area LDCs agreed that an Integrated Regional Resource Planning process was appropriate for the area. The participants in the planning process became the Working Group that developed this IRRP.

The NW GTA IRRP process started in 2013 in response to strong growth in peak electrical demand throughout the sub-region. A major consideration for triggering an IRRP was the location of new growth: urban boundaries have been expanding northward throughout Halton and Peel regions, which has placed additional strain on a transmission system that is largely concentrated in the southern portion of the region.

The Northwest GTA IRRP is a "transitional" IRRP in that it began prior to the development of the OEB's regional planning process; some of the work was completed before the new process and its requirements were known. Much of the work completed in the early days of the study focused on development of the load forecast and identifying needs and options. The approaches used in conducting these elements of the study were consistent with the new OEB process. As a result, the Terms of Reference were not revised, but an explanatory note was added to communicate the updated planning framework. These Terms of Reference are available on the IESO's Regional Planning website.[2]

[2] http://powerauthority.on.ca/sites/default/files/planning/NW-GTA-Terms-of-Reference.pdf

4. Background and Study Scope

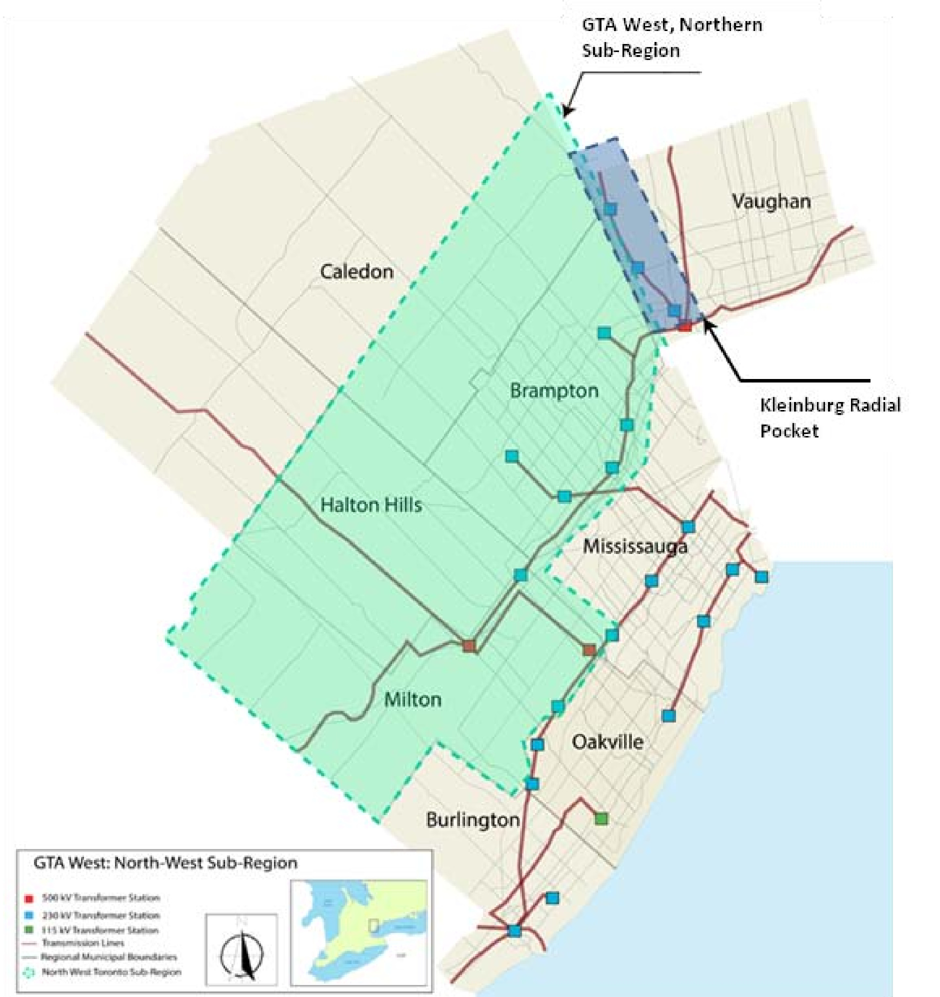
This report presents an integrated regional electricity plan for NW GTA for the 20-year period from 2014 to 2033. The planning process leading to this IRRP began in 2013, in recognition of the high electrical demand growth observed over the previous 10 years, expanding urban boundaries, limited existing electrical infrastructure and the requirement for coordination with ongoing bulk system planning in this sub-region.

To set the context for this IRRP, the scope of this IRRP and the region's existing electricity system are described in Section 4.1, the recommendations and implementation of the 2006 West GTA Supply Study are summarized in Section 4.2 and a brief introduction to the ongoing bulk system study is provided in Section 4.3.

4.1 Study Scope

The West Greater Toronto Area Region ("West GTA") roughly encompasses the municipalities of Mississauga, Oakville, Brampton, Milton, southern Halton Hills (including Georgetown and Acton) and southern Caledon (including Bolton and the areas south of the Greenbelt). Based on an early review of growth and existing infrastructure, this region was broken into two sub-regions: Northwest GTA, highlighted in green in Figure 4-1, below and Southwest GTA.

Figure 4-1: Northwest GTA Planning Sub-region



The Northwest GTA sub-region is roughly defined by the municipalities of Brampton, Milton, southern Halton Hills and southern Caledon. It is the focus of this IRRP.

Immediately adjacent to the Northwest GTA boundary is a short radial circuit (V43/44), which runs radially from Claireville TS and terminates at Kleinburg TS (Kleinburg radial pocket, highlighted in blue, above). Although the Kleinburg radial pocket is located within the GTA North Region, this pocket was included within the scope of the Northwest GTA IRRP for the following reasons:

- Electrical demand growth in this pocket is driven largely by new customers in southern Caledon, in particular the Town of Bolton. As a result, any capacity needs would have greater implications for customers in the Northwest GTA sub-region.

- The Northwest GTA sub-region is characterized by a large number of similarly configured radial pockets, meaning that restoration needs would be a common issue addressed across the entire planning area. The fact that there are so many radial pockets provides an opportunity for investigating common solutions.

The Southern sub-region of West GTA ("Southwest GTA") is not included in this IRRP. A separate Needs Assessment and Scoping Assessment were carried out for this sub-region in 2014. These assessments concluded that the sub-region's capacity needs would be best addressed directly by the distributor and transmitter, and restoration needs through a bulk transmission system study under development by the IESO. Some restoration needs for the Southwest GTA sub-region were also identified as part of the Scoping Assessment and will be considered as part of the bulk transmission system study already underway for West GTA (see Section 4.3, below, for more details). If these restoration needs are not resolved through the bulk transmission system study, they will be revisited as part of the regional planning process. Information on the Southwest GTA study, including links to the Needs Assessment and Scoping Assessment reports, is available on the IESO Regional Planning webpage.[3]

Growth in Peel region is expected to continue to expand northward into the undeveloped greenfield areas of north Brampton and south Caledon, farther from existing transmission assets. Within Halton region, the municipalities of Halton Hills and Milton are expected to see growth along underdeveloped areas to the north and south of Highway 401, the vicinity of James Snow Parkway and through southern Georgetown. The blue and orange highlighted areas in Figure 4-2 show these growth clusters:

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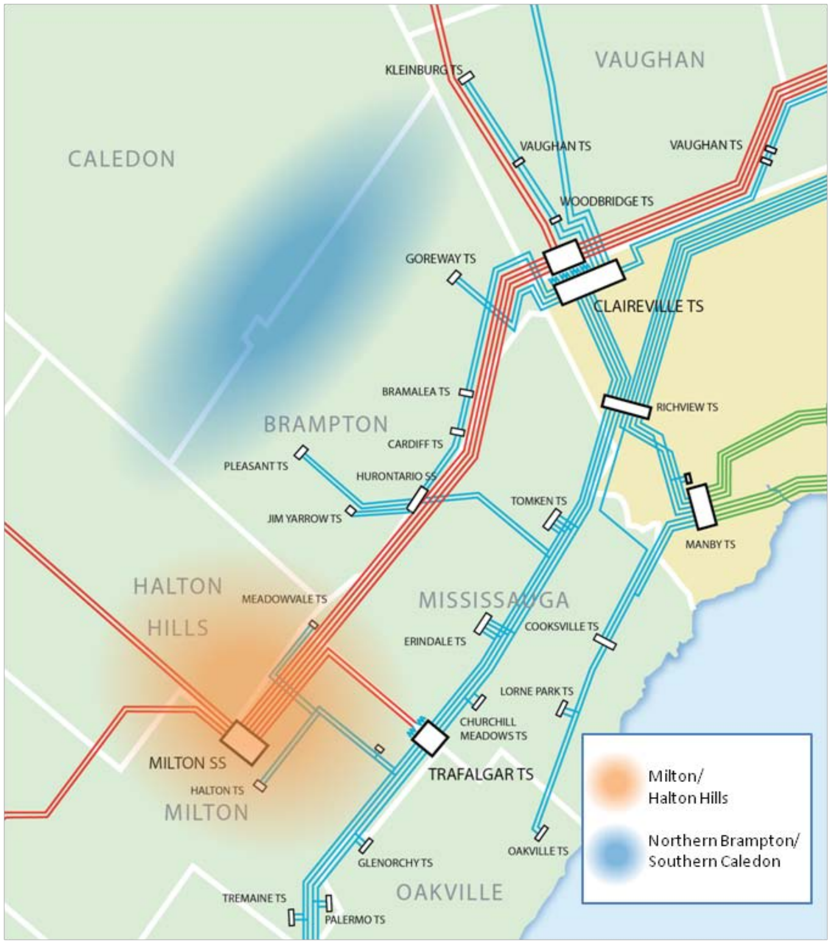
[3] http://www.powerauthority.on.ca/power-planning/regional-planning/gta-west/southern-sub-region

Figure 4-2: Anticipated Growth Clusters, by Municipality



The continued high growth shown in this forecast is consistent with the *Places to Grow Growth Plan for the Greater Golden Horseshoe* (2013 consolidated), which projects an additional 790,000 people living in the Peel and Halton regions by 2031. This represents an average annual population increase of 1.84% per year.

4.2 2006 West GTA Supply Study

The 2006 West GTA Supply Study was a joint study undertaken by Enersource Hydro Mississauga, Halton Hills Hydro Inc., Hydro One Brampton, Hydro One Networks Inc. Distribution, Milton Hydro and Hydro One Networks Inc. Transmission. This study was initiated in 2004, before the establishment of the OPA, but had a similar purpose to the current regional planning initiative, namely to identify the need for transmission capacity and voltage stability in West GTA and assess the capability of the transmission system to meet the load requirements for a 10-year study period (from 2005 to 2015). Several new transmission reinforcements were recommended and ultimately adopted, including:

- Extension of circuits V72/73R from Cardiff TS to Pleasant TS tap and construction of Hurontario SS with radial supply to Jim Yarrow MTS
- Construction of Winston Churchill MTS
- Construction of a third set of step down transformers (Dual Element Spot Network, or "DESN") at Pleasant TS
- Construction of a second DESN at Goreway TS

The measures undertaken as a result of the 2006 study have supported the continued electrical load growth in this area over the past decade. This IRRP builds upon the previous planning initiatives in this area, including the 2006 West GTA study, to ensure that the forecast electrical load growth in the area can continue to be met.

A copy of the report is available on Hydro One's Regional Planning website.[4]

4.3 Bulk Transmission System Study

A bulk system study was initiated by the IESO for West GTA in 2014 to identify and recommend solutions to address emerging bulk transmission system needs. These needs differ from those driving the regional plan, as they are impacted by changes in the broader Ontario electricity system, rather than the local system. These needs include planned refurbishment and retirement of nuclear generation facilities, incorporating renewable generation in southwest Ontario and changes in electricity consumption patterns across the GTA. Due to the potential for overlaps between bulk and regional planning, as described in Section 3.1, it is important for regional planning to be coordinated with bulk system planning, particularly in the case of West GTA. The bulk system study will therefore account for regional needs that may be more efficiently solved through bulk system solutions.

The West GTA region is supplied by the 500 kV and 230 kV bulk transmission network with 500-230 kV transformation facilities at Claireville TS and Trafalgar TS. Load supply stations and major generating stations in the area are connected to the 230 kV network. The 500 kV transmission network is the backbone of the Ontario system and the 500-230 kV transformers provide the link between the 500 kV and the 230 kV networks. Milton SS, which is located in

[4] http://www.hydroone.com/RegionalPlanning/GTAWest/Documents/GTA%20West%20Supply%20Study%202006.pdf

the area, provides switching for 500 kV circuits. Currently there are no 500-230 kV transformation facilities at this station.

The bulk system studies conducted indicate that the following facilities may require relief from overloads within the next 10 years:

- 500-230 kV transformers at Trafalgar TS
- 500-230 kV transformers at Claireville TS
- Trafalgar to Richview 230 kV lines

These three facilities are highlighted on the map below:

Figure 4-3: West GTA Bulk Facilities with Potential Needs

The two primary factors driving the overloads on the 500-230 kV transformers and the Trafalgar to Richview 230 kV lines are load growth in the GTA and changes in generation patterns across Ontario. While all growth within the GTA has some impact on the bulk system, growth within West GTA (the municipalities of Mississauga, Oakville, Milton, Halton Hills, Brampton and Caledon) has the greatest contribution due to proximity to the affected bulk facilities.

Specific contributors to changes in provincial generation patterns, particularly those driving bulk system needs in West GTA, include the completion of refurbishment of nuclear units at Bruce GS, significant uptake of renewable generation in southwestern Ontario, the planned retirement of nuclear generation at Pickering GS and the scheduled refurbishment of nuclear generation at Darlington GS. These changes are expected to result in increased inter-regional power flows into the GTA from the west towards the east through transmission facilities in West GTA. These higher inter-regional power flows contribute to overloads of the 500-230 kV transformers at Trafalgar TS and the Trafalgar-to-Richview 230 kV lines.

Based on the early results of the bulk system study, upgrades to the bulk transmission system in the area may be needed by 2020. These may include installing new autotransformers at Milton SS and new transmission infrastructure along existing transmission corridors. Because solutions to these bulk system needs are also capable of addressing several needs identified in this IRRP, in particular those associated with restoration capability, the scope of the bulk system study will include consideration for these local restoration needs. More details on the restoration needs within the Northwest GTA IRRP are available in Section 6.2. The Scoping Assessment for Southwest GTA is located on the IESO Regional Planning webpage.[5]

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[5] http://www.powerauthority.on.ca/power-planning/regional-planning/gta-west/southern-sub-region

5. Load Forecast

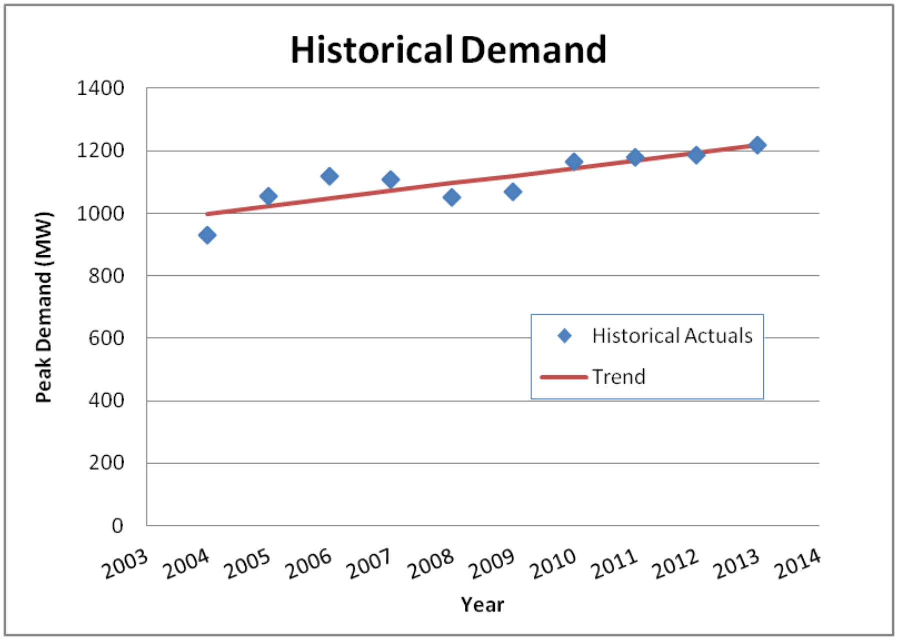
This section outlines the forecast of electricity demand within the Northwest GTA sub-region. It highlights the assumptions made for peak-demand load forecasts, the contribution of conservation to reducing peak demand and the role of distributed generation resources in supplying demand in this area. The resulting net demand forecast is used in assessing the electricity needs of the area over the planning horizon.

To evaluate the adequacy of the electric system, the regional planning process involves measuring the demand observed at each station for the hour of the year when overall demand in the study area is at a maximum. This is called "coincident peak demand" and represents the moment when assets are most stressed and resources most constrained. This is different from a non-coincident peak, which is measured by summing each station's individual peak, regardless of whether the stations' peaks occur at different times. Within Northwest GTA, the peak loading hour for each year typically occurs in mid-afternoon of the hottest weekday during summer, driven by the 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 Historical Demand

Growth within Northwest GTA has been strong over the past decade, largely driven by expanding urban boundaries and intensifying downtown cores. Within the study area, peak electrical demand has grown at an average of 2.2% over the past 10 years, representing an increase of approximately 220 MW for the study area after applying regression (see Figure 5-1, below):

Figure 5-1: 10-year Historical Peak Demand, with Trend Line



Growth has been particularly pronounced over the past five years, averaging 2.7% for the study area as a whole. Actual coincident peak demand for each LDC in the study area is shown below for the past five years, along with the resulting average percent growth:

Table 5-1: 5-year Historical Peak Demand and Average Percent Growth, by LDC (in MW)

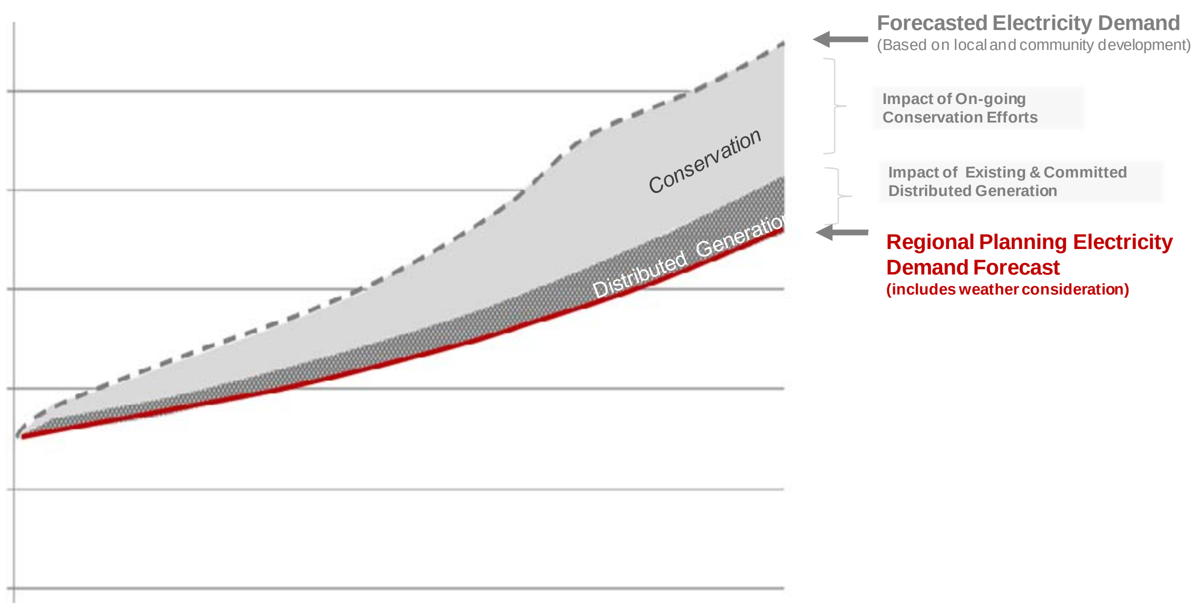
LDC	2009	2010	2011	2012	2013	Avg % Growth
Hydro One Brampton	739.35	800.67	807.70	810.65	825.55	2.32 %
Milton Hydro	130.82	143.42	156.18	156.93	168.28	6.05 %
Halton Hills Hydro	85.67	93.67	92.69	92.83	97.09	2.41 %
Hydro One Distribution (Caledon)	114.39	128.42	123.28	125.45	126.44	1.73 %
TOTAL	1070.24	1166.17	1179.85	1185.86	1217.36	2.74 %

5.2 Demand Forecast Methodology

Regional electricity needs are driven by the limits of the infrastructure supplying an area, which is sized to meet peak-demand requirements. Regional planning typically focuses on growth in regional-coincident peak demand. Energy adequacy is usually not a concern of regional planning, as the region can generally draw upon energy available from the provincial electricity grid, with energy adequacy for the province being planned through a separate process.

