A - ENVIRONMENTAL DEFENCE INTERROGATORY - 001

Reference:

Exhibit A-3-1, Page 29

Interrogatory:

a) How many kilometres of transmission lines does HONI expect to replace over 2023-2027? Please provide a table showing an estimate for each year and an estimated total over the whole period.

b) How many kilometres of distribution lines does HONI expect to replace over 2023-2027? Please provide a table showing an estimate for each year and an estimated total over the whole period.

Response:

a) Please see Interrogatory A-Staff-059.

b) The number of distribution line kilometres expected to be replaced over 2023-2027 are shown in the table below.

	2023	**2024**	**2025**	**2026**	**2027**	**Total**
*Distribution Overhead Line Replacements (km of rebuilds and relocations)	90	85	112	84	110	481
*Distribution Cable Replacements (km)	1	1	1	2	2	7
**Distribution Submarine Cable Replacements (# of submarine cables replaced)	280	280	280	280	280	1400

**kms of overhead distribution line and cable includes only work that is part of ISD D-SR-10. For projects less than $1M, km accomplishments are not tracked and the values provided are estimated.*

***Number of submarine cables includes only work that is part of ISD D-SR-09.*

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B1 - ENVIRONMENTAL DEFENCE INTERROGATORY - 002

Reference:

Exhibit B-1-1, SPF Section 1.2, Page 17

Interrogatory:

a) Please provide a status update on the Merivale TS to Hawthorne TS – 230kV Conductor Upgrade (T-SS-03).

b) Please provide the expected in-service date and advise whether this has changed since approval of the leave to construct.

Response:

a) The project is under execution and on schedule. Major material for the project has been ordered.

b) As noted in ISD T-SS-03 in Exhibit B-2-1, TSP Section 2.11, the planned in-service date for this investment is Q4 2023, which aligns with the proposed in-service date in the leave to construct application.

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B1 - ENVIRONMENTAL DEFENCE INTERROGATORY - 003

Reference:

Exhibit B-1-1, SPF Section 1.2, Page 15

Interrogatory:

a) Please provide a list of all RIP projects that involve new conductors or replaced conductors of 1 km in length or longer.

b) For the list of projects in (a), please complete the following table:

Project	Forecast cost	Current conductor size	Proposed conductor size	Maximum conductor size without tower replacement	Would an upsized conductor be cost-effective if losses are valued at $120/MWh?	Has an upsized conductor been screened out? If yes, why.
Project 1						
…						
Project n						

c) Please provide a list of all RIP projects with a current cost estimate of more than $10 million.

Response:

a) Please refer to response in part (b) below for a list of all RIP projects planned within the 2023 to 2027 period that involve new conductors or replaced conductors of 1km in length or longer.

b) Please see completed table below for all RIP projects planned within the 2023 to 2027 period that involve new conductors or replaced conductors of 1km in length or longer.

Project	**Forecast Gross Cost ($ Millions)**	**Current conductor size**	**Proposed conductor size**	**Maximum conductor size without tower replacement**	**Would an upsized conductor be cost-effective if losses are valued at $120/MWh?**	**Has an upsized conductor been screened out? If yes, why.**
115 kV B7/B8: Transmission Line: Refurbish sections from Burlington TS to Nelson Jct.	2.7	605kcmil	997kcmil	Project initiated before the Transmission Line Loss Guideline was developed. Project currently in execution phase.		
Merivale TS to Hawthorne TS – 230kV Conductor Upgrade	21.3	1843kcmil	2 x 1443kcmil	Please refer to EB-2020-0265		
Reconductor 230kV H29/H30 Transmission Line	8.0	795kcmil	(Note 1)			
115kV C5E/C7E Underground Cables: Refurbish cable sections from Esplanade TS to Terauley TS	108.2	2500kcmil and 1250kcmil	Please refer to EB-2020-0188			
115kV H1L/H3L/H6LC/H8LC: Transmission Lines: Refurbish line sections from Leaside Jct. to Bloor St. Jct.	6.6	795kcmil	(Note 1)			
115kV L9C/L12C Transmission Lines: Refurbish line sections from Leaside TS to Balfour Jct.	3.0	605kcmil	(Note 1)			
Richview TS to Manby TS 230 kV Corridor Reinforcement	23.1	New Line	(Note 1)			
115kV A4L Circuit – Beardmore Jct x Longlac TS Refurbishment	(Note 2)					
115kV E1C Circuit – Refurbishment Ear Falls TS x Slate Falls DS; Etruscan Jct x Crow River DS	(Note 2)					
Chatham x Lakeshore	(Note 3)					
Sections of M6E/M7E circuits line refurbishment	(Note 2)					
Sections of E8V/E9V circuits line refurbishment	(Note 2)					
Sections of D1M/D2M circuit’s line refurbishment	(Note 2)					

