COST ALLOCATION AND RATE POOL REVENUE REQUIREMENT

1.0 INTRODUCTION

This Schedule sets the basis for transmission cost allocation in this Application and provides Hydro One's proposed transmission rates revenue requirement input that is used as an input to determine the Uniform Transmission Rates (UTR).

The remaining schedules of Exhibit H provide further explanation on:

- the cost allocation methodology to functional categories (refer to Exhibit H-01-02);
- the aggregation of functional categories into the Network, Line Connection and Transformation Connection rate pools (refer to Exhibit H-01-03);
- a list of transmission line and station assets by functional category and the allocation factors for dual function lines and generator connections (refer to Exhibit H-02-01 and H-02-02, and Exhibit H-03-01, H-03-02 and H-03-03);
- the allocation of depreciation, return on capital and taxes, and OM&A costs into the rate pools (refer to Exhibit H-04-01, H-04-02, H-04-03, and H-04-04); and
- the allocation of rates revenue requirement to the three rate pools (refer to Exhibit H-05-01).

2.0 SUMMARY

In Hydro One's 2020 to 2022 Transmission Rate Application (EB-2019-0082), the OEB approved Hydro One's methodology to allocate the transmission rates revenue requirement into three rate pools: Network, Line Connection and Transformation Connection. The cost allocation methodology proposed in this Application has not changed from what was approved by the OEB in the Decision and Rate Order in EB-2019-0082.

The revenue required to be collected through transmission rates is based on Hydro One's proposed total transmission revenue requirement as shown in Exhibit D-01-01, offset by Other Revenues consisting of: external revenue, revenue for Meter Service Provider (MSP) services, regulatory assets, export transmission service revenue, and funding for low voltage switchgear (LVSG) credit. This calculation is the same methodology applied and approved in previous OEB proceedings, most recently in EB-2019-0082. The rates revenue requirement calculations for 2023 to 2027 are provided in Table 1.

Table 1 - Rates Revenue Requirement ($ Millions)

	2023	2024	2025	2026	2027
Total Revenue Requirement ($M)[1]	**$1,823.2**	**$1,937.8**	**$2,027.5**	**$2,140.3**	**$2,219.0**
Other Revenues:					
External Revenue ($M)[2]	($40.1)	($36.2)	($36.5)	($36.2)	($37.3)
WMS Revenue ($M)[3]	($0.03)	($0.02)	$0.00	$0.00	$0.00
Regulatory Assets ($M)[4]	$1.1	$1.1	$1.1	$1.1	$1.1
Export Revenues ($M)[5]	($37.4)	($37.1)	($37.3)	($37.2)	($37.2)
Funding for LVSG Credit ($M)[6]	$16.5	$17.5	$18.2	$19.2	$19.8
Rates Revenue Requirement ($M)	**$1,763.3**	**$1,883.1**	**$1,973.1**	**$2,087.2**	**$2,165.5**

[1] Attachments 1 to 5, Exhibit D-01-02; [2] Table 1, Exhibit D-02-01; [3] Table 1, Exhibit H-08-01;
[4] Exhibit G-01-03; [5] Exhibit H-09-01; [6] Table 6, Exhibit H-01-03

Hydro One has allocated the annual transmission rates revenue requirement for 2023 to 2027 into three rate pools: Network, Line Connection and Transformation Connection using the methodologies approved by the OEB in EB-2019-0082. The cost allocation methodologies used in this Application for the cost of service test year, and for the subsequent years of the Custom IR period[1], have not changed from what was approved in EB-2019-0082.

The proposed rates revenue requirement by rate pool for the 2023 test year, and for the following years from 2024 to 2027, are summarized in Table 2. A description and detailed calculations for the allocation of the 2023 rates revenue requirement to the rate pools are provided in Exhibit H-01-03.

The rate pool revenue requirement is Hydro One Transmission's input to the provincial UTRs. The UTRs are collected by the Independent Electricity System Operator (IESO) from market participants who are transmission customers in Ontario.

Table 2 - Summary of Rates Revenue Requirement by Rate Pool ($ Millions)

Year	Network	Line Connection	Transformation Connection	Total
2023	$1,047.9	$184.7	$530.7	$1,763.3
2024	$1,120.2	$197.0	$565.9	$1,883.1
2025	$1,174.5	$206.2	$592.4	$1,973.1
2026	$1,243.2	$217.9	$626.0	$2,087.2
2027	$1,290.5	$226.0	$649.0	$2,165.5

[1] See Exhibit A-04-01 for a description of the 5-year Custom Incentive Rate-Setting approach.

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DESCRIPTION OF TRANSMISSION COST ALLOCATION METHODOLOGY

1.0 INTRODUCTION

Hydro One Transmission's rate base and rates revenue requirement components are described in Exhibit C-01-01 and Exhibit H-01-03, respectively. This Schedule describes the methodology used to allocate these costs into functional categories for the 2023 test year, which is based on cost of service.

The cost allocation methodology described below is the same methodology approved in previous OEB proceedings, and most recently in EB-2019-0082.

2.0 KEY STEPS OF COST ALLOCATION METHODOLOGY

The cost allocation methodology consists of the basic steps identified below:

a) Review OEB decisions that impact cost allocation and rate design.
b) Functionalize assets into the transmission functional categories. The term "transmission functional categories" refers to the groupings to which all physical assets and their associated costs are assigned on the basis of the criteria described in Section 3.
c) Apportion Hydro One's transmission rates revenue requirement components to the functional categories on the basis of direct assignment, to the extent possible. Allocate remaining costs, which cannot be directly assigned, among the functional categories using the previously approved methodology as summarized in Section 4.

The cost allocation activities described by the above steps result in the split of the Hydro One transmission rates revenue requirement by functional category, which is a necessary intermediate step to defining Hydro One's transmission rates revenue requirement by rate pool. Details on the mapping of functional categories to the rate pools are described in Exhibit H-01-03.

3.0 FUNCTIONALIZATION OF ASSETS

A key activity in determining the rates revenue requirement for each rate pool is the process of grouping similar physical assets owned by Hydro One into functional categories. The assignment of functional categories is based on the normal system operating condition of assets in-service as of the end of 2020, with due consideration given to the OEB Decision in Proceeding EB-2011-0043 in regards to the expanded definition of Network assets, the electrical system and customer connectivity, and the load forecast data for the 2023 test year.

A simplified diagram of the basic elements of the transmission system, useful in understanding the assignment of assets to functional categories, is provided in Figure 1.

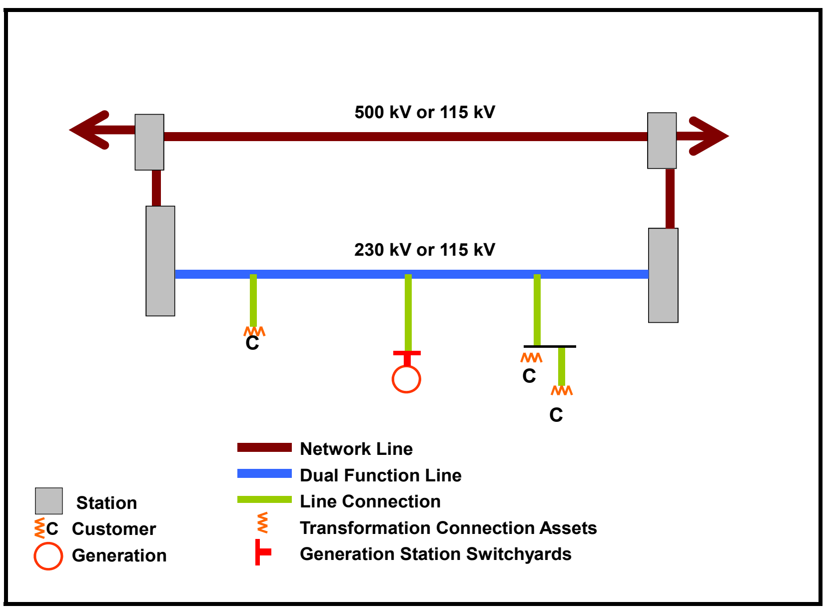

Figure 1: Transmission System Basic Elements

The functional categories to which assets are assigned are Network, Dual Function Line, Line Connection, Transformation Connection, Generation Line and Transformation Connection, Common, and Other. Descriptions of each of these functional categories are provided below.

For the purpose of delineating costs to the rate pools, the asset values for the Dual Function Line (DFL), and the Generation Line and Transformation Connection functional categories are further separated as per the methodology described in Section 3.2 and Section 3.5, respectively.

Listings of all transmission lines and stations, with the functional categories to which they are allocated as described below, are provided in Exhibit H-02-01 and Exhibit H-02-02, respectively.

3.1 NETWORK ASSETS

Hydro One's Network assets are those of its assets that form part of "network facilities" in accordance with the Transmission System Code (TSC) or that form part of assets that the OEB has otherwise deemed to be network facilities. Generally, network assets are designed to provide for the reliability of the integrated transmission system and enhance overall electricity market efficiency, and are comprised of the integrated transmission facilities operating at 500kV or 230kV that link major sources of generation to major load centres.

More particularly, section 2.0.45 of the TSC defines "network facilities" to mean those facilities, other than connection facilities,[1] that form part of a transmission system that are shared by all users, comprised of network stations and the transmission lines connecting them, and has the extended meaning given to it in section 3.0.14. The TSC defines a "network station" as meaning:

(a) any station with one or more of the following:
   i. a 500 kV element, including a 500/230 kV or a 500/115 kV autotransformer;
   ii. a 230 kV or 115 kV element that switches lines that normally operate in parallel with lines that connect transmission stations containing 500 kV elements;
   iii. a 345 kV, 230 kV or 115 kV element that switches a 345 kV, 230 kV or 115 kV line that connects with the transmission system of a neighbouring Ontario transmitter

[1] Connection facilities are described in Section 3.3 and 3.4

or with a transmission system outside Ontario, including a 345/230 kV autotransformer; or

iv. a 345 kV, 230 kV or 115 kV element that switches a 345 kV, 230 kV or 115 kV line that connects interconnection circuits to any network station referred to in any of (i) to (iii) above; and

(b) any station that the OEB has determined should be treated as a network facility in or through a Decision, Order or Decision and Order issued before August 26, 2013, and has the extended meaning given to it in section 3.0.14.

In addition, based on the extended meanings given in section 3.0.14 of the TSC, and subject to section 3.0.15,

a) a "network facility" includes any line that forms part of the physical path between:
   i. two network stations; or
   ii. a network station and the transmission system of a neighbouring Ontario transmitter or a transmission system outside Ontario, such that electricity can be transmitted along the entire path under some operating conditions, which may or may not reflect normal operating conditions; and
b) a "network station" includes any station with one or more of the following:
   i. an element that is greater than 500kV;
   ii. an autotransformer that steps down voltage from a higher transmission level to a lower transmission level;
   iii. a transmission switchyard to which all of the following are connected:
      A. one or more generation facilities with a minimum aggregate installed rated capacity of 250 MW;
      B. one or more load facilities with a minimum aggregate load of 150 MW; and
      C. a minimum of four transmission circuits.

However, section 3.0.15 provides that the extended definitions in section 3.0.14 only apply where the line referred to in 3.0.14(a) or the station referred to in 3.0.14(b):

a) commences to be constructed on or after August 26, 2013; or
b) is expanded or reinforced for the purposes of increasing its capacity, and the expansion or reinforcement (or the expanded or reinforced line or station) commences to be constructed on or after August 26, 2013, regardless of when the line or station was originally placed into service.

Therefore, based on the foregoing definitions from the TSC, Hydro One regards its Network assets as including, but not necessarily being limited to:

- All 500kV circuits and 500/230kV autotransformer facilities.
- All capacitor bank facilities located at transformation or switching stations.
- All 230kV circuits that are not tapped to supply load and that are normally operated in parallel with the 500kV circuit(s); such parallel circuits may be circuit(s) that form a group of transmission circuits that together normally operate in parallel with the 500kV circuit(s).
- All 115kV circuits that are not tapped to supply load and that are normally operated in parallel with network circuits noted above.
- The 230/115kV autotransformer facilities normally connecting the 230kV and 115kV circuits noted above and/or a portion of Dual Function Lines, as described in Section 3.2 below.
- All 230kV and 345kV "interconnection circuits", which are lines connecting Hydro One's transmission system to the transmission systems owned by other transmitters in Ontario and/or by neighbouring jurisdictions.
- All 230kV circuits that are not tapped to supply load and that are normally operated in such a manner that they connect the "interconnection circuits", directly or through a group of transmission circuits, to any of the 500kV and 230kV network circuits noted above.

- The specific sections of 115kV circuits that interconnect with transmission systems owned by other transmitters in Ontario and/or by the neighbouring jurisdictions, beginning from the junction or station from/at which Hydro One Transmission's customer load is supplied up to the border of the other transmitters system.
- The transformation or switching stations, or portions thereof, including the circuit breakers and associated assets that switch the network circuits and the Dual Function Lines described in Section 3.2 below.

3.2 DUAL FUNCTION LINE ASSETS

Transmission circuits that provide both Network and Line Connection functions are classified as Dual Function Line (DFL) assets for cost allocation purposes. More specifically, DFL assets are used for both the common benefit of all customers, and for providing a connection between a network station and load supply point(s) for one or more customers.

The transmission circuits comprising the following types of electrical assets are assigned to the DFL functional category of assets:

- All 230kV and 115kV circuits that are tapped to supply load and that are normally operated in parallel with the 500kV circuit(s); such parallel circuits may be circuit(s) that form a group of transmission circuits that together normally operate in parallel with the 500kV circuit(s).
- All 115kV circuits that are tapped to supply load and that are normally operated in parallel with network circuits or Dual Function Lines noted above.
- All 230kV circuits that are tapped to supply load and that are normally operated in such a manner that they connect the "interconnection circuits", directly or through a group of transmission circuits, to any of the 500kV and 230kV network circuits noted above.
- A "local loop" under the condition that an existing Line Connection has been reconfigured to create a new independent delivery path emanating from one network station and ending uninterrupted at another network station, and where the transfer capacity

between these two existing network stations has been increased thereby providing a network benefit.

For cost allocation purposes, the value of each DFL is split between the Network and Line Connection functions of each asset using the methodology approved by the OEB in Proceeding EB-2019-0082. The customer load connected to the DFL (DFL Customer Demand) and the minimum of the average of summer and winter transmission capacity of the DFL (Minimum DFL Capacity) are used to allocate the DFL asset value between the Network and Line Connection functions as follows:

Line Connection Portion of DFL:

$$\text{Proportion Allocated to the Line Connection Portion of DFL} = \frac{\text{Average Monthly DFL Customer Demand}}{\text{Minimum DFL Capacity}}$$

Network Portion of DFL:

$$\text{Proportion Allocated to the Network Portion of DFL} = 1 - \text{Proportion Allocated to the Line Connection Portion of DFL}$$

The DFL Customer Demand is the total of the allocated portion of each customers' average forecast monthly coincident peak demand that is associated with the DFL asset. Hydro One considers this an appropriate allocator as it reflects the load diversity inherent in the use of a DFL.

Exhibit H-03-01 lists the DFLs and the corresponding proportions of asset value that are allocated to the Network and Line Connection portions of the DFL functional categories.

3.3 LINE CONNECTION ASSETS

Hydro One's Line Connection assets are those of its assets that form part of "line connection facilities" in accordance with the TSC. Generally, line connection assets are the transmission circuits and intermediate stations operating at 230kV or 115kV that are used to provide a connection between Hydro One's transmission facilities with a customer's facilities, which includes an enabler facility but excludes any network assets.[2]

More particularly, section 2.0.39 of the TSC defines "line connection" to mean radial lines that do not, under normal operating conditions, connect network stations and whose sole purpose is to serve one or more persons. Similarly, lines used to provide a connection between a DFL and delivery point(s) for one or more customers are also categorized Line Connection assets.

Line Connection assets do not reinforce the integrated transmission system that is commonly shared by a large portion of the Province, or the entire Province. Specifically, the transmission circuits or stations comprising the following type of electrical assets, excluding any assets referred to in Section 3.1 and 3.2 above, are assigned to Line Connection functional category of assets:

- The 230kV or 115kV transmission circuits that are radial and connect (directly or indirectly via other connection circuits) to one of the network stations or Dual Function Lines defined above.
- The intermediate 230kV or 115kV radial station assets that serve one or more customers.
- A local loop, as described in Section 3.2, if it does not increase the transfer capability along the full length of the transmission interface between two existing network stations.
- Intermediate radial stations, or portions thereof, dropping voltage from 230kV to 115kV are also categorized as a Line Connection asset if they are not already categorized as a Network asset as per the guidelines above. These facilities cannot be classified as

[2] Section 2.0.13, 2.0.14, 2.0.18, 2.0.19 and 2.0.28A of the TSC defines a connection facility, a customer, customer's facility and an enabler facility

Transformation Connection assets, since they do not meet the "drop the voltage from above 50kV to below 50kV" criteria.

The treatment of Line Connection assets that are partially or fully used to connect generating stations to the transmission system is described in Section 3.5.

3.4 TRANSFORMATION CONNECTION ASSETS

Hydro One's Transformation Connection assets are those of its assets that form part of "transformation connection facilities" in accordance with the TSC. Generally, transformation connection assets are transformation connection facilities, or portions thereof, that connect Hydro One's transmission system with a customers' facilities, which includes an enabler facility but excludes any network assets.[3]

More particularly, Section 2.0.60 of the TSC defines "transformation connection" as transformation facilities, tapped off a transmission system, that step down voltages from transmission levels to distribution levels (i.e. from more than 50 kV to 50 kV or less) in order to supply the facilities of a person.

Transformation Connection assets also include facilities that are partially or fully used to connect generating stations to the transmission system, the treatment of which is further described in Section 3.5.

As per the OEB's Decision in Proceeding EB-2019-0082, Wholesale Revenue Metering (WRM) assets that formerly made up the Wholesale Meter functional category are included in the Transformation Connection functional category. The costs and revenue related to Meter Service Provider (MSP) services to WRM assets are described in Exhibit H-08-01.

[3] Section 2.0.13, 2.0.14, 2.0.18, 2.0.19 and 2.0.28A of the TSC defines a connection facility, a customer, customer's facility and an enabler facility

3.5 GENERATION LINE AND TRANSFORMATION CONNECTION ASSETS

Some of the existing Line Connection assets and Transformation Connection assets, described in Sections 3.3 and 3.4 above, are partially or fully used to connect generating stations to the transmission system.

For a connection facility, including a Generation Station switchyard, that is used solely to connect a generating station(s), the asset value can be fully allocated to the appropriate Generation Connection functional category; either Generation Line Connection or Generation Transformation Connection depending on the type of electrical asset.

In cases where a connection facility, including a Generation Station switchyard, is used to connect one or more generating station(s) and one or more transmission load customer delivery points, it is appropriate that the portion of connection facility costs associated with the generating station(s) be separately identified. In this manner, some of the costs associated with that facility are allocated to the appropriate Generation Connection functional category, and the remaining costs are allocated to the load customer through either the Line Connection or Transformation Connection functional category. In these cases, the allocation of the asset value is based on the sum of the maximum annual non-coincident peak demand of all delivery points connected to the connection facility and the maximum installed capacity of generation connected to that facility as follows:

Generator Connections Portion:

$$\begin{array}{c}\text{Proportion Allocated to the}\\\text{Generator Connections}\end{array} = \frac{\text{Generation Capacity}}{\text{Generation Capacity} + \text{Non-Coincident Peak Demand}}$$

Load Customer Connections Portion:

$$\begin{array}{c}\text{Proportion Allocated to the}\\\text{Load Connections}\end{array} = 1 - \begin{array}{c}\text{Proportion Allocated to the}\\\text{Generator Connections}\end{array}$$

This use of a delivery point's maximum annual non-coincident peak demand and the maximum generator installed capacity as the basis for allocating the costs of connection assets specifically dedicated for their joint use is appropriate since these values represent the maximum extent to which the assets could be used by either party.

Listings of the transmission lines and stations, which are used for connecting generation stations to the transmission network, are provided in Exhibit H-03-02 and Exhibit H-03-03, respectively. These Exhibits show the corresponding proportions of those assets that are allocated to the Generator Line Connection and Load Connection functional categories in accordance with the methodology described above.

3.6 COMMON ASSETS

Commonly used facilities that serve the operation of the overall provincial transmission system are categorized as Common assets. Common assets include telecommunication and control equipment, administration buildings and control rooms, minor fixed assets (such as office computers and equipment), and electrical equipment held in reserve.

3.7 OTHER ASSETS

Remaining Hydro One Transmission owned facilities that cannot be assigned to any of the functional categories listed above are categorized as Other assets. These assets include facilities such as disconnect switches in customer-owned stations and transmission facilities that cannot be allocated to one of the other functional categories under normal operating conditions.

4.0 ALLOCATION OF REVENUE REQUIREMENT TO FUNCTIONAL CATEGORIES

The first stage in the allocation of revenue requirement to the rate pools entails the apportionment of the revenue requirement components into the functional categories. There are two basic elements of the revenue requirement allocated or assigned to the functional categories:

1. Operations, Maintenance and Administration (OM&A) costs; and
2. Expenses associated with fixed assets such as: return on capital, income taxes, property taxes, asset removal costs, and depreciation and amortization costs.

The following subsections describe how the functionalization of transmission assets, as described in Section 3, is used as a basis to allocate Hydro One's transmission revenue requirement components into functional categories. The mapping of allocated transmission revenue requirement from the functional categories is then assigned rate pools, which is described in Exhibit H-01-03.

4.1 ALLOCATION OF ASSET VALUE

As a starting point, it is necessary to allocate the Gross Book Value (GBV) of transmission assets to functional categories. Assignment of the physical assets to the functional categories and the subsequent split of the Dual Function Lines and Generation Connection assets, as described in Section 3, yields the functionalization of the GBV of transmission assets into the categories shown below:

- Network
- Network Portion of Dual Function Line
- Line Connection
- Line Connection Portion of Dual Function Line
- Transformation Connection
- Generator Line Connection
- Generator Transformation Connection (includes Generation Station Switchyards)
- Common
- Other

Once the GBV has been allocated to the functional categories, the Net Book Value (NBV) of transmission assets is determined by assigning the accumulated depreciation, discussed in Exhibit C-01-01, to the functional categories listed above in proportion to the share of GBV of assets in each functional category by Uniform System of Accounts (USofA). A summary of the GBV and NBV of assets by functional category is provided in Exhibit H-04-01.

The breakdown of the asset values among the functional categories is the basis of, or contributes to, the data required to establish the various factors to appropriately allocate the revenue requirement components among the functional categories on the basis of either GBV, NBV, rate base, or OM&A, as described below.

4.2 ASSIGNMENT OF DEPRECIATION AND AMORTIZATION COSTS, RETURN ON CAPITAL, AND TAXES

The Depreciation and Amortization costs on transmission fixed assets are allocated to the functional categories in proportion to the average GBV of the functional categories over two years by USofA. The asset removal costs and capitalized depreciation determined per Exhibit E-08-01 are assigned to the functional categories in proportion to the GBV. A summary of the Depreciation and Amortization, and asset removal costs by functional category is provided in Exhibit H-04-02.

Return on Capital and Income Taxes, as described in Exhibit F-01-03 and Exhibit E-09-02-01, are assigned on the basis of the rate base in each functional category. The rate base is determined by adding the Working Capital, which includes cash working capital as well as materials and supply inventory identified in Exhibit C-01-01, to the NBV of the functional categories. The share of Working Capital added to each functional category is in proportion to the distribution of OM&A. A summary of the Return on Capital and Income Taxes by functional category is provided in Exhibit H-04-03.

The amount for property taxes, as described in Exhibit E-09-04, is assigned to the functional categories in proportion to the NBV.

4.3 ALLOCATION OF OM&A COSTS

The allocation of OM&A costs is in accordance with the methodology approved by the OEB in Proceeding EB-2019-0082. The OM&A costs for revenue requirement are allocated as per the methodology described in this Section are the totals summarized in Exhibit E-02-01 and D-01-01, less the amount for property taxes.

The allocation of these expenditures for the various OM&A projects and programs, which are described in Exhibit E, to the functional categories, is based on the following approach:

a) Where work is readily identifiable thereby making direct assignment possible, costs are directly assigned to specific functional categories.
b) Where direct assignment is not possible, allocation to the functional categories is based on parameters representative of the relative OM&A expenditure requirements, such as:
    i. the kilometers of line in each functional category as a percent of the total number of kilometres installed.
    ii. the GBV of stations within a particular functional category as a percent of the total GBV of all stations.
    iii. the length of underground circuit-km in a functional category as a percent of the total length of underground lines within the system.

In order to allocate costs to the functional categories, the OM&A spending associated with the Network and Line Connection portions of DFLs, as well as the OM&A spending associated with the generator and load portions of Generation Line and Transformation Connection assets must be determined. The methodology to determine these costs is described below.

Allocation of the OM&A costs described below results in the split of total OM&A costs between the functional categories, which is summarized in Exhibit H-04-04.

4.3.1 OM&A COSTS FOR GENERATION CONNECTIONS

The OM&A costs associated with Generator Line and Transformation Connections used solely to connect a generating station(s) can be fully assigned to the appropriate Generation Connection functional category; either Generation Line Connection or Generation Transformation Connection depending on the type of electrical asset.

In cases where a connection facility is used to connect one or more generating station(s) and one or more load customers, some of the costs associated with that facility are allocated to the appropriate Generation Connection functional category, and the remaining costs are allocated to load customer under the appropriate Connection functional category. Using the asset value data from Section 4.1 and the OM&A costs determined as per Section 4.3, the following formula is used to estimate the generator's share of OM&A costs for each of the Line and Transformation Connection functional categories:

$$\text{Proportion Allocated to the Generator Line or Transformation Connection} = \text{Total Generation Line or Transformation OM\&A Costs} \times \left[\frac{\text{Generation Line or Transformation Connection NBV}}{\text{Generation Line or Transformation Connection NBV} + \text{Line or Transformation Connection NBV}} \right]$$

Therefore, the formula used for the load customers' share of OM&A costs is:

$$\text{Proportion Allocated to the Load Customer Line or Transformation Connections} = 1 - \text{Proportion Allocated to the Generator Line or Transformation Connection}$$

4.3.2 OM&A COSTS FOR DUAL FUNCTION LINES

The OM&A costs of each DFL asset are split between the Network portion and Line portion of the DFL functional category. The allocation factors for OM&A costs are derived using the NBV of assets determined as per Section 4.1. The following formulas are used to estimate the portion of OM&A costs to the appropriate DFL functional category.

Network Portion:

$$\text{Proportion Allocated to the Network Portion of Dual Function Lines} = \text{Total OM\&A Costs for DFL} \times \left[\frac{\text{NBV of Network Portion of DFL}}{\text{Sum of Total NBV of DFL}} \right]$$

Line Connection Portion:

$$\text{Proportion Allocated to the Line Connection Portion of Dual Function Lines} = 1 - \text{Proportion Allocated to the Network Portion of Dual Function Lines}$$

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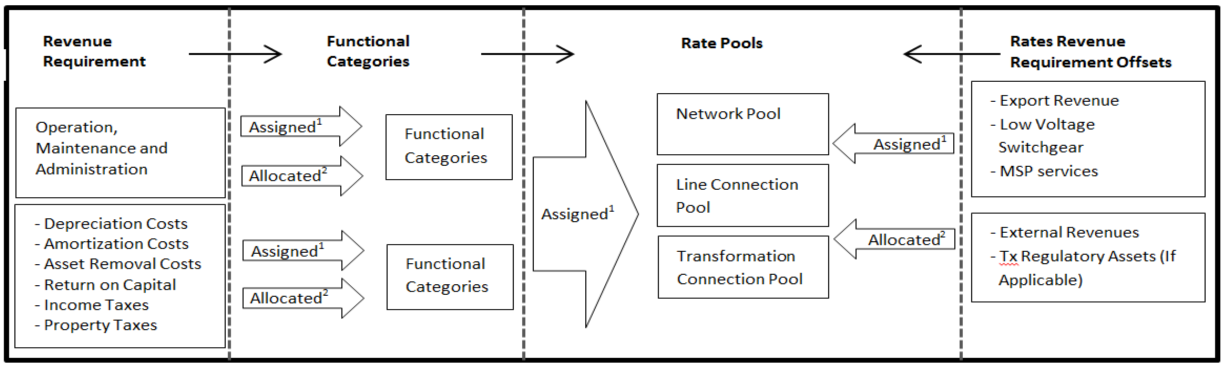
NETWORK, LINE CONNECTION AND TRANSFORMATION CONNECTION RATE POOLS

1.0 INTRODUCTION

This Schedule describes the activities to determine the transmission rates revenue requirement for the Network, Line Connection, and Transformation Connection rate pools, and provides a summary of the associated asset values and rates revenue requirement. A detailed account of the 2023 to 2027 transmission rates revenue requirements by rate pool is provided in Exhibit H-05-01.

2.0 ALLOCATION OF RATES REVENUE REQUIREMENT TO RATE POOLS

The allocation of the transmission rates revenue requirement to the rate pools is summarized in Figure 1. This process is the same as was presented and approved by the OEB in Hydro One's 2020-2022 Transmission Rate Application (EB-2019-0082).



[1] *The term "Assigned" refers to a value that is designated to a particular Functional Category or Rate Pool (i.e. Export Revenues are directly assigned to the Network Rate Pool).*
[2] *The term "Allocated" indicates that a parameter(s) is used to calculate the proportion of the values that are designated to more than one Functional Category or Rate Pool (i.e. load forecast data is applied to the value of Dual Function Line assets to determine the proportion of its value that is allocated to the Network Functional Category and to the Line Connection Functional Category).*

Figure 1: Schematic Outlining the Allocation of Revenue Requirement to Rate Pools

As illustrated in Figure 1, once the allocation of revenue requirement components into the functional categories is completed, as described in Exhibit H-01-02, then the next steps include:

1. Mapping of allocated transmission costs from the functional categories to the assigned rate pools; and
2. Assignment and allocation of the rates revenue requirement offset components such as: Export Transmission Service (ETS) revenue, regulatory assets (if applicable), the Low Voltage Switchgear (LVSG) funding, Meter Service Provider (MSP) revenue and other external revenues into the rate pools.

These two steps are discussed further in Section 2.1 and Section 2.2, respectively.

2.1 MAPPING OF FUNCTIONAL CATEGORY TO RATE POOL

The allocated transmission costs that are derived using the cost allocation methodology described in Exhibit H-01-02 are aggregated from the functional categories to the three rate pools: Network, Line Connection, and Transformation Connection; as shown in Table 1 and described below.

Table 1 - Functional Category to Rate Pool Mapping

Functional Category	Rate Pool
Network	Network
Network Portion of DFL	Network
Line Connection	Line Connection
Line Connection Portion of DFL	Line Connection
Transformation Connection	Transformation Connection
Generation Line Connection	Network
Generation Transformation Connection	Network
Common and Other	Prorate to Network, Line and Transformation

Network, Line Connection, and Transformation Connection Assets

The financial values associated with the Network, Line Connection, and Transformation Connection functional categories are directly assigned to the Network, Line Connection, and Transformation Connection rate pools, respectively. This is also applicable to the portions of Dual Function Line (DFL) assets that are allocated to the Network and Line Connection functional categories.

Generation Line and Transformation Connection Assets

The financial values associated with the Generator Line and Transformation Connection functional categories are assigned to the Network rate pool, based on the OEB Decision in Proceeding RP-1999-0044; which states that generators do not pay transmission service charges with respect to transmission connection facilities used to transfer electricity from the generating station to the network. This approach is considered fair and equitable, since generators connected to the transmission system enhance and contribute to the electricity market for all load customers. This aligns with the cost allocation to the Network rate pool where costs are recovered through Network rates applicable to all load customers (including generators when they are taking load), while the costs for Connection rate pools are recovered only from load customers that utilize those connections.

Common and Other Assets

The financial values associated with the functional categories "Common" and "Other" are allocated to the Network, Line Connection and Transformation Connection rate pools in proportion to the corresponding amounts of financial values that are already assigned to those rate pools by revenue requirement component. For example, "Common" and "Other" OM&A costs are allocated to the rate pools based on the relative share of OM&A costs already assigned to the rate pools.

2.2 ALLOCATION OF RATES REVENUE REQUIREMENT OFFSETS

Hydro One Transmission's revenue requirement to be recovered through rates includes amounts in addition to the fixed asset depreciation costs, return on capital, income taxes and OM&A costs allocated above. These additional costs are summarized in Table 1 of Exhibit H-01-01 and are generically referred to as "Rates Revenue Requirement Offsets" for the purpose of this exhibit.

Table 2 below identifies the Rates Revenue Requirement Offset items, the total revenues to be collected, and the allocators used to divide these costs among the functional categories. Allocation of the items in Table 2 is done on the same basis as in Proceeding EB-2019-0082.

Table 2 - Rates Revenue Requirement Offsets ($ Millions)

Items	2023 Rates Revenue Requirement Offsets	Allocator
Regulatory Assets	$0.9	Prorated based on the amounts of financial values that are already assigned to those functional categories
ETS Revenue Variance	$0.2	Direct Assignment to Networks
ETS Revenue	($37.4)	Direct Assignment to Networks
External Revenues	($40.1)	Prorated based on the amounts of financial values that are already assigned to those functional categories
Revenue for MSP Services	($0.03)	Direct Assignment to Transformation Connection
Funding for LVSG Compensation	$16.5	Direct Assignment to Transformation Connection

3.0 SUMMARY OF ASSET VALUE AND REVENUE REQUIREMENT FOR RATE POOLS

This Section provides the annual mid-year net book value and transmission rates revenue requirement for each of the three rate pools: Network, Line Connection, and Transformation Connection. For 2023, this is derived using the methodology described above in Section 2. For the remaining years, 2024 to 2027, the net book value and the transmission rates revenue requirement have been allocated among the three rate pools using the same percentage split as 2023.

3.1 NETWORK RATE POOL

The mid-year net book value and rates revenue requirement for the Network rate pool are provided in Table 3.

The rates revenue requirement for the Network rate pool includes an offset to account for ETS revenue forecast to be collected, as discussed in Exhibit H-05-01; as well as an offset to account for any ETS revenue variance (included in regulatory assets amount).[1]

Table 3 - Network Rate Pool ($ Millions)

Year	Net Book Value	Rates Revenue Requirement
2023	$9,048.1	$1,047.9
2024	$9,579.9	$1,120.2
2025	$10,200.5	$1,174.5
2026	$10,787.1	$1,243.2
2027	$11,322.6	$1,290.5

3.2 LINE CONNECTION RATE POOL

The mid-year net book value and rates revenue requirement for the Line Connection rate pool are provided in Table 4.

Table 4 - Line Connection Rate Pool ($ Millions)

Year	Net Book Value	Rates Revenue Requirement
2023	$1,570.4	$184.7
2024	$1,662.7	$197.0
2025	$1,770.4	$206.2
2026	$1,872.2	$217.9
2027	$1,965.1	$226.0

[1] Exhibit G-01-03 provides details on the proposed disposition of the balance associated with Excess Export Service Revenue Variance Account

3.3 TRANSFORMATION CONNECTION RATE POOL

The mid-year net book value and rates revenue requirement for the Transformation Connection rate pool are provided in Table 5.

The rates revenue requirement for the Transformation Connection rate pool includes the LVSG credit amount, as outlined in Table 6 below, as well as an offset to account for revenue associated with MSP services to be collected in each year, as discussed in Exhibit H-08-01.

Table 5 - Transformation Connection Rate Pool ($ Millions)

Year	Net Book Value	Rates Revenue Requirement
2023	$3,942.2	$530.7
2024	$4,173.9	$565.9
2025	$4,444.3	$592.4
2026	$4,699.9	$626.0
2027	$4,933.2	$649.0

Low Voltage Switchgear Credit

As first approved by the OEB in Proceeding EB-2006-0501, the revenue requirement for the Transformation Connection pool also includes an amount that is payable by Hydro One Transmission to Toronto Hydro-Electric System Inc. and Hydro Ottawa Inc. as compensation for LVSG equipment that those utilities own, operate and maintain within certain transformation stations owned by Hydro One. The compensation amount is based on the LVSG as a proportion of the total transformation station costs, including OM&A and capital-related charges, incurred by Hydro One.

The estimated cost of providing low voltage switchgear service, and the methodology used to calculate the annual LVSG compensation payable to each utility, was most recently reviewed approved in Proceeding EB-2019-0082. The average low voltage switchgear service costs continue to comprise approximately 19.0% of Hydro One Transmission’s total station costs.

The LVSG compensation is based on the forecast of each eligible utility's total monthly non-coincident peak demand supplied from all Hydro One Transmission transformer stations in which the utilities own the LVSG facilities, multiplied by the LVSG proportion of Hydro One Transmission's Transformation Connection rate.

The annual LVSG compensation amounts proposed are shown in Table 6. These amounts are added to the revenue to be collected by the Transformation Connection service rates.

Table 6 - LVSG Credit

Year	LVSG Component of Transformation Connection Rate ($/kW/Month)	Average Monthly NCP Demand for Toronto Hydro and Hydro Ottawa (MW)	Total Credit ($ Millions)
2023	$0.51	32,150	$16.5
2024	$0.54	32,167	$17.5
2025	$0.57	32,027	$18.2
2026	$0.60	31,998	$19.2
2027	$0.62	31,892	$19.8

LIST OF TRANSMISSION LINES BY FUNCTIONAL CATEGORY

N= Network *LC= Line Connection* *DFL=Dual Function Line*

Operation Designation	Section	From	To	Functional Category
15M1	10	Rabbit Lake SS	Kenora MTS JCT	LC
15M1	13	Kenora MTS JCT	Kenora MTS JCT	LC
15M1	14	Kenora MTS JCT	Kenora MTS	LC
15M1	15	Kenora MTS JCT	Kenora MTS	LC
15M1	16	Kenora MTS JCT	Kenora MTS	LC
29M1	1	Ignace JCT	Ignace DS JCT	LC
29M1	2	Ignace DS JCT	Camp Lake JCT	LC
29M1	3	Camp Lake JCT	Valora JCT	LC
29M1	4	Valora JCT	Mattabi JCT	LC
29M1	7	Valora JCT	Valora DS	LC
29M1	8	Camp Lake JCT	Agimak DS JCT	LC
29M1	12	Agimak DS JCT	Agimak DS	LC
29M1	13	Agimak DS JCT	Agimak DS	LC
3024F2	1	Tisdale JCT	Pamour JCT	OTHER
56M1	1	Nipigon JCT	Red Rock JCT	LC
56M1	2	Red Rock JCT	Red Rock DS	LC
56M1	3	Red Rock JCT	56M1 T#256 JCT	OTHER
57M1	1	Reserve JCT	Nipigon JCT	LC
57M1	2	Nipigon JCT	Nipigon DS	LC
61M18	1	Seaforth 61M18 JCT	Constance DS	LC
61M18	2	Constance DS	Goderich TS	LC
61M18	3	Seaforth TS	Seaforth 61M18 JCT	LC
61M18	4	Seaforth 61M18 JCT	Seaforth LSO JCT	OTHER
61M18	5	Constance DS	Constance DS	LC
79M1	1	Gamble H9A JCT	Rockland JCT	LC
79M1	2	Rockland JCT	Rockland East DS JCT	LC
79M1	3	Rockland East DS JCT	Clarence DS	LC
79M1	4	Clarence DS	Wendover JCT	LC
79M1	5	Wendover JCT	Cassburn JCT	LC
79M1	6	Cassburn JCT	Hawkesbury MTS #1	LC
79M1	10	Rockland JCT	Rockland DS	LC
79M1	11	Wendover JCT	Wendover DS	LC
79M1	13	Rockland East DS JCT	Rockland East DS JCT	LC

79M1	14	Rockland East DS JCT	Rockland East DS	LC
79M1	15	Rockland East DS JCT	Rockland East DS	LC
79M1	16	Clarence DS	Clarence DS	LC
A1B	1	Aguasabon SS	AV Terrace Bay JCT	DFL
A1B	2	AV Terrace Bay JCT	Terrace Bay SS	DFL
A1B	3	AV Terrace Bay JCT	AV Terrace Bay CTS	LC
A1T	4	Toronto Pwr T#56 JCT	Niagara A1T T#49 JCT	OTHER
A1T	5	Montrose JCT	Toronto Pwr T#56 JCT	OTHER
A1T	6	Michigan JCT	Montrose JCT	OTHER
A1T	7	Michigan JCT	Crowland STR 46 JCT	OTHER
A1T	11	Toronto Pwr T#56 JCT	Niagara A1T T#49 JCT	OTHER
A1T	13	Farr Road JCT	Crowland JCT	OTHER
A1T	16	Crowland STR 46 JCT	Crowland JCT	OTHER
A1T	17	Crowland JCT	Crowland JCT	OTHER
A2	1	Hawthorne TS	Blackburn JCT	LC
A2	2	Blackburn JCT	Cyrville Rd JCT	LC
A2	3	Cyrville JCT	Bilberry Creek JCT	LC
A2	4	Bilberry Creek JCT	Bilberry Creek TS	LC
A2	5	Cyrville JCT	Nationl Research JCT	LC
A2	6	Nationl Research JCT	NRC TS	LC
A2	7	Nationl Research JCT	Nationl Research JCT	OTHER
A2	8	Cyrville Rd JCT	Cyrville JCT	LC
A2	9	Cyrville Rd JCT	Cyrville MTS	LC
A21L	1	Mackenzie TS	Lakehead TS	N
A22L	1	Mackenzie TS	Lakehead TS	N
A23P	1	Algoma TS	Mississagi TS	N
A24P	1	Algoma TS	Mississagi TS	N
A36N	1	Allanburg TS	Kalar JCT	LC
A36N	3	Kalar JCT	Murray TS	LC
A36N	4	Kalar JCT	Kalar MTS	LC
A37N	1	Allanburg TS	Kalar JCT	LC
A37N	3	Kalar JCT	Murray TS	LC
A37N	4	Kalar JCT	Kalar MTS	LC
A3C	9	D3A T#1FHK JCT	Michigan JCT	OTHER
A3C	10	Michigan JCT	Farr Road JCT	OTHER
A3M	1	Mackenzie TS	Moose Lake TS	N
A3RM	1	Billings JCT	Merivale MTS	DFL
A3RM	2	Ellwood JCT	Billings JCT	DFL
A3RM	4	Ellwood JCT	Riverdale JCT	LC

A3RM	6	Riverdale JCT	Riverdale TS	LC
A3RM	7	Riverdale TS	Slater TS	LC
A3RM	10	Hawthorne TS	Ellwood JCT	DFL
A3RM	14	Billings JCT	Billings JCT	OTHER
A3RM	15	Billings JCT	Billings JCT	OTHER
A3RM	16	Merivale MTS	Merivale TS	DFL
A41T	1	Hawthorne TS	IPB Masson JCT	N
A42T	1	Hawthorne TS	IPB Masson JCT	N
A4CA	1	Gage TS	Gage TS	OTHER
A4H	2	Ansonville TS	Fournier JCT	DFL
A4H	3	Fournier JCT	Fournier JCT	LC
A4H	4	Hunta SS	LSR MSO JCT	LC
A4H	5	Fournier JCT	Hunta SS	DFL
A4H	6	Fournier JCT	Power JCT	LC
A4H	7	Power JCT	Cochrane West JCT	LC
A4H	8	Cochrane West JCT	Cochrane MTS	LC
A4H	10	Cochrane West JCT	Cochrane West DS	LC
A4K	1	Hawthorne TS	Blackburn JCT	LC
A4K	2	Blackburn JCT	Cyrville Rd JCT	LC
A4K	3	Cyrville JCT	Moulton JCT	LC
A4K	4	Overbrook TS	King Edward TS	LC
A4K	9	Moulton JCT	Overbrook TS	LC
A4K	10	Moulton JCT	Moulton MTS	LC
A4K	11	Cyrville Rd JCT	Cyrville JCT	LC
A4K	12	Cyrville Rd JCT	Cyrville MTS	LC
A4L	1	Alexander SS	A4L STR 217 JCT	LC
A4L	2	Beardmore JCT	Namewaminikan JCT	LC
A4L	6	Jellicoe DS #3 JCT	Longlac TS	LC
A4L	7	Beardmore JCT	Beardmore DS #2	LC
A4L	10	A.P. Nipigon JCT	Beardmore JCT	LC
A4L	11	A.P. Nipigon JCT	A.P. Nipigon CGS	LC
A4L	12	Jellicoe DS #3 JCT	Jellicoe DS #3	LC
A4L	13	Namewaminikan JCT	Jellicoe DS #3 JCT	LC
A4L	14	Namewaminikan JCT	Namewaminikan CGS	LC
A4L	15	A4L STR 217 JCT	A.P. Nipigon JCT	LC
A565L	1	Ashfield SS	Longwood TS	N
A592K	1	Ashfield SS	K2 Wind 500 CGS	N
A5A	1	Alexander SS	Minnova JCT	DFL
A5A	2	Minnova JCT	Schreiber JCT	DFL

A5A	3	Schreiber JCT	Aguasabon SS	DFL
A5A	4	Schreiber JCT	Schreiber Winnipg DS	LC
A5A	6	Minnova JCT	Minnova JCT	LC
A5H	1	Fournier JCT	Hunta SS	DFL
A5H	2	A.P. Tunis JCT	Fournier JCT	DFL
A5H	3	Iroquois Fls DS JCT	Iroq Falls 115 JCT	DFL
A5H	4	Ansonville TS	Iroquois Fls DS JCT	DFL
A5H	10	Iroq Falls 115 JCT	A.P. Tunis JCT	DFL
A5H	15	Fournier JCT	Fournier JCT	LC
A5H	17	Iroquois Fls DS JCT	Iroquois Falls DS	LC
A5H	18	A.P. Tunis JCT	A.P. Tunis JCT	LC
A5RK	1	Hawthorne TS	Blackburn JCT	LC
A5RK	2	Blackburn JCT	Russell TS	LC
A5RK	3	Russell TS	Riverdale JCT	LC
A5RK	4	Riverdale JCT	Riverdale TS	LC
A5RK	5	Riverdale TS	Slater TS	LC
A5RK	6	Riverdale JCT	A5RK STR O7 JCT	LC
A5RK	7	Overbrook TS	King Edward TS	LC
A5RK	8	A5RK STR O7 JCT	Overbrook TS	LC
A6C	1	Allanburg TS	Allanburg TS	LC
A6C	2	Hurricane JCT	Michigan JCT	LC
A6C	3	Hurricane JCT	BF Goodrich JCT	LC
A6C	4	Allanburg TS	Allanburg TS	LC
A6C	5	Crowland TS	Tunnel JCT	LC
A6C	6	BF Goodrich JCT	Cytec Welland CTS	LC
A6C	7	BF Goodrich JCT	Oxy Vinyls CTS	LC
A6C	8	Michigan JCT	Crowland TS	LC
A6C	9	Allanburg TS	Hurricane JCT	LC
A6C	10	Tunnel JCT	Vale Inco JCT	LC
A6C	11	Vale Inco JCT	Port Colborne TS	LC
A6P	1	Alexander SS	Reserve JCT	DFL
A6P	2	Reserve JCT	Port Arthur TS #1	DFL
A6P	3	Reserve JCT	Reserve JCT	LC
A6R	1	Hawthorne TS	Blackburn JCT	LC
A6R	2	Blackburn JCT	Russell TS	LC
A6R	3	Russell TS	Riverdale JCT	LC
A6R	4	Riverdale JCT	OHSC JCT	LC
A6R	5	OHSC JCT	Riverdale TS	LC
A6R	6	OHSC JCT	OHSC JCT	LC

A6R	8	Riverdale JCT	Overbrook TS	LC
A7C	1	Allanburg TS	Allanburg TS	LC
A7C	2	Hurricane JCT	Michigan JCT	LC
A7C	3	Hurricane JCT	BF Goodrich JCT	OTHER
A7C	4	Allanburg TS	Allanburg TS	LC
A7C	6	BF Goodrich JCT	Cytec Welland CTS	OTHER
A7C	7	BF Goodrich JCT	Oxy Vinyls CTS	OTHER
A7C	8	Michigan JCT	Crowland TS	LC
A7C	9	Allanburg TS	Hurricane JCT	LC
A7L	1	Alexander SS	Reserve JCT	N
A7L	2	Reserve JCT	Lakehead TS	N
A8G	1	A8G STR2 JCT	Rosedene JCT	OTHER
A8G	2	Rosedene JCT	Railway JCT	OTHER
A8G	3	Railway JCT	A8G T#43 JCT	OTHER
A8G	4	Beach JCT	Gage TS	OTHER
A8G	5	Railway JCT	Glanford JCT	OTHER
A8K	1	Ansonville TS	A8K-19EO JCT	N
A8K	2	A8K-19EO JCT	Monteith SS JCT	N
A8K	4	Monteith SS JCT	A8K-47EO JCT	N
A8K	5	A8K-47EO JCT	Kirkland Lake TS	N
A8L	1	Alexander SS	Lakehead TS	N
A8M	1	Billings JCT	Merivale TS	DFL
A8M	2	Hawthorne TS	Billings JCT	DFL
A8M	9	Billings JCT	Billings JCT	LC
A8M	10	Billings JCT	Billings JCT	LC
A8M	11	Billings JCT	Uplands JCT	LC
A8M	12	Uplands JCT	Uplands MTS #2	LC
A9K	1	Ansonville TS	Monteith DS JCT	DFL
A9K	2	Monteith DS JCT	Ramore TS	DFL
A9K	3	Ramore TS	Kirkland Lake TS	DFL
A9K	4	Monteith DS JCT	Monteith DS	LC
B1	1	Beach Road JCT	Beach TS	LC
B10	1	Burlington TS	Gage JCT	LC
B10	2	Gage JCT	Gage TS	LC
B10	3	Gage JCT	Birmingham TS	OTHER
B11	1	Burlington TS	Gage JCT	LC
B11	2	Gage JCT	Gage TS	LC
B11	3	Gage JCT	Birmingham TS	OTHER
B12BL	1	Burlington TS	Dundas #2 JCT	DFL

B12BL	2	Dundas #2 JCT	Horning Mountain JCT	DFL
B12BL	3	Horning Mountain JCT	Newton TS	LC
B12BL	4	Dundas #2 JCT	Dundas TS #2	LC
B12BL	5	Horning Mountain JCT	Alford JCT	DFL
B12BL	6	Alford JCT	Powerline JCT	DFL
B12BL	7	Powerline JCT	Brant TS	DFL
B12BL	8	Powerline JCT	Powerline MTS	LC
B12BL	9	Alford JCT	Mohawk Str 31 EP JCT	OTHER
B13BL	1	Burlington TS	Dundas #2 JCT	DFL
B13BL	2	Dundas #2 JCT	Horning Mountain JCT	DFL
B13BL	3	Horning Mountain JCT	Newton TS	LC
B13BL	4	Dundas #2 JCT	Dundas TS #2	LC
B13BL	5	Horning Mountain JCT	Alford JCT	DFL
B13BL	6	Alford JCT	Powerline JCT	DFL
B13BL	7	Powerline JCT	Brant TS	DFL
B13BL	8	Powerline JCT	Powerline MTS	LC
B15C	1	Cooksville TS	Lorne Park TS	LC
B15C	2	Lorne Park TS	Ford JCT	LC
B15C	3	Ford JCT	Oakville TS #2	LC
B15C	4	Ford JCT	Ford Oakville CTS	LC
B16C	1	Cooksville TS	Lorne Park TS	LC
B16C	2	Lorne Park TS	Ford JCT	LC
B16C	3	Ford JCT	Oakville TS #2	LC
B16C	4	Ford JCT	Ford Oakville CTS	LC
B16C	5	Cooksville TS	Cooksville TS	LC
B18H	1	Burlington TS	Beach Road JCT	DFL
B18H	2	Beach Road JCT	Beach TS	DFL
B18H	3	Beach Road JCT	Lake TS	LC
B1S	1	Barrett Chute SS	Ardoch JCT	DFL
B1S	2	Ardoch JCT	Northbrook JCT	DFL
B1S	3	Northbrook DS	Lodgeroom DS	DFL
B1S	4	Lodgeroom DS	Sidney TS	DFL
B1S	5	Ardoch JCT	Ardoch DS	LC
B1S	6	Northbrook JCT	Northbrook DS	DFL
B1S	7	Ardoch JCT	Ardoch JCT	DFL
B1S	8	Ardoch JCT	Ardoch DS	OTHER
B2	1	Brant TS	Toyota Woodstock JCT	DFL
B2	2	Toyota Woodstock JCT	Commerce Way JCT	DFL
B2	3	Commerce Way JCT	Commerce Way TS	DFL

B2	4	Commerce Way JCT	Commerce Way TS	DFL
B2	5	Toyota Woodstock JCT	Toyota Woodstock TS	LC
B20H	1	Burlington TS	Beach Road JCT	DFL
B20H	2	Beach Road JCT	Beach TS	DFL
B20H	3	Beach Road JCT	Lake TS	LC
B20P	1	Bruce A TS	Bruce HW Plant D JCT	LC
B20P	2	Bruce HW Plant D JCT	Douglas Point TS	LC
B20P	4	Bruce HW Plant D JCT	Bruce HW Plant D TS	OTHER
B20P	8	Bruce A TS	Bruce HW Plant B TS	LC
B22D	1	Bruce A TS	Majestic JCT	DFL
B22D	2	Wingham JCT	Seaforth TS	DFL
B22D	3	Seaforth TS	Festival MTS #1 JCT	DFL
B22D	4	Stratford JCT	Detweiler TS	DFL
B22D	5	Stratford JCT	Stratford TS	LC
B22D	6	Wingham JCT	Wingham TS	LC
B22D	7	Majestic JCT	Armow JCT	DFL
B22D	8	Majestic JCT	Majestic CTS	LC
B22D	9	Festival MTS #1 JCT	Stratford JCT	DFL
B22D	10	Festival MTS #1 JCT	Festival MTS #1	LC
B22D	11	Armow JCT	Wingham JCT	DFL
B22D	12	Armow JCT	Armow CSS	LC
B23D	1	Bruce A TS	Majestic JCT	DFL
B23D	2	Wingham JCT	Seaforth TS	DFL
B23D	3	Seaforth TS	Zurich JCT	DFL
B23D	4	Stratford JCT	Detweiler TS	DFL
B23D	5	Stratford JCT	Stratford TS	LC
B23D	6	Wingham JCT	Wingham TS	LC
B23D	7	Majestic JCT	Wingham JCT	DFL
B23D	8	Majestic JCT	Majestic CTS	LC
B23D	9	Festival MTS #1 JCT	Stratford JCT	DFL
B23D	10	Festival MTS #1 JCT	Festival MTS #1	LC
B23D	11	Zurich JCT	Festival MTS #1 JCT	DFL
B23D	12	Zurich JCT	Zurich CSS	LC
B24P	1	Bruce A TS	Bruce HW Plant D JCT	LC
B24P	2	Bruce HW Plant D JCT	Douglas Point TS	LC
B24P	4	Bruce HW Plant D JCT	Bruce HW D EP JCT	OTHER
B24P	8	Bruce A TS	Bruce HW Plant B TS	LC
B27S	1	Bruce A TS	Owen Sound JCT	DFL
B27S	2	Owen Sound JCT	Owen Sound TS	LC

B27S	3	Owen Sound JCT	Owen Sound TS	DFL
B28S	1	Bruce A TS	Owen Sound TS	LC
B3	1	Burlington TS	Dundas JCT	LC
B3	2	Dundas JCT	McMaster JCT	LC
B3	3	McMaster JCT	Horning Mountain JCT	LC
B3	6	McMaster JCT	McMaster CTS	LC
B3	7	Horning Mountain JCT	Newton TS	LC
B3	8	Dundas JCT	Dundas TS	LC
B3	12	Horning Mountain JCT	Glanford JCT	LC
B3	13	Glanford JCT	Mohawk TS	LC
B31L	2	IPB Baudet JCT	B5D-B31L SS JCT	N
B31L	3	B5D-B31L SS JCT	Raisin River JCT	N
B31L	4	Raisin River JCT	St.Lawrence TS	N
B31L	5	B5D-B31L SS JCT	B5D-B31L SS JCT	N
B31L	6	St.Lawrence TS	St.Lawrence TS	N
B31L	7	St.Lawrence TS	St.Lawrence TS	N
B3E	1	Blind River TS	Elliot Lake JCT	LC
B3E	2	Elliot Lake JCT	Elliot Lake TS	LC
B3N	2	Mid R. JCT Bunce Crk	Sun Oil Co JCT	N
B3N	3	Sun Oil Co JCT	Vidal JCT	N
B3N	4	Vidal JCT	Sarnia Scott JCT	N
B3N	5	Sarnia Scott JCT	Sarnia Scott TS	N
B4	1	Burlington TS	Dundas JCT	LC
B4	2	Dundas JCT	McMaster JCT	LC
B4	3	McMaster JCT	Horning Mountain JCT	LC
B4	4	Horning Mountain JCT	Glanford JCT	LC
B4	6	McMaster JCT	McMaster CTS	LC
B4	7	Horning Mountain JCT	Newton TS	LC
B4	8	Dundas JCT	Dundas TS	LC
B4	11	M34H T#81 JCT	Nebo JCT	OTHER
B4	13	Glanford JCT	Mohawk TS	LC
B40C	1	Burlington TS	Cumberland TS	LC
B41C	1	Burlington TS	Cumberland TS	LC
B4B	1	Blind River TS	Algoma TS	LC
B4E	1	Blind River TS	Elliot Lake TS	LC
B4V	1	Bruce A TS	Underwood JCT	DFL
B4V	2	Hanover TS	Southgate JCT	DFL
B4V	3	Amaranth JCT	Orangeville TS	DFL
B4V	4	Amaranth JCT	Amaranth CTS	LC