A regional peak-demand forecast, illustratively shown in Figure 5-2, was developed for the 20-year planning horizon. LDCs provided gross demand forecasts, which were modified by the IESO to reflect (1) the impact that provincial conservation targets and distributed generation programs have on peak demand and (2) extreme weather conditions. Using a planning forecast that is net of provincial conservation targets provides consistency with the province's Conservation First policy by reducing demand requirements before assessing any growth-related needs.[6]

Figure 5-2: Development of Expected Growth Scenario



To account for the uncertainty associated with applying conservation assumptions based on long-term energy targets, two net demand forecast scenarios were developed to reflect a range of possible outcomes:

- An "Expected Growth" scenario was developed to reflect the full allocation of energy savings from targeted conservation, with assumptions made for the translation of

[6] This assumes that the conservation targets will be met and that the targets, which are energy-based, will produce estimated local peak demand impacts. Monitoring the actual peak demand impacts of conservation programs delivered by LDCs will be an important aspect of plan implementation.

energy to peak-demand savings. This scenario was the default forecast primarily used to identify regional needs.

- A "Higher Growth" scenario was developed assuming some combination of Higher Growth or lower projected peak-demand savings, resulting in a higher net electrical demand throughout the 20-year study period. More details on the assumptions used to develop this scenario are included in Section 5.4.

5.3 Gross Demand Forecast

Each participating LDC prepared gross demand forecasts at the transformer station level or bus level for multi-bus stations. Since LDCs have the most direct experience with customers and applicable local growth expectations, their information is considered the most accurate for regional planning purposes. Most LDCs had cited alignment with municipal and regional Official Plans as a primary source for input data. Other common considerations included known connection applications and typical electrical demand intensity for similar customer types.

The gross demand forecasts provided by the LDCs are provided in Appendix A.

5.4 Conservation Assumed in the Forecast

Conservation plays a key role in maximizing the utilization of existing infrastructure and maintaining reliable supply by keeping demand within equipment capability. It is achieved through a mix of program-related activities, behavioural changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize results. The conservation savings forecast for West GTA are applied to the gross peak-demand forecast, along with distributed generation resources, to determine the net peak demand for the region.

In December 2013 the Ministry of Energy released a revised Long-Term Energy Plan that outlined a provincial conservation target of 30 terawatt-hours of energy savings by 2032. To represent the effect of these targets within regional planning, the IESO developed an annual forecast for peak-demand savings resulting from the provincial energy savings target, which was then expressed as a percentage of demand in each year. These percentages were applied to the LDCs' demand forecasts to develop an estimate of the peak-demand impacts from the provincial targets in Northwest GTA. The resulting conservation assumed in the Expected Growth forecast is shown in Table 5-2. Additional conservation forecast details are provided in Appendix A.

Table 5-2: Peak MW Offset Due to Conservation Targets from 2013 LTEP, Select Years

	2013	2015	2017	2019	2021	2023	2025	2027	2029	2031
Total	0.9 %	2.2 %	3.1 %	5.0 %	6.8 %	8.0 %	9.5 %	10.9 %	12.3 %	13.7 %
MW assumed	11.0	29.8	42.7	72.8	104.4	127.7	158.0	189.1	218.8	249.6

It is assumed existing demand response ("DR") already in the base year will continue. Assumptions related to potential DR projects that do not yet have a contract will be handled when considering solutions to needs and not during development of the load forecast.

For the Higher Growth forecast, half of the peak-demand reduction shown in Table 5-2 was accounted for in the forecast. Applying this uncertainty was done for several reasons:

- Conservation targets used to develop this forecast were based on the 2013 LTEP and were only developed for annual energy consumption. Converting annual energy savings into summer peak-demand savings requires several assumptions regarding load profiles, customer type and end-use of future conservation measures and activities. These additional assumptions all carry associated uncertainties, especially over a 20-year planning horizon.
- Historical achievement of peak-demand conservation targets has varied greatly across different years and programs. The OPA's 2013 Annual Conservation and Demand Management Report, submitted to the OEB in October 2014, showed that while energy targets have been largely successful, only 48% of the 2014 peak-demand target was achieved by the end of 2013. In a follow-up letter to LDCs sent December 17, 2014, the OEB noted that "A large majority of distributors cautioned the Board that they do not expect to meet their peak demand targets," and that, "the Board will not take any compliance action related to distributors who do not meet their peak demand targets."
- Similar higher net growth sensitivity scenarios have been developed for other planning initiatives to manage risk of insufficient power system capacity due to higher underlying growth or lower peak-demand effect of conservation initiatives. This is a practice that has been used successfully within other regional plans and has been used as evidence at rate hearings and other regulatory submissions.

5.5 Distributed Generation Assumed in the Forecast

The effect of existing distributed generation is assumed to be represented in the historical data points used by LDCs to develop their gross demand forecasts. The IESO accounted for future DG projects in cases where a contract was signed, but the project had not yet reached commercial operation as of the peak-demand date used by LDCs to build their forecasts.[7] The in-service date for future DG projects is based on the milestone date for commercial operation listed on the contract.

The IESO applied capacity factors for solar and wind technologies based on the data used in the most recent Methodology to Perform Long Term Assessment. All other generation types are assumed to be fully operational at peak. Based on the May 2013 Long Term Assessment,[8] wind and solar peak capacity factors were assumed at:

- Wind: 13.6%
- Solar: 34.0%

The resulting effective capacity of all new DGs was subtracted from the forecast load at the connecting station, as shown below:

Table 5-3: DG Capacity Assumed by Station

Station	Effective kW
BRAMALEA TS	1,538
GOREWAY TS	2,231
HALTON TS	510
JIM YARROW MTS	697
KLEINBURG TS	420
PLEASANT TS	1,705
TRAFALGAR TS	85
WOODBRIDGE TS	216

5.6 Planning Forecasts

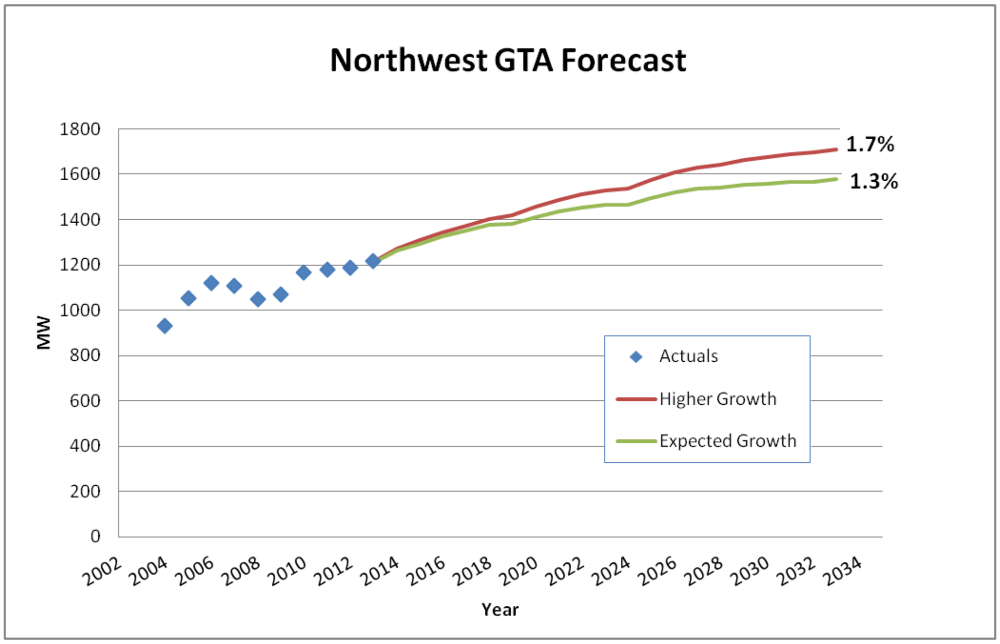
As described above, the IESO developed two planning forecasts:

- an Expected Growth forecast that considered the combined expected impact of conservation and distributed generation by station across the study area
- a Higher Growth forecast that was developed assuming half the peak conservation impact used in the Expected Growth forecast.

[7] For example, if the summer peak of July 17, 2012, was used to build the Gross Forecast and a FIT contract had come into service in September 2012, the contribution of this project would need to be accounted for in the net forecast.
[8] http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2013may.pdf.

The final forecasts were adjusted to account for typical LDC station loading and operational practices. Figure 5-3 shows both planning forecasts, along with historic demand in the area. Annual load by station is provided in Appendix A.

Figure 5-3: Historical Demand and Expected and Higher Growth Forecasts



Under the Expect Growth forecast, growth averages 1.68% per year in the near and medium term, but drops to 0.82% per year for the second decade. For the Higher Growth forecast, growth averages 2.06% per year for the first decade and drops to an average of 1.18% per year for the long term. Over the 20-year planning period, the Expected and Higher Growth forecasts average 1.3% and 1.7% per year, respectively.

6. Needs

Based on the demand forecasts, system capability and application of provincial planning criteria, the Northwest GTA Working Group identified electricity needs in the near-to-medium term and in the long term. This section describes these identified needs, grouped into three major categories: step-down capacity, supply security, and restoration and transmission line capacity. Each section begins with a brief description of the category, including how needs are identified, followed by details on each identified need.

6.1 Step-down 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. Several factors limit the amount of electricity that can be supplied to customers, including a step-down transformer's rating, the number of available distribution feeders and their capacity. These needs are identified by comparing the net station forecast to the ratings of the station's facilities (i.e., transformers and feeders). Where multiple LDCs or customers share electrical capacity at the same station, the amount of effective feeder capacity remaining for each is considered, as this may be a limiting factor. For this reason, if only a limited amount of capacity remains for a transformer, two LDCs may hit their supply limit at different times based on the amount of capacity remaining on their respective feeders.

The table below shows the anticipated years when load at several NW GTA stations is expected to reach installed capacity, based on the Expected Growth forecast and under the Higher Growth forecast.

Table 6-1: Step-down Capacity Need Dates, by Station and LDC

Station	LDC	Expected Growth	Higher growth
Halton 27.6 TS	Halton Hills Hydro	2018	2018
	Milton Hydro	2020	2019
Pleasant 44 kV TS	Hydro One Brampton, Halton Hills Hydro, Hydro One Distribution	2033	2026
Kleinburg 44 kV TS	Hydro One Distribution, Powerstream	--	2033

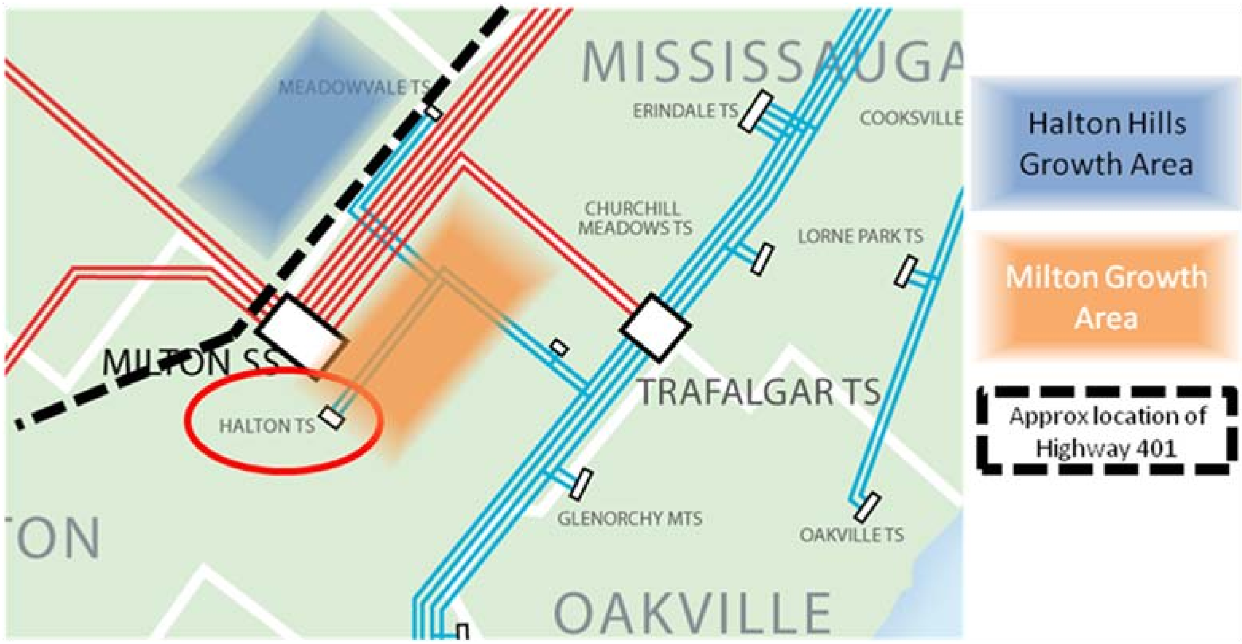
When a step-down station's capacity is reached, options for offloading the limiting station or asset include reducing net growth in the supply area (e.g., through enhanced conservation and/or DG measures), transferring loads through the distribution system to nearby stations with surplus capacity, or building a new step-down supply station to serve incremental growth. Typically, measures to reduce or transfer net demand growth are not able to defer the need for a new station indefinitely, so the cost of these measures must be compared to the value of deferring construction of a new station. These assessments are done by comparing the cost per megawatt of the added capacity provided by the various options.

Additional information on capacity-related needs for the identified stations is provided in the sections below.

6.1.1 Halton 27.6 kV TS

Halton TS is a 207 megavolt ampere ("MVA") capacity 27.6 kV station, with 12 feeders each capable of supplying about 15.5 MW to nearby loads (effective station capacity is therefore approximately 186 MW, based on LDC feeder loading practices). Three feeders are allocated to Halton Hills Hydro and nine to Milton Hydro. The highest peak experienced on this station within the past five years was 166 MW (in 2011), an increase of over 30 MW since 2006. Most recent peaks, namely 2013, were slightly lower as a result of temporary load transfers made by Milton Hydro to a new transformer station (Glenorchy MTS), which is providing temporary relief in the southern part of its service territory.

Figure 6-1: Halton TS and Surrounding Service Territory



Based on current forecasts, remaining capacity on the Halton Hills Hydro supply feeders will be exhausted by 2018. The remaining capacity allocated to Milton Hydro will be exceeded in 2020:

Table 6-2: Halton TS Station Loading by LDC, Expected Demand (in MW)

LDC	Max Capability	2014	2015	2016	2017	2018	2019	2020
Halton Hills Hydro	46.5	33.9	36.9	39.6	44.9	50.0	54.6	58.2
Milton	139.5	92.1	101.0	109.1	118.8	127.8	134.8	141.8

This forecast assumes that Milton Hydro makes full use of available load transfers to nearby stations. However, long-term supply from these adjacent stations is not a preferred option, as Milton's existing and future load centres are located close to Halton TS. Transporting energy through long distribution lines is not efficient, resulting in higher losses and lowering customer reliability. Likewise, near-term Halton Hills load growth is expected close to Halton TS, immediately north of Highway 401, followed by longer-term growth in the south Georgetown area, located approximately 10 km farther north. Figure 6-1, above, shows the existing transmission system assets in the vicinity of Halton TS, the approximate location of the near-term Halton Hills growth area, Milton growth area and Highway 401.

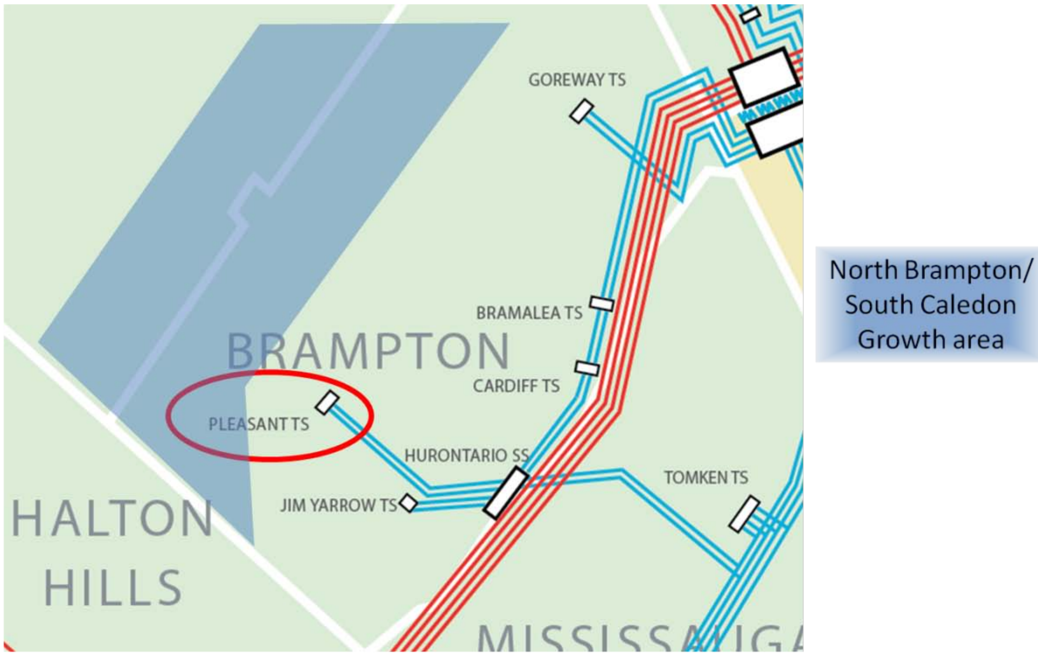
The following constraints must be accounted for when developing options for providing relief to Halton TS:

- **Lack of air rights over Highway 401.** Highway 401 bisects the Halton Hills/Milton growth pocket, with Halton TS (which currently supplies the majority of load in the area) located on the south side along with most of Milton's existing and anticipated customer load. The municipality of Halton Hills is located on the north side of Highway 401 and in the past, has received supply from Halton TS via several distribution feeders spanning over the highway. However, Halton Hills Hydro has informed the IESO that obtaining air rights for additional overhead distribution feeders represents a significant challenge. As an example, the 230 kV TransCanada transmission connection for Halton Hills Hydro GS (located close to Halton TS, but on the north side of Highway 401) was pursued as an undergrounded connection given the associated commercial challenges of spanning over Highway 401. As a result, it is assumed that future feeder crossings will be required to tunnel underneath the highway. The underground option is estimated to cost approximately $2 million per feeder.
- **Distribution voltages.** Step-down stations in the study area provide electrical supply at a voltage of either 27.6 kV or 44 kV. The selection of voltage is based on economics and technical requirements, such as how much electricity customers consume and the distance between major supply points and customer demand. Typically, 27.6 kV service is used for denser urban areas, while 44 kV service is used for rural areas and industrial zones. Almost all growth in the Milton/Halton growth pocket is expected to be served at the 27.6 kV level, which will require supply from a station capable of providing this voltage.
- **Transmission system connection availability and proximity to load centres.** Step-down transformer stations are supplied by high-voltage transmission lines and so must be directly connected to a high voltage circuit capable of providing the incremental forecast demand. To reduce reliance on long distribution lines, step-down stations are typically located close to growth centres.

6.1.2 Pleasant TS (44 kV)

Pleasant TS is a transformer station with two 230/27.6 kV step-down facilities and one 230/44 kV facility. This station is located in northern Brampton and supplies power to northwest Brampton, southwest Caledon and parts of Georgetown.

Figure 6-2: Pleasant TS and Surrounding Growth Areas



While electrical demand on the 27.6 kV system is expected to continue to grow, adequate 27.6 kV capacity is available for supplying the incremental 27.6 kV growth in the Pleasant TS service territory over the long term; however, this is not the case for the 44 kV system. Based on growth forecasts, an alternative supply may be required by 2033. The sensitivity analysis on the need date has shown it is very sensitive to small changes in net growth rates and could potentially move forward several years. For example, under the Higher Growth forecast, the need date is advanced to 2026, as shown in Table 6-3, below.

Table 6-3: Pleasant TS (44 kV) Transformer Capacity Demand in MW (by Need Dates)[9]

	Maximum Capability	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Expected Growth	148.1	138.0	139.9	141.1	141.8	142.0	142.7	143.8	144.7	145.8	148.4
Higher Growth	148.1	144.9	147.3	149.1	150.6	151.6	152.8	154.5	156.2	158.1	161.0

[9] Note that these needs are only related to the capacity of the transformers at Pleasant TS. This station is also potentially limited by the ability of transmission circuits to deliver high-voltage power, as described in Section 6.3.1, below.