Notes:
1. Conductor size to be determined later as part of detailed design and estimating.
2. Please refer to response to Exhibit I-9-B2-ED-005.
3. Please refer to response to Exhibit I-9-B2-ED-006.

c) A list of all RIP projects for the 2023 to 2027 period with a cost estimate of more than $10 million are provided below.

1. Beach TS: Auto-Transformer (T1/T7/T8) Replacement and DESN Switchgear (T-SR-01)
2. Burlington TS: T12 Autotransformer and LV Switchgear (T-SR-03)
3. Birmingham TS: MV Metalclad Switchgear Refurbishment (T-SR-03)
4. Caledonia TS: T1 and Component Replacement (T-SR-03)
5. Jarvis TS: T3, T4 & Component Replacement
6. Lake TS: T1/T2 Transformers and LV Switchyard Refurbishment (T-SR-03)
7. Newton TS: Station Refurbishment (T-SR-03)
8. Nebo TS: T3/T4 Transformers and Component Replacements (T-SR-03)
9. Arnprior TS: Transformer (T1/T2) Replacement (T-SR-03)
10. Longueuil TS: Transformer (T3/T4) Replacement (T-SR-03)
11. Slater TS: Transformer (T1/T2/T3) Replacement (T-SR-03)
12. Lincoln Heights TS: Transformer (T1/T2) Replacement (T-SR-03)
13. Albion TS: Transformer (T1/T2) Replacement (T-SR-03)
14. Russell TS: Transformer (T1/T2) Replacement (T-SR-03)
15. Bilberry Creek TS: Transformer (T1/T2) Replacement (T-SR-03)
16. Nepean TS: Transformer (T3/T4) Replacement (T-SR-03)
17. Merivale TS: Autotransformer (T22) and HV Breaker Replacement (T-SR-01)
18. Merivale TS: Addition of Autotransformer and Station Expansion (T-SS-05)
19. Merivale TS to Hawthorne TS – 230kV Conductor Upgrade (T-SS-03)
20. Cherrywood TS: LV DESN Switchyard Refurbishment (T-SR-03)
21. Cherrywood TS: ABCB Breaker Replacement (T-SR-02)
22. Connection of a new load station in Northern York Region (T-SA-09)
23. Woodbridge TS: Transformer (T5) Replacement (T-SR-03)
24. Connection of a new load station “Halton TS #2” (T-SA-03)
25. Milton SS: Component Replacement (T-SR-01)
26. Bramalea TS: T3/T4 Transformer and Component Replacement (T-SR-03)
27. Erindale TS: PCT and Component Replacement (T-SR-03)
28. Halton TS: PCT and Component Replacement (T-SR-03)
29. Palermo TS: T3 / T4 Supply Transformer (T-SR-03)
30. Campbell TS: PCT and Component Replacement (T-SR-03)
31. Cedar TS: Transformer (T7/T8) Replacement (T-SR-03)
32. Preston TS: Transformer (T3/T4) Replacement (T-SR-03)
33. Bermondsey TS: Transformer (T3/T4) Replacement (T-SR-03)
34. John TS: Station Reinvestment (T-SR-03)
35. Leslie TS: Transformer (T1) Replacement (T-SR-03)
36. 115kV C5E/C7E Underground Cables: Refurbish cable sections from Esplanade TS to Terauley TS (T-SR-18)