B4V	5	Underwood JCT	Hanover TS	DFL
B4V	6	Underwood JCT	Underwood CGS	LC
B4V	7	GV3 WF JCT	Amaranth JCT	DFL
B4V	8	GV3 WF JCT	GV3 WF CGS	LC
B4V	9	Southgate JCT	GV3 WF JCT	DFL
B4V	10	Southgate JCT	Southgate CGS	LC
B501M	1	Bruce B SS	Willow Creek JCT	N
B501M	2	Willow Creek JCT	Milton SS	N
B502M	1	Bruce A TS	Willow Creek JCT	N
B502M	2	Willow Creek JCT	Milton SS	N
B540TC	1	Bowmanville SS	Clarington JCT	N
B540TC	2	Clarington JCT	Cherrywood TS	N
B540TC	3	Clarington JCT	Clarington TS	N
B541C	1	Bowmanville SS	Cherrywood TS	N
B542C	1	Bowmanville SS	Cherrywood TS	N
B543TC	1	Bowmanville SS	Clarington JCT	N
B543TC	2	Clarington JCT	Cherrywood TS	N
B543TC	3	Clarington JCT	Clarington TS	N
B560V	1	Bruce A TS	Willow Creek JCT	N
B560V	2	Milton SS	Milton SS	N
B560V	3	Willow Creek JCT	Milton SS	N
B560V	4	Milton SS	Claireville TS	N
B561M	1	Bruce B SS	Bruce JCT	N
B561M	2	Bruce JCT	Willow Creek JCT	N
B561M	3	Willow Creek JCT	Milton SS	N
B561M	4	Bruce JCT	Bruce JCT	N
B562E	1	Bruce A TS	Willow Creek JCT	N
B562E	2	Willow Creek JCT	Evergreen SS	N
B563A	1	Bruce B SS	Bruce JCT	N
B563A	2	Bruce JCT	Willow Creek JCT	N
B563A	3	Willow Creek JCT	Ashfield SS	N
B563A	4	Bruce JCT	Bruce JCT	N
B569B	1	Bruce A TS	Bruce JCT	N
B569B	2	Bruce JCT	Bruce B SS	N
B569B	3	Bruce JCT	Bruce JCT	N
B5C	1	Burlington TS	Harper's JCT	DFL
B5C	2	Harper's JCT	Puslinch JCT	DFL
B5C	3	Puslinch JCT	Arlen MTS JCT	DFL
B5C	4	Arlen MTS JCT	Hanlon JCT	DFL

B5C	5	Hanlon JCT	Cedar TS	DFL
B5C	6	Harper's JCT	Westover JCT	LC
B5C	7	Westover JCT	Westover A JCT	LC
B5C	8	Westover A JCT	Enbrg Westover S CTS	LC
B5C	9	Westover A JCT	Enbrg Westover N CTS	LC
B5C	10	Puslinch JCT	Puslinch DS	LC
B5C	11	Arlen MTS JCT	Arlen MTS	LC
B5C	12	Hanlon JCT	Hanlon TS	LC
B5D	2	IPB Baudet JCT	B5D-B31L SS JCT	OTHER
B5D	3	B5D-B31L SS JCT	St.Isidore TS	N
B5D	4	B5D-B31L SS JCT	B5D-B31L SS JCT	N
B5D	5	St.Isidore TS	Longueuil JCT	LC
B5D	6	Longueuil JCT	Longueuil TS	LC
B5D	7	Longueuil JCT	Ivaco CTS	OTHER
B5QK	1	Barrett Chute SS	Sharbot JCT	DFL
B5QK	2	Sharbot JCT	Hinchinbrooke DS	DFL
B5QK	3	Hinchinbrooke DS	Harrowsmith JCT	DFL
B5QK	4	Harrowsmith JCT	Railton JCT	DFL
B5QK	5	Railton JCT	Frontenac TS	LC
B5QK	6	Railton JCT	Cataraqui TS	DFL
B5QK	7	Harrowsmith JCT	Harrowsmith DS	LC
B5QK	8	Sharbot JCT	Sharbot DS	LC
B5V	1	Bruce A TS	Underwood JCT	DFL
B5V	2	Hanover TS	Amaranth JCT	DFL
B5V	3	Underwood JCT	Hanover TS	DFL
B5V	4	Underwood JCT	Underwood CGS	LC
B5V	5	Amaranth JCT	Orangeville TS	DFL
B5V	6	Amaranth JCT	Amaranth CTS	LC
B6C	1	Burlington TS	Harper's JCT	DFL
B6C	2	Harper's JCT	Puslinch JCT	DFL
B6C	3	Puslinch JCT	Arlen MTS JCT	DFL
B6C	4	Arlen MTS JCT	Hanlon JCT	DFL
B6C	5	Hanlon JCT	Cedar TS	DFL
B6C	6	Puslinch JCT	Puslinch DS	LC
B6C	7	Arlen MTS JCT	Arlen MTS	LC
B6C	8	Hanlon JCT	Hanlon TS	LC
B6M	1	Birch TS	Murillo JCT	DFL
B6M	2	Stanley JCT	Shabaqua JCT	DFL
B6M	3	Shabaqua JCT	Shebandowan JCT	DFL

B6M	4	Shebandowan JCT	Kashabowie JCT	DFL
B6M	5	Kashabowie JCT	Sapawe JCT	DFL
B6M	6	Caland Ore JCT	Moose Lake TS	DFL
B6M	7	Shabaqua JCT	Shabaqua DS	LC
B6M	12	Murillo JCT	Stanley JCT	DFL
B6M	15	Sapawe JCT	Caland Ore JCT	DFL
B6M	16	Sapawe JCT	Sapawe DS	LC
B6M	17	Murillo JCT	Murillo DS	LC
B7	1	Burlington TS	Palermo JCT	LC
B7	2	Palermo JCT	Bronte TS	LC
B8	1	Burlington TS	Palermo JCT	LC
B8	2	Palermo JCT	Bronte TS	LC
B88H	1	Brown Hill TS	York EnergyCentr JCT	DFL
B88H	2	York EnergyCentr JCT	Holland Marsh JCT	DFL
B88H	3	Holland Marsh JCT	Holland TS	DFL
B88H	4	Holland TS	Armitage TS	DFL
B88H	5	York EnergyCentr JCT	York EnergyCentr CGS	LC
B89H	1	Brown Hill TS	York EnergyCentr JCT	DFL
B89H	2	York EnergyCentr JCT	Holland Marsh JCT	DFL
B89H	3	Holland Marsh JCT	Holland TS	DFL
B89H	4	Holland TS	Armitage TS	DFL
B89H	5	York EnergyCentr JCT	York EnergyCentr CGS	LC
BP76	1	Beck #2 TS	Mid R. JCT Niagara	N
BSC105	1	Beck #1 SS	Parks TS	OTHER
BSC105	2	Parks TS	Mid R. JCT Niagara	OTHER
C10A	1	Cherrywood TS	Duffin JCT	LC
C10A	2	Duffin JCT	Agincourt JCT	LC
C10A	3	Agincourt JCT	Agincourt TS	LC
C10A	4	Duffin JCT	Seaton JCT	OTHER
C10A	5	Agincourt JCT	Cavanagh MTS	LC
C10A	6	Agincourt JCT	Leaside JCT	OTHER
C10A	7	Seaton JCT	Seaton MTS	OTHER
C11R	1	Cherrywood TS	Leaside JCT	OTHER
C12	1	Caledonia TS	Hartford JCT	LC
C12	3	Hartford JCT	Vanessa JCT	LC
C12	4	Vanessa JCT	Bloomsburg JCT	LC
C12	5	Bloomsburg JCT	Norfolk TS	LC
C12	6	Bloomsburg JCT	Bloomsburg DS	LC
C14L	1	Cherrywood TS	Scarboro JCT	DFL

C14L	2	Scarboro JCT	Bermondsey TS	DFL
C14L	3	Bermondsey TS	Leaside TS	DFL
C14L	4	Scarboro JCT	Scarboro TS	LC
C14L	5	Scarboro JCT	Warden TS	LC
C14L	6	Scarboro JCT	Scarboro JCT	LC
C14L	7	Leaside Str 4-5 JCT	Leaside Idle JCT	OTHER
C15L	1	Cherrywood TS	Sheppard TS	DFL
C15L	2	Sheppard TS	Scarboro JCT	DFL
C15L	3	Scarboro JCT	Leaside TS	DFL
C15L	4	Scarboro JCT	Scarboro TS	LC
C16L	1	Cherrywood TS	Sheppard TS	DFL
C16L	2	Sheppard TS	Leaside TS	DFL
C17L	1	Cherrywood TS	Scarboro JCT	DFL
C17L	2	Bermondsey TS	Leaside TS	DFL
C17L	3	Scarboro JCT	Bermondsey TS	DFL
C17L	4	Scarboro JCT	Warden TS	LC
C18R	1	Cherrywood TS	Fairchild TS	DFL
C18R	3	Fairchild TS	Bathurst JCT	DFL
C18R	4	Bathurst JCT	Richview TS	DFL
C18R	8	Bathurst JCT	Bathurst TS	LC
C1A	1	Cameron Falls GS	Alexander SS	LC
C1A	2	Alexander SS	Alexander GS	LC
C1A	3	Alexander SS	Alexander SS	LC
C20R	1	Cherrywood TS	Agincourt JCT	DFL
C20R	2	Fairchild TS	Bathurst JCT	DFL
C20R	3	Bathurst JCT	Finch JCT	DFL
C20R	4	Finch JCT	Richview TS	DFL
C20R	6	Finch JCT	Finch TS	LC
C20R	7	Leslie JCT	Fairchild TS	DFL
C20R	10	Agincourt JCT	Leslie JCT	DFL
C20R	11	Agincourt JCT	Cavanagh MTS	LC
C21J	1	Chatham SS	Romney JCT	DFL
C21J	2	Sandwich JCT	Malden JCT	DFL
C21J	3	Malden JCT	Ojibway JCT	DFL
C21J	4	Malden JCT	Malden TS	LC
C21J	5	Leamington JCT	Sandwich JCT	DFL
C21J	6	Leamington JCT	Leamington TS	LC
C21J	7	Ojibway JCT	Keith TS	DFL
C21J	8	Romney JCT	Leamington JCT	DFL

C22J	1	Chatham SS	Leamington JCT	DFL
C22J	2	Sandwich JCT	Malden JCT	DFL
C22J	3	Malden JCT	Ojibway JCT	DFL
C22J	4	Malden JCT	Malden TS	LC
C22J	5	Leamington JCT	Sandwich JCT	DFL
C22J	6	Leamington JCT	Leamington TS	LC
C22J	7	Ojibway JCT	Keith TS	DFL
C23Z	1	Chatham SS	Dillon RWEC CGS JCT	DFL
C23Z	2	Sandwich JCT	Lauzon TS	DFL
C23Z	3	KEPA Wind Farm JCT	Comber WF JCT	DFL
C23Z	4	KEPA Wind Farm JCT	Port Alma WF CSS	OTHER
C23Z	5	Dillon RWEC CGS JCT	KEPA Wind Farm JCT	DFL
C23Z	6	Dillon RWEC CGS JCT	Dillon RWEC CGS	LC
C23Z	7	Comber WF JCT	Comber WF CTS	LC
C23Z	8	Comber WF JCT	Belle River JCT #2	DFL
C23Z	9	Belle River JCT #2	Sandwich JCT	DFL
C23Z	10	Belle River JCT #2	Belle River CSS	LC
C24Z	1	Chatham SS	KEPA Wind Farm JCT	DFL
C24Z	2	Sandwich JCT	Lauzon TS	DFL
C24Z	3	KEPA Wind Farm JCT	Comber WF JCT	DFL
C24Z	4	KEPA Wind Farm JCT	Port Alma WF CSS	LC
C24Z	5	Comber WF JCT	Sandwich JCT	DFL
C24Z	6	Comber WF JCT	Comber WF CTS	LC
C25H	1	Chats Falls SS	Havelock TS	N
C27P	1	Bannockburn JCT	Dobbin TS	DFL
C27P	2	Galetta JCT	Bannockburn JCT	DFL
C27P	3	Chats Falls SS	Galetta JCT	DFL
C27P	5	Galetta JCT	Arnprior GS	LC
C2A	1	Cameron Falls GS	Alexander SS	LC
C2A	2	Alexander SS	Alexander GS	LC
C2A	3	Alexander SS	Alexander SS	LC
C2L	1	C2L C3L STR 85 JCT	Ellesmere TS	OTHER
C2L	2	Ellesmere TS	C2L C3L STR 34 JCT	OTHER
C2L	5	Cherrywood TS	Ellesmere JCT	DFL
C2L	6	Ellesmere JCT	Scarboro JCT	DFL
C2L	7	Scarboro JCT	Leaside TS	DFL
C2L	8	Scarboro JCT	Scarboro TS	LC
C2L	9	Ellesmere JCT	Ellesmere TS	LC
C2M	1	Pickle Lake SS	C2M T#NB1 JCT	LC

C2P	1	Crowland TS	Tunnel JCT	LC
C2P	2	Tunnel JCT	JBL JCT	LC
C2P	3	Vale Inco JCT	Port Colborne TS	LC
C2P	4	Tunnel JCT	Panabrasives CTS	LC
C2P	5	Vale Inco JCT	ValeCanLtd-PrtClbrne	LC
C2P	6	JBL JCT	Vale Inco JCT	LC
C2P	7	JBL JCT	JBL CSS	LC
C31	1	Chatham SS	C31 SKWP CMS JCT	LC
C35P	1	Cherrywood TS	Markham #2 JCT	DFL
C35P	2	Markham #2 JCT	Markham #3 JCT	DFL
C35P	3	Markham #3 JCT	Parkway TS	DFL
C35P	4	Markham #2 JCT	Markham #2 PH JCT	LC
C35P	5	Markham #2 PH JCT	Markham MTS #2	LC
C35P	6	Markham #3 JCT	Markham #3 PH JCT	LC
C35P	7	Markham #3 PH JCT	Markham MTS #3	LC
C36P	1	Cherrywood TS	Markham #2 JCT	DFL
C36P	2	Markham #2 JCT	Markham #3 JCT	DFL
C36P	3	Markham #3 JCT	Parkway TS	DFL
C36P	4	Markham #2 JCT	Markham #2 PH JCT	LC
C36P	5	Markham #2 PH JCT	Markham MTS #2	LC
C36P	6	Markham #3 JCT	Markham #3 PH JCT	LC
C36P	7	Markham #3 PH JCT	Markham MTS #3	LC
C3A	1	Cameron Falls GS	Alexander SS	LC
C3A	2	Alexander SS	Alexander GS	LC
C3A	3	Alexander SS	Alexander SS	LC
C3L	1	C2L C3L STR 85 JCT	Ellesmere TS	OTHER
C3L	2	Ellesmere TS	C2L C3L STR 34 JCT	OTHER
C3L	4	Leaside Str 4-5 JCT	Leaside TS	DFL
C3L	5	Cherrywood TS	Ellesmere JCT	DFL
C3L	6	Ellesmere JCT	Scarboro JCT	DFL
C3L	7	Scarboro JCT	Leaside Str 4-5 JCT	DFL
C3L	8	Scarboro JCT	Scarboro TS	LC
C3L	9	Ellesmere JCT	Ellesmere TS	LC
C3L	10	Leaside Str 4-5 JCT	Leaside TS	DFL
C3S	1	Chats Falls SS	South March TS	N
C3S	3	South March TS	Kanata MTS #1	LC
C4R	1	Cherrywood TS	Malvern TS	DFL
C4R	2	Malvern TS	Agincourt JCT	DFL
C4R	3	Agincourt JCT	Leslie TS	DFL

C4R	4	Finch JCT	Richview TS	DFL
C4R	5	Agincourt JCT	Agincourt TS	LC
C4R	6	Finch JCT	Finch TS	LC
C4R	9	Leslie TS	Finch JCT	DFL
C550VP	15	Parkway JCT	Parkway TS	N
C550VP	18	Cherrywood TS	Parkway JCT	N
C550VP	19	Parkway JCT	Claireville TS	N
C551V	21	Cherrywood TS	Claireville TS	N
C552V	1	Cherrywood TS	Claireville TS	N
C553VP	1	Cherrywood TS	Parkway JCT	N
C553VP	2	Parkway JCT	Claireville TS	N
C553VP	3	Parkway JCT	Parkway TS	N
C5E	1	Cecil TS	Terauley TS	LC
C5E	2	Terauley TS	Manhole A OPF	LC
C5E	3	Manhole A OPF	Esplanade TS	LC
C5R	1	Cherrywood TS	Malvern TS	DFL
C5R	2	Malvern TS	Agincourt JCT	DFL
C5R	3	Agincourt JCT	Leslie TS	DFL
C5R	4	Leslie TS	Richview TS	DFL
C5R	6	Leslie TS	Leslie TS	LC
C7BM	1	Arnprior JCT	Barrett Chute SS	DFL
C7BM	2	Fitzroy JCT	Arnprior JCT	DFL
C7BM	3	Chats Falls SS	Fitzroy JCT	OTHER
C7BM	4	Fitzroy JCT	Bellman JCT	DFL
C7BM	5	Manordale JCT	Manordale JCT	OTHER
C7BM	6	NQL1 B JCT	Merivale TS	DFL
C7BM	7	NQL1 B JCT	Centre Point JCT	LC
C7BM	8	Woodroffe TS	Lincoln Heights TS	LC
C7BM	9	NQL1 B JCT	Manordale JCT	LC
C7BM	10	Arnprior JCT	Arnprior TS	LC
C7BM	11	Centre Point JCT	Woodroffe TS	LC
C7BM	14	Manordale JCT	Manordale JCT	LC
C7BM	19	Centre Point JCT	Centre Point MTS	LC
C7BM	20	Centre Point MTS	Centre Point MTS	LC
C7BM	21	Centre Point MTS	Centre Point MTS	LC
C7BM	24	Manordale JCT	Manordale MTS	LC
C7BM	25	Manordale JCT	Manordale MTS	LC
C7BM	26	Bellman JCT	NQL1 B JCT	DFL
C7E	1	Cecil TS	Terauley TS	LC

C7E	2	Terauley TS	Manhole A OPF	LC
C7E	3	Manhole A OPF	Esplanade TS	LC
C9	1	Caledonia TS	Caledonia Q35M-C9 J	LC
C9	2	Caledonia Q35M-C9 J	Hartford JCT	LC
C9	3	Hartford JCT	Vanessa JCT	LC
C9	4	Caledonia Q35M-C9 J	Caledonia Q35M-C9 J	OTHER
C9	5	Vanessa JCT	Bloomsburg JCT	LC
C9	6	Bloomsburg JCT	Norfolk TS	LC
C9	7	Bloomsburg JCT	Bloomsburg DS	LC
D10H	1	Detweiler TS	Leong JCT	LC
D10H	2	Leong JCT	Waterloo JCT	LC
D10H	3	Waterloo JCT	Wallenstein JCT	LC
D10H	4	Wallenstein JCT	Palmerston TS	OTHER
D10H	5	Palmerston TS	Hanover TS	LC
D10H	6	Waterloo JCT	Rush MTS	LC
D10H	7	Wallenstein JCT	Elmira TS	LC
D10S	1	DeCew Falls SS	Hooper's JCT	LC
D10S	2	Hooper's JCT	Vansickle TS	LC
D10S	3	Vansickle TS	Louth JCT	LC
D10S	4	Louth JCT	Glendale TS	LC
D10S	6	Louth JCT	Carlton TS	LC
D11J	1	Copeland SS	Lower Simcoe St JCT	LC
D11J	2	Lower Simcoe St JCT	John TS	LC
D11K	1	Detweiler TS	Kitchener #1&4 JCT	LC
D11K	2	Kitchener #1&4 JCT	Kitchener MTS#1	LC
D11K	3	Kitchener #1&4 JCT	Kitchener MTS#4	LC
D12J	1	Copeland SS	Lower Simcoe St JCT	LC
D12J	2	Lower Simcoe St JCT	John TS	LC
D12K	1	Detweiler TS	Kitchener #1&4 JCT	LC
D12K	2	Kitchener #1&4 JCT	Kitchener MTS#1	LC
D12K	3	Kitchener #1&4 JCT	Kitchener MTS#4	LC
D1A	1	Holland Road JCT	Allanburg TS	LC
D1A	2	Fibre JCT	Holland Road JCT	LC
D1A	3	Gibson JCT	Fibre JCT	LC
D1A	4	St.Johns Valley JCT	Gibson JCT	LC
D1A	5	Hooper's JCT	St.Johns Valley JCT	LC
D1A	6	DeCew Falls SS	Hooper's JCT	LC
D1A	7	Holland Road JCT	ResFP Thorold CTS	LC
D1A	8	Fibre JCT	D1A STR 4A JCT	OTHER

D1A	9	Gibson JCT	Thorold TS	LC
D1M	1	Des Joachims TS	Minden TS	N
D1W	1	Detweiler JCT	Wolverton JCT	LC
D1W	2	Wolverton JCT	D1W STR 82 JCT	OTHER
D1W	3	Wolverton JCT	Wolverton DS	LC
D23G	2	Pinard TS	Pinard D23G JCT	LC
D26A	1	Dryden TS	Mackenzie TS	N
D2H	1	Pinard TS	Pinard JCT #2	LC
D2H	2	Pinard JCT #2	Hwy 634 JCT	LC
D2H	3	Pinard JCT #2	Hwy 634 JCT	LC
D2H	4	Hwy 634 JCT	Island Falls JCT	LC
D2H	5	Hwy 634 JCT	Island Falls JCT	LC
D2H	6	Island Falls JCT	Greenwater Pr Pk JCT	LC
D2H	7	Island Falls JCT	Greenwater Pr Pk JCT	LC
D2H	8	Greenwater Pr Pk JCT	Calder JCT	LC
D2H	9	Greenwater Pr Pk JCT	Calder JCT	LC
D2H	10	Hunta JCT	Hunta SS	LC
D2H	11	Hunta JCT	Hunta JCT	LC
D2H	12	Hwy 634 JCT	Hwy 634 JCT	LC
D2H	13	Island Falls JCT	Island Falls JCT	LC
D2H	14	Greenwater Pr Pk JCT	Greenwater Pr Pk JCT	LC
D2H	15	Pinard JCT #2	Pinard JCT #2	LC
D2H	18	Calder JCT	Calder JCT	LC
D2H	19	Calder JCT	Hunta JCT	LC
D2H	20	Calder JCT	Hunta JCT	LC
D2H	21	Calder JCT	Calder CSS	LC
D2L	1	Dymond TS	New Liskeard JCT	DFL
D2L	2	Upper Notch JCT	Cassels 2 JCT	DFL
D2L	4	Cassels 2 JCT	Herridge Lake JCT	DFL
D2L	6	Herridge Lake JCT	Marten River JCT	DFL
D2L	8	Marten River JCT	D2L STR 409 JCT	DFL
D2L	10	Cassels JCT	Temagami DS	LC
D2L	13	Cassels 2 JCT	Cassels JCT	DFL
D2L	14	Cassels JCT	Cassels 2 JCT	DFL
D2L	15	Herridge Lake JCT	Herridge Lake DS	DFL
D2L	16	Herridge Lake DS	Herridge Lake JCT	DFL
D2L	17	D2L STR 409 JCT	Crystal Falls SS	DFL
D2L	18	New Liskeard JCT	Upper Notch JCT	DFL
D2L	19	New Liskeard JCT	New Liskeard JCT #2	LC

D2M	1	Des Joachims TS	Otter Creek JCT	DFL
D2M	2	Otter Creek JCT	Minden TS	DFL
D2M	3	Otter Creek JCT	Wallace JCT	LC
D2M	4	Otter Creek JCT	Otter Creek JCT	LC
D2M	5	Wallace JCT	Wallace TS	LC
D2M	6	Wallace JCT	Wallace TS	LC
D3A	1	Fibre JCT	Allanburg TS	LC
D3A	2	St.Johns Valley JCT	Gibson JCT	LC
D3A	3	Hooper's JCT	St.Johns Valley JCT	LC
D3A	4	DeCew Falls SS	Hooper's JCT	LC
D3A	5	Gibson JCT	Thorold TS	LC
D3A	6	Allanburg TS	D3A T#1FHK JCT	LC
D3A	7	Michigan JCT	ASW Steel JCT	LC
D3A	8	Gibson JCT	Fibre JCT	LC
D3A	9	Fibre JCT	Fibre JCT	OTHER
D3A	10	ASW Steel JCT	ASW Steel CTS	LC
D3A	11	ASW Steel JCT	ASW Steel CTS	LC
D3A	13	D3A T#1FHK JCT	Michigan JCT	LC
D3H	1	Pinard TS	Pinard JCT #2	LC
D3H	2	Pinard JCT #2	Hwy 634 JCT	LC
D3H	3	Pinard JCT #2	Hwy 634 JCT	LC
D3H	4	Hwy 634 JCT	Island Falls JCT	LC
D3H	5	Hwy 634 JCT	Island Falls JCT	LC
D3H	6	Island Falls JCT	Greenwater Pr Pk JCT	LC
D3H	7	Island Falls JCT	Greenwater Pr Pk JCT	LC
D3H	8	Greenwater Pr Pk JCT	Calder JCT	LC
D3H	9	Greenwater Pr Pk JCT	Calder JCT	LC
D3H	10	Hunta JCT	Hunta SS	LC
D3H	11	Hunta JCT	Hunta JCT	LC
D3H	12	Hwy 634 JCT	Hwy 634 JCT	LC
D3H	13	Island Falls JCT	Island Falls JCT	LC
D3H	14	Greenwater Pr Pk JCT	Greenwater Pr Pk JCT	LC
D3H	15	Pinard JCT #2	Pinard JCT #2	LC
D3H	16	Calder JCT	Hunta JCT	LC
D3H	17	Calder JCT	Hunta JCT	LC
D3H	18	Calder JCT	Calder JCT	LC
D3K	1	Dymond TS	Nine Mile JCT	DFL
D3K	2	Nine Mile JCT	Dane JCT	DFL
D3K	3	Dane JCT	Gull Lake South JCT	DFL

D3K	4	Dane JCT	Notre Developmnt CTS	OTHER
D3K	5	Gull Lake South JCT	Kirkland Lake TS	DFL
D3K	7	Gull Lake South JCT	Gull Lake South JCT	LC
D3M	1	Des Joachims TS	Minden TS	N
D4	1	Pinard TS	Pinard JCT #2	LC
D4	2	Pinard JCT #2	Abitibi Canyon GS	LC
D4	3	Pinard JCT #2	Abitibi Canyon GS	LC
D4M	1	Des Joachims TS	Otter Creek JCT	N
D4M	2	Otter Creek JCT	Minden TS	N
D4W	1	Detweiler TS	Kitchener #9 JCT	DFL
D4W	2	Kitchener #9 JCT	Buchanan TS	DFL
D4W	3	Kitchener #9 JCT	Kitchener MTS#9	LC
D4Z	1	Dymond TS	Nine Mile JCT	N
D4Z	2	Nine Mile JCT	IPB Casey JCT	N
D501P	3	Pinard TS	Porcupine TS	N
D5A	1	St.Isidore TS	Cumberland JCT	N
D5A	2	Cumberland JCT	Orleans JCT #2	DFL
D5A	3	St.Isidore TS	Longueuil JCT	LC
D5A	4	Longueuil JCT	Ivaco CTS	LC
D5A	5	Longueuil JCT	Longueuil TS	LC
D5A	6	Cumberland JCT	IPB Masson JCT	N
D5A	7	Orleans JCT #2	Orleans TS	LC
D5A	10	Orleans JCT #2	Hawthorne TS	DFL
D5D	1	Dryden TS	Dryden JCT B	LC
D5D	2	Dryden JCT B	Domtar Dryden CTS	LC
D5D	3	Dryden JCT B	Dryden JCT B	OTHER
D5H	1	Des Joachims TS	Otto Holden TS	N
D5W	1	Detweiler TS	Kitchener #9 JCT	DFL
D5W	2	Kitchener #9 JCT	Buchanan TS	DFL
D5W	3	Kitchener #9 JCT	Kitchener MTS#9	LC
D6	1	Des Joachims TS	Des Joachims JCT	LC
D6	2	Des Joachims JCT	Tee Lake JCT	LC
D6	3	Tee Lake JCT	Deep River DS	LC
D6	4	Deep River DS	Chalk River CTS	LC
D6	5	Des Joachims JCT	Des Joachims DS	LC
D6	7	Chalk River CTS	19D684-1 JCT	LC
D6	8	Petawawa JCT	Forest Lea JCT	LC
D6	9	Forest Lea JCT	Pembroke TS	OTHER
D6	10	Forest Lea JCT	Forest Lea DS	LC

D6	11	Petawawa JCT	Craig JCT	LC
D6	12	Craig JCT	Petawawa DS	LC
D6	13	Craig JCT	Craig DS	LC
D6	14	19D684-1 JCT	Petawawa JCT	LC
D6T	1	Pinard TS	Pinard JCT #2	LC
D6T	2	Pinard JCT #2	Abitibi Canyn JCT #2	LC
D6T	3	Pinard JCT #2	Abitibi Canyn JCT #2	LC
D6T	4	Abitibi Canyn JCT #2	P Sutherland Sr JCT	LC
D6T	5	Otter Rapids SS	Otter Rapids SS	LC
D6T	6	Otter Rapids SS	Otter Rapids SS	OTHER
D6T	7	Otter Rapids SS	Otter Rapids GS	OTHER
D6T	8	P Sutherland Sr JCT	Otter Rapids SS	LC
D6T	9	P Sutherland Sr JCT	P Sutherland Sr SYD	LC
D6V	1	Detweiler TS	Waterloo North 3 JCT	DFL
D6V	2	Scheifele JCT	Guelph North JCT	DFL
D6V	3	Fergus JCT	Orangeville TS	DFL
D6V	4	Fergus JCT	Fergus TS	LC
D6V	5	Guelph North JCT	Fergus JCT	DFL
D6V	6	Guelph North JCT	Campbell TS	DFL
D6V	7	Waterloo North 3 JCT	Scheifele JCT	DFL
D6V	8	Waterloo North 3 JCT	Waterloo North MTS 3	LC
D6V	9	Scheifele JCT	Scheifele MTS	LC
D6V	10	Campbell TS	Speed River JCT	DFL
D6V	11	Speed River JCT	Cedar TS	DFL
D6Y	1	Duplex TS	Glengrove TS	LC
D7F	1	Detweiler TS	Detweiler JCT	DFL
D7F	2	Detweiler JCT	Kitchener #6 JCT	DFL
D7F	3	Kitchener #6 JCT	Siebert JCT	DFL
D7F	4	Siebert JCT	D7F_D9F T#162 PH JCT	DFL
D7F	5	Kitchener MTS#7	Freeport SS	DFL
D7F	6	Siebert JCT	Kitchener #2&3 JCT	LC
D7F	7	Kitchener #2&3 JCT	Kitchener MTS#3	LC
D7F	9	Kitchener MTS#7	Kitchener MTS#7	LC
D7F	10	D7F_D9F T#162 PH JCT	D7F_D9F T#157 PH JCT	DFL
D7F	11	D7F_D9F T#157 PH JCT	Kitchener MTS#7	DFL
D7V	1	Detweiler TS	Waterloo North 3 JCT	DFL
D7V	2	Scheifele JCT	Guelph North JCT	DFL
D7V	3	Fergus JCT	Orangeville TS	DFL
D7V	4	Fergus JCT	Fergus TS	LC

D7V	5	Guelph North JCT	Fergus JCT	DFL
D7V	6	Guelph North JCT	Campbell TS	DFL
D7V	7	Waterloo North 3 JCT	Scheifele JCT	DFL
D7V	8	Waterloo North 3 JCT	Waterloo North MTS 3	LC
D7V	9	Scheifele JCT	Scheifele MTS	LC
D7V	10	Campbell TS	Speed River JCT	DFL
D7V	11	Speed River JCT	Cedar TS	DFL
D8S	1	Detweiler TS	Leong JCT	LC
D8S	2	Leong JCT	St.Marys TS	LC
D8S	3	Leong JCT	Rush MTS	LC
D9F	1	Detweiler TS	Detweiler JCT	DFL
D9F	2	Detweiler JCT	Kitchener #6 JCT	DFL
D9F	3	Kitchener #6 JCT	Siebert JCT	DFL
D9F	4	Siebert JCT	D7F_D9F T#162 PH JCT	DFL
D9F	5	Kitchener MTS#7	Freeport SS	DFL
D9F	6	Siebert JCT	Kitchener #2&3 JCT	LC
D9F	7	Kitchener #2&3 JCT	Kitchener MTS#3	LC
D9F	9	Kitchener MTS#7	Kitchener MTS#7	LC
D9F	10	D7F_D9F T#162 PH JCT	D7F_D9F T#157 PH JCT	DFL
D9F	11	D7F_D9F T#157 PH JCT	Kitchener MTS#7	DFL
D9HS	1	DeCew Falls SS	Hooper's JCT	LC
D9HS	2	Hooper's JCT	Vansickle TS	LC
D9HS	3	Vansickle TS	Louth JCT	LC
D9HS	7	Louth JCT	Carlton TS	LC
D9HS	8	Beach Road JCT	Beach TS	LC
D9HS	9	Louth JCT	Glendale TS	LC
E1C	1	Ear Falls TS	Selco JCT	DFL
E1C	2	Selco JCT	Slate Falls JCT	DFL
E1C	3	Etruscan JCT	Placer JCT	DFL
E1C	5	Etruscan JCT	Etruscan Entrprs CTS	OTHER
E1C	8	Golden Patricia JCT	Etruscan JCT	DFL
E1C	11	Slate Falls JCT	Golden Patricia JCT	DFL
E1C	12	Slate Falls JCT	Slate Falls DS	LC
E1C	17	Golden Patricia JCT	Golden Patricia JCT	LC
E1Q	2	Quirke Lake JCT	Quirke Lake CTS	OTHER
E20S	1	Essa TS	Stayner TS	N
E21S	1	Essa TS	Stayner TS	N
E26	1	Essa TS	Waubaushene JCT	LC
E26	2	Waubaushene JCT	Holmur JCT	LC

E26	3	Parry Sound JCT	Parry Sound TS	LC
E26	4	Waubaushene JCT	Waubaushene TS	LC
E26	5	Holmur JCT	Parry Sound JCT	LC
E26	6	Holmur JCT	Holmur CSS	LC
E27	1	Essa TS	Waubaushene JCT	LC
E27	2	Waubaushene JCT	Holmur JCT	LC
E27	3	Parry Sound JCT	Parry Sound TS	LC
E27	4	Waubaushene JCT	Waubaushene TS	LC
E27	5	Holmur JCT	Parry Sound JCT	LC
E27	6	Holmur JCT	Holmur CSS	LC
E28	1	Essa TS	Allandale TPS JCT	LC
E28	2	Allandale TPS JCT	Barrie TS	LC
E28	3	Allandale TPS JCT	Allandale TPS	LC
E29	1	Essa TS	Allandale TPS JCT	LC
E29	2	Allandale TPS JCT	Barrie TS	LC
E29	3	Allandale TPS JCT	Allandale TPS	LC
E2Q	1	Elliot Lake TS	Quirke Lake JCT	OTHER
E2Q	2	Quirke Lake JCT	Denison Mines CTS	OTHER
E2R	1	Ear Falls TS	Pakwash JCT	LC
E2R	2	Pakwash JCT	Balmer JCT	LC
E2R	4	Balmer JCT	Red Lake TS	LC
E34M	1	Merivale TS	Terry Fox JCT	DFL
E34M	2	Terry Fox JCT	Terry Fox JCT	DFL
E34M	3	Terry Fox JCT	Didsbury Road JCT	DFL
E34M	4	Didsbury Road JCT	Almonte TS	DFL
E34M	5	Almonte TS	Almonte TS	LC
E34M	6	Almonte TS	Almonte TS	DFL
E34M	7	Terry Fox JCT	Terry Fox MTS	LC
E34M	8	Terry Fox JCT	Terry Fox MTS	LC
E34M	11	Cambrian JCT	Cambrian MTS	DFL
E3B	1	Essa TS	Barrie TS	LC
E4B	1	Essa TS	Barrie TS	LC
E4D	1	Ear Falls TS	Scout Lake JCT	DFL
E4D	2	Scout Lake JCT	Dryden TS	DFL
E4D	3	Scout Lake JCT	Perrault Falls DS	LC
E510V	1	Essa TS	Claireville TS	N
E511V	1	Essa TS	Claireville TS	N
E564L	1	Evergreen SS	Longwood TS	N
E578P	1	Evergreen SS	Parkhill CTS	N

E6L	1	Seaforth TS	Egmondville CSS	LC
E8F	1	Essex TS	Chrysler WAP MTS	LC
E8F	2	Chrysler WAP MTS	G.M.Windsor MTS	LC
E8F	3	G.M.Windsor MTS	Ford Annex MTS	LC
E8F	4	Ford Annex MTS	Ford Windsor MTS	LC
E8F	5	Ford Windsor MTS	East Windsor CGS	LC
E8V	1	Essa TS	Alliston JCT	DFL
E8V	2	Alliston JCT	Everett JCT	DFL
E8V	3	Alliston JCT	Alliston TS	LC
E8V	4	Alliston JCT	Alliston TS	LC
E8V	6	Alliston JCT	Alliston JCT	DFL
E8V	7	Everett JCT	Orangeville TS	DFL
E8V	8	Everett JCT	Everett TS	LC
E9F	1	Essex TS	Chrysler WAP MTS	LC
E9F	2	Chrysler WAP MTS	G.M.Windsor MTS	LC
E9F	3	G.M.Windsor MTS	Ford Annex MTS	LC
E9F	4	Ford Annex MTS	Ford Windsor MTS	LC
E9F	5	Ford Windsor MTS	East Windsor CGS	LC
E9V	1	Essa TS	Alliston JCT	DFL
E9V	2	Alliston JCT	Everett JCT	DFL
E9V	3	Alliston JCT	Alliston TS	LC
E9V	4	Alliston JCT	Alliston TS	OTHER
E9V	6	Alliston JCT	Alliston JCT	DFL
E9V	7	Everett JCT	Orangeville TS	DFL
E9V	8	Everett JCT	Everett TS	LC
F10MV	1	Merivale TS	City View JCT	LC
F10MV	2	City View JCT	Val Tetreau JCT	LC
F10MV	4	City View JCT	Woodroffe TS	LC
F10MV	5	Woodroffe TS	Lincoln Heights TS	LC
F10MV	6	Val Tetreau JCT	Hinchey TS	LC
F11C	1	Freeport SS	Speedsville JCT	DFL
F11C	2	Speedsville JCT	Preston TS	OTHER
F11C	3	Speedsville JCT	Speed River JCT	DFL
F11C	4	Speed River JCT	Cedar TS	DFL
F11C	5	Freeport SS	Kitchener Graber JCT	LC
F11C	6	Kitchener Graber JCT	Kitchener MTS#5	LC
F11C	7	Freeport SS	Freeport SS	DFL
F12C	1	Freeport SS	Speedsville JCT	DFL
F12C	2	Speedsville JCT	Preston TS	DFL

F12C	3	Speedsville JCT	Speed River JCT	DFL
F12C	4	Speed River JCT	Cedar TS	DFL
F12C	5	Freeport SS	Kitchener Graber JCT	LC
F12C	6	Kitchener Graber JCT	Kitchener MTS#5	LC
F12C	7	Freeport SS	Freeport SS	DFL
F1B	1	Fort Frances TS	Fort Frances JCT	LC
F1B	2	Burleigh JCT	Burleigh DS	LC
F1B	3	Fort Frances TS	Fort Frances MTS	LC
F1B	4	Fort Frances JCT	Burleigh JCT	LC
F1B	5	Burleigh JCT	Hwy #11 JCT	OTHER
F1E	1	Kapuskasing TS	AP Calstock CSS JCT	LC
F1E	2	Nagagami CSS JCT	Hearst TS	LC
F1E	3	Kapuskasing TS	Spruce Falls TS	N
F1E	4	AP Calstock CSS JCT	A.P. Calstock CSS	LC
F1E	5	AP Calstock CSS JCT	Nagagami CSS JCT	LC
F1E	6	Nagagami CSS JCT	Nagagami CSS	LC
F25A	1	Fort Frances TS	Mackenzie TS	N
F2B	1	Fort Frances TS	H2O Pwr FtFrnces CGS	LC
F3M	1	Fort Frances TS	H2O Pwr FtFrnces CGS	N
F3M	2	H2O Pwr FtFrnces CGS	Int'l Bdy Minn JCT	N
FA16G3K	1	Matachewan JCT	Indian Chute JCT	OTHER
FS23M1	1	Elliot Lake TS	Quirke Lake JCT	OTHER
FS9M6	1	Martindale TS	Dominion Drive DS	OTHER
H	1	Summerhaven SS	Summerhaven CSS	LC
H BUS	1	Rabbit Lake SS	Kenora DS	LC
H10DE	1	Hearn SS	Hearn SS	LC
H10DE	2	Hearn SS	Don Fleet JCT	LC
H10DE	3	Don Fleet JCT	Esplanade TS	LC
H10DE	4	Esplanade TS	Lower Simcoe St JCT	OTHER
H10DE	5	Lower Simcoe St JCT	Copeland SS	OTHER
H11L	1	Hearn SS	Waverly OPF	LC
H11L	2	Main TS	Lumsden JCT	LC
H11L	3	Lumsden JCT	Todmorden JCT	LC
H11L	4	Todmorden JCT	Leaside TS	LC
H11L	7	Waverly OPF	Brookside OPF	LC
H11L	8	Brookside OPF	Main TS	LC
H12P	1	Hearn SS	Portlands Energy JCT	LC
H12P	3	Hearn SS	Hearn SS	LC
H13P	1	Hearn SS	Portlands Energy JCT	LC

H13P	3	Hearn SS	Hearn SS	LC
H14P	1	Hearn SS	Portlands Energy JCT	LC
H14P	3	Hearn SS	Hearn SS	LC
H1L	1	Hearn SS	Basin TS	LC
H1L	2	Basin TS	Mill Street JCT	LC
H1L	3	Mill Street JCT	Gerrard TS	LC
H1L	4	Gerrard TS	Bloor Street JCT	LC
H1L	5	Bloor Street JCT	Leaside TS	LC
H1L	6	Basin TS	Basin TS	LC
H1L	7	Gerrard TS	Carlaw TS	LC
H2	1	Wiltshire TS	Wiltshire TS	N
H22D	1	Harmon GS	Harmon JCT	LC
H22D	2	Harmon JCT	Smoky Falls JCT	LC
H22D	3	Little Long JCT	Pinard TS	LC
H22D	4	Little Long JCT	Little Long 2 JCT	LC
H22D	5	Harmon JCT	Kipling JCT	LC
H22D	6	Smoky Falls JCT	Little Long JCT	LC
H22D	7	Kipling JCT	Kipling GS	LC
H22D	9	Smoky Falls JCT	Smoky Falls 2 JCT	LC
H23B	1	Hinchinbrooke SS	Stone Mills JCT	DFL
H23B	2	Pancake JCT	Belleville TS	DFL
H23B	3	Stone Mills JCT	Pancake JCT	DFL
H23B	4	Stone Mills JCT	Stone Mills CGS	LC
H23S	1	Otto Holden TS	Widdifield SS	N
H23S	2	Widdifield SS	Pedley JCT	DFL
H23S	3	Pedley JCT	Martindale TS	DFL
H23S	4	Pedley JCT	Crystal Falls TS	LC
H24S	1	Otto Holden TS	Widdifield SS	N
H24S	2	Widdifield SS	A.P. North Bay JCT	DFL
H24S	3	Grant JCT	Martindale TS	DFL
H24S	4	Widdifield SS	Trout Lake TS	LC
H24S	5	Grant JCT	Crystal Falls TS	LC
H24S	6	A.P. North Bay JCT	Grant JCT	DFL
H24S	7	A.P. North Bay JCT	A.P. North Bay JCT	LC
H27H	1	Hinchinbrooke SS	Bannockburn JCT	N
H27H	2	Bannockburn JCT	Havelock TS	N
H29	1	Hurontario SS	Pleasant TS	LC
H2CA	1	Gage TS	Gage TS	OTHER
H2JK	1	Hearn SS	Basin TS	LC

H2JK	2	Basin TS	Don Fleet JCT	LC
H2JK	3	Basin TS	Don Fleet JCT	LC
H2JK	4	Don Fleet JCT	Esplanade TS	LC
H2JK	5	Esplanade TS	John TS	OTHER
H2JK	6	John TS	Strachan TS	LC
H2JK	8	Riverside JCT	Manby TS	LC
H2JK	10	Strachan TS	Riverside JCT	LC
H2JK	11	Hearn SS	Basin TS	OTHER
H2JK	12	John TS	John TS	LC
H2JK	16	Hearn SS	Hearn SS	LC
H2JK	17	Strachan TS	Strachan TS	LC
H2JK	18	Strachan TS	Strachan TS	LC
H2N	3	Calstock DS JCT	Calstock DS	LC
H30	1	Hurontario SS	Pleasant TS	LC
H35D	1	Beach TS	Dof.Bay Front CTS	LC
H36D	1	Beach TS	Dof.Bay Front CTS	LC
H3L	1	Hearn SS	Basin TS	LC
H3L	2	Basin TS	Mill Street JCT	LC
H3L	3	Mill Street JCT	Gerrard TS	LC
H3L	5	Gerrard TS	Bloor Street JCT	LC
H3L	6	Bloor Street JCT	Leaside TS	LC
H3L	7	Basin TS	Basin TS	LC
H3L	8	Gerrard TS	Carlaw TS	LC
H3L	9	Gerrard TS	Bloor Street JCT	LC
H4Z	1	Otto Holden TS	IPB La Cave JCT	N
H5K	1	Beach TS	Kenilworth TS	LC
H6K	1	Beach TS	Kenilworth TS	LC
H6LC	1	Hearn SS	Don Fleet JCT	LC
H6LC	2	Gerrard JCT	Bloor Street JCT	LC
H6LC	3	Bloor Street JCT	Leaside TS	LC
H6LC	4	Gerrard JCT	Cecil TS	LC
H6LC	5	Don Fleet JCT	Gerrard JCT	LC
H6T	1	Hunta SS	Tisdale JCT	DFL
H6T	2	Tisdale JCT	Laforest Road JCT	DFL
H6T	3	Laforest Road JCT	Timmins TS	DFL
H6T	4	Laforest Road JCT	Laforest Road DS	LC
H75	1	Lakeshore TS	South Middle Road TS	LC
H76	1	Lakeshore TS	South Middle Road TS	LC
H7L	1	Hearn SS	Waverly OPF	LC

H7L	2	Main TS	Lumsden JCT	LC
H7L	3	Lumsden JCT	Todmorden JCT	LC
H7L	4	Todmorden JCT	Leaside TS	LC
H7L	7	Waverly OPF	Brookside OPF	LC
H7L	8	Brookside OPF	Main TS	LC
H7T	1	Hunta SS	Warkus JCT	DFL
H7T	2	Warkus JCT	Timmins TS	DFL
H7T	3	Warkus JCT	Kidd Minesite CTS	LC
H82V	1	Holland TS	Holland JCT	DFL
H82V	2	Holland JCT	Vaughan #4 JCT	DFL
H82V	3	Vaughan #4 JCT	Woodbridge JCT	DFL
H82V	4	Woodbridge JCT	Claireville TS	DFL
H82V	5	Vaughan #4 JCT	Vaughan MTS #4	LC
H82V	6	Holland TS	Holland TS	DFL
H83V	1	Holland TS	Holland JCT	DFL
H83V	2	Holland JCT	Vaughan #4 JCT	DFL
H83V	3	Vaughan #4 JCT	Woodbridge JCT	DFL
H83V	4	Woodbridge JCT	Claireville TS	DFL
H83V	5	Vaughan #4 JCT	Vaughan MTS #4	LC
H83V	6	Holland TS	Holland TS	DFL
H8LC	1	Hearn SS	Don Fleet JCT	LC
H8LC	2	Gerrard JCT	Bloor Street JCT	LC
H8LC	3	Bloor Street JCT	Leaside TS	LC
H8LC	4	Gerrard JCT	Cecil TS	LC
H8LC	5	Don Fleet JCT	Gerrard JCT	LC
H9A	1	Hawthorne TS	Orleans JCT #2	LC
H9A	2	Borromee JCT	Wilhaven JCT	LC
H9A	3	Cumberland JCT	Gamble H9A JCT	LC
H9A	5	Borromee JCT	Navan DS	LC
H9A	7	Wilhaven JCT	Cumberland JCT	LC
H9A	10	Orleans JCT	Bilberry Creek JCT	LC
H9A	11	Cumberland DS JCT	Orleans JCT	LC
H9A	12	Gamble H9A JCT	Cumberland DS JCT	LC
H9A	13	Gamble H9A JCT	IPB Masson JCT	N
H9A	15	Bilberry Creek JCT	Bilberry Creek TS	LC
H9A	16	Cumberland DS JCT	Cumberland DS	LC
H9A	17	Cumberland DS JCT	Cumberland DS	LC
H9A	19	Wilhaven JCT	Wilhaven DS	LC
H9A	20	Cumberland DS JCT	Cumberland DS JCT	LC

H9A	21	Bilberry Creek JCT	Bilberry Creek JCT	OTHER
H9A	22	Cumberland DS JCT	Cumberland DS JCT	LC
H9A	23	Cumberland DS JCT	Cumberland DS	OTHER
H9A	24	Gamble H9A JCT	Gamble H9A JCT	LC
H9A	25	Orleans JCT #2	Borromee JCT	LC
H9A	26	Orleans JCT #2	Orleans TS	LC
H9DE	1	Hearn SS	Hearn SS	LC
H9DE	2	Hearn SS	Don Fleet JCT	LC
H9DE	3	Don Fleet JCT	Esplanade TS	LC
H9DE	4	Esplanade TS	Lower Simcoe St JCT	OTHER
H9DE	5	Lower Simcoe St JCT	Copeland SS	OTHER
H9K	1	Hunta H9K JCT	Smooth Rock Fals JCT	DFL
H9K	2	Hunta H9K JCT	H9K STR 127A JCT	DFL
H9K	3	H9K STR 127A JCT	Smooth Rk Fls JCT #2	DFL
H9K	4	Smooth Rk Fls JCT #2	Yellow Falls JCT	DFL
H9K	5	Fauquier JCT	Carmichael Falls JCT	DFL
H9K	6	Carmichael Falls JCT	Spruce Falls JCT	DFL
H9K	7	Spruce Falls JCT	Kapuskasing TS	DFL
H9K	10	Fauquier JCT	Fauquier DS	LC
H9K	11	Carmichael Falls JCT	Carmichael Falls JCT	LC
H9K	14	Hunta SS	Hunta H9K JCT	DFL
H9K	15	Smooth Rock Fals JCT	H9K STR 127A JCT	DFL
H9K	16	Smooth Rock Fals JCT	Smooth Rock Falls DS	LC
H9K	18	Kapuskasing TS	Kapuskasing CTS	OTHER
H9K	19	Yellow Falls JCT	Fauquier JCT	DFL
H9K	20	Yellow Falls JCT	Yellow Falls CGS	LC
H9W	1	Beach TS	West Lincoln JCT	LC
H9W	2	West Lincoln JCT	West Lincoln CSS	LC
HIGHFAL2	1	Anjigami TS	Anjigami JCT	N
HIGHFAL2	3	Anjigami JCT	Wawa TS	OTHER
HL3	1	Beach TS	Birmingham TS	LC
HL3	2	Birmingham TS	Stirton TS	LC
HL3	4	Stirton TS	Elgin TS	OTHER
HL3	5	Elgin TS	Newton TS	LC
HL4	1	Beach TS	Birmingham TS	LC
HL4	2	Birmingham TS	Stirton TS	LC
HL4	4	Stirton TS	Elgin TS	OTHER
HL4	5	Elgin TS	Newton TS	LC
HLNGWTH1	1	Anjigami TS	Anjigami JCT #2	N

HLNGWTH1	3	Anjigami JCT #2	Wawa TS	OTHER
IDLE12	1	Beach Road JCT	Beach TS	OTHER
IDLE13	1	Beach Road JCT	Beach TS	OTHER
IDLE14	1	Beach TS	Beach STR 44 JCT	OTHER
IDLE15	1	Allanburg West JCT	Rosedene JCT	OTHER
IDLE18	1	IDLE18 STR2 J	IDLE18 STR14 J	OTHER
IDLE19	1	Atikokan TGS	Marmion Lake JCT	OTHER
IDLE20	1	Buchanan TS	Buchanan JCT	OTHER
IDLE22	1	Des Joachims TS	Colony Lane JCT	OTHER
IDLE23	1	Nia Park EP J	Mid R. JCT Niagara	OTHER
IDLE24	1	Leong JCT	Nafziger Road JCT	OTHER
IDLE25	1	Major Ln Str 16 JCT	MacPherson Road JCT	OTHER
IDLE25	2	Major Ln Str 16 JCT	MacPherson Road JCT	OTHER
IDLE26	1	Buchanan JCT	Buchanan East JCT	OTHER
IDLE28	1	Kent TS	Kent JCT	OTHER
IDLE28	2	Kent JCT	T9K T#207 JCT	OTHER
IDLE29	1	Holland Marsh JCT	Holland JCT	OTHER
IDLE30	1	Holland Marsh JCT	Holland JCT	OTHER
IDLE31	2	D3A T#8S JCT	D3A T#11S JCT	OTHER
IDLE8	1	Claireville TS	Claireville JCT	OTHER
IDLE9	1	Claireville TS	Claireville JCT	OTHER
J1B	1	Keith TS	Brighton Intface JCT	LC
J20B	1	Keith TS	Brighton Intface JCT	LC
J3E	1	Keith TS	Keith TS	N
J3E	2	Crawford JCT	Essex TS	DFL
J3E	3	Crawford JCT	Crawford TS	LC
J3E	4	Keith TS	Ojibway JCT	DFL
J3E	5	Ojibway JCT	Crawford JCT	DFL
J4E	1	Keith TS	Keith TS	N
J4E	2	Crawford JCT	Essex TS	DFL
J4E	3	Crawford JCT	Crawford TS	LC
J4E	4	Keith TS	Ojibway JCT	DFL
J4E	5	Ojibway JCT	Crawford JCT	DFL
J5D	1	Keith TS	McKee JCT	N
J5D	3	McKee JCT	Mid R. JCT Waterman	N
K1	1	Kirkland Lake TS	Gull Lake North JCT	OTHER
K10SB	1	Richview JCT	Manby TS	OTHER
K10SB	2	Scarboro Idle JCT	Leaside Idle JCT	OTHER
K11W	1	Manby TS	Runnymede TS	DFL

K11W	2	Runnymede TS	Wiltshire TS	DFL
K12	1	Karn TS	Woodstock TS	DFL
K12	2	Woodstock TS	Commerce Way TS	DFL
K12W	1	Manby TS	Runnymede TS	DFL
K12W	2	Runnymede TS	Wiltshire TS	DFL
K13J	1	Manby TS	Riverside JCT	LC
K13J	3	Strachan TS	John TS	LC
K13J	4	Riverside JCT	Strachan TS	LC
K13J	5	Strachan TS	Strachan TS	LC
K14J	1	Manby TS	Riverside JCT	LC
K14J	3	Strachan TS	John TS	LC
K14J	4	Riverside JCT	Strachan TS	LC
K14J	5	Strachan TS	Strachan TS	LC
K1G	1	Kenilworth TS	Gage TS	OTHER
K1W	1	Manby TS	St.Clair Avenue JCT	DFL
K1W	2	St.Clair Avenue JCT	Wiltshire TS	DFL
K1W	4	St.Clair Avenue JCT	Fairbank TS	LC
K2	1	Kirkland Lake TS	Gull Lake North JCT	LC
K2	2	Gull Lake North JCT	Gull Lake North JCT	LC
K2	6	Gull Lake North JCT	Holloway Holt JCT	LC
K21C	1	Manby TS	Manby TS	LC
K21C	2	Manby TS	Applewood JCT	LC
K21C	3	Manby TS	Applewood JCT	LC
K21C	4	Applewood JCT	Applewood JCT	LC
K21C	5	Applewood JCT	Cooksville TS	LC
K21C	6	Cooksville TS	Cooksville TS	LC
K21W	1	Kenora TS	IPB Manitoba 230 JCT	N
K22W	1	Kenora TS	IPB Manitoba 230 JCT	N
K23C	1	Manby TS	Applewood JCT	LC
K23C	2	Applewood JCT	Cooksville TS	LC
K23C	3	Applewood JCT	Applewood JCT	OTHER
K23D	1	Kenora TS	TCPL Vermill Bay JCT	DFL
K23D	2	TCPL Vermill Bay JCT	Dryden TS	DFL
K23D	3	TCPL Vermill Bay JCT	TCPL Vermill Bay CTS	LC
K24F	1	Kenora TS	Rainy River Gold JCT	DFL
K24F	2	Rainy River Gold JCT	Fort Frances TS	DFL
K24F	3	Rainy River Gold JCT	Rainy River Gold CSS	LC
K25BUS	1	Sandusk SS	Sandusk CGS	LC
K2G	1	Kenilworth TS	Gage TS	OTHER