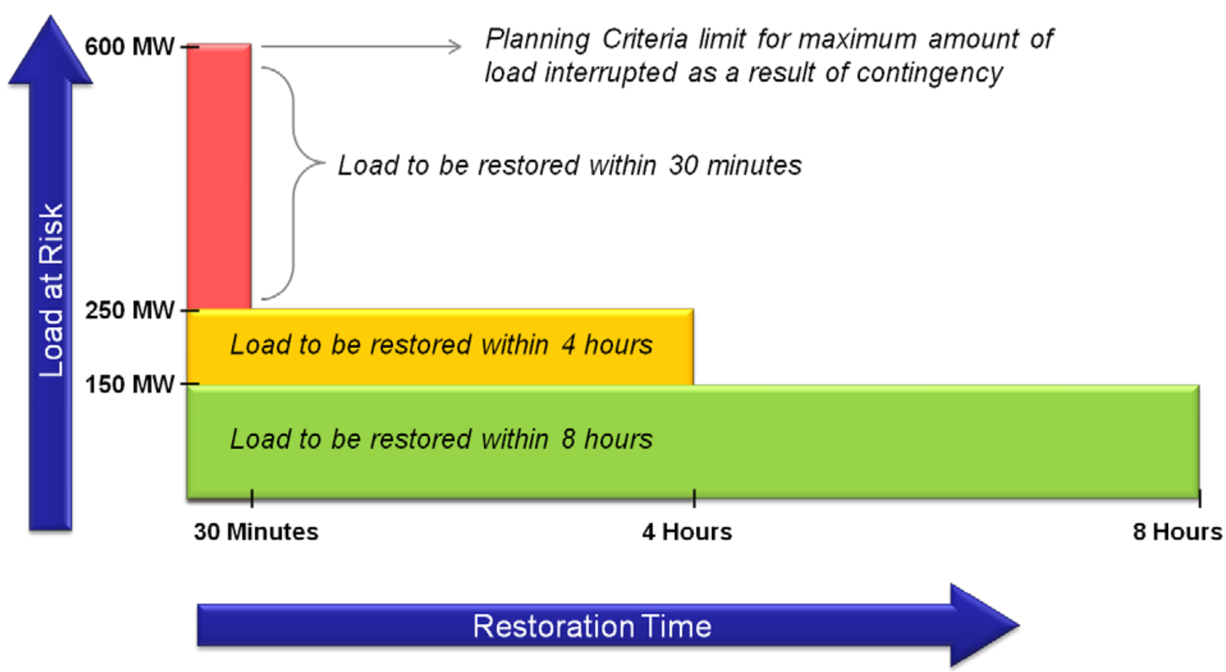
Actual loading on the 44 kV Pleasant TS will need to be reviewed during the next regional planning cycle given that the actual need date may vary from 2033. If new loads cannot be fully offset through conservation and DG initiatives, a new transmission line will be required to enable incremental capacity to be served, since there is no available transmission line capacity in the area that is able to accommodate a new step-down station.

6.2 Supply Security and Restoration Needs

Several areas within the NW GTA study area have been identified as being at risk for not meeting restoration levels as defined in the Ontario Resource and Transmission Assessment Criteria. ORTAC requires that, for the loss of two elements, any load in excess of 250 MW should be restored within 30-minutes and any load in excess of 150 MW should be restored within four hours. The assessment must also consider restoration of all loads within eight hours. These restoration levels are summarized in Figure 6-3, below.

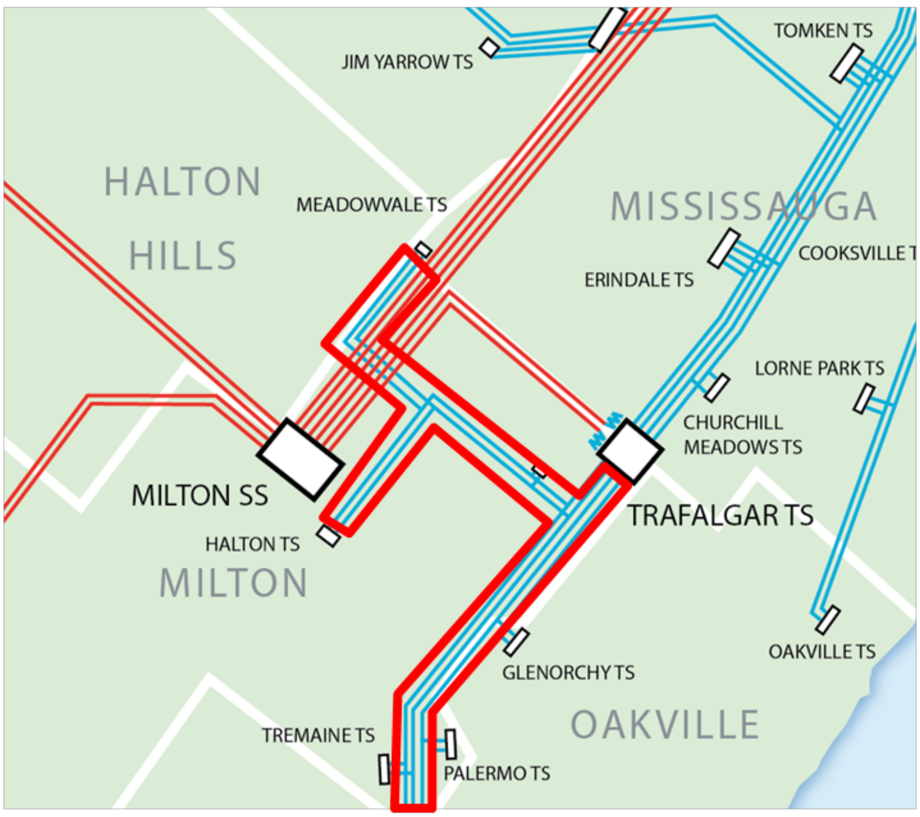
Because NW GTA is a densely populated area, it is assumed that sufficient maintenance and operations workforce are nearby to perform necessary repairs and restore loads within eight hours for expected failure modes. As a result, this analysis will only focus on 30-minute and four-hour restoration capability.

Figure 6-3: ORTAC Load Restoration Criteria



Whenever the loss of two major power system elements has the potential to interrupt over 600 MW of load, the security criteria specified in ORTAC is not met. The IESO analyzed the security and restoration capabilities of the system in the study area by taking the sum of net forecasts from stations that would lose supply following the loss of two major power system elements. In this study area, the security criteria are not expected to be met in 2026 under the Expected Growth forecast for circuits T38/39B. These circuits run from Burlington to Trafalgar TS and supply the stations of Tremaine TS, Trafalgar DESN, Meadowvale TS and Halton TS. These facilities are shown in the following figure:

Figure 6-4: T38/39B and Surrounding Area



Because the majority of these stations serve the northern section of Halton and the transmission is configured in a largely radial path (no redundancy to restore loads through transmission), this area is referred to as the “Halton Radial Pocket.” The table below shows the forecast peak load for this pocket, under the Expected Growth and Higher Growth scenarios:

Table 6-4: Halton Radial Pocket: T38/39B Station Loading (in MW)

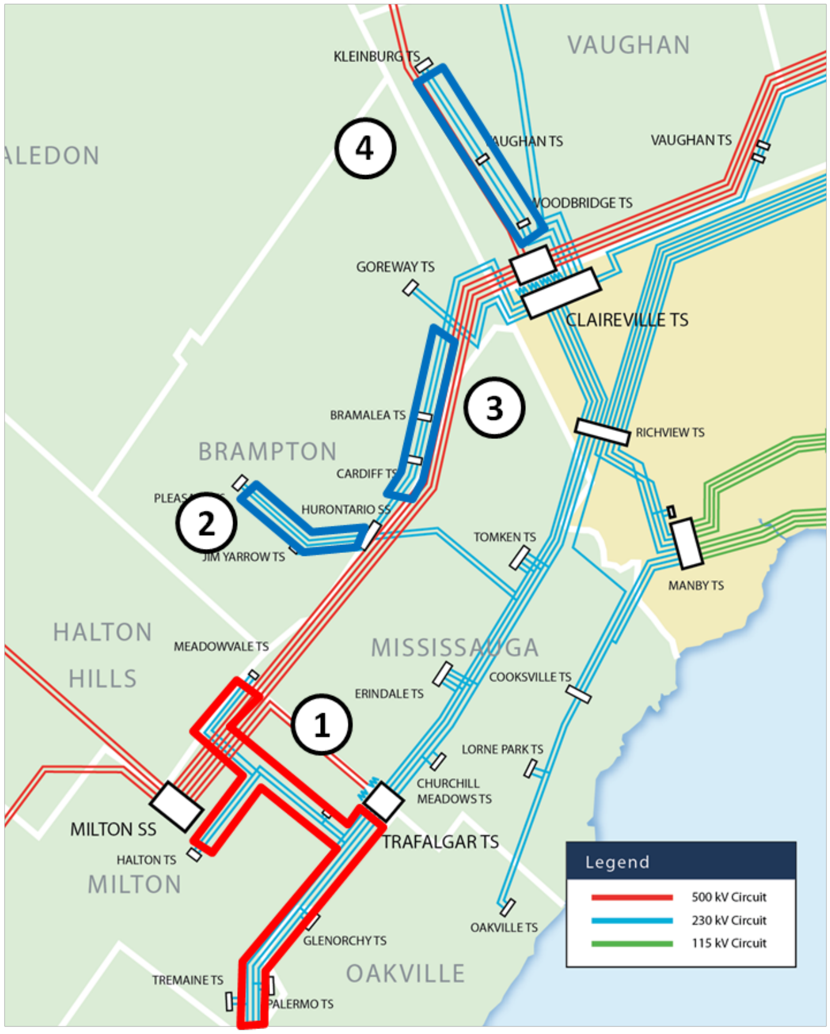
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Expected Growth	432	444	456	472	482	486	492	507	521	574	584	598	610
Higher Growth	435	449	462	478	487	495	510	527	543	599	613	629	645

The analysis performed shows that the Halton Radial Pocket may exceed ORTAC security criteria in the medium term. Given the high initial loads in the area, the need date is only mildly sensitive to assumptions in net growth rates, as demonstrated by a small (two-year) gap between the two scenarios.

Of the remaining restoration criteria, the 30-minute/250 MW restoration point is typically the most limiting, as it largely relies on the availability of remotely controlled equipment rather than manual actions by field operations staff.

Several sections of the study area are currently at risk of being unable to meet the 30-minute restoration criteria associated with loss of two power system elements. This is due in part to the configuration of the transmission system in the area, which relies on long radial circuits to connect northern loads to the more reinforced transmission grid to the south. The areas identified as being at risk for not meeting restoration criteria are shown in blue in Figure 6-5 below, with areas potentially at risk of not meeting security criteria (e.g., Halton Radial Pocket) over the next decade highlighted in red:

Figure 6-5: Areas with Potential Restoration Needs Within the Study Area



The extent of the restoration shortfall depends on the amount of load that can be restored through emergency distribution load transfers following a contingency. LDCs provided estimates of the load-transfer capability currently available to any given step-down station following the loss of transmission supply.

Table 6-5 below shows the forecast load levels and amount of available distribution load-transfer capability within 30-minutes of the loss of station supply for the four load pockets identified as having potential restoration needs. Also included is the restoration shortfall as per the ORTAC criteria. Results are provided for the most recent summer peak and the 2023 forecast under the Expected Growth and Higher Growth assumptions:

Table 6-5: 30-minute Restoration Capability and Needs (in MW)

Load Pockets	2013			2023 Expected Growth		2023 Higher Growth	
	Actual Demand	Available 30-minute Restoration	30-Minute restoration shortfall	Forecast	30-Minute restoration shortfall	Forecast	30-Minute restoration shortfall
1. Halton Radial Pocket: T38/39B Halton TS, Meadowvale TS, Trafalgar DESN TS, Tremaine TS, Halton CGS	409	146	13	574	178	599	203
2. Pleasant Radial Pocket: H29/30 Pleasant TS	354	52	52	398	96	418	116
3. Bramalea/ Cardiff Supply: Bramalea TS, Cardiff TS, Sithe Goreway	438	140	48	447	57	466	76
4. Kleinburg Radial Pocket: V43/44 Kleinburg TS, Vaughan 3 MTS, Woodbridge TS	380	122	8	458	86	467	95

It is also acceptable under ORTAC for distributors and transmitters to agree to a lower level of reliability, where it is agreed that "satisfying the security and restoration criteria on facilities not designated as part of the bulk system is not cost justified."[10] Solutions considered to address restoration needs in NW GTA must ensure that any investment developed to rectify the need

[10] http://www.ieso.ca/imoweb/pubs/marketadmin/imo_req_0041_transmissionassessmentcriteria.pdf

can be economically justified by accounting for the relative cost and benefit from the customer's perspective. This is discussed further in Section 7.1.3.2.

6.3 Transmission Capacity Needs

Transmission capacity needs arise when the electrical demands exceeds the capability of the transmission line to deliver the electrical energy. Facility limitations can manifest as constrained energy carrying capability (often referred to as thermal limitations) or the inability to deliver electrical service at the required power quality (such as voltage levels). These types of needs are triggered by growth in net load at stations within the study area. The Northwest GTA IRRP has identified two areas with potential transmission capacity needs emerging within the next 10 years: H29/30 circuits providing supply to Pleasant TS and T38/39B circuits providing supply to Halton TS, Meadowvale TS, Trafalgar TS and Tremaine TS. These areas and needs are described in greater detail below.

6.3.1 Supply to Pleasant TS

Pleasant TS has three step-down stations located at the same facility in northwest Brampton. Two of the step-down stations output at 27.6 kV and one at 44 kV. Combined, these three stations reached an all-time peak demand of 375 MW in 2012. Although these assets have a maximum rated capacity of 515 MW, the transmission line serving this station (circuits H29/H30) is not capable of supplying this load.

Figure 6-6: H29/30 Supply to Pleasant TS

Based on the assessment carried out as part of the NW GTA IRRP, the maximum carrying capacity of the transmission line to Pleasant TS is approximately 417 MW. Since the need is dependent on the total loading of all three step-down facilities supplied by this line, the actual need date is sensitive to assumptions about the net growth rate. The table below summarizes forecast need dates under the Expected and Higher Growth scenarios:

Table 6-6: H29/30 Circuit Capacity Need Dates, Based on Net Load at Pleasant TS (in MW)

	Maximum loading	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Expected Growth	417	396	398	395	404	408	411	408	409	410	410	411	417
Higher Growth	417	414	418	418	431	439	445	446	449	452	455	458	465

Although the Expected Growth forecast shows a need date of 2033 (in red, above), growth is assumed to be offset by new conservation measures between the years 2026 and 2032, with peak demand stable between 408 MW and 410 MW (shown in orange). Given the risk that the energy-based conservation may not affect peak demand to this extent, it is recommended that solutions be pursued assuming a need date of 2026 for the Expected Growth forecast and 2023 for Higher Growth forecast. This recommended advancement is shown in Figure 6-7:

Figure 6-7: Recommended Advancement of H29/30 Supply to Pleasant TS Need Date

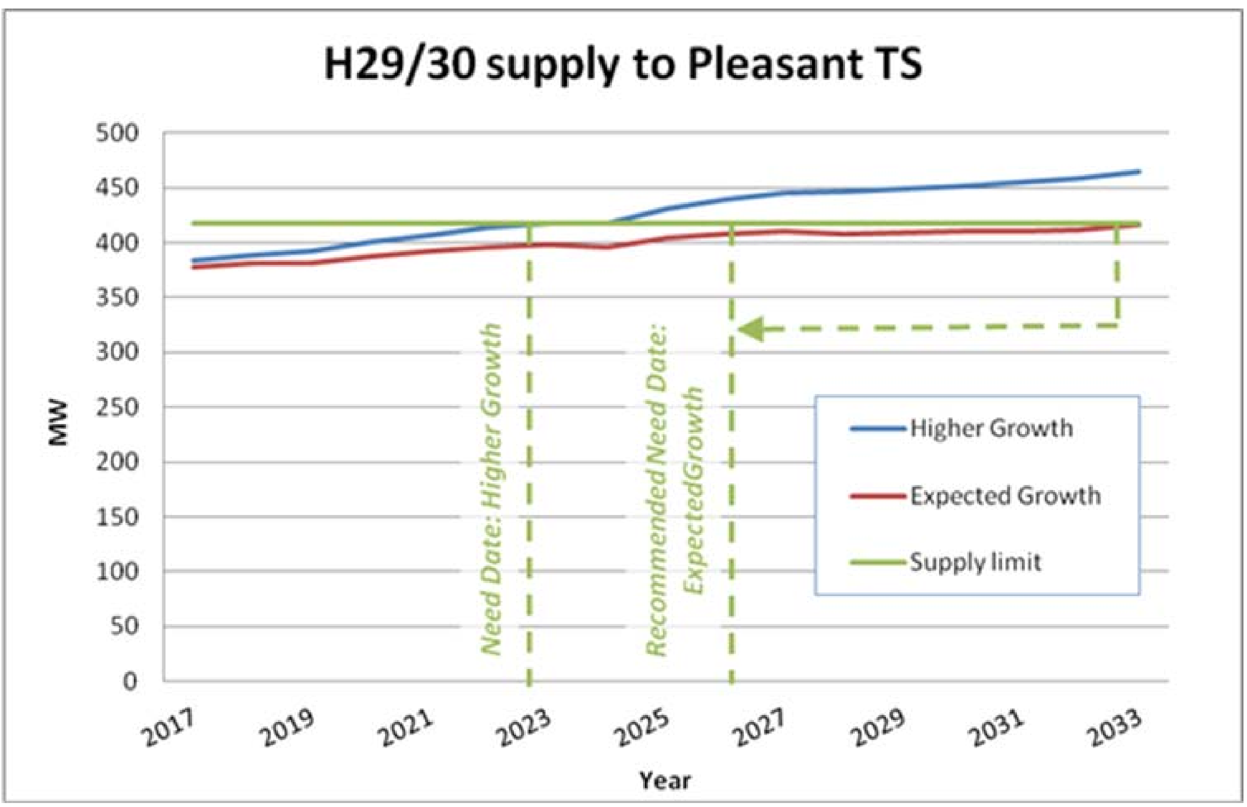


Figure 6-7 also shows that the need date under the Higher Growth forecast is less sensitive to small variations in demand, due to a stronger annual growth rate. As a result, it is not recommended that the need date be advanced under the Higher Growth forecast.

The H29/30 supply need was previously identified in 2007 through the System Impact Assessment ("SIA") for the third step-down station installed at Pleasant TS. The SIA conclusions noted that the supplying transmission lines (circuits H29/30) were expected to hit their thermal limit when the combined Pleasant TS loads hit approximately 408 MW.[11] The SIA required that a plan be put in place to mitigate this issue before load reached 408 MW. A second SIA prepared shortly thereafter for the Hurontario SS to Jim Yarrow MTS 230 kV transmission connection repeated this need, with a revised capacity for the transmission line of 412 MW.[12] Note that small variations in transmission line capability may occur between different studies, due to different assumptions used for running system models (as shown in the difference between H29/30 limits in the two SIAs and this IRRP).

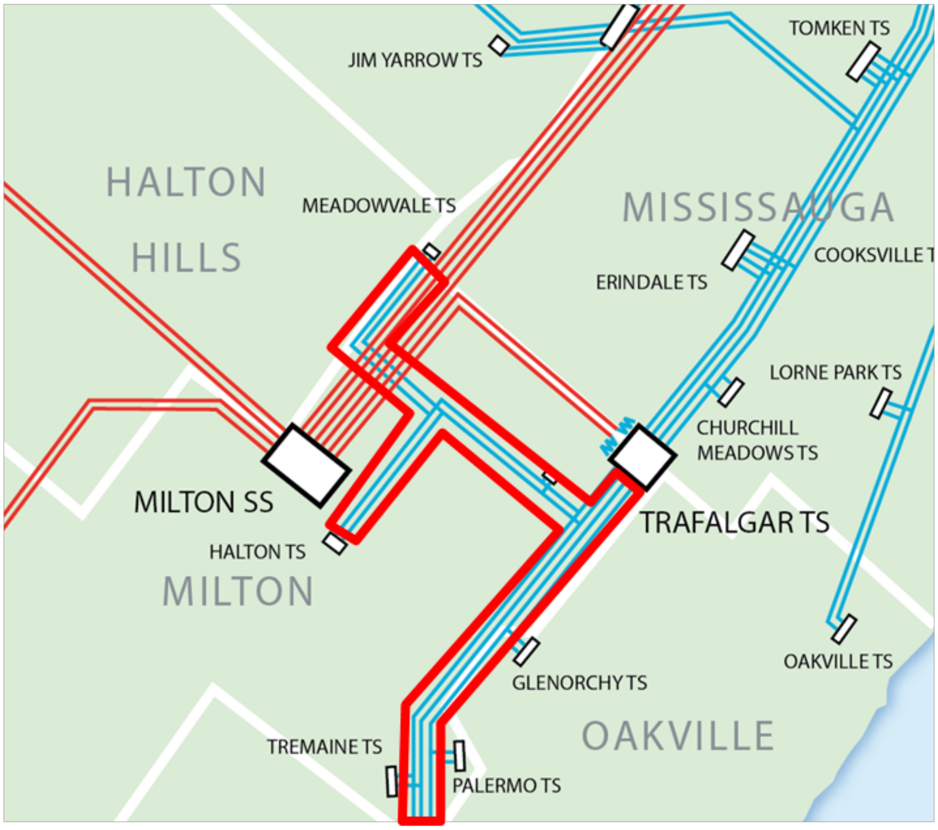
6.3.2 Halton Radial Pocket

A large section of Halton region is currently supplied by two circuits, T38/39B, which span between Burlington TS and Trafalgar TS and contain a long radial section stretching north towards the Town of Milton. The peak load supplied by these two circuits was 410 MW, in 2013, representing the combined loads of Halton TS, Meadowvale TS, Trafalgar TS and Tremaine TS. Growth among these stations is forecast to continue to increase at a net rate of over 3% per year for the coming 10 years. As a result, this area is expected to exceed ORTAC security criteria in the mid-2020s, once total load is above 600 MW (see Section 6.2, above). In addition, there is also a risk of exceeding line capacity (thermal constraints) beginning in the early-to-mid 2020s.