37. Richview TS to Manby TS 230 kV Corridor Reinforcement: Replace existing idle 115 kV double circuit line with new 230 kV double circuit line between Richview TS and Manby TS (T-SS-06)
38. Marathon TS: Component Replacement (T-SR-01)
39. Fort Frances TS – Transformer Replacement (T-SR-01)
40. Kenora TS – Component Replacement (T-SR-01)
41. Lakehead TS – Component Replacement (T-SR-01)
42. Mackenzie TS – Component Replacement (T-SR-01)
43. Port Arthur TS #1 – PCT & Component Replacement (T-SR-03)
44. Rabbit Lake SS – Component Replacement (T-SR-01)
45. 115kV A4L Circuit – Beardmore Jct x Longlac TS Refurbishment (T-SR-13)
46. 115kV E1C Circuit – Ear Falls TS x Slate Falls DS Refurbishment; Etruscan Jct x Crow River DS Refurbishment (T-SR-13)
47. Keith TS: Autotransformer (T11/T12) Replacement (T-SR-01)
48. Lauzon TS: Transformer (T5, T6, T7 and T8) and Component Replacement (T-SR-03)
49. Supply Capacity need to Kingsville – Leamington area: Build new switching station at Leamington Junction (Lakeshore TS)
50. Supply Capacity need to Kingsville – Leamington area: Build Leamington Area Transformer Stations – South Middle Road DESN1 and DESN2 ("Leamington Area Station #4") in T-SA-10
51. Supply Capacity need to Kingsville – Leamington area: Build 230 kV double-circuit transmission line from Chatham SS to the new Lakeshore TS (Station costs reflected in T-SS-07)
52. Wonderland TS: Station Refurbishment (T-SR-03)
53. Buchanan TS: T2, T3 and Component Replacement (T-SR-01)
54. Clarke TS: DESN transformer replacement (T-SR-03)
55. Clarke TS: PCT & Switchyard Replacement (T-SR-03)
56. Port Hope TS: Transformer Replacement (T-SR-03)
57. Havelock TS: Transformer Replacement (T-SR-03)
58. Orangeville TS: Transformer (T1/T2) Replacement (T-SR-03)
59. Parry Sound TS: Transformer Replacement (T-SR-03)
60. Sections of M6E/M7E circuits line refurbishment (T-SR-13)
61. Sections of E8V/E9V circuits line refurbishment (T-SR-13)
62. Sections of D1M/D2M circuit's line refurbishments (T-SR-13)
63. Martindale TS: T25 & T26 Transformer Replacement (T-SR-03)
64. Elliot Lake TS: Component Replacement (T-SR-03)
65. Algoma TS: Component Replacement (T-SR-01)
66. Clarabelle TS: T1 & T2 Transformer Replacement (T-SR-03)
67. St. Andrews TS: Transformer (T3/T4) Replacement and DESN Refurbishment (T-SR-03)
68. Sarnia Scott TS: Transformer (T5) and component Replacement (T-SR-01)
69. Lambton TS: T7/T8, T5/T6, DESN Replacement (T-SR-03)
70. Seaforth TS – Transformer T1/T2/T5/T6 and component replacement (T-SR-01)

B1 - ENVIRONMENTAL DEFENCE INTERROGATORY - 004

Reference:

Exhibit B-1-1, SPF Section 1.2, Page 23

Preamble:

The evidence lists the following project:

Supply Capacity need to Kingsville – Leamington area:

- Build new switching station at Leamington Junction (Lakeshore TS),
- Build Leamington Area Transformer Stations – South Middle Road DESN1 and DESN2 (referred to as "Leamington Area Station #4") in T-SA-10; and
- Build 230 kV double-circuit transmission line from Chatham SS to the new Lakeshore TS (Station costs reflected in T-SS-07, transmission line costs have been excluded, see Exhibit A-03-01 for further information) .

Interrogatory:

a) What is the status of this project?

b) What is the forecast cost?

c) Will HONI be conducting further analysis to determine if all or part of the project can be avoided or deferred cost-effectively through distributed energy resources?