K2M	1	Rabbit Lake SS	Norman JCT	LC
K2Z	1	Kent TS	Kent JCT	OTHER
K2Z	2	Kent JCT	Tilbury JCT	OTHER
K2Z	3	Tilbury JCT	Woodslee JCT	LC
K2Z	4	Woodslee JCT	Lauzon JCT	LC
K2Z	5	Tilbury JCT	Tilbury West JCT	LC
K2Z	6	Woodslee JCT	Gosfield CGS JCT	LC
K2Z	7	Tilbury JCT	Belle River JCT	OTHER
K2Z	8	Tilbury West JCT	Tilbury West JCT	OTHER
K2Z	9	Tilbury West JCT	Tilbury West JCT	OTHER
K2Z	10	Tilbury West JCT	Tilbury West DS	LC
K2Z	12	Lauzon JCT	Lauzon TS	LC
K2Z	13	Rourke Line JCT	Belle River JCT	OTHER
K2Z	14	Lauzon JCT	Rourke Line JCT	LC
K2Z	15	Rourke Line JCT	Belle River TS	LC
K2Z	16	Gosfield CGS JCT	Kingsville TS	LC
K2Z	17	Gosfield CGS JCT	Gosfield Wind CGS	LC
K38S	1	Kapuskasing TS	Spruce Falls JCT	DFL
K38S	2	Spruce Falls JCT	O'brien JCT	DFL
K38S	3	Spruce Falls JCT	A.P. Kapuskasing JCT	LC
K38S	5	O'brien JCT	Spruce Falls TS	DFL
K38S	6	O'brien JCT	Kapuskasing CTS	LC
K3D	1	Rabbit Lake SS	K3D-10 SW JCT	DFL
K3D	2	K3D-10 SW JCT	Vermilion Bay JCT	DFL
K3D	3	Vermilion Bay JCT	Eton JCT	DFL
K3D	4	Vermilion Bay JCT	Vermilion Bay DS	LC
K3D	5	Dryden TS	Sam Lake DS	LC
K3D	6	Eton JCT	Dryden TS	DFL
K3D	7	Eton JCT	Eton DS	LC
K3W	1	Manby TS	St.Clair Avenue JCT	DFL
K3W	2	St.Clair Avenue JCT	Wiltshire TS	DFL
K3W	4	St.Clair Avenue JCT	Fairbank TS	LC
K4	1	Kirkland Lake TS	Macassa Mill JCT	LC
K4	3	Macassa #3 JCT	93K4-89 JCT	LC
K4	4	Matachewan JCT	Extender Min. JCT	OTHER
K4	5	Extender Min. JCT	Elk Lake JCT	OTHER
K4	7	Macassa #3 JCT	Macassa #3 JCT	LC
K4	8	Matachewan JCT	Young-Davidson CTS	LC
K4	9	93K4-89 JCT	Matachewan JCT	LC

K4	10	Macassa Mill JCT	Macassa #3 JCT	LC
K4	11	Macassa Mill JCT	Macassa Mill JCT	LC
K40M	1	Sandusk SS	Sandusk JCT	DFL
K40M	2	Sandusk JCT	Caledonia JCT	DFL
K40M	3	Caledonia JCT	Middleport TS	DFL
K40M	4	Caledonia JCT	Caledonia TS	LC
K4W	1	Rabbit Lake SS	Minaki JCT	LC
K4W	2	Minaki JCT	Whitedog Falls SS	LC
K4W	3	Minaki JCT	Minaki DS	LC
K4W	4	Minaki JCT	Minaki DS	LC
K5W	1	Rabbit Lake SS	Minaki JCT	LC
K5W	3	Minaki JCT	Whitedog Falls SS	LC
K6F	1	Rabbit Lake SS	Margach JCT	DFL
K6F	2	Margach JCT	Sioux Narrows JCT	DFL
K6F	3	K6F-10 SW JCT	Nestor Falls JCT	DFL
K6F	4	Nestor Falls JCT	Ainsworth JCT	DFL
K6F	5	Sioux Narrows JCT	Sioux Narrows DS	LC
K6F	6	Nestor Falls JCT	Nestor Falls DS	LC
K6F	7	Sioux Narrows JCT	K6F-10 SW JCT	DFL
K6F	8	Ainsworth JCT	Fort Frances JCT	DFL
K6F	10	Margach JCT	Margach DS	LC
K6F	11	Margach JCT	Margach DS	OTHER
K6F	12	Ainsworth JCT	Barwick JCT	LC
K6F	13	Fort Frances JCT	Fort Frances TS	DFL
K6F	14	Fort Frances JCT	Fort Frances JCT	OTHER
K6F	15	Barwick JCT	Ainsworth Str #4 JCT	LC
K6F	16	Barwick JCT	Barwick TS	LC
K6F	17	Barwick JCT	Barwick TS	LC
K6J	1	Manby TS	Riverside JCT	LC
K6J	3	Strachan TS	John TS	LC
K6J	6	Riverside JCT	Strachan TS	LC
K6J	7	Strachan TS	Strachan TS	LC
K6J	8	Strachan TS	Strachan TS	LC
K6Z	1	Kent TS	Tilbury JCT	OTHER
K6Z	3	Belle River JCT	Rourke Line JCT	LC
K6Z	4	Kingsville TS	K6Z STR 15 JCT	LC
K6Z	5	Lauzon JCT	Lauzon TS	LC
K6Z	6	Rourke Line JCT	Lauzon JCT	LC
K6Z	7	Rourke Line JCT	Belle River TS	LC

K6Z	11	Pte-Aux-RochesWF JCT	Belle River JCT	LC
K6Z	12	Pte-Aux-RochesWF JCT	Pte-Aux-RochesWF CGS	LC
K6Z	13	K6Z STR 15 JCT	Pte-Aux-RochesWF JCT	LC
K7	1	Karn TS	Woodstock TS	DFL
K7	2	Woodstock TS	Commerce Way TS	DFL
K7B	7	Vansco JCT	Manby TS	OTHER
K7K	1	Kenora TS	Kenora TS	DFL
K7K	2	Kenora TS	Rabbit Lake SS	DFL
K7K	3	Kenora TS	Weyerhaeuser Ken CTS	LC
K8B	7	Vansco JCT	Manby TS	OTHER
K9S	1	Richview JCT	Manby TS	OTHER
K9S	2	Scarboro Idle JCT	Leaside Idle JCT	OTHER
L12C	1	Leaside TS	Balfour JCT	LC
L12C	2	Balfour JCT	Charles TS	LC
L12C	3	Charles TS	Cecil TS	LC
L13W	1	Leaside TS	Balfour JCT	DFL
L13W	2	Balfour JCT	Bridgman JCT	DFL
L13W	3	Bridgman JCT	Dufferin JCT	DFL
L13W	4	Dufferin JCT	Wiltshire TS	DFL
L13W	5	Dufferin JCT	Dufferin TS	LC
L13W	7	Bridgman JCT	Bridgman TS	OTHER
L13W	8	Dufferin JCT	Dufferin JCT	LC
L14W	1	Leaside TS	Bayview JCT	DFL
L14W	2	Bayview JCT	Birch JCT	DFL
L14W	3	Birch JCT	Bridgman JCT	DFL
L14W	4	Bridgman JCT	Wiltshire TS	DFL
L14W	5	Bridgman JCT	Bridgman TS	LC
L15	1	Leaside TS	Bayview JCT	LC
L15	2	Bayview JCT	Balfour JCT	LC
L15	3	Balfour JCT	Bridgman JCT	LC
L15	4	Bridgman JCT	Bridgman TS	LC
L16D	1	Leaside TS	Duplex TS	LC
L18W	1	Leaside TS	Leaside TS	DFL
L18W	2	Leaside TS	Bayview JCT	DFL
L18W	3	Bayview JCT	Birch JCT	DFL
L18W	4	Birch JCT	Bridgman JCT	DFL
L18W	5	Bridgman JCT	Bartlett JCT	DFL
L18W	6	Bartlett JCT	Wiltshire TS	DFL
L18W	7	Bridgman JCT	Bridgman TS	LC

L18W	8	Bartlett JCT	Bartlett JCT	LC
L18W	9	Bartlett JCT	Dufferin TS	LC
L1MB	4	St.Lawrence TS	Lunenburg JCT	LC
L1MB	5	Lunenburg JCT	Morrisburg JCT	LC
L1MB	6	Morrisburg JCT	Casco JCT	LC
L1MB	7	Cardinal JCT	Brockville Chem. JCT	LC
L1MB	8	Brockville Chem. JCT	Brockville TS	OTHER
L1MB	9	Morrisburg JCT	Morrisburg TS	LC
L1MB	10	Cardinal JCT	Enbridge PL Card CTS	LC
L1MB	11	Brockville Chem. JCT	Dyno Nobel CTS	LC
L1MB	13	Casco JCT	Cardinal JCT	LC
L1MB	15	Casco JCT	Cardinal Power CSS	LC
L1S	1	Crystal Falls SS	Verner JCT	DFL
L1S	2	Verner JCT	Warren DS	DFL
L1S	3	Warren DS	Sudbury JCT	DFL
L1S	5	Sudbury JCT	Martindale TS	DFL
L1S	6	Sudbury JCT	Milman Foundry JCT	LC
L1S	7	Verner JCT	Verner POLE 45 JCT	LC
L1S	8	Verner POLE 45 JCT	Verner DS	OTHER
L1S	9	Verner POLE 45 JCT	Verner DS	LC
L1S	10	Warren DS	Warren DS	LC
L1S	11	Milman Foundry JCT	Milman Foundry CTS	LC
L1S	12	Milman Foundry JCT	Milman Foundry CTS	LC
L20D	1	Little Long JCT	Smoky Falls JCT	LC
L20D	3	Little Long JCT	Pinard TS	DFL
L20D	4	Little Long SS	Little Long JCT	DFL
L20D	5	Smoky Falls JCT	Harmon JCT	LC
L20D	6	Harmon JCT	Kipling JCT	LC
L20D	7	Kipling JCT	Kipling 2 GS	LC
L20D	8	Harmon JCT	Harmon 2 GS	LC
L20D	10	Smoky Falls JCT	Smoky Falls 2 JCT	LC
L20H	1	St.Lawrence TS	Easton JCT	DFL
L20H	2	Easton JCT	Crosby JCT	DFL
L20H	3	Easton JCT	Brockville TS	LC
L20H	4	Crosby JCT	Hinchinbrooke SS	DFL
L20H	7	Crosby JCT	Crosby TS	LC
L20H	9	Crosby JCT	Crosby TS	LC
L21H	1	St.Lawrence TS	Easton Yule JCT	DFL
L21H	2	Easton Yule JCT	Crosby JCT	DFL

L21H	3	Easton Yule JCT	Smiths Falls TS	LC
L21H	4	Crosby JCT	Hinchinbrooke SS	DFL
L21H	7	Crosby JCT	Crosby TS	LC
L21H	9	Crosby JCT	Crosby TS	OTHER
L21K	2	Haig JCT	Applewood JCT	OTHER
L21K	3	Haig JCT	Applewood JCT	OTHER
L21S	1	Little Long SS	Knob JCT	N
L21S	6	A.P. Kapuskasing JCT	Kapuskasing TS	N
L21S	7	Knob JCT	A.P. Kapuskasing JCT	N
L22H	1	St.Lawrence TS	Raisin River JCT	DFL
L22H	2	Raisin River JCT	Easton Yule JCT	DFL
L22H	3	Easton Yule JCT	Easton JCT	DFL
L22H	4	Easton JCT	Hinchinbrooke SS	DFL
L22H	5	Easton JCT	Brockville TS	LC
L22H	6	Easton Yule JCT	Smiths Falls TS	LC
L22K	2	Haig JCT	Applewood JCT	OTHER
L22K	3	Haig JCT	Applewood JCT	OTHER
L23CK	2	Haig JCT	Applewood JCT	OTHER
L23CK	3	Haig JCT	Applewood JCT	OTHER
L23N	1	Lambton TS #2	Talford JCT	DFL
L23N	2	Talford JCT	Sarnia Scott TS	DFL
L23N	6	Talford JCT	Dupont JCT	LC
L23N	12	Dupont JCT	Shell Sarnia CTS	LC
L23N	13	Dupont JCT	Nova St Clair R CTS	LC
L24A	1	Raisin River JCT	Crysler JCT #2	DFL
L24A	2	St.Lawrence TS	Raisin River JCT	DFL
L24A	3	Crysler JCT #2	Hawthorne TS	DFL
L24A	4	Crysler JCT #2	Crysler CGS	LC
L24CR	2	Haig JCT	Applewood JCT	OTHER
L24CR	3	Haig JCT	Applewood JCT	OTHER
L24L	1	Lambton TS #2	Longwood TS	DFL
L24L	2	Longwood TS	Longwood TS	DFL
L24L	3	Longwood TS	Longwood TS	LC
L25V	1	Lambton TS #2	Nova Moore JCT	DFL
L25V	2	Nova Moore JCT	Nova SS	DFL
L25V	4	Nova Moore JCT	Nova Moore CTS	LC
L26L	1	Lambton TS #2	Longwood TS	DFL
L26L	2	Longwood TS	Longwood TS	DFL
L26L	3	Longwood TS	Longwood TS	LC

L27V	1	Lambton TS #2	Nova Moore JCT	DFL
L27V	2	Nova Moore JCT	Nova SS	DFL
L27V	4	Nova Moore JCT	Nova Moore CTS	LC
L27V	5	Nova SS	Nova Corunna CTS	LC
L27V	6	Nova SS	Nova SS	DFL
L28C	1	Lambton TS #2	GSPC JCT	DFL
L28C	2	Lynwood JCT	Chatham SS	DFL
L28C	3	Lynwood JCT	Kent TS	LC
L28C	4	GSPC JCT	Lynwood JCT	DFL
L29C	1	Lambton TS #2	East Lk StClair JCT	DFL
L29C	2	Lynwood JCT	Chatham SS	DFL
L29C	3	Lynwood JCT	Kent TS	LC
L29C	4	East Lk StClair JCT	North Kent 1 JCT	DFL
L29C	5	East Lk StClair JCT	East Lk StClair CGS	LC
L29C	6	North Kent 1 JCT	Lynwood JCT	DFL
L29C	7	North Kent 1 JCT	North Kent 1 CGS	LC
L2M	1	Limebank JCT	Limebank JCT	LC
L2M	2	Chesterville N. JCT	Marionville JCT	OTHER
L2M	3	Newington JCT	Chesterville S. JCT	LC
L2M	4	St.Lawrence TS	Lunenburg JCT	LC
L2M	5	Lunenburg JCT	Morrisburg JCT	LC
L2M	6	Lunenburg JCT	Newington JCT	LC
L2M	7	Osgoode JCT	Limebank JCT	LC
L2M	8	Morrisburg JCT	Casco JCT	LC
L2M	9	Morrisburg JCT	Morrisburg TS	LC
L2M	10	Brockville Chem. JCT	Dyno Nobel CTS	LC
L2M	11	Brockville Chem. JCT	Brockville TS	OTHER
L2M	12	Casco JCT	Brockville Chem. JCT	LC
L2M	13	Casco JCT	Cardinal Power CSS	LC
L2M	14	Marionville JCT	Osgoode JCT	LC
L2M	15	Osgoode JCT	Russell DS	OTHER
L2M	16	Marionville JCT	Marionville DS	LC
L2M	17	Newington JCT	Newington DS	LC
L2M	19	Chesterville S. JCT	Chesterville TS	LC
L2M	20	Chesterville N. JCT	Chesterville TS	OTHER
L2M	21	Chesterville S. JCT	Chesterville N. JCT	OTHER
L2M	22	Limebank JCT	Limebank JCT	LC
L2M	23	Limebank JCT	Limebank MTS	LC
L2M	24	Limebank JCT	Limebank MTS	LC

L2M	25	Limebank JCT	Merivale TS	LC
L2M	26	Limebank JCT	Limebank MTS	LC
L2Y	1	Leaside TS	Glengrove TS	LC
L33P	1	St.Lawrence TS	Massena JCT	N
L34P	1	St.Lawrence TS	Massena JCT	N
L37G	1	Lambton TS #2	Greenfld Intface JCT	N
L38G	1	Lambton TS #2	Greenfld Intface JCT	N
L3P	1	Lakehead TS	Port Arthur TS #1	N
L4C	1	Leaside TS	Charles TS	LC
L4D	1	Lambton TS #2	Mid R JCT St Cl L4D	N
L4P	1	Lakehead TS	Port Arthur TS #1	N
L4R	1	L4R STR 30 JCT	L4R STR 17 JCT	OTHER
L4S	1	Leaside TS	L4S L5S STR 9 JCT	OTHER
L4S	2	Bermondsey JCT	Scarboro TS	OTHER
L51D	1	Lambton TS #2	Mid R JCT St Cl L51D	N
L51D	3	Lambton TS #2	Lambton TS #2	N
L51D	4	Lambton TS #2	Lambton TS #2	N
L5C	4	St.Lawrence TS	L5C MSO JCT	OTHER
L5D	1	Leaside TS	Duplex TS	LC
L5H	1	Otto Holden TS	Mattawa JCT	DFL
L5H	2	North Bay TS	Commanda JCT	DFL
L5H	3	Commanda JCT	Crystal Falls SS	DFL
L5H	4	Commanda JCT	Commanda JCT	OTHER
L5H	6	Commanda JCT	Commanda JCT	OTHER
L5H	7	Mattawa JCT	North Bay TS	DFL
L5H	8	Mattawa JCT	Mattawa DS	LC
L5S	1	Leaside TS	L4S L5S STR 9 JCT	OTHER
L5S	2	Bermondsey JCT	Scarboro TS	OTHER
L7S	2	Kirkton JCT	Devizes JCT	LC
L7S	3	Seaforth L7S JCT	Goshen JCT	LC
L7S	4	Devizes JCT	Portland JCT	LC
L7S	5	Portland JCT	St.Marys TS	LC
L7S	6	Portland JCT	St.Marys Cement CTS	LC
L7S	7	Devizes JCT	Enbrg Bryanston CTS	LC
L7S	8	Kirkton JCT	Biddulph JCT	LC
L7S	9	Biddulph JCT	Grand Bend East JCT	LC
L7S	10	Grand Bend East JCT	Lake Huron WTP CTS	LC
L7S	11	Biddulph JCT	Centralia TS	LC
L7S	12	Centralia TS	McGillivray R&BP CTS	LC

Witness: LI Clement

L7S	13	Seaforth TS	Seaforth L7S JCT	LC
L7S	14	Seaforth L7S JCT	Seaforth LSO JCT	OTHER
L7S	15	Grand Bend East JCT	Grand Bend East DS	LC
L7S	16	Goshen JCT	Kirkton JCT	LC
L7S	17	Goshen JCT	Goshen CSS	LC
L9C	1	Leaside TS	Balfour JCT	LC
L9C	2	Balfour JCT	Charles TS	LC
L9C	3	Charles TS	Cecil TS	LC
M11S	1	G.M.St Cath CTS	McKinnon's JCT	OTHER
M1R	1	Merivale TS	South Gloucester JCT	LC
M1R	2	South Gloucester JCT	Greely JCT	LC
M1R	3	Greely JCT	Russell DS	LC
M1R	4	Greely JCT	Greely DS	LC
M1R	5	South Gloucester JCT	South Gloucester DS	LC
M1R	6	South Gloucester DS	South Gloucester DS	LC
M1R	7	South Gloucester DS	South Gloucester DS	OTHER
M1R	8	Russell DS	Russell DS	LC
M1R	9	Russell DS	Russell DS	LC
M1R	10	Russell DS	Russell DS	OTHER
M1S	1	Moose Lake TS	Valerie Falls JCT	LC
M1S	2	Mill Creek JCT	H2O Pwr SturgFls CGS	LC
M1S	4	Mill Creek JCT	H2O Pwr Calm Lk CGS	LC
M1S	6	Valerie Falls JCT	Mill Creek JCT	LC
M20D	1	Middleport TS	Carluke JCT	DFL
M20D	2	Carluke JCT	Trinity JCT	DFL
M20D	3	Trinity JCT	Galt South JCT	DFL
M20D	5	Galt JCT	Kitchener #8 JCT	DFL
M20D	6	Galt JCT	Preston JCT	DFL
M20D	7	Detweiler JCT	Detweiler TS	DFL
M20D	8	Detweiler JCT	Kitchener MTS#6	LC
M20D	9	Preston JCT	Cambridge #1 JCT	DFL
M20D	10	Cambridge #1 JCT	Preston TS	DFL
M20D	11	Cambridge #1 JCT	EnergyInc(Cam) MTS#1	LC
M20D	12	Kitchener #8 JCT	Detweiler JCT	DFL
M20D	13	Kitchener #8 JCT	Kitchener MTS#8	LC
M20D	15	Preston JCT	Galt TS	LC
M20D	16	Preston TS	Preston TS	OTHER
M20D	17	Galt South JCT	Galt JCT	DFL
M21D	1	Middleport TS	Carluke JCT	DFL

M21D	2	Carluke JCT	Trinity JCT	DFL
M21D	3	Trinity JCT	Galt JCT	DFL
M21D	5	Galt JCT	Galt North JCT	DFL
M21D	6	Galt JCT	Ameristeel Cambr JCT	DFL
M21D	7	Ameristeel Cambr JCT	Preston JCT	DFL
M21D	8	Ameristeel Cambr JCT	Ameristeel Cambr CTS	LC
M21D	9	Detweiler JCT	Detweiler TS	DFL
M21D	10	Detweiler JCT	Kitchener MTS#6	LC
M21D	11	Preston JCT	Cambridge #1 JCT	DFL
M21D	12	Cambridge #1 JCT	Preston TS	DFL
M21D	13	Cambridge #1 JCT	EnergyInc(Cam) MTS#1	LC
M21D	14	Kitchener #8 JCT	Detweiler JCT	DFL
M21D	15	Kitchener #8 JCT	Kitchener MTS#8	LC
M21D	16	Preston TS	Preston TS	OTHER
M21D	18	Preston JCT	Galt TS	LC
M21D	19	Galt North JCT	Kitchener #8 JCT	DFL
M23L	1	Marathon TS	Greenwich WF CGS JCT	DFL
M23L	2	Greenwich WF CGS JCT	Lakehead TS	DFL
M23L	4	Greenwich WF CGS JCT	Greenwich LakeWF CSS	LC
M24L	1	Marathon TS	Greenwich WF CGS JCT	DFL
M24L	2	Greenwich WF CGS JCT	Lakehead TS	DFL
M24L	4	Greenwich WF CGS JCT	Greenwich LakeWF CSS	LC
M27B	1	Middleport TS	Carluke JCT	DFL
M27B	2	Carluke JCT	Southcote JCT	DFL
M27B	3	Southcote JCT	Horning JCT	DFL
M27B	4	Horning JCT	Burlington TS	DFL
M27B	5	Horning JCT	Horning TS	LC
M28B	1	Middleport TS	Carluke JCT	DFL
M28B	2	Carluke JCT	Southcote JCT	DFL
M28B	3	Southcote JCT	Horning JCT	DFL
M28B	4	Horning JCT	Burlington TS	DFL
M28B	5	Horning JCT	Horning TS	LC
M2D	1	Ignace JCT	Dryden TS	DFL
M2D	2	Moose Lake TS	Ignace JCT	DFL
M2D	4	Dryden TS	Dryden TS	DFL
M2D	5	Dryden TS	Dryden JCT B	OTHER
M2W	1	Marathon TS	Pic JCT	LC
M2W	2	Pic JCT	Manitouwadge JCT	LC
M2W	4	Manitouwadge JCT	Willroy JCT	LC

M2W	6	Manitouwadge JCT	Manitouwadge JCT B	LC
M2W	8	Marathon TS	Black River JCT	LC
M2W	9	Williams Mine JCT	Hemlo Mine JCT	LC
M2W	10	Hemlo Mine JCT	Animki JCT	LC
M2W	15	Marathon TS	Pic DS	LC
M2W	16	Black River JCT	Umbata Falls JCT	LC
M2W	22	Manitouwadge JCT B	Manitouwadge DS #1	LC
M2W	25	Umbata Falls JCT	Williams Mine JCT	LC
M2W	26	Manitouwadge JCT B	Manitouwadge TS	LC
M2W	27	Animki JCT	White River DS	LC
M30A	1	Merivale TS	Albion JCT	DFL
M30A	2	Albion JCT	Ellwood MTS JCT	DFL
M30A	3	Albion JCT	Albion TS	LC
M30A	5	Ellwood MTS JCT	Ellwood MTS	LC
M30A	6	Ellwood MTS JCT	Hawthorne TS	DFL
M31	1	Espanola TS	Espanola A JCT	LC
M31	2	Eddy Tap A JCT	Domtar Espanola CGS	LC
M31	3	Espanola A JCT	Eddy Tap A JCT	LC
M31	4	S2B-M31 JCT	Espanola A JCT	OTHER
M31A	1	Merivale TS	Albion JCT	DFL
M31A	2	Albion JCT	Ellwood MTS JCT	DFL
M31A	3	Albion JCT	Albion TS	LC
M31A	5	Ellwood MTS JCT	Ellwood MTS	LC
M31A	6	Ellwood MTS JCT	Hawthorne TS	DFL
M31W	1	Middleport TS	Carluke JCT	DFL
M31W	2	Carluke JCT	Salford JCT	DFL
M31W	3	Salford JCT	Buchanan TS	DFL
M31W	4	Salford JCT	Ingersoll JCT	DFL
M31W	5	Ingersoll JCT	Ingersoll TS	LC
M31W	6	Ingersoll JCT	Karn TS	DFL
M32S	1	Merivale TS	Nepean TS	DFL
M32S	2	Nepean TS	South March TS	DFL
M32S	3	South March TS	Kanata MTS #1	LC
M32W	1	Middleport TS	Carluke JCT	DFL
M32W	2	Carluke JCT	Newport JCT	DFL
M32W	3	Newport JCT	Salford JCT	DFL
M32W	4	Salford JCT	Buchanan TS	DFL
M32W	5	Newport JCT	Brantford TS	LC
M32W	6	Salford JCT	Ingersoll JCT	DFL

M32W	7	Ingersoll JCT	Ingersoll TS	LC
M32W	8	Ingersoll JCT	Karn TS	DFL
M33W	1	Middleport TS	Carluke JCT	DFL
M33W	2	Carluke JCT	Newport JCT	DFL
M33W	3	Newport JCT	Salford JCT	DFL
M33W	4	Salford JCT	Buchanan TS	DFL
M33W	5	Newport JCT	Brantford TS	LC
M34H	1	Middleport TS	Carluke JCT	N
M34H	2	Carluke JCT	Southcote JCT	N
M34H	3	Southcote JCT	Neale JCT	N
M34H	4	Neale JCT	Hannon JCT	N
M34H	5	Hannon JCT	Beach TS	N
M3E	1	Manitou Falls GS	Ear Falls TS	LC
M4G	1	Merivale TS	Nepean Epworth JCT	LC
M4G	2	Nepean Epworth JCT	Ottawa JCT	LC
M4G	3	Carling TS	Lisgar TS	LC
M4G	4	Lisgar TS	Slater TS	LC
M4G	5	Ottawa JCT	Carling TS	LC
M4G	6	Nepean Epworth JCT	Nepean Epworth MTS	LC
M570V	1	Milton SS	Claireville TS	N
M571V	1	Milton SS	Claireville TS	N
M572T	1	Milton SS	Trafalgar TS	N
M573T	1	Milton SS	Trafalgar TS	N
M585M	1	Middleport TS	Milton SS	N
M5G	1	Merivale TS	Nepean Epworth JCT	LC
M5G	2	Nepean Epworth JCT	Ottawa JCT	LC
M5G	3	Carling TS	Lisgar TS	LC
M5G	4	Ottawa JCT	Carling TS	LC
M5G	5	Nepean Epworth JCT	Nepean Epworth MTS	LC
M6E	1	Minden TS	Cooper's Falls JCT	DFL
M6E	2	Cooper's Falls JCT	Orillia TS	DFL
M6E	3	Orillia TS	Midhurst TS	DFL
M6E	4	Cooper's Falls JCT	Bracebridge JCT	LC
M6E	5	Midhurst TS	Essa TS	DFL
M6E	6	Bracebridge JCT	Muskoka TS	LC
M6E	7	Bracebridge JCT	Bracebridge TS	LC
M7E	1	Minden TS	Cooper's Falls JCT	DFL
M7E	2	Cooper's Falls JCT	Orillia TS	DFL
M7E	3	Orillia TS	Midhurst TS	DFL

M7E	4	Cooper's Falls JCT	Bracebridge JCT	LC
M7E	5	Midhurst TS	Essa TS	DFL
M7E	6	Bracebridge JCT	Muskoka TS	LC
M80B	1	Minden TS	Beaverton JCT	DFL
M80B	2	Beaverton JCT	Beaver JCT	DFL
M80B	3	Beaver JCT	Brown Hill TS	DFL
M80B	5	Beaverton JCT	Lindsay TS	LC
M80B	6	Beaver JCT	Beaverton TS	LC
M81B	1	Minden TS	Beaverton JCT	DFL
M81B	2	Beaverton JCT	Beaver JCT	DFL
M81B	3	Beaver JCT	Brown Hill TS	DFL
M81B	5	Beaverton JCT	Lindsay TS	LC
M81B	6	Beaver JCT	Beaverton TS	LC
M9K	1	Moosonee DS	Moosonee JCT	LC
M9K	2	Moosonee JCT	Moosonee JCT	LC
M9K	3	Moosonee JCT	Moosonee SS	LC
M9K	4	Moosonee JCT	Moosonee DS	LC
M9K	5	Moosonee JCT	Moosonee DS	LC
N1S	1	Sarnia Scott TS	Vidal JCT	LC
N1S	3	Vidal JCT	Suncor CTS	LC
N20K	1	Nanticoke TS	Imp Oil Nanticok JCT	DFL
N20K	2	Imp Oil Nanticok JCT	Sandusk JCT	DFL
N20K	3	Sandusk JCT	Sandusk SS	DFL
N20K	4	Imp Oil Nanticok JCT	Imp Oil Nanticok JCT	LC
N21J	1	Nanticoke TS	Stelco JCT	LC
N21J	2	Stelco JCT	Jarvis TS	LC
N21J	3	Stelco JCT	Nanticoke Creek JCT	LC
N21W	1	Sarnia Scott TS	Lucasville JCT	DFL
N21W	2	Lucasville JCT	Wanstead JCT	DFL
N21W	3	Bostwick Road JCT	N21W-W42L T22-471 J	DFL
N21W	4	Lucasville JCT	Plank Road JCT	LC
N21W	5	Bostwick Road JCT	Wonderland TS	LC
N21W	6	Plank Road JCT	Confederation Rd JCT	LC
N21W	7	Confederation Rd JCT	Modeland TS	LC
N21W	8	Wanstead JCT	Bostwick Road JCT	DFL
N21W	9	Wanstead JCT	Wanstead TS	LC
N21W	10	N21W-W42L T22-471 J	N21W T2 JCT	OTHER
N21W	11	N21W T2 JCT	Buchanan TS	DFL
N21W	12	N21W-W42L T22-471 J	N21W T2 JCT	DFL

N21W	13	N21W-W42L T22-471 J	N21W T466 JCT	OTHER
N22J	1	Nanticoke TS	Stelco JCT	LC
N22J	2	Stelco JCT	Jarvis TS	LC
N22J	3	Stelco JCT	Nanticoke Creek JCT	LC
N22W	1	Sarnia Scott TS	Lucasville JCT	DFL
N22W	2	Lucasville JCT	Wanstead JCT	DFL
N22W	3	Bostwick Road JCT	Buchanan TS	DFL
N22W	4	Lucasville JCT	Plank Road JCT	LC
N22W	5	Bostwick Road JCT	Wonderland TS	LC
N22W	6	Plank Road JCT	Confederation Rd JCT	LC
N22W	7	Confederation Rd JCT	Modeland TS	LC
N22W	8	Wanstead JCT	Bostwick Road JCT	DFL
N22W	9	Wanstead JCT	Wanstead TS	LC
N25N	1	Nanticoke TS	Nanticoke Solar GS	LC
N37S	1	Nanticoke TS	Summerhaven SS	N
N4S	1	Sarnia Scott TS	Vidal JCT	LC
N4S	3	Vidal JCT	Suncor CTS	LC
N580M	1	Nanticoke TS	Middleport TS	N
N581M	1	Nanticoke TS	Middleport TS	N
N582L	1	Nanticoke TS	Longwood TS	N
N5K	1	Wallaceburg TS	Kent TS	OTHER
N5K	2	Kimball JCT	Wallaceburg TS	LC
N5K	3	Sarnia Scott TS	Kimball JCT	LC
N5M	1	Nanticoke TS	Grand JCT	DFL
N5M	2	Caledonia JCT	Middleport TS	DFL
N5M	3	Caledonia JCT	Caledonia TS	LC
N5M	4	Grand JCT	Caledonia JCT	DFL
N5M	5	Grand JCT	Grand CSS	LC
N6C	1	Sarnia Scott TS	St.Andrews TS	LC
N6M	1	Nanticoke TS	Caledonia JCT	DFL
N6M	2	Caledonia JCT	Middleport TS	DFL
N6M	3	Caledonia JCT	Caledonia TS	LC
N6S	1	Sarnia Scott TS	Sarnia Scott JCT	LC
N6S	2	Sarnia Scott JCT	Vidal JCT	OTHER
N6S	3	Sarnia Scott JCT	Arlanxeo Can Inc JCT	LC
N6S	4	Arlanxeo Can Inc JCT	TransAlta Energy JCT	LC
N6S	5	Arlanxeo Can Inc JCT	Arlanxeo Can Inc CTS	LC
N6S	7	TransAlta Energy JCT	Imperial Oil CTS	LC
N6S	9	TransAlta Energy JCT	TransAlta Energy JCT	LC

N7C	1	Sarnia Scott TS	St.Andrews TS	LC
N7S	1	Sarnia Scott TS	Sarnia Scott JCT	LC
N7S	2	Sarnia Scott JCT	Arlanxeo Can Inc JCT	LC
N7S	3	Arlanxeo Can Inc JCT	TransAlta Energy JCT	LC
N7S	4	TransAlta Energy JCT	Imperial Oil CTS	LC
N7S	5	Arlanxeo Can Inc JCT	Arlanxeo Can Inc CTS	LC
N7S	7	TransAlta Energy JCT	TransAlta Energy JCT	LC
N93A	1	Atikokan TGS	Marmion Lake JCT	LC
N93A	2	Marmion Lake JCT	Mackenzie TS	LC
NA12M6	1	Buttonville TS	Gormley JCT	OTHER
NA153M3	1	Holland Marsh JCT	153M3 STR162 JCT	OTHER
NA153M3	3	153M3 STR162 JCT	West Gwillimbry JCT	OTHER
NA41M31	1	Armitage TS	Old Armitage JCT	OTHER
NA41M31	2	Old Armitage JCT	Gormley JCT	OTHER
NA54M14	1	O1S STR 141 JCT	O1S STR 131A JCT	OTHER
NA54M14	2	O1S STR 128 JCT	O1S STR 119 JCT	OTHER
NA64M28	1	Alford JCT	Mohawk Str 31 EP JCT	OTHER
NA70M2	1	Clarke L7S-70M2 JCT	Prospect L7S-70M2JCT	OTHER
NAF5M16	1	MacPherson Road JCT	Kent TS	OTHER
NAF5M16	2	MacPherson Road JCT	Kent TS	OTHER
NAL23M5	1	Crosby S1K JCT	Newboro DS	OTHER
NAL23M6	1	Crosby S1K JCT	Elgin JCT	OTHER
NAL82M28	1	Smiths Falls TS	Jasper DS	OTHER
NAR43M21	1	Warden TS	Lumsden JCT	OTHER
NAR43M21	2	Lumsden JCT	Todmorden JCT	OTHER
NAR43M31	1	Warden TS	Lumsden JCT	OTHER
NAR43M32	1	Warden TS	Lumsden JCT	OTHER
NF3M11	1	Toronto Power TS	Drummond Road JCT	OTHER
O1S	2	O1S STR 119 JCT	O1S STR 110 JCT	OTHER
P13T	1	Porcupine TS	Timmins TS	N
P15C	1	Dobbin TS	Cherrywood TS	N
P15T	1	Porcupine TS	Timmins TS	N
P1P	1	Port Arthur TS #1	Port Arthur JCT	OTHER
P1T	1	Port Arthur TS #1	TBPI Thunder Bay JCT	OTHER
P1T	2	TBPI Thunder Bay JCT	TBPI Thunder Bay CTS	OTHER
P1T	3	TBPI Thunder Bay JCT	TBPI Thunder Bay JCT	OTHER
P1T	4	TBPI Thunder Bay JCT	TBPI Thunder Bay CTS	OTHER
P21G	1	Mississagi TS	P21G POLE 261 JCT	N
P21R	1	Parkway TS	Markham #1 JCT	DFL

P21R	2	Markham #1 JCT	IBM Markham JCT	DFL
P21R	3	IBM Markham JCT	Leaside JCT	DFL
P21R	4	Leaside JCT	Leslie East JCT	DFL
P21R	5	Leslie East JCT	Leslie West JCT	DFL
P21R	6	Leslie West JCT	Finch JCT	DFL
P21R	7	Finch JCT	Richview TS	DFL
P21R	8	Markham #1 JCT	Markham MTS #1	LC
P21R	9	IBM Markham JCT	IBM Markham CTS	LC
P21R	10	Leslie East JCT	Leslie TS	LC
P21R	11	Leslie West JCT	Leslie TS	LC
P21R	12	Finch JCT	Finch TS	LC
P22R	1	Parkway TS	Markham #1 JCT	DFL
P22R	2	Markham #1 JCT	IBM Markham JCT	DFL
P22R	3	IBM Markham JCT	Leaside JCT	DFL
P22R	4	Leaside JCT	Bathurst JCT	DFL
P22R	5	Bathurst JCT	Finch JCT	DFL
P22R	6	Finch JCT	Richview TS	DFL
P22R	7	Markham #1 JCT	Markham MTS #1	LC
P22R	8	Bathurst JCT	Bathurst TS	LC
P22R	9	Finch JCT	Finch TS	LC
P22R	10	IBM Markham JCT	IBM Markham CTS	LC
P25W	1	Mississagi TS	Aubrey Falls JCT	DFL
P25W	2	Aubrey Falls JCT	Wawa TS	DFL
P25W	3	Aubrey Falls JCT	Aubrey Falls CGS	LC
P26W	1	Mississagi TS	Aubrey Falls JCT	DFL
P26W	2	Aubrey Falls JCT	Wawa TS	DFL
P26W	3	Aubrey Falls JCT	Aubrey Falls CGS	LC
P27C	1	Pickering B SS	Cherrywood TS	LC
P2O	1	P2O STR 100 JCT	P2O STR 24A JCT	OTHER
P30C	1	Pickering B SS	Cherrywood TS	LC
P31C	1	Pickering B SS	Cherrywood TS	LC
P32C	1	Pickering B SS	Cherrywood TS	LC
P33C	2	IPB Ottawa River JCT	Chats Falls SS	N
P3B	1	Port Arthur TS #1	Birch TS	N
P3S	1	Dobbin TS	Dale JCT	DFL
P3S	3	Dale JCT	Sidney TS	DFL
P3S	6	Dale JCT	Port Hope TS	LC
P45	1	Parkway TS	Markham #4 JCT	LC
P45	2	Markham #4 JCT	Buttonville TS	LC

P45	3	Markham #4 JCT	Markham MTS #4	LC
P46	1	Parkway TS	Markham #4 JCT	LC
P46	2	Markham #4 JCT	Buttonville TS	LC
P46	3	Markham #4 JCT	Markham MTS #4	LC
P4S	1	Dobbin TS	Dobbin DS	DFL
P4S	2	Dale JCT	Vernonville JCT	DFL
P4S	3	Vernonville JCT	Hilton JCT	DFL
P4S	4	Hilton JCT	Sidney TS	DFL
P4S	5	Dale JCT	Port Hope TS	LC
P4S	6	Vernonville JCT	TCPL Cobourg CTS	LC
P4S	7	Hilton JCT	Enbridge PL Hilt CTS	LC
P4S	9	Dobbin DS	Dale JCT	DFL
P4S	10	Dobbin DS	Dobbin DS	LC
P502X	1	Porcupine TS	Hanmer TS	N
P5M	1	Port Arthur TS #1	Conmee JCT	LC
P5M	4	P5M STR 603 JCT	P5M STR 608 JCT	OTHER
P5M	6	P5M STR 621 JCT	P5M STR 626 JCT	OTHER
P6C	1	Pickering A SS	Cherrywood TS	LC
P7B	1	Port Arthur TS #1	P7B STR 320 JCT	N
P7B	2	P7B STR 320 JCT	Birch TS	N
P7C	1	Pickering A SS	Cherrywood TS	LC
P7G	1	Porcupine TS	Dome Site JCT	LC
P7G	2	Dome Site JCT	Bell Creek JCT	LC
P7G	3	Ecstall JCT	Kidd Contractor CTS	OTHER
P7G	4	Ecstall JCT	Kidd Creek Mine JCT	OTHER
P7G	5	Kidd Creek Mine JCT	Kidd Zinc Refin CTS	OTHER
P7G	6	Kidd Creek Mine JCT	Kidd Metsite CTS	OTHER
P7G	8	Hoyle JCT	Hoyle Pond Site JCT	LC
P7G	9	Hoyle JCT	Hoyle DS	LC
P7G	12	Hoyle Pond Site JCT	Ecstall JCT	OTHER
P7G	17	Bell Creek JCT	Hoyle JCT	LC
P7G	18	Bell Creek JCT	Bell Creek CTS	LC
P7G	19	Reid JCT	Echo B. Aquarius JCT	OTHER
P8C	1	Pickering A SS	Cherrywood TS	LC
P91G	1	Porcupine TS	Erg Resources JCT	DFL
P91G	2	Erg Resources JCT	Hoyle JCT	DFL
P91G	3	Erg Resources JCT	Erg Resources CTS	OTHER
P91G	4	Hoyle JCT	Kidd Metsite CTS	LC
P91G	5	Hoyle JCT	Ansonville JCT	DFL

P91G	6	Ansonville JCT	Ansonville TS	DFL
P9C	1	Pickering A SS	Cherrywood TS	LC
PA27	1	Beck #2 TS	Mid R. JCT Niagara	N
PA301	1	Beck #2 TS	Beck #2 TS	N
PA301	2	Beck #2 TS	Mid R JCT Niagra 345	N
PA302	1	Beck #2 TS	Beck #2 TS	N
PA302	2	Beck #2 TS	Mid R JCT Niagra 345	N
PS4	1	Lambton TS #2	Lambton TS #2	OTHER
PS51	1	Lambton TS #2	Lambton TS #2	OTHER
Q10M	3	McKinnon's JCT	G.M.St Cath CTS	OTHER
Q10P	1	Abit Cons NAN91 JCT	Abit Cons NAN91 JCT	LC
Q10P	2	Abit Cons NAN91 JCT	Abit Cons NAN91 JCT	OTHER
Q10P	3	Abit Cons NAN91 JCT	Q10P STR 9 JCT	LC
Q11S	1	Beck #1 SS	Warner Road JCT	LC
Q11S	2	Warner Road JCT	NOTL York MTS #1 JCT	LC
Q11S	3	McKinnon's JCT	Glendale JCT	LC
Q11S	4	Glendale JCT	Glendale TS	LC
Q11S	5	Warner Road JCT	N.O.T.L. MTS #2	LC
Q11S	6	Glendale JCT	Bunting TS	LC
Q11S	7	Warner Road JCT	Warner Road JCT	OTHER
Q11S	8	NOTL York MTS #1 JCT	McKinnon's JCT	LC
Q12S	1	Beck #1 SS	Warner Road JCT	LC
Q12S	2	Glendale JCT	Glendale TS	LC
Q12S	3	Glendale JCT	Bunting TS	LC
Q12S	4	NOTL York MTS #1 JCT	Glendale JCT	LC
Q12S	5	NOTL York MTS #1 JCT	N.O.T.L. York MTS #1	LC
Q12S	6	Warner Road JCT	NOTL York MTS #1 JCT	LC
Q12S	7	NOTL York MTS #1 JCT	NOTL York MTS #1 JCT	OTHER
Q1N	1	Beck #1 SS	Dresser JCT	OTHER
Q21P	1	Beck #2 TS	Beck Pump Storage GS	LC
Q22P	1	Beck #2 TS	Beck Pump Storage GS	LC
Q23BM	1	Beck #2 TS	Niagara West JCT	DFL
Q23BM	3	Hannon JCT	Neale JCT	DFL
Q23BM	4	Neale JCT	Southcote JCT	DFL
Q23BM	5	Southcote JCT	Mount Hope JCT	DFL
Q23BM	6	Mount Hope JCT	Carluke JCT	DFL
Q23BM	7	Carluke JCT	Middleport TS	DFL
Q23BM	8	Neale JCT	Burlington TS	DFL
Q23BM	9	Burlington TS	Burlington TS	DFL

Q23BM	10	Burlington TS	Burlington TS	LC
Q23BM	11	Niagara West JCT	Hannon JCT	DFL
Q23BM	12	Niagara West JCT	Niagara West MTS	LC
Q24HM	1	Beck #2 TS	Hannon JCT	DFL
Q24HM	3	Hannon JCT	Nebo JCT	DFL
Q24HM	4	Neale JCT	Southcote JCT	DFL
Q24HM	5	Southcote JCT	Trinity JCT	DFL
Q24HM	6	Trinity JCT	Carluke JCT	DFL
Q24HM	7	Carluke JCT	Middleport TS	DFL
Q24HM	8	Hannon JCT	Beach TS	DFL
Q24HM	9	Nebo JCT	Neale JCT	DFL
Q24HM	10	Beach TS	Dof.Kenilworth CTS	LC
Q24HM	11	Nebo JCT	Nebo TS	LC
Q25BM	1	Beck #2 TS	Niagara West JCT	DFL
Q25BM	3	Hannon JCT	Neale JCT	DFL
Q25BM	4	Neale JCT	Southcote JCT	DFL
Q25BM	5	Southcote JCT	Mount Hope JCT	DFL
Q25BM	6	Mount Hope JCT	Carluke JCT	DFL
Q25BM	7	Carluke JCT	Middleport TS	DFL
Q25BM	8	Neale JCT	Burlington TS	DFL
Q25BM	9	Burlington TS	Burlington TS	DFL
Q25BM	10	Burlington TS	Burlington TS	LC
Q25BM	11	Niagara West JCT	Hannon JCT	DFL
Q25BM	12	Niagara West JCT	Niagara West MTS	LC
Q26M	1	Beck #2 TS	Abit Cons NAN91 JCT	DFL
Q26M	2	Abit Cons NAN91 JCT	Crossline JCT	DFL
Q26M	3	Crossline JCT	Allanburg TS	LC
Q26M	4	Allanburg West JCT	Middleport TS	DFL
Q26M	5	Abit Cons NAN91 JCT	Abit Cons NAN91 JCT	OTHER
Q26M	6	Crossline JCT	Allanburg West JCT	DFL
Q28A	1	Beck #2 TS	Abit Cons NAN91 JCT	LC
Q28A	2	Abit Cons NAN91 JCT	Allanburg TS	LC
Q28A	3	Abit Cons NAN91 JCT	Abit Cons NAN91 JCT	LC
Q29HM	1	Beck #2 TS	Hannon JCT	DFL
Q29HM	3	Hannon JCT	Nebo JCT	DFL
Q29HM	4	Neale JCT	Southcote JCT	DFL
Q29HM	5	Southcote JCT	Carluke JCT	DFL
Q29HM	6	Carluke JCT	Middleport TS	DFL
Q29HM	7	Hannon JCT	Beach TS	DFL

Q29HM	8	Nebo JCT	Neale JCT	DFL
Q29HM	9	Beach TS	Dof.Kenilworth CTS	LC
Q29HM	10	Nebo JCT	Nebo TS	LC
Q2A	1	Beck #1 Q2AH JCT	Crossline JCT	OTHER
Q2AH	1	Beck #1 Q2AH JCT	Holland Road JCT	LC
Q2AH	2	Holland Road JCT	Allanburg TS	LC
Q2AH	3	Holland Road JCT	St.Johns Valley JCT	LC
Q2AH	4	St.Johns Valley JCT	Pelham JCT	LC
Q2AH	5	St.Anns JCT	Dunnville TS	LC
Q2AH	8	Pelham JCT	Rosedene JCT	LC
Q2AH	9	Rosedene JCT	St.Anns JCT	LC
Q2AH	11	St.Anns JCT	Caistor JCT	OTHER
Q2AH	13	Caistor JCT	Railway JCT	OTHER
Q2AH	14	Railway JCT	Glanford JCT	OTHER
Q2AH	15	St.Johns Valley JCT	Louth JCT	LC
Q2AH	16	Louth JCT	Cherry JCT	LC
Q2AH	17	Cherry JCT	Beamsville TS	LC
Q2AH	18	Beamsville TS	Winona JCT	OTHER
Q2AH	19	Saltfleet JCT	Beach TS	LC
Q2AH	20	Cherry JCT	Vineland DS	LC
Q2AH	21	St.Anns JCT	St.Anns JCT	LC
Q2AH	22	Winona JCT	Saltfleet JCT	LC
Q2AH	23	Winona JCT	Winona TS	LC
Q2AH	24	Winona JCT	Winona TS	LC
Q2AH	26	Beck #1 SS	Beck #1 Q2AH JCT	LC
Q2AH	27	St.Anns JCT	St.Anns JCT	OTHER
Q30M	1	Beck #2 TS	Allanburg Q30M JCT	DFL
Q30M	3	Allanburg Q30M JCT	Mount Hope JCT	DFL
Q30M	4	Mount Hope JCT	Carluke JCT	DFL
Q30M	5	Carluke JCT	Middleport TS	DFL
Q30M	6	Allanburg Q30M JCT	Allanburg TS	LC
Q35M	1	Beck #2 TS	Abit Cons NAN91 JCT	DFL
Q35M	2	Abit Cons NAN91 JCT	Crossline JCT	DFL
Q35M	3	Crossline JCT	Allanburg TS	LC
Q35M	4	Allanburg West JCT	St.Anns JCT	DFL
Q35M	5	St.Anns JCT	Caledonia Q35M-C9 J	DFL
Q35M	6	Caledonia Q35M-C9 J	Middleport TS	DFL
Q35M	7	Crossline JCT	Allanburg West JCT	DFL
Q35M	8	St.Anns JCT	St.Anns JCT	OTHER

Q35M	9	Caledonia Q35M-C9 J	Caledonia Q35M-C9 J	OTHER
Q3K	1	Cataraqui TS	Westbrook JCT	LC
Q3K	2	Westbrook JCT	Frontenac TS	LC
Q3M6	1	Frontenac TS	Novelis CTS	LC
Q3N	1	Beck #1 SS	Portal JCT	LC
Q3N	2	Portal JCT	Dresser JCT	LC
Q3N	3	Dresser JCT	Niagara JCT	LC
Q3N	4	Niagara JCT	Murray TS	LC
Q3N	5	Portal JCT	Stanley TS	LC
Q3N	6	Dresser JCT	Trei-bacher JCT	OTHER
Q4B	1	Thunder Bay SS	Abitibi JCT	LC
Q4B	2	Abitibi JCT	James Street JCT	LC
Q4B	3	James Street JCT	St.Paul JCT	LC
Q4B	4	St.Paul JCT	Walsh Street JCT	LC
Q4B	5	Walsh Street JCT	Birch TS	LC
Q4B	6	James Street JCT	ResFP Thundr Bay CTS	LC
Q4B	7	St.Paul JCT	ResFP Kraft CTS	OTHER
Q4B	8	Walsh Street JCT	Fort William TS	LC
Q4C	2	IPB Ottawa River JCT	Chats Falls SS	N
Q4N	1	Beck #1 SS	Portal JCT	LC
Q4N	2	Portal JCT	Stanley TS	LC
Q4N	3	Portal JCT	Dresser JCT	LC
Q4N	4	Dresser JCT	Niagara JCT	LC
Q4N	6	Dresser JCT	Trei-bacher JCT	OTHER
Q4N	8	Niagara JCT	Murray TS	LC
Q5B	1	Thunder Bay SS	Abitibi JCT	LC
Q5B	2	Abitibi JCT	James Street JCT	LC
Q5B	3	James Street JCT	St.Paul JCT	LC
Q5B	4	St.Paul JCT	Walsh Street JCT	LC
Q5B	5	Walsh Street JCT	Birch TS	LC
Q5B	6	Abitibi JCT	Erco JCT	OTHER
Q5B	7	Erco JCT	Q5B STR A6 JCT	OTHER
Q5B	8	James Street JCT	ResFP Thundr Bay CTS	OTHER
Q5B	9	St.Paul JCT	ResFP Kraft CTS	LC
Q5B	10	Walsh Street JCT	Fort William TS	LC
Q5G	1	Beck #1 SS	Holland Road JCT	OTHER
Q5G	2	Holland Road JCT	Beamsville TS	OTHER
Q5G	3	Beamsville TS	West Lincoln JCT	OTHER
Q5G	4	Beach JCT	Gage TS	OTHER

Q6A	1	Beck #1 Q2AH JCT	Crossline JCT	OTHER
Q6A	3	Beck #1 SS	Q6A T#C JCT	OTHER
Q6N	1	Selby JCT	Napanee TS	OTHER
Q6S	1	Cataraqui TS	Westbrook JCT	DFL
Q6S	2	Westbrook JCT	Odessa JCT	DFL
Q6S	3	Odessa JCT	Selby JCT	DFL
Q6S	4	Selby JCT	Milltown JCT	DFL
Q6S	5	Milltown JCT	Sidney TS	DFL
Q6S	6	Odessa JCT	Invista JCT	LC
Q6S	7	Invista JCT	Amherst Island JCT	LC
Q6S	9	Milltown JCT	TCPL Belleville CTS	LC
Q6S	10	Amherst Island JCT	Q6S STR M60 JCT	OTHER
Q6S	11	Amherst Island JCT	Amherst Island CSS	LC
Q8B	1	Thunder Bay SS	Birch TS	LC
Q9B	1	Thunder Bay SS	Birch TS	OTHER
R13K	1	Richview TS	Manby TS	DFL
R13K	2	Manby TS	Manby TS	DFL
R13K	3	Manby TS	Vansco JCT	LC
R13K	4	Vansco JCT	Horner TS	LC
R14T	1	Richview TS	Tomken JCT	DFL
R14T	2	Tomken JCT	Erindale JCT	DFL
R14T	3	Erindale JCT	Trafalgar TS	DFL
R14T	5	Erindale JCT	Erindale TS	LC
R14T	6	Tomken JCT	Tomken TS	LC
R15K	1	Richview TS	Manby TS	LC
R17T	1	Richview TS	Tomken JCT	DFL
R17T	2	Tomken JCT	Erindale JCT	DFL
R17T	3	Erindale JCT	Trafalgar TS	DFL
R17T	5	Erindale JCT	Erindale TS	LC
R17T	6	Tomken JCT	Tomken TS	LC
R19TH	1	Richview TS	Tomken JCT	DFL
R19TH	2	Tomken JCT	Hanlan JCT	DFL
R19TH	3	Hanlan JCT	Erindale JCT	DFL
R19TH	4	Erindale JCT	Churchill MeadowsJCT	DFL
R19TH	5	Hanlan JCT	Hurontario SS	DFL
R19TH	6	Erindale JCT	Erindale TS	LC
R19TH	7	Tomken JCT	Tomken TS	LC
R19TH	8	Hurontario SS	Hurontario SS	DFL
R19TH	9	Hurontario SS	Jim Yarrow MTS	LC