[11] http://www.ieso.ca/Documents/caa/caa_SIAReportFinalDraft_2006-231_R2.pdf.

[12] http://www.ieso.ca/Documents/caa/caa_SIAReportFinalDraft_2006-248_R2.pdf

Figure 6-8: T38/39B Halton Radial Pocket



Following the loss of either T38B or T39B, the companion circuit must be able to supply all the electrical demand of the connected stations. While the capacity to transmit power varies at different sections of the circuit (typical for long and branching circuits), load flows show that potential needs are observed when Halton Hills GS is out of service and the total radial pocket load exceeds approximately 528 MW. Table 6-7 shows the total net forecast demand of all stations supplied by the T38/39B circuits, with potential needs highlighted:

Table 6-7: T38/39B Circuit Loading (in MW)

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Expected Growth	432	444	456	472	482	486	492	507	521
Higher Growth	435	449	462	478	487	495	510	527	543

Overloading on the companion T38/39B circuit can be avoided by running Halton Hills GS, a 620 MW gas-fired power plant, during hours when the total area load exceeds 528 MW. This generation facility is located in southern Halton Hills and, in electrical terms, is at the furthest end of the T38/39B radial pocket. This means that any power output by Halton Hills GS reduces the amount of power transmitted into the area. T38/39B's potential overloading is one of the reasons Halton Hills GS was constructed in this area in 2010.

Due to the presence of local generation, the risk of exceeding the line capacity on T38/39B only occurs when there is a single circuit contingency and Halton Hills GS is unavailable. If either T38B or T39B and local generation are out of service, up to 150 MW of load shedding is permitted to prevent system overloads. ORTAC criteria allow this practice, given the low probability of occurrence. Applying this control action would eliminate the risk of system overloads for the duration of the study period under the Expected Growth forecast and until 2029 under the Higher Growth forecast. To ensure that any load interruptions have a minimal impact on customers, Special Protection Schemes can be designed in advance to ensure that critical loads are not impacted.

6.4 Needs Summary

The NW GTA is a rapidly growing area with an electrical system characterized by heavily loaded radial supply circuits. Within the near-to-medium term, growth is expected to continue northward into greenfield areas, further stressing a radial transmission system that is concentrated to the south. Both step-down stations and the supplying lines are expected to exceed their rated limits within the next decade and will require relief. Additionally, several restoration needs have been identified and will continue to worsen as electrical demand increases, potentially triggering a supply security need in the mid-2020s, when electrical demand in the radial pocket is forecast to exceed 600 MW. In the longer term, significant supply capacity is expected to be needed across a wide range of north Brampton and south Caledon, where no supporting power system infrastructure currently exists.

Table 6-8: Summary of Needs

	Near Term (2014-2018)	Medium Term (2019-2023)	Long Term (2024-2033)
Step-down Station Capacity	Halton TS • Halton Hills Hydro	Halton TS • Milton Hydro	Pleasant TS Kleinburg TS (Higher Growth)
Transmission Capacity	--	Supply to Pleasant TS (Higher Growth)	Supply to Pleasant TS (Expected Growth)
Supply Restoration	Halton Radial Pocket Pleasant Radial Pocket Cardiff/Bramalea supply Kleinburg Radial Pocket	--	--
Supply Security	--	--	Halton Radial Pocket

7. Alternatives for Meeting Near- and Medium-Term Needs

This section describes the alternatives considered in developing the near-term plan for Northwest GTA, provides details of and rationale for the recommended plan, and outlines an implementation plan.

7.1 Alternatives Considered

In developing the near-term plan, the Working Group considered a range of integrated options. The Working Group considered technical feasibility, cost and consistency with long-term needs and options in Northwest GTA when evaluating alternatives. Solutions that maximized the use of existing infrastructure were given priority.

The following sections detail the alternatives considered and comment on their performance in the context of the criteria described above. The alternatives are grouped according to three major solution categories: (1) conservation, (2) local generation and (3) transmission and distribution.

7.1.1 Conservation

Conservation was considered as part of the planning forecast, which includes the local peak-demand effects of the provincial conservation targets (see Section 5.4). Across the planning area, the LTEP energy reduction targets account for approximately 130 MW, or 33% of the forecast demand growth during the first 10 years of the study. Achieving the estimated peak-demand reductions of the provincial conservation targets defers several needs, including transmission line supply to Pleasant TS and Pleasant TS transformer capacity (more details provided below). Given the power system and customer benefits, conservation efforts should focus first on encouraging energy-saving measures that also offset peak demand. Maximizing savings in locations where there is potential to defer longer-term solutions should be a secondary consideration.

Although current LDC conservation targets are based on energy savings, peak-demand savings are required to defer the need for new infrastructure, especially in areas like Northwest GTA where new growth is outstripping the ability of the existing system to meet demand. As part of the Conservation First Framework 2015-2020, all Ontario LDCs are required to produce a conservation and demand management plan by May 1, 2015, outlining how they intend to meet their mandated energy savings targets within their allocated CDM budget.

Details on these plans have been provided by LDCs in Appendix D.

This IRRP will help inform the development and implementation of conservation programs by:

1. Identifying areas in the Northwest GTA where conservation will be most beneficial, and
2. Quantifying the expected benefit of achieving different levels of peak-demand reduction.

The latter is useful for determining whether the incremental cost of targeting peak-demand savings in one particular area is cost effective, given the expected societal benefit from the deferred investment.

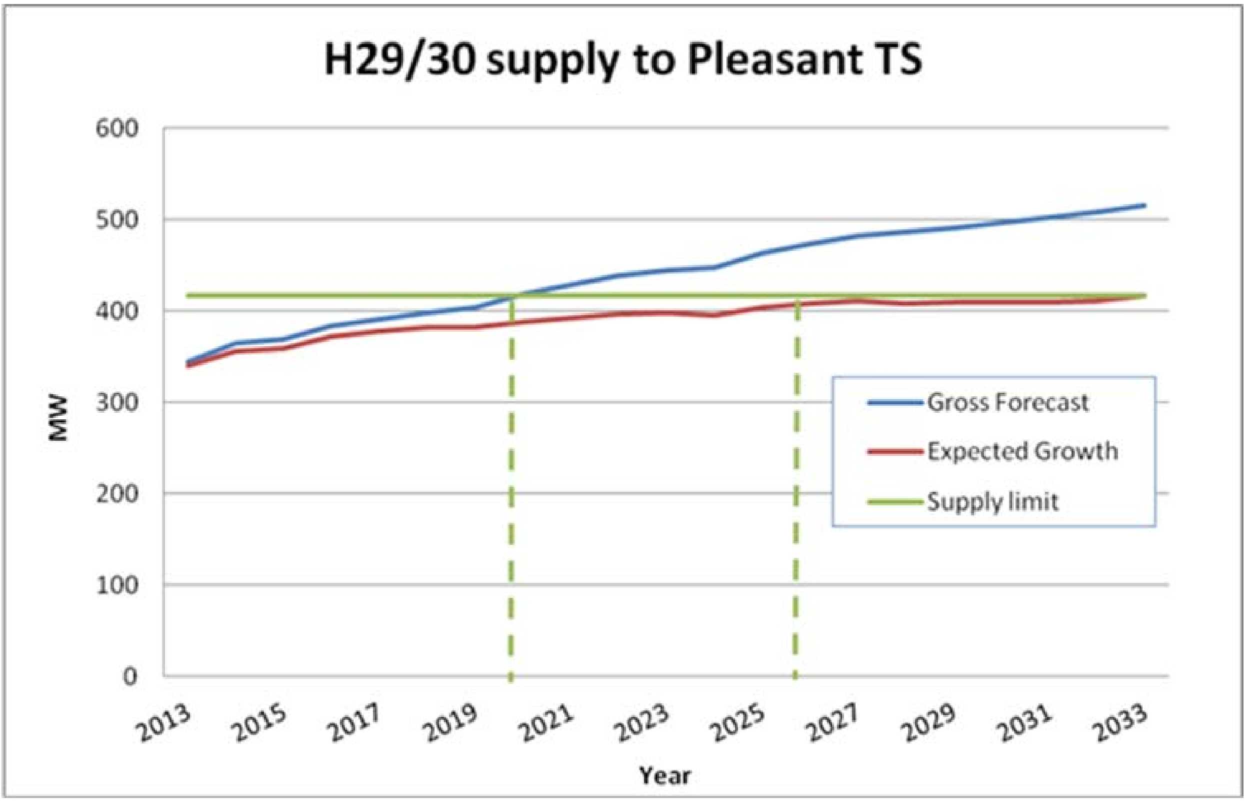
The examples below demonstrate the expected economic benefit from the achievement of the expected peak-demand savings from the LTEP energy reduction targets in two key areas in Northwest GTA: the Pleasant TS and Kleinburg TS service territories. While Pleasant TS and Kleinburg TS have been highlighted, peak-demand reductions will also benefit other parts of the study area, for example, by offsetting the need for distribution expansion. A breakdown of economic assumptions and calculations are provided in Appendix C.

Pleasant TS – Transmission line and step-down transformer needs

Pleasant TS has three step-down stations located at the same facility in northwest Brampton. As mentioned in Sections 6.1.2 and 6.3.1, there are two potential capacity needs associated with this station: (1) limits on the transmission lines that supply electricity to the station and (2) limits on the step-down transformers that convert high voltage electricity from the transmission system to lower voltages for distribution to customers. Both of these needs can be deferred several years by reducing peak demand, as the gap in need dates under the different forecasts demonstrates.

The Expected Growth forecast assumes 65 MW of peak-demand reduction within the Pleasant TS service territory by 2026, primarily from conservation measures. Achieving these reductions successfully defers the need for relief on the H29/30 circuits supplying Pleasant TS by six years, from 2020 to 2026. As described in Section 7.1.3.3, once the capacity limit on H29/30 is reached, these circuits will need to be upgraded to a higher carrying capacity, which is estimated to cost approximately $6.5 million. The expected present day economic value of deferring this investment from 2020 to 2026 is approximately $1.45 million.

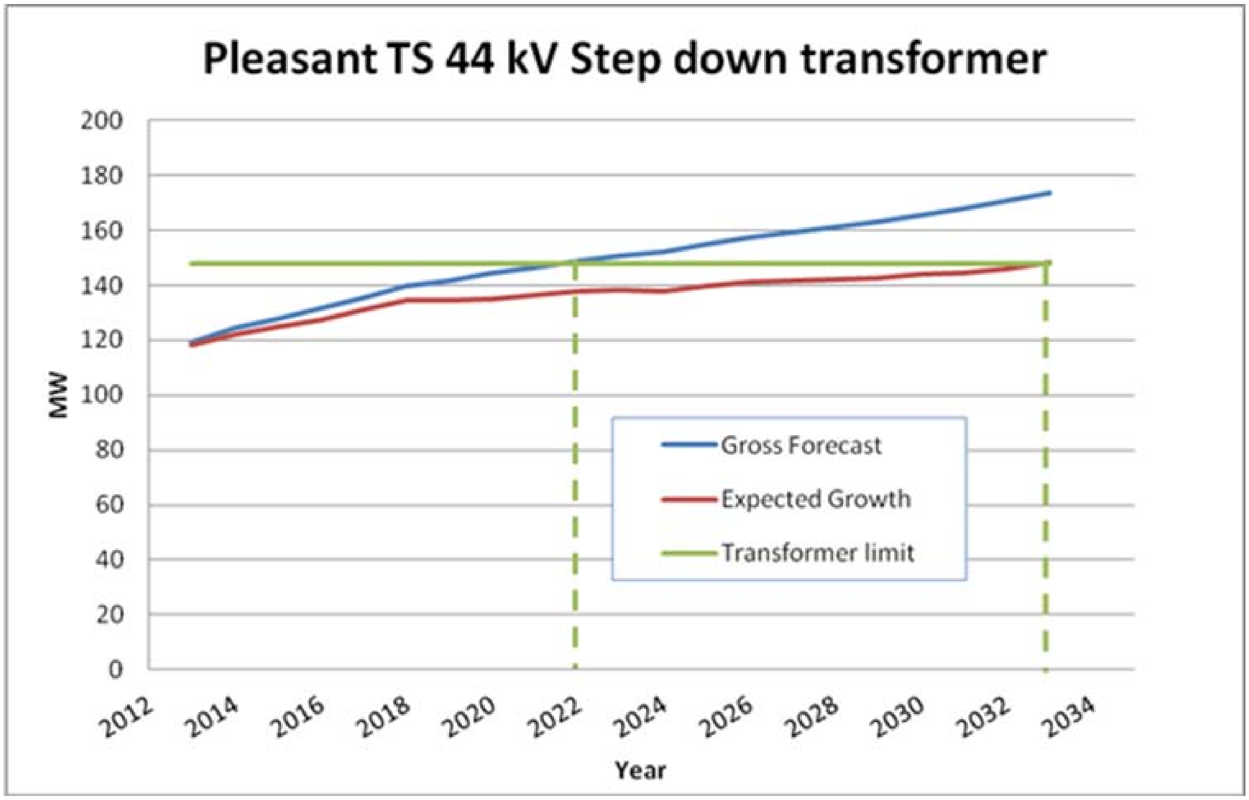
Figure 7-1: Effect of Conservation on H29/30 Needs



Of the three step-down facilities at Pleasant TS, the 44 kV transformers are expected to reach their maximum capacity first. While the LDCs' initial gross extreme weather forecast (the "Gross Forecast") originally anticipated a need date of 2022, the 25 MW of peak-demand reduction applied by the IESO in developing the Expected Growth forecast successfully defers the need for relief by 11 years. Assuming that the H29/30 needs are resolved through other means, such as upgrading the transformers, the expected present day economic value (based strictly on transmission infrastructure deferment) of the peak-demand effects of achieving provincial energy targets is approximately $11.60 million.

Note that this estimate is based only on deferring a $30 million step-down station and does not consider other system upgrades that may be required to ensure the new step-down station has adequate transmission supply. Thus, the actual benefit of deferring is expected to be higher, as new transmission facilities would be required to enable the connection and operation of this step-down station. Long-term supply options are described in greater detail in Section 8.1.1.

Figure 7-2: Effect of Conservation on Pleasant TS 44 kV Transformer Needs

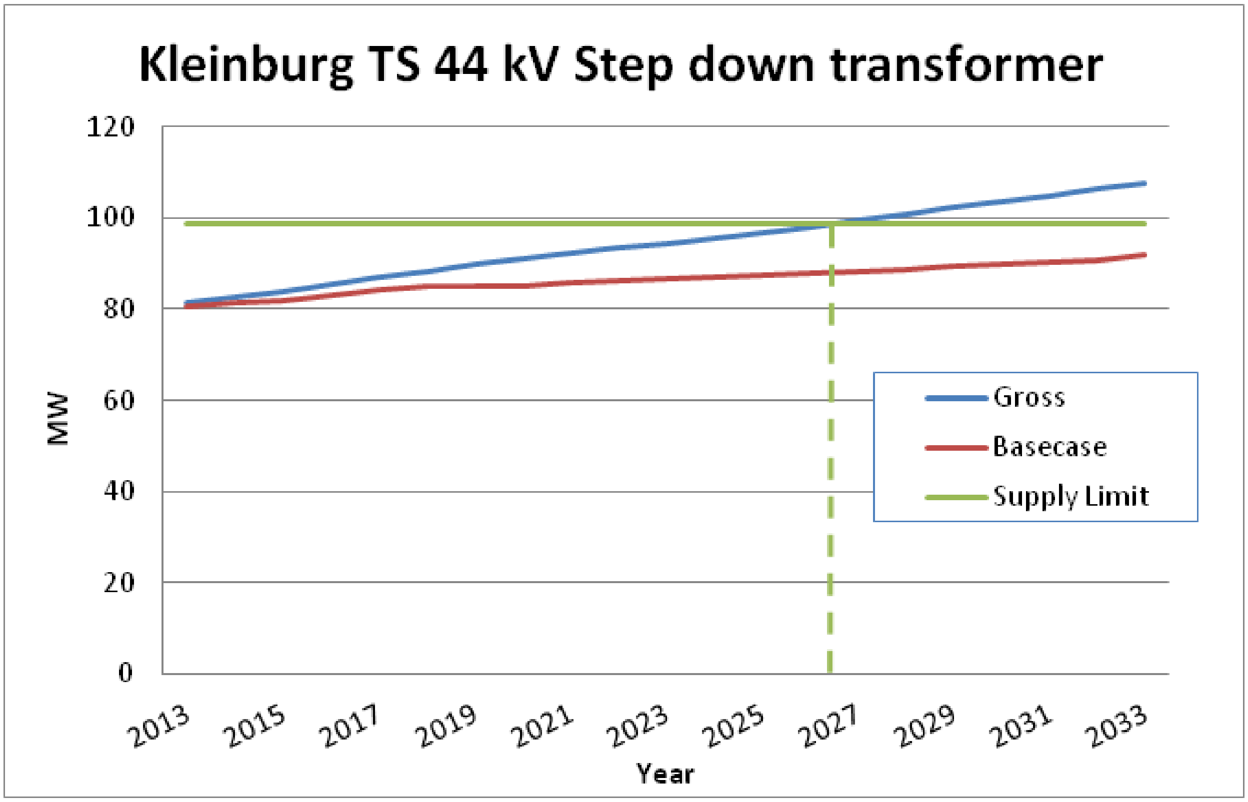


Kleinburg TS – Step-down transformer needs

Kleinburg TS has two step-down stations located at the same facility in northwest Vaughan, close to the boundary with Caledon. The station has a total load serving capacity of approximately 195 MW, shared between 27.6 kV and 44 kV loads. Demand on the station currently peaks at around 130 MW, or about 67% capacity. Load from Kleinburg TS primarily serves Hydro One Distribution customers, particularly in southern Caledon and the town of Bolton, which is expected to drive most new growth over the study period.

Based on the Gross Forecasts provided by LDCs, the 44 kV facilities at Kleinburg TS may hit their limit as early as 2027. In order to defer station overload needs beyond the current planning horizon, 10 MW of peak-demand reduction measures are required. The Expected Growth forecast developed in this IRRP already assumes that conservation programs will provide 15 MW of peak-demand reduction. The expected economic value of the peak-demand effects of achieving provincial energy targets estimated in the Kleinburg 44 kV service territory is approximately $6.53 million, assuming that achieving these targets successfully defers the need for a new $30 million step-down station from 2027 to 2034.

Figure 7-3: Effect of Conservation on Kleinburg TS 44 kV Transformer Needs



Although the Expected Growth forecast does not anticipate that Kleinburg TS (44 kV and 27.6 kV transformers) will reach their capacity limit before the end of the study period, relatively small changes in development levels could have a large effect on this facility's need date, due to the large greenfield areas within the Kleinburg TS service territory and a lack of alternate step-down stations to serve growth. As a result, actual loading on both step-down stations at this facility should be reviewed during the next regional planning cycle and needs revisited as required.

7.1.2 Local Generation

Large, transmission-connected generation and small-scale distribution-connected DG options were ruled out as viable alternatives for meeting near- and medium-term needs in Northwest GTA.