Response:

a) The current status of the referenced projects above are as follows:

#	Project	Status	Planned Completion
1	Lakeshore TS	Execution	Q3 2022
2	South Middle Road TS DESN#1	Execution	Q3 2022
3	South Middle Road TS DESN#2 *	Planning	Q3 2025
4	Chatham x Lakeshore – New 230kV Double Circuit Line – Station Work *	Planning	Q4 2025

** For additional information on Item #3 and #4, please refer to T-SA-10, and T-SS-07 respectively.*

Witness: REINMULLER Robert

b) The forecast cost of the referenced projects above are as follows:

#	Project	Forecast Total ($ Millions, Net)
1	Lakeshore TS	173.0
2	South Middle Road TS DESN #1	40.5
3	South Middle Road TS DESN#2 *	42.7
4	Chatham x Lakeshore – New 230kV Double Circuit Line – Station Work *	35.9 **

** For additional information on Item #3 and #4, please refer to T-SA-10 and T-SS-07 respectively.*
***Transmission line costs associated with Item #4 have been excluded from this Application as outlined on page 3 in Exhibit B-2-1, TSP Section 2.8.*

c) No. The assessment of whether regional supply needs can be addressed through non-wires alternatives, including distributed energy resources is the accountability of the IESO as part of the Integrated Regional Resource Plan (IRRP) of the Regional Planning Process. Specifically, the assessment of non-wires alternatives for the Windsor-Essex Region, was carried out by the IESO and published in the Windsor-Essex Integrated Regional Resource Plan[1] on September 3, 2019.

[1] https://ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Windsor-Essex/Windsor_Essex_IRRP_Report_20190903.ashx

B2 - ENVIRONMENTAL DEFENCE INTERROGATORY - 005

Reference:

Exhibit B-2-1, TSP Section 2.1, Page 5

Preamble:

> *Transmission Line Components Refurbishment (T-SR-04 to T-SR-08, T-SR-13, T-SR-17) – 16 individual investments that target the refurbishment of 1,571 km poor condition conductors, and other capital programs that replace poor condition lines components such as wood poles, insulators, shieldwires at the cost of $1,919M over the five-year period.*

Interrogatory:

a) Please complete the following table for the 16 individual investments mentioned above.

Project	Forecast cost	Length of lines to be replaced	Current conductor size	Proposed conductor size	Maximum conductor size without tower replacement	Would an upsized conductor be cost-effective if losses are valued at $120/MWh?	Has an upsized conductor been screened out? If yes, why.
Project 1							
…							
Project n							

b) Please indicate for each of the 16 projects whether leave to construct will be required, and if not, why not.

Response:

a) For the 16 investments in T-SR-13, the conductor size has not been finalized. Conductor size will be determined as part of the detailed design and estimating. The table below has been completed with information that is available.

ISD Ref.	Lines	Forecast Cost (M)	Length of lines to be replaced (Circuit-km)	Current conductor size (Predominant)	Proposed conductor size	Maximum conductor size without tower replacement	Would an upsized conductor be cost-effective if losses are valued at $120/MWh?	Has an upsized conductor been screened out? If yes, why.
T-SR-13.1	T22C and T28C 230 kV	79.6	231	795 kcmil ACSR	Conductor size for all projects will be determined as part of detailed design and estimating.			
T-SR-13.2	T25B 230 kV	82.7	120	795 kcmil ACSR				
T-SR-13.3	E1C 115 kV	51.8	162	167 kcmil ACSR				
T-SR-13.4	D2H, D3H, D6T and D4 115 kV	89.9	183	666 kcmil ACSR 715 kcmil ACSR				
T-SR-13.5	T33E 230 kV	170.6	252	795 kcmil ACSR				
T-SR-13.6	Q2AH and A8G 115 kV	9.2	22	211 kcmil Copper				
T-SR-13.7	E8V and E9V 230 kV	58.3	112	795 kcmil ACSR				
T-SR-13.8	L22H 230 kV	58.2	65	795 kcmil ACSR				
T-SR-13.9	M6E and M7E 230 kV	25.5	50	795 kcmil ACSR				
T-SR-13.10	A4H and A5H 115 kV	19.7	47	203 kcmil ACSR 500 kcmil ACSR				
T-SR-13.11	B5QK 115 kV	29.6	60	477 kcmil ACSR				
T-SR-13.12	A4L 115 kV	23.8	78	211 kcmil ACSR				
T-SR-13.13	D1M, D2M, D3M and D4M 230 kV	121.3	248	795 kcmil ACSR				
T-SR-13.14	N5K 115 kV	33.1	65	336 kcmil ACSR				
T-SR-13.15	S2N 115 kV	28.0	54	477 kcmil ACSR				
T-SR-13.16	C27P 230 kV	80.3	130	795 kcmil ACSR				