R19TH	10	Churchill MeadowsJCT	Trafalgar TS	DFL
R19TH	11	Churchill MeadowsJCT	Churchill Meadows TS	LC
R1K	1	Richview TS	Manby TS	N
R1LB	1	Pine Portage SS	Lakehead TS	N
R1LB	2	Lakehead TS	Birch TS	N
R1LB	3	Lakehead TS	Lakehead TS	N
R21D	1	Otter Rapids SS	Pinard JCT	LC
R21D	2	Pinard JCT	Pinard TS	LC
R21D	3	Pinard JCT	Abitibi Canyon GS	LC
R21D	4	Otter Rapids GS	Otter Rapids SS	LC
R21TH	1	Richview TS	Tomken JCT	DFL
R21TH	2	Tomken JCT	Hanlan JCT	DFL
R21TH	3	Hanlan JCT	Erindale JCT	DFL
R21TH	4	Erindale JCT	Churchill MeadowsJCT	DFL
R21TH	5	Hanlan JCT	Hurontario SS	DFL
R21TH	6	Erindale JCT	Erindale TS	LC
R21TH	7	Tomken JCT	Tomken TS	LC
R21TH	8	Hurontario SS	Hurontario SS	DFL
R21TH	9	Hurontario SS	Jim Yarrow MTS	LC
R21TH	10	Churchill MeadowsJCT	Trafalgar TS	DFL
R21TH	11	Churchill MeadowsJCT	Churchill Meadows TS	LC
R24C	1	Richview TS	Applewood JCT	LC
R24C	2	Applewood JCT	Cooksville TS	LC
R2K	1	Richview TS	Manby TS	LC
R2K	2	Manby TS	Vansco JCT	LC
R2K	3	Vansco JCT	Horner TS	LC
R2K	4	Manby TS	Manby TS	LC
R2LB	1	Pine Portage SS	Lakehead TS	N
R2LB	2	Lakehead TS	Birch TS	N
R2LB	3	Lakehead TS	Lakehead TS	N
R9A	1	Pine Portage SS	Alexander SS	DFL
R9A	2	Alexander SS	Alexander GS	LC
R9A	3	Alexander SS	Alexander SS	DFL
S1C	1	Conmee JCT	Lac Des Iles JCT	LC
S1C	2	Lac Des Iles JCT	Silver Falls GS	LC
S1C	6	Lac Des Iles JCT	Lac Des Iles Min CSS	LC
S1H	1	Owen Sound TS	Hanover TS	N
S1K	4	Battersea DS	Frontenac TS	LC
S1R	1	S1R STR 1A JCT	S1R STR 24 JCT	OTHER

S21N	1	Martindale TS	Vale Frd Stbe #2 JCT	LC
S21N	2	Vale Frd Stbe #2 JCT	Vale Copper #4 CTS	LC
S21N	3	Vale Frd Stbe #2 JCT	Vale Frd Stbe #2 CTS	OTHER
S22A	1	Martindale TS	Clarabelle JCT	DFL
S22A	2	Clarabelle JCT	Algoma TS	DFL
S22A	3	Clarabelle JCT	Clarabelle TS	LC
S24V	1	Orangeville TS	Shannon CSS	LC
S25L	2	Saunders JCT	St.Lawrence TS	LC
S26L	2	Saunders JCT	St.Lawrence TS	LC
S2B	1	Martindale TS	Copper Cliff JCT	LC
S2B	2	Copper Cliff JCT	Creighton JCT	LC
S2B	3	Creighton JCT	Ethel Lake JCT	LC
S2B	5	Ethel Lake JCT	Turbine JCT	LC
S2B	7	Turbine JCT	Eacom Nairn Ctr JCT	LC
S2B	8	Eacom Nairn Ctr JCT	Espanola JCT	LC
S2B	9	Espanola JCT	Eddy Tap JCT	LC
S2B	10	Espanola A JCT	Espanola TS	OTHER
S2B	11	Espanola TS	S2B-M31 JCT	LC
S2B	12	Baldwin JCT	Massey JCT	LC
S2B	13	Massey JCT	Cameron Falls JCT	LC
S2B	14	Cutler JCT	Serpent River JCT	LC
S2B	16	Ethel Lake JCT	Whitefish DS	LC
S2B	19	Espanola A JCT	McLeans Mtn JCT	LC
S2B	20	Massey JCT	Massey DS	LC
S2B	23	Eacom Nairn Ctr JCT	Eacom Nairn Ctr CTS	LC
S2B	24	Spanish JCT	Cutler JCT	LC
S2B	25	Serpent River JCT	Carmeuse Lime JCT	LC
S2B	27	Carmeuse Lime JCT	Blind River TS JCT	LC
S2B	30	Cameron Falls JCT	Spanish JCT	LC
S2B	32	Espanola JCT	Baldwin JCT	OTHER
S2B	33	Blind River TS JCT	Algoma TS	LC
S2B	34	Blind River TS JCT	Blind River TS	OTHER
S2B	35	Eddy Tap JCT	Espanola A JCT	LC
S2B	37	Eddy Tap JCT	Eddy Tap A JCT	OTHER
S2B	38	Creighton JCT	S5M-S2B T#1 JCT	OTHER
S2B	39	Spanish JCT	Spanish DS	LC
S2B	40	McLeans Mtn JCT	Manitoulin TS	LC
S2B	41	McLeans Mtn JCT	McLeans Mtn CSS	LC
S2B	42	S2B-M31 JCT	Baldwin JCT	LC

S2E	1	Essa JCT	Essa TS	OTHER
S2N	1	Strathroy TS	Sydenham JCT	LC
S2N	2	Sydenham JCT	Adelaide JCT	LC
S2N	3	Adelaide JCT	Kerwood JCT	OTHER
S2N	4	Kerwood JCT	Ennisbrook JCT	LC
S2N	5	Ennisbrook JCT	Sarnia Scott TS	LC
S2N	7	Adelaide JCT	Landon JCT	LC
S2N	8	Kerwood JCT	Sun Cdn Pipeline CTS	LC
S2N	9	Ennisbrook JCT	Forest Jura DS	LC
S2N	13	Landon JCT	Enbrg Keyser CTS	LC
S2N	14	Landon JCT	Landon CGS	LC
S2S	1	Owen Sound TS	Meaford TS	DFL
S2S	2	Meaford TS	Stayner TS	DFL
S30L	2	Saunders JCT	St.Lawrence TS	LC
S32L	2	Saunders JCT	St.Lawrence TS	LC
S39M	1	Summerhaven SS	Caledonia JCT	DFL
S39M	2	Caledonia JCT	Middleport TS	DFL
S39M	3	Caledonia JCT	Caledonia TS	LC
S3S	2	Kapuskasing R Jct	Kapuskasing CTS	OTHER
S3S	4	S3S_S4S STR 8 JCT	Kapuskasing R Jct	OTHER
S47C	1	Spence SS	Erieau WF JCT	DFL
S47C	2	Erieau WF JCT	Chatham SS	DFL
S47C	3	Erieau WF JCT	Erieau WF CGS	LC
S4S	1	S3S_S4S STR 8 JCT	Kapuskasing R Jct	OTHER
S4S	2	Kapuskasing R Jct	Kapuskasing CTS	OTHER
S5M	1	Martindale TS	Donaldson Cres JCT	LC
S5M	2	McCrea JCT	Onaping JCT	LC
S5M	3	Onaping JCT	Onaping Area M&M CTS	LC
S5M	5	Onaping JCT	Hillcrest JCT	LC
S5M	6	Nickel Basin JCT	Larchwood TS	LC
S5M	7	Donaldson Cres JCT	McCrea JCT	LC
S5M	8	Hillcrest JCT	Nickel Basin JCT	LC
S5M	10	Nickel Basin JCT	S5M-S2B T#1 JCT	OTHER
S6F	1	Martindale TS	Falconbridge JCT	LC
S6F	2	Falconbridge JCT	Falconbridge 61 JCT	LC
S6N	1	Selby JCT	Napanee TS	OTHER
S7M	1	South March SS	Marchwood JCT	DFL
S7M	2	Marchwood JCT	Bridlewood JCT	DFL
S7M	3	Bridlewood JCT	X523A STR 654 JCT	DFL

S7M	4	X523A STR 654 JCT	S7M STR 673N JCT	DFL
S7M	5	S7M STR 673N JCT	Merivale TS	DFL
S7M	7	Bridlewood JCT	Bridlewood MTS	LC
S7M	11	Manotick JCT	Richmond South MTS	LC
S7M	13	Manotick STR A40 JCT	Manotick DS	LC
S7M	14	Manotick STR A40 JCT	Manotick DS	LC
S7M	15	Fallowfield JCT	Fallowfield MTS	LC
S7M	16	S7M T#N1 JCT	Manordale JCT	OTHER
S7M	17	X523A STR 654 JCT	Didsbury Road JCT	OTHER
S7M	18	Marchwood JCT	Marchwood MTS	LC
S7M	20	Cambrian JCT	Cambrian MTS	LC
S7M	21	S7M T#N1 JCT	Fallowfield JCT	LC
S7M	22	Fallowfield JCT	Manotick JCT	LC
S7M	23	Manotick JCT	S7M STR 20A JCT	LC
S7M	24	S7M STR 20A JCT	Manotick STR A40 JCT	LC
S7M	25	S7M STR 673N JCT	S7M T#N1 JCT	LC
S7S	2	Dominion Drive DS	Gervais JCT	OTHER
SK1	1	Rabbit Lake SS	Keewatin JCT	LC
SK1	2	Forgie JCT	IPB Manitoba 115 JCT	N
SK1	4	Forgie JCT	Clearwater Bay DS	LC
SK1	5	Keewatin JCT	Forgie JCT	LC
SK1	6	Keewatin JCT	Keewatin DS	LC
SW-X503E	1	Nobel SS	Nobel SS	N
SW-X504E	1	Nobel SS	Nobel SS	N
T1B	1	Rayner CGS	Wharncliffe JCT	LC
T1B	2	Sowerby JCT	Red Rock CGS JCT	LC
T1B	3	Red Rock CGS	Red Rock CGS JCT	LC
T1B	4	Cobden JCT	Striker DS	LC
T1B	5	Striker DS	Algoma TS	LC
T1B	6	Sowerby JCT	Sowerby DS	LC
T1B	7	Cobden JCT	North Shore DS	LC
T1B	8	Wharncliffe JCT	Sowerby JCT	LC
T1B	9	Wharncliffe JCT	Wharncliffe DS	LC
T1B	10	Red Rock CGS JCT	Cobden JCT	LC
T1B	11	Red Rock CGS JCT	Red Rock CGS	LC
T1M	1	Terrace Bay SS	Angler Switch JCT	DFL
T1M	2	Angler Switch JCT	Pic JCT	DFL
T1M	3	Pic JCT	Marathon TS	DFL
T1M	4	Pic JCT	Marathon DS JCT	LC

T1M	5	Marathon DS JCT	Marathon DS	LC
T22C	1	Chats Falls SS	Marine JCT	DFL
T22C	2	Marine JCT	Clarington TS	DFL
T22C	3	Marine JCT	Otonabee TS	LC
T23C	1	Clarington TS	Wilson JCT	DFL
T23C	2	Wilson JCT	Whitby JCT	DFL
T23C	3	Whitby JCT	T23C T26C Tie JCT	DFL
T23C	4	T23C T26C Tie JCT	Cherrywood TS	DFL
T23C	5	Wilson JCT	Wilson TS	LC
T23C	6	Whitby JCT	Whitby TS	LC
T23C	7	T23C T26C Tie JCT	T23C T26C Tie JCT	OTHER
T24C	1	Clarington TS	Columbus JCT	DFL
T24C	2	Columbus JCT	Whitby JCT	DFL
T24C	3	Whitby JCT	Cherrywood TS	DFL
T24C	4	Columbus JCT	Lasco JCT	LC
T24C	5	Lasco JCT	Thornton JCT	LC
T24C	6	Thornton JCT	Thornton TS	LC
T24C	7	Thornton JCT	Oshawa G.M. JCT	LC
T24C	8	Oshawa G.M. JCT	Oshawa G.M. TS	LC
T24C	9	Lasco JCT	Atlantic Packgng JCT	LC
T24C	10	Atlantic Packgng JCT	Gerdau A. Whitby CTS	LC
T24C	11	Atlantic Packgng JCT	Atlantic Packgng CTS	LC
T24C	12	Oshawa G.M. JCT	G.M.Oshawa JCT	OTHER
T24C	13	Whitby JCT	Whitby TS	LC
T25B	1	Belleville TS	Pancake JCT	N
T25B	2	Pancake JCT	Clarington TS	N
T26C	1	Clarington TS	Columbus JCT	DFL
T26C	2	Columbus JCT	Whitby JCT	DFL
T26C	3	Whitby JCT	T23C T26C Tie JCT	DFL
T26C	4	T23C T26C Tie JCT	Cherrywood TS	DFL
T26C	5	Columbus JCT	Lasco JCT	LC
T26C	6	Lasco JCT	Thornton JCT	LC
T26C	7	Thornton JCT	Thornton TS	LC
T26C	8	Thornton JCT	Oshawa G.M. JCT	LC
T26C	9	Oshawa G.M. JCT	Oshawa G.M. TS	LC
T26C	10	Lasco JCT	Atlantic Packgng JCT	LC
T26C	11	Atlantic Packgng JCT	Whitby CGS JCT	LC
T26C	12	Whitby CGS JCT	Gerdau A. Whitby CTS	LC
T26C	13	Atlantic Packgng JCT	Atlantic Packgng CTS	LC

T26C	14	Whitby CGS JCT	Whitby CGS	LC
T26C	16	Oshawa G.M. JCT	G.M.Oshawa JCT	OTHER
T26C	17	Whitby JCT	Whitby TS	LC
T27P	1	Wells CGS	Mississagi TS	LC
T28C	1	Clarington TS	Seaton JCT	N
T28C	2	Duffin JCT	Cherrywood TS	N
T28C	3	Seaton JCT	Duffin JCT	N
T28C	4	Seaton JCT	Seaton MTS	LC
T28P	1	Wells CGS	Mississagi TS	LC
T29C	1	Clarington TS	Wilson JCT	DFL
T29C	2	Wilson JCT	Whitby JCT	DFL
T29C	3	Whitby JCT	Cherrywood TS	DFL
T29C	4	Wilson JCT	Wilson TS	LC
T29C	5	Whitby JCT	Whitby TS	LC
T2N	2	Toronto Power TS	Drummond Road JCT	OTHER
T2R	1	Timmins TS	Wawaitin GS	OTHER
T2R	2	Wawaitin GS	Shiningtree JCT	OTHER
T2R	3	Shiningtree JCT	Blezard Valley JCT	OTHER
T2R	4	Shiningtree JCT	Blezard Valley JCT	OTHER
T2R	5	Blezard Valley JCT	Copper Cliff JCT	OTHER
T2R	6	Blezard Valley JCT	Copper Cliff JCT	OTHER
T2R	10	Blezard Valley JCT	Falconbridge T2R CTS	OTHER
T31H	1	Havelock TS	Marine JCT	DFL
T31H	2	Marine JCT	Clarington TS	DFL
T31H	3	Marine JCT	Otonabee TS	LC
T32H	1	Havelock TS	Marine JCT	N
T32H	2	Marine JCT	Clarington TS	N
T33E	1	Almonte TS	Almonte TS	LC
T33E	2	Almonte TS	Clarington TS	DFL
T33E	3	Almonte TS	Almonte TS	DFL
T36B	1	Trafalgar TS	Lantz JCT	DFL
T36B	2	Palermo TxB JCT	Burlington TS	DFL
T36B	3	Palermo TxB JCT	Palermo TS	LC
T36B	4	Lantz JCT	Glenorchy JCT	DFL
T36B	5	Lantz JCT	Trafalgar TS	OTHER
T36B	6	Glenorchy JCT	Palermo TxB JCT	DFL
T36B	7	Glenorchy JCT	Glenorchy MTS #1	LC
T37B	1	Trafalgar TS	Lantz JCT	DFL
T37B	2	Palermo TxB JCT	Burlington TS	DFL

T37B	3	Palermo TxB JCT	Palermo TS	LC
T37B	4	Lantz JCT	Glenorchy JCT	DFL
T37B	5	Lantz JCT	Trafalgar TS	N
T37B	6	Glenorchy JCT	Palermo TxB JCT	DFL
T37B	7	Glenorchy JCT	Glenorchy MTS #1	LC
T38B	1	Trafalgar TS	Lantz JCT	DFL
T38B	2	Lantz JCT	Tremaine JCT	DFL
T38B	3	Lantz JCT	Trafalgar DESN JCT	LC
T38B	4	Hornby JCT	PEC Halton Hills JCT	LC
T38B	5	Hornby JCT	Meadowvale TS	LC
T38B	6	Trafalgar DESN JCT	Hornby JCT	LC
T38B	7	Trafalgar DESN JCT	Trafalgar TS	LC
T38B	8	PEC Halton Hills JCT	Halton TS	LC
T38B	9	PEC Halton Hills JCT	PEC Halton Hills JCT	LC
T38B	12	Tremaine JCT	Burlington TS	DFL
T38B	13	Tremaine JCT	Tremaine TS	LC
T39B	1	Trafalgar TS	Lantz JCT	DFL
T39B	2	Lantz JCT	Tremaine JCT	DFL
T39B	3	Lantz JCT	Trafalgar DESN JCT	LC
T39B	4	Hornby JCT	PEC Halton Hills JCT	LC
T39B	5	Hornby JCT	Meadowvale TS	LC
T39B	6	Trafalgar DESN JCT	Hornby JCT	LC
T39B	7	Trafalgar DESN JCT	Trafalgar TS	LC
T39B	8	PEC Halton Hills JCT	Halton TS	LC
T39B	9	PEC Halton Hills JCT	PEC Halton Hills JCT	LC
T39B	12	Tremaine JCT	Burlington TS	DFL
T39B	13	Tremaine JCT	Tremaine TS	LC
T61S	1	Timmins JCT	Shiningtree DS	LC
T61S	2	Timmins JCT	Ogden JCT	LC
T61S	3	Ogden JCT	Timmins WestMine JCT	LC
T61S	4	Ogden JCT	Kam Kotia DS	OTHER
T61S	5	Timmins TS	Timmins JCT	LC
T61S	6	Timmins WestMine JCT	Weston Lake DS	LC
T61S	7	Timmins WestMine JCT	Timmins WestMine CTS	LC
T7M	1	Otter Rapids SS	Onakawana JCT	LC
T7M	2	Onakawana JCT	Renison JCT	LC
T7M	3	Renison JCT	Moosonee SS	LC
T7M	4	Onakawana JCT	Onakawana CTS	LC
T7M	5	Renison JCT	Renison CTS	LC

T8M	1	Otter Rapids SS	Moosonee SS	LC
UB3B	1	H2O Pwr FtFrnces CGS	Int'l Bdy Minn JCT	OTHER
UN21-W42	1	N21W-W42L T22-471 J	N21W-W42L T22-471 J	OTHER
V12M	1	Merivale TS	Val Tetreau JCT	LC
V12M	3	Val Tetreau JCT	Hinchey TS	LC
V41H	1	Claireville TS	Claireville TS	DFL
V41H	2	Claireville TS	Sithe Goreway JCT	DFL
V41H	3	Sithe Goreway JCT	Bramalea TS	DFL
V41H	4	Bramalea TS	Cardiff JCT	DFL
V41H	5	Cardiff JCT	Hurontario SS	DFL
V41H	6	Sithe Goreway JCT	Sithe Goreway JCT	LC
V41H	8	Cardiff JCT	Cardiff TS	LC
V41N	1	Nova SS	St.Clair E.C. JCT	DFL
V41N	2	Nova SS	Nova Corunna CTS	LC
V41N	3	St.Clair E.C. JCT	Sarnia Scott TS	DFL
V41N	4	St.Clair E.C. JCT	St.Clair E.C. CGS	LC
V41N	5	Nova SS	Nova SS	DFL
V42H	1	Claireville TS	Claireville TS	DFL
V42H	2	Claireville TS	Claireville TS	DFL
V42H	3	Claireville TS	Sithe Goreway JCT	DFL
V42H	4	Sithe Goreway JCT	Bramalea TS	DFL
V42H	5	Bramalea TS	Cardiff JCT	DFL
V42H	6	Cardiff JCT	Hurontario SS	DFL
V42H	7	Sithe Goreway JCT	Sithe Goreway JCT	LC
V42H	9	Cardiff JCT	Cardiff TS	LC
V42H	10	Claireville TS	Goreway JCT	LC
V42H	11	Goreway JCT	Goreway PH JCT	LC
V42H	12	Goreway PH JCT	Goreway TS	LC
V43	1	Claireville TS	Claireville TS	LC
V43	2	Claireville TS	Goreway JCT	LC
V43	3	Goreway JCT	Goreway PH JCT	LC
V43	4	Goreway PH JCT	Goreway TS	LC
V43	5	Claireville TS	Woodbridge JCT	LC
V43	6	Woodbridge JCT	Vaughan #3 JCT	LC
V43	7	Vaughan #3 JCT	Kleinburg TS	LC
V43	8	Woodbridge JCT	Woodbridge TS	LC
V43	9	Vaughan #3 JCT	Vaughan MTS #3	LC
V43N	1	Nova SS	Talford JCT	DFL
V43N	2	Talford JCT	St.Clair E.C. JCT	DFL

V43N	3	Talford JCT	Dupont JCT	LC
V43N	4	Dupont JCT	Shell Sarnia CTS	LC
V43N	5	Dupont JCT	Nova St Clair R CTS	LC
V43N	6	St.Clair E.C. JCT	Sarnia Scott TS	DFL
V43N	7	St.Clair E.C. JCT	St.Clair E.C. CGS	LC
V44	1	Claireville TS	Woodbridge JCT	LC
V44	2	Woodbridge JCT	Vaughan #3 JCT	LC
V44	3	Vaughan #3 JCT	Kleinburg TS	LC
V44	4	Woodbridge JCT	Woodbridge TS	LC
V44	5	Vaughan #3 JCT	Vaughan MTS #3	LC
V586M	1	Claireville TS	Milton SS	N
V586M	2	Milton SS	Middleport TS	N
V586M	3	Milton SS	Milton SS	N
V71P	1	Claireville TS	Toronto Star JCT	DFL
V71P	2	Toronto Star JCT	Grainger South JCT	DFL
V71P	3	Vaughan #1 JCT	Richmond Hill JCT	DFL
V71P	4	Richmond Hill JCT	Richmond Hill #2 JCT	DFL
V71P	5	Richmond Hill #2 JCT	Parkway TS	DFL
V71P	6	Toronto Star JCT	Toronto Star JCT	LC
V71P	7	Toronto Star JCT	Vaughan MTS #2	LC
V71P	8	Vaughan #1 JCT	Vaughan #1 PH JCT	LC
V71P	9	Vaughan #1 PH JCT	Vaughan MTS #1	LC
V71P	10	Richmond Hill JCT	Richmond Hill MTS #1	LC
V71P	11	Richmond Hill #2 JCT	Richmond Hill MTS #2	LC
V71P	12	Grainger South JCT	Vaughan #1 JCT	DFL
V72R	3	Richview TS	Richview TS	LC
V72R	4	Claireville TS	Richview TS	DFL
V72R	5	Richview TS	Richview TS	DFL
V73R	4	Claireville TS	Richview TS	N
V74R	1	Claireville TS	Westmore JCT	DFL
V74R	2	Westmore JCT	Richview TS	DFL
V74R	3	Westmore JCT	Rexdale TS	LC
V74R	8	Richview TS	Richview TS	DFL
V74R	9	Richview TS	Richview TS	LC
V74R	12	Westmore JCT	Westmore JCT	LC
V75P	2	Claireville TS	Toronto Star JCT	DFL
V75P	3	Toronto Star JCT	Vaughan #1 JCT	DFL
V75P	4	Vaughan #1 JCT	Grainger North JCT	DFL
V75P	5	Richmond Hill JCT	Richmond Hill #2 JCT	DFL

V75P	6	Richmond Hill #2 JCT	Parkway TS	DFL
V75P	7	Toronto Star JCT	Toronto Star JCT	LC
V75P	8	Toronto Star JCT	Vaughan MTS #2	LC
V75P	9	Vaughan #1 JCT	Vaughan #1 PH JCT	LC
V75P	10	Vaughan #1 PH JCT	Vaughan MTS #1	LC
V75P	11	Richmond Hill JCT	Richmond Hill MTS #1	LC
V75P	12	Richmond Hill #2 JCT	Richmond Hill MTS #2	LC
V75P	19	Grainger North JCT	Richmond Hill JCT	DFL
V76R	1	Claireville TS	Westmore JCT	DFL
V76R	4	Westmore JCT	Richview TS	DFL
V76R	5	Westmore JCT	Rexdale TS	LC
V76R	9	Westmore JCT	Westmore JCT	LC
V77R	1	Claireville TS	Richview TS	N
V79R	1	Claireville TS	Richview TS	N
W12	1	Buchanan TS	Ingersoll TS	LC
W14	1	Buchanan TS	W14 T#2 JCT	OTHER
W14	2	W14 T#2 JCT	Kettle Creek JCT	OTHER
W14	3	W14 T#2 JCT	Kettle Creek JCT	OTHER
W14	4	Kettle Creek JCT	St.Thomas JCT	OTHER
W14	5	Kettle Creek JCT	St.Thomas JCT	OTHER
W14	6	Kettle Creek JCT	W14 STR B JCT	OTHER
W14	7	Kettle Creek JCT	W14 STR B JCT	OTHER
W14	8	St.Thomas JCT	Lyons JCT	OTHER
W14	9	Lyons JCT	Cranberry JCT	OTHER
W14	10	Lyons JCT	Lyons JCT	OTHER
W2	1	Whitedog Falls GS	Whitedog Falls SS	LC
W21M	1	Wawa TS	Marathon TS	N
W22M	1	Wawa TS	Marathon TS	N
W23K	1	Wawa TS	MacKay JCT	N
W2C	1	Wawa TS	Chapleau JCT	LC
W2C	3	Chapleau JCT	Chapleau DS	LC
W2C	4	Chapleau JCT	Chapleau DS	LC
W2C	5	Chapleau JCT	Chapleau MTS	LC
W2S	1	Buchanan TS	Sydenham JCT	LC
W2S	2	Sydenham JCT	Strathroy TS	LC
W36	1	Buchanan TS	Oxford Street JCT	LC
W36	2	Oxford Street JCT	Clarke TS	LC
W36	3	Oxford Street JCT	Talbot TS	LC
W37	1	Buchanan TS	Dundas Street JCT	LC

W37	2	Dundas Street JCT	Clarke TS	LC
W37	3	Dundas Street JCT	Talbot TS	LC
W3B	1	Barrett Chute JCT	Barrett Chute SS	DFL
W3B	2	Stewartville TS	Barryvale Rd JCT	DFL
W3B	3	Barrett Chute JCT	Mountain Chute DS	LC
W3B	4	Barryvale Rd JCT	Barrett Chute JCT	DFL
W3C	1	Whitedog Falls SS	Caribou Falls GS	LC
W42L	1	Buchanan TS	Buchanan TS	DFL
W42L	2	Buchanan TS	N21W T2 JCT	DFL
W42L	3	Buchanan TS	Buchanan TS	LC
W42L	4	N21W T466 JCT	Longwood TS	OTHER
W43L	1	Buchanan TS	Buchanan TS	DFL
W43L	2	Buchanan TS	Longwood TS	DFL
W43L	3	Buchanan TS	Buchanan TS	LC
W44LC	1	Buchanan TS	Cowal JCT	DFL
W44LC	2	Cowal JCT	Duart JCT	DFL
W44LC	3	Cowal JCT	Longwood TS	DFL
W44LC	4	Buchanan TS	Edgeware TS	LC
W44LC	5	Buchanan TS	Buchanan TS	DFL
W44LC	6	Duart JCT	Chatham SS	DFL
W44LC	7	Duart JCT	Duart TS	LC
W45LS	1	Buchanan TS	Cowal JCT	DFL
W45LS	2	Cowal JCT	Duart JCT	DFL
W45LS	3	Cowal JCT	Longwood TS	DFL
W45LS	4	Buchanan TS	Edgeware TS	LC
W45LS	5	Buchanan TS	Buchanan TS	DFL
W45LS	6	Duart JCT	Spence SS	DFL
W45LS	7	Duart JCT	Duart TS	LC
W5N	1	Buchanan TS	Nelson TS	LC
W6CS	1	Stewartville TS	Arnprior JCT	DFL
W6CS	2	Arnprior JCT	Mississippi JCT	DFL
W6CS	3	Mississippi JCT	Chats Falls SS	OTHER
W6CS	4	Mississippi JCT	Marchwood JCT	DFL
W6CS	5	Arnprior JCT	Arnprior TS	LC
W6CS	6	Marchwood JCT	Marchwood JCT	DFL
W6CS	7	Marchwood JCT	Marchwood JCT	OTHER
W6CS	8	Marchwood JCT	South March SS	DFL
W6CS	9	Marchwood JCT	Marchwood MTS	LC
W6NL	1	Buchanan TS	Buchanan JCT	LC

W6NL	2	Buchanan JCT	Highbury TS	LC
W6NL	3	Buchanan JCT	Nelson TS	LC
W7	1	Buchanan TS	Ingersoll TS	LC
W71D	1	Widdifield SS	Lower Notch JCT	DFL
W71D	2	Lower Notch JCT	Dymond TS	DFL
W71D	3	Widdifield SS	Trout Lake TS	LC
W71D	4	Lower Notch JCT	Lower Notch GS	LC
W71D	5	Lower Notch JCT	Lower Notch GS	LC
W8T	1	Buchanan TS	W8T STR A1 JCT	LC
W8T	4	Edgeware JCT	Lyons JCT	LC
W8T	5	Lyons JCT	Cranberry JCT	LC
W8T	9	W8T STR A1 JCT	Edgeware JCT	LC
W8T	10	Lyons JCT	Lyons JCT	LC
W9L	1	Buchanan TS	Highbury TS	LC
WT1A	1	Lyons JCT	Silvercreek JCT	LC
WT1A	2	Silvercreek JCT	Aylmer TS	LC
WT1A	3	Silvercreek JCT	Silvercreek CGS	LC
WT1T	1	Cranberry JCT	ESWF JCT	LC
WT1T	2	Tillsonburg JCT	Tillsonburg TS	LC
WT1T	3	Tillsonburg JCT	Tillsonburg TS	LC
WT1T	4	ESWF JCT	Tillsonburg JCT	LC
WT1T	5	ESWF JCT	ESWF CSS	LC
WW1C	1	Ingersoll TS	Lafarge Woodstk. CTS	LC
X1H	1	Lennox TS	Lafarge JCT	DFL
X1H	2	Lafarge JCT	NPIF Kingston JCT	DFL
X1H	3	Cataraqui TS	Hinchinbrooke SS	N
X1H	4	Lafarge JCT	Lafarge Bath CTS	LC
X1H	6	NPIF Kingston JCT	Cataraqui TS	DFL
X1H	8	NPIF Kingston JCT	NPIF Kingston JCT	LC
X1P	1	Massanoga JCT	Dobbin TS	LC
X1P	2	Mountain Chute JCT	Massanoga JCT	LC
X1P	3	Chenaux TS	Mountain Chute JCT	LC
X1P	4	Mountain Chute JCT	Mountain Chute GS	LC
X1P	5	Massanoga JCT	Mazinaw DS	LC
X21	1	Lennox TS	Gretna JCT	LC
X21	2	Gretna JCT	Napanee TS	LC
X21	3	Gretna JCT	Long Reach East JCT	LC
X21	4	Long Reach East JCT	Long Reach West JCT	LC
X21	5	Long Reach West JCT	Picton TS	LC

X22	1	Lennox TS	Gretna JCT	LC
X22	2	Gretna JCT	Napanee TS	LC
X22	3	Gretna JCT	Long Reach East JCT	LC
X22	4	Long Reach East JCT	Long Reach West JCT	LC
X22	5	Long Reach West JCT	Picton TS	LC
X23N	1	Hanmer TS	Vale Frd Stbe #2 JCT	LC
X23N	2	Vale Frd Stbe #2 JCT	Clarabelle JCT	LC
X23N	3	Clarabelle JCT	Vale Copper #4 CTS	LC
X23N	4	Vale Frd Stbe #2 JCT	Vale Frd Stbe #2 CTS	LC
X23N	5	Clarabelle JCT	Clarabelle TS	LC
X25S	1	Hanmer TS	Hanmer Parllel B JCT	N
X25S	2	Hanmer Parllel B JCT	Martindl Parll B JCT	N
X25S	3	Hanmer Parllel B JCT	Martindl Parll B JCT	N
X25S	4	Martindl Parll B JCT	Martindale TS	N
X26S	1	Hanmer TS	Hanmer Parllel A JCT	N
X26S	2	Hanmer Parllel A JCT	Martindl Parll A JCT	N
X26S	3	Hanmer Parllel A JCT	Martindl Parll A JCT	N
X26S	4	Martindl Parll A JCT	Martindale TS	N
X27A	1	Hanmer TS	Algoma TS	N
X2H	1	Lennox TS	Lafarge JCT	DFL
X2H	2	Lafarge JCT	NPIF Kingston JCT	DFL
X2H	3	Westbrook JCT	Cataraqui TS	DFL
X2H	4	Cataraqui TS	Hinchinbrooke SS	DFL
X2H	5	Lafarge JCT	Lafarge Bath CTS	OTHER
X2H	6	Westbrook JCT	Gardiner STR 44 JCT	LC
X2H	7	NPIF Kingston JCT	Westbrook JCT	DFL
X2H	9	NPIF Kingston JCT	NPIF Kingston JCT	LC
X2H	10	Gardiner STR 44 JCT	Gardiner TS	LC
X2H	11	Gardiner STR 44 JCT	Gardiner TS	LC
X2Y	2	Chenaux JCT	IPB Bryson JCT	N
X2Y	4	Chenaux JCT	Magellan Arospce JCT	LC
X2Y	5	Magellan Arospce JCT	Haley JCT	LC
X2Y	6	Haley JCT	Cobden TS	LC
X2Y	8	Cobden TS	Pembroke TS	LC
X2Y	9	Magellan Arospce JCT	Magellan Arospce CTS	LC
X2Y	10	Cobden TS	Cobden TS	LC
X2Y	11	Chenaux TS	Chenaux JCT	LC
X3H	1	Lennox TS	Kingston Solar JCT	DFL
X3H	2	Cataraqui TS	Hinchinbrooke SS	N

X3H	3	Kingston Solar JCT	Cataraqui TS	DFL
X3H	4	Kingston Solar JCT	Kingston Solar CGS	LC
X4H	1	Lennox TS	Westbrook JCT	DFL
X4H	2	Westbrook JCT	Cataraqui TS	DFL
X4H	3	Cataraqui TS	Hinchinbrooke SS	DFL
X4H	4	Westbrook JCT	Gardiner STR 44 JCT	LC
X4H	5	Gardiner STR 44 JCT	Gardiner TS	LC
X4H	6	Gardiner STR 44 JCT	Gardiner TS	LC
X503E	1	Hanmer TS	Nobel SS	N
X503E	2	Nobel SS	Essa TS	N
X504E	1	Hanmer TS	Nobel SS	N
X504E	2	Nobel SS	Essa TS	N
X520B	1	Lennox TS	Bowmanville SS	N
X521B	1	Lennox TS	Bowmanville SS	N
X522A	1	Lennox TS	Hawthorne TS	N
X523A	1	Lennox TS	Hawthorne TS	N
X526B	1	Lennox TS	Bowmanville SS	N
X527B	1	Lennox TS	Bowmanville SS	N
X534N	1	Lennox TS	Napanee CSS	N
X538N	1	Lennox TS	Napanee CSS	N
X6	2	Cobden X6 JCT	Cobden TS	LC
X6	3	Cobden X6 JCT	Pembroke TS	LC
X6	4	Pembroke TS	Pembroke TS	LC
X6	5	Chenaux TS	Cobden X6 JCT	LC
X74P	1	Hanmer TS	Mississagi TS	N
Z1E	1	Lauzon TS	Windsor Airport JCT	DFL
Z1E	2	Jefferson JCT	Walker JCT	DFL
Z1E	3	Walker JCT	Windsor Transalt JCT	DFL
Z1E	4	Jefferson JCT	Ford Essex JCT	LC
Z1E	5	Walker JCT	Walker TS #1	LC
Z1E	6	Windsor Transalt JCT	Essex TS	DFL
Z1E	7	Windsor Transalt JCT	Windsor Transalt CGS	LC
Z1E	10	Windsor Airport JCT	Jefferson JCT	DFL
Z1E	11	Windsor Airport JCT	Windsor Airport CGS	LC
Z1E	12	Jefferson JCT	Jefferson JCT	LC
Z7E	1	Lauzon TS	Jefferson JCT	DFL
Z7E	2	Jefferson JCT	Walker JCT	DFL
Z7E	5	Walker JCT	Essex TS	DFL
Z7E	7	Jefferson JCT	Ford Essex JCT	LC

Z7E	8	Walker JCT	Walker TS #1	LC
Z7E	10	Jefferson JCT	Jefferson JCT	LC

LIST OF TRANSMISSION STATIONS BY FUNCTIONAL CATEGORY

N = Network *TC = Transformation Connection* *LC = Line Connection*

GC = Generation Line/Transformation Connection

Station Number	Station Name	Functional Category
1001	Agincourt TS	TC
1002	Applewood JCT	LC
1003	Armitage TS	TC
1004	Balfour JCT	LC
1005	Bartlett JCT	LC
1007	Bayview JCT	LC
1008	Beaverton TS	TC
1010	Bloor Street JCT	LC
1011	Copeland SS	LC
1012	Goreway TS	TC
1013	Bramalea TS	TC
1014	Bronte TS	TC
1015	Brown Hill TS	N,TC
1018	Buttonville TS	TC
1019	Cherrywood TS	N,TC
1021	Claireville JCT	LC
1022	Claireville TS	N
1024	Tremaine TS	TC
1026	Cooksville TS	TC
1028	Dobbin TS	N,TC
1034	Dufferin JCT	LC
1035	Erindale TS	TC
1038	Gerrard JCT	LC
1044	Kleinburg TS	TC
1049	Lorne Park TS	TC
1050	Lumsden JCT	LC
1051	Manby TS	N,LC,TC
1056	Oakville TS #2	TC
1057	Thornton TS	TC
1058	Wilson TS	TC
1059	Otonabee TS	TC

1062	Palermo TS	TC
1064	Pickering A SS	GC
1065	Pleasant TS	TC
1066	Port Hope TS	TC
1070	Rexdale TS	TC
1071	Westmore JCT	LC
1073	Richview TS	N,TC
1074	Scarboro TS	TC
1075	Ellesmere TS	TC
1076	Riverside JCT	LC
1077	Birch JCT	LC
1082	Todmorden JCT	LC
1083	Tomken TS	TC
1084	Basin TS	TC
1086	Bathurst TS	TC
1087	Bermondsey TS	TC
1088	Bridgman TS	TC
1089	Carlaw TS	TC
1090	Cecil TS	LC,TC
1091	Charles TS	TC
1094	Dufferin TS	TC
1095	Duplex TS	TC
1096	Esplanade TS	TC
1097	Fairbank TS	TC
1098	Fairchild TS	TC
1099	Finch TS	TC
1100	Gerrard TS	TC
1101	Glengrove TS	TC
1102	Horner TS	TC
1103	John TS	LC,TC
1104	Leaside TS	N,TC
1105	Leslie TS	TC
1106	Main TS	TC
1107	Malvern TS	TC
1109	Runnymede TS	TC
1110	Sheppard TS	TC
1112	Strachan TS	TC
1113	Terauley TS	TC
1114	Warden TS	TC

1116	Wiltshire TS	N,TC
1118	Trafalgar TS	N,TC
1119	Vansco JCT	LC
1124	Woodbridge TS	TC
1135	Lindsay TS	TC
1139	Markham #2 PH JCT	LC
1154	Milton SS	N
1157	Pickering B SS	GC
1169	Whitby TS	TC
1173	Bowmanville SS	N
1174	Markham #3 PH JCT	LC
1184	Halton TS	TC
1186	Meadowvale TS	TC
1193	Toronto Star JCT	LC
1217	Hearn SS	LC
1262	Vaughan #1 PH JCT	LC
1265	Goreway PH JCT	LC
1275	Bridgman JCT	LC
1276	Clarington TS	N
1277	Cardiff TS	TC
1278	Parkway TS	N
1283	Waverly OPF	LC
1284	Brookside OPF	LC
1287	Oshawa G.M. TS	TC
1302	Holland TS	TC
1310	Hurontario SS	N
1317	Churchill Meadows TS	TC
2001	Almonte TS	TC
2003	Barrett Chute SS	N
2005	Arnprior TS	TC
2009	Belleville TS	N,TC
2010	Bilberry Creek TS	TC
2011	Billings JCT	LC
2016	Brockville TS	TC
2020	Cataraqui TS	N
2024	Chats Falls SS	N,GC
2027	Chesterville TS	TC
2030	Chenaux TS	LC
2031	Cobden TS	TC

2035	Cyrville JCT	LC
2048	Frontenac TS	LC,TC
2057	Havelock TS	N,TC
2061	Hinchinbrooke SS	N
2065	Gardiner TS	TC
2068	Longueuil TS	TC
2071	Manotick JCT	LC
2074	Merivale TS	N
2079	Morrisburg TS	TC
2083	Napanee TS	TC
2091	Odessa JCT	N,LC
2094	Carling TS	TC
2095	NRC TS	TC
2096	Albion TS	TC
2097	Hawthorne TS	N,TC
2098	Hinchey TS	TC
2099	King Edward TS	TC
2100	Lincoln Heights TS	TC
2101	Lisgar TS	TC
2103	Overbrook TS	TC
2104	Riverdale TS	TC
2105	Russell TS	TC
2106	Slater TS	TC
2107	Woodroffe TS	TC
2109	Pembroke TS	TC
2113	Picton TS	TC
2127	Smiths Falls TS	TC
2129	South March TS	N,TC
2130	St.Isidore TS	N,TC
2131	St.Lawrence TS	N,LC,TC
2136	Val Tetreau JCT	LC
2137	Wallace TS	TC
2141	Sidney TS	N,TC
2143	Lennox TS	N
2145	Orleans TS	TC
2170	Nepean TS	TC
2176	Bellman JCT	N,LC
2179	Massanoga JCT	LC
2194	B5D-B31L SS JCT	N

2197	Crosby TS	TC
2237	Des Joachims TS	N,LC
2238	Stewartville TS	N,TC
2255	Long Reach West JCT	LC
2256	Long Reach East JCT	LC
2290	Magellan Arospce JCT	LC
2329	19D684-1 JCT	LC
2330	Didsbury Road JCT	N,LC
2332	South March SS	N
2337	Northbrook JCT	LC
2340	Enfield TS	TC
3001	Alliston TS	TC
3003	Barrie TS	TC
3004	Midhurst TS	TC
3006	Bruce B SS	N
3007	Bruce A TS	N
3008	Bruce HW Plant B TS	TC
3014	Cooper's Falls JCT	N,LC
3017	Essa TS	N
3018	Hanover TS	N,TC
3019	Meaford TS	TC
3021	Minden TS	N,TC
3022	Muskoka TS	TC
3023	Orangeville TS	N,TC
3024	Orillia TS	TC
3025	Owen Sound TS	N,TC
3026	Ashfield SS	N
3028	Parry Sound TS	TC
3029	Stayner TS	N,TC
3032	Waubaushene TS	TC
3034	Wingham TS	TC
3035	Bruce JCT	N
3052	Douglas Point TS	TC
3054	Nobel SS	N
3065	Bracebridge TS	TC
3079	Everett TS	TC
4003	Allanburg TS	LC,TC
4007	Beamsville TS	TC
4010	Brant TS	N,TC

4011	Brantford TS	TC
4013	Burlington TS	N,TC
4014	Cumberland TS	TC
4017	Caledonia TS	LC,TC
4021	Crowland TS	TC
4028	Detweiler TS	N,LC
4030	Dundas TS	TC
4031	Dunnville TS	TC
4032	Elmira TS	TC
4033	Fergus TS	TC
4035	Freeport SS	N
4037	Galt TS	TC
4038	Gibson JCT	LC
4040	Nebo TS	TC
4043	Guelph North JCT	N,LC
4044	Campbell TS	TC
4045	Cedar TS	N,TC
4046	Hanlon TS	TC
4049	Beach TS	N,LC,TC
4050	Birmingham TS	TC
4051	Elgin TS	TC
4052	Gage TS	TC
4053	Horning TS	TC
4054	Kenilworth TS	TC
4055	Lake TS	TC
4056	Mohawk TS	TC
4057	Newton TS	TC
4058	Stirton TS	TC
4070	Jarvis TS	TC
4072	Louth JCT	LC
4074	Nanticoke TS	N
4081	Newport JCT	N,LC
4082	Murray TS	TC
4084	Stanley TS	TC
4085	Norfolk TS	TC
4088	Port Colborne TS	TC
4091	Preston TS	N,TC
4097	Beck #2 TS	N
4101	Bunting TS	TC

4102	Carlton TS	TC
4103	Glendale TS	LC,TC
4104	Vansickle TS	TC
4108	Thorold TS	TC
4110	Vanessa JCT	LC
4123	Summerhaven SS	N
4130	Middleport TS	N
4134	Sandusk SS	N
4165	Edgeware JCT	LC
4177	Palmerston TS	TC
4181	D7F_D9F T#157 PH JCT	LC
4182	D7F_D9F T#162 PH JCT	LC
4195	Hartford JCT	LC
4213	DeCew Falls SS	LC
4214	Beck #1 SS	LC
4215	Caledonia Q35M-C9 J	N,LC
4230	Puslinch JCT	LC
4237	Imp Oil Nanticok JCT	LC
4256	Winona TS	TC
4257	Dundas TS #2	TC
4258	Winona JCT	LC
4289	Beach JCT	LC
5005	Algoma TS	N,LC
5011	Blind River TS	LC
5014	Cassels JCT	N,LC
5025	Creighton JCT	LC
5031	Dymond TS	N,TC
5035	Elliot Lake TS	TC
5037	Espanola TS	TC
5050	Hearst TS	TC
5052	Hunta SS	N
5056	Kapuskasing TS	N,TC
5059	Larchwood TS	TC
5063	Manitoulin TS	TC
5065	Martindale TS	N,TC
5071	Mississagi TS	N
5076	North Bay TS	TC
5079	Otter Rapids SS	LC
5087	Ramore TS	TC

5096	Clarabelle TS	TC
5103	Timmins TS	N,LC,TC
5105	Trout Lake TS	TC
5111	Warkus JCT	N,LC
5113	Wawa TS	N
5120	Widdifield SS	N
5121	Crystal Falls TS	TC
5127	Hanmer TS	N
5148	Kirkland Lake TS	N,TC
5158	Porcupine TS	N
5162	Pinard TS	N
5171	Spruce Falls TS	N
5227	Ansonville TS	N
5243	Little Long SS	N
5244	Lower Notch JCT	GC
5245	Otto Holden TS	N,TC
5306	Moosonee SS	LC
5407	Crystal Falls SS	N
6013	Conmee JCT	LC
6016	Dryden TS	N,TC
6020	Fort Frances TS	N
6022	Fort William TS	TC
6033	Kenora TS	N
6035	Lakehead TS	N
6036	Longlac TS	TC
6037	Mackenzie TS	N
6042	Manitouwadge TS	TC
6045	Marathon TS	N
6050	Moose Lake TS	N,TC
6062	Port Arthur TS #1	N,LC,TC
6064	Birch TS	N,TC
6065	Rabbit Lake SS	N
6066	Red Lake TS	TC
6084	Terrace Bay SS	N
6095	Alexander SS	N
6098	Whitedog Falls SS	LC
6099	Barwick TS	TC
6110	Kashabowie JCT	N,LC
6112	Marmion Lake JCT	LC

6152	Minnova JCT	LC
6174	Thunder Bay SS	GC
6191	Aguasabon SS	N
6192	Ear Falls TS	LC,TC
6193	Pine Portage SS	N
6199	Ainsworth JCT	N,LC
6202	Murillo JCT	N,LC
6226	Angler Switch JCT	LC
6231	K3D-10 SW JCT	N,LC
6232	K6F-10 SW JCT	N,LC
7003	Aylmer TS	TC
7007	Buchanan TS	N,LC,TC
7009	Centralia TS	TC
7011	Chatham SS	N
7013	Cranberry JCT	LC
7017	Dundas Street JCT	LC
7019	Essex TS	N,TC
7022	Goderich TS	TC
7025	Ingersoll TS	TC
7030	Duart TS	TC
7031	Kent TS	TC
7035	Kingsville TS	TC
7036	Kirkton JCT	LC
7038	Lambton TS	TC
7039	Lambton TS #2	N
7040	Clarke TS	TC
7041	Highbury TS	TC
7042	Nelson TS	TC
7045	Talbot TS	TC
7047	Wonderland TS	TC
7048	Lucasville JCT	N,LC
7054	Oxford Street JCT	LC
7056	Nova SS	N
7060	Modeland TS	TC
7062	St.Andrews TS	TC
7064	Sarnia Scott TS	N,LC
7065	Seaforth TS	LC,TC
7068	St.Marys TS	TC
7070	St.Thomas JCT	TC

7071	Edgeware TS	TC
7073	Stratford TS	TC
7077	Strathroy TS	TC
7084	Tillsonburg TS	TC
7085	Tilbury JCT	LC
7087	Wallaceburg TS	TC
7088	Wanstead TS	TC
7092	Crawford TS	TC
7093	Lauzon TS	N,TC
7095	Malden TS	TC
7096	Walker TS #1	TC
7098	Woodstock TS	TC
7106	Evergreen SS	N
7120	Longwood TS	N,TC
7129	Ojibway JCT	LC
7136	Cowal JCT	N,LC
7139	Leamington JCT	LC
7143	McKee JCT	LC
7144	Leamington TS	TC
7169	Keith TS	N,TC
7176	Plank Road JCT	LC
7177	Confederation Rd JCT	LC
7199	W8T STR A1 JCT	LC
7214	Belle River TS	TC
7222	Commerce Way TS	TC
7227	Toyota Woodstock TS	TC
7238	Karn TS	N
7242	Spence SS	N

ALLOCATION FACTORS FOR DUAL FUNCTION LINES

Operation Designation	% Network	% Connection
A1B	81%	19%
A3RM	63%	37%
A4H	83%	17%
A5A	97%	3%
A5H	96%	4%
A6P	97%	3%
A8M	94%	6%
A9K	85%	15%
B12BL	17%	83%
B13BL	17%	83%
B18H	94%	6%
B1S	84%	16%
B2	82%	18%
B20H	94%	6%
B22D	85%	15%
B23D	85%	15%
B27S	93%	7%
B4V	100%	0%
B5C	74%	26%
B5QK	54%	46%
B5V	100%	0%
B6C	75%	25%
B6M	96%	4%
B88H	89%	11%
B89H	89%	11%
C14L	77%	23%
C15L	83%	17%
C16L	90%	10%
C17L	84%	16%
C18R	73%	27%
C20R	71%	29%
C21J	86%	14%
C22J	86%	14%
C23Z	100%	0%

Operation Designation	% Network	% Connection
C24Z	100%	0%
C27P	100%	0%
C2L	85%	15%
C35P	85%	15%
C36P	88%	12%
C3L	85%	15%
C4R	75%	25%
C5R	75%	25%
C7BM	61%	39%
D2L	97%	3%
D2M	91%	9%
D3K	100%	0%
D4W	98%	2%
D5A	90%	10%
D5W	98%	2%
D6V	65%	35%
D7F	85%	15%
D7V	65%	35%
D9F	85%	15%
E1C	98%	2%
E34M	83%	17%
E4D	100%	0%
E8V	86%	14%
E9V	88%	12%
F11C	85%	15%
F12C	85%	15%
H23B	100%	0%
H23S	99%	1%
H24S	90%	10%
H6T	96%	4%
H7T	84%	16%
H82V	88%	12%
H83V	88%	12%
H9K	95%	5%
J3E	91%	9%
J4E	89%	11%
K11W	88%	12%

Operation Designation	% Network	% Connection
K12	93%	7%
K12W	88%	12%
K1W	82%	18%
K23D	100%	0%
K24F	95%	5%
K38S	82%	18%
K3D	86%	14%
K3W	82%	18%
K40M	98%	2%
K6F	80%	20%
K7	93%	7%
K7K	96%	4%
L13W	69%	31%
L14W	83%	17%
L18W	63%	37%
L1S	95%	5%
L20D	100%	0%
L20H	89%	11%
L21H	89%	11%
L22H	85%	15%
L23N	98%	2%
L24A	100%	0%
L24L	98%	2%
L25V	98%	2%
L26L	98%	2%
L27V	97%	3%
L28C	92%	8%
L29C	93%	7%
L5H	73%	27%
M20D	70%	30%
M21D	69%	31%
M23L	100%	0%
M24L	100%	0%
M27B	96%	4%
M28B	96%	4%
M2D	100%	0%
M30A	93%	7%

Operation Designation	% Network	% Connection
M31A	93%	7%
M31W	94%	6%
M32S	83%	17%
M32W	79%	21%
M33W	95%	5%
M6E	29%	71%
M7E	34%	66%
M80B	88%	12%
M81B	88%	12%
N20K	95%	5%
N21W	85%	15%
N22W	85%	15%
N5M	98%	2%
N6M	98%	2%
P21R	65%	35%
P22R	70%	30%
P25W	100%	0%
P26W	100%	0%
P3S	71%	29%
P4S	51%	49%
P91G	99%	1%
Q23BM	89%	11%
Q24HM	84%	16%
Q25BM	90%	10%
Q26M	89%	11%
Q29HM	84%	16%
Q30M	82%	18%
Q35M	89%	11%
Q6S	100%	0%
R13K	91%	9%
R14T	78%	22%
R17T	78%	22%
R19TH	58%	42%
R21TH	58%	42%
R9A	100%	0%
S22A	94%	6%
S2S	88%	12%

Operation Designation	% Network	% Connection
S39M	98%	2%
S47C	100%	0%
S7M	59%	41%
T1M	97%	3%
T22C	83%	17%
T23C	76%	24%
T24C	78%	22%
T26C	78%	22%
T29C	76%	24%
T31H	85%	15%
T33E	94%	6%
T36B	91%	9%
T37B	91%	9%
T38B	77%	23%
T39B	77%	23%
V41H	67%	33%
V41N	99%	1%
V42H	67%	33%
V43N	98%	2%
V71P	59%	41%
V72R	84%	16%
V74R	77%	23%
V75P	59%	41%
V76R	93%	7%
W3B	100%	0%
W42L	93%	7%
W43L	92%	8%
W44LC	93%	7%
W45LS	93%	7%
W6CS	81%	19%
W71D	93%	7%
X1H	98%	2%
X2H	88%	12%
X3H	100%	0%
X4H	91%	9%
Z1E	82%	18%
Z7E	82%	18%

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ALLOCATION FACTORS FOR GENERATOR LINE CONNECTIONS

Operation Designation	Section	From	To	% Generator	% Load
61M18	1	Seaforth 61M18 JCT	Constance DS	5%	95%
61M18	2	Constance DS	Goderich TS	7%	93%
61M18	3	Seaforth TS	Seaforth 61M18 JCT	5%	95%
A36N	1	Allanburg TS	Kalar JCT	34%	66%
A36N	3	Kalar JCT	Murray TS	34%	66%
A37N	1	Allanburg TS	Kalar JCT	34%	66%
A37N	3	Kalar JCT	Murray TS	34%	66%
A3RM	4	Ellwood JCT	Riverdale JCT	13%	87%
A3RM	6	Riverdale JCT	Riverdale TS	13%	87%
A4H	3	Fournier JCT	Fournier JCT	73%	27%
A4H	4	Hunta SS	LSR MSO JCT	100%	0%
A4H	6	Fournier JCT	Power JCT	73%	27%
A4K	1	Hawthorne TS	Blackburn JCT	13%	87%
A4K	2	Blackburn JCT	Cyrville Rd JCT	13%	87%
A4K	3	Cyrville JCT	Moulton JCT	13%	87%
A4K	9	Moulton JCT	Overbrook TS	13%	87%
A4K	11	Cyrville Rd JCT	Cyrville JCT	13%	87%
A4L	1	Alexander SS	A4L STR 217 JCT	72%	28%
A4L	2	Beardmore JCT	Namewaminikan JCT	41%	59%
A4L	10	A.P. Nipigon JCT	Beardmore JCT	39%	61%
A4L	11	A.P. Nipigon JCT	A.P. Nipigon CGS	100%	0%
A4L	14	Namewaminikan JCT	Namewaminikan CGS	100%	0%
A4L	15	A4L STR 217 JCT	A.P. Nipigon JCT	72%	28%
A5H	18	A.P. Tunis JCT	A.P. Tunis JCT	100%	0%
A5RK	1	Hawthorne TS	Blackburn JCT	13%	87%
A5RK	2	Blackburn JCT	Russell TS	13%	87%
A5RK	3	Russell TS	Riverdale JCT	13%	87%
A5RK	4	Riverdale JCT	Riverdale TS	13%	87%
A5RK	6	Riverdale JCT	A5RK STR O7 JCT	13%	87%
A5RK	8	A5RK STR O7 JCT	Overbrook TS	13%	87%
A6R	1	Hawthorne TS	Blackburn JCT	13%	87%
A6R	2	Blackburn JCT	Russell TS	13%	87%
A6R	3	Russell TS	Riverdale JCT	13%	87%