The most pressing near-term needs are associated with low voltage feeder capacity and step-down transformer capacity for Halton Hills Hydro and Milton Hydro (Halton TS). A transmission-connected generation project would not address this need given that the problem is at the distribution voltage level. Distribution-connected DG projects were determined to be technically, logistically and economically infeasible because the DG options would need to be optimally dispersed across a number distribution feeders such that existing feeder capacity is freed up to enable carrying forecast growth in electrical demand across the service territory. Developing and implementing such a complex solution within the time period of the need in this high-growth area was not determined to be practical.

A second set of identified needs for this sub-region are associated with restoration capability in four transmission/restoration pockets, as discussed in Section 6.2. Addressing restoration needs through large transmission-connected generation would require the implementation of a generation facility within Halton radial pocket, Pleasant TS, Cardiff/Bramalea and Kleinburg radial pocket. This solution was determined to be impractical from a technical and economic perspective, given the scale and number of facilities that would therefore be required within the region.

Transmission line capacity to Pleasant TS was also identified as a need in the 2023-2026 time period. Addressing this need through large-scale transmission-connected generation would require the implementation of a major facility in close proximity to Pleasant TS, which is located within a highly developed area of central Brampton. As discussed in Section 7.1.3.3, this need can best be met by upgrading an existing transmission line, with minimal cost and community impact. Since the large scale generation option would cost substantially more than the line upgrade option and result in significantly higher community impact, this option was not considered further.

In addition, because local generation would contribute to the overall generation capacity for the province, the generation capacity situation at the provincial level must be considered. Currently, the province has a surplus of generation capacity, and no new capacity is forecast to be needed until the end of the decade at the earliest. This was an additional consideration in ruling out local generation for meeting the near-term needs.

Small-scale, distributed generation was also rejected as a viable alternative for meeting the transmission line capacity need at Pleasant TS. Existing DG projects have already been accounted for in the forecast and contracted DG projects that are not yet in service have been assumed in the forecast based on their contracted in-service date. These future DG projects were applied by netting their expected contribution at peak load times, in a similar manner as conservation. Meeting the need for transmission line capacity to Pleasant TS through DG was rejected due to the availability of a low-cost, low community impact transmission solution (upgrading an existing line) as discussed in Section 7.1.3.3. This upgrade would be more economic and easier to implement than the option of small scale, DG.

Potential for meeting long-term needs, such as step-down transformer capacity needs at Pleasant TS or Kleinburg TS, will be reviewed as part of regular regional planning cycles closer to these facilities' expected need dates, while actual uptake will be monitored on a yearly basis.

7.1.3 Transmission and Distribution

A number of transmission and distribution, or "wires," alternatives were considered by the Working Group to meet the near-term needs. Wires infrastructure solutions can refer to new or upgraded transmission or distribution system assets, including lines, stations, or related equipment. These solutions are often characterized by high upfront capital costs, but have high reliability over the lifetime of the asset.

7.1.3.1 Halton TS Capacity Relief (Step-down Transformers and LDC Feeders)

There is a near-term need for additional step-down capacity to relieve overloading at Halton TS. Due to the near-term need, a separate product was prepared by the IESO and relevant LDCs concurrent to the IRRP process, to ensure a preferred solution could be identified, discussed and ultimately recommended with as short a lead time as possible. This paper, entitled "Transmission and Distribution Options and Relative Costs for Meeting Near-Term Forecast Electrical Demand within the NW GTA Study Area", is attached in Appendix E and considered three alternatives for meeting this need:

1. Distribution load transfers
2. Single step-down station (with enhanced distribution connections)
3. Two new step-down stations.

The two station solution, further described below, was ultimately recommended as the least costly of the feasible alternatives.

Distribution load Transfers

As an alternative to building new step-down stations to supply growing load in the vicinity of Halton TS, a number of neighbouring stations were considered for their ability to supply local demand through extensions of the low voltage (distribution) feeder network (See Figure 7-4). These options were rejected for the following reasons:

- **Palermo TS**: No remaining capacity is available at this station and as a result this station cannot be considered for providing load-transfer capability.
- **Glenorchy MTS**: This station is located too far south from the anticipated growth centers in Milton (approximately 9 km) to make this a preferable long-term supply option. However, this station can provide valuable flexibility in meeting near-term electrical demand. To minimize costs in the area, Oakville Hydro (the owner and operator of this station) has entered into a short-term leasing agreement with Milton Hydro, allowing Milton Hydro to use up to 40 MW of capacity until the year 2023, after which time Oakville Hydro anticipates requiring this capacity to meet their own growth. The 40 MW of Milton load currently being supplied by Glenorchy MTS will then require a suitable step-down station to provide this supply.
- **Trafalgar TS** (step-down facilities): Although approximately 30 MW of capacity remains at this station, it is approximately 12 km removed from Milton Hydro's growth centre and, as a result, is too far removed to be considered a suitable candidate. However, this station should be considered for meeting any long-term Milton Hydro load growth that may occur in the (currently largely rural) south eastern section of the municipality.
- **Tremaine TS**: This station is too far away to meet anticipated near-term growth in central Milton Hydro territory (the station is approximately 15 km from the growth centre) and, as a result, is not suitable for providing load-transfer capability to relieve Halton TS. Instead, Milton Hydro has been allocated two feeders (approximately 35 MW), which will be used to supply south Milton loads, primarily belonging to lower density and slower-growing customer pockets.
- **Jim Yarrow MTS**: This station is approaching its maximum capacity and is expected to be fully loaded by 2020. As a result, it was not considered a suitable station for transferring Halton TS area loads. Additionally, Jim Yarrow MTS is located too far from anticipated Milton and Halton Hills load centres to provide reliable service at the 27.6 kV level.
- **Pleasant TS**: Any load transfers to this station would advance thermal overloads anticipated on the supplying circuit in the mid-2020s. Additionally, Hydro One Brampton has indicated that new feeder egress is extremely limited and space for accommodating all anticipated feeders to serve Hydro One Brampton has already been obtained, limiting options for supply to other LDCs. Pleasant TS is also located too far

from anticipated Milton and Halton Hills load centres to provide reliable service at the 27.6 kV level. For these reasons, load transfers to Pleasant TS were not considered.

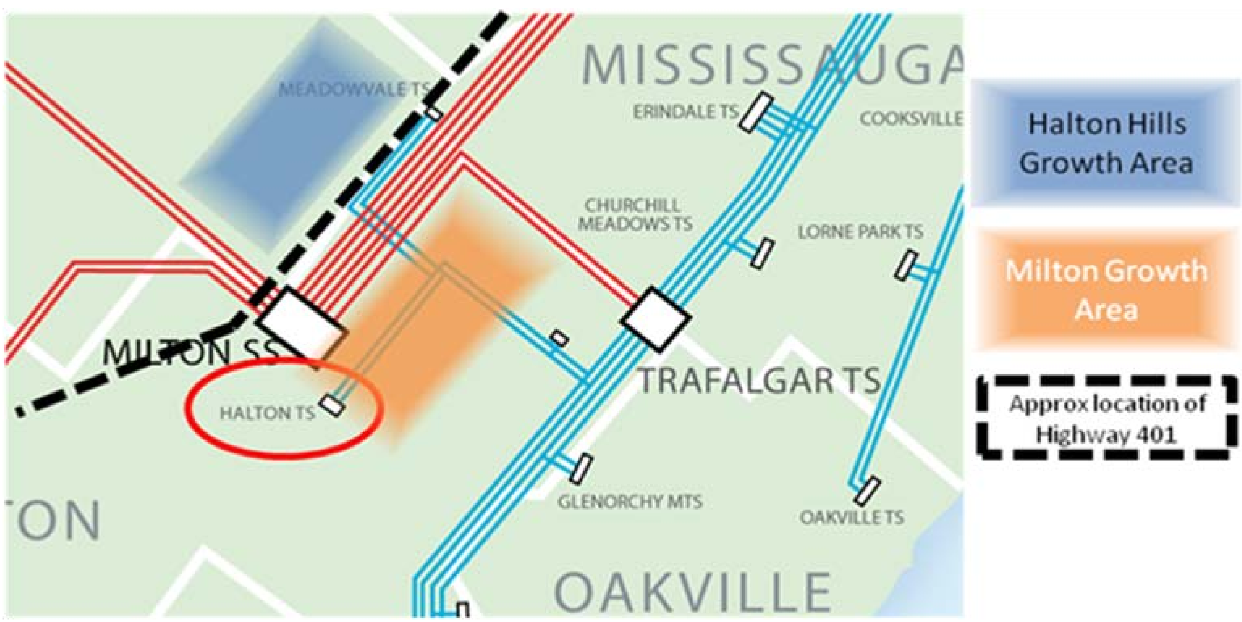
- **Meadowvale TS**: This station outputs at the 44 kV distribution level and so is not suitable for meeting growth currently supplied at the 27.6 kV level from Halton TS.

In addition to the specific reasons mentioned above, all distribution transfer options would require customers to be supplied by longer distribution connections than had they been supplied by a newer, closer station. Longer feeder connections result in poorer reliability, have the potential to trigger power quality issues and will require a greater investment in distribution infrastructure. Due to the unavailability of suitable stations, distribution load transfers were not considered as a potential solution to the Halton TS capacity need.

Single new step-down station (with enhanced distribution connections)

Under this alternative, a single step-down station is constructed on the south side of Highway 401 to meet load growth in both the Halton Hills Hydro and Milton Hydro service territories. Due to the challenges of acquiring air rights over Highway 401, it is assumed that the feeders for serving Halton Hills Hydro customers must be tunneled under the highway at a cost of $2 million per feeder.

Figure 7-4: Halton TS and Nearby Elements



Over the next 20 years, expected load growth in the Halton Hills territory will require the tunneling of eight distribution feeders. Additionally, under the Higher Growth forecast, a single step-down station will not provide sufficient capacity to meet expected long-term load growth in Milton and Halton Hills, so a second station would be required in 2028. As a result, the single station alternative performs poorer under high growth conditions than the two station alternative, as the latter allows the stations to be optimally sited for meeting growth and avoids the need for costly distribution investments.

This alternative also performs poorer than the two station alternative from the perspective of land use, as there would be a greater reliance on distribution infrastructure, especially through the eastern portions of Milton. Using more distribution lines can also contribute to lower customer reliability, as they are more prone to outages than equivalent transmission assets.

Two new step-down stations

This alternative consists of building two new step-down stations: one to provide long-term supply for Halton Hills Hydro loads and a second for Milton Hydro. The Halton Hills Hydro station is required in 2018 and would be located on the north side of Highway 401, while the Milton station, required in 2020, would be located on the south side. This solution eliminates the need to run distribution feeders across Highway 401, which would otherwise present a major technical and financial barrier to integrating a single new station. A suitable location has been found in existing electrical infrastructure facilities for both proposed stations: a new station north of Highway 401 located on the grounds of the TransCanada Halton Hills Gas Generation facility and a new station on the south side located within the existing Milton SS and Halton TS grounds.

After carrying out a net present value cost comparison (summarized in Table 7-1, below), the two station option proved more economic than the single station alternative and was adopted as the recommended outcome for meeting this need. A full list of economic assumptions and methodology is available in Appendix E.

Table 7-1: Cost of Providing Halton TS Capacity Relief, Alternative and Load Growth Scenarios

Alternative	Cost of Alternative, in $M 2014 (Expected Growth)	Cost of Alternative, in $M 2014 (Higher Growth)
Distribution load transfers	Not technically feasible	Not technically feasible
One new step-down station (Halton TS #2, and Halton TS #3 required under Higher Growth forecast)	$51.6	$67.9
Two new step-down stations (Halton Hills Hydro MTS + Halton TS #2)	$48.5	$49.9

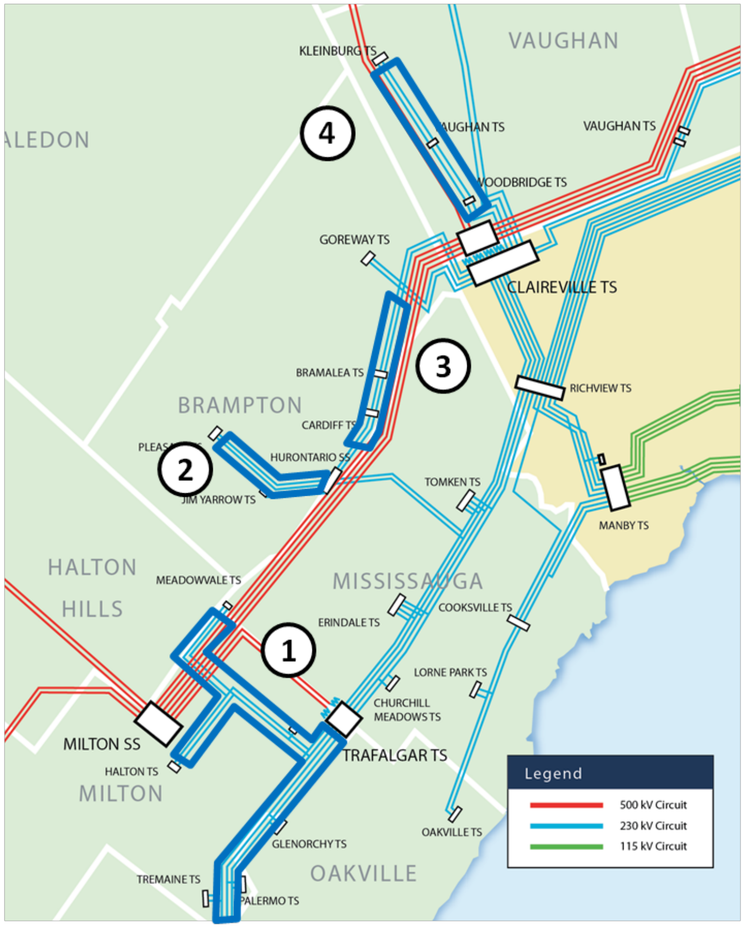
Under the Expected Growth forecast, the cost of a second step-down station is also slightly less when considering the cost of additional feeders, including tunneling, required to supply Halton Hills Hydro loads from a single station located south of Highway 401. As a result, the two station alternative is slightly more economic. Under the Higher Growth forecast, a second station is required regardless, meaning the initial two station solution is much more economic since it eliminates the need for distribution expansion.

7.1.3.2 Restoration needs

As described in Section 6.2, four areas in the Northwest GTA sub-region are at risk for not meeting restoration criteria following the loss of two transmission elements. These are:

1. Halton radial pocket
2. Pleasant radial pocket
3. Bramalea/Cardiff supply
4. Kleinburg radial pocket

Figure 7-5: Areas with Potential Restoration Needs Within the Study Area



Possible infrastructure solutions were investigated and their conclusions discussed below.

Bulk transmission study underway

As described in Section 4.3, a bulk system study is underway for West GTA to address overload issues on the 500 kV and some 230 kV transmission assets in the area. Since the bulk transmission study will investigate major changes to the transmission system that can impact restoration capability, the regional restoration needs for the Halton radial pocket, Bramalea/Cardiff supply and the Kleinburg radial pocket will be factored into the bulk system analysis. If these restoration needs are not adequately addressed through the bulk transmission study, they will be revisited as part of the regional planning process.

Restoration needs for Pleasant TS are not being considered as part of the bulk study, as this pocket is not directly linked to any bulk system assets. The Pleasant TS restoration needs were considered separately as part of this NW GTA IRRP (see below).

Pleasant TS Restoration

Pleasant TS is served by a radial 230 kV two-circuit overhead transmission line that supplies approximately 375 MW of electrical demand during summer peak. The station itself includes three step-down transformers facilities (DESNs): one serving 44 kV distribution loads and two serving 27.6 kV loads. Growth in electricity demand in the area served by this station is expected to increase this demand to 400 MW by 2023 and 415 MW by 2033, the end of the study period. Under the Higher Growth forecast, electrical demand in these same years is forecast at 420 MW and 465 MW, respectively. Table 6-5 summarizes the ORTAC load restoration criteria and the degree to which these criteria are exceeded for the four areas with potential issues, including Pleasant TS. The Pleasant TS restoration need stems from the occurrence of a double circuit outage to the transmission line supplying the transformer station, which is a low probability event.

As mentioned in Section 6.2, the restoration criteria within ORTAC provide flexibility in cases where "satisfying the security and restoration criteria on facilities not designated as part of the bulk system is not cost justified." Since the radial supply facilities to Pleasant TS do not form part of the integrated bulk transmission system, a cost justification assessment was undertaken. Several jurisdictions within the electricity industry take guidance on cost justification for low probability/high-impact events by accounting for the cost risk (probability and consequence) of the failure event and determining if mitigating solutions can reduce the overall cost to customers. This is accomplished by:

1. Assessing the probability of the failure event occurring
2. Estimating the expected magnitude and duration of outages to customers served by the supply lines
3. Monetizing the cost of a supply interruptions to the affected customers
4. Determining the cost of mitigating solutions and their impact on supply interruptions to the affect customers.

If the customer cost impact associated with the mitigating solutions exceeds the cost of customer supply interruptions under the status quo, the mitigating solutions are not considered cost-justified.

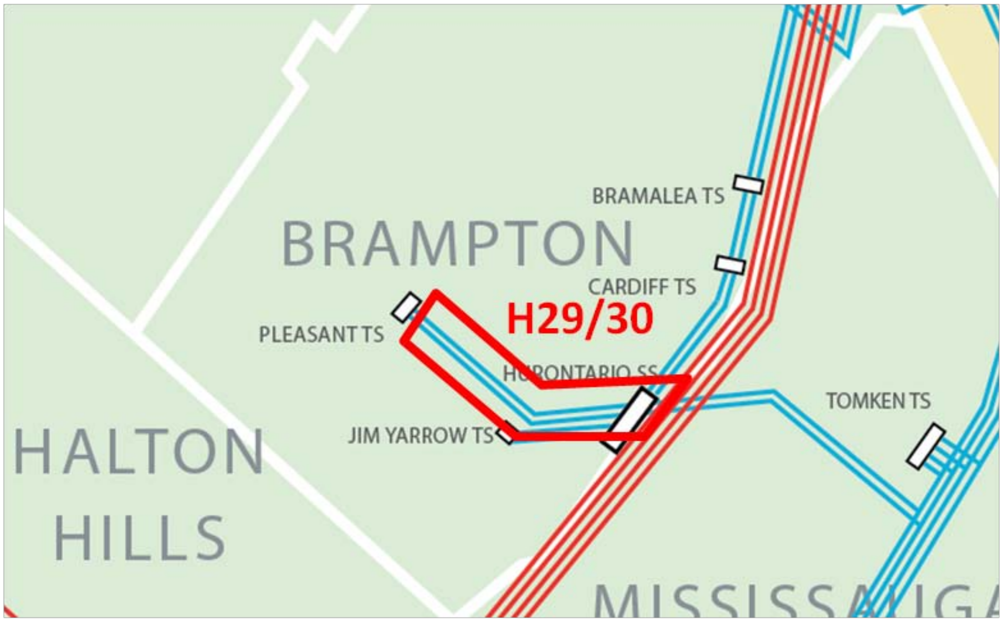
The assessment for the Pleasant TS supply situation found that mitigating solutions were estimated to be significantly more costly to customers in the area than the status quo. This is primarily due to the low probability of the event occurring. As a result, it is not economically prudent to pursue a transmission- or distribution-based solution at this time. Details of this assessment can be found in Appendix C.

The existing long-term forecast indicates that the service area immediately to the north of Pleasant TS is expected to grow substantially over the next 20 years. As described in Section 8.1.1, supplying this long-term growth area will require the introduction of a new transmission supply line and transformer station in the 2026-2033 time period. Once this new supply point is introduced, it is expected that more economic restoration options for the low probability failure event to Pleasant TS would become available. This will be reviewed in updates to this plan.

7.1.3.3 Supply to Pleasant TS

As described in Section 6.3.1, the H29/30 circuits that supply Pleasant TS (shown below) are expected to reach their capacity limit in approximately 2026 under the Expected Growth forecast, or 2023 under the Higher Growth forecast. Conservation and distributed generation can reduce peak demand and defer this need, but a transmission-based solution is expected to be required in the medium to long term.

Figure 7-6: H29/30 Supply to Pleasant TS



Two transmission-based solutions are considered below: upgrading the existing H29/30 circuits to a higher rating and advancing the construction of a new transmission supply path into the area.

Upgrading circuits H29 / 30

The H29/30 circuits supplying Pleasant TS are currently rated at 1090 A,[13] which limits the maximum load-carrying capacity to approximately 417 MW. Based on a preliminary assessment performed by Hydro One, the asset owner, the existing towers are able to support a conductor large enough to carry 1400 A, or supply loads of over 500 MW. Since replacing the conductors would not require changes to the existing tower structures, the estimated preliminary cost of this upgrade is around $6.5 million.

This upgrade would fully address this need and allow the step-down transformer facilities at Pleasant TS to be loaded up to their maximum rated capacity.