b) The need to seek leave to construct approval will be determined during the detailed design and estimating process.

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B2 - ENVIRONMENTAL DEFENCE INTERROGATORY - 006

Reference:

Exhibit B-2-1, TSP Section 2.1, Page 5

Interrogatory:

a) Please complete the following table:

Project	Forecast cost	Current conductor size	Proposed conductor size	Maximum conductor size without tower replacement	Would an upsized conductor be cost-effective if losses are valued at $120/MWh?	Has an upsized conductor been screened out? If yes, why.
West of Chatham Transmission Reinforcement (T-SS-07)						
West of London Transmission Reinforcement (T-SS-09)						

Response:

a) The scope and cost of both projects ISD T-SS-07 (West of Chatham Reinforcement) and ISD T-SS-09 (West of London Reinforcement) as filed in this Application encompass only the station work associated with these Transmission Reinforcement projects. The forecast of these station costs are detailed in the respective ISDs (T-SS-07 and T-SS-09 in Exhibit B-2-1, TSP Section 2.11).

The transmission line component of the projects associated with the West of Chatham Transmission Reinforcement (ISD T-SS-07) and West of London Transmission Reinforcement (ISD T-SS-09) have been excluded from this Application as outlined on page 3 in Exhibit B-2-1, TSP Section 2.8. Furthermore, these projects are intended to connect net new transmission lines and as such Hydro One is unable to complete the table as requested as the projects are not intended to replace any existing transmission line infrastructure. Both of these projects are currently in the planning phase, specific details surrounding the proposed conductor sizing will be made available in the respective Section 92 application.

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B2 - ENVIRONMENTAL DEFENCE INTERROGATORY - 007

Reference:

Exhibit B-2-1, TSP Section 2.1, Page 20

Preamble:

The evidence states:

> *Hydro One plans to renew its stations facilities at the Bruce A and Bruce B switching stations that connect the Bruce A and B Nuclear Generating Stations (NGS). Hydro One has similar plans at Cherrywood TS which connects the Pickering NGS and Darlington NGS. Hydro One also plans to undertake renewal work at the Milton TS and Claireville TS which receive power coming from the Bruce NGS and serve as major hubs of the southern Ontario transmission system*

Interrogatory:

a) Please provide a table listing the cost of each of the above projects and a total cost for all of those projects.

b) For each of the above-referenced projects, please indicate whether the renewal will increase the station capacity, and if yes, by how much and the rationale for the increased capacity.

Response:

a) Please see TSP Section 2.11 T-SR-01 Appendix B and T-SR-02 Appendix B for further details on the projects referenced:

ISD Ref.	Station Name	Investment Cost ($M)
T-SR-01.01	Claireville TS	21.7
T-SR-01.06	Milton SS	19.2
T-SR-02.01	Cherrywood TS	111.6
T-SR-02.03	Bruce B SS	180.2
T-SR-02.04	Cherrywood TS	74.9
T-SR-02.09	Bruce A TS	239.5
T-SR-02.11	Cherrywood TS	92.1
	Total:	**739.2**

b) The transformation capacity of the above-referenced stations will not change.

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B2 - ENVIRONMENTAL DEFENCE INTERROGATORY - 008

Reference:

Exhibit B-2-1, TSP Section 2.3, Attachment 4

Interrogatory:

a) Please provide a list of all documentation provided to Stantec.