Operation Designation	Section	From	To	% Generator	% Load
A6R	4	Riverdale JCT	OHSC JCT	13%	87%
A6R	5	OHSC JCT	Riverdale TS	13%	87%
A6R	6	OHSC JCT	OHSC JCT	100%	0%
B20P	8	Bruce A TS	Bruce HW Plant B TS	47%	53%
B22D	8	Majestic JCT	Majestic CTS	100%	0%
B22D	12	Armow JCT	Armow CSS	100%	0%
B23D	8	Majestic JCT	Majestic CTS	100%	0%
B23D	12	Zurich JCT	Zurich CSS	100%	0%
B24P	8	Bruce A TS	Bruce HW Plant B TS	47%	53%
B4V	4	Amaranth JCT	Amaranth CTS	100%	0%
B4V	6	Underwood JCT	Underwood CGS	100%	0%
B4V	8	GV3 WF JCT	GV3 WF CGS	100%	0%
B4V	10	Southgate JCT	Southgate CGS	100%	0%
B5V	4	Underwood JCT	Underwood CGS	100%	0%
B5V	6	Amaranth JCT	Amaranth CTS	100%	0%
B88H	5	York EnergyCentr JCT	York EnergyCentr CGS	100%	0%
B89H	5	York EnergyCentr JCT	York EnergyCentr CGS	100%	0%
C1A	1	Cameron Falls GS	Alexander SS	100%	0%
C1A	2	Alexander SS	Alexander GS	100%	0%
C1A	3	Alexander SS	Alexander SS	100%	0%
C23Z	6	Dillon RWEC CGS JCT	Dillon RWEC CGS	100%	0%
C23Z	7	Comber WF JCT	Comber WF CTS	100%	0%
C23Z	10	Belle River JCT #2	Belle River CSS	100%	0%
C24Z	4	KEPA Wind Farm JCT	Port Alma WF CSS	100%	0%
C24Z	6	Comber WF JCT	Comber WF CTS	100%	0%
C27P	5	Galetta JCT	Arnprior GS	100%	0%
C2A	1	Cameron Falls GS	Alexander SS	100%	0%
C2A	2	Alexander SS	Alexander GS	100%	0%
C2A	3	Alexander SS	Alexander SS	100%	0%
C31	1	Chatham SS	C31 SKWP CMS JCT	100%	0%
C3A	1	Cameron Falls GS	Alexander SS	100%	0%
C3A	2	Alexander SS	Alexander GS	100%	0%
C3A	3	Alexander SS	Alexander SS	100%	0%
C5E	1	Cecil TS	Terauley TS	43%	57%
C5E	2	Terauley TS	Manhole A OPF	43%	57%
C5E	3	Manhole A OPF	Esplanade TS	43%	57%

Operation Designation	Section	From	To	% Generator	% Load
C7E	1	Cecil TS	Terauley TS	43%	57%
C7E	2	Terauley TS	Manhole A OPF	43%	57%
C7E	3	Manhole A OPF	Esplanade TS	43%	57%
D10S	1	DeCew Falls SS	Hooper's JCT	34%	66%
D10S	2	Hooper's JCT	Vansickle TS	34%	66%
D10S	3	Vansickle TS	Louth JCT	34%	66%
D10S	4	Louth JCT	Glendale TS	34%	66%
D1A	1	Holland Road JCT	Allanburg TS	34%	66%
D1A	2	Fibre JCT	Holland Road JCT	34%	66%
D1A	3	Gibson JCT	Fibre JCT	34%	66%
D1A	4	St.Johns Valley JCT	Gibson JCT	34%	66%
D1A	5	Hooper's JCT	St.Johns Valley JCT	34%	66%
D1A	6	DeCew Falls SS	Hooper's JCT	34%	66%
D2H	1	Pinard TS	Pinard JCT #2	98%	2%
D2H	2	Pinard JCT #2	Hwy 634 JCT	98%	2%
D2H	3	Pinard JCT #2	Hwy 634 JCT	98%	2%
D2H	4	Hwy 634 JCT	Island Falls JCT	98%	2%
D2H	5	Hwy 634 JCT	Island Falls JCT	98%	2%
D2H	6	Island Falls JCT	Greenwater Pr Pk JCT	98%	2%
D2H	7	Island Falls JCT	Greenwater Pr Pk JCT	98%	2%
D2H	8	Greenwater Pr Pk JCT	Calder JCT	98%	2%
D2H	9	Greenwater Pr Pk JCT	Calder JCT	98%	2%
D2H	10	Hunta JCT	Hunta SS	98%	2%
D2H	11	Hunta JCT	Hunta JCT	98%	2%
D2H	12	Hwy 634 JCT	Hwy 634 JCT	98%	2%
D2H	13	Island Falls JCT	Island Falls JCT	98%	2%
D2H	14	Greenwater Pr Pk JCT	Greenwater Pr Pk JCT	98%	2%
D2H	15	Pinard JCT #2	Pinard JCT #2	98%	2%
D2H	18	Calder JCT	Calder JCT	98%	2%
D2H	19	Calder JCT	Hunta JCT	98%	2%
D2H	20	Calder JCT	Hunta JCT	98%	2%
D2H	21	Calder JCT	Calder CSS	100%	0%
D2L	19	New Liskeard JCT	New Liskeard JCT #2	100%	0%
D3A	1	Fibre JCT	Allanburg TS	34%	66%
D3A	2	St.Johns Valley JCT	Gibson JCT	34%	66%
D3A	3	Hooper's JCT	St.Johns Valley JCT	34%	66%

Operation Designation	Section	From	To	% Generator	% Load
D3A	4	DeCew Falls SS	Hooper's JCT	34%	66%
D3A	8	Gibson JCT	Fibre JCT	34%	66%
D3H	1	Pinard TS	Pinard JCT #2	98%	2%
D3H	2	Pinard JCT #2	Hwy 634 JCT	98%	2%
D3H	3	Pinard JCT #2	Hwy 634 JCT	98%	2%
D3H	4	Hwy 634 JCT	Island Falls JCT	98%	2%
D3H	5	Hwy 634 JCT	Island Falls JCT	98%	2%
D3H	6	Island Falls JCT	Greenwater Pr Pk JCT	98%	2%
D3H	7	Island Falls JCT	Greenwater Pr Pk JCT	98%	2%
D3H	8	Greenwater Pr Pk JCT	Calder JCT	98%	2%
D3H	9	Greenwater Pr Pk JCT	Calder JCT	98%	2%
D3H	10	Hunta JCT	Hunta SS	98%	2%
D3H	11	Hunta JCT	Hunta JCT	98%	2%
D3H	12	Hwy 634 JCT	Hwy 634 JCT	98%	2%
D3H	13	Island Falls JCT	Island Falls JCT	98%	2%
D3H	14	Greenwater Pr Pk JCT	Greenwater Pr Pk JCT	98%	2%
D3H	15	Pinard JCT #2	Pinard JCT #2	98%	2%
D3H	16	Calder JCT	Hunta JCT	98%	2%
D3H	17	Calder JCT	Hunta JCT	98%	2%
D3H	18	Calder JCT	Calder JCT	98%	2%
D3K	7	Gull Lake South JCT	Gull Lake South JCT	100%	0%
D4	1	Pinard TS	Pinard JCT #2	100%	0%
D4	2	Pinard JCT #2	Abitibi Canyon GS	100%	0%
D4	3	Pinard JCT #2	Abitibi Canyon GS	100%	0%
D6T	1	Pinard TS	Pinard JCT #2	66%	34%
D6T	2	Pinard JCT #2	Abitibi Canyn JCT #2	66%	34%
D6T	3	Pinard JCT #2	Abitibi Canyn JCT #2	66%	34%
D6T	4	Abitibi Canyn JCT #2	P Sutherland Sr JCT	66%	34%
D6T	9	P Sutherland Sr JCT	P Sutherland Sr SYD	100%	0%
D9HS	1	DeCew Falls SS	Hooper's JCT	34%	66%
D9HS	2	Hooper's JCT	Vansickle TS	34%	66%
D9HS	3	Vansickle TS	Louth JCT	34%	66%
D9HS	9	Louth JCT	Glendale TS	34%	66%
E26	1	Essa TS	Waubaushene JCT	67%	33%
E26	2	Waubaushene JCT	Holmur JCT	67%	33%
E26	6	Holmur JCT	Holmur CSS	67%	33%

Operation Designation	Section	From	To	% Generator	% Load
E27	1	Essa TS	Waubaushene JCT	67%	33%
E27	2	Waubaushene JCT	Holmur JCT	67%	33%
E27	6	Holmur JCT	Holmur CSS	67%	33%
E6L	1	Seaforth TS	Egmondville CSS	100%	0%
E8F	1	Essex TS	Chrysler WAP MTS	63%	37%
E8F	2	Chrysler WAP MTS	G.M.Windsor MTS	75%	25%
E8F	3	G.M.Windsor MTS	Ford Annex MTS	83%	17%
E8F	4	Ford Annex MTS	Ford Windsor MTS	88%	12%
E8F	5	Ford Windsor MTS	East Windsor CGS	100%	0%
E9F	1	Essex TS	Chrysler WAP MTS	63%	37%
E9F	2	Chrysler WAP MTS	G.M.Windsor MTS	75%	25%
E9F	3	G.M.Windsor MTS	Ford Annex MTS	83%	17%
E9F	4	Ford Annex MTS	Ford Windsor MTS	88%	12%
E9F	5	Ford Windsor MTS	East Windsor CGS	100%	0%
F1E	1	Kapuskasing TS	AP Calstock CSS JCT	65%	35%
F1E	4	AP Calstock CSS JCT	A.P. Calstock CSS	100%	0%
F1E	5	AP Calstock CSS JCT	Nagagami CSS JCT	46%	54%
F1E	6	Nagagami CSS JCT	Nagagami CSS	77%	23%
H	1	Summerhaven SS	Summerhaven CSS	100%	0%
H10DE	1	Hearn SS	Hearn SS	43%	57%
H10DE	2	Hearn SS	Don Fleet JCT	43%	57%
H10DE	3	Don Fleet JCT	Esplanade TS	43%	57%
H11L	1	Hearn SS	Waverly OPF	43%	57%
H11L	2	Main TS	Lumsden JCT	43%	57%
H11L	3	Lumsden JCT	Todmorden JCT	43%	57%
H11L	4	Todmorden JCT	Leaside TS	43%	57%
H11L	7	Waverly OPF	Brookside OPF	43%	57%
H11L	8	Brookside OPF	Main TS	43%	57%
H12P	1	Hearn SS	Portlands Energy JCT	100%	0%
H12P	3	Hearn SS	Hearn SS	100%	0%
H13P	1	Hearn SS	Portlands Energy JCT	100%	0%
H13P	3	Hearn SS	Hearn SS	100%	0%
H14P	1	Hearn SS	Portlands Energy JCT	100%	0%
H14P	3	Hearn SS	Hearn SS	100%	0%
H1L	1	Hearn SS	Basin TS	43%	57%
H1L	2	Basin TS	Mill Street JCT	43%	57%

Operation Designation	Section	From	To	% Generator	% Load
H1L	3	Mill Street JCT	Gerrard TS	43%	57%
H1L	4	Gerrard TS	Bloor Street JCT	43%	57%
H1L	5	Bloor Street JCT	Leaside TS	43%	57%
H22D	1	Harmon GS	Harmon JCT	100%	0%
H22D	2	Harmon JCT	Smoky Falls JCT	100%	0%
H22D	3	Little Long JCT	Pinard TS	100%	0%
H22D	4	Little Long JCT	Little Long 2 JCT	100%	0%
H22D	5	Harmon JCT	Kipling JCT	100%	0%
H22D	6	Smoky Falls JCT	Little Long JCT	100%	0%
H22D	7	Kipling JCT	Kipling GS	100%	0%
H22D	9	Smoky Falls JCT	Smoky Falls 2 JCT	100%	0%
H23B	4	Stone Mills JCT	Stone Mills CGS	100%	0%
H24S	7	A.P. North Bay JCT	A.P. North Bay JCT	100%	0%
H3L	1	Hearn SS	Basin TS	43%	57%
H3L	2	Basin TS	Mill Street JCT	43%	57%
H3L	3	Mill Street JCT	Gerrard TS	43%	57%
H3L	5	Gerrard TS	Bloor Street JCT	43%	57%
H3L	6	Bloor Street JCT	Leaside TS	43%	57%
H3L	9	Gerrard TS	Bloor Street JCT	43%	57%
H6LC	1	Hearn SS	Don Fleet JCT	43%	57%
H6LC	2	Gerrard JCT	Bloor Street JCT	43%	57%
H6LC	3	Bloor Street JCT	Leaside TS	43%	57%
H6LC	4	Gerrard JCT	Cecil TS	43%	57%
H6LC	5	Don Fleet JCT	Gerrard JCT	43%	57%
H7L	1	Hearn SS	Waverly OPF	43%	57%
H7L	2	Main TS	Lumsden JCT	43%	57%
H7L	3	Lumsden JCT	Todmorden JCT	43%	57%
H7L	4	Todmorden JCT	Leaside TS	43%	57%
H7L	7	Waverly OPF	Brookside OPF	43%	57%
H7L	8	Brookside OPF	Main TS	43%	57%
H8LC	1	Hearn SS	Don Fleet JCT	43%	57%
H8LC	2	Gerrard JCT	Bloor Street JCT	43%	57%
H8LC	3	Bloor Street JCT	Leaside TS	43%	57%
H8LC	4	Gerrard JCT	Cecil TS	43%	57%
H8LC	5	Don Fleet JCT	Gerrard JCT	43%	57%
H9DE	1	Hearn SS	Hearn SS	43%	57%

Operation Designation	Section	From	To	% Generator	% Load
H9DE	2	Hearn SS	Don Fleet JCT	43%	57%
H9DE	3	Don Fleet JCT	Esplanade TS	43%	57%
H9K	11	Carmichael Falls JCT	Carmichael Falls JCT	100%	0%
H9K	20	Yellow Falls JCT	Yellow Falls CGS	100%	0%
H9W	1	Beach TS	West Lincoln JCT	100%	0%
H9W	2	West Lincoln JCT	West Lincoln CSS	100%	0%
J1B	1	Keith TS	Brighton Intface JCT	100%	0%
J20B	1	Keith TS	Brighton Intface JCT	100%	0%
K2	1	Kirkland Lake TS	Gull Lake North JCT	91%	9%
K2	2	Gull Lake North JCT	Gull Lake North JCT	100%	0%
K25BUS	1	Sandusk SS	Sandusk CGS	100%	0%
K2M	1	Rabbit Lake SS	Norman JCT	95%	5%
K2Z	4	Woodslee JCT	Lauzon JCT	29%	71%
K2Z	6	Woodslee JCT	Gosfield CGS JCT	36%	64%
K2Z	12	Lauzon JCT	Lauzon TS	22%	78%
K2Z	17	Gosfield CGS JCT	Gosfield Wind CGS	100%	0%
K38S	3	Spruce Falls JCT	A.P. Kapuskasing JCT	100%	0%
K4W	1	Rabbit Lake SS	Minaki JCT	98%	2%
K4W	2	Minaki JCT	Whitedog Falls SS	98%	2%
K5W	1	Rabbit Lake SS	Minaki JCT	98%	2%
K5W	3	Minaki JCT	Whitedog Falls SS	98%	2%
K6Z	3	Belle River JCT	Rourke Line JCT	37%	63%
K6Z	5	Lauzon JCT	Lauzon TS	27%	73%
K6Z	6	Rourke Line JCT	Lauzon JCT	27%	73%
K6Z	11	Pte-Aux-RochesWF JCT	Belle River JCT	37%	63%
K6Z	12	Pte-Aux-RochesWF JCT	Pte-Aux-RochesWF CGS	100%	0%
L12C	1	Leaside TS	Balfour JCT	43%	57%
L12C	2	Balfour JCT	Charles TS	43%	57%
L12C	3	Charles TS	Cecil TS	43%	57%
L1MB	4	St.Lawrence TS	Lunenburg JCT	58%	42%
L1MB	5	Lunenburg JCT	Morrisburg JCT	58%	42%
L1MB	6	Morrisburg JCT	Casco JCT	58%	42%
L1MB	15	Casco JCT	Cardinal Power CSS	58%	42%
L20D	1	Little Long JCT	Smoky Falls JCT	100%	0%
L20D	5	Smoky Falls JCT	Harmon JCT	100%	0%
L20D	6	Harmon JCT	Kipling JCT	100%	0%

Operation Designation	Section	From	To	% Generator	% Load
L20D	7	Kipling JCT	Kipling 2 GS	100%	0%
L20D	8	Harmon JCT	Harmon 2 GS	100%	0%
L20D	10	Smoky Falls JCT	Smoky Falls 2 JCT	100%	0%
L24A	4	Crysler JCT #2	Crysler CGS	100%	0%
L29C	5	East Lk StClair JCT	East Lk StClair CGS	100%	0%
L29C	7	North Kent 1 JCT	North Kent 1 CGS	100%	0%
L2M	4	St.Lawrence TS	Lunenburg JCT	58%	42%
L2M	5	Lunenburg JCT	Morrisburg JCT	58%	42%
L2M	8	Morrisburg JCT	Casco JCT	58%	42%
L2M	13	Casco JCT	Cardinal Power CSS	58%	42%
L7S	3	Seaforth L7S JCT	Goshen JCT	51%	49%
L7S	13	Seaforth TS	Seaforth L7S JCT	51%	49%
L7S	17	Goshen JCT	Goshen CSS	100%	0%
L9C	1	Leaside TS	Balfour JCT	43%	57%
L9C	2	Balfour JCT	Charles TS	43%	57%
L9C	3	Charles TS	Cecil TS	43%	57%
M1S	1	Moose Lake TS	Valerie Falls JCT	89%	11%
M1S	2	Mill Creek JCT	H2O Pwr SturgFls CGS	89%	11%
M1S	4	Mill Creek JCT	H2O Pwr Calm Lk CGS	100%	0%
M1S	6	Valerie Falls JCT	Mill Creek JCT	89%	11%
M23L	4	Greenwich WF CGS JCT	Greenwich LakeWF CSS	100%	0%
M24L	4	Greenwich WF CGS JCT	Greenwich LakeWF CSS	100%	0%
M2W	1	Marathon TS	Pic JCT	51%	49%
M2W	2	Pic JCT	Manitouwadge JCT	51%	49%
M2W	6	Manitouwadge JCT	Manitouwadge JCT B	53%	47%
M2W	8	Marathon TS	Black River JCT	39%	61%
M2W	9	Williams Mine JCT	Hemlo Mine JCT	21%	79%
M2W	10	Hemlo Mine JCT	Animki JCT	53%	47%
M2W	16	Black River JCT	Umbata Falls JCT	39%	61%
M2W	25	Umbata Falls JCT	Williams Mine JCT	21%	79%
M2W	26	Manitouwadge JCT B	Manitouwadge TS	56%	44%
M3E	1	Manitou Falls GS	Ear Falls TS	100%	0%
N25N	1	Nanticoke TS	Nanticoke Solar GS	100%	0%
N5M	5	Grand JCT	Grand CSS	100%	0%
N6S	1	Sarnia Scott TS	Sarnia Scott JCT	81%	19%
N6S	3	Sarnia Scott JCT	Arlanxeo Can Inc JCT	81%	19%

Operation Designation	Section	From	To	% Generator	% Load
N6S	4	Arlanxeo Can Inc JCT	TransAlta Energy JCT	81%	19%
N6S	9	TransAlta Energy JCT	TransAlta Energy JCT	81%	19%
N7S	1	Sarnia Scott TS	Sarnia Scott JCT	81%	19%
N7S	2	Sarnia Scott JCT	Arlanxeo Can Inc JCT	81%	19%
N7S	3	Arlanxeo Can Inc JCT	TransAlta Energy JCT	81%	19%
N7S	7	TransAlta Energy JCT	TransAlta Energy JCT	81%	19%
N93A	1	Atikokan TGS	Marmion Lake JCT	100%	0%
N93A	2	Marmion Lake JCT	Mackenzie TS	100%	0%
P25W	3	Aubrey Falls JCT	Aubrey Falls CGS	100%	0%
P26W	3	Aubrey Falls JCT	Aubrey Falls CGS	100%	0%
P27C	1	Pickering B SS	Cherrywood TS	100%	0%
P30C	1	Pickering B SS	Cherrywood TS	100%	0%
P31C	1	Pickering B SS	Cherrywood TS	100%	0%
P32C	1	Pickering B SS	Cherrywood TS	100%	0%
P5M	1	Port Arthur TS #1	Conmee JCT	54%	46%
P6C	1	Pickering A SS	Cherrywood TS	100%	0%
P7C	1	Pickering A SS	Cherrywood TS	100%	0%
P8C	1	Pickering A SS	Cherrywood TS	100%	0%
P9C	1	Pickering A SS	Cherrywood TS	100%	0%
Q10P	1	Abit Cons NAN91 JCT	Abit Cons NAN91 JCT	100%	0%
Q10P	3	Abit Cons NAN91 JCT	Q10P STR 9 JCT	100%	0%
Q11S	1	Beck #1 SS	Warner Road JCT	34%	66%
Q11S	2	Warner Road JCT	NOTL York MTS #1 JCT	34%	66%
Q11S	3	McKinnon's JCT	Glendale JCT	34%	66%
Q11S	4	Glendale JCT	Glendale TS	34%	66%
Q11S	8	NOTL York MTS #1 JCT	McKinnon's JCT	34%	66%
Q12S	1	Beck #1 SS	Warner Road JCT	34%	66%
Q12S	2	Glendale JCT	Glendale TS	34%	66%
Q12S	4	NOTL York MTS #1 JCT	Glendale JCT	34%	66%
Q12S	6	Warner Road JCT	NOTL York MTS #1 JCT	34%	66%
Q21P	1	Beck #2 TS	Beck Pump Storage GS	100%	0%
Q22P	1	Beck #2 TS	Beck Pump Storage GS	100%	0%
Q26M	3	Crossline JCT	Allanburg TS	34%	66%
Q28A	1	Beck #2 TS	Abit Cons NAN91 JCT	34%	66%
Q28A	2	Abit Cons NAN91 JCT	Allanburg TS	34%	66%
Q28A	3	Abit Cons NAN91 JCT	Abit Cons NAN91 JCT	100%	0%

Operation Designation	Section	From	To	% Generator	% Load
Q2AH	1	Beck #1 Q2AH JCT	Holland Road JCT	34%	66%
Q2AH	2	Holland Road JCT	Allanburg TS	34%	66%
Q2AH	26	Beck #1 SS	Beck #1 Q2AH JCT	34%	66%
Q30M	6	Allanburg Q30M JCT	Allanburg TS	34%	66%
Q35M	3	Crossline JCT	Allanburg TS	34%	66%
Q3N	1	Beck #1 SS	Portal JCT	34%	66%
Q3N	2	Portal JCT	Dresser JCT	34%	66%
Q3N	3	Dresser JCT	Niagara JCT	34%	66%
Q3N	4	Niagara JCT	Murray TS	34%	66%
Q4N	1	Beck #1 SS	Portal JCT	34%	66%
Q4N	3	Portal JCT	Dresser JCT	34%	66%
Q4N	4	Dresser JCT	Niagara JCT	34%	66%
Q4N	8	Niagara JCT	Murray TS	34%	66%
Q6S	6	Odessa JCT	Invista JCT	100%	0%
Q6S	7	Invista JCT	Amherst Island JCT	100%	0%
Q6S	11	Amherst Island JCT	Amherst Island CSS	100%	0%
R21D	1	Otter Rapids SS	Pinard JCT	100%	0%
R21D	2	Pinard JCT	Pinard TS	100%	0%
R21D	3	Pinard JCT	Abitibi Canyon GS	100%	0%
R21D	4	Otter Rapids GS	Otter Rapids SS	100%	0%
R9A	2	Alexander SS	Alexander GS	100%	0%
S1C	1	Conmee JCT	Lac Des Iles JCT	54%	46%
S1C	2	Lac Des Iles JCT	Silver Falls GS	100%	0%
S24V	1	Orangeville TS	Shannon CSS	100%	0%
S25L	2	Saunders JCT	St.Lawrence TS	100%	0%
S26L	2	Saunders JCT	St.Lawrence TS	100%	0%
S2B	1	Martindale TS	Copper Cliff JCT	59%	41%
S2B	2	Copper Cliff JCT	Creighton JCT	59%	41%
S2B	3	Creighton JCT	Ethel Lake JCT	59%	41%
S2B	5	Ethel Lake JCT	Turbine JCT	63%	37%
S2B	7	Turbine JCT	Eacom Nairn Ctr JCT	63%	37%
S2B	8	Eacom Nairn Ctr JCT	Espanola JCT	65%	35%
S2B	9	Espanola JCT	Eddy Tap JCT	65%	35%
S2B	14	Cutler JCT	Serpent River JCT	14%	86%
S2B	19	Espanola A JCT	McLeans Mtn JCT	65%	35%
S2B	24	Spanish JCT	Cutler JCT	14%	86%

Witness: LI Clement

Operation Designation	Section	From	To	% Generator	% Load
S2B	25	Serpent River JCT	Carmeuse Lime JCT	14%	86%
S2B	27	Carmeuse Lime JCT	Blind River TS JCT	14%	86%
S2B	30	Cameron Falls JCT	Spanish JCT	15%	85%
S2B	33	Blind River TS JCT	Algoma TS	14%	86%
S2B	35	Eddy Tap JCT	Espanola A JCT	65%	35%
S2B	41	McLeans Mtn JCT	McLeans Mtn CSS	100%	0%
S2N	1	Strathroy TS	Sydenham JCT	93%	7%
S2N	2	Sydenham JCT	Adelaide JCT	93%	7%
S2N	7	Adelaide JCT	Landon JCT	93%	7%
S2N	14	Landon JCT	Landon CGS	100%	0%
S30L	2	Saunders JCT	St.Lawrence TS	100%	0%
S32L	2	Saunders JCT	St.Lawrence TS	100%	0%
S47C	3	Erieau WF JCT	Erieau WF CGS	100%	0%
T1B	1	Rayner CGS	Wharncliffe JCT	100%	0%
T1B	2	Sowerby JCT	Red Rock CGS JCT	86%	14%
T1B	3	Red Rock CGS	Red Rock CGS JCT	86%	14%
T1B	4	Cobden JCT	Striker DS	78%	22%
T1B	5	Striker DS	Algoma TS	69%	31%
T1B	8	Wharncliffe JCT	Sowerby JCT	90%	10%
T1B	10	Red Rock CGS JCT	Cobden JCT	86%	14%
T1B	11	Red Rock CGS JCT	Red Rock CGS	86%	14%
T26C	5	Columbus JCT	Lasco JCT	17%	83%
T26C	10	Lasco JCT	Atlantic Packgng JCT	36%	64%
T26C	11	Atlantic Packgng JCT	Whitby CGS JCT	40%	60%
T26C	14	Whitby CGS JCT	Whitby CGS	100%	0%
T27P	1	Wells CGS	Mississagi TS	100%	0%
T28P	1	Wells CGS	Mississagi TS	100%	0%
T38B	3	Lantz JCT	Trafalgar DESN JCT	66%	34%
T38B	4	Hornby JCT	PEC Halton Hills JCT	66%	34%
T38B	6	Trafalgar DESN JCT	Hornby JCT	66%	34%
T38B	9	PEC Halton Hills JCT	PEC Halton Hills JCT	66%	34%
T39B	3	Lantz JCT	Trafalgar DESN JCT	66%	34%
T39B	4	Hornby JCT	PEC Halton Hills JCT	66%	34%
T39B	6	Trafalgar DESN JCT	Hornby JCT	66%	34%
T39B	9	PEC Halton Hills JCT	PEC Halton Hills JCT	66%	34%
V41H	6	Sithe Goreway JCT	Sithe Goreway JCT	60%	40%

Operation Designation	Section	From	To	% Generator	% Load
V41N	4	St.Clair E.C. JCT	St.Clair E.C. CGS	100%	0%
V42H	7	Sithe Goreway JCT	Sithe Goreway JCT	60%	40%
V43N	7	St.Clair E.C. JCT	St.Clair E.C. CGS	100%	0%
W2	1	Whitedog Falls GS	Whitedog Falls SS	98%	2%
W2S	1	Buchanan TS	Sydenham JCT	49%	51%
W2S	2	Sydenham JCT	Strathroy TS	49%	51%
W3C	1	Whitedog Falls SS	Caribou Falls GS	100%	0%
W71D	4	Lower Notch JCT	Lower Notch GS	100%	0%
W71D	5	Lower Notch JCT	Lower Notch GS	100%	0%
W8T	1	Buchanan TS	W8T STR A1 JCT	48%	52%
W8T	4	Edgeware JCT	Lyons JCT	48%	52%
W8T	5	Lyons JCT	Cranberry JCT	55%	45%
W8T	9	W8T STR A1 JCT	Edgeware JCT	48%	52%
W8T	10	Lyons JCT	Lyons JCT	29%	71%
WT1A	1	Lyons JCT	Silvercreek JCT	29%	71%
WT1A	3	Silvercreek JCT	Silvercreek CGS	100%	0%
WT1T	1	Cranberry JCT	ESWF JCT	55%	45%
WT1T	5	ESWF JCT	ESWF CSS	100%	0%
X1H	8	NPIF Kingston JCT	NPIF Kingston JCT	100%	0%
X1P	1	Massanoga JCT	Dobbin TS	63%	37%
X1P	2	Mountain Chute JCT	Massanoga JCT	64%	36%
X1P	3	Chenaux TS	Mountain Chute JCT	61%	39%
X1P	4	Mountain Chute JCT	Mountain Chute GS	100%	0%
X2H	9	NPIF Kingston JCT	NPIF Kingston JCT	100%	0%
X3H	4	Kingston Solar JCT	Kingston Solar CGS	100%	0%
X4H	4	Westbrook JCT	Gardiner STR 44 JCT	56%	44%
X4H	6	Gardiner STR 44 JCT	Gardiner TS	56%	44%
Z1E	7	Windsor Transalt JCT	Windsor Transalt CGS	100%	0%
Z1E	11	Windsor Airport JCT	Windsor Airport CGS	100%	0%

1 # ALLOCATION FACTORS FOR GENERATOR STATION CONNECTIONS

N= Network *LC= Line Connection* *TC=Transformation Connection*

Asset Number	Station Name	Functional Category	% Generator	% Load
549	Algoma TS	LC	31%	69%
5354	Allanburg TS	LC	34%	66%
1013	Balfour JCT	LC	36%	64%
1021	Billings JCT	LC	12%	88%
1023	Bloor Street JCT	LC	43%	57%
915	Brookside OPF	LC	43%	57%
8211	Bruce HW Plant B TS	TC	47%	53%
7566	Chenaux TS	LC	61%	39%
1220	Conmee JCT	LC	54%	46%
1043	Cranberry JCT	LC	55%	45%
1044	Creighton JCT	LC	59%	41%
1046	Cyrville JCT	LC	12%	88%
3879	DeCew Falls SS	LC	34%	66%
252	E.V. Buchanan TS	LC	12%	88%
232	Ear Falls TS	TC	75%	25%
3401	Ear Falls TS	LC	51%	49%
1060	Edgeware JCT	LC	48%	52%
1079	Gerrard JCT	LC	43%	57%
1080	Gibson JCT	LC	34%	66%
2047	Goderich TS	TC	7%	93%
251	Hamilton Beach TS	LC	48%	52%
1114	Louth JCT	LC	34%	66%
1117	Lumsden JCT	LC	43%	57%
6689	Manitouwadge TS	TC	56%	44%
3828	Marmion Lake JCT	LC	100%	0%
1125	Massanoga JCT	LC	63%	37%
257	Moose Lake TS	TC	97%	3%
15154	Ojibway JCT	LC	12%	88%
7665	Otter Rapids SS	LC	92%	8%
6952	R.L. Hearn SS	LC	43%	57%
196	Seaforth TS	LC	35%	65%
2942	Sir Adam Beck #1 SS	LC	34%	66%

3450	St. Catharines Glendale TS	LC	34%	66%
218	St. Lawrence TS	LC	58%	42%
1173	Todmorden JCT	LC	43%	57%
1107	Toronto Cecil TS	LC	43%	57%
1184	W8T STR A1 JCT	LC	48%	52%
896	Waverly OPF	LC	43%	57%
4	Whitedog Falls SS	LC	98%	2%

1 # ASSET VALUE BY FUNCTIONAL CATEGORY

2 **(Mid-Year Average)**

3

Functional Category	2023 Gross Book Value ($M)	2023 Net Book Value ($M)
Network	$8,454.2	$5,290.5
Line Connection	$1,521.5	$975.9
Transformation Connection	$4,809.4	$2,918.2
Network - Dual Function Line	$1,691.7	$1,098.3
Line Connection - Dual Function Line	$288.4	$186.6
Generation Line Connection	$409.7	$263.1
Generation Transformation Connection	$76.6	$45.8
Common	$5,406.9	$3,624.1
Other Assets	$254.1	$158.2
TOTAL	**$22,912.6**	**$14,560.7**

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DEPRECIATION BY FUNCTIONAL CATEGORY

(Includes Depreciation of Fixed Assets, Capitalized Depreciation and Asset Removal Costs)

Functional Category	2023 Depreciation ($M)
Network	$181.5
Line Connection	$27.9
Transformation Connection	$115.1
Network - Dual Function Line	$27.9
Line Connection - Dual Function Line	$4.8
Generation Line Connection	$8.0
Generation Transformation Connection	$1.8
Common	$156.4
Other Assets	$4.8
TOTAL	**$528.2**

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RETURN ON CAPITAL AND INCOME TAXES BY FUNCTIONAL CATEGORY

Functional Category	2023 Return on Capital and Income Taxes ($M)
Network	$314.7
Line Connection	$58.1
Transformation Connection	$173.6
Network - Dual Function Line	$65.3
Line Connection - Dual Function Line	$11.1
Generation Line Connection	$15.6
Generation Transformation Connection	$2.7
Common	$216.1
Other Assets	$9.4
TOTAL	$866.8

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OM&A COSTS BY FUNCTIONAL CATEGORY

(Excludes Property Tax and Rights Payments)

Functional Category	2023 OM&A ($M)
Network	$87.3
Line Connection	$18.1
Transformation Connection	$54.9
Network - Dual Function Line	$17.5
Line Connection - Dual Function Line	$3.0
Generation Line Connection	$3.2
Generation Transformation Connection	$1.4
Common	$162.6
Other Assets	$8.9
TOTAL	$356.8

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DETAILED TRANSMISSION REVENUE REQUIREMENT BY RATE POOL

Table 1 - 2023 Detailed Transmission Revenue Requirement by Rate Pool

	Rate Pool Revenue Requirement ($M)				
	Network	**Line Connection**	**Transformation Connection**	**Total**	**Reference (See Note)**
OM&A	$210.5	$40.6	$105.7	$356.8	Exhibit E-02-01
Property Taxes and Rights Payments	$44.3	$7.7	$19.3	$71.4	Exhibit E-09-04
Depreciation of Fixed Assets	$286.8	$42.1	$152.9	$481.8	Exhibit E-08-01
Capitalized Depreciation	($9.1)	($1.6)	($4.1)	($14.8)	Exhibit E-08-01
Asset Removal Costs	$37.7	$6.4	$17.1	$61.2	Exhibit E-08-01
Return on Debt	$211.0	$36.6	$91.9	$339.5	Exhibit F-01-03
Return on Equity	$302.5	$52.5	$131.8	$486.8	Exhibit F-01-03
Income Taxes	$25.2	$4.4	$11.0	$40.5	Exhibit E-09-02-01
SUB-TOTAL	**$1,108.9**	**$188.8**	**$525.5**	**$1,823.2**	
External Revenue	($24.4)	($4.2)	($11.6)	($40.1)	Exhibit D-02-01
MSP Service Revenue	$0.00	$0.0	($0.03)	($0.03)	Exhibit H-08-01
Regulatory Assets	$0.6	$0.1	$0.3	$0.9	Exhibit G-01-03
Export Revenue Variance	$0.2	$0.0	$0.0	$0.2	Exhibit G-01-03
Export Revenue	($37.4)	$0.0	$0.0	($37.4)	Exhibit H-09-01
LVSG Credit	$0.0	$0.0	$16.5	$16.5	Exhibit H-01-03
TOTAL	**$1,047.9**	**$184.7**	**$530.7**	**$1,763.3**	

**Note: The OMA, Depreciation and Amortization expenses include the impact of the environmental provision, as described in Exhibit D-01-01. Refer to the exhibit references noted above for more details.*

The detailed revenue requirement by rate pool for 2024 to 2027 are provided below in Tables 3 to 6, in consecutive order for each year. The methodology uses the proposed 2023 total revenue requirement as shown in Table 1 to determine the percentage split by rate pool for 2024 to 2027, which is shown in Table 2. This methodology to allocate rates revenue requirement for each year that follow the test year, was approved by the OEB in Proceeding EB-2019-0082.

Table 2 - Percentage Split of Total Revenue Requirement by Transmission Rate Pool

	Network	Line Connection	Transformation Connection	Total
2023 Proposed Total Revenue Requirement	1,108.9	$188.8	$525.5	1,823.2
Percentage Split by Rate Pool	61%	10%	29%	100%

This percentage allocation is used to allocate the total revenue requirement in 2024 to 2027 among the three transmission rate pools The rates revenue requirement offsets are then applied to the total revenue requirement to derive the total rates revenue requirement. The External Revenues and Regulatory Assets Balance are allocated based on the total revenue requirement spilt by rate pools; whereas Export Revenues are 100% allocated to the Network rate pool and MSP service and LVSG revenues are 100% allocated to the Transformation Connection rate pool.

Table 3 - 2024 Detailed Revenue Requirement by Rate Pool

	Rate Pool Revenue Requirement ($M)			
	Network	Line Connection	Transformation Connection	Total
Percentage Split by Rate pool	61%	10%	29%	100%
Total Revenue Requirement	**$1,178.6**	**$200.6**	**$558.6**	**$1,937.8**
External Revenue	($22.0)	($3.8)	($10.4)	($36.2)
MSP Service Revenue			($0.02)	($0.02)
Export Revenue	($37.1)			($37.1)
Regulatory Assets	$0.56	$0.09	$0.26	$0.9
Export Revenue Variance	$0.2			$0.2
LVSG Credit			$17.5	$17.5
Total Rates Revenue Requirement	**$1,120.2**	**$197.0**	**$565.9**	**$1,883.1**

Table 4 - 2025 Detailed Revenue Requirement by Rate Pool

	Rate Pool Revenue Requirement ($M)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
Percentage Split by Rate pool	61%	10%	29%	100%
Total Revenue Requirement	**$1,233.15**	**$209.9**	**$584.4**	**$2,027.5**
External Revenue	($22.19)	($3.8)	($10.5)	($36.5)
MSP Service Revenue			$0.0	$0.0
Export Revenue	($37.3)			($37.3)
Regulatory Assets	$0.56	$0.09	$0.26	$0.9
Export Revenue Variance	$0.2			$0.2
LVSG Credit			$18.2	$18.2
Total Rates Revenue Requirement	**$1,174.5**	**$206.2**	**$592.4**	**$1,973.1**

Table 5 - 2026 Detailed Revenue Requirement by Rate Pool

	Rate Pool Revenue Requirement ($M)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
Percentage Split by Rate pool	61%	10%	29%	100%
Total Revenue Requirement	**$1,301.7**	**$221.6**	**$616.9**	**$2,140.3**
External Revenue	($22.0)	($3.7)	($10.4)	($36.2)
MSP Service Revenue			$0.0	$0.0
Export Revenue	($37.2)			($37.2)
Regulatory Assets	$0.56	$0.09	$0.26	$0.9
Export Revenue Variance	$0.2			$0.2
LVSG Credit			$19.2	$19.2
Total Rates Revenue Requirement	**$1,243.2**	**$217.9**	**$626.0**	**$2,087.2**

1 **Table 6 - 2027 Detailed Revenue Requirement by Rate Pool**

	Rate Pool Revenue Requirement ($M)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
Percentage Split by Rate pool	61%	10%	29%	100%
Total Revenue Requirement	**$1,349.65**	**$229.74**	**$639.65**	**$2,219.0**
External Revenue	($22.7)	($3.9)	($10.7)	($37.3)
MSP Service Revenue			$0.0	$0.0
Export Revenue	($37.2)			($37.2)
Regulatory Assets	$0.56	$0.09	$0.26	$0.9
Export Revenue Variance	$0.2			$0.2
LVSG Credit			$19.8	$19.8
Total Rates Revenue Requirement	**$1,290.5**	**$226.0**	**$649.0**	**$2,165.5**

OVERVIEW OF UNIFORM TRANSMISSION RATES

Transmission rates in Ontario have been established on a uniform basis for all transmitters in Ontario since April 30, 2002.[1] For the purposes of this Application, Hydro One has used the Ontario Uniform Transmission Rates (UTR) that were made effective from January 1, 2021 as part of the OEB's Decision and Rate Order under Proceeding EB-2020-0251, issued on December 17, 2020, as the current UTR. This UTR Schedule is filed as Exhibit H-11-01.

Since rates are established on a uniform basis, Hydro One's proposed transmission rates revenue requirement for the 2023 to 2027 Custom IR period will contribute to the total revenue requirement to be collected through the provincial UTRs for each corresponding year. The rates revenue requirements for all the other transmitters in the province approved to participate in the UTRs must be added to that of Hydro One Transmission in order to determine the total transmission revenue requirement for the province.[2]

The total revenue requirement from all transmitters must be allocated to the Network, Line Connection and Transformation Connection rate pools in order to establish uniform rates by pool. The revenue requirement allocated to each rate pool for the other transmitters is currently based on the proportions established by Hydro One Transmission's Cost Allocation process, except for B2M Limited Partnership and Niagara Reinforcement Limited Partnership whose costs are 100% allocated to the Network rate pool given that all of its assets are used to provide Network services. Once the revenue requirement by rate pool has been established, rates are determined by applying the provincial charge determinants for each pool to the total revenue for each pool. The

[1] Per the OEB's Decision in Proceeding RP-2001-0034/RP-2001-0035/RP-2001-0036/RP-1999-0044

[2] The other five transmitters currently included in the UTRs are Hydro One Networks Sault Ste. Marie LP (formerly Great Lakes Power Transmission LP), Canadian Niagara Power Inc., Five Nations Energy Inc., B2M LP, and Niagara Reinforcement LP. It is expected that by 2023, Upper Canada Transmission and Wataynikaneyap Power LP will also be included as transmitters in the UTR.

provincial charge determinants are the sum of all charge determinants, by rate pool, approved by the OEB for each of the transmitters participating in the UTR.

Table 1 below provides the forecast UTRs for the period 2023 to 2027. The forecast UTRs are calculated using the revenue requirement and charge determinant values proposed for Hydro One in this Application, while maintaining these values as approved by the OEB in the UTR Order under Proceeding EB-2020-0251 for other transmitters. The proposed rate schedule for the 2023 UTRs is provided as Exhibit H-11-02 Attachment 1.

Table 1 - Forecast of Uniform Transmission Rates

Year	Network ($/kW)	Line Connection ($/kW)	Transformation Connection ($/kW)
2023	4.80	0.84	2.76
2024	5.09	0.89	3.02
2025	5.31	0.93	3.16
2026	5.59	0.98	3.32
2027	5.79	1.01	3.44

TRANSMISSION CHARGE DETERMINANTS

1.0 INTRODUCTION

This Schedule provides the derivation of Hydro One Transmission's charge determinants for the approved rate pools, which when combined with the charge determinants of the other transmitters for the Network, Line Connection and Transformation Connection rate pools, can be used by the OEB to determine Uniform Transmission Rates (UTRs). The 2023 to 2027 charge determinants are based on forecast demand by customer delivery point, as described in Exhibit D-04-01, and are subject to the Terms and Conditions defined in the proposed Transmission Rate Schedule provided in Exhibit H-11-02-01.

2.0 SUMMARY OF CHARGE DETERMINANTS

The rate pool charge determinants for Hydro One Transmission are summarized in Table 1 for the 2023 to 2027 period. All charge determinants have been calculated per the methodology approved by the OEB, most recently in Proceeding EB-2019-0082.

Table 1 - Summary of Rate Pool Charge Determinants (MW)

Charge Determinant	Network	Line Connection	Transformation Connection
2023	231,026	224,267	190,775
2024	231,926	225,134	191,512
2025	232,162	225,361	191,705
2026	232,605	225,788	192,068
2027	232,875	226,048	192,289

3.0 NETWORK CHARGE DETERMINANT AND PAYMENT OBLIGATIONS

The proposed Network service charge (NSC) determinant is the higher of: (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all Provincial Transmission Service (PTS) customers is highest for the month; and (b) 85% of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by Independent Electricity System Operator (IESO), as detailed in the proposed Ontario Transmission Rate Schedules provided in Exhibit H-11-02-01.

The NSC determinant provides time-of-use signals that encourage customers to shift their demand from coinciding with the time of the total system's monthly peak. Customers with a monthly peak demand that occurs away from the time of the total system's monthly peak will potentially benefit from a reduced Network charge. No transmission Network charges apply to customers that avoid consuming between 7 AM to 7 PM on IESO business days[1], which is the defined transmission system on-peak period.

All customers that are connected to Hydro One's transmission system incur Network service charges on a per transmission delivery point basis. The 2023 to 2027 hourly load forecast data for each customer's transmission delivery points, adjusted for losses as appropriate, are used to calculate the total charge determinants that attract Network service charges as shown in Table 1.

4.0 CONNECTION CHARGE DETERMINANT AND PAYMENT OBLIGATIONS

Hydro One applies the corresponding charges to transmission customers with delivery points that are supplied from Line or Transformation connection assets owned by Hydro One.

[1] Unless the monthly system peak demand occurs outside of the 7 AM to 7 PM period, in which case the customer's Network charge determinant will be their coincident peak demand

4.1 LINE CONNECTION

The Line Connection service charge determinant is the transmission delivery point's non-coincident monthly peak demand, as detailed in the proposed Ontario UTR Schedules provided in Exhibit H-11-02-01.

All customers that utilize Line Connection assets owned by Hydro One Transmission incur Line Connection service charges on a per transmission delivery point basis. The customer demand supplied from a transmission delivery point will not incur Line Connection service charges if a customer fully owns all Line Connection assets that connect the transmission delivery point to a network station. Similarly, customers will not incur Line Connection service charges for demand at a transmission delivery point located at a network station.

The billing demand for the Line Connection service charge is the loss-adjusted demand supplied to the delivery point from the transmission system. Furthermore, the demand that is supplied by a generator unit, through a transmission delivery point that attracts Line Connection service charges, is added to the billing demand if the required government approvals for the generator unit were obtained after October 30, 1998 and if the generator unit rating is 2MW or more for renewable generation and 1MW or higher for non-renewable generation. These charges also apply to the incremental capacity amount associated with any refurbishments to a generator unit approved after October 30, 1998, for which the incremental generator capacity is 2MW or more for renewable generation and 1MW or higher for non-renewable generation of the approved refurbishment.

The 2023 to 2027 hourly load forecast data for each transmission delivery point, adjusted for losses as appropriate, is used to calculate the total charge determinants that attract Line Connection service charges as shown in Table 1 above.

4.2 TRANSFORMATION CONNECTION

The Transformation Connection service charge determinant is the customer's non-coincident monthly peak demand, as detailed in the proposed Ontario UTR Schedules provided in Exhibit H-11-02-01.

All customers that utilize Transformation Connection assets owned by the Hydro One Transmission incur charges on a transmission delivery point basis. Customer demand supplied from a transmission delivery point will not incur Transformation Connection service charges if a customer fully owns all Transformation Connection assets associated with that transmission delivery point.

The billing demand for the Transformation Connection service charge is the loss-adjusted demand supplied to the delivery point from the transmission system. Furthermore, the demand that is supplied by a generator unit, through a transmission delivery point that attracts Transformation Connection service charges, is added to the billing demand if the required government approvals for the generator unit were obtained after October 30, 1998 and if the generator unit rating is 2MW or more for renewable generation and 1MW or higher for non-renewable generation. These charges also apply to the incremental capacity amount associated with any refurbishments to a generator unit approved after October 30, 1998, for which the incremental generator capacity is 2MW or more for renewable generation and 1MW or higher for non-renewable generation of the approved refurbishment.

The 2023 to 2027 hourly load forecast data for each transmission delivery point, adjusted for losses as appropriate, is used to calculate the total charge determinants that attract Transformation Connection service charges as shown in Table 1 above.

WHOLESALE METER SERVICE FEES

1.0 INTRODUCTION

This Exhibit summarizes Hydro One's proposal for the derivation of the proposed Wholesale Meter Service (WMS) fee that will recover the revenue requirement associated with Meter Service Provider (MSP) services to wholesale revenue metering (WRM) assets.

2.0 COSTS ASSOCIATED WITH WHOLESALE REVENUE METERING ASSETS

The WRM installations are comprised of such assets as: recorders, physical meters and related instrument transformers, wiring, and panels that require ongoing operations and maintenance expenses, including costs associated with activities to comply with the Market Rules administered by the Independent Electricity System Operator (IESO), and asset related charges such as depreciation and a share of the other revenue requirement costs (e.g., return on capital, taxes, etc.).

For every metering installation with respect to which a Metered Market Participant (MMP) arranges to exit the transitional arrangement, Hydro One Transmission shall cease to be responsible for these direct or indirect costs that are required to maintain, repair, or replace any equipment necessary for wholesale revenue metering or any other purpose related to the metering installation.

Since market opening in 2002, MMPs have been making arrangements to exit the transitional arrangement upon seal expiry of their WRM installations, as per the Market Rules, reducing Hydro One Transmission's ownership of WRMs.

Although the number of WRM installations and the associated direct and indirect costs has significantly reduced, there is still a cost associated with the remaining small number of WRM assets. The costs for the wholesale revenue meter function are required to be collected from the remaining meter service customers that are served by these WRM installations, which are scheduled to exit the transitional arrangement by 2024.

3.0 RECOVERY OF COSTS ASSOCIATED WITH WHOLESALE REVENUE METERING ASSETS

Given the small amount of costs associated with WRM assets, the costs are assigned to the Transformation Connection functional category, and subsequently recovered through the Transformation Connection service rate. This methodology is described in Exhibit H-01-02 and Exhibit H-01-03. This is the same methodology approved in previous OEB applications, most recently in EB-2019-0082.

Hydro One proposes that the current annual fee of $7,900 per meter point for MSP services and the current exit fee of $5,200 per meter point remain in effect until the remaining MMPs exit the transitional arrangement. The WMS fee is administered by Hydro One, and the amount collected from the proposed WMS fee will be directly assigned to the Transformation Connection rate pool to offset the wholesale meter costs that are part of that rate pool.

The WMS fee is in addition to the existing Exit Meter fee, and will not be applied to MMPs that exit the transitional arrangement in accordance with Hydro One Transmission's wholesale meter exit policy.

4.0 FORECAST REVENUE FOR MSP SERVICE

The calculation of forecast mid-year revenue collected for providing MSP services are shown in Table 1. The remaining MMPs are scheduled to exit the transitional arrangement by 2024. As a result, Hydro One will cease to collect revenue associated with MSP services at that time.

Table 1 - Forecast Revenue for MSP Service

Year	Forecast Number of Meter Points (Mid-Year)	WMS Fee ($/year)	Forecast Revenue Collected for MSP Service ($/year)
2023	4	$7,900	$31,600
2024	2	$7,900	$15,800
2025	0	$7,900	Not Applicable
2026	0	$7,900	Not Applicable
2027	0	$7,900	Not Applicable

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RATES FOR EXPORT TRANSMISSION SERVICE

1.0 INTRODUCTION

The Independent Electricity System Operator (IESO) collects Export Transmission Service (ETS) revenues based on the approved ETS rate and remits those revenues on a monthly basis to Hydro One, whose transmission system is used to facilitate export transactions at points of interconnection with neighbouring markets.

2.0 EXPORT TRANSMISSION SERVICE RATE

2.1 BACKGROUND

Since the ETS rate was first established, there have been many competing views advanced by stakeholders with respect to the appropriate basis for, and level of the ETS rate. Over the years, the ETS rate has been determined through a combination of stakeholder agreements and interim OEB decisions, informed by OEB-directed studies performed by or on behalf of the both IESO and Hydro One Transmission.

In response to the OEB's direction in EB-2012-0031 that Hydro One "perform a cost allocation study to establish a cost basis for the ETS rate"[1], Hydro One engaged Elenchus Research Associates Inc. (Elenchus) to perform a cost allocation study for EB-2014-0140, Hydro One's 2015/2016 Transmission Rate Application.[2] The final Elenchus report was included in Exhibit H1-05-01, Attachment 1 of that application.

The key parameters of Elenchus' recommended methodology for allocating costs to ETS service (the May 2014 methodology) are as follows:

- Allocate dedicated assets used to serve export customers and related expenses to the export customer class;

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[1] EB-2012-0031 Decision and Order dated June 6, 2013, p 9
[2] EB-2014-0140 Exhibit H1-05-01, Attachment 1

- Shared Network OM&A Costs are allocated to export customers, but no Shared Network asset related costs are allocated to export customers;
- Allocate OM&A expenses related to the use of shared assets to export customers using composite assets as allocator; and
- Utilize the 12 Coincident Peak[3] (CP) as the allocator in apportioning assets between domestic and export customers in order to develop composite allocators to allocate shared expenses.

Based on the May 2014 methodology, Elenchus recommended an ETS rate of $1.70/MWh[4] for 2015 and 2016 as being reflective of the cost of providing export service.

For the purpose of reaching a settlement, all parties agreed to an ETS rate change from the $2.00/MWh that was in effect at the time, to $1.85/MWh. The OEB approved the settlement in EB-2014-0149, thereby approving $1.85/MWh as the ETS rate in effect for 2015 and 2016. The OEB subsequently approved the continuation of the ETS rate at $1.85/MWh for 2017 and 2018 (EB-2016-0160), for 2019 (EB-2018-0130), and most recently for 2020 to 2022 (EB-2019-0082).

In its Decision on Hydro One's 2020 to 2022 transmission rate application, the OEB "determined that the use of shared network facilities by exporters needs to be considered in setting the ETS rates"[5] The OEB directed Hydro One to provide an ETS study using a cost allocation methodology that includes the allocation of shared network costs to exporters in the next transmission rebasing application[6].

In addition, the OEB stated that it would be assisted by an updated jurisdictional review that provides the ETS rates in other jurisdictions, rationale behind those rates and market implications. Recognizing that the operation of the electricity market is the responsibility of the IESO rather than Hydro One, the OEB indicated its expectation that Hydro One discuss the approach to the

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[3] Domestic and Export Demand at Ontario system peak
[4] Elenchus recommended an ETS rate at $1.70/MWh in its May 2014 report, given the range of values calculated using 2015 and 2016 data and the related scenario sensitivity results.
[5] EB-2019-0082 Decision and Order dated April 23, 2020 p. 180
[6] EB-2019-0082 Decision and Order dated April 23, 2020 pp. 180 and 183.

jurisdictional review with the IESO and OEB staff to determine the best approach to complete the review before Hydro One's next transmission rebasing.[7]

In response to the OEB's directions, Hydro One is providing an ETS study, prepared by Elenchus, which uses a cost allocation methodology that includes a number of options for the allocation of shared network costs to exporters, as discussed in Section 2.2. Hydro One is also providing an updated ETS jurisdictional review, prepared by Charles River Associates (CRA), as discussed in Section 2.3. In addition, through Hydro One's discussions with the IESO and OEB staff, it was agreed that the IESO would provide comments as part of the pre-filed evidence in this Application on the implications for Ontario's electricity market of changes to the ETS rate. A copy of the IESO's comments is provided in Attachment 3.

2.2 EXPORT TRANSMISSION SERVICE STUDY

Hydro One retained Elenchus to supplement the May 2014 methodology to identify cost-based methodologies that could potentially be used for allocating Shared Network Asset-related costs to exporters.

Elenchus reviewed the May 2014 methodology to calculate the ETS rate, held discussions with the IESO on how exports are treated in Ontario, reviewed the OEB report on Pole Attachment Charges and the OEB Decision and Order on Hydro One's transmission application (EB-2019-0082), as well as surveyed whether other jurisdictions use cost allocation principles for the purpose of allocating shared network costs between domestic and export classes.

The Elenchus report considers three methodologies in developing a cost-based cost allocation for Shared Network Asset-related costs to export customers, which is provided as Attachment 1 to

[7] EB-2019-0082 Decision and Order dated April 23, 2020 pp. 180 and 183.

this exhibit.[8] The three methodologies allocate Shared Network Asset-related costs on the basis of Shared Net Fixed Assets, with adjustments to the Shared Net Fixed Assets allocator applied to each scenario. The Shared Net Fixed Assets allocator is underpinned by the 12 Coincident Peak (12CP), which represents the relative export and domestic class demands in the peak hours of each month. The portion of Shared Net Fixed Assets allocated to the export class is adjusted for each option as described below:

1. Fully allocate Shared Network Asset-related costs on the basis of Shared Net Fixed Assets.
2. Apply an adjusted Shared Net Fixed Assets allocator with export 12CP discounted by 50%, as a proxy for a hybrid model, half-way between no allocation and full allocation of Shared Network Asset-related costs to exports.
3. Apply an adjusted Shared Net Fixed Assets allocator with a percentage of export demand discounted based on the service curtailment that affected exports in the last few years. Assuming that exports were curtailed 20% of the hours in the last few years, adjust export volumes to 80%.

An allocation on the basis of Shared Net Fixed Assets with unadjusted export demand volumes could be justifiable as the historical export hourly usage data will reflect the extent to which export customers are curtailed in peak hours. The 50% method is aligned with the OEB's decision on Pole Attachment Charges. The curtailment percentage method provides a more direct link between the reduction of Shared Network Asset-related costs allocated to exports and the number of hours in which they are curtailed.