Advancement of long-term transmission solution

As described in Section 8.1.1, there is a long-term need for new transmission infrastructure in northern Brampton/southern Caledon. As an alternative to upgrading circuits H29/30,

[13] Summer Long Term Emergency planning rating.

transmission investment could be made earlier to provide an alternative point of supply to serve growing loads in the current Pleasant TS service territory. Note that this option would require limiting the loading at Pleasant TS step-down facilities below their maximum ratings to avoid overloading the supplying circuits.

Based on high level planning estimates for the cost of new transmission infrastructure to supply the area north of Pleasant TS and the need dates from the Expected Growth forecast, the cost of advancing this investment to 2026 from 2033 is approximately $25 million:

Table 7-2: Cost of Advancing West GTA Transmission Corridor, Expected Growth Forecast

Investment	Capital Cost (excludes financing) ($M)	2026 in-service date (2014 $M)	2033 in-service date (2014 $M)
25 km new 2x230 kV transmission	$75	$54.3	$38.2
New step-down transformer	$30	$23.2	$16.3
Reconfigure Kleinburg, other circuit terminations	$10	$7.7	$5.4
TOTAL	**$115**	**$85.3**	**$59.9**
Advancement Cost:			**$25.4**

Under the Higher Growth forecast, this infrastructure is required in 2023 to address overloads on H29/30, a three-year advancement from the 2026 need date if H29/30 were upgraded:

Table 7-3: Cost of Advancing West GTA Transmission Corridor, Higher Growth Forecast

Investment	Capital Cost (excludes financing) ($M)	2023 in service (2014 $M)	2026 in service (2014 $M)
25 km new 2x230 kV transmission	$75	$62.7	$54.3
New step-down transformer	$30	$26.8	$23.2
Reconfigure Kleinburg, other circuit terminations	$10	$8.9	$7.7
TOTAL	**$115**	**$98.5**	**$85.3**
Advancement Cost:			**$13.2**

Based on this assessment, the cost of advancing the need date for a major new transmission corridor is two to four times more costly than upgrading the H29/30 conductors to a higher rating (estimated to be $6.5 million). Therefore, upgrading the H29/30 conductors is the recommended alternative.

Details on economic assumptions used in this analysis are available in Appendix C.

7.2 Recommended Near-Term Plan

The Working Group recommends the actions described below to meet the near-term electricity needs of NW GTA. Successful implementation of this plan will address the region's electricity needs until the early-to-mid 2020s.

7.2.1 Conservation

As achieving demand reductions associated with the conservation targets is a key element of the near-term plan, the Working Group recommends that LDCs' conservation efforts focus on peak-demand reductions. Monitoring conservation success, including measuring peak-demand savings, is an important element of the near-term plan and will lay the foundation for the long-term plan by gauging conservation measures' performance and assessing the potential for further conservation efforts.

Particular attention should be directed to the areas with the highest value conservation potential, namely for reducing peak demand in the service areas supplied by Pleasant TS and, in the longer term, by Kleinburg TS.

Details on each LDC's conservation plan are provided in Appendix D.

7.2.2 Two Station Solution: Halton Hills Hydro MTS and Halton TS #2

Halton Hills Hydro should proceed to gain the necessary approvals to construct, own and operate a new step-down station at the Halton Hills Gas Generation facility. Based on technical and economic analysis, the Working Group believes that building this facility is the least-cost option for serving growth within Halton Hills. Currently analysis recommends a targeted in-service date of 2018.

The Working Group recommends the transmitter, Hydro One, should initiate technical and engineering work for the development of Halton TS #2, at the site of the existing Halton TS, with a tentative in-service date of 2020. Based on the current load forecast and a typical three-year lead time from initiation of approvals to in-service date, construction of Halton TS #2 is not yet required. The Working Group recommends that actual load growth be monitored on an annual basis before a RIP is initiated.

7.2.3 Reinforcement of H29/30

The Working Group recommends the transmitter, Hydro One, should proceed with the preliminary work required to validate the technical, feasibility and cost for the replacement of conductors on the H29/30 circuits to a summer LTE planning rating of 1400 A. It is recommended that this measure be implemented before peak loads at Pleasant TS exceed approximately 417 MW. Based on the current load forecast, this may occur as soon as 2023 under the Higher Growth scenario. The Working Group recommends that actual load growth be reviewed annually and this issue be reassessed during the next iteration of the regional planning cycle.

7.2.4 Restoration Needs

Four pockets in the study area are at risk for not meeting ORTAC restoration criteria. The ongoing bulk system study will consider solutions to address these needs at three of the four pockets. If these restoration needs are not adequately addressed through the bulk transmission study, they will be revisited as part of the regional planning process. The fourth pocket, Pleasant TS, was considered as part of this IRRP; pursuing transmission- or distribution-based solution at this time is not economically prudent. Opportunities will be reassessed in updates to this plan.

7.3 Implementation of Near-Term Plan

To ensure that the near-term electricity needs of Northwest GTA are addressed, it is important that the near-term plan recommendations be implemented in a timely manner. Table 7-4 shows the plan's deliverables, timeframe for implementation and the parties responsible for implementation.

The Northwest GTA Working Group will continue to meet at regular intervals as this IRRP is implemented to monitor developments in the region and to track progress toward these deliverables. In particular, the actions and deliverables in Table 7-4 with estimated timeframes for completion will require annual monitoring of system conditions to determine when projects must be initiated. Preliminary engineering and design work should be initiated at an appropriate time to ensure that the plan can be implemented as required.

Table 7-4: Implementation of Near-Term Plan for Northwest GTA

Recommendation	Action(s)/Deliverable(s)	Lead Responsibility	Timeframe
1. Implement conservation and distributed generation	Develop CDM plans	LDCs	May 2015
	LDC CDM programs implemented	LDCs	2015-2020
	Conduct Evaluation, Measurement and Verification of programs, including peak-demand impacts and provide results to Working Group	LDCs	Annually
	Continue to support provincial distributed generation programs	LDCs/IESO	Ongoing
2. Develop new step-down station in Halton Hills	Design, develop and construct new step-down station in southern Halton Hills, at the Halton Hills GS site	Halton Hills Hydro	In-service spring 2018
3. Develop new step-down station in Milton	Design, develop and construct new step-down station in Milton at the existing Halton TS site	Hydro One	In-service spring 2020 (estimated)
4. Upgrade H29/30 conductors	Upgrade H29/30 circuits to higher rated conductors	Hydro One	2023-2026 (estimated)

8. Options for Meeting Long-Term Needs

The following sections describe various approaches for meeting the long-term electricity needs of Northwest GTA. The purpose in describing different approaches is not to advocate for one over another, but to present the factors that must be balanced when forming long-term electricity plans.

In the case of Northwest GTA, long-term needs are characterized by constraints on a system largely built to the south, while new development continues to expand northward, beyond the existing system's ability to meet new demand. These needs are not limited to the electricity system, as all forms of infrastructure will be challenged to accommodate expanding development. One major infrastructure initiative already underway is the development of the West GTA transportation corridor, led by the Ministry of Transportation. This project is working to identify and secure land for the development of a 400-series highway and transitway extending from Highway 400 (between Kirby Road and King-Vaughan Road) in the east to the Highway 401/407 ETR interchange area in the west, passing along the south Caledon border with Brampton and along the eastern Halton border with Peel.

More information on this project is available at http://www.gta-west.com/.

This proposed route aligns well with the long term electricity infrastructure needs described in this IRRP and provides the opportunity to plan for a transmission corridor in the general vicinity to meet the transmission needs. The coordination of these infrastructure facilities is consistent with the 2014 Provincial Policy Statement ("PPS").[14] The PPS reinforces the link between electricity infrastructure planning and land use planning. It also promotes the efficient and coordinated use of land, resources, infrastructure and public service facilities in Ontario communities. Regardless of the approach pursued to meet long-term electrical demand growth in Northwest GTA, there will remain a long-term need for new transmission infrastructure. Establishing the corridor at this time is recommended due to the unique opportunity provided by the simultaneous planning of the West GTA transportation corridor.

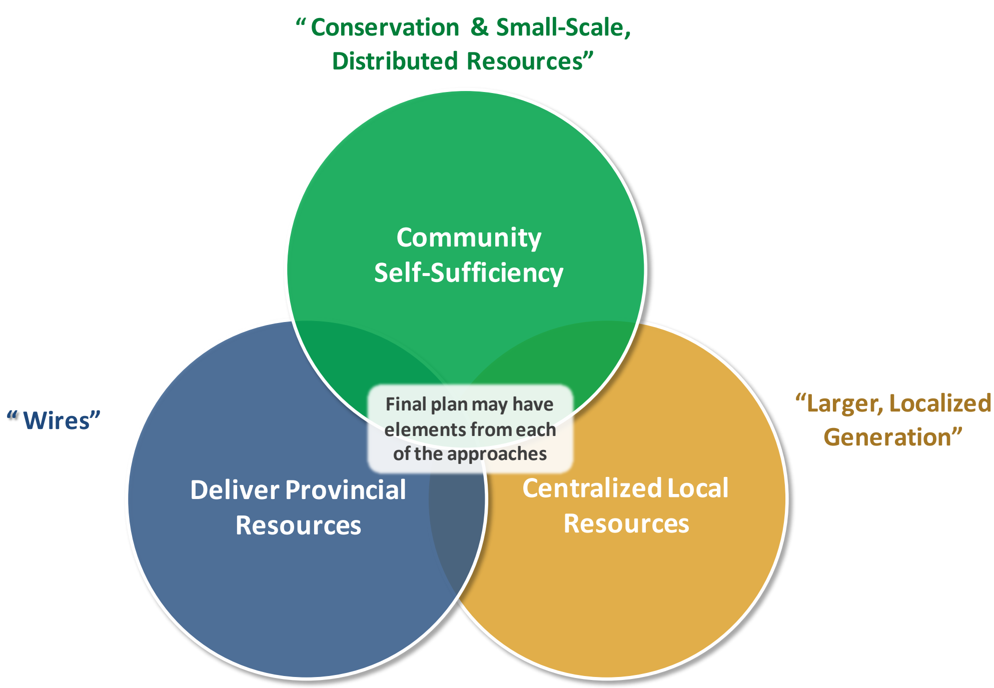
[14] http://www.mah.gov.on.ca/AssetFactory.aspx?did=10463

8.1 Approaches to Meeting Long-Term Needs

In recent years, a number of trends, including technology advances, policy changes supporting distributed generation, greater emphasis on conservation as part of electricity system planning and increasing community interest and desire for involvement in electricity planning and infrastructure siting, are changing the landscape for regional electricity planning. Traditional, "wires"-based approaches to electricity planning, while still technically feasible, may not be the best fit for all communities. New approaches that acknowledge and take advantage of these trends should also be considered.

To facilitate discussions about how a community might plan its future electricity supply, three conceptual approaches for meeting a region's long-term electricity needs provide a useful framework (see Figure 8-1). Based on regional planning experience across the province over the last 10 years, it is clear that different approaches are preferred in different regions, depending on local electricity needs and opportunities and the desired level of involvement by the community in planning and developing its electricity infrastructure.

Figure 8-1: Approaches to Meeting Long-Term Needs



The intent of this framework is to identify which approach is to be emphasized in a particular region. In practice, certain elements of electricity plans will be common to all three approaches and there will necessarily be some overlap between them. For example, provincially mandated conservation targets will be an element in all regional electricity plans, regardless of which planning approach is adopted for a region. In fact, it is likely that all plans will contain some combination of conservation, local generation, transmission and distribution elements. Once a decision on the basic approach is made, the plan is developed around that approach, which affects the relative balance of conservation, generation and "wires" in the plan.

The three approaches are as follows:

- **Delivering provincial resources**, or "wires" planning, is the traditional regional electricity planning approach associated with the development of centralized electric power systems over many decades. This approach involves using transmission and distribution infrastructure to supply a region's electricity needs, taking power from the provincial electricity system. This model takes advantage of generation that is planned at the provincial level, with generation sources typically located remotely from the region. In this approach, utilities (transmitters and distributors) play a lead role in development.
- The **centralized local resources** approach involves developing one or a few large, local generation resources to supply a community. While this approach shares the goal of providing supply locally with the community self-sufficiency approach below, the emphasis is on large central-plant facilities rather than smaller, distributed resources.
- The **community self-sufficiency** approach entails an emphasis on meeting community needs largely with local, distributed resources, which can include: aggressive conservation beyond provincial targets; demand response; distributed generation and storage; smart grid technologies for managing distributed resources; integrated heat/power/process systems; and electric vehicles. While many of these applications are not currently in widespread use, for regions with long-term needs (i.e., 10-20 years in the future) there is an opportunity to develop and test out these options before long-term plan commitment decisions are required. The success of this approach depends on early action to explore potential and develop options and on the local community taking a lead role. This could be through a municipal/community energy planning process, or an LDC or other local entity taking initiative to pursue and develop options.

Details of how these three approaches could be developed to meet the specific long-term needs of Northwest GTA are provided in the following sections.

8.1.1 Delivering Provincial Resources

Under a "wires"-based approach, the traditional approach taken to address regional electricity needs, the long-term needs of Northwest GTA would be met primarily through transmission and distribution system enhancements. Due to the continued northern expansion of urban growth throughout the study area in general and through northern Brampton and southern Caledon in particular, it is anticipated that new transmission infrastructure will be required in this area in the long term. As described earlier, this could be triggered by one of three needs:

- Overloads on the H29/30 circuits providing supply to Pleasant TS
- Overloads on the transformers at Pleasant TS and/or Kleinburg TS and
- Limitations on the distribution network due to distances between transmission supply points (transformer stations) and new end use customers located in northern Brampton and southern Caledon.

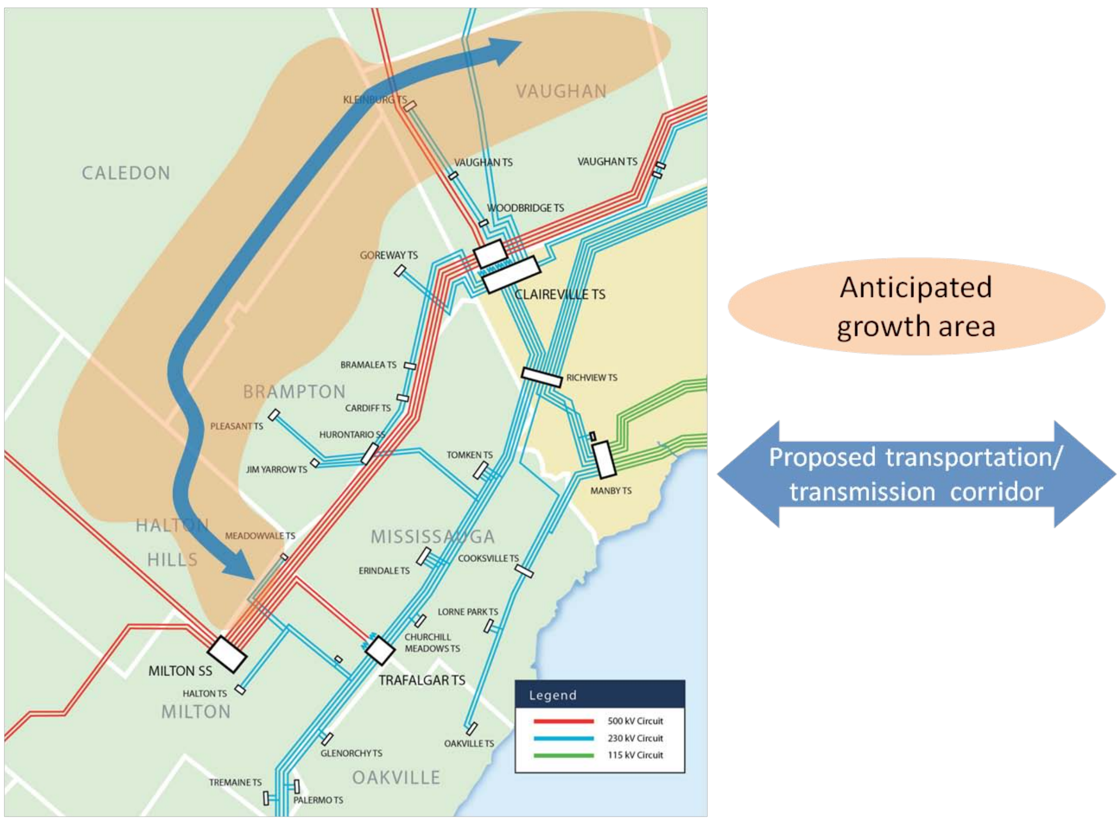
If peak reduction efforts, including conservation and distributed generation, are unable to defer these capacity needs (both circuit and transformer) and distribution solutions such as load transfers prove technically or economically infeasible, a new step-down transformer station will be required in the general northern Brampton/southern Caledon area. Since existing circuits are unable to supply this additional station demand, a new transmission corridor will also be required in this general service area.

In addition to these potential capacity issues, the need for new transmission infrastructure could also be triggered as a result of an inability to provide adequate power quality for new customers located in new development lands in northern Brampton and southern Caledon. These new development lands, shown in Figure 8-2, below, are distant from existing supply points such as Pleasant TS and Goreway TS, resulting in long distribution feeders that impact reliability and voltage performance. Hydro One Brampton has already experienced challenges in providing adequate voltage on the long feeders extending from Pleasant TS and Goreway TS to the existing growth areas in north Brampton. As loads to the north of existing transmission infrastructure develop further, there is a potential for distribution voltage performance to worsen.

When capacity needs arise in the northern Brampton/southern Caledon area, new step-down transformer stations will be required in the general vicinity of anticipated growth to supply new customer loads. Due to a lack of available transmission supply in the area, a new transmission corridor will also be required to provide supply to any future stations.

A suitable location for this future transmission corridor is being assessed in the general vicinity of the proposed West GTA transportation corridor, currently under development by the Ministry of Transportation.[15] The alignment of these infrastructure facilities is consistent with the 2014 PPS.[16] The 2014 PPS reinforces the link between electricity infrastructure planning and land use planning. It also promotes the efficient and coordinated use of land, resources, infrastructure and public service facilities in Ontario communities.

Figure 8-2: Approximate West GTA Transportation Corridor Route and Greenfield Growth Areas



Long-term population projections and development plans are based on the *Places to Grow Growth Plan for the Greater Golden Horseshoe* (2013 consolidated), which projects an additional 473,000 people living in the Peel Region in 2031 than in 2011. The majority of this increase is expected in the northern municipalities of Brampton and Caledon, which collectively estimate a

[15] Up to date information on this project is available at http://www.gta-west.com/.
[16] http://www.mah.gov.on.ca/AssetFactory.aspx?did=10463

population increase of over 360,000 between 2011 and 2031, based on a draft update to the Region of Peel official plan.

Figure 8-2 identifies the area of anticipated greenfield growth throughout Brampton and Caledon, in addition to the neighbouring municipalities of Halton Hills and Vaughan, both of which are also expected to support the West GTA transportation corridor.

Given the location of expected growth and other infrastructure developments in the area, the IESO recommends that a transmission corridor be planned in the vicinity of the proposed West GTA transportation corridor.

8.1.2 Large, Localized Generation

Addressing Northwest GTA's long-term needs primarily with large local generation would require that the size, location and characteristics of local generation facilities be consistent with the needs of the region. As the requirements are for additional capacity during times of peak demand, a large generation solution would need to be capable of being dispatched when needed and to operate at an appropriate capacity factor. This would mean that peaking facilities, such as a single-cycle combustion turbine technology, would be more cost-effective than technologies designed to operate over a wider range of hours, or that are optimized to a host facility's requirements.

Based on the anticipated long-term needs for this area, this type of investment would likely only provide marginal benefit and would not be suitable for meeting capacity-related needs (those expected to trigger the need for new transmission infrastructure). This is because siting any large generator in the areas expected to experience capacity needs would still require the same basic transmission infrastructure to connect this facility to the grid. This means that enabling large, localized generation to meet long-term load growth would also require a duplication of the infrastructure needs described in Section 8.1.1, above, plus the added cost of the generator itself, with little additional benefit to the area.

8.1.3 Community Self-Sufficiency

Addressing the long-term needs of Northwest GTA through a community self-sufficiency approach requires leadership from the community to identify opportunities and implement solutions. As this approach relies to a great degree on emerging technologies, there will be a need to develop and test out solutions to establish their potential and cost-effectiveness, so that they can be appropriately assessed in future regional plans.