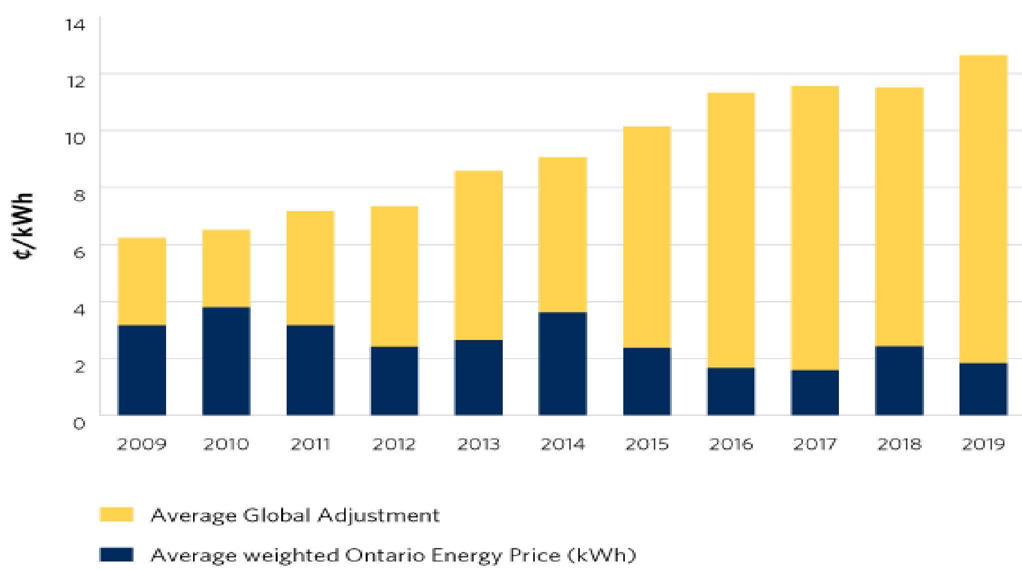
b) Please provide a copy of all documentation provided to Stantec.

c) In preparing its report, did Stantec consider the appropriateness of valuing transmission losses based on the HOEP? If yes, please provide all analysis of this.

d) Does the Stantec report address the appropriateness of valuing transmission losses based on the HOEP?

e) In Stantec's opinion, is it appropriate to value loss reductions based on the HOEP?

f) In Stantec's opinion, does the HOEP represent the full avoided cost of electricity? If yes, please explain how that can be the case in light of the below figure from the IESO's website:



g) Please explain why the Transmission Line Loss Guidelines requires planners to calculate the cost of annual losses based on the HOEP (per step 4 on page 25).

h) Does Hydro One take the position that it must follow a loss valuation methodology set out by the IESO? Please confer with the IESO to determine if it agrees with Hydro One's answer to this question.

i) Is Hydro One or the IESO responsible for the decision to value transmission losses at the HOEP? Please confer with the IESO to determine if it agrees with Hydro One's answer to this question.

j) Please provide an update of the figure cited in (f) above that incudes 2020.

k) Please confirm that transmission loss reductions can lower capacity needs.

l) Please confirm that transmission losses are taken in to account when determining resource adequacy.

m) Please discuss the options considered by Hydro One aside from the HOEP for the valuation of transmission losses. For example, did Hydro One consider using the avoided energy and capacity costs as set out in the Annual Planning Outlook and the full wholesale cost (HOEP & GA)? Please fully explain the rational for Hydro One's decisions in this regard. Please also provide the original documentation wherein the analysis took place.

n) Do the transmission line loss guidelines apply to system renewal projects where lines will be replaced? If not, why not and how will transmission lines be considered?

o) Has the guideline been applied to the 16 line refurbishment projects described on Exhibit B-2-1, Section 2.1, Page 5? If yes, please provide a copy of the outcome of that analysis for each project.

p) Please provide a live excel copy of the workbook at page 30.

q) Does the guideline cover other equipment replacement, such as transformers? If not, please provide the guideline for this other equipment, including the document which details the appropriate valuation of losses.

r) Please prepare a side-by-side document comparing the steps in Hydro One's guideline for assessing potential transmission loss reduction opportunities with the steps it uses for distribution loss reduction opportunities.