As in the May 2014 suggested methodology, Elenchus suggests that the three proposed methodologies in this report to calculate an ETS rate are adjusted to include other transmitters' approved revenue requirement.[9] The ETS rates that result from applying these methodologies

[8] The May 2014 report directly allocated the assets and costs dedicated to interconnect directly to the Export class. The Elenchus report proposes a refinement to that methodology to include the contribution of imports, which serve domestic load. The details are provided in Section 6.2 of the Elenchus report.
[9] Rates are adjusted by 7.77%, calculated as the sum of HONI's 2023 Network Revenue Requirement and the Network Revenue Requirements of all other transmitters (as per EB-2020-0251) divided by HONI's 2023 Network Revenue Requirement.

using Hydro One's 2023 revenue requirement and actual 2020 load and consumption data, as well as the associated adjusted ETS rates, are provided in the following table:

Methodology	**Allocator for Shared Network Asset-related costs**		**ETS Rate ($/MWh)**	**Adjusted ETS Rate ($/MWh)**
	Domestic Share	**Export Share**		
Allocation on Basis of 100% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP	$6.07	$6.54
Allocation on Basis of 50% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 50%	$3.40	$3.66
Allocation on Basis of 80% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 80%	$5.03	$5.42

While the Elenchus report presents options for allocating Shared Network Asset-related costs to exports on a cost causality basis, Elenchus' view is that whether or not the OEB should change ETS rates to reflect those network costs is a broader policy question for the OEB to determine.

2.3 ETS JURISDICTIONAL REVIEW

Hydro One engaged CRA to update its 2012 Jurisdictional Review[10] to reflect current export transmission service rates in other jurisdictions, the rationale behind those rates and how market implications are considered in the setting of export transmission service rates in those jurisdictions (the CRA Study). CRA found that the ETS rate levels in general have increased since 2012 and display no changes in rate design. The observed rate level changes are attributable to inflation and transmission expansion since 2012. The regulatory rationale for rate design differs across the markets that were studied. Most jurisdictions included in the CRA Study apply Open Access Transmission Tariff (OATT) rates for export services, which promote competitive and non-

[10] Export Transmission Service (ETS) Tariff Study – Review of Rates in Neighbouring Markets, Charles River Associates, May 16, 2012

discriminatory transmission access. The CRA Study is provided as Attachment 2. A summary of the 2020 rates in each jurisdiction for Firm and Non-Firm Point-to-Point (PTP) and Export Transmission Services (ETS) is provided as Appendix A of the CRA Study.

3.0 EXPORT TRANSMISSION SERVICE REVENUE

Hydro One's ETS revenue, used for establishing the rates revenue requirement proposed in this Application, is calculated using the currently approved tariff of $1.85/MWh and the three year historical rolling average volume of electricity exported from Ontario. For the purpose of this Application Hydro One has assumed no change to the current ETS rate of $1.85/MWh. Hydro One will revise its rates revenue requirement to reflect the OEB's Decision and Order with respect to the ETS tariff as part of the Draft Rate Order to be submitted in finalizing the 2023 Uniform Transmission Rates.

Table 1 provides the forecast of ETS revenue for the period 2023 to 2027.

Table 1 - ETS Revenue Forecast

Year	ETS Revenue ($M)
2023	$37.3
2024	$37.1
2025	$37.3
2026	$37.2
2027	$37.2

The ETS revenue will continue to be disbursed as a decrease to the revenue requirement for the Network rate pool, as per the cost allocation process approved by the OEB.

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Export Transmission Service Rate Cost Allocation Methodology

Report prepared by
Michael Roger, Andrew Blair
Elenchus Research Associates Inc.

Month 2017

Report Prepared for:
Hydro One Networks Inc.

July 21, 2021

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EXECUTIVE SUMMARY

Hydro One Networks Inc. ("HONI") retained Michael Roger and Andrew Blair of Elenchus Research Associates Inc. ("Elenchus") in order to supplement the May 2014 cost-based methodology to establish the Export Transmission Service ("ETS") rate in Ontario, by identifying cost-based methodologies that could be used for allocating Shared Network Asset-related costs[1] to exporters and which take into consideration the fact that exporters do not receive the same priority access as domestic service until they are scheduled.

The cost-based methodologies that have been identified in this report are intended to inform the OEB's decision-making on ETS rates going forward.

Elenchus reviewed the May 2014 cost-based methodology to calculate the ETS rate, held discussions with the IESO on how exports are treated in Ontario, reviewed the OEB's March 22, 2018 report on Pole Attachment Charges (EB-2015-0304) and the OEB's Decision and Order on HONI's most recent transmission revenue requirement application (EB-2019-0082), and surveyed how export rates are set in other jurisdictions.

Based on the information provided by the IESO on how exports are treated compared to domestic customers, exporters are able to use the transmission assets much of the time, in spite of the fact that exports are subject to more service interruptions than domestic customers. In the past few years, exports have been affected by fewer and fewer service interruptions and in 2019 and 2020 curtailments were close to 20% of the hours. In the five peaks hours in each of the past five years, exports were curtailed in 11 out of the 25 hours and 10% of volumes were curtailed in those hours.

As stated by the OEB in its report on Pole Attachment Charges, when developing a cost-based methodology, consideration can also be given to the value that users obtain from leveraging an established network. This means that there should not be users of a shared network that do not pay their fair share of costs for use of the shared network, also referred to as "free riders".

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[1] Asset-related costs include depreciation, interest, ROE, and taxes.

Since exporters are able to use the transmission system much of the time, even at the times of the Ontario system peak, Elenchus believes that a reasonable basis exists for Shared Network Asset-related costs to be allocated to exports based on the principle of cost causality.

Even though export demand needs are not taken into account when HONI designs the transmission system and the IESO does not factor exports into its reliability planning assessments, the fact that exporters can use the transmission system much of the time supports the allocation of Shared Network Asset-related costs in a cost allocation methodology to exports. Elenchus considered a range of potential cost-based methodologies.

Elenchus considers the following three methodologies to be appropriate options to allocate Shared Network Asset-related costs to the export class. The three methodologies allocate Shared Network Asset-related costs on the basis of Shared Net Fixed Assets, with adjustments to the Shared Net Fixed Assets allocator applied to each scenario. The Shared Net Fixed Assets allocator is underpinned by the 12 Coincident Peak ("12CP")[2] allocator.

1) Fully allocate Shared Network Asset-related costs on the basis of Shared Net Fixed Assets.
2) Apply an adjusted Shared Net Fixed Assets allocator with export 12CP discounted by 50%, as a proxy for a hybrid model, half-way between no allocation and full allocation of Shared Network Asset-related costs to exports.
3) Apply an adjusted Shared Net Fixed Assets allocator with a percentage of export demand discounted based on the service curtailment that affected exports in the last few years. Assuming that exports were curtailed 20% of the hours in the last few years, adjust export volumes to 80%.

[2] The 12CP allocator represents the relative Export and Domestic class demands in the peak hours of each month. Please see the full description in Section 3.4.

An allocation on the basis of Shared Net Fixed Assets with unadjusted export demand volumes could be justifiable as the historical export hourly usage data will reflect the extent to which export customers are curtailed in peak hours.

The 50% method is aligned with the OEB's decision on Pole Attachment Charges.

The curtailment percentage method provides a more direct link between the reduction of Shared Network Asset-related costs allocated to exports and the number of hours in which they are curtailed.

If export customers are allocated a portion of Shared Network Asset-related costs, it is Elenchus' view that export customers should also be allocated a portion of external revenues received by HONI for use of their assets. Elenchus recommends for full External Transmission Revenues to be allocated by the same methodology as Shared Network Asset-related costs.

The ETS rates that would result from applying these methodologies are provided in the following table using 2020 demand data and HONI's proposed 2023 revenue requirement:

Methodology	**Allocator for Shared Network Asset-related costs**		**ETS Rate ($/MWh)**
	Domestic Share	**Export Share**	
OEB 2020 Approved ETS rate			$1.85
2014 Report Methodology	Domestic 12CP	-	$1.67
Allocation on Basis of 100% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP	$6.07
Allocation on Basis of 50% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 50%	$3.40
Allocation on Basis of 80% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 80%	$5.03

The cost allocation methodologies presented in this report to calculate the ETS rate are based on the following considerations:

- Direction from the OEB to HONI to review the allocation of Shared Network Asset-related costs to exports
- OEB report on Pole Attachment Charges
- Elenchus jurisdictional review of cost allocation methodologies
- IESO treatment of exports
- Export service curtailment in the last few years and expected curtailment in the near future

Elenchus views the cost allocation methodology presented in the May 2014 report and each of the methodologies identified in this report as being cost-based.

The May 2014 methodology was based on how the transmission system is designed and, since export needs are not considered in the planning of the transmission system, exports were not allocated a portion of Shared Network Asset-related costs.

The methodologies identified in this report reflect exports' use of the transmission system and how they are being treated by the IESO with not much service interruptions. Exports use the transmission system almost as much as domestic customers use the system, therefore, a reasonable basis exists for allocating a portion of Shared Network Asset-related costs to exports.

As in the May 2014 suggested methodology, Elenchus suggests that the three proposed methodologies in this report to calculate an ETS rate be adjusted to include other transmitters' approved revenue requirement.

While this report presents options for allocating Shared Network Asset-related costs to exports on a cost causality basis, Elenchus' view is that whether or not the OEB should change ETS rates to reflect those network costs is a broader policy question for the OEB to determine.

1 INTRODUCTION

Hydro One Networks Inc. (“HONI”) retained Michael Roger and Andrew Blair of Elenchus Research Associates Inc. (“Elenchus”) in order to supplement the May 2014 cost-based methodology to establish the Export Transmission Service (“ETS”) rate in Ontario, by identifying cost-based methodologies for allocating Shared Network Asset-related costs to exporters and which includes different scenarios to take into consideration the fact that exporters do not receive the same priority access as domestic service until they are scheduled.

The cost-based methodologies that have been identified in this report are intended to inform the OEB’s decision-making on ETS rates going forward.

In its Decision and Order in HONI’s most recent Transmission rate application, dated April 23, 2020 (EB-2019-0082), with respect to Export Transmission Service rates the Ontario Energy Board (“OEB”) directed HONI to undertake further work on developing a cost-based ETS rate.

More specifically, the OEB stated on page 180 of its Decision and Order:

> *“Hydro One supported intervenor arguments that a cost allocation methodology that includes the allocation of shared network costs to exporters should be provided in Hydro One’s next transmission rebasing application. The OEB agrees. This study should include different scenarios to take into consideration the fact that exporters do not receive the same priority access as domestic service until they are scheduled. The OEB agrees with the OEB panel for the ETS Decision that export service should continue to be viewed as a separate class. This study should be filed with Hydro One’s next transmission rebasing application.”*

This report presents the results of the review undertaken by Elenchus to establish potential cost-based allocation methodologies that allocate Shared Network Asset-related costs to export customers.

This report is divided into 8 main sections. Section 2 provides a background on the 2014 cost-based methodology previously developed by Elenchus to calculate an ETS rate, section 3 presents the principles of cost allocation and describes the previously developed cost-based methodology, section 4 describes the characteristics of the export class in Ontario, section 5 presents the results of Elenchus' survey of Export and Curtailable Transmission Rate-setting in other jurisdictions, section 6 describes three cost allocation methodologies that allocate Shared Network Asset-related costs to export customers, section 7 presents the results of these methodologies using 2020 data and section 8 provides conclusions. Appendix A contains the CVs for Michael Roger and Andrew Blair.

Michael Roger has been an expert dealing with cost allocation, rate design and rate regulation issues for over 40 years. Michael worked for over 32 years at Ontario Hydro, Ontario Power Generation and Hydro One and spent most of his career dealing with Cost Allocation and Rate Design issues for wholesale and retail electricity customers in Ontario. Since 2010, Michael has been an associate consultant at Elenchus. He has testified on numerous occasions at OEB proceedings and at proceedings across Canada on behalf of regulators, utilities and other stakeholders and also has provided expert advice to the OEB in various task forces dealing with cost allocation and rate design issues. Michael's vast experience with Cost Allocation issues was applied in reviewing and modifying the cost-based cost allocation methodology to calculate the ETS rate and forms the basis for Elenchus recommended methodology to the OEB.

Andrew has worked as a research analyst with Elenchus for five years. He has experience contributing to Elenchus reports on cost allocation and rate design matters in Ontario and other jurisdictions across Canada.

2 BACKGROUND

2.1 SUMMARY OF 2014 REPORT

In its May 2014 Report Elenchus proposed a cost allocation methodology to determine the ETS rate that was based on cost causality, was simple and followed the traditional three steps of a cost allocation methodology.

The assumptions used in developing the May 2014 methodology were that:

- Export is only served when there is spare capacity available,

- Generators and importers in Ontario do not pay for the use of the Transmission System,
- HONI's planning of the Network transmission system does not take into consideration the capacity needs of export customers,
- Export is treated as "Interruptible" for cost allocation purposes.

The May 2014 methodology main characteristics were that:

- Only dedicated Export Network Assets were allocated to Export,
- Export is considered to be "Interruptible", therefore no Shared Network Asset-related costs are allocated to Export,
- Shared Network OM&A Costs are allocated to Export, and
- 12 Coincident Peak (CP) is used as the allocator

Additionally, the May 2014 methodology:

- Used prior year actual hourly data for domestic and export customers,
- Used the 12 CP allocator in apportioning assets between domestic and export customers in order to develop composite allocators to allocate shared OM&A costs,
- Allocated only the rate base cost of dedicated assets that are used to serve export customers and the related costs to the export customer class,
- Allocated OM&A costs related to the use of shared assets to export customers using composite assets as the allocator,
- Allocated no external revenues to the export customer class,
- Based the ETS rate on HONI's OEB approved Network revenue requirement in determining the Uniform Transmission Rates, adjusted to include other transmitters' approved revenue requirement.

2.2 OEB DECISION EB-2019-0082

The OEB in its Decision and Order in Proceeding EB-2019-0082, page 180, provided the following reasoning in support of its decision, quoted above, directing HONI to do further work on the ETS rate cost allocation methodology:

"Shared network facilities have been paid for by domestic customers. The OEB has determined that the use of shared network facilities by exporters needs to be considered in setting the ETS rates. The OEB does see some similarity with the rate established for attachments to distribution poles by third parties such as telecommunications and cable companies, as noted by SEC. For pole attachments, the OEB adopted a hybrid methodology to allocate common costs. The OEB has insufficient information to conclude what the appropriate allocation of common network costs should be for exporters. This needs to take into consideration that while exporters make use of the network system, Hydro One does not plan its system for the benefit of exporters. However, at the oral hearing Hydro One testified that once scheduled, with the exception of an emergency or supply issue, exporters are treated as firm as domestic load."

2.3 Pole Attachment Rate Decision (EB-2015-0304)

In Proceeding EB-2015-0304 dealing with Wireline Pole Attachment Charges, the OEB in its report dated March 22, 2018 said on page 30:

"In regulatory economics and practice in most jurisdictions, it is uncontroversial that each attacher to the network will be responsible for the direct or incremental costs that the attachment drives. The question that the OEB must answer is how much of the common costs of the pole network will be assigned to the incumbent power utility owners and each party wishing to attach to ensure that a reasonable charge is established. In addition, ***one must also consider the value that third party attachers obtain from leveraging an established network that spans the entire province****, (emphasis added)"*

On page 33 of the report the OEB concluded that:

"For these reasons, the OEB is of the view that the hybrid ***equal sharing methodology is an efficient and fair cost allocation to be applied to third party attachers*** *(emphasis added). As noted previously, given that Ontario's vast network of more than 200,000 km of low voltage distribution lines provide tremendous value to third party attachers through an existing network, readily available for expansion, the* ***OEB will consider moving from a cost-based approach to a value-based approach*** *(emphasis added) as part of the Part II review."*

The above OEB report was taken into consideration by Elenchus in its review and development of cost-based methodologies for allocating Shared Network Asset-related costs to export customers.

3 MAY 2014 COST ALLOCATION METHODOLOGY

Elenchus' proposed May 2014 cost allocation methodology to determine the ETS rate was based on cost causality, was simple and followed the traditional three steps of a cost allocation methodology: functionalization, classification and allocation.

Elenchus looked at how transmission assets are being used to sell electricity, either to domestic customers or to neighbouring jurisdictions by exporters.

In Ontario, generators do not pay for the use of the transmission system when they inject power into the grid in order to supply domestic electricity needs. Elenchus applied this same principle when evaluating the interconnected assets with neighbouring jurisdictions used by exporters. The interconnected assets are used to both export and import power and since generators in Ontario do not pay for the use of the transmission assets and the ETS rate is not applied to power imported into Ontario, Elenchus assumed that importers would also continue to not be charged for the use of the transmission system.

The May 2014 methodology considered the sale of electricity to domestic customers and neighbouring jurisdictions, not how the electricity was sourced and made available to satisfy sales. It focused narrowly on cost drivers without considering other value drivers that can be relevant to designing equitable rates.

HONI's 2013 transmission assets and revenue requirements were used in developing the May 2014 approach.

The May 2014 cost allocation methodology to determine the ETS rate reflected the interruptible nature of exports. The basis for treating exports as interruptible loads was found in the OEB's Decision with Reason in proceeding EB-2012-0031 that on page 5 stated that:

> *"First, whether curtailments originate from generation issues or transmission issues, the Board agrees that export service does not receive the same priority access as*

domestic service. The Board accepts that the market rules treat exporters more as an interruptible load. This difference in treatment related to generation capacity has consequences for the overall service, even if export transmissions rights are technically as firm as domestic transmission rights. As a result, the Board finds that it may be appropriate for the export service to be viewed as a separate class."

3.1 FUNCTIONALIZATION

In consultation with HONI, Elenchus determined that the assets and costs associated with export activities can be found in the following HONI transmission asset functions:

- Network (500 kV, 230 kV, and 115 kV lines)
- Dual Function lines (Network portion)
- Generation Line Connection
- Generation Transformation Connection
- Common (telecommunication equipment, control centre)
- Other (facilities not allocated to other functions under normal operating conditions)

These functions included dedicated and shared assets, and related costs used by domestic and export customers.

The remaining functions used by HONI in determining its revenue requirement (e.g. transformation, line connection, line connection portion of dual function lines) were considered to be used only by domestic customers. Each function is divided into three categorizes:

- Dedicated to Domestic
- Dedicated to Interconnect
- Shared

External revenues were also considered in the development of the May 2014 cost allocation methodology. These revenues result mainly from secondary land use in right of ways and from providing maintenance services to other entities. These revenues are the result of using HONI's assets which have been designed to serve domestic customers only, therefore, no external revenues were allocated to export customers.

3.2 CLASSIFICATION

Generally in cost allocation, transmission assets and related costs are classified as demand related. Transmission assets are designed to meet the maximum demand imposed by users of the system. Based on the functions evaluated, it was determined that the assets and related costs considered in the development of the May 2014 ETS rate methodology were all demand related. There were no energy related or customer related assets and costs.

3.3 ALLOCATION

In the cost allocation methodology developed to derive the ETS rate two customer classes were considered: domestic and export.

3.3.1 ASSETS DEDICATED TO DOMESTIC

Assets dedicated to domestic customers are assets that only serve to connect HONI customers' load to the network. Assets, asset-related costs, OM&A, and external revenues dedicated to domestic are directly allocated to the Domestic class.

3.3.2 ASSETS DEDICATED TO INTERCONNECT

Assets dedicated to interconnect are assets that only serve to connect to another transmission utility. The May 2014 report directly allocated the assets and costs dedicated to interconnect directly to the Export class. This report recommends a refinement to that methodology to include the contribution of imports in Section 6.2.

3.3.3 SHARED

Shared assets are those that serve both domestic and export customers, including assets associated with generation connection.

As export was considered to be interruptible service, no asset-related costs associated with shared assets, including depreciation, interest, return on equity and taxes, were allocated to the export customer class.

Under the strict cost driver approach, this methodology was considered appropriate because, as confirmed by HONI staff, HONI's planning of the Network transmission system does not take into consideration the capacity needed to supply export customers. Transmission planning is based only on the capacity needs of domestic customers.

The OM&A costs related to the use of shared assets were allocated between domestic and export customers using the allocators described below.

3.4 COINCIDENT PEAK ALLOCATOR

In cost allocation, the allocation of demand related assets that are closest to the customer are allocated based on the non-coincident demand of the customer. The required assets are sized reflecting the maximum customer electricity demand.

Further away from the customer and closer to the generation system, it is the aggregate electricity demand of all customers, and not the sum of the individual customer demands, that determines the size of the facilities required to satisfy customers' electricity needs. In cost allocation, when apportioning assets and costs further away from the customer (e.g. generation, transmission network) and closer to the generation of electricity, it is the coincident demand that is used as an allocator, reflecting the criteria used to size the required assets.

In Proceeding RP-1999-0044, the OEB reviewed allocators that could be used to recover Network assets and costs and recommended against the use of non-coincident peak and settled on the use of coincident peak. With respect to using 1 CP, in paragraph 3.4.27 of the OEB Decision it states that:

> *"A rate design aimed at customer demand reduction during the system's coincident peak hours would meet the test of economic efficiency, but only if the network transmission system is generally capacity-constrained. This is not the case for the OHNC [Hydro One] network transmission system either today or in the foreseeable future."*

12 CP continues to be used by HONI in apportioning assets and costs when allocating Dual Function Line assets (EB-2019-0082, Exhibit I1, Tab 1, Schedule 2, pages 5-7).

Coincident peak is the hourly demand of domestic and export customers at the hour of maximum demand in the Ontario electricity system.

1 CP is the demand for each customer class at the hour of maximum system demand in a year. 12 CP is the sum of the demand for each customer class at the hour of each month's maximum system demand.

1 CP or 12 CP are commonly used by utilities in cost allocation studies to apportion generation and transmission costs amongst customer classes.

Transmission system coincident peak data from 2011 to 2013, used in Elenchus's 2014 report, are provided below for reference. Updated values used to calculate ETS rates under the methodologies discussed in this report are provided in Section 6.2.1.

Table 1

Coincident peak 2011 to 2013

	2011			2012			2013		
	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total
1CP	2,549	25,450	27,999	2,179	24,636	26,815	1,952	24,927	26,879
12CP	31,343	250,819	282,161	28,164	251,842	280,006	30,240	255,417	285,657

	2011 to 2013 Average		
	Export	Domestic	Total
1CP	2,227	25,004	27,231
12CP	29,916	252,692	282,608

The relative shares of 1CP and 12CP are used to derive the following allocators.

Table 2

Coincident peak %

	2013 Data			Average 2011 – 2013 Data		
Coincident Peak	Total	Domestic	Export	Total	Domestic	Export
1 cp	100.00	92.74	7.26	100.00	91.82	8.18
12 cp	100.00	89.41	10.59	100.00	89.41	10.59

Elenchus recommended in the May 2014 methodology that 12 CP be used to allocate shared assets between domestic and export customers using the last year for which information was available.

When system loads are relatively flat and do not show a pronounced yearly peak, 12 CP is usually used by utilities to allocate demand related assets and costs. In instances where there is a significant yearly peak compared to other peaks in the year, that is a very peaky load profile with low load factor, then 1 CP would more commonly be used to allocate demand related assets and costs.

As discussed further in Section 4.2, though Ontario's domestic peaks are generally in the summer months, high exports in the winter often cause the transmission system peak to occur in December and January. A 1 CP could vary considerably from year to year depending on the month the transmission system peak occurs. For example, the export class is responsible for 7.58% of the 2016 1CP, which occurs in September 2016, and 15.83% of the 2017 1CP occurring in December 2017. Using the 12 CP is considerably more consistent over time, and therefore continues to be the recommended allocator.

3.5 Composite Allocators

The asset functions identified were apportioned between domestic and export customers using the 12 CP allocator based on 2012 actual hourly data in order to develop composite allocators used to allocate shared OM&A costs to domestic and export customer classes in the May 2014 methodology. Table 3 below includes the composite allocators used in the May 2014 methodology.

Table 3

Net Fixed Assets

	Total	Domestic	Export
2014 Report	**100.00%**	92.89%	7.11%

The OM&A costs related to the identified shared functions were allocated in the May 2014 cost allocation methodology to domestic and export customers using Net Fixed Assets as composite allocators.

4 CHARACTERISTICS OF HONI'S EXPORT TRANSMISSION CLASS

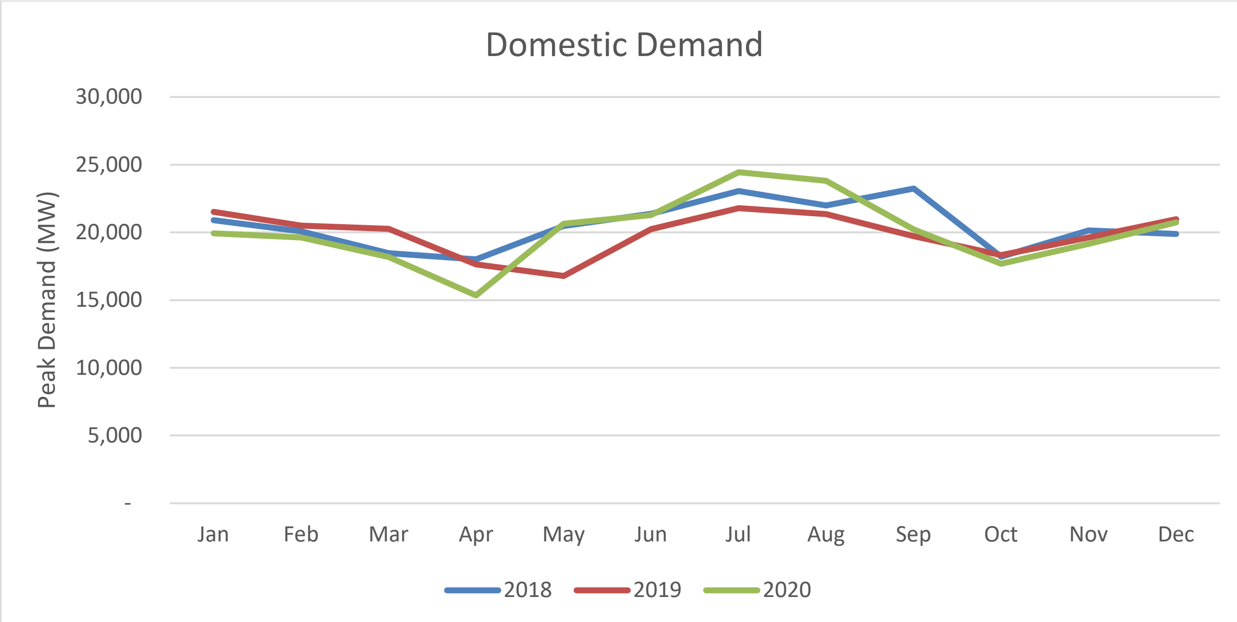
4.1 EXPORT TREATMENT BY IESO

Elenchus discussed with the IESO how exports are being treated in Ontario. The IESO provided the following explanations:

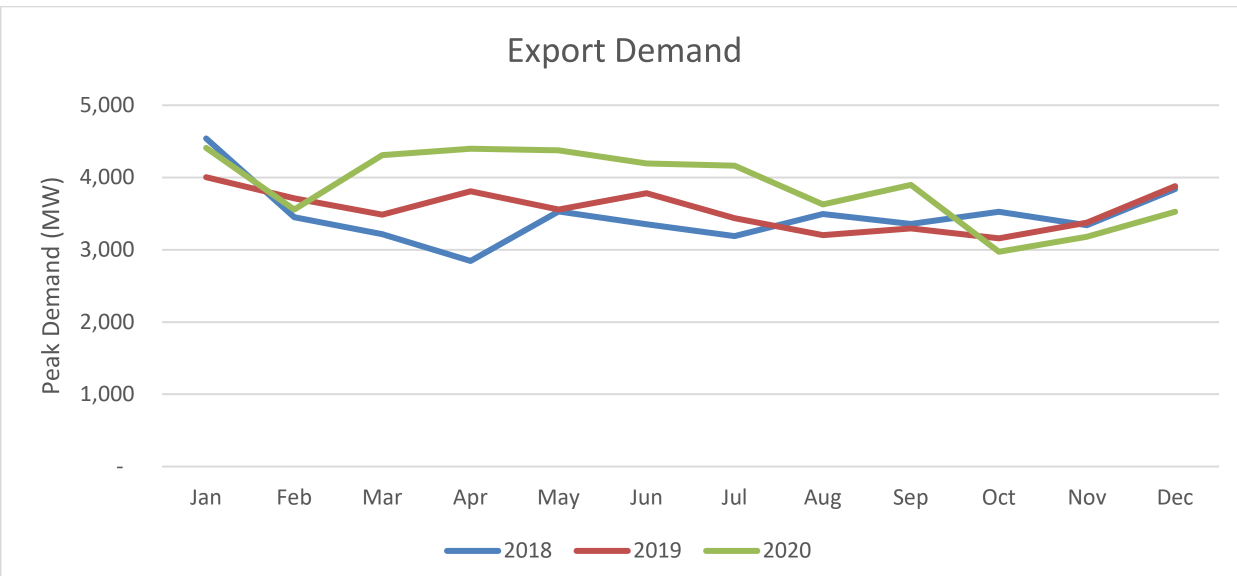
> *The IESO provides market participants and consumers (including exporters and domestic loads) with the same access to service. This is consistent with requirements of Section 1(e) of the Electricity Act, 1998:*
>
> > *(e) to provide generators, retailers, market participants and consumers with non-discriminatory access to transmission and distribution systems in Ontario*
>
> *While exports do receive the same access as domestic loads, exports are subject to more frequent interruption in service compared with domestic load. From a planning perspective, the IESO treats loads differently than exports. In contrast to domestic load, the IESO does not factor exports into its reliability planning assessments. This means that the IESO does not procure generation or transmission assets to serve future export demand.*

4.2 DOMESTIC AND EXPORT DEMAND PROFILES

Ontario is a summer-peaking province, with peak demands generally occurring in the summer months and smaller peaks occurring in winter months. However, in some recent years the domestic peak occurred in September.



Export demand peaks in the winter months as shown in the graph below.



The following table shows Domestic, Export, and Total Transmission System peaks over the past 10 years, along with the months in which the peak occurs.

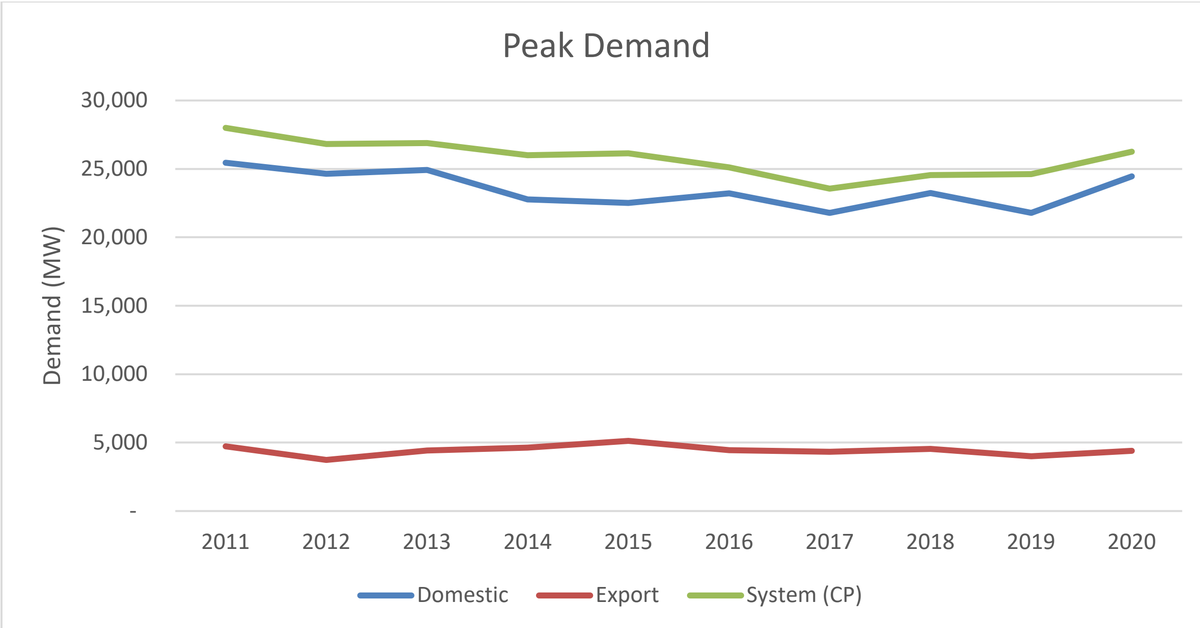
Table 4

Peak Demands 2011-2020

	Domestic		Export		System (1CP)	
	Peak	Month	Peak	Month	Peak	Month
2011	25,450	July	4,736	January	27,999	July
2012	24,636	July	3,735	January	26,815	July
2013	24,927	July	4,417	January	26,879	July
2014	22,774	January	4,629	January	26,012	January
2015	22,516	July	5,127	February	26,151	January
2016	23,213	September	4,438	January	25,118	September
2017	21,786	September	4,320	December	23,558	December
2018	23,240	September	4,540	January	24,550	January
2019	21,791	July	4,004	January	24,613	July
2020	24,446	July	4,410	January	26,258	July

From 2011 to 2013, the years analysed for Elenchus' 2014 ETS Report, the transmission system peak was in July, driven by domestic demands. In the following seven years, four of the transmission system peaks have occurred in December or January, driven by higher export demands.

Peak demands have declined in recent years. The average transmission system peak demand declined by 7.3% from the 2011 to 2015 period to the 2016 to 2020 period. The following chart displays domestic, export, and system peak demands from 2011 to 2020.



Domestic consumption volumes have declined and Export volumes have increased over the same period.

Table 5

Consumption 2011-2020

	Domestic MWh	Export MWh	Total MWh
2011	141,473,805	12,848,505	154,322,310
2012	141,287,009	14,627,403	155,914,412
2013	140,736,784	18,309,407	159,046,191
2014	139,803,825	19,073,299	158,877,124
2015	137,011,780	22,618,058	159,629,838
2016	136,989,747	21,858,101	158,847,848
2017	132,090,992	19,097,894	151,188,886
2018	137,436,546	18,590,935	156,025,737
2019	135,162,188	19,796,035	154,958,223
2020	132,225,424	20,377,407	152,602,831

Average domestic volumes have declined by 3.8% from the 2011 to 2015 period to the 2016 to 2020 period, whereas average export volumes have increased by 14% between the same periods.

4.3 CURTAILMENTS

The IESO considers exporters to be a "curtailable" rather than "interruptible" class, consistent with the North American Reliability Council (NERC) definition of interruptible.

As domestic peak demands have declined in recent years, the approximate number of hours when exports curtailments were active have also fallen.

Table 6

Year	Hours with Export Curtailment
2016	35%
2017	33%
2018	28%
2019	22%
2020 (until October)	18%

With respect to potential curtailments that exports may be subjected to, the IESO provided the following explanation:

> *"Exports are subject to materially different treatment from domestic load in several ways and as a result are curtailed more frequently than internal load. The IESO does not factor exports into its reliability planning assessments, which means it does not procure generation or transmission assets to serve export demand. Also, compared to domestic load, there are more reasons that export transactions could be subject to curtailment. Exports can be curtailed due to internal and external transmission security and adequacy reasons. As a result, the IESO curtails exports for reliability reasons more often than domestic load. In the first ten months of 2020, the IESO curtailed exports in approximately 18% of all hours to manage reliability.*

To provide an indication of the degree to which exports are curtailed at peak times, the IESO provided the following:

> *Over the top 5 peak hours over the last 5 years, the IESO curtailed exports in 11 out of 25 hours. The average quantity of exports curtailed was 158MW or approximately 10% of exports scheduled.*

5 EXPORT AND CURTAILABLE TRANSMISSION RATE-SETTING IN OTHER JURISDICTIONS

Elenchus researched transmission rate-setting processes in jurisdictions across Canada and the United States. Transmission rate-setting in Ontario differs considerably from the processes used in other jurisdictions. Elenchus did not find any jurisdictions in which cost allocation principles are used for the purpose of allocating shared network costs between domestic and export classes. Furthermore, cost allocation principles are not used to determine differential firm and non-firm charges.

5.1 OPEN ACCESS TRANSMISSION TARIFF

The majority of jurisdictions surveyed by Elenchus, including all Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) in the United States and most ISOs and transmitters in Canada set Open Access Transmission Tariffs (OATTs) in accordance with FERC Orders No. 888, 889, 890, and 2000. All Canadian provinces operate within the OATT framework except Ontario and Alberta.

These jurisdictions have postage stamp “Network Service charges” that are analogous to Ontario’s domestic transmission tariff. Exports are analogous to “Point-to-Point” transmission service, which are applied to the transmission of energy along specific paths, from a point of receipt to a point of delivery. Unlike Ontario’s Domestic and Export rates, which are set based on an allocation basis, Point-to-Point charges are calculated[3] based on the Network Service charge.

5.2 INTERRUPTIBLE VS. NON-FIRM

Point-to-Point service can be firm or non-firm. Firm service is offered only if the remaining transmission capacity is sufficient to provide that service.

[3] Point-to-Point charges may be equal to Network Service charges, or otherwise calculated with the same revenue requirements and billing determinants.

Transmission service that can be curtailed is classified as “Non-Firm” rather than interruptible. The same charges apply to both Firm and Non-Firm customers.

In practice, Firm Point-to-Point service customers schedule short-term capacity when it is available. Non-Firm Point-to-Point service have lower priority, and therefore a higher chance of being curtailed, but service scheduling is more flexible. Firm Service is provided for periods ranges of one year to one day and can be scheduled the day prior to service (generally by 10:00 am). Non-Firm service can be scheduled up to one day at 2:00pm prior to service for periods of one hour to one month. Point-to-point service may also be subject to discounted prices as long as they are submitted on the OASIS and available to all customers on a non-discriminatory basis.[4]

5.3 CAPACITY-BASED CHARGES ($/kW)

Most jurisdictions surveyed apply capacity-based service charges for both Network and Point-to-Point services.[5] The service charges can be considered reserved demand charges as charges are applied based on the capacity that is reserved during scheduling, regardless of the actual capacity utilized. By FERC Order No. 890, Annual charges are calculated based on the combined revenue requirements of transmitters within an RTO or ISO, divided by the system capacity and monthly charges are derived as one twelfth of the annual charge. Weekly, daily, and hourly charges are typically derived by RTO/ISOs from the annual service charge by the calculations provided in Table 7.

[4] Discounts are typically offered in times that there is excess transmission system capacity. Discounts may be priced dynamically to maximize revenues or may be set according to a defined policy, such as reducing prices to off-peak rates in nominally on-peak periods. Discounts may be offered on specific paths or points of departure.

[5] NYISO is an exception. Energy-based ($/kWh) charges apply to Point-to-point service.

Table 7

Charge	Methodology
Annual Charge	$\frac{\text{Revenue Requirement}}{\text{Total Capacity}}$
Monthly Charge	1/12 of Annual Charge
Weekly Charge	1/52 of Annual Charge
Daily On-Peak Charge	1/5 of Weekly Charge
Daily Off-Peak Charge	1/7 of Weekly Charge
Hourly On-Peak Charge	1/16 of Daily On-Peak Charge
Hourly Off-Peak Charge	1/24 of Daily Off-Peak Charge

The same charges apply to Network and Point-to-Point service and Firm and non-Firm service. Hourly charges are only available for Non-Firm service and not all jurisdictions have separate Off-Peak and On-Peak charges.

5.4 ALBERTA

The transmission charges applicable to exporters in Alberta are established in the Alberta Electricity System Operator ("AESO") tariff proceedings before the Alberta Utilities Commission ("AUC"). The AESO is responsible for collecting the transmission revenue requirements of Alberta's transmitters.

The principal transmission charge is the Demand Transmission Service rate ("Rate DTS"). Rate DTS incudes a capacity charge and a consumption charge. Other rates, including the Demand Opportunity Service rate ("Rate DOS"), Export Opportunity Service Rate ("Rate XOS"), and Export Opportunity Merchant Service rate ("Rate XOM"), are derived based on Rate DTS.

Demand Opportunity Service is interruptible, temporary, and available only when there is surplus transmission capacity. There are three rates: service in 7-minute increments, service in hour increments, or service for longer than 8 hours. Rates are charged based on consumption and differ significantly between the three types of service.

Export Opportunity Service and Export Opportunity Merchant Service applies to exporters. Nominally the export service differs based on the year the intertie was put in service, however, there is no difference in the rate charged.

For each tariff proceeding the AESO conducts a cost allocation study which allocates costs to Rate DTS and Supply Transmission Service rate ("Rate STS"). Costs related to loses and generation connections are allocated to Rate STS and the remainder is allocated to Rate DTS. The Rate DTS revenue requirement is functionalized to the following components: Bulk System, Regional System, Point of Delivery, Operating Reserve, Voltage Control, and Other System Support and classified as either fixed-based or usage-based. Bulk System and Regional System are analogous to the Shared Network function within HONI's ETS model.

The DTS functions are classified between capacity and energy. The classified functions are then each divided by the energy forecast to provide the DTS rate by its components. Export rates are calculated as a subset of the DTS rate components, some of which are pro-rated. The export rate is comprised of 100% of the energy-classified Bulk System and Regional System rates that are applicable to the DTS rate, 20% of the capacity-classified Bulk System and Regional System rates and 32% of the Operating Reserve rate. The export rate does not receive a share of Point of Delivery, Voltage Control, or Other System Support rate components.

The AESO provided the following rational for applying 20% to capacity-related Bulk and Network System costs: "The 20% contribution represents a minimal amount as Rate XOS includes no contract capacity or ratchet-based charges in hours in which XOS 1 Hour interchange transactions are not scheduled."[6] The AUC has accepted this methodology in subsequent tariff applications.

The total revenue from the export rate is grouped with other revenue offsets to reduce the total DTS revenue requirement. The revenue is not used to offset the specific functions for which the export rate is attributed costs. For example, Point of Delivery costs are not attributed to the export rate but export revenue is used, in part, to reduce the Point of

[6] AESO Response to information request, AESO 2010 ISO Tariff Application (AUC.AESO-008)

Delivery component of the revenue requirement. Elenchus does not consider the manner that AESO sets export rates to be underpinned by a cost allocation methodology.

6 Cost Allocation Methodology Options

Elenchus reviewed the May 2014 cost-based methodology to calculate the ETS rate, held discussions with the IESO on how exports are treated in Ontario, reviewed the OEB report on Pole Attachment Charges and the OEB Decision and Order on HONI's transmission application (EB-2019-0082) and surveyed how export rates are set in other jurisdictions.

Based on the review conducted by Elenchus, this report presents cost-based methodologies that allocate Shared Network Asset-related costs to export customers.

Based on the information provided by the IESO on how exports are treated compared to domestic customers, exporters are able to use the transmission assets in the same manner as domestic customers unless they are curtailed by the IESO. Exports are subject to more service interruption than domestic customers. In the past few years, exports have been affected by fewer and fewer service interruptions and in 2019 and 2020 curtailments of some portion of export demand were close to 20% of the hours.

At times of the transmission system peak, exporters are able to use the transmission system. The IESO provided Elenchus with the information that:

> *"Over the top 5 peak hours over the last 5 years, the IESO curtailed exports in 11 out of 25 hours. The average quantity of exports curtailed was 158MW or approximately 10% of exports scheduled. "*

6.1 "No Free Riders" Principle

As stated by the OEB in its report on Pole Attachment Charges, when developing a cost-based methodology, consideration can also be given to the value that users obtain from leveraging an established network. This means that there should not be users of a shared network that do not pay their fair share of costs for use of the shared network, also referred to as "free riders".

This principle is not unique to the OEB. For example, the Régie de l'énergie in Quebec has a long-standing "no free service"[7] guiding principle for cost allocation and rate design. FERC Order No. 1000 states as its first cost allocation principle that "costs should be allocated in a way that is roughly commensurate with benefits".[8]

6.2 COST ALLOCATION METHODOLOGY FOR ASSETS DEDICATED TO INTERCONNECT

Assets dedicated to interconnect serve both exports and imports. The May 2014 methodology recommended allocating all assets and costs for functions dedicated to interconnect to the Export class because importers do not pay for the use of the transmission system.

Since importers also use interconnection assets not all asset-related costs and OM&A related to interconnection should be directly allocated only to the Export class. Energy is imported to serve domestic load therefore a portion of interconnection assets, asset-related costs, and OM&A should be allocated to the Domestic class. Elenchus recommends that the intertie 12CP be used to allocate Dedicated to Interconnect assets and costs to the Export and Domestic classes. The intertie 12CP is derived in Table 8.

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[7] *"l'absence de service gratuity"* - For example, see Régie Decisions D-429 and D-97-47. Elenchus discussed this principle in its *Report on Énergir's Cost Allocation and Pricing of Gas Supply, Transportation and Load Balancing Services and Supply of Interruptible Service* (R-3867-2013A-0219)
.

[8] FERC Order No. 1000 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* addresses cost allocation with respect to new transmission facilities

Table 8

Intertie Coincident peak 2018 to 2020

	2018			2019			2020		
	Export	Import	Total	Export	Import	Total	Export	Import	Total
1CP	4,343	2,519	6,862	3,556	1,589	5,145	3,485	2,159	5,644
12CP	35,099	21,110	56,209	35,779	18,806	54,585	39,117	15,430	54,547

	2018 to 2020 Average		
	Export	Import	Total
1CP	3,795	2,089	5,884
12CP	36,665	18,449	55,114

The intertie 1 CP and 12 CP percentage allocators using 2018 to 2020 data are shown in the table below.

Table 9

Intertie Coincident peak %

	2020 Data			Average 2018 – 2020 Data		
Coincident Peak	**Export**	**Import**	**Total**	**Export**	**Import**	**Total**
1CP	61.75	38.25	100.00	64.49	35.51	100.00
12CP	71.71	28.29	100.00	66.53	33.47	100.00

Elenchus proposes to allocate assets and expenses that are categorized as Dedicated to Interconnect by the Intertie 12CP between Domestic and Export class.

6.3 COST ALLOCATION METHODOLOGY FOR SHARED NETWORK ASSETS

Since exporters are able to use the transmission system unless they are curtailed by the IESO, even at the times of the Ontario transmission system peak, Shared Network Asset-related costs can be allocated to export customers based on the cost causality principle. Elenchus' suggested allocator is based on data from peak periods, including peak periods in which export customers are curtailed. When they are curtailed, export peak volumes are reduced which is reflected in the suggested allocator and results in a reduction in the portion of costs allocated to exports.

Even though export demand needs are not taken into account when HONI designs the transmission system and the IESO does not factor exports into its reliability planning assessments, the fact that exporters can use the transmission system much of the time, including during peak periods, would support the allocation of Shared Network Asset-related costs to export customers.

6.3.1 ALLOCATORS

The data used in the May 2014 methodology were updated by Elenchus to reflect more up to date information. The demand imposed on the transmission system by both domestic and export customers is available from the IESO on an hourly basis. Elenchus recommends that the same allocators be used in the three identified methodologies.

Using 2018, 2019 and 2020 actual hourly load data for domestic and export customers from the IESO, transmission system coincident peak ("CP") allocators were developed.

Table 10
Transmission System Coincident peak 2018 to 2020

	2018			2019			2020		
	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total
1CP	4,121	20,429	24,550	2,822	21,791	24,613	2,583	23,675	26,258
12CP	25,336	241,536	266,872	27,510	237,055	264,565	28,428	237,606	266,034

	2018 to 2020 Average		
	Export	Domestic	Total
1CP	3,175	21,965	25,140
12CP	27,487	238,507	265,994

The 1 CP and 12 CP percentage allocators using 2018 to 2020 data are shown in the table below:

Table 11

Coincident Peak %

	2020 Data			Average 2018 – 2020 Data		
Coincident Peak	**Export**	**Domestic**	**Total**	**Export**	**Domestic**	**Total**
1 cp	9.84	90.16	100.00	12.63	87.37	100.00
12 cp	10.69	89.31	100.00	10.33	89.67	100.00

Table 12 includes the percentage allocation of the composite allocators to the two customer classes based on 12 CP using 2020 data.

Table 12

Allocators using 2020 Actual Hourly Data

Allocator	Basis	Export	Domestic	Total
Shared Net Fixed Assets	Transmission System 12CP	10.69%	89.31%	100.00%
Dedicated to Domestic	Direct Allocation	0.00%	100.00%	100.00%
Dedicated to Interconnect	Intertie 12CP	71.71%	21.29%	100.00%

6.3.2 SHARED NETWORK ASSETS

The cost allocation methodology recommended in Elenchus' May 2014 report, which informed the setting of the current ETS rate, was to allocate Shared Network Asset OM&A between the Domestic and Export classes by the Net Fixed Assets allocator. Depreciation expense, return on capital, and PILs[9] related to Shared Network Assets were allocated fully to the Domestic class.

If Shared Network Asset-related costs are to be allocated, one of Elenchus' suggested methodologies is for Shared Network Asset-related costs to be allocated using the Shared Net Fixed Assets allocator (12CP). Assets Dedicated to Domestic and Dedicated to Interconnect would be excluded. To the extent that export customers are curtailed, the

[9] HONI is now subject to income taxes and not PILs following its IPO

export hourly data that is used as an allocator will reflect the impact of service interruptions.

Using Shared Net Fixed Assets as an allocator for Shared Network Asset-related costs between domestic and export customers will reflect each customer group's use of the transmission system, including the impact of service curtailment to export customers.

The other two methodologies adjust the 12CP by 50% reflecting the hybrid model and 20% reflecting the curtailment percentage model. The three Net Fixed Asset allocators are provided in the following table.

Table 13

Shared Network Asset Allocation Methodologies

	Net Fixed Assets			Hybrid Model			Curtailment % Model		
	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total
12CP	28,428	237,606	266,034	22,742	237,606	260,348	14,214	237,606	251,820
%	10.69%	89.31%	100.00%	8.74%	91.26%	100.00%	5.64%	94.36%	100.00%

6.3.3 External Revenues from Shared Network Assets

If export customers are allocated a portion of Shared Network Asset-related costs, it is reasonable that export customers should also be allocated a portion of external revenues received by HONI related to the use of those assets. The allocator suggested by Elenchus for full External Transmission Revenues is the same allocator recommended for Shared Network Asset-related costs, which is Shared Net Fixed Assets.

6.3.4 Deferral and Variance Account Balances

HONI's Rates Revenue Requirement includes deferral and variance account balances. Aside from the Excess Export Service Revenue Variance Account, the accounts are generally not attributable to either Domestic or Export customers or the specific assets used by each customer group, so it is appropriate to allocate these balances to the Export class. The sum of HONI's deferral and variance account balances, excluding Excess

Export Revenues, are allocated based on each class's share of the Revenue Requirement.

7 ETS RATE RESULTS

7.1 METHODOLOGIES CONSIDERED

The following cost-based methodologies were considered by Elenchus to be appropriate options to allocate Shared Network Asset-related costs to export customers:

- Fully allocate Shared Network Asset-related costs on the basis of Shared Net Fixed Assets.
- Apply an adjusted Shared Net Fixed Assets allocator with export 12CP discounted by 50%, as a proxy for a hybrid model, half-way between no allocation and full allocation of Shared Network Asset-related costs to exports.
- Apply an adjusted Shared Net Fixed Assets allocator with a percentage of export demand discounted based on the service curtailment that affected exports in the last few years. Assuming that exports were curtailed 20% of the hours in the last few years, adjust export volumes to 80%.

The results of these methodologies are provided in the following table using 2020 data[10]:

Table 14

Methodology	Allocator for Shared Network Asset-related costs		ETS Rate ($/MWh)
	Domestic Share	Export Share	
OEB 2020 Approved ETS rate			$1.85
2014 Report Methodology	Domestic 12CP	-	$1.67
Allocation on Basis of 100% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP	$6.06
Allocation on Basis of 50% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 50%	$3.40
Allocation on Basis of 80% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 80%	$5.03

As in the May 2014 suggested methodology, Elenchus suggests that the three proposed methodologies in this report to calculate an ETS rate be adjusted to include other transmitters' approved revenue requirement. The adjusted ETS rates under the proposed methodologies is provided in Table 15.[11]

Table 15

Adjusted ETS Rates

Methodology	Allocator for Shared Network Asset-related costs		Adjusted ETS Rate ($/MWh)
	Domestic Share	Export Share	
Allocation on Basis of 100% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP	$6.54
Allocation on Basis of 50% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 50%	$3.66
Allocation on Basis of 80% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 80%	$5.42

[10] HONI's 2023 revenue requirement and actual 2020 load and consumption data

[11] Rates are adjusted by 7.77%, calculated as the sum of HONI's 2023 Network Revenue Requirement and the Network Revenue Requirements of all other transmitters (as per EB-2020-0251) divided by HONI's 2023 Network Revenue Requirement.

8 CONCLUSIONS

Elenchus has identified cost allocation methodologies that allocate Shared Network Asset-related costs to export customers for the purpose of informing the OEB's decision-making on ETS rates going forward. Our analysis has taken the following into consideration:

- Direction from the OEB to HONI to review the allocation of Shared Network Asset-related costs to export
- OEB report on Pole Attachment charges
- Elenchus jurisdictional review of cost allocation methodologies
- IESO treatment of export
- Export service curtailment in the last few years and expected curtailment in the near future

Elenchus views each cost allocation methodology, including the May 2014 approach and the methodologies included in this report, as being cost-based. The changes arise from the inclusion of "no free service" as an appropriate principle to adopt in addition to the strict cost causality principle.

The May 2014 methodology was based on how the transmission system is designed and since exports needs are not considered in the planning of the transmission system, exports would not be allocated a portion of Shared Network Assets.

The methodologies identified in this report account for how exports are being treated by the IESO. Exports use the transmission system almost as much as domestic customers use the system, including at peak times, therefore, exports could be allocated a portion of Shared Network Asset-related costs. If exports are to be allocated a portion of Shared Network Asset-related costs, Elenchus is of the view that exports should also then be allocated a portion of External Transmission Revenues received by HONI.

While this report presents options for allocating Shared Network Asset-related costs to exports on a cost causality basis, Elenchus' view is that whether or not the OEB should change ETS rates to reflect those network costs is a policy question for the OEB to determine.

APPENDIX A - CVS

MICHAEL J. ROGER

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ASSOCIATE, RATES AND REGULATION

Michael has over 40 years of experience in the electricity industry dealing in areas of finance, cost allocation, rate design and regulatory environment. Michael has been an expert witness at numerous Ontario Energy Board proceedings and has participated in task forces dealing with his areas of expertise. Michael is a leader and team player that gets things done and gets along well with colleagues.

PROFESSIONAL OVERVIEW

Elenchus **2010 - Present**

Associate Consultant, Rates & Regulation

- Provide guidance on the Regulatory environment in Ontario for distributors and other stakeholders, with particular emphasis on electricity rates in Ontario and the regulatory review and approval process for cost allocation, rate design and special studies such as Working Capital Allowance and shared services studies. Prepare and defend related evidence. Appear as expert witness at regulatory proceedings.
- Some of the clients that Michael provides advice include: Hydro Quebec Energy Marketing Inc., GTAA, Ontario Energy Board, City of Hamilton, Hydro One Transmission, Powerstream, Hydro Ottawa, Ontario Power Generation, Veridian, SaskPower, British Columbia Utilities Commission and APPrO.

Hydro One Networks Inc. **2002 - 2010**

Manager, Pricing, Regulatory Affairs, Corporate and Regulatory Affairs

- In charge of Distribution and Transmission pricing for directly connected customers to Hydro One's Distribution system, embedded distributors and customers connected to Hydro One's Transmission system.
- Determine prices charged to customers that conform to guidelines and principles established by the Ontario Energy Board, (OEB).
- Provide expert testimony at OEB Hearings on behalf of Hydro One in the areas of Cost Allocation and Rate Design.
- Keep up to date on Cost Allocation and Rate Design issues in the industry.
- Ensure deliverables are of high quality, defensible and meet all deadlines.

- Keep staff focused and motivated and work as a team member of the Regulatory Affairs function. Provide support to other units as necessary.

Ontario Power Generation Inc. **1999 - 2002**

Manager, Management Reporting and Decision Support, Corporate Finance

- Produce weekly, monthly, quarterly and annual internal financial reporting products.
- Input to and coordination of senior management reporting and performance assessment activities.
- Expert line of business knowledge in support of financial and business planning processes.
- Coordination, execution of review, and assessment of business plans, business cases and proposals of an operational nature.
- Provide support to other units as necessary.
- Work as a team member of the Corporate Finance function.

Ontario Hydro **1998 - 1999**

Acting Director, Financial Planning and Reporting, Corporate Finance

- Responsible for the day to day operation of the division supporting the requirements of Ontario Hydro's Board of Directors, Chairman, President and CEO, and the Chief Financial Officer, to enable them to perform their due diligence role in running the company.
- Interact with business units to exchange financial information.