One promising tool for identifying and studying emerging technologies in a region is through the development of a municipal energy plan. A municipal energy plan is a comprehensive long-term plan to improve energy efficiency, reduce energy consumption and greenhouse gas emissions. A number of municipalities across the province are undertaking energy plans to better understand their local energy needs, identify opportunities for energy efficiency and clean energy, and develop plans to meet their goals. Municipal energy plans take an integrated approach to energy planning by aligning energy, infrastructure and land use planning. Innovative measures that have been investigated in similar urban settings include:

- Advanced fuel cell technologies
- Advanced storage technologies – particularly in combination with fuel cells
- Aggressive demand response programs – particularly residential and small commercial demand response programs enabled by aggregators
- Aggressive conservation programs targeted at residential consumers and enabled by next-generation home area networks
- Battery electric vehicle storage capabilities, especially for load intensification cluster applications
- Enhanced renewable generation opportunities enabled by next-generation storage technologies
- Micro-grid and micro-generation technologies coupled with next-generation storage technologies
- Combined heat and power opportunities
- Renewed consideration of the load serving entity/aggregator market model

The Working Group recognizes significant risks associated with this strategy, the most crucial being the necessity to successfully meet the growth in electricity demand with new and unproven load management and storage technologies.

Other key risks include demonstrating consumer value, cost recovery certainty for innovative technologies and the associated risk of asset stranding, risk/reward incentives and technological obsolescence as a causal factor for asset replacement.

Given the magnitude of the long-term capacity needs expected throughout northern Brampton, southern Caledon and parts of the neighbouring municipalities of Halton Hills and Vaughan, it is not expected that emerging or innovative technologies will be able to provide a technically feasible alternative to conventional infrastructure in the long term. As a result, it is recommended that while measures could be encouraged where a sound business case is available, a commitment to community self-sufficiency cannot replace the need for acquiring corridor rights for future transmission infrastructure in this area.

8.2 Recommended Actions and Implementation

There is a long-term need to provide electrical service to a significant new development area within the northern Brampton/southern Caledon area. Due to a lack of transmission in this area, new step-down stations cannot be accommodated until additional transmission infrastructure is built. Given the long lead times associated with this type of investment and the benefits of coordinating the planning of linear infrastructure corridors, it is recommended that work continue to establish a corridor for a future transmission near the planned West GTA transportation corridor. Coordinated planning for linear infrastructure corridors is consistent with the direction provided in the PPS. Actual construction of the transmission facilities would not be triggered until the need for the supply path and associated step-down capacity is identified within a near- to medium-term planning horizon. This may occur as a result of the need for additional step-down capacity to relieve existing stations (Pleasant TS and Kleinburg TS), or, as a result of power quality issues on the distribution system that may arise when customer loads are served by long feeders.

In November 2014, the OPA provided a letter to Hydro One supporting the long term need for this project, provided in Appendix F. Based on the analysis described in this letter, it was estimated that growth across these four municipalities will require the availability of new transmission infrastructure to support the increase in electrical demand (beyond the currently available system capacities) of 300-570 MW by 2031 and 570-950 MW by 2041. Given that the timeline is beyond the typical planning horizon for the IRRP and the affected area extends beyond the Northwest GTA, these electrical demand forecasts were based on the Places To Grow official plan and a range of demand per capita coefficients. Even under the most conservative of estimates, growth of this magnitude would require significant new transmission infrastructure to reliably serve new customer demand. As a result, it was recommended that sufficient corridor width be preserved to allow for the economic, safe and reliable construction, operation and maintenance of two double circuit 230 kV lines. The corridor may be required over the next 20 years, depending on the timing and location of the development in the area.

The use of undergrounded transmission lines (cables), as opposed to overhead lines, was not recommended as they are significantly more costly with costs ranging from five to ten times higher. Instead, cables are typically reserved for situations where overhead options are not feasible, such as in densely populated areas with no remaining right-of-way allowances. Identifying and preserving transmission rights-of-way early and well ahead of the forecast need can help electricity customers avoid costs associated with underground cables in the future. Allowing the area to develop without reserving an overhead transmission corridor and attempting to incorporate underground transmission facilities at a later date could result in hundreds of millions of dollars in additional costs when upgrading the system and is inconsistent with the PPS.

The IESO will continue to work with Hydro One and relevant municipal, regional and provincial entities to consider the planning of this long-term strategic asset.

Table 8-1: Summary of Solutions Considered for Near-, Medium- and Long-term Needs

Needs	Conservation	DR	DG	Wires Infrastructure
Near-term Needs				
Halton TS capacity relief	--	--	--	Yes
Restoration	--	--	--	Yes
Medium-term Needs				
Supply to Pleasant TS	Yes	Yes	Yes	Yes
Long-term Needs				
Pleasant TS capacity relief	Yes	Yes	Yes	--
Kleinburg TS capacity relief	Yes	Yes	Yes	--
New northern Brampton/southern Caledon supply	--	--	--	Yes

9. Community, Aboriginal 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 activities undertaken to date for the NW GTA IRRP and those that will take place to discuss the long-term needs identified in the plan and obtain input in the development of options.

A phased community engagement approach has been developed for the NW GTA 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 to determine how to improve the regional planning process, and they are now guiding the IRRP outreach with communities and will ensure this dialogue continues and expands as the plan moves forward.

Figure 9-1: Summary of NW GTA IRRP Community Engagement Process

Creating Transparency:

Creation of NW GTA IRRP Information Resources

- Dedicated NW GTA IRRP webpage created on IESO (former OPA) website providing background information, the IRRP Terms of Reference and listing the Working Group members
- Dedicated webpage added to Hydro One website and information posted on LDC websites
- Self-subscription service established for NW GTA IRRP for subscribers to receive regional specific updates
- Status: complete

Engaging Early and Often:

Municipal, First Nation & Métis Outreach

- Presentation and discussion at three group meetings with municipal planners from across the planning region
- Information provided to First Nation communities who may have an interest in the planning area
- Presentation and discussion with First Nation communities as requested
- Information provided to Métis Nation of Ontario
- Status: initial outreach complete; dialogue to continue

Bringing Communities to the Table:

Broader Community Outreach

- Presentation at Municipal Councils, First Nation community meetings and Métis Nation of Ontario as requested
- Webinar to discuss electricity needs, near-term solutions and formation of a Local Advisory Committee ("LAC")
- Formation of LAC to discuss longer-term options, including new transmission right of way
- Broader community outreach to be undertaken; feedback from this phase on community values and preferences will inform the decisions to be made in the next planning cycle
- Status: beginning in May 2015; no time limit

Creating Transparency

To start the dialogue on the NW GTA IRRP and build transparency in the planning process, a number of information resources were created for the plan. A dedicated webpage was created on the IESO (former OPA) website to provide a map of the regional planning area, information on why the plan was being developed, the Terms of Reference for the IRRP and a listing of the organizations involved was posted on the websites of the Working Group members. A dedicated email subscription service was also established for the NW GTA IRRP where communities and stakeholders could subscribe to receive email updates about the IRRP.

Engaging Early and Often

The first step in the engagement of the NW GTA IRRP was meeting with representatives from the municipalities and First Nation communities in the region. For the municipal meetings, presentations were made to the NW GTA area municipal planners and CAOs at three group meetings held in Halton Hills, Brampton and Milton. The IESO held a separate meeting with representatives of the Six Nations Elected Council.

During these meetings, key topics of discussion involved confirmation of growth projections for the area, addressing near- and medium-terms needs through the development of two new step-down stations, and the recommendation of a future transmission corridor to provide for longer-term capacity needs as a result of continued growth in the northern Brampton, southern Caledon, and Halton Hills area. Invitations to meet to discuss the NW GTA IRRP were also extended to the Mississaugas of the New Credit First Nation and to the Haudenosaunee Confederacy Chiefs Council. The IESO remains committed to responding to any questions or concerns from these communities.

Also discussed was a bulk system study that has been initiated for West GTA to identify and recommend solutions to address emerging bulk transmission system needs, primarily driven by the retirement of Pickering Nuclear GS.

Bringing Communities to the Table

This engagement will begin with a public webinar hosted by the working group to discuss the plan and potential approaches of possible long-term options. Presentations on the NW GTA IRRP will also be made to Municipal Councils and First Nation communities on request.

To further continue the dialogue, a West GTA local advisory committee will be established as an advisory body to the NW GTA Working Group, as well as the broader West GTA Region. The purpose of the committee is to establish a forum for members to be informed of the regional planning processes. Their input and recommendations, information on local priorities, and ideas on the design of community engagement strategies will be considered throughout the engagement, and planning processes. LAC meetings will be open to the public and meeting information will be posted on the IESO website. Note that LACs are formed on a regional basis, and will therefore encompass the entire West GTA planning region, including the municipalities of Mississauga and Oakville, which were not part of the NW GTA IRRP. Information on the formation of the West GTA LAC is available on the NW GTA IRRP main webpage.

Strengthening processes for early and sustained engagement with communities and the public were introduced following an engagement held in 2013 with 1,250 Ontarians on how to enhance regional electricity planning. This feedback resulted in the development of a series of recommendations that were presented to, and subsequently adopted by the Minister of Energy. Further information can be found in the report entitled "Engaging Local Communities in Ontario's Electricity Planning Continuum"[17] available on the IESO website.

Information on outreach activities for the NW GTA IRRP can be found on the IESO website and updates will be sent to all subscribers who have requested updates on the NW GTA IRRP.

[17] http://www.powerauthority.on.ca/stakeholder-engagement/stakeholder-consultation/ontario-Regional-energy-planning-review

10. Conclusion

This report documents an IRRP that has been carried out for NW GTA, a sub-region of the West GTA OEB planning region, and, combined with the planning activities for Southwest GTA, largely fulfils the OEB requirement to conduct regional planning in the West GTA Region.[18] The IRRP identifies electricity needs in the region over the 20-year period from 2014 to 2033, recommends a plan to address near- and medium-term needs and identifies actions to develop alternatives for the long term.

Implementation of the near-term plan is already underway, with the LDCs developing CDM plans consistent with the Conservation First policy and with development work initiated for a new step-down transformer station being developed by Halton Hills Hydro. A transmission solution to address additional capacity needs for Halton TS is required for 2020 under the Expected Growth forecast. This will be planned further by the transmitter through the RIP process. Additionally, the RIP should consider a "wires" solution to address overloading needs on H29/30, with a potential need date of 2023-2026.

To support development of the long-term plan, a number of actions have been identified to develop alternatives, engage with the community and monitor growth in the region. Responsibility has been assigned to appropriate members of the Working Group for these actions. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the IRRP for NW GTA.

The planning process does not end with the publishing of this IRRP. Communities will be engaged in the development of the options for the long term. In addition, the NW GTA Working Group will continue to meet regularly throughout the implementation of the plan to monitor progress and developments in the area and will produce annual update reports that will be posted on the IESO website. Of particular importance, the Working Group will track closely the expected timing of the needs that are forecast to arise in the long term under the Expected Growth forecast. If demand grows as anticipated, it may not be necessary to revisit the plan until 2020, in accordance with the OEB-mandated 5-year schedule. This would allow more time to develop alternatives and to take advantage of advances in technology in the next planning cycle.

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[18] A bulk planning process underway for West GTA will consider the restoration needs described in this report.

Appendix D

Stantec HHH Load Forecast - January 2017

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Load Forecast Report for Halton Hills Hydro 27.6 kV Distribution System

Load Forecast of 27.6kV Distribution System of Halton Hills Hydro Inc.

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January 11, 2017
133560158.200
Revision 1.0

Sign-off Sheet

This document entitled Load Forecast Report for Halton Hills Hydro 27.6 kV Distribution System was prepared by Stantec Consulting Ltd. (“Stantec”) for the account of Halton Hills Hydro Inc. (the “Client”). Any reliance on this document by any third party is strictly prohibited. The material in it reflects Stantec’s professional judgment in light of the scope, schedule and other limitations stated in the document and in the contract between Stantec and the Client. The opinions in the document are based on conditions and information existing at the time the document was published and do not take into account any subsequent changes. In preparing the document, Stantec did not verify information supplied to it by others. Any use which a third party makes of this document is the responsibility of such third party. Such third party agrees that Stantec shall not be responsible for costs or damages of any kind, if any, suffered by it or any other third party as a result of decisions made or actions taken based on this document.

Prepared by ______________________________
(signature)

Amir Tashakori, P.Eng.

Reviewed by ______________________________
(signature)

Mike Voll

Revision Record

Revision	Description	Prepared by		Checked by		Approved by	
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B	Issued for Review	A. Tashakori	AT	M.Boloorchi	MB	M.Voll	12/9/2016
C	Final Report Issue	A. Tashakori	AT	M.Boloorchi	MB	M.Voll	12/20/16
D	Revised Final Report including Client Comments	M.Voll	MV	A.Tashakori	AT	M.Voll	01/11/17

Table of Contents

Executive Summary

This load forecast has been performed for three 27.6 kV feeders, Nos. 41M21, 41M29 and 41M30, out of the Halton 230kV-27.6kV transformer station (TS), which are supplying Halton Hills Hydro's (HHH) southern territory.

Forecasting the load growth on each of the above feeders, has been performed for a 10-year period, starting from 2016, based on the methodology, assumptions, load records and information as described herein.

Because of the effect of the provincially mandated conservation target, a stable load growth rate has been considered for load growth projection during the 10-year study period. Two growth rates have been used to develop the expected growth forecast and higher growth forecast scenarios. The combined expected impact of conservation and distributed generation by station across the study area, has been considered to develop the expected growth forecast. However, for the higher growth forecast, half of the peak-demand reduction due to the conservation target was accounted for in the forecast. In addition, other expected loads, as specified by HHH are added to the calculated load of each year. Planned load growth in Georgetown South (the Vision Georgetown document) is added to the closest feeder (41M30).

Studies show that by 2020, assuming a high load growth forecast, the feeders will be overloaded, as each 27.6 kV feeder can only supply about 15.5 MW to nearby loads, and new feeders will be needed to avoid equipment overloading or load shedding and unwanted service interruption at peak time. This conclusion is valid if load transfer between feeders (e.g. from 41M21 to 41M29 or vice versa or between other feeders) is possible. Otherwise, new feeders are needed earlier when any of the feeders has reached its maximum allowed load, with no (further) possibility of load transfer to other feeders.

Abbreviations

CCAP	Climate Change Action Plan
GHG	Greenhouse Gases
HHH	Halton Hills Hydro (Client)
HONI	Hydro One Networks Inc.
LF	Loss Factor
OPO	Ontario Planning Outlook
PF	Power factor
TS	Transformer/Transmission Station

Glossary

Diversity Factor	The ratio of the sum of the individual non-coincident maximum demands of various subdivisions of the system to the maximum demand of the complete system. The diversity factor is always 1 or greater.
Maximum Demand	The greatest of all the demands that have occurred during a specified period of time; determined by measurement over a prescribed time interval.

1.0 INTRODUCTION

Halton Hills Hydro Inc. (HHH) wishes to develop a load forecast for their distribution system. This report addresses the first section of their system associated with the 27.6kV system.

The goal of this report is to prepare a load forecast for each small area which is supplied by each of the three 27.6 kV feeders, Nos. 41M21, 41M29 and 41M30, out of the Halton 230 kV-27.6kV transformer station (TS), thereby increasing the accuracy of the analysis. The intent is to structure this report in such a way as to facilitate the streamlined integration of other feeder systems in the future.

Total Halton Hills load is around 87MW and almost 35% of it is on the 27.6 kV feeders. Halton TS has 12 feeders and three of them (41M21, 41M29, and 41M 30) belong to HHH. The Halton TS is already expanded to its full capacity and there is not enough space for adding new feeders. The IESO IRRP [6] concludes that by 2018, two new transmission substations are required for serving the future loads in Milton and Halton Hills. Based on the technical and economic considerations, one of stations should be on the north side of the 401 highway (serving Halton Hills), and the other one on the south side of the 401 highway (for serving Milton). In this way, a minimum or no crossing of the highway for distribution lines is expected.

2.0 METHODOLOGY

For the current studies, available historical records on HHH 27.6 kV loads and other load forecasting reports as addressed in the references are analyzed to provide a basis for each feeder's load, load growth rate and annual load increase. Then, with a calculated basis of each feeder load and growth rate, the load for the perspective years, (period of 2017 to 2026) for each feeder is calculated.

The Climate Change Action Plan (CCAP) is very high level and although some of the referenced tables within this report detail a high rate of substitution of gas and oil with electricity, the total load growth rate is still below the calculated growth rate in this report (see Section 4.0). In addition, any significant, referenced loads within the CCAP, such as new transportation electrification facilities, have already been accounted for in this load forecast. For this reason, input from the CCAP does not impact this load forecast.

In this study the following formula is used for load forecasting:

$$Y_n = Y_{n-1} * (1+r_n) + Y_{ne}$$

In which;

Y_n: Load at year n;

Y_{n-1}: Load at year n-1;

r_n: Load growth rate at year n; and

Y_{ne}: Expected load at year n;

Note: The expected load at year n (Y_{ne}), is the load that is not forecasted in the load growth rate calculation. This load (except for the Vision Georgetown anticipated loads), is only considered in the load forecasting with higher growth rate.

3.0 ANALYZING LOAD RECORDS

Table 1 below summarizes the load history received from HHH. Table 1 outlines a maximum demand for each feeder at each year in the period of 2005 to 2016. As shown, for the first five years, the total 27.6 kV distribution system maximum demand is not provided, therefore, diversity factors and load growth rates have only been calculated based on information given for the period of 2010 to 2016. The 2016 maximum demand is calculated from current records since the maximum demand occurs in the summer. Monthly data has been provided under Appendix A.

Table 1 – Maximum Demand for Each Feeder and for 27.6 kV Distribution System within the Period of 2005 to 2016 Based on HHH Historical Data

Year	41M21 (MW)	41M29+ 41M30 (MW)	Total (MW)	Diversity factor
2005	19.9	-	NA	
2006	17.0	18.8	NA	
2007	17.7	8.3	NA	
2008	16.8	17.1	NA	
2009	17.5	25.2	NA	
2010	20.2	18.4	28.5	1.353
2011	19.2	19.0	30.1	1.272
2012	19.6	18.9	30.0	1.282
2013	14.3	20.3	30.9	1.120
2014	17.3	20.8	29.2	1.306
2015	17.7	20.4	29.5	1.293
2016	15.3	26.9	31.4	1.343
Annual Load Growth Rate			**1.65%**	

3.1 NORTHWEST GTA FORECAST

The IESO IRRP [6] states that "Under the Expected Growth forecast, growth averages 1.68% per year in the near and medium term, but drops to 0.82% per year for the second decade. For the Higher Growth forecast, growth averages 2.06% per year for the first decade and drops to an average of 1.18% per year for the long term. Over the 20-year planning period, the Expected and Higher Growth forecasts average 1.3% and 1.7% per year, respectively."

Figure 1 below shows both planning forecasts, along with historic demand in the Northwest greater Toronto Area including the Halton Hills Hydro distribution system.

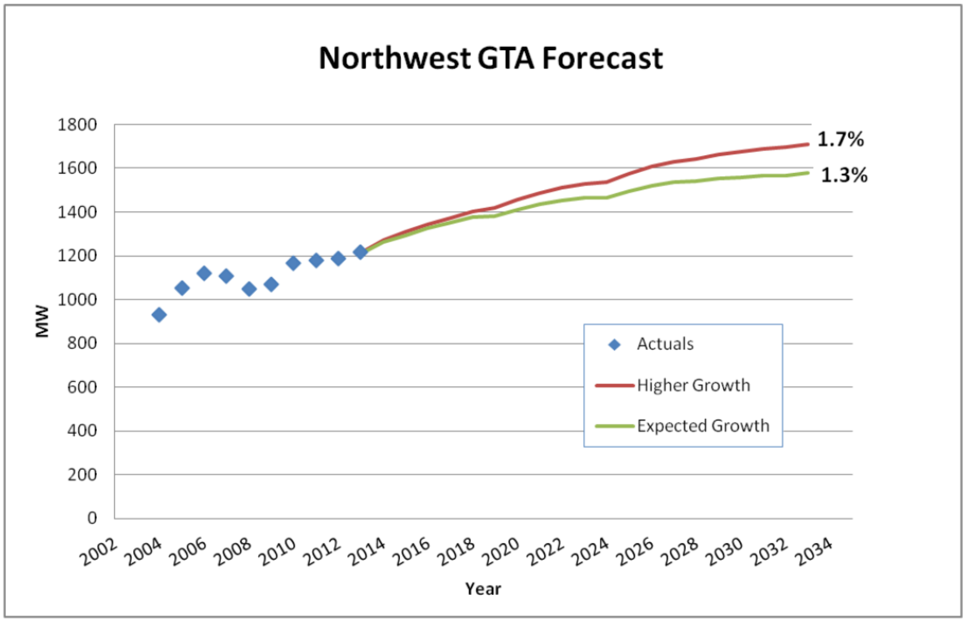

Figure 1 – Historical Demand and Expected and Higher Growth Forecasts from IESO Report [6]

Review and analysis of the information, given in Table 1 above, indicates that:

1. The maximum annual peak demand occurs between July and September.
2. The growth rate of maximum demand during the period of 2010 to 2016 is around 1.65%, based on the maximum demand of 28.5MW at 2010.