Response:

a) Hydro One provided Stantec with the following documentation:

No.	Description	Hyperlink or Attachment
1	EB-2019-0082 Decision and Order (Sections related to transmission line losses)	Hyperlink
2	National Grid Strategy Paper on Transmission Losses	Hyperlink
3	IESO Presentation #1 – Transmission Losses Public Information Session #1	Hyperlink
4	Hydro One's Transmission System Plan (EB-2019-0082) • Sections 1.1.4, 1.1.5, 1.2.1,1.2.2, 1.8, 1.8.1 (EPRI Report)	Hyperlink
5	Transmission Line Losses Workbook Calculation Example	Attachment 1
6	National Grid ESO Transmission Losses Presentation	Hyperlink
7	IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)	Hyperlink
8	Historical Voltage Profiles for Hydro One Stations	Attachment 2
9	Hydro One Transmission Line Loss Guideline	TSP 2.3 Attachment 4 – Appendix A
10	IESO Presentation #2 – Transmission Losses Stakeholder Engagement	Hyperlink

b) Please refer to a).

c) Stantec's response:

The scope of Stantec's review was focused on assessing the principles and completeness of Hydro One's transmission line loss processes. The application of HOEP (or any other energy price) as part of such processes was beyond the scope of Stantec's review. It is up to the transmitter in any jurisdiction to consider the inclusion of energy price in its line loss processes and analysis, as applicable in that jurisdiction.

d) Stantec's response:

Line loss energy is not a function of energy price. The scope of Stantec's review, as summarized in response to part c) above, did not entail a consideration of the appropriateness of valuing transmission losses based on the HOEP (or whether the HOEP or other energy price represents the full avoided cost of electricity).

e) Stantec's response:

See response to part d) above.

f) Stantec's response:

See response to part d) above.

g) The IESO recovers the cost of transmission losses through the Net Energy Market Settlement Uplift[1]. The charge covers the difference between the amount paid to suppliers and the amount received from the buyers in each hour. This charge is reflected in the 5-minute Energy Market Reference Price for each metering interval in the settlement hour. The Hourly Ontario Energy Price (HOEP) is the hourly average of the 5-minute market price[2].

The rationale for requiring Hydro One planners to calculate the cost of annual losses using the HOEP is that currently this is the only settlement mechanism to recover costs due to transmission losses.

h) In Hydro One's last transmission application (EB-2019-0082), Hydro One and Environmental Defence agreed to a settlement on the issue of Transmission Line Losses. Further to and consistent with that settlement, Hydro One continues to participate in, and contribute to, the IESO stakeholder engagement regarding transmission line losses (including IESO's transmission line loss valuation methodology). Hydro One is of the view that the final determination of the methodology to evaluate transmission line losses remains within the scope of the IESO's stakeholder engagement on transmission line losses.

i) Please see part g) and h) above.

---

[1] Please refer to EB-2017-0150 Exhibit I Tab 5.1 Schedule 4.03ED3

[2] EB-2017-0150 Exhibit I Tab 5.1 and Schedule 4.07ED7

j) Hydro One did not produce the figure cited in f) and is unable to update it.

k) Loss reduction does not necessarily lower capacity needs. Any loss reduction being realized at a point in time outside a system peak would not reduce capacity needs.

l) The IESO is required to consider losses when scheduling resources.

m) Please see part h).

n) Yes, Hydro One's Transmission Line Loss Guideline applies to System Renewal investments.

o) Please see Interrogatory B2-ED-005.

p) Please see Attachment 3.

q) Yes, Hydro One's Transmission Line Loss Guideline takes into account equipment included in each investment alternative.

r) Hydro One Transmission's line loss mitigation practices were described in TSP 1.8 in the EB-2019-0082 application. Hydro One Distribution's line loss mitigation practices are described in DSP Section 3.6, page 9 of the current application.