Financial Advisor, Financial Planning and Reporting, Corporate Finance **1997**

- Responsible for co-ordinating Retail, Transmission, and Central Market Operation divisions' support of Corporate Finance function of Ontario Hydro to ensure financial information consistency between business units and Corporate Office, review business units compliance with corporate strategy.
- Provide advice to Chief Financial Officer and Vice President of Finance on business unit issues subject to review by Corporate Officers.
- Participate or lead task team dealing with issues being evaluated in the company.
- Supervise professional staff supporting the function.
- Co-ordinate efforts with advisors for GENCO and Corporate Function divisions to ensure consistent treatment throughout the company.

Section Head, Pricing Implementation, Pricing **1986 - 1997**

- Responsible for pricing experiments, evaluation of marginal costs based prices, cost-of-service studies for municipal utilities, analysis and comparison of prices in the electric industry, rate structure reform evaluation, analysis of cost of servicing individual customers and support the cost allocation process used to determine prices to end users.

- Responsible for the derivation of wholesale prices charged to Municipal Electric Utilities and retail prices for Direct Industrial customers, preparation of Board Memos presented to Ontario Hydro's Board of Directors and support the department's involvement at the Ontario Energy Board Hearings by providing expert witness testimony.

Section Head (acting), Power Costing, Financial Planning & Reporting, Corporate Finance **1994 - 1995**

- Responsible for the allocation of Ontario Hydro's costs among its customer groups and ensure that costs are tracked properly and are used to bill customers.
- Maintain the computer models used for cost allocation and update the models to reflect the structural changes at Ontario Hydro.
- Participate at the Ontario Energy Board Hearings providing support and expert testimony on the proposed cost allocation and rates.
- Provide cost allocation expertise to other functions in the company.

Additional Duties **1991**

- Manager (acting) Rate Structures Department.
- Review of utilities' rates and finances for regulatory approval.
- Consultant: Sent by Ontario Hydro International to Estonia to provide consulting services on cost allocation and rate design issues to the country's electric company.

Analyst, Rates **1983 - 1986**

- In charge of evaluating different marketing strategies to provide alternatives to customers for the efficient use of electricity.
- Co-ordinate and supervise efforts of a work group set up to develop a cost of service study methodology recommended for implementation by Municipal Electric Utilities and Ontario Hydro's Rural Retail System.
- Provide support data to Ontario Hydro's annual Rate Submission to the Ontario Energy Board.
- Participate in various studies analysing cost allocation areas and financial aspects of the company.

Forecast Analyst, Financial Forecasts **1980 – 1983**

- Evaluating cost data related to electricity production by nuclear plants and preparing short term forecasts of costs used by the company. Maintain and improve computer models used to analyse the data.
- Review Ontario Hydro's forecast of customer revenues, report actual monthly, quarterly and yearly results and explain variances from budget.
- Support the development of new computerized models to assist in the short-term forecast of revenues.

Project Development Analyst, Financial Forecasts **1979 - 1980**

- In charge of developing computerized financial models used by forecasting analysts planning Ontario Hydro's short term revenue and cost forecasts and also in the preparation of Statement of Operations and Balance Sheet for the Corporation.

Assistant Engineer – Reliability Statics, Hydroelectric Generations Services **1978 – 1979**

- In charge of analysing statistical data related to hydroelectric generating stations and producing periodic report on plants' performance.

ACADEMIC ACHIEVEMENTS

1977	Master of Business Administration, University of Toronto. Specialized in Management Science, Data Processing and Finance. Teaching Assistant in Statistics.
1975	Bachelor of Science in Industrial and Management Engineering, Technion, Israel Institute of Technology, Haifa, Israel.

ANDREW BLAIR

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RESEARCH ANALYST

Andrew Blair joined Elenchus in January 2016 as a research analyst. He previously worked for the Ontario provincial government over a seven-year period as a trust analyst and a trust accountant. Andrew has a Master's Degree in Economics from Carleton University and a Bachelor's Degree in Economics and Financial Management from Wilfrid Laurier University.

PROFESSIONAL OVERVIEW

Elenchus Research Associates **January 2016 - Present**

Research Analyst

- Consulting in the areas of cost allocation modeling and load forecasting
- Provide research and modeling support for economic feasibility studies
- Support existing Elenchus applications, such as RateMaker
- Research background information related to regulatory filings
- Prepare cross-examination documents for regulatory hearings
- Design and monitor content for new forward-looking electricity-focused information service

Office of the Public Guardian and Trustee **May 2012 – June 2013**

Trust Analyst **Summers 2010 & 2011**

- Designed estate allocation and payment disbursement system
- Summarized and analyzed aggregate account information
- Allocated interest and fees to close out accounts
- Researched Public Guardian clients' files and family histories to determine estate beneficiaries
- Located beneficiaries and distributed estates

Accountant of the Superior Court of Justice **Co-op Student 2006**

Trust Accounting Officer **Summers 2007 - 2009**

- Reconciled client account balances
- Located clients with an outstanding balance with the court
- Updated client account balances as well as pension and disability allowances

ACADEMIC ACHIEVEMENTS

June 2014	Master of Arts, Economics, Carleton University
June 2012	Bachelor of Arts, Economics and Financial Management, Wilfrid Laurier University

Andrew Blair, Elenchus

Prepared for:

Hydro One Networks Inc.

Jurisdictional Review of Export Transmission Service (ETS) Rates Study

Final Report

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Date: March 29, 2021

CRA Project No. 32328

Disclaimer

The conclusions set forth herein are based on independent research and publicly available material. The authors and Charles River Associates accept no duty of care or liability of any kind whatsoever to any party for any claim or loss arising as a result of decisions made, or not made, or actions taken, or not taken, based on this paper.

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1. Executive Summary

1.1. Background and Scope of Study

A May 16, 2012 report by Charles River Associates (CRA) entitled "Export Transmission Service Tariff Study - Review of Rates in Neighboring Markets" (the "2012 Jurisdictional Review") was prepared for the Independent Electricity System Operator (IESO) in response to the Ontario Energy Board's (Board) decision in proceeding EB-2010-0002. The Board at that time had directed the IESO to undertake a comprehensive study to identify a range of proposed Export Transmission Service (ETS) tariffs, and their advantages and disadvantages. The 2012 Jurisdictional Review was to support modeling of export transactions with each neighboring market for identified ETS tariff structure/rate and would provide comparable data for the assessment of the proposed rates/rate structures for consistency with rates/rate structures in adjacent markets.[1] To that end, the 2012 Jurisdictional Review reviewed the export transmission tariff designs and rates in the electricity markets adjacent to Ontario and well as certain other U.S. markets as part of an evaluation of potential export tariff rates and structures.[2]

The Board in its Decision and Order on Hydro One's most recent transmission rate application (EB-2019-0082) ordered Hydro One to provide an updated jurisdictional review that provides the rates in other jurisdictions, rationale behind those rates and market implications.[3] Torys LLP (Torys) as legal counsel on behalf of Hydro One Networks Inc. (Hydro One), retained CRA to update the 2012 Jurisdictional Review to reflect current export transmission service rates in other jurisdictions, the rationale behind those rates and how market implications are considered in the setting of export transmission service rates in those jurisdictions. Torys and Hydro One also requested that CRA consider whether any additional electricity market jurisdictions, including Canadian jurisdictions, should be added to the 6 jurisdictions considered in the 2012 Jurisdictional Review and if so, to include these additional jurisdictions in CRA's work.

This Study (Study) therefore is an update to the 2012 Jurisdictional Review, and reports on the current (2020) ETS rates for the jurisdictions included. In addition, where suitable information is available, this Study describes the regulatory rationale supporting the ETS rates in those jurisdictions.

CRA's research methodology was to: 1) identify the applicable tariffed service and rate for generation export service in each jurisdiction; 2) obtain the applicable posted Open Access Transmission Tariff (OATT) from each market operator's website; 3) review the relevant tariff and confirm applicable rates and services for exports; and 4) conduct telephonic discussions with market operator staff where needed to confirm applicable tariff services and rates for exports. To conduct our research for regulatory rationale, CRA conducted extensive research on applicable regulatory commission websites such as the Federal Energy Regulatory

1 See 2012 Jurisdictional Review, page 5.

2 The 2012 Jurisdictional Review included the following jurisdictions: MidContinent ISO (MISO), PJM, New York ISO (NYISO) and TransÉnergie (Québec). The rates provided in the 2012 ETS Review used C$1.0 = US $1.0117 conversion based on average rate during 2011; the conversion used for this update is C$1.0 = US $0.79 conversion as of January 2021.

3 See EB-2019-0082, Decision and Order dated April 23, 2020, page 180.

Commission (FERC) for U.S. jurisdictions, and applicable provincial commissions for Canadian jurisdictions to identify and obtain regulatory evidence where available; and, CRA reviewed regulatory evidence to evaluate rationale where information was available.

1.2. Findings Summary

Appendix A summarizes the 2020 rates in each jurisdiction for Firm and Non-Firm Point-to-Point (PTP) Export Transmission Services (ETS). Also shown for comparative purposes is the approved export tariff for Ontario. The rates are reported on an annual, monthly, weekly and daily basis, consistent with how they appear in the relevant tariff.

We observe that ETS rate levels in general have increased since 2012 and display no changes in rate design. The rate level change is attributable to inflation and transmission expansion since 2012. The regulatory rationale for rate design differs across markets studied. For certain established U.S. jurisdictions including ISO-NE, NYISO, PJM, and MISO, the OATT and rates currently in place for transmission service, including service for exports, appear to have developed from principles affirmed by the FERC Order No. 888-A.[4] Current ETS rate design was "inherited" from the former power pools that were in place in those regions prior to ISO/RTO implementation. These rates are designed to recover the total annual transmission revenue requirement (ATRR) over the forecasted annual billing units (12 Coincident Peak (CP) or zonal peak demand, or another basis). In these cases, the rates for export service are designed to recover total ATRR and there is no specific rate design step applied to encourage a particular export market result. Other jurisdictions studied appear to rely on a variation to the above approach for each jurisdiction as described further in this report.

4 https://www.ferc.gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform/order-no-888 In 1996, before the formation of ISOs, FERC Order No. 888 ("the Order") directed transmission owners to establish a Pro Forma Open Access Transmission Tariff (OATT). The primary goal of the Order is to promote competitive and non-discriminatory transmission access. So long as transmission owners meet that directive, the Order does not mandate uniform OATT schedules. In fact, the Commission does not make blanket revisions to point-to-point service provisions in OATTs because there is "no distinction between different tiers of physical entitlements to the transmission system in an organized market environment."

2. Export Transmission Service Rates

2.1. Additional Jurisdictions Included in 2020 Study Update

CRA evaluated whether additional jurisdictions should be included in the Study. Based upon our evaluation of current markets, we included three additional jurisdictions: California ISO (CAISO), Southwest Power Pool (SPP), and Alberta Electric System Operator (AESO). Our rationale for adding these is as follows:

- CAISO initiated operations of the Western Energy Imbalance Market (WEIM) in 2014 which provides the opportunity to make valuable observations as to how export pricing within an imbalance market could operate.
- SPP is an expanding ISO with a physical footprint in 14 US states and is increasingly integrated and exchanging power with other US jurisdictions.
- AESO –Alberta is key Canadian merchant market that has been active in evaluating export rates and can serve as a good comparator.

2.2. 2020 Rate Updates

Please refer to Table 1 – Summary of 2020 Rates for Export Transmission Service for updated 2020 ETS rate-level results. Note the results reported in this table are shown in CAD, converted for US jurisdictions, and native market currency for Canadian jurisdictions.[5] As a comparison, Table 2 shows a summary of rates from the 2012 study. ETS rate levels have increased since 2012, most likely attributable to system growth and inflation effects over time; note however some jurisdictions have increased more than others. For instance, the ISO-NE rate has nearly doubled, most likely due to transmission expansions in the region. These differences suggest that the pace and magnitude of transmission investment over time, as well as system usage, differs across the jurisdictions between the two study periods.

CRA also observes that there are no rate design changes since 2012 for those jurisdictions covered in that study. Table 1 also shows a wide disparity among ETS rate levels. For instance, demand-based rates range from $8.69/kW-year (SPP) to $163.62/kW-year (ISO-NE). Energy-based rates, on the other hand, range from $1.85/MWh (Ontario) to $15.84/MWh (CAISO). Disparities among rate levels also were present in 2012. Finally, CRA observes that some tariffs offer firm and non-firm export services which are priced equally. The primary difference between firm and non-firm services is that export transactions using the latter are the first to be recalled or curtailed by the ISO at any time and at its discretion, for instance, when outages reduce transfer capability. The rules that specify the circumstances under which an ISO may recall non-firm service vary in each jurisdiction. Other jurisdictions do not specify a firm or non-firm basis of service for exports per the tariff service definitions.

Please refer to Appendix A for additional tables that provide an expanded summary of current ETS rates. Table 3 presents rates in the currency and rate format (capacity or energy) as

5 All US market USD values converted at January 20, 2021 rate of 0.79 CAD/USD - source based on Bank of Canada daily rates - https://www.bankofcanada.ca/rates/exchange/daily-exchange-rates

they appear in posted tariffs[6]; Table 4 presents the same but all in Canadian dollars; and Table 5 presents the rates in Canadian dollars and in an energy-based format (assuming a 100% load factor conversion) to allow for comparability to the current Ontario ETS rate of $1.85/MWh.

Note: rate adders for ancillary services are shown in Appendix B

Table 1 – Summary of 2020 Rates for Export Transmission Service (CAD)

		Annual Service $/kW-year	Monthly Service $/kW-month	Weekly Service $/kW-week	Daily On-Peak Service $/kW-day	Daily off-Peak Service $/kW-day	Hourly On-Peak Charge $/MWh	Hourly Off-Peak Charge $/MWh
MISO	Firm	52.4801	4.3733	1.0092	0.2019	0.1438		
	Non-Firm		4.3733	1.0092	0.2019	0.1438	12.6154	5.9909
PJM	Firm	23.9089	1.9924	0.4597	0.0919	0.0657		
	Non-Firm		1.9924	0.4597	0.0919	0.0657	5.7468	2.7342
NYISO[3]		The energy-based rate for the Firm PTP service is different for each transmission company at the seam of NYISO, and it ranges between $4.11 per MWh (Hydro-Québec) to $7.75 per MWh (PJM).						
ISO-NE[1]		163.6226						
SPP[5]	Firm	8.6951	0.7246	0.1672	0.0334	0.0239		
	Non-Firm		0.7246	0.1672	0.0334	0.0239	2.0899	0.9924
CAISO[4]								15.8482
Trans-Énergie[2]	Firm	78.06	6.51	1.50	0.30			
	Non-Firm		6.51	1.50	0.21		8.91	
Alberta[4]							8.28	
Ontario[6]							1.85	

1. ISO-NE does not distinguish between Firm and Non-Firm transactions and does not offer monthly, weekly, or daily transmission services. It offers hourly transmission service, and this is noted in Table 1 of Section 3 of this report.
2. TransÉnergie offers the same daily transmission service irrespective of time of day.
3. Non-firm service not offered.
4. Firm service not offered.
5. Schedules 7 and 8 rates also apply on a zonal basis for Point-to-Point transactions, in a range of $16.8/kW-year to $71.8/kW-year for annual firm service, and $1.92/MWh to $8.19/MWh non-firm.
6. Not clearly defined as either firm or non-firm, although rate is specific on energy basis and line capacity cannot be reserved for extended periods, therefore implied non-firm.

6 Some rates are stated on a demand-basis (rates charged on a unit of capacity unit basis – $ per MW or kW) and others on an energy-basis (rates charged on a unit of energy basis – $ per MWh, or kWh).

Table 2 – Summary of 2012 Rates for Export Transmission Service (CAD)[7]

		Annual $/kW-year	Month $/kW-month	Week $/kW-week	Day-Peak $/kW-day	Day-Off-Peak $/kW-day	Hour-Peak $/MWh	Hour-Off-Peak $/MWh
MISO	Firm	29.3756	2.448	0.5649	0.1130	0.0805		
	Non-Firm		2.448	0.5649	0.1130	0.0805	7.0608	3.3531
PJM	Firm	18.669	1.556	0.3590	0.0718	0.0513		
	Non-Firm		1.556	0.3590	0.0718	0.0513	4.4875	2.1350
NYISO								
ISO-NE	Firm	63.135					7.207	
Trans-Énergie	Firm	72.45	6.04	1.39	0.28			
	Non-Firm	72.45	6.04	1.39	0.20		8.24	

7 The 2012 Jurisdictional Review report used the average rate of exchange during 2011 that was C$1.0 = US $1.0117; Source: Bank of Canada.

3. Regulatory Research by Region

CRA researched regulatory rationale for the ETS rates reviewed. CRA's steps included a systematic search and review of relevant documentation for the various ISOs/RTOs and the FERC in the United States, and appropriate commissions and market operators in Canada. Our research covered applicable regulatory orders and related documentation.

3.1. ISO-New England (ISO-NE)

In New England, the outbound point-to-point rates – or Through or Out Service (TOUT)[8] – setting process was adopted as part of the tariff reform in response to FERC's restructuring directive in Order No. 888. Specifically, the process used at the time by the New England Power Pool (NEPOOL) was considered compliant by the FERC and adopted during the inception of the ISO.[9]

Notably, there is no difference between firm and non-firm transmission service as to rates; however, the ISO could curtail any external transactions to maintain system reliability. Per the ISO-NE procedure, *"All curtailments are determined in a nondiscriminatory manner and an appropriate reason is indicated."*[10] ISO-NE and NYISO have entered into a reciprocal agreement, in the form of a memorandum of understanding (MOU), that has adopted an exception to the rule such that the TOUT rate is reduced to zero for any Through or Out Service transaction that goes through or out of the New England Control Area and has the New England/New York Control Area boundary as its Point of Delivery.[11] The ISO-NE tariff states rates on an annual $/kW-Yr basis, however service can be provided on hourly and monthly terms.[12]

3.2. New York ISO (NYISO)

In a similar way that ISO-NE applies, NYISO's method derives from the pre-ISO era rates used by the NY Power Pool (NYPP). These power pool rates were later adopted during the formation of the NYISO on December 1, 1999.[13] NYISO provides Point to Point service with the Firm Point to Point rate including specific Transmission Owner charges needed to recover the embedded cost of transmission. As per the NYISO OATT Schedule H, the wholesale transmission service charge (TSC) recovers each Transmission Owner's embedded costs, as well as the transmission component of their control area costs, and is determined separately for each load zone. The TSC is adjusted to account for revenues from grandfathered

8 In accordance with Section II.25.3 of the ISO-NE OATT, a Transmission Customer pays to the ISO the RNS Rate for Through or Out Service reserved for it in accordance with Section II.24 of the ISO-NE OATT. The Transmission Customer shall also be obligated to pay any applicable ancillary service charges.

9 *New England Power Pool,* 83 FERC P. 61,045 at 61,237 (1998)

10 ISO New England Operating Procedure No. 9 Scheduling and Dispatch of External Transactions, https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op9/op9_rto_final.pdf

11 ISO-NE Transmission, Markets & Services Tariff, Section II25.3, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf#page=47 I

12 ISO-NE's rate per hour for Through or Out Service is the annual TOUT Rate divided by 8760. Similarly, the month rate is the annual divided by 12.

13 FERC Docket OA97-470 - FERC order establishing of New York Independent System Operator.

agreements, financial transmission rights, and congestion payments. The net of all these quantities for each Transmission Owner is divided by the total annual billing quantities (MWh) to give a $/MWh rate. The purpose of this rate design, developed by the Transmission Owners during the formation of the NYISO, was to allocate charges and revenues for exports and wheel-through transactions in a way that reflected the use of multiple Transmission Owners' facilities by a single transaction, as well as the divergence of revenue requirements for each Transmission Owner.

Per the NYISO formation Order: *"Export transactions and through transactions pay a charge based on the cost of the transmission provider that owns the intertie which serves as the point of delivery to the adjacent control area."*[14,15] Section 3.1.6 of the NYISO OATT provides details related to the curtailment of Firm Point to Point service *"In the event that a curtailment of the NYS Transmission System…Curtailments will be made on a non-discriminatory basis to the Transactions that effectively relieve the Constraint."*[16] Non-Firm Point to Point Transmission Service is not available in the markets administered by the NYISO.[17] Per the MOU described above, there are no Transmission Service Charges for transactions with Point of Delivery to the New England border.

3.3. Pennsylvania-New Jersey-Maryland Interconnection (PJM)

Under the guidance of FERC Order No. 888, PJM adopted a transmission service structure that includes firm and non-firm point-to-point transmission service to each zone in PJM and to the border of the PJM Region under Part II of the PJM Tariff ("Border Rate"). The ETS rate reflects the composite or average cost of service in the PJM Region under the principle that all of the facilities are available to provide such service.

The Border Rate does not apply to any point-to-point transmission service or network service to serve load in the Midcontinent Independent System Operator, Inc. (MISO). This reciprocal arrangement falls under the Joint Agreement between MISO and PJM and is incorporated in Schedules 7 and 8 that provide the Border Rate.[18]

The Border Rate level has not changed significantly since 2012. In 2019, PJM's proposed Tariff revisions were accepted by the FERC and included changes in the Border Rate calculation methodology going from the 12-month coincident peak sum to the sum of all zonal peak loads for the purposes of cost allocation and billing units for the rates; changes also included addition of a methodology for updating rates on an annual basis beginning after 2020 to more accurately reflect the cost of transmission and other services. This update also includes an annual update for zonal transmission system costs. The regulatory rationale

14 FERC Docket No. ER97-1523 Page 15

15 Note that "cost" refers to a total transmission cost burden assessed based on the zone in which the load is located (or, in the case of exports, the zone of exit), rather than a subset of costs for export and through or out service.

16 NYISO OATT, Section 3.1.6

17 NYISO OATT, Section 3.2 of

18 In Docket ER19-2105, the PJM TOs noted that under an agreement approved by the FERC, there is no charge under schedules 7 and 8 for points of delivery within the MISO region. The JOA is located here: https://www.pjm.com/directory/merged-tariffs/miso-joa.pdf

behind this move appears to be to lower the Border rate so that it is more comparable to the Network Integration Service[19] Rate charged to PJM customers for open access to the transmission system.[20]

3.4. Southwest Power Pool (SPP)

Order No. 888 principles were applied to the ETS rate design for SPP as well. Since the inception of the two organizations, there has been limited activity related to the update of design to ETS rates.

SPP Schedule 11 Through & Out rate is based on the sum of all base zonal ATRRs and 12 CP average system load and is offered on both a firm and non-firm basis. Schedules 7 (firm) and 8 (non-firm) also apply to point-to-point export service, where the transmission customer pays the zonal rate for the zone interconnected with the balancing authority area, external to the SPP region, that is the designated point of delivery. Where there is more than one Zone interconnected with such balancing authority area, the lowest zonal rate of the interconnected zones is applicable.

3.5. California ISO (CAISO)

CAISO uses energy-based determinants to derive its transmission rate. Firm annual billing units (MWh) are divided into total annual transmission revenue requirements for CAISO's high-voltage network system. Exports are charged the resulting high-voltage transmission access charge (HV-TAC) rate ($/MWh based) for each transaction.

In 2000, FERC approved a 10-year transition period to a uniform ISO-wide HV-TAC to encourage high-cost transmission facilities to join the ISO. Over the transition period, the ISO-wide high-voltage revenue requirement was blended with each transmission owner's individual high-voltage revenue requirement.[21]

In 2014, CAISO's OATT evolved to accommodate a Western Energy Imbalance Market (WEIM), a sub-hourly exchange of renewable power across multiple balancing authority areas[22] outside the ISO in the Western United States. CAISO's OATT assesses high-voltage wheeling access charges upon exports from transmission facilities with voltage ratings of 200 kV or higher. In 2014, FERC waived high-voltage wheeling access charges for exports sinking to WEIM-participating balancing authority areas.

In 2018, CAISO internally proposed redesigning its fully volumetric tariff to a hybrid energy-based and demand-based ETS rate. This proposal has been deferred.

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19 Network Integration Service relies on the use of the entire transmission network for transmitting energy; this differs from Point to Point service that assumes a particular receipt and delivery path.

20 FERC Docket ER19-2105, pp. 11 and 18

21 CAISO, 91 FERC 61,205 ¶ (2000).

22 A balancing authority is a utility or similar planning entity that plans generation and load for a small geographic area, the balancing authority area. In the case of the WEIM, balancing authorities will exchange power on a 15-minute basis.

3.6. Alberta Electricity System Operator (AESO)

AESO offers two rates: one a transmission rate from merchant interties (Rate XOM)[23] and the other an export transmission rate from an AESO network intertie (Rate XOS).[24] The primary billing determinant in Rates XOS and XOM is energy consumption, at a flat rate.

AESO's export service is non-firm, fulfilled only when sufficient capacity exists on the transmission system to accommodate the capacity scheduled for export.[25] The export service features the following attributes:

- A $500/month transaction fee is added for all participants which utilize the service.[26]
- The market participant may contract for export opportunity service for a term from one hour to one month.[27]
- Exports are subject to loss correction of 1%[28] and a trading charge of $0.38/MWh.[29]

Decision 2013-325[30] added the merchant rate export opportunity to the tariff with the same function, classification, and allocation of the AESO's revenue requirement as directed in Decision 2010-606.[31]

Decision 2013-421[32] plus a 2018 follow-up study for AESO tariff applications include cost allocation case studies that influence rates XOS and XOM. Please refer to Appendix C for more detail about the cost allocation studies.

Firm Rate Consideration

Alberta has a history of considering firm export rates; however current export rates continue to be offered only on a non-firm basis. Some of the issues and reasons for not implementing

23 AESO tariff, XOM rate, https://www.aeso.ca/rules-standards-and-tariff/tariff/rate-export-opportunity-merchant-service-xom/download/Rate-XOM-Effective-Jan-1-2021.pdf

24 AESO tariff, XOS rate, https://www.aeso.ca/rules-standards-and-tariff/tariff/rate-export-opportunity-service-xos/download/Rate-XOS-Effective-Jan-1-2021.pdf

25 Ibid.

26 Ibid.

27 Ibid.

28 Rider E Calibration Calculation Factor for the Fourth Quarter of 2020, https://www.aeso.ca/assets/Uploads/2020-Q4-Rider-E-Report-Layout.pdf

29 Energy market trading charge, https://www.aeso.ca/market/energy-market-trading-charge/

30 Decision 2013-325, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2013/2013-325.pdf

31 Decision 2010-606, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2010/2010-606.pdf

32 Decision 2013-421, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2013/2013-421.pdf

a firm rate were given include: congestion management, lack of sufficient transfer capability, reliability of the lines, and administrative complexities.[33] [34] [35] [36] [37]

3.7. TransÉnergie (Hydro-Québec)

Québec offers firm and non-firm point-to-point transmission service and uses demand as its primary point-to-point rate determinant. Decisions D-2016-029, D-2016-046, and D-2016-050[38] established HQ's firm (short and long term) and non-firm (short and long term) tariff terms.

Export rates are discounted for certain transactions.[39] Hydro-Québec offers discounts when it estimates that transactions are otherwise unlikely to clear at the full tariff rate, i.e., during times of low export pricing in neighboring jurisdictions. Discounting is based on allocation of export value between transmission generation assets. This is done on an opportunistic, market-based approach, rather than a set formula.

33 Decision 2002-99, p. 100, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2002/2002099.pdf

34 Decision 2005-096, Section 5.8, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2005/2005096.pdf

35 Decision 2007-106, Section 7, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2007/2007106.pdf

36 Decision 2010-606, Section 9.2, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2010/2010606.pdf

37 Firm rates were considered on the basis of the internal point system access service (Demand Transmission Service, “DTS”). The DTS comprises of components charged on a capacity and energy basis, including a Bulk System Charge, Regional System Charge, and Point of Delivery Charge. (https://www.aeso.ca/rules-standards-and-tariff/tariff/rate-dts-demand-transmission-service/download/Rate-DTS-Effective-Jan-1-2021.pdf)

38 Hydro-Québec OATT, Schedules 9 and 10, http://www.oatioasis.com/HQT/HQTdocs/HQT_OATT_2017_2016-12-13.pdf

39 Testimony of Philip Raphals, Peter Bradford, and E.O. Disher, 2000, https://www.rncreq.org/pdf/R-3401-98%20RNCREQ%20Rapport.pdf

Appendix A – Expanded Summary of 2020 ETS Rates

Table 3 – Summary of Rates for Export Transmission Service – As Reported in Native Tariffs

The ETS rates by jurisdiction are provided below – Note that MISO, PJM, NYISO, ISO-NE, SPP and CAISO rates are stated in USD; rates for Canadian jurisdictions stated in CAD.

		Annual Service $/kW-year	Monthly Service $/kW-month	Weekly Service $/kW-week	Daily On-Peak Service $/kW-day	Daily Off-Peak Service $/kW-day	Hourly On-Peak Charge $/MWh	Hourly Off-Peak Charge $/MWh	Schedule/Service Name
MISO	Firm	41.4593	3.4549	0.7973	0.1595	0.1136			Schedule 07: Long-Term and Short-Term Firm Point-To-Point Service Schedule 07: Michigan Long-Term and Short-Term Firm Service
	Non-Firm		3.4549	0.7973	0.1595	0.1136	9.9662	4.7328	Schedule 08 - Non-Firm Point-To-Point Transmission Service Schedule 08: Michigan Non-Firm Point-to-Point Transmission Service
PJM	Firm	18.888	1.574	0.3632	0.0726	0.0519			Schedule 7: Long-Term Firm and Short -Term Firm Point to Point Transmission Service
	Non-Firm		1.574	0.3632	0.0726	0.0519	4.54	2.16	Schedule 8: Non-Firm Point-to-Point Transmission Service
NYISO[3]		The energy-based rate for the Firm PTP service is different for each transmission company at the seam of NYISO, and it ranges between $3.25 per MWh (Hydro-Québec) to $6.12 per MWh (PJM).							Schedule 7: Firm Point-to-Point Transmission Service Schedule 8: Non-Firm Point-to-Point Transmission Service
ISO-NE[1]		129.26182							Schedule 8: A Transmission Customer shall pay to the ISO the Pool PTF Rate for Through or Out Service reserved Schedule 9: Provides the pool PTF rates for ISO-NE
SPP[5]	Firm	6.8691	0.5724	0.1321	0.0264	0.0189			Schedule 11: Through and Out Zonal Point-to-Point Service
	Non-Firm		0.5724	0.1321	0.0264	0.0189	1.651	0.784	
CAISO[4]								12.5201	Schedule 3: Regional Access Charge and Wheeling Access Charge
Trans-Énergie[2]	Firm	78.06	6.51	1.50	0.30				Schedule 9 : Long-Term and Short-Term Firm Point-to-Point Transmission Service
	Non-Firm		6.51	1.50	0.30		6.51		Schedule 10: Non-Firm Point-to-Point Transmission Service
Alberta[4]							8.28		Export Opportunity Service, Export Opportunity Merchant Service (for merchant lines)
Ontario[6]							1.85		ETS Rate Schedule included as part of Ontario Uniform Transmission Rate Schedule

1. ISO-NE does not distinguish between Firm and Non-Firm transactions and does not offer monthly, weekly, or daily transmission services. It offers hourly transmission service, and this is noted in Table 1 of Section 3 of this report.
2. TransÉnergie offers the same daily transmission service regardless of time of day.
3. Non-firm service not offered.
4. Firm service not offered.

5. Schedules 7 and 8 rates also apply on a zonal basis for Point-to-Point transactions, in a range of $13.3/kW-year to $56.7/kW-year for annual firm service, and $1.52/MWh to $6.47/MWh non-firm.
6. Not clearly defined as either firm or non-firm, although rate is specified on energy basis and line capacity cannot be reserved for extended periods, therefore implied non-firm.

Table 4 – Summary of Rates for Export Transmission Service – All Stated in CAD

The ETS rates by jurisdiction are provided below - *All US market USD values converted at January 20, 2021 rate of 0.79 CAD/USD (source based on Bank of Canada daily rates - https://www.bankofcanada.ca/rates/exchange/daily-exchange-rates/).*

		Annual Service $/kW-year	**Monthly Service $/kW-month**	**Weekly Service $/kW-week**	**Daily On-Peak Service $/kW-day**	**Daily Off-Peak Service $/kW-day**	**Hourly On-Peak Charge $/MWh**	**Hourly Off-Peak Charge $/MWh**
MISO	Firm	52.4801	4.3733	1.0092	0.2019	0.1438		
	Non-Firm		4.3733	1.0092	0.2019	0.1438	12.6154	5.9909
PJM	Firm	23.9089	1.9924	0.4597	0.0919	0.0657		
	Non-Firm		1.9924	0.4597	0.0919	0.0657	5.7468	2.7342
NYISO[3]		The energy-based rate for the Firm PTP service is different for each transmission company at the seam of NYISO, and it ranges between $4.11 per MWh (Hydro-Québec) to $7.75 per MWh (PJM).						
ISO-NE[1]		163.6226						
SPP[5]	Firm	8.6951	0.7246	0.1672	0.0334	0.0239		
	Non-Firm		0.7246	0.1672	0.0334	0.0239	2.0899	0.9924
CAISO[4]								15.8482
Trans-Énergie[2]	Firm	78.06	6.51	1.50	0.30			
	Non-Firm		6.51	1.50	0.21		8.91	
Alberta[4]							8.28	
Ontario[6]							1.85	

1. ISO-NE does not distinguish between Firm and Non-Firm transactions and does not offer monthly, weekly, or daily transmission services. It offers hourly transmission service, and this is noted in Table 1 of Section 3 of this report.
2. TransÉnergie offers the same daily transmission service regardless of time of day.
3. Non-firm service not offered.
4. Firm service not offered.

5. Schedules 7 and 8 rates also apply on a zonal basis for Point-to-Point transactions, in a range of $16.8/kW-year to $71.8/kW-year for annual firm service, and $1.92/MWh to $8.19/MWh non-firm.
6. Not clearly defined as either firm or non-firm, although rate is specified on energy basis and line capacity cannot be reserved for extended periods, therefore implied non-firm.

Table 5 – Energy-Only Rates for Export Transmission Service – All Stated in CAD$/MWh

The ETS rates by jurisdiction are provided below – *Note that all rates are stated on CAD$/MWh basis, converted at 100% load factor, and January 20th, 2021 exchange rate of 0.79 CAD/USD.*

		Annual Service $/MWh	Monthly Service $/MWh	Weekly Service $/MWh	Daily On-Peak Service $/MWh	Daily Off-Peak Service $/MWh	Hourly On-Peak Charge $/MWh	Hourly Off-Peak Charge $/MWh
MISO	Firm	5.9909	5.9908	5.9909	8.4124	5.9916		
	Non-Firm		5.9908	5.9909	8.4124	5.9916	12.6154	5.9909
PJM	Firm	2.7293	2.7293	2.7291	3.8291	2.7373		
	Non-Firm		2.7293	2.7291	3.8291	2.7373	5.7468	2.7342
NYISO[3]		The energy-based rate for the Firm PTP service is different for each transmission company at the seam of NYISO, and it ranges between $4.11 per MWh (Hydro-Québec) to $7.75 per MWh (PJM).						
ISO-NE[1]		18.6784						
SPP[5]	Firm	0.9926	0.9925	0.9926	1.3924	0.9968		
	Non-Firm		0.9925	0.9926	1.3924	0.9968	2.0899	0.9924
CAISO[4]								15.8482
Trans-Énergie[2]	Firm	8.9110	8.9178	8.9041	12.5000			
	Non-Firm		8.9178	8.9041	8.7500		8.91	
Alberta[4]							8.28	
Ontario[6]							1.85	

1. ISO-NE does not distinguish between Firm and Non-Firm transactions and does not offer monthly, weekly or daily transmission services. It offers hourly transmission service, and this is noted in Table 1 of Section 3 of this report.
2. TransÉnergie offers the same daily transmission service irrespective of time of day.
3. Non-firm service not offered.
4. Firm service not offered.

5. Schedule 7 and 8 rates also apply on a zonal basis for Point-to-Point transactions, in a range of $1.52/MWh to $6.47/MWh.
6. Not clearly defined as either firm or non-firm, although rate is specified on energy basis and line capacity cannot be reserved for extended periods, therefore implied non-firm.

Appendix B – Rate Adders

Table 6 – MISO Ancillary Services and Other Charges Applicable to ETS Transactions (USD)

MISO			
Item	**Peak $/MWh**	**Off-Peak $/MWh**	**Source**
Scheduling, System Control, and Dispatch Service	0.1901	0.0903	Schedule 1
Reactive Supply and Voltage Control	0.4859	0.2308	Schedule 2
ISO Cost Recovery Adder	0.1144	0.1144	Schedule 10
Network Upgrade Charge for Transmission Expansion Plan	0.8865	0.4210	Schedule 26
Black Start Service	0.0080	0.0038	Schedule 33
Cost Recovery of NERC Recommendation or Essential Action	0.0197	0.0094	Schedule 45
FTR-related	0.0072	0.0072	Schedule 16
Market Administration	0.0932	0.0932	Schedule 17
Local Balancing Authority Cost Recovery	0.0127	0.0127	Schedule 24
Total Charges	***1.8177***	***0.9828***	

Table 7 – PJM Ancillary Services and Other Charges Applicable to ETS Transactions (USD)

PJM		
Item	**$/MWh**	**Source**
PJM Administrative Fees	0.47	2019 State of the Market Report for PJM - Introduction Table 1-10
NERC/RFC	0.03	
Voltage Control	0.44	
Black Start	0.08	
Operating Reserve	0.04	
Regulation & Frequency Control	0.12	
Synchronized Reserve	0.04	
Transmission Owner (Schedule 1A)	0.09	
Transmission Enhancement Cost Recovery	0.55	
Total Charges	***1.86***	

Table 8 – NYISO Ancillary Services and Other Charges Applicable to ETS Transactions (USD)

NYISO		
Item	**$/MWh**	**Source**
NYISO Cost of Operations	0.73	NYISO Monthly Report - Appendix B Page 38 (Updated to October 2020)
FERC Fee Recovery	0.10	
Voltage Support and Black Start	0.45	
Operating Reserve	0.61	
Regulation & Frequency Control	0.11	
Uplift: Statewide Share	(0.13)	
Total Charges	***1.87***	

Table 9 – ISO-NE Ancillary Services and Other Charges Applicable to ETS Transactions (USD)

ISO-NE			
Item	**$/MWh**	**$/kW-year**	**Source**
Scheduling, System Control, and Dispatch Service	0.199	1.745	Schedule 1
Reactive Supply and Voltage Control Service	0.125	1.093	Schedule 2
Total Charges	***0.324***	***2.838***	

Table 10 – SPP Ancillary Services and Other Charges Applicable to ETS Transactions (USD)

	SPP		
Item	**Peak $/MWh**	**Off-Peak $/MWh**	**Source**
Scheduling, System Control, and Dispatch Service	0.3060	0.1450	Schedule 1
Tariff Administrative Charges	0.3130	0.3130	Schedule 1A
Reactive Supply and Voltage Control	0.0040-0.6580	0-0.0200	Schedule 2
FERC Assessment Charge	0.0834	0.0834	Schedule 12
Total Charges	***0.7064-1.3604***	***0.5414-0.5614***	

Table 11 – TransÉnergie Ancillary Services and Other Charges Applicable to ETS Transactions (CAD)

	TransÉnergie						
Item	**Annual per kW reserved**	**Monthly per kW reserved**	**Weekly per kW reserved**	**Daily Firm per kW reserved**	**Daily Non-Firm per kW reserved**	**Daily Non-Firm per kW reserved**	**Source**
System Control Service	Currently this is not a separate rate and is included in transmission charge.						Schedule 1
Voltage Control Service	0.31	0.03	5.96	1.19	0.85	0.04	Schedule 2
Frequency Control Service	0.31	0.03	5.96	1.19	0.85	0.04	Schedule 3
Energy Imbalance Receipt - shortfall	Imbalance service charges are calculated and applied based on conditions in neighboring markets at time of service.						Schedule 4
Energy Imbalance Delivery - excess							Schedule 5
OR – Spinning Reserve	1.15	0.10	22.12	4.42	3.15	0.13	Schedule 6
OR – Non–Spinning Reserve	0.57	0.05	10.96	2.19	1.56	0.07	Schedule 7
Total Charges	***2.34***	***0.21***	***45.00***	***8.99***	***6.41***	***0.28***	

Appendix C – AESO's OATT Cost Causation Study

London Economics International LLC developed transmission cost causation studies for the years 2014–2016 and 2018–2020 to support AESO's tariff filings. The transmission cost allocation studies set functionalization and classification values for the AESO tariff. The 2014 and 2018 cost causation studies analyze four key areas: (i) functionalization of transmission facility owner related capital costs, for both existing and planned assets; (ii) functionalization of related operations and maintenance costs; (iii) classification of all costs functionalized as bulk and regional; and (iv) implementation considerations (i.e., discussion of the potential impact of implementing the functionalization and classification results on rates/recovery of the revenue requirement). The 2018 study involves an identical analysis using updated inputs that became available since the time the 2014 study was performed.

Though these studies are not specific to export rates, they influence the $/MWh transmission rates developed in Rates XOS and XOM. For example, in accordance with Section 34 of the Transmission Regulation in Alberta's Electric Utilities Act,[40] the cost of transmission losses is allocated to generators, export and import services, and demand opportunity service.

Each year, the cost allocation studies are updated to reflect the Tariff year's forecast revenue requirement, wires costs functionalization and classification, and forecast billing determinants.[41] Rates XOS and XOM (specifically, levels of dollar-based and percentage of pool price amounts) are allocated according to their cost burden on the entire transmission system.

AESO's 2021 Tariff includes the cost causation study framework for the entire transmission system, with updated calculations for 2021, in Appendix B. Allocations to export rates are found in Tab B-11.[42]

The calculation for determining the $8.24/MWh XOS/XOM rate based on the 2018-2020 transmission cost allocation study is as follows:

40 Province of Alberta, Electric Utilities Act (2007) https://www.qp.alberta.ca/documents/Regs/2007_086.pdf

41 Alberta Electric System Operator 2018 ISO Tariff Compliance Filing Pursuant to Decision 22942-D02-2019 and 2020 ISO Tariff Update Application, January 31, 2020, https://www.aeso.ca/assets/Uploads/25175-X0002-2018ISOTariffComplianceFilingandUpdateAp-0002.pdf

42 Alberta Electric System Operator 2021 ISO Tariff Application, November 12, 2020 https://www.aeso.ca/assets/Uploads/AESO-2021-ISO-Tariff-Update-Application.pdf, Appendix B, Tab B-11 https://www.aeso.ca/assets/Uploads/Appendix-B-2021-Rate-Calculations.xlsx

Component	Fixed		Usage		Total	
Export Opportunity Service (XOS/XOM) Rates	**XOS/XOM, $/MWh**					
Connection – Bulk System	$	3.46	$	1.21	$	4.67
Connection – Regional System		1.58		0.92		2.50
Connection – POD		-		-		-
Operating Reserve		-		1.07		1.07
Voltage Control		-		-		-
Other System Support		-		-		-
Total XOS Costs	$	5.03	$	3.20	$	8.24

Source: see footnote 40

Market Implications of the Export Transmission Service Rate

July 2021

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1. Executive Summary

In this report, the Independent Electricity System Operator (IESO) addresses the market implications of the Export Transmission Service (ETS) rate in response to the Ontario Energy Board's (OEB) Decision and Order in EB-2019-0082. The report presents an overview of intertie trading in Ontario in light of the recent market rule changes, discusses the implications of an increased ETS rate for the Ontario market, and comments on jurisdictional comparisons and the suitability of the OEB's pole attachment approach for setting the ETS rate.

When considering any adjustment of the ETS rate, it is important for the OEB and interveners to appreciate the following aspects of intertie trading:

- **Intertie trading is a competitive marketplace:** As part of the regular operation of the electricity market, Ontario efficiently imports and exports electricity on an hour-by-hour basis delivered across interties with two Canadian provinces (Manitoba and Quebec) and three U.S. states (Minnesota, Michigan, and New York). Electricity trading over the interties is a competitive marketplace driven by profit-seeking traders transacting based on the expected electricity price differences between jurisdictions. These factors make intertie capacity a scarce resource resulting in traders competing for access to these resources.
- **Exports from Ontario provide operational and economic benefits:** In operational terms, interties provide flexibility that enable system operators to address power system needs and reliably manage the grid during changing system conditions. From an economic standpoint, exports of energy from Ontario have contributed approximately $330-520 million annually to Ontario between 2017 and 2020. Intertie trading reduces total costs for Ontario consumers by generating revenues, contributing to fixed system costs and avoiding incremental system costs.
- **Exporters contribute to the costs of the transmission system through "congestion rent":** In addition to paying the ETS rate, intertie traders exporting energy from Ontario pay the Intertie Congestion Pricing (ICP), a dynamic charge set based on its market value to traders, administered through the IESO-administered market. ICP revenues are collected entirely from intertie importers and exporters for the purpose of offsetting transmission service charges paid for all transmission customers. Since 2017, an average of $160 million per year of ICP revenue has been returned in reduced transmission costs, the majority of which has gone to domestic consumers.
- **Market design changes**: Market design changes since 2015 provide greater certainty on how Transmission Rights Clearing Account (TRCA) funds are disbursed. ICP revenues are now distributed on a semi-annual basis. The IESO also improved the design of the Transmission Rights market to increase the amount of revenues available to be disbursed and change the proportion of the distribution to return almost all available funds to domestic consumers.

The 2021 Elenchus Report[1] presents three ETS rate options based on different cost allocation methodologies ($6.54/MWh, $3.66/MWh, and $5.42/MWh respectively). Each ETS rate option

[1] EB-2021-0110, Exhibit H-09-01-01

represents a significant increase over the approved 2020 ETS rate of $1.85/MWh and is outside of the historical range for the ETS rate ($1-2/MWh).

The IESO expects the market implications of a higher ETS rate would be as follows:

- **Corresponding decrease in ICP revenue:** The IESO expects that any increase in revenue resulting from a higher ETS would be offset by an equivalent reduction in revenue from the ICP, which in turn will decrease the amount of disbursements from the TRCA paid to Ontario consumers. The ICP and ETS are both transaction costs that negatively impact the profit margins of competitive intertie trade. The ICP and ETS have an offsetting relationship such that an increase in the ETS will lead to a proportionate decrease in the ICP. This offsetting relationship means that, assuming the quantity of exports remains constant, the overall value that Ontario ratepayers derive from exports would remain unchanged even if the ETS rate is increased.
- **Reduction of exports and adverse impact to operational/economic benefits:** Exports are highly price-sensitive. A higher ETS would have the effect of reducing energy exports from Ontario and by extension the operational and economic benefits that those lost exports provide. In contrast to the dynamic nature of the ICP, the ETS is a fixed charge applied on all exports regardless of market conditions. This means there will be occasions when market conditions are such that the ETS charge will make exports uneconomic and prevent an otherwise economic export from transacting. Even a relatively small increase in the ETS rate beyond the historical range of $1-2/MWh could have a material impact on heavily traded interties where price margins are already small. Less exports will mean less operational and economic benefits provided by exports, which is likely to increase system costs for domestic consumers. Prior analysis demonstrates that in one case increasing the ETS rate from $0 to $5.80/MWh would cause a 50% reduction in export volumes (expressed as a percentage of status quo volumes).[2]

Revenue from the ETS is only one component of the value that Ontario receives from exports and historically has been the smallest component of the economic benefits associated with exports. When setting the ETS, consideration should be given to maximizing the operational and economic benefits provided by exports by minimizing transaction costs. Any increase in the ETS rate will reduce the value of interties, leading to less system flexibility and higher costs for Ontario consumers.

2. Introduction

In its Decision and Order in EB-2019-0082, the OEB directed Hydro One Networks Inc. (HONI) to consult with the IESO in the preparation of an updated ETS jurisdictional review that includes an assessment of market implications:

> *File an updated ETS jurisdictional review that provides the rates in other jurisdictions, rationale behind those rates and market implications. Hydro One is expected to discuss the approach to a jurisdictional review with the IESO and OEB*

[2] IESO internal analysis based on data presented in Export Transmission Service (ETS) Tariff Study, Charles River Associates, May 16, 2012, Pg. 18-20

staff to determine the best approach to complete a review before Hydro One's next transmission rebasing application[3].

The last ETS jurisdictional review was prepared by Charles Rivers & Associates (CRA) in 2012 as part of a stakeholder engagement undertaken by the IESO (the 2012 CRA Study)[4]. The 2012 CRA Study was filed with the OEB in EB-2012-0031 and was the subject of an extensive review in that proceeding. In addition to reviewing tariff rates and structures in neighbouring markets, the 2012 CRA Study assessed the implications of various ETS options on the Ontario electricity market as a whole.

HONI has retained Elenchus Research Associates Inc. (Elenchus) to prepare an update to the Export Transmission Service Rate Cost Allocation Methodology Report (the 2021 Elenchus Report) in response to the OEB's direction in EB-2019-0082. The 2021 Elenchus Report presents three ETS rate options based on different cost allocation methodologies ($6.54/MWh, $3.66/MWh, and $5.42/MWh respectively). Each ETS rate option represents an increase over the approved 2020 ETS rate of $1.85/MWh and is outside of the historical range for the ETS rate ($1-2/MWh).

The 2021 Elenchus Report contains a review of cost allocation methodologies used in other North American jurisdictions and concludes that transmission rate-setting in Ontario differs considerably from the processes used in these jurisdictions. One cost allocation methodology in the 2021 Elenchus Report incorporates principles from the OEB's decision on Pole Attachment Charges (EB-2015-0304).

The 2021 Elenchus Report does not examine the implications of a higher ETS rate for the Ontario electricity market as a whole. HONI and the IESO have agreed that, given the IESO's role as system operator, it would be appropriate for the IESO to perform a qualitative review of the implications of a higher ETS rate on the Ontario electricity market. Given the significant time and expense already incurred to study the ETS rate, the IESO's view was that the current work should avoid unnecessary duplication of past studies and focus on new and informative insights.

In EB-2012-0031, the IESO concluded that, based on the 2012 CRA analysis, reducing ETS rate to zero "would best encourage the efficient use of electricity and promote economic efficiency in the generation, transmission and sale of electricity"[5]. There was however uncertainty at the time as to the extent to which ICP revenues (also referred to as "congestion rent") would defray domestic consumer costs[6] and, as the IESO acknowledged, this uncertainty meant the zero ETS rate would result in increased consumer costs unless ICP revenues were allocated to consumer costs[7]. The OEB determined that, while it may be appropriate to depart from strict cost causality where there will be demonstrable and significant benefits from an alternative approach, it was not justified considering the uncertainties around the benefits of a more efficient market.

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[3] EB-2019-0082 Decision and Order, April 23, 2020, Pg. 183

[4] Export Transmission Service (ETS) Tariff Study – Review of Rates in Neighbouring Markets, Charles River Associates, May 16, 2012

[5] IESO Submission in EB-2012-0003, March 8, 2013, Pg. 5

[6] As noted by the OEB, *"There was disagreement amongst the experts, and amongst the parties, as to how the allocation of the producer surplus and ICR [ICP] should be viewed. The allocation of these amounts to Ontario consumers, either directly or indirectly, impacts which ETS rate option appears to provide the greatest benefit",* OEB Decision and Order for 2013 Export Transmission Service Rate, June 6, 2013, Pg. 6

[7] IESO Submission to EB-2012-0031, March 8, 2013, Pg. 10

Exporters contribute to the cost of the transmission system through two mechanisms. The first mechanism is through the ETS rate, a fixed volumetric charge, which is the focus of this rate application. The second mechanism is through the ICP mechanism, a dynamic charge set based on its market value to traders, administered through the IESO-administered market. ICP revenues are collected entirely from intertie importers and exporters for the purpose of offsetting transmission service charges[8].

Since the 2012 CRA study, the IESO has passed market design changes that have clarified how ICP revenues reduce transmission costs for ratepayers. Since 2017, the ICP mechanism has disbursed approximately $160 million per year, primarily to domestic customers to offset transmission charges in addition to the approximately $30-40 million per year collected from exporters through the ETS rate.

In this report, the IESO will present an overview of intertie trading in the Ontario market in light of the recent rule changes, discuss the implications of an increased ETS for the Ontario market, and comment on jurisdictional comparisons and the suitability of the OEB's pole attachment approach for setting the ETS rate.

3. Overview of Intertie Trading in the Ontario Market

The Competitive Nature of Intertie Trading

As part of the regular operation of the electricity market, Ontario imports and exports electricity on an hour-by-hour basis delivered across interties with two Canadian provinces (Manitoba and Quebec) and three U.S. states (Minnesota, Michigan, and New York).

Being part of an interconnected grid means that Ontario has the ability to simultaneously export and import power across multiple locations as part of the regular operation of its electricity market, to provide operational and planning flexibility, as well as enhance the reliability, resiliency and cost-effectiveness of the electricity system. The operational and economic benefits of intertie trading is discussed in greater detail below.

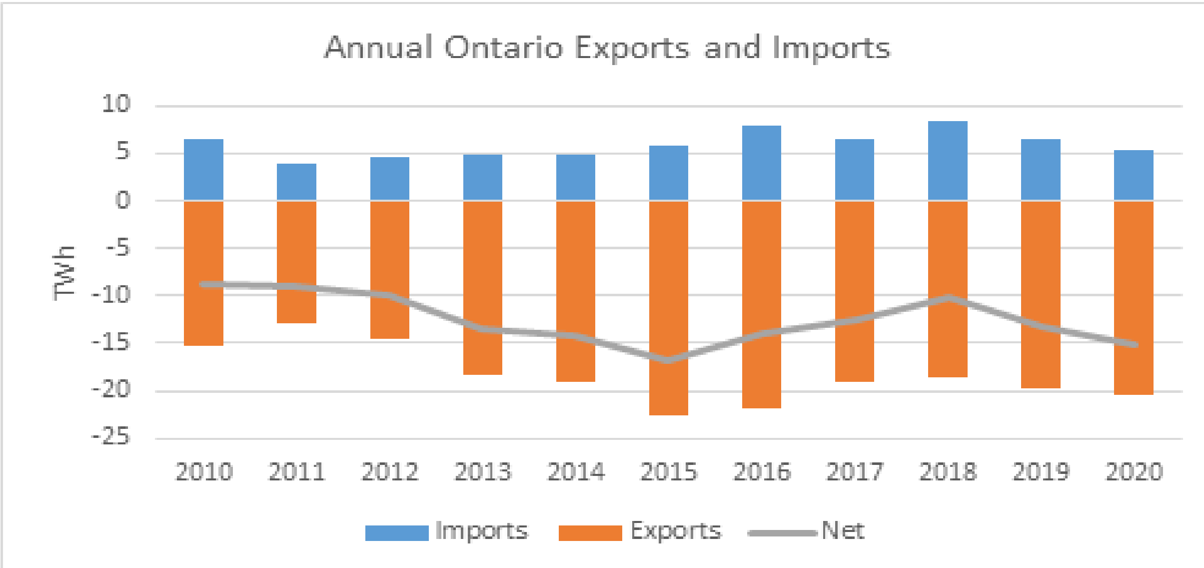
Electricity trading over the interties is a competitive marketplace driven by profit-seeking traders transacting based on the expected electricity price differences between jurisdictions. Traders look for "price spread" opportunities across the different interconnected markets and make profit when they can buy energy at a lower price in one jurisdiction and export it to another jurisdiction to be sold for a higher price. Electricity prices can differ between jurisdictions for a variety of reasons, including different supply mix characteristics, weather, demand patterns, as well as market and system conditions.

For example, if Ontario is expecting a surplus of energy during the overnight hours, electricity market prices in Ontario would likely be lower relative to its neighbouring jurisdictions, signaling a trading

[8] IESO Market Rules, Chapter 8, Section 4.18.2.

opportunity. A trader could export power from Ontario and earn a profit equal to the price differences between the two jurisdictions less any transaction costs. In the case of an export from Ontario, the relevant transaction costs include the ETS, the ICP and Uplifts. The impact of these factors on intertie trading is explored further below.

Historically, Ontario has been a net exporter of electricity, primarily to the U.S. jurisdictions, and a net importer from Quebec.



Source: IESO Power Data (https://www.ieso.ca/en/power-data/supply-overview/imports-and-exports)

The Role of Intertie Trading in System Planning

The IESO undertakes reliability assessments to ensure the system meets the needs of domestic consumers. Ontario's interties provide reliability benefits (e.g., supply and demand balancing, frequency and regulation control, and other emergency measures), and the IESO plans the system, in accordance with established planning standards, to ensure export capability is sufficient to maintain system reliability and operability. However, the needs and activities of competitive exporters (e.g., volume and direction of transactions) are not considered when planning the transmission system, and so are not a primary driver of investment.

Considering this further, the electricity system in Ontario is designed to simultaneously supply domestic load and exports, at the full capability of the interties, for only a limited set of system conditions. When designing the system, the focus is on ensuring that domestic load can be supplied for a wide a range of system conditions. For many of these conditions planning standards do not require the system to support exports simultaneously.