The calculated actual load growth rate (1.65%) is comparable to the IESO forecasted expected rate (1.68%). As stated above, as per the IESO IRRP [6], the expected load growth rate and high load growth rate for the mid-term planning period are 1.65% and 2.06%. The mid-term planning period is a ten-year period starting from 2015 [6]. After the mid-term, as per the IESO IRRP [6], there will be a decrease in load growth rate for the years beyond 2025. The maximum demand growth rate, for the mid-term and long-term planning periods, are summarized in Table 2 below and is compared with the calculated maximum demand growth rate for the period of 2010-2016 only.

Table 2 – Load Growth Rate for Different Periods and Scenarios (Mid-Term and Long Term)

Period	2015-2025 Mid-Term(1)	2026-2035 Next Medium-Term(1)	2015-2035 Long-Term(1)	Calculated Growth Rate for 2010-2016
Expected	1.68%	0.82%	1.3%	1.65%
Highest	2.06%	1.18%	1.7%	Not calculated

(1) Reference: Integrated Regional Resource Plan, Northwest Greater Toronto Area Sub-Region, IESO 2015

4.0 ONTARIO CLIMATE CHANGE ACTION PLAN (CCAP)

The purpose of Ontario Climate Change Action Plan is to reduce pollution and Greenhouse Gases (GHG) by reduction of oil and gas usage. Based on this plan, the IESO has conducted studies which are combined with load forecast studies for Ontario to investigate if the IESO-controlled grid has sufficient capacity to supply the new loads. This IESO Ontario Planning Outlook (OPO) [7] report details the target energy consumption (in TWh) which will be required to meet the objectives of the CCAP.

There are four outlooks presented in the IESO report, A through D. Outlook A is related to the minimum increase of electrical load and outlook D is related to the maximum load increase, (maximum energy consumption that will be transferred from oil and gas to electricity). As per Outlook D, which represents the highest increase in electrical load, the maximum energy consumption is forecasted to be 198 TWh by 2035, while it has been 144.5 TWh in 2015. It is expected most of this additional load will be related to heating devices and will be added to the winter load. However, based on the preliminary calculation as given in Table 3 below, the summer maximum demand is still higher than the winter maximum demand, and shall therefore be considered as the annual maximum demand.

Table 3 – 27.6 kV Feeders Load Considering Climate Change Action Plan

Ontario 2015 Load (TWh)	Ontario 2035 Outlook D Load (TWh)	HHH 2035 Load (0.43% of Ontario Load) (TWh)	HHH 2035 Maximum Load, Load Factor =0.7 (MW)	27.6kV Feeders load-35% of Total HHH Load (MW)
144.5	198	0.843	137.4	48.1

5.0 LOAD FORECASTING FOR PERIOD OF 2016 TO 2025

The maximum annual demand of each feeder, for the period of 2010 to 2026, based on the expected growth rate of 1.65% is shown in Table 4 below and based on the higher growth rate of 2.06% is given in Table 5. Please note that both Table 4 and Table 5 include anticipated additional loads in addition to load forecasts associated with Vision Georgetown [3], which is based on an average, linear annual growth rate over the forecasting period.

For the purposes of this assessment, a 27.6 kV feeder is assumed to be at full capacity when it reaches 15.5 MW.

Table 4 – Expected Load Forecast with 1.65% Load Growth Rate and Planned New Loads are in Service

	From	Load statistic-MW							10 years Load Forecast-MW									
		2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Feeder																		
41M21 load including expected load	**Halton TS**	**12.8**	**13.0**	**13.2**	**13.4**	**13.6**	**13.9**	**14.1**	**14.3**	**14.7**	**14.9**	**15.2**	**15.4**	**15.7**	**15.9**	**16.2**	**16.4**	**16.7**
41M21 Base Load Calculation[1]		12.8	13.0	13.2	13.4	13.6	13.9	14.1	14.3	14.6	14.8	15.0	15.3	15.5	15.8	16.1	16.3	16.6
Expected Annual load growth[1]			0.21	0.21	0.22	0.22	0.23	0.23	0.23	0.24	0.24	0.24	0.25	0.25	0.26	0.26	0.27	0.27
Expected new loads										0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108
41M29 load including expected load	**Halton TS**	**8.8**	**9.0**	**9.1**	**9.3**	**9.4**	**9.6**	**9.8**	**11.4**	**11.5**	**11.7**	**11.9**	**12.0**	**12.2**	**12.4**	**12.6**	**12.8**	**12.9**
41M29 Base Load Calculation[1]		8.8	9.0	9.1	9.3	9.4	9.6	9.8	9.9	10.1	10.2	10.4	10.6	10.8	10.9	11.1	11.3	11.5
Expected Annual load growth[1]			0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.19
Expected new loads			0.15	0.15	0.15	0.15	0.16	0.16	0.16	0.16	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.19
41M30 load including expected load	**Halton TS**	**6.9**	**7.0**	**7.1**	**7.2**	**7.3**	**7.5**	**8.6**	**13.4**	**15.7**	**16.4**	**18.8**	**23.6**	**26.4**	**29.3**	**32.1**	**34.9**	**37.7**
41M30 Base Load Calculation[1]		6.9	7.0	7.1	7.2	7.3	7.5	7.6	7.7	7.8	8.0	8.1	8.2	8.4	8.5	8.7	8.8	8.9
Expected Annual load growth[1]			0.11	0.12	0.12	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.15
Expected new loads without Vision Georgetown								1.00	5.68	7.89	8.44	10.69	12.71	12.71	12.71	12.71	12.71	12.71
Vision Georgetown													2.68	5.36	8.04	10.71	13.39	16.07
Total		28.5	29.0	29.4	29.9	30.4	30.9	32.4	39.1	41.9	43.0	45.8	51.1	54.3	57.6	60.8	64.1	67.4

1- Load growth rate 1.65%

Table 5 – High Load Forecast with 2.06% Load Growth Rate and Planned New Loads are in Service

	From	Load statistic-MW							10 years Load Forecast-MW										
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Feeder																		
41M21 load including expected load	**Halton TS**	**12.8**	**13.0**	**13.3**	**13.6**	**13.9**	**14.1**	**14.4**	**14.7**	**15.1**	**15.5**	**15.8**	**16.1**	**16.4**	**16.8**	**17.1**	**17.5**	**17.8**
41M21 Base Load Calculation[1]		12.8	13.0	13.3	13.6	13.9	14.1	14.4	14.7	15.0	15.3	15.7	16.0	16.3	16.7	17.0	17.3	17.7
Expected Annual load growth[1]			0.26	0.27	0.27	0.28	0.29	0.29	0.30	0.30	0.31	0.32	0.32	0.33	0.34	0.34	0.35	0.36
Expected new loads										0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108	0.108
41M29 load including expected load	**Halton TS**	**8.8**	**9.0**	**9.2**	**9.4**	**9.6**	**9.8**	**10.0**	**11.7**	**11.9**	**12.1**	**12.3**	**12.5**	**12.7**	**13.0**	**13.2**	**13.5**	**13.7**
41M29 Base Load Calculation[1]		8.8	9.0	9.2	9.4	9.6	9.8	10.0	10.2	10.4	10.6	10.8	11.1	11.3	11.5	11.8	12.0	12.3
Expected Annual load growth[1]			0.18	0.19	0.19	0.19	0.20	0.20	0.21	0.21	0.21	0.22	0.22	0.23	0.23	0.24	0.24	0.25
Expected new loads									1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45	1.45
41M30 load including expected load	**Halton TS**	**6.9**	**7.0**	**7.2**	**7.3**	**7.5**	**7.6**	**8.8**	**13.6**	**16.0**	**16.7**	**19.1**	**24.0**	**26.9**	**29.7**	**32.6**	**35.4**	**38.3**
41M30 Base Load Calculation[1]		6.9	7.0	7.2	7.3	7.5	7.6	7.8	7.9	8.1	8.3	8.4	8.6	8.8	9.0	9.2	9.3	9.5
Expected Annual load growth[1]			0.14	0.14	0.15	0.15	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.18	0.18	0.18	0.19	0.19
Expected new loads without Vision Georgetown								1.000	5.683	7.893	8.442	10.69	12.71	12.71	12.71	12.71	12.71	12.71
Vision Georgetown													2.679	5.357	8.036	10.71	13.39	16.07
Total		28.5	29.1	29.7	30.3	30.9	31.6	33.2	40.0	43.0	44.2	47.2	52.6	56.0	59.5	62.9	66.4	69.8

1- Load growth rate 2.06%

6.0 CONCLUSIONS AND RECOMMENDATIONS

Preliminary load analysis and load forecast results are presented within Table 1 to Table 5 of this report. The load forecast is done for a 10-year period from 2017 to 2026. Ten years' forecast is considered as a mid-term load forecast.

As shown in Table 5 above, feeder overloading will begin in 2017; however, the addition of new feeders may not be required considering the load transfer capability between the feeders. Nevertheless, this load transfer capability will end by the end of 2019 and the addition of a new feeder will then be needed. This new feeder cannot be provided through expansion of the existing Halton TS #1; as there is no space for further expansion. Therefore, it is essential to have the new Halton TS by the end of 2019 at the latest. This assessment is consistent with Table 6-1 in the IESO IRRP where, for meeting both the Expected and Higher Growth scenarios, a new 27.6 kV step-down station serving Halton Hills Hydro is required, approximately by 2018.

7.0 REFERENCES

[1] HHH_Map_Operators_276k_Oct28_2016_R2.

[2] HHH Historical Loading for Halton TS spreadsheet. (Appendix A)

[3] Vision Georgetown Second Status Update – Phase 2 File D08 VI (Vision Georgetown)

[4] Load Forecast - Engineering Dec 2016 spreadsheet (Appendix B)

[5] Halton_Appl_Exhibit- 2_Rate_Base_Part_2_Distribution_System_Plan_ 20151 (HHH DSP).

[6] NORTHWEST GREATER TORONTO AREA INTEGRATED REGIONAL RESOURCE PLAN, Part of the GTA West Planning Region | April 28, 2015 (IESO IRRP)

[7] Ontario Planning Outlook, a technical report on the electricity system prepared by IESO September 1,2016 (IESO OPO)

[8] Ontario Energy Board HHH 2015 Yearbook

[9] Ontario's Five Year Climate change action plan 2016-2020

APPENDIX A

Halton TS Non-Coincident Peak Data

Stantec

APPENDIX A
HALTON TS NON-COINCIDENT PEAK DATA

Year	Month	M21 (kW)	M29 & M30 (kW)	M21 (MW)	M29 & M30 (MW)	Total (MW)	Diversity Factor
2005	1	12569		19.9	N/A	N/A	
	2	10505					
	3	10547					
	4	9961					
	5	11754					
	6	19470					
	7	19876					
	8	18531					
	9	16766					
	10	13336					
	11	11938					
	12	13547					
2006	1	12039		17.0	18.8	N/A	
	2	12220					
	3	12220					
	4	13416	7196				
	5	15272	7614				
	6	14747	18759				
	7	16974	7796				
	8	13268	7997				
	9	9333	7714				
	10	9920	6967				
	11	10427	3436.59				
	12	11834	3628				
2007	1	11150	3647	17.7	8.3	N/A	
	2	11911	3894				
	3	10607	7036				
	4	9399	7179				
	5	12709	8072				
	6	17736	8338				
	7	17269	8305				
	8	16613	8162				
	9	15740	7859				
	10	13777	7670				
	11	12655	4406				
	12	14139	7705				

APPENDIX A
HALTON TS NON-COINCIDENT PEAK DATA

Year	Month	M21 (kW)	M29 & M30 (kW)	M21 (MW)	M29 & M30 (MW)	Total (MW)	Diversity Factor
2008	1	12277	4227	16.8	17.1	N/A	
	2	12369	5331				
	3	10889	6991				
	4	9479	15214				
	5	9628	8074				
	6	16597	8498				
	7	16821	8546				
	8	15356	8857				
	9	14992	8666				
	10	11030	8658				
	11	14011	5080				
	12	12990	17082				
2009	1	13273	5370	17.5	25.2	N/A	
	2	11801	5351				
	3	10742	25163.97				
	4	9961	8848				
	5	10566	9037				
	6	17181	8942				
	7	12783	9506				
	8	17499	9455				
	9	12525	9262				
	10	10781	9206				
	11	12492	5511				
	12	13832	8830				
2010	1	13070	5783	20.2	18.4	28.5	1.353
	2	12265	6051.07				
	3	11019	9364.61				
	4	10167	9369.99				
	5	17181	9577.28				
	6	19115	9632.73				
	7	20177	9843.35				
	8	17889	10092.41				
	9	12574	11311.95				
	10	10090	9326.1				
	11	11643	5747.26				
	12	5321	18401.33				

APPENDIX A
HALTON TS NON-COINCIDENT PEAK DATA

Year	Month	M21 (kW)	M29 & M30 (kW)	M21 (MW)	M29 & M30 (MW)	Total (MW)	Diversity Factor
2011	1	0	17390.52	19.2	19.0	30.1	1.272
	2	9832	17982.13				
	3	11061	19039.72				
	4	9757	9938.61				
	5	15275	10488.84				
	6	16807	10792				
	7	19229	11428.18				
	8	15868	11212.11				
	9	12207	18939.35				
	10	10605	9831.06				
	11	12322	12430.49				
	12	12754	10123.93				
2012	1	12098	15960.39	19.6	18.9	30.0	1.282
	2	12630	16376.61				
	3	10712	8971.07				
	4	10166	9548.55				
	5	15939.48	16456.39				
	6	18747.7	15533.37				
	7	19560.37	13947.49				
	8	13033.31	14548.21				
	9	12830.36	18862.84				
	10	8457.87	16588.05				
	11	9575.57	11576.78				
	12	10251.92	11046.94				
2013	1	9717.87	8954.72	14.3	20.3	30.9	1.120
	2	9333.01	8342.63				
	3	8849.7	11290.85				
	4	7814.83	17082.68				
	5	11022.26	20319.96				
	6	13392.46	15731.27				
	7	14310.85	17503.37				
	8	12302.06	17081.87				
	9	13240.45	17333.31				
	10	11244.17	13753.65				
	11	9703.96	13497.86				
	12	9950.76	13793.46				

APPENDIX A
HALTON TS NON-COINCIDENT PEAK DATA

Year	Month	M21 (kW)	M29 & M30 (kW)	M21 (MW)	M29 & M30 (MW)	Total (MW)	Diversity Factor
2014	1	9659.04	18128.47	17.3	20.8	29.2	1.306
	2	9028.08	10463.17				
	3	8880.1	13682.56				
	4	7110.23	13339.36				
	5	9785.89	14587.96				
	6	17310.46	15518.23				
	7	17157.82	16483.61				
	8	12064.32	17297.18				
	9	12414.99	17459.62				
	10	7675.92	14249.08				
	11	12702.03	20777.79				
	12	13745.19	11213.94				
2015	1	9116.33	18578.88	17.7	20.4	29.5	1.293
	2	182.83	19572.69				
	3	1008.02	19399.21				
	4	11141.01	19618.02				
	5	17670.6	13082.79				
	6	10805.76	14492.41				
	7	13576.47	16403.37				
	8	13546.53	16322.33				
	9	14583.26	20421.72				
	10	7744.21	18695.73				
	11	8963.28	19064.56				
	12	9240.78	18536.17				
2016	1	9619.74	9685.66	15.3	26.9	31.4	1.343
	2	8802.41	9468.35				
	3	8397.16	12551.15				
	4	8240.88	19181.35				
	5	12319.27	14539.07				
	6	14538.61	26920.07				
	7	14832.44	25791.96				
	8	14539.58	16426.29				
	9	15305.4	17024.98				
	10	7892.03	13665.48				
	11	N/A	N/A				
	12	N/A	N/A				
Annual Load Growth Rate						1.651%	

APPENDIX B

Halton Load Forecast Data

APPENDIX B
HALTON LOAD FORECAST DATA

Load Forecast - Engineering (Dec. 2016)

Development Name	# of Lots	Proposed Feeder	Number of Transformers	Size of Transformation (kW)	Number of Connections	Customer Specified Demand Load (kW)	Estimate Load kW (Low)	Estimate Load kW (Medium)	Estimate Load kW (High)	Connection Date (Estimated)
First Gulf @ Cleve Court	1	41M29	1	2500	1-2	1540	924	1232	1540	2017
Building A - West Bridge Drive			1	1000	1	n/a	750	775	800	2017
Building B - West Bridge Drive			1	2000	1	n/a	1500	1550	1600	2017
Building C - West Bridge Drive	3	41M30	1	3000	1	1900	1425	1472.5	1520	2017
Toronto Premium Outlets	1		3-4	2500-3500	6	n/a	1300	1450	1600	2018
Toronto Premium Outlets	1	41M30	1	750	1	667	500.25	516.925	533.6	2017
Halton Hills Village Phase 5 & 6 (Residential)					50	n/a	125	175	225	2017
Halton Hills Village Phase 5 & 6 (Residential)					91	n/a	227.5	318.5	409.5	2018
Halton Hills Village Phase 5 & 6 (Residential)					122	n/a	305	427	549	2019
Halton Hills Village Phase 5 & 6 (Residential)					141	n/a	352.5	493.5	634.5	2020
Halton Hills Village Phase 5 & 6 (Residential)	649		74	50	169	n/a	422.5	591.5	760.5	2021
Halton Hills Village Phase 5 & 6 (School)	1	41M30	1	300	1	n/a	150	195	240	? (see Note1)
Region of Halton Water Pump Station (Trafalgar Road)	1	41M21	1	150	1	90	72	90	108	2018
Norval Development Area (F4 in HHHI DSP)	300-400	41M30	45-50	50	?	n/a	1200	1560	1920	? (see Note1)
Broccolini, 11400 Steeles Avenue	1	41M30	1	1000	1	1250	750	1000	1250	2016
9 Brigden Gate	1	41M29	1	750	1	274	164.4	219.2	274	2017
29 Brownridge Drive	1	41M30	1	500	1	n/a	375	387.5	400	2017/2018
Premier Gateway Phase 1B	Study phase only. No siginficant land use concepts yet. Potential of commerical development to replace developable lands frozen by MTO for 400 series highway.									
Town Surplus Land (Halton Hills Drive).	?	41M21	?	DSP identifies connection to 27.6kV, Support Trafalgar Road MS Better.						
Vision Georgetown (Residential Lots)	7000	New TS	784	50	7000	n/a	19600	25480	31360	2021-2031
Vision Georgetown (Elementary School)	6	New TS	6	500	6	n/a	1800	2100	2400	2021-2031
Vision Georgetown (High School)	1	New TS	1	1000	1	n/a	600	700	800	2021-2031
Vision Georgetown (Municipal Public Building)	1	New TS	1	500	1	n/a	250	325	400	2021-2031
Vision Georgetown (Grocery Stores)	1	New TS	1	1000	1-2	n/a	500	650	800	2021-2031
Vision Georgetown (Gas Stations)	2	New TS	2	150	1-2	n/a	150	180	210	2021-2031

Revised November 16, 2016 - First Gulf (Cleve Court) and TPO Parking Garage. TPO demand load increased from original estimate, see comments in "Customer specified Demand Load" for both sites.

Revised December 14, 2016 - Modified anticipated connection horizon for highlighted cells. Expanded Halton Hills Village Phase 5 & 6 to 5 years connection horizon and included approximate connection per year based on current information. Estimated load for HHVH Ph 5 & 6 is based on

Note 1: Connection date for load forecasting in current report is considered 2020.

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Appendix E

2015 Town CAO Letter

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TOWN OF
HALTON HILLS
Working Together Working for You!

December 15, 2015

Mr. Arthur Skidmore
President & CEO
Halton Hills Hydro Inc.
43 Alice Street
Acton, Ontario.
L7J 2A9

Re: Vision Georgetown

Dear Mr. Skidmore,

Further to our discussion of Halton Hills Hydro Inc.'s rate application process wherein your Regulator has inquired about the likelihood of Vision Georgetown proceeding, I can confirm that Vision Georgetown is definitely going ahead as per Regional Official Plan Amendment No. 38/ Sustainable Halton. There is an active Vision Georgetown Committee consisting of developers, councillors and Town staff.

It is the Town's expectation that Halton Hills Hydro Inc. will be able to provide the necessary energy needs to Vision Georgetown prior to 2021.

Thank you for your continued efforts and dedication to the community of Halton Hills.

Sincerely,

Brent Marshall
Chief Administrative Officer
Town of Halton Hills

1 Halton Hills Drive, Halton Hills, Ontario L7G 5G2

Tel: 905-873-2601 Toll Free: 1-877-712-2205 Fax: 905-873-2347 Web: www.haltonhills.ca

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