Hydro One Transmission's and Distribution's line loss mitigation approaches are similar. However, due to the nature of the distribution system (e.g., operated at lower voltage levels) not all transmission system loss mitigation practices may be applicable or relevant to the distribution system.

A comparison of the Transmission and Distribution System loss mitigation practices is highlighted in the table below.

Comparison of Hydro One's Transmission and Distribution Loss Mitigation Practices

Methods	Transmission System Practices	Distribution System Practices
Investment Planning Process		
Investment Planning Process	The planning process assesses all investments for safety, reliability and environmental risks	The planning process assesses all investments for safety, reliability and environmental risks.
Development of Alternatives	Losses are considered in the development of alternatives. Nominal line voltage, route length etc. all affect losses.	Losses are considered in the development of alternatives. Nominal line voltage, route length etc. all affect losses.
Line loss assessments	Losses are considered in alternative selection if they are consequential.	Losses are considered in the selection of the preferred alternative.
Line Loss Mitigation Practices Considered During System Planning Stage		
Raising Nominal Voltage	Higher voltages result in lower current and thus reduced losses. Transmission system expansion is driven by reliability and adequacy needs and, wherever practical, new lines being developed are built to be operated at 230kV. Hydro One continues to evaluate opportunities to convert 115kV systems to 230kV operation for cost effectiveness and reduction of losses.	Hydro One uses higher distribution system operating voltages where practical, if multiple distribution voltages are available for new connections or enhancement work. By increasing the nominal operating voltage, line losses are reduced. Examples of this approach can be seen in the proposed investments under ISD D-SR-11, “Life Cycle Optimization”. Typically, these investments involve converting localized pockets of lower system voltages to the surrounding system voltage (e.g. 27.6 kV).
Optimization of Voltage Profile	Hydro One’s transmission system is already operated at voltages that are at or near equipment limits and therefore there is limited opportunity to reduce losses by further optimizing the transmission system voltage profile.	Hydro One’s Distribution system is operated close to 106% of nominal voltage at points of regulation, in compliance with CSA C-235-83 steady-state voltage standards. This helps to minimize losses, and all customers receive adequate voltage under both light load and peak load conditions.
Reduce Transformational Steps	Hydro One minimizes the transformation steps with a majority of stations stepping down voltage from 230kV or 115kV directly to 44kV, 27.6kV or 13.8 kV.	Hydro One minimizes transformation steps where practical, such as using higher distribution system operating voltages if multiple distribution voltages are available for new connections. The reduction of transformation steps is also achieved through investments under ISD D-SR-11, “Life Cycle Optimization”.
Network Reinforcement	Hydro One considers system reinforcement or building a new line in parallel to provide capacity or increase reliability, which results in reducing line losses.	New feeders are built to provide capacity. Loading will be balanced between feeders where practical, resulting in reduced losses.

Line Loss Mitigation Practices at Equipment Selection Stage		
Use Lower Loss Conductors	Hydro One currently uses lower loss conductor (i.e., compact ACSR/TW conductors) for capacity needs. Hydro One will also continue to consider the use of larger conductors with a corresponding lower resistance, where cost effective.	Hydro One uses larger conductor size at the feeder head. These conductors have lower resistance and therefore minimize losses.
Bundle Conductor Optimization	Hydro One currently uses bundled conductors for 500kV and some 230kV lines.	Not applicable. Bundled conductor is not applicable to Distribution.
Improve Corona Losses	Hydro One implements insulator hardware systems that have been designed to eliminate corona. Conductor sizes are also selected to avoid corona.	Not applicable. Corona is not an issue at distribution level voltages.
Shieldwire Segmentation	Hydro One does not use shieldwire segmentation due to high tower ground potential rise.	Not applicable. Shieldwire is not used on Distribution lines.
Improve Insulation Losses	Hydro One considers losses during insulation coordination design of insulator assemblies and structure configurations.	Not applicable. Insulator losses are not an issue at Distribution voltages.
Installation of Low-Loss Transformers	Hydro One's purchase specifications already include cost of losses. Hydro One assesses the