It is also important to note that while the IESO provides market participants and consumers with the same access to grid service,[9] the way the system is designed and the priority given to exporters results in exports being subject to more frequent service interruption compared to domestic load. Exporters can be curtailed for more reasons than Ontario consumers, including internal

[9] See Electricity Act, 1998, SO 1998, c. 15, Schedule A, Section 26 (Non-discriminatory access)

adequacy or reliability issues in neighbouring jurisdictions. As a result, the IESO curtails exports for reliability reasons more often than domestic load.[10]

In summary, IESO planning assessments do consider maintaining export capability where required to ensure system reliability and operability, but do not specifically consider competitive exporter activity. Exporters have the same access to the transmission system as other market participants but they have lower priority than domestic load and this is reflected in the planning standards. Thus, from a system planning perspective, investments made within Ontario are primarily for supplying domestic load. On this basis, competitive exports are not a key driver of investment cost to the transmission system in Ontario.

The Operational Benefits of Intertie Trading

Interties with neighbouring jurisdictions provide a range of operational benefits and enhance system reliability for Ontario consumers. In operational terms, interties provide flexibility that enable system operators to address power system needs and reliably manage the grid during changing system conditions.

The operational benefits provided by intertie trading include:

- **System Flexibility:** Intertie trading provides flexibility hour-by-hour to balance supply and demand in Ontario, including for response to near to real-time needs (e.g., unexpected generation or transmission outage) and other operational issues such as surplus baseload generation (SBG)[11]. Beyond SBG, interties also provide flexibility to balance the system resulting from changes in weather, demand patterns and other market conditions.
- **Ancillary Services:** Intertie trading helps maintain stability to the system through frequency and voltage regulation, and operating reserve. This is particularly so in real-time operations where interties help maintain system frequency and voltage to enable a reliable grid for Ontario consumers.
- **Regional Reliability:** Intertie trading supports regional grid reliability through the Simultaneous Activation of Reserve (SAR) program. SAR is a voluntary program with neighbouring jurisdictions to jointly activate reserves when one of the jurisdictions suffers a supply loss ≥500 MW. In this respect the interties enable Ontario to assist other jurisdictions during contingency events and support regional reliability.
- **Emergency Events:** In addition to the system flexibility that interties provide to manage unexpected events (e.g., one-off generation outages) they also provide support for emergency events (e.g., major system disruption) in Ontario through emergency imports. While the system is planned, built and operated to high levels of reliability based on Ontario resources, the interties provide the ability to draw on additional support from neighbouring jurisdictions during emergencies to maintain reliability for domestic consumers.

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[10] Based on internal analysis, the IESO has curtailed export annually between 18-35% of all hours since 2016

[11] SBG occurs when domestic supply exceeds domestic demand. In these situations, interties provide flexibility to balance the grid by flowing electricity out of the province to neighbouring jurisdictions. In this respect, interties avoid the need for costly shut-down of domestic supply resources to balance the grid

- **Geographical Distribution:** The geographical distribution of interties around Ontario ensure all regions have access to the operational benefits of interties, and can support with local and system-wide reliability.

Intertie trading provides a range of operational benefits including system flexibility to balance supply and demand, and ancillary services to support grid stability. Interties also play a key role supporting system operations during unplanned or emergency events. From a broader perspective, interties support regional grid reliability and enable Ontario to assist other jurisdictions during contingency events.

The Economic Benefits of Exports

From an economic standpoint, exports of energy from Ontario have contributed between $330-520 million of value annually[12] to Ontario between 2017 and 2020 as shown on Table 1. Intertie trading reduces total costs for Ontario consumers by generating revenues, contributing to fixed system costs and avoiding incremental system costs.

Table 1: Value from Exports 2017-2020

$Millions	2017	2018	2019	2020
Congestion Rents Collected from Exports	208	191	134	99
Export Transmission Service Tariff (ETS)	35	34	37	38
Uplift collected from Exports	43	52	48	38
Avoided System Costs[13]	180	240	190	153
Total Value from Exports	**466**	**517**	**409**	**327**

Source: internal IESO analysis

Each of the identified economic benefits of exports are described in more detail below:

- **Congestion Rents:** As detailed in the next section, the IESO allocates access to the interties based on economics. When demand for intertie access is greater than the physical capability, the intertie is considered "congested" and traders are charged "congestion rent" in the form of the ICP – a premium for access based on willingness-to-pay. The ICP is collected by the IESO and ultimately disbursed back to domestic consumers and exporters to offset transmission service charges.[14] Since 2017, an average of approximately $160 million per year has been paid out in disbursements, the majority of which has been disbursed to domestic consumers.[15]

[12] Range of total value from exports 2017-2020. For more details, see Table 1

[13] Based on avoided nuclear and renewable resource curtailment, equal to 14TWh, 12TWh, 13TWh and 14TWh for 2017-20 respectively

[14] Revenue collected by the IESO from intertie congestion flows into the TRCA, which then disburses funds to market participants (domestic load and exporters) to offset transmission costs, Market Rules, Chapter 8, Section 4.18.2. The disbursement methodology is defined in the Market Rules, Chapter 9, Section 4.7. See Market Rule amendment: https://www.ieso.ca/-/media/Files/IESO/Document-Library/tp/2020/iesotp-20200623-mr-00443-tr-clearing-account-amendment-proposal.ashx

[15] Average of TRCA disbursements 2017-2020. For more details, see Table 2

- **ETS:** Exporters contribute to the costs of maintaining a reliable transmission system by paying ETS and Uplift. The IESO typically collects between $30 and 40 million per year[16] through ETS which is charged each time an exporter flows electricity out of Ontario. ETS revenues collected are used to reduce transmission costs paid by domestic consumers.
- **Uplift**: Exporters also contribute approximately $40-50 million per year[17] in uplift charges for system reliability provided through Ancillary Services and Operating Reserve. The export contribution reduces the cost that has to be recovered from domestic consumers for these services.
- **Avoided System Costs**: Intertie trading helps Ontario avoid additional system costs that would otherwise have been incurred. From an economic efficiency standpoint, imports enable energy providers from outside the province to compete and displace more expensive domestic suppliers to meet Ontario's electricity needs at the lowest cost. Equally, exporters reduce the operational system cost by taking surplus energy out of Ontario when demand is low. This brings in revenue to cover fixed costs and avoids curtailing wind resources, spilling water at hydroelectric stations and maneuvering of nuclear units. Without exports, Ontario consumers would have to pay for the cost of the foregone energy that is spilled or curtailed. Between 2017 and 2020, this would likely have added $150-240 million per year[18] to Global Adjustment which would be recovered from domestic consumers.

As can be seen from Table 1, revenue from the ETS is only one component of the value that Ontario receives from exports and historically has been the smallest component of the economic benefits associated with exports. As such, it is important to consider the implications of increasing the ETS rate for exports on the other economic benefits that exports provide for Ontario consumers.

The Intertie Congestion Price

There is a maximum quantity of energy that can be transacted over a specific intertie at one time due to the physical limitations of the respective intertie. As noted above, electricity trading over the interties is a competitive marketplace driven by profit-seeking traders transacting based on the expected electricity price differences between jurisdictions. These factors make intertie capacity a scarce resource resulting in traders competing for access to these resources.

When there is more export demand than available intertie capacity, exporters compete for scarce intertie capacity by paying the ICP – a premium based on their willingness-to-pay. The ICP is set hourly based on competitive trader bids indicating how much they would be willing to pay to export over the intertie for a specific hour. The highest bids are accepted to export over the intertie during the given hour. This willingness-to-pay approach of the ICP means intertie access to flow exports is fairly allocated to the competitive traders who value the export service highest for the given time period.[19]

An important feature of the ICP is that it is dynamic and automatically adjusts with the value of the intertie capacity, which itself is dependent upon hourly market conditions. If hourly wholesale market prices are expected to be lower in Ontario relative to its neighbouring jurisdictions, traders will

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16 ETS collected 2017-2020. For further details, see Table 1

17 Uplifts collected from exporters 2017-2020. For further details, see Table 1

18 Average of avoided curtailments through exports 2017-2020. For further details, see Table 1

19 Exports are scheduled on an hourly basis

compete against one another by bidding up the price for intertie access relative to expected profit conditions. Increased competition and willingness-to-pay to flow the electricity out of Ontario will increase the ICP for which exports are charged.

For example, the ICP on the intertie to Michigan (where there has historically been high demand to export) averaged $19/MWh[20] in 2017 while annual prices on the Minnesota and New York interties are in the range of $7-9/MWh.

Market Design Changes

Revenues from the ICP are collected by the IESO in the Transmission Rights Clearing Account (TRCA). In addition to ICP revenue, the TRCA also contains revenue from Transmission Rights (TR) auctions. TRs are a financial contract that entitle their holder to a share of the ICP revenue on the intertie specified in the contract. TRs do not involve any use of the physical transmission system, and do not entitle the purchasers of the rights to utilize the transmission assets. By purchasing a TR, the TR holder gains insurance against changes in the ICP on the specified intertie (which can be unpredictable and volatile).

The IESO pays the TR holders from the ICP revenues. Revenues from the TR auction plus any residual ICP revenues after payments to TR holders are disbursed, subject to a TRCA balance threshold, on a semi-annual basis to domestic consumers and exporters to offset transmission costs.

As shown in Table 2, approximately $160 million per year has been paid out in disbursements since 2017.

Table 2: TRCA Historical Flows 2017-2020

$Millions	2017	2018	2019	2020	Average
Total Allocated TR Auction Revenues	153	156	136	93	134
Congestion Rents Received from the Market[21]	219	208	137	105	167
Interest earned on TR Bank Account	1	2	3	1	2
Payments to TR Rights Holders	(206)	(173)	(135)	(86)	(150)
TR Clearing Account Disbursement[22]	(173)	(188)	(149)	(118)	(157)

Source: IESO Power Data (https://www.ieso.ca/en/Power-Data/Monthly-Market-Report)

As part of the OEB's 2012 ETS Decision[23], the OEB expressed uncertainty as to the extent to which ICP revenues defray domestic consumer costs and, as the IESO acknowledged, this uncertainty meant the zero ETS rate would result in increased consumer costs unless ICP revenues were allocated to consumer costs.

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[20] Based on ICP prices on the Michigan intertie which averaged $19/MWh in 2017

[21] Includes congestion rents received from both Export and Import

[22] The TRCA disbursements do not clear the TRCA balance due to a combination of a) maintaining the reserve threshold as defined in Chapter 8, section 4.18 of the Market Rules, and b) time-lag between collection of revenues from Congestion Rents and TR Auctions and disbursement

[23] EB-2012-0031 Decision and Order, June 6, 2013

The IESO is continuously improving and evolving the wholesale electricity market to ensure system reliability, resilience, and efficiency to meet the system needs. Since the 2012 CRA Analysis was performed, the IESO has implemented a number of market design changes that provide greater transparency and certainty as to how revenues are collected from exporters through the ICP and disbursed through the TRCA. These recent market design changes are summarized below:

- **Transmission Rights[24] Review (effective from 2015):** the Transmission Rights (TR) Review introduced a new methodology to refine the quantity of TRs auctioned ensuring revenues were balanced. As a result, starting in 2015 significantly higher amounts of intertie congestion funds were available to be disbursed to domestic consumers and exporters from the TRCA on a semi-annual basis.[25] This was followed by a market rule amendment that extended the period over which the disbursements were assessed to improve fairness.[26]

- **TRCA Disbursement Methodology (effective from 2021):** historically, disbursements from the TRCA were made based on volumetric consumption. The IESO adopted a recommendation from the OEB's Market Surveillance Panel to allocate TRCA surplus disbursements based on proportion of transmission service charges paid.[27] The design change will ensure that a greater portion of TRCA disbursements are returned to domestic load, compared to other market participants such as exporters. Based on historical estimates, disbursements of TRCA surplus funds to domestic load will increase between 87-98%.[28]

These market design changes mean the vast majority of funds disbursed through the TRCA reduce transmission costs for domestic consumers. Further, it should be noted that the dynamic nature of the ICP and design changes made to the TRCA are aligned with wider IESO initiatives, including the Market Renewal Program[29], to ensure Ontario has a dynamic market that delivers transparent and competitive outcomes.

4. Market Implications of an Increased Export Transmission Service Rate

Increasing the ETS from its current rate risks increasing the transaction costs of exporting energy which is likely to reduce the volume of economically efficient exports and have a negative impact both in terms of operational and economic benefits provided by exports. From an operational perspective, less exports would reduce the flexibility to balance the system and adversely impact the ability for exports to provide other services to help maintain grid stability. From an economic standpoint, exports contribute between $330-520 million per year[30] to Ontario that directly reduce transmission costs for domestic consumers and help avoid the cost of forgone energy to balance the

[24] Transmission Rights provide the holder with insurance against changes in the ICP
[25] TR Auction Process Update, SE-110 – Webinar, December 12, 2016
[26] See IESO Market Rule Amendment Proposal MR-00421, September 18, 2015
[27] TRCA Disbursement Methodology – Vote to Post, IESO Technical Panel, May 26, 2020
[28] TRCA Disbursement Methodology – Vote to Post, IESO Technical Panel, May 26, 2020, pg. 8
[29] For more information on the IESO Market Renewal Program see: https://www.ieso.ca/en/Market-Renewal
[30] Range of total value from exports 2017-2020. For more details, see Table 1

grid. Any increase in ETS from its current rate will likely reduce the value to ratepayers of exports using the interties, which in turn will result in higher system costs that would need to be recovered from domestic consumers.

The 2021 Elenchus Report presents three ETS rate options based on different cost allocation methodologies ($6.54/MWh, $3.66/MWh, and $5.42/MWh respectively). Each ETS rate option represents a significant increase over the approved 2020 ETS rate of $1.85/MWh and is outside of the historical range for the ETS rate ($1-2/MWh). In light of the options presented in the 2021 Elenchus Report, the IESO has focused its analysis on the market implications of an increased ETS rate.

The IESO expects that any increase in revenue resulting from a higher ETS would be offset by an equivalent reduction in revenue from the ICP, which in turn will decrease the amount that is disbursed from the TRCA to Ontario consumers. Intertie trade is driven by expected hourly price differences between electricity markets so exporters are highly sensitive to costs as it directly impacts profit margins. As noted above, exporters must pay the ICP in addition to ETS whenever they flow electricity over a congested intertie. The ICP and ETS are both transaction costs that negatively impact the profit margins of competitive intertie trade. This means that, if wholesale price differences between markets are held constant, the ICP and ETS have an offsetting relationship such that an increase in the ETS will lead to a proportionate decrease in the ICP. This offsetting relationships means that, assuming the quantity of exports remains constant, the overall value that Ontario ratepayers derive from exports would remain unchanged even if the ETS rate is increased.

In addition to decreasing ICP revenue, a higher ETS could have the effect of reducing energy exports from Ontario and by extension the operational and economic benefits that those lost exports provide. In contrast to the dynamic nature of the ICP, the ETS is a fixed charge applied on all exports regardless of market conditions. This means there will be occasions when market conditions are such that the ETS charge will make exports uneconomic and prevent an otherwise economic export from transacting.

The impact of a higher ETS on the Ontario market can be explored by the following two scenarios:

- **Wide price spread between markets:** occurs when there is a wider difference, or 'spread', between the price to buy electricity in Ontario and sell electricity in neighbouring jurisdictions. In this scenario an increase to the ETS will result in an offsetting decrease in ICP but no impact to export flows. As an example, if the expected price spread was $20, ETS was $2, Uplift was $1 and the ICP was $16, then a $2 increase in ETS would likely result in an offsetting $2 decrease in ICP.
- **Tight price spread between markets:** occurs when there is less price difference to buy electricity in Ontario and sell electricity in neighbouring jurisdictions. In this scenario the tighter price spread means there will be less demand to export, and therefore the ICP will be less to start with. As a result, there will be less or no ICP to offset an increase to the ETS. This means exports will become uneconomic on basis of a smaller increase in ETS compared to the wide price spread scenario. As an example, if the price spread was $5, ETS was $2, Uplift was $1 and the ICP was $1, then a $2 increase in ETS to $4 would stop the trade as even if ICP went to $0, there would still be no profit incentive for the exporter to transact. When exports do not flow, no ICP, ETS or Uplift revenues are collected to defray domestic consumer system costs. In this respect it can be understood that export flows are more sensitive to increases in ETS under a tight price spread than under a wide price spread. It also

means more exports will be prevented under the tight price scenario, and so have a greater negative economic and operational impact.

The tight price spread scenario illustrates the risk of reduced exports in the event of a higher ETS rate. The magnitude of economic exports reduced by increased ETS will ultimately be dependent upon the level of the ETS and the price spread between Ontario and neighbouring jurisdictions. At this time, the IESO has not undertaken a quantitative analysis to estimate the impact of a higher ETS rate on exports; however, even a relatively small increase in the ETS rate beyond the historical range of $1-2/MWh could have a material impact on heavily traded interties where price margins are already small. The 2012 CRA analysis demonstrates that in one case increasing the ETS rate from $0 to $5.80/MWh would cause a 50% reduction in export volumes (expressed as a percentage of status quo volumes)[31].

Fewer exports will have a negative operational impact across a number of areas, foremost in reducing the flexibility that interties provide to efficiently balance the grid in the course of normal system operations, surplus baseload management and unexpected events. Furthermore, less exports will reduce the role that interties can play in supporting regional reliability and diversification. This is likely to become increasingly important as the system evolves with the growth of more intermittent and distributed energy resources.

From an economic standpoint, exports contribute between $330-520 million per year[32] to Ontario that directly reduces transmission costs for domestic consumers and helps to avoid the cost of forgone energy to balance the grid. This benefit is detailed above. A reduction in exports would negatively impact the revenue collection and increase costs for domestic consumers in several ways including:

- **Congestion revenues:** Reduced exports would reduce congestion on the interties and the revenues that the IESO collects from congestion, which in turn is likely to reduce TRCA disbursements which, as noted above, have averaged $160 million per year since 2017.[33] The majority of these disbursements have gone to domestic consumers. Less exports would mean reduced TRCA disbursements and so increased transmission costs for domestic consumers.
- **ETS and Uplift:** Similar to congestion revenues, less exports would mean a reduced contribution from exports to system costs. Collectively exports contribute between $70 and 90 million per year in ETS and Uplift.[34] Many of these system costs would remain, regardless of exports and so the cost would have to be recovered from domestic consumers.
- **Avoided System Costs:** Exporters flow surplus energy out of Ontario when demand is low, which brings in revenue to cover fixed costs and avoids curtailing wind, spilling water at hydroelectric stations and maneuvering of nuclear units. Without exports these resources would have to be paid for their foregone energy, likely adding between $150-240 million per year to system costs which would have to be recovered from domestic consumers through increased Global Adjustment.[35]

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[31] IESO internal analysis based on data presented in Export Transmission Service (ETS) Tariff Study, Charles River Associates, May 16, 2012, Pg. 18-20

[32] Range of total value from exports 2017-2020. For more details, see Table 1

[33] Average of TRCA disbursements 2017-2020. For more details, see Table 2

[34] Range of ETS and Uplifts 2017-2020. For more details, see Table 1

[35] Range of Avoided curtailments through Exports 2017-2020. For more details, see Table 1

The ICP and ETS are closely linked meaning that even a relatively small increase in ETS beyond the current rate could materially reduce export volumes on some heavily traded interties where price margins can be slim. In response, the IESO may need to curtail output from domestic baseload generators, such as hydroelectric, variable generation and potentially nuclear production. These actions would be highly undesirable, both from a financial and operational perspective, and likely result in increased costs for domestic consumers. Furthermore, a higher ETS would directly and negatively impact the amount of ICP revenue collected and reduce the total revenue currently returned to Ontario consumers.

5. Jurisdictional Comparison

In response to OEB direction in the EB-2019-0082 proceeding, Hydro One engaged CRA to prepare a jurisdictional review that compares the Ontario ETS rate to tariffs in neighbouring jurisdictions[36]. The 2021 Elenchus Report also contains a review of cost allocation methodologies used in other North American jurisdictions.

A review of export tariffs in other jurisdictions may suggest Ontario's ETS rate of $1.85/MWh is low and misaligned compared to other regions. However, it is important to consider other factors when comparing ETS in other jurisdictions.

First, as noted above, the ETS is just one component of the total charges on exporters, with other charges including ICP and Uplifts. Combining these charges means total revenues collected from exporters in Ontario is far higher than the $1.85/MWh ETS rate (for example, the ICP alone has recently averaged $7-15/MWh[37]). When comparing jurisdictions, it is important to consider all-in costs which reflect that Ontario collects significant revenues from exporters through the ICP in addition to the ETS.

Second, it is important to consider the benefits of Ontario's ICP design that dynamically adjusts to market conditions, compared to the 'point-to-point' model in many other US jurisdictions where exporters gain access to flow on a first-come, first-serve basis. In contrast to the ICP, the point-to-point model limits the collection of greater revenues beyond the ETS rate, even if exporters are willing to pay more. In this respect it can be seen that the ICP is a more effective mechanism with its fair allocation of access and dynamic adjustment to market conditions.

6. Pole Attachments Methodology

The interdependent relationship of the ETS with the willingness-to-pay and dynamic aspects of the ICP are important to recognize when considering the appropriateness of using the OEB's pole attachment approach for setting the ETS rate.

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[36] EB-2021-0110, Exhibit H-09-01-02

[37] Average ICP across interties with Michigan, Minnesota and New York, 2017-2019

While both exporters and pole attachers are seeking to use installed infrastructure – transmission lines for exports and telecom wires for pole attachers – there are importance differences in usage that require alternative approaches to revenue collection.

In the case of exporters, their marginal costs and willingness-to-pay varies hour-to-hour with market conditions as detailed above. Pole attachers by contrast make infrastructure usage decisions based on multi-year, fixed investments. In this context it can be seen that the dynamic approach of the ICP, which adjusts to reflect the changing marginal costs and willingness-to-pay of exports is more appropriate than the fixed rate approach used for pole attachers.

7. Conclusion

Through this submitted evidence, the IESO provides an update to the OEB on past uncertainties related to how ICP defrays consumer costs. Since the 2012 OEB ETS Decision, the IESO has made market design changes that clarify the role of ICP and has disbursed significant revenues back to domestic consumers through reduced transmission costs.

Exporters contribute to the cost of the Ontario transmission system through two mechanisms. The first mechanism is through the fixed ETS rate and the second mechanism is through the dynamic ICP mechanism. When considered together, exporters not only contribute approximately $30-40 million per year towards the transmission system through the ETS rate but have also paid an average of $160 million per year towards the cost of the transmission system from the ICP mechanism.

Interties with neighbouring jurisdictions provide a range of operational benefits and enhance system reliability for Ontario consumers. In operational terms, interties provide flexibility that enable system operators to address power system needs and reliably manage the grid during changing system conditions. Ontario exports electricity to neighbouring jurisdictions when it is surplus to domestic needs and economic to recover the operational cost of generation. Exports provide Ontario with critical operational and economic benefits to help the IESO reliably operate the grid and reduce system costs for domestic consumers.

Intertie trading is highly competitive and is driven by price spread opportunities between jurisdictions that fluctuate on an hourly basis. As a result, export transactions are highly price sensitive and transaction costs deter economically efficient trade. A higher ETS rate increases the transaction costs of exporting energy and will lead to fewer economically efficient trades, which in turn reduces the benefits that exports provide to the grid. A higher ETS rate would reduce trade volumes and ICP revenue, resulting in less efficient outcomes. Under some market conditions, even a relatively small increase in ETS could materially impact exports and require the IESO to curtail and spill output from domestic generators. These actions result in higher costs for domestic consumers.

In summary, when setting the ETS, consideration should be given to maximizing the operational and economic benefits provided by exports by minimizing transaction costs. Any increase in the ETS rate will reduce the value of interties, leading to less system flexibility to reliability manage the grid and higher costs for Ontario consumers.

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TRANSMISSION BILL IMPACTS

1.0 BILL IMPACTS ON TRANSMISSION AND DISTRIBUTION-CONNECTED CUSTOMERS

The impact of transmission rates on a customer's total bill varies between transmission-connected and distribution-connected customers. For the purpose of determining the impact of the proposed changes to transmission rates on an average customer's bill, the same approach used in the EB-2019-0082 transmission rate application has been adopted.

Table 1, below, shows the estimated average transmission cost as a percentage of the total bill for a transmission and a distribution-connected customer.

Table 1 **- Estimated Transmission Cost as a Percentage of Total Bill**

	Cost Component	¢/kWh	Source*
A	Commodity	12.58	IESO Monthly Market Report December 2019 (YTD Weighted Average Rate)
B	Wholesale Market Service Charges	0.39	IESO Monthly Market Report December 2019
C	Wholesale Transmission Charges	1.06	IESO Monthly Market Report December 2019
D	Distribution Service Charges	3.02	2019 Yearbook of Electricity Distributors
E	**Total Monthly Cost for Tx-connected customers**	**14.03**	E=A+B+C
F	**Total Monthly Cost for Dx-connected customers**	**17.05**	F=A+B+C+D
G	*Transmission as % of Total Cost for Tx-connected customers*	*7.6%*	G=C/E
H	*Transmission as % of Total Cost for Dx-connected customers*	*6.2%*	H=C/F

** 2020 Yearbook of Electricity Distributors is not yet available*

The figures from Table 1 have been applied to the proposed increase in transmission rates revenue requirement in 2023 to 2027 to establish average bill impacts as shown in Table 2.

Table 2 - Average Bill Impacts on Transmission and Distribution-connected Customers

	2022	2023	2024	2025	2026	2027
Revenue Requirement ($ Millions)	1,807.6	1,823.2	1,937.8	2,027.5	2,140.3	2,219.0
Adjustments to Revenue Requirement ($ Millions) (Note 1)	71.2	-16.4	-54.7	-54.4	-53.1	-53.5
Rates Revenue Requirement ($ Millions)	1,878.8	1,806.8	1,883.1	1,973.1	2,087.2	2,165.5
% Increase in Rates Revenue Requirement over prior year		-3.8%	4.2%	4.8%	5.8%	3.8%
% Impact of load forecast change		0.6%	-0.4%	-0.1%	-0.2%	-0.1%
Net Impact on Average Transmission Rates (Note 2)		-3.1%	3.6%	4.4%	5.3%	3.4%
Transmission as a % of Tx-connected customer's Total Bill		7.6%	7.6%	7.6%	7.6%	7.6%
Estimated Average Bill Impact		-0.2%	0.3%	0.3%	0.4%	0.3%
Transmission as a % of Dx-connected customer's Total Bill		6.2%	6.2%	6.2%	6.2%	6.2%
Estimated Average Bill Impact		-0.2%	0.2%	0.3%	0.3%	0.2%

**Note 1: Adjustments include non-rate revenues, export revenues, disposition of regulatory accounts and funding for the low voltage switchgear credit. For purpose of estimating rate impacts, adjustments also include historical misallocated Future Tax Savings amounts being recovered in 2022 (+$87.1) and 2023 (+$43.5) per the OEB Decision in proceeding EB-2020-0194. The 2022 OEB approved rates revenue requirement will be established as part of the 2022 Annual Update.*

***Note 2: The calculation of net impact on transmission rates accounts for Hydro One's revenue disbursement allocation factor of 94.2% as approved for 2021 UTR Revenue Requirement (EB-2020-0251 issued on December 17, 2020).*

The total bill impact for a typical Hydro One medium density residential (R1) customer, consuming either 400 kWh, 750 kWh or 1,800 kWh monthly, is determined based on the forecast increase in the customer's Retail Transmission Service Rates (RTSRs) as detailed below in Table 3.

Table 3 **- Typical Medium Density (R1) Residential Customer Bill Impacts**

	Typical R1 Residential Customer		
	400 kWh	**750 kWh**	**1,800 kWh**
Total Bill as of July 1, 2021[1]	$83.97	$127.23	$257.01
RTSR included in 2021 R1 Customer's Bill[2]	$6.67	$12.51	$30.02
Estimated 2022 Monthly RTSR[2]	$7.39	$13.86	$33.25
Estimated 2023 Monthly RTSR[3]	$7.16	$13.43	$32.23
2023 change in Monthly Bill	($0.23)	($0.43)	($1.02)
2023 change as a % of total bill	-0.3%	-0.3%	-0.4%
Estimated 2024 Monthly RTSR[3]	$7.42	$13.91	$33.40
2024 change in Monthly Bill	$0.26	$0.49	$1.16
2024 change as a % of total bill	0.3%	0.4%	0.4%
Estimated 2025 Monthly RTSR[3]	$7.75	$14.53	$34.87
2025 change in Monthly Bill	$0.33	$0.61	$1.47
2025 change as a % of total bill	0.4%	0.5%	0.6%
Estimated 2026 Monthly RTSR[3]	$8.16	$15.29	$36.70
2026 change in Monthly Bill	$0.41	$0.77	$1.84
2026 change as a % of total bill	0.5%	0.6%	0.7%
Estimated 2027 Monthly RTSR[3]	$8.44	$15.82	$37.96
2027 change in Monthly Bill	$0.28	$0.52	$1.26
2027 change as a % of total bill	0.3%	0.4%	0.5%

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2021 and distribution rates effective July 1, 2021 approved per Distribution Rate Order EB-2020-0194, dated May 27, 2021

[2]The approved 2021 RTSR is based on the 2020 Ontario Interim Uniform Transmission Rate Schedules issued on December 19, 2019 (EB-2019-0296)

[3]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 2, adjusted for Hydro One's total revenue disbursement allocator per 2021 UTR Order (EB-2020-0251 dated December 17, 2020)

The total bill impact for a typical Hydro One General Service Energy less than 50 kW (GSe) customer, consuming either 1,000 kWh, 2,000 kWh or 15,000 kWh monthly, is determined based on the forecast increase in the customer’s RTSR as detailed below in Table 4.

Table 4 - Typical General Service Energy less than 50 kW (GSe) Customer Bill Impacts

	GSe Customer Monthly Bill		
	1,000 kWh	**2,000 kWh**	**15,000 kWh**
Total Bill as of July 1, 2021[1]	$215.96	$400.10	$2,793.91
RTSR included in 2021 GSE Customer's Bill[2]	$13.26	$26.52	$198.92
Estimated 2022 Monthly RTSR[2]	$14.69	$29.38	$220.35
Estimated 2023 Monthly RTSR[3]	$14.24	$28.48	$213.57
2023 change in Monthly Bill	($0.45)	($0.90)	($6.78)
2023 change as a % of total bill	-0.2%	-0.2%	-0.2%
Estimated 2024 Monthly RTSR[3]	$14.75	$29.51	$221.29
2024 change in Monthly Bill	$0.51	$1.03	$7.72
2024 change as a % of total bill	0.2%	0.3%	0.3%
Estimated 2025 Monthly RTSR[3]	$15.40	$30.81	$231.04
2025 change in Monthly Bill	$0.65	$1.30	$9.75
2025 change as a % of total bill	0.3%	0.3%	0.4%
Estimated 2026 Monthly RTSR[3]	$16.21	$32.43	$243.21
2026 change in Monthly Bill	$0.81	$1.62	$12.17
2026 change as a % of total bill	0.4%	0.4%	0.4%
Estimated 2027 Monthly RTSR[3]	$16.77	$33.54	$251.54
2027 change in Monthly Bill	$0.56	$1.11	$8.34
2027 change as a % of total bill	0.3%	0.3%	0.3%

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2021 and distribution rates effective July 1, 2021 approved per Distribution Rate Order EB-2020-0194, dated May 27, 2021).

[2]The approved 2021 RTSR is based on the 2020 Ontario Interim Uniform Transmission Rate Schedules issued on December 19, 2019 (EB-2019-0296)

[3]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 2, adjusted for Hydro One's total revenue disbursement allocator per 2021 UTR Order (EB-2020-0251 dated December 17, 2020)

2.0 TRANSMISSION REVENUE REQUIREMENT AND RATES IN CANADIAN PROVINCES

In its April 23, 2020 Decision and Order in Hydro One's last transmission revenue requirement application (EB-2019-0082), the OEB directed Hydro One to provide comparisons of its proposed transmission revenue requirement and resulting rates to those of other jurisdictions as part of its evidence in future applications.[1] Hydro One understood from the context of the OEB's direction that the requested comparison is to other Canadian provinces in particular.

Hydro One has undertaken a review based on reasonably available public information of transmission rate setting in other Canadian provinces in an effort to provide the requested comparisons. However, for the reasons discussed below, Hydro One believes that these comparisons are ultimately not appropriate or helpful for the purposes of considering Hydro One's transmission revenue requirement and rate requests. Accordingly, Hydro One requests that the OEB's direction to provide such comparisons be discontinued in future applications.

2.1 COMPARING TRANSMISSION RATES

Due to the significant differences between the regulatory regimes in place across Canada, Ontario's Uniform Transmission Rates (UTRs)[2] are not reasonably comparable to the transmission rates in other Canadian jurisdictions. In Ontario, UTRs recover the revenue requirements for all Ontario transmitters, and are not specific to any individual transmitter. Additionally, UTRs are charged based on the specific transmission network, line connection or transformation connection facilities that are used to provide customers with transmission service. No other province in Canada has a comparable transmission rate setting regime.

The majority of Canadian provinces have an Open Access Transmission Tariff (OATT). In those jurisdictions, transmitters recover their revenue requirements through the provision of services under their province's OATT. "Network Service" under those OATTs recover revenue for

[1] Transmission Revenue Requirement Decision, EB-2019-0082, April 23, 2020, p. 11
[2] Established per RP-1999-0044 since Ontario electricity Market Opening in 2002

services that are most similar to Ontario's UTR. However, Network Service is a single charge that is derived and charged on a basis that does not allow for a reasonable comparison to Ontario's UTRs. This is because, under UTRs, transmission charges are derived and applied on the basis of customer usage of transmission assets. For example, if a customer is directly connected to a transmitter's network facilities, the customer pays only a Network charge to compensate the transmitter for providing service using the transmitter's network assets. In contrast, under OATTs, a customer that chooses to receive Network Service will pay a Network charge that includes the costs associated with all transmission assets, including network, line connection and transformation connection facilities. As such, a reasonable comparison of UTRs to transmission rates under OATTs cannot be made.

Besides Ontario, one exception to the use of an OATT is Alberta, where the transmission pricing regime is driven by statutory obligations assigned to the Alberta Electric System Operator (the AESO). The monthly transmission "rate" that each transmitter levies to the AESO for use of their transmission facilities simply represents one twelfth ($1/12^{th}$) of each transmitter's annual revenue requirement. The AESO then calculates a complex mix of fixed and variable charges that apply to transmission customers in Alberta. Notwithstanding these limitations, Table 2 in Attachment 1 to this exhibit provides information on the transmission rates in Ontario, Alberta, and the eight Canadian provinces that have adopted OATTs. The large differences in the complexity and structures of these transmission rates, as well as the large differences in the rates themselves, further illustrates the difficulties in providing meaningful comparisons.

2.2 COMPARING TRANSMISSION REVENUE REQUIREMENTS

As discussed above, it is not appropriate or helpful to compare Ontario's UTRs to the transmission rates in other jurisdictions. Ultimately, rates reflect a utility's revenue requirement which, as discussed below, is also not readily comparable across jurisdictions.

There are significant challenges in comparing the total transmission revenue requirements of transmission utilities across Canadian jurisdictions, and the efficacy of such a comparison is questionable. First, there is the obvious issue of differences in the size of utilities and total demand served by each utility, which would influence their revenue requirement. Second, utilities' transmission revenue requirements are driven by a number of complex factors that cannot be accounted for by simply comparing their total revenue requirements, including: the diversity and age of transmission assets, differences in service territory geography, differences in concentrations of population centres, differences in economies and differences in how revenue requirement is calculated under the regulatory regimes they are subject to. To account for the different circumstances of transmission utilities, normalization for such factors is required.

An appropriately normalized comparison of Hydro One Transmission to other utilities is provided in Exhibit A-4-1-1, Section 3 "Transmission Cost Benchmarking". This benchmarking and productivity research includes transmission cost benchmarking research that takes into account kilometres of transmission line, peak demand, business condition variables such as regional input prices, percent of transmission plant in total electric utility plant, number of transmission substations and average voltages of transmission lines,[3] providing a meaningful comparison.

Notwithstanding that the econometric benchmarking research attached as Exhibit A-04-01-01 to this Application provides a normalized comparison of Hydro One Transmission to other utilities, Attachment 1 to this exhibit presents the results of Hydro One's comparison of transmission revenue requirements[4] in a number of Canadian jurisdictions as directed by the OEB. Note that because Hydro One is one of six licensed electricity transmitters that contribute to Ontario's total transmission revenue requirement, the total Ontario transmission revenue requirement identified in the calculation of the UTRs is used for comparison purposes rather than Hydro One's transmission revenue requirement. The large variances in the total transmission revenue

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[3] Complete list of business condition variables taken into account in the transmission total cost benchmarking is at page 20 of the report, filed at Exhibit A-04-01-01
[4] Table 1, Exhibit H-10-01-01

amounts shown in Attachment 1 to this exhibit further illustrate the challenges in providing meaningful comparisons.

ATTACHMENT 1 – TRANSMISSION RATES

This Attachment provides supplemental information on Ontario's Uniform Transmission Rates (UTRs), the Open Access Transmission Tariffs (OATTs) used in many Canadian jurisdictions, and transmission rates in Alberta. Tables 1 and 2 compare the transmission revenue requirements and transmission rates in Ontario, Alberta, and the eight Canadian provinces that have adopted OATTs.

1.0 ONTARIO'S UNIFORM TRANSMISSION RATES

Transmission rates in Ontario, UTRs, are established on a uniform basis for all transmitters in the province. Revenue requirements for all transmitters are added in order to determine the total provincial transmission revenue requirement for a given year. The total revenue requirement is then allocated to Network, Line Connection and Transformation Connection rate pools and the respective rates for each type of transmission service are determined by applying the provincial charge determinants (forecast consumption) for each rate pool to the total revenue requirement for each rate pool.

UTRs are then charged to all transmission-connected customers, including distributors, based on the nature of each customer's connection(s) to the transmission system. For example, a customer will be charged (i) only a Network charge if directly connected to a transmitter's network facilities, (ii) both Network and Line Connection charges if they are connected to transmitter's network assets through line connection facilities, or (iii) all three charges if they rely on transformation connection facilities and line connection facilities owned by a transmitter to connect to the transmitter's network assets.

2.0 OPEN ACCESS TRANSMISSION TARIFFS

To access US markets through the interconnected North American electricity grid, most Canadian utilities that own and operate transmission systems have adopted OATTs to govern and set rates for wholesale electricity transmission into, out of and within the provinces in which they operate. OATTs use a common model developed by the US Federal Energy Regulatory Commission (FERC) over 20 years ago.[1] For Canadian utilities to export and sell electricity in the US market, FERC requires a power marketing authority licence. This license has a condition requiring all transmitters to provide reciprocal transmission access under a transmission tariff that is equal to or superior to FERC's OATT. This requirement led to the development and implementation of OATTs by all Canadian provinces, with the exception of Alberta and Ontario, which already offer reciprocal transmission access by virtue of their disaggregated electricity market structures.

OATTs establish the terms and conditions between transmission providers and their customers pursuant to which transmitters provide and charge for transmission services. Under OATTs, Canadian utilities provide the following transmission services:

1. Point-to-Point Service (PTP), which refers to the reservation of capacity for the transmission of energy from a point of delivery to a point of receipt. This service is typically used for the import or export of electricity.
2. Network Service (Network), which is a transmission service used for the delivery of both capacity and energy to the high side of the substation transformer of a transmission customer. This service is typically used for the supply of load within a provincial grid.
3. Ancillary Services, which includes various services required for the movement of electricity into, out of, through or within a control area.

The generally accepted approach to transmission rate design under OATTs is based on a cost of service methodology. Given that the majority of Canadian utilities are vertically integrated, each utility is required to identify the specific portion of its revenue requirement that is associated with providing transmission services. Their transmission revenue requirement is then allocated to services offered under their applicable OATT, based on transmission system usage in providing each of these services. System usage is typically determined on the basis of monthly coincident peak system load. The nominal rates for each

[1] FERC Orders 888 and 889

service are then determined by dividing their respective revenue requirements by corresponding billing determinants. For PTP, the billing determinant is typically transmission capacity reserved by a customer. For Network, the billing determinant varies, with the majority of Canadian transmitters using an average monthly coincident peak and others using monthly non-coincident peak demand.

3.0 TRANSMISSION RATES IN ALBERTA

Alberta has a unique electricity market structure whereby its transmission pricing regime is driven by statutory obligations assigned to the AESO. While there are multiple transmitters in Alberta, known as transmission facility owners (TFOs), the AESO is the sole customer for each of the TFOs.

Under the *Electric Utilities Act*[2] (EUA), each TFO prepares a tariff setting out the revenue requirement, using a conventional forward test year cost of service basis, to be paid by the AESO for use of the TFOs' transmission facilities. These tariffs must be approved by the Alberta Utilities Commission (AUC) in a tariff application. The AESO is the sole customer of each of the TFOs in that the AESO contracts with them through their respective tariffs and manages the costs associated with system access services and losses, among other things. Once the AUC approves a TFO's tariff (i.e. revenue requirement), the AESO pays the full amount of the annual revenue requirement in equal monthly instalments.

The AESO is responsible for collecting the transmission revenue requirements of Alberta's transmitters from transmission customers. The principal transmission charge is the Demand Transmission Service rate (Rate DTS). Rate DTS incudes a capacity charge and a consumption charge. For each tariff proceeding the AESO conducts a cost allocation study which allocates costs to Rate DTS and Supply Transmission Service (Rate STS). Costs related to losses and generation connections are allocated to Rate STS and the remainder is allocated to Rate DTS. The Rate DTS revenue requirement is functionalized to the following components: Bulk System (DTS Bulk), Regional System (DTS Regional), Point of Delivery (DTS POD) as well a number of other system support services. The DTS services are classified as either fixed-based or usage-based. Bulk System and Regional System are analogous to the Shared Network function within HONI's ETS model.

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[2] SA 2003, Ch. E-5.1

Table 1 - Transmission Revenue Requirements

Canadian Jurisdiction	Provincial Transmitter(s)	Provincial Transmission Revenue Requirement	
		Year	Revenue Requirement ($M)
Ontario	All Transmitters[1]	2020	1,686[2]
Alberta	All Transmitters[3]	2020	1,762[4]
British Columbia	British Columbia Hydro and Power Authority	2020	1,048[5]
Manitoba	Manitoba Hydro-Electric Board	2020	199
New Brunswick	New Brunswick Power Corporation	2018/19	117[6]
Newfoundland & Labrador	Newfoundland and Labrador Hydro	2018	110[7]
Nova Scotia	Nova Scotia Power Inc.	2014	115
Prince Edward Island	Maritime Electric Company Limited	2014	9[8]
Québec	Hydro-Québec (TransÉnergie)	2016	2,744[9]
Saskatchewan	SaskPower	2019	83

[1] *Ontario has the following electricity transmitters: B2M Limited Partnership; Canadian Niagara Power Inc.; Hydro One Networks Sault Ste. Marie LP; Five Nations Energy Inc.; Hydro One Networks Inc. and Niagara Reinforcement Limited Partnership.*
[2] *EB-2020-0180, Decision and Order, 2020 Uniform Transmission Rates.*
[3] *Alberta has the following electricity transmitters: (i) ATCO Electric Ltd., (ii) AltaLink Management Ltd., (iii) ENMAX Power Corporation, (iv) EPCOR Distribution and Transmission Inc. For illustration purposes, we combined all transmitters revenue requirements to reflect the process used in Ontario to derive the UTRs. There are currently outstanding compliance requirements for 2018 and 2019, and the application for 2020-2022 ATCO transmission tariff is ongoing, so 2017 is the most recent year with final transmission rates for ATCO. (i) ATCO $53,350,000/month, AUC Decision 22158-D01-2016 2016 [link], ii) AltaLink $70,514,302/month. This is the 2017 interim rate since the final 2017 revenue requirement was only approved on November 21, 2017, so the interim rate would have been in place most of the year, and then corrected AUC Decision 22860-D01-2017 does not state how the correction occurred. It is typically done on a one-time payment or refund, but given the timing, it may have just been all addressed with the December payment AUC Decision 24025-D01-2018 [link], (iii) EPCOR $9,036,66717/month, AUC Decision 25664-D01-2020 [link], (iv) ENMAX $8,048,975 AUC Decision 25019-D01-2019 [link].*
[4] *This value is obtained by adding the annual revenue requirements from the individual TFO's tariffs. It should be noted that due to the length of tariff proceedings, the AUC will often approve an interim tariff, and then later approve a final tariff. There may be a true-up and/or adjustments to the monthly rates to balance the interim tariff and final revenue requirement. As a result, TFOs' monthly rates presented in Appendix B below may not always align with the total provincial revenue requirements presented in Appendix A.*
[5] *BC Hydro, 2020/21 Revenue Requirements Application, Chapter 9 [link]*
[6] *2018/19 NB Power Transmission Revenue Requirements, section 3.*
[7] *Newfoundland and Labrador System Operator Methodology for the Development of Rates for Transmission Service, February 2018, p.23 (Post LIL/LTA) [link].*
[8] *2017 Maritime Electric's Open Access Transmission Tariff Application, section 7 [link].*
[9] *Hydro-Québec Open Access Transmission Tariff, Attachment H [link]*

Table 2 - Transmission Rates[1]

Canadian Jurisdiction	Transmission Rates				
	Type	Year	Rates		Units
Ontario	UTR	2020	Network	4.30	$/kW-month
			Line Con.	0.81	$/kW-month
			Transform. Con.	2.39	$/kW-month
Alberta	DTS Bulk[2]	2020	Coincident metered demand	10,814.00	$/MW/month
		2020	Metered energy	1.13	$/MWh
	DTS Regional[3]	2020	Billing capacity	2,799.00	$/MW/month
		2020	Metered energy	0.86	$/MWh
	DTS POD[4]	2020	Substation fraction	14,291.00	$/month
		2020	First (7.5 × SF) MW of billing capacity	4,703.00	$/MW/month
		2020	Next (9.5 × SF) MW of billing capacity	2,789.00	$/MW/month
		2020	Next (23 × SF) MW of billing capacity	1,867.00	$/MW/month
		2020	All remaining MW of billing capacity	1,150.00	$/MW/month
British Columbia	OATT	2020	Network	80,399,000[5]	$/month
			PTP (firm)	6,793.92[6]	$/MW-month
Manitoba	OATT	2020	Network	16,624,455[7]	$/month
			PTP (firm)	3,582.86[8]	$/MW-month
New Brunswick	OATT	2019	Network	1.94[9]	$/kW-month
Newfoundland & Labrador	OATT	2018	Network	5,606.38[10]	$/MW-month
Nova Scotia	OATT	2017	Network	4,241.21[11]	$/MW-month
Prince Edward Island	OATT	2017	Network	3,051.60[12]	$/MW-month
Québec	OATT	2016	Network	228,635,125[13]	$/month
			PTP (firm)	6.02[14]	$/kW-month
Saskatchewan	OATT	2019	Network	6,919,975[15]	$/month
			PTP (firm)	3,733[16]	$/MW-month

[1] *The primary transmission rates most similar to Ontario's UTR are shown for comparison purposes. Customers connected to Transmission service providers in jurisdictions with OATT are charged their load ratio share of the monthly Network Transmission Revenue Requirement per month. All of the transmission service providers listed above also apply supplementary tariffs. Also shown for comparison purposes are the firm PTP rates for jurisdictions with a monthly fixed rate for network services. Although the firm PTP rates apply to export services, they represent an equivalent rate for network services in most cases.*

[2] *AESO: 2020 ISO Tariff Effective April 1st, 2020 - Rate DTS (Demand Transmission Service), pages 1 and 2*

[3] *Ibid*

[4] *Ibid*

[5] *BC Hydro, OATT Schedule 00 [link]*

[6] *BC Hydro, OATT Schedule 1 [link]*

[7] *Manitoba Hydro, Open Access Transmission Tariff, Attachment O, effective January 1, 2020 [link]*

[8] *Ibid.*

[9] *New Brunswick Power Corporation, Open Access Transmission Tariff, January 1, 2019, Attachment H [link]*

[10] *Newfoundland and Labrador System Operator Methodology for the Development of Rates for Transmission Service, February 2018 (Post LIL/LTA) [link].*

[11] *NSPI, Open Access Transmission Tariff – 2017 Schedule, Schedule 10 [link]*

[12] *MECL's OATT, January 1, 2017, Attachment H [link]*

[13] *Hydro-Québec Open Access Transmission Tariff, p.86 & Attachment H [link]*

[14] *Ibid., Schedule 9*

[15] *SaskPower, Open Access Transmission Tariff, pp. 87, 137 [link]*

[16] *SaskPower, OATT Tariff Rate Schedule, effective January 1, 2019 [link]*

CURRENT ONTARIO TRANSMISSION RATE SCHEDULES

The current Uniform Transmission Rate (UTR) Schedule and the revenue requirement and charge determinants for all transmitters used to establish the proposed UTRs and revenue disbursement allocators are included in the following attachments.

Attachment 1: Current Ontario Uniform Transmission Rate Schedules
Attachment 2: Current Uniform Transmission Rates and Revenue Disbursement Allocators

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Filed: 2021-08-05
EB-2021-0110
Exhibit H-11-1
Attachment 1
Page 1 of 6

2021 ONTARIO FINAL UNIFORM TRANSMISSION RATE

SCHEDULES EB-2020-0251

The rate schedules contained herein shall be implemented as of January 1, 2021

Issued: December 17, 2020
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) ofOntario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO- administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N): $ Per kW of Network Billing Demand [1,2]	**4.67**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand [1,3]	**0.77**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand [1,3,4]	**2.53**

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:
1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by an embedded generator unit for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation, on the demand supplied by the incremental capacity associated with a refurbishment approved after October 30, 1998, to a generator unit that existed on or prior to October 30, 1998.. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio- oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted for losses.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2020-0251

2021 Uniform Transmission Rates and Revenue Disbursement Allocators
Effective January 1, 2021 to December 31, 2021

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$5,091,523	$848,370	$2,356,752	$8,296,645
CNPI	$3,114,833	$519,006	$1,441,787	$5,075,626
H1N SSM	$26,453,762	$4,407,831	$12,244,856	$43,106,449
H1N	$1,035,594,842	$172,554,927	$479,353,752	$1,687,503,521
B2MLP	$35,062,648	$0	$0	$35,062,648
NRLP	$12,455,767	$0	$0	$12,455,767
All Transmitters	$1,117,773,375	$178,330,134	$495,397,147	$1,791,500,656

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	Line Connection	Transformation Connection	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	234,886.872	228,497.312	194,724.427	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
All Transmitters	239,138.412	232,030.054	195,981.977	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**4.67**	**0.77**	**2.53**	
FNEI Allocation Factor	**0.00456**	**0.00476**	**0.00476**	
CNPI Allocation Factor	**0.00279**	**0.00291**	**0.00291**	
H1N SSM Allocation Factor	**0.02367**	**0.02472**	**0.02472**	
H1N Allocation Factor	**0.92647**	**0.96761**	**0.96761**	
B2MLP Allocation Factor	**0.03137**	**0.00000**	**0.00000**	
NRLP Allocation Factor	**0.01114**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

* The sum of 12 monthly charge determinants for the year.

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order EB-2016-0231 dated January 18, 2018 and FNEI 2020 Foregone Revenue Letter, dated November 20,2020.
Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2015-0354 dated January 14, 2016 and CNPI 2020 Foregone Revenue Letter, dated November 20,2020.
Note 3: H1N SSM 2021 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2020-0227 dated December 17, 2020 and H1N SSM Foregone Revenue Letter, dated November 20,2020.
Note 4: H1N Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2020-0202, dated December 17, 2020 and H1N Foregone Revenue Letter, dated November 20,2020.
Note 5: B2M LP 2021 Revenue Requirement per OEB Decision and Order EB-2020-0226 dated November 26, 2020 and B2M LP Foregone Revenue Letter, dated November 20,2020.
Note 6: NRLP 2021 Revenue Requirement per OEB Decision and Order EB-2020-0225 December 17, 2020 and NRLP Foregone Revenue Letter, dated November 20,2020.
Note 7: Calculated data in shaded cells.

PROPOSED ONTARIO TRANSMISSION RATE SCHEDULES

The proposed Uniform Transmission Rate (UTR) Schedule and the revenue requirement and charge determinants for all transmitters used to establish the proposed UTRs and revenue disbursement allocators are included in the following attachments.

Attachment 1: Proposed 2023 Ontario Uniform Transmission Rate Schedules

Attachment 2: Proposed 2023 Uniform Transmission Rates and Revenue Disbursement Allocators

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2023 PROPOSED ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2023-XXXX

The rate schedules contained herein shall be effective January 1, 2023

Issued: Month, Year
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) ofOntario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's Business Corporations Act. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO- administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N): $ Per kW of Network Billing Demand [1,2]	4.80
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand [1,3]	0.84
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand [1,3,4]	2.76

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:

1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlementsystems.

3. The Billing Demand for Line and Transformation Connection Services is defined as the Non-Coincident Peak demand (MW) in any hour of the month. The customer demand in any hour is the sum of (a) the loss-adjusted demand supplied from the transmission system plus (b) the demand that is supplied by an embedded generator unit for which the required government approvals are obtained after October 30, 1998 and which have installed capacity of 2MW or more for renewable generation and 1 MW or higher for non-renewable generation, on the demand supplied by the incremental capacity associated with a refurbishment approved after October 30, 1998, to a generator unit that existed on or prior to October 30, 1998.. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio- oil, Bio-gas, landfill gas, or water. The demand supplied by embedded generation will not be adjusted forlosses.

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

2023 Proposed Uniform Transmission Rates and Revenue Disbursement Allocators

(Effective for period January 1, 2023 to December 31, 2023)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$4,977,087	$877,255	$2,442,303	$8,296,645
CNPI	$3,044,825	$536,677	$1,494,124	$5,075,626
H1N SSM	$25,859,191	$4,557,911	$12,689,347	$43,106,449
H1N	$1,047,890,237	$184,699,897	$514,209,533	$1,746,799,666
B2MLP	$35,062,648	$0	$0	$35,062,648
NRLP	$12,455,767	$0	$0	$12,455,767
All Transmitters	$1,129,289,755	$190,671,740	$530,835,307	$1,850,796,801

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	Line Connection	Transformation Connection	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	231,026.496	224,267.232	190,774.753	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
All Transmitters	235,278.036	227,799.974	192,032.303	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**4.80**	**0.84**	**2.76**	
FNEI Allocation Factor	**0.00441**	**0.00460**	**0.00460**	
CNPI Allocation Factor	**0.00270**	**0.00281**	**0.00281**	
H1N SSM Allocation Factor	**0.02290**	**0.02390**	**0.02390**	
H1N Allocation Factor	**0.92791**	**0.96869**	**0.96869**	
B2MLP Allocation Factor	**0.03105**	**0.00000**	**0.00000**	
NRLP Allocation Factor	**0.01103**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

* The sum of 12 monthly charge determinants for the year.

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order EB-2016-0231 dated January 18, 2018 and FNEI 2020 Foregone Revenue Letter, dated November 20,2020.
Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2015-0354 dated January 14, 2016 and CNPI 2020 Foregone Revenue Letter, dated November 20,2020.
Note 3: H1N SSM 2021 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2020-0227 dated December 17, 2020 and H1N SSM Foregone Revenue Letter, dated November 20,2020.
Note 4: H1N Proposed Rates Revenue Requirement per Exhibit H, Tab 1, Schedule 3, and Charge Determinants per Exhibit H, Tab 7, Schedule 1.
Note 5: B2M LP 2021 Revenue Requirement per OEB Decision and Order EB-2020-0226 dated November 26, 2020 and B2M LP Foregone Revenue Letter, dated November 20,2020.
Note 6: NRLP 2021 Revenue Requirement per OEB Decision and Order EB-2020-0225 December 17, 2020 and NRLP Foregone Revenue Letter, dated November 20,2020.
Note 7: Calculated data in shaded cells.

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WHOLESALE METER SERVICE AND EXIT FEE SCHEDULE

The current Wholesale Meter Service and Exit Fee Schedule was approved under Decision EB-2019-0082 dated April 23, 2020. The schedule is attached hereto.

Attachment 1: Wholesale Meter Service and Exit Fee Schedule

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HYDRO ONE NETWORKS INC.
WHOLESALE METER SERVICE
AND EXIT FEE SCHEDULE

APPLICABILITY:

This fee schedule is applicable to the *metered market participants** that are transmission customers of Hydro One Networks ("Networks") and to *metered market participants* that are customers of a Local Distribution Company ("LDC") that is connected to the transmission system owned by Networks.

* The terms and acronyms that are italicized in this schedule have the meanings ascribed thereto in Chapter 11 of the Market Rules for the Ontario Electricity Market.

a) Fee for Wholesale Meter Service

The *metered market participant* in respect of a *load facility* (including customers of an LDC) shall be required to pay an annual fee of $7,900 for each *meter point* that is under the transitional arrangement for a *metering installation* in accordance with Section 3.2 of Chapter 6 of the Market Rules for the Ontario Electricity Market.

This Wholesale Meter Service annual fee shall remain in place until all the remaining meter points exit the transitional arrangement.

b) Fee for Exit from Transitional Arrangement

The *metered market participant* in respect of a *load facility* (including customers of an LDC) or a *generation facility* may exit from the transitional arrangement for a *metering installation* upon payment of a one-time exit fee of $ 5,200 per *meter point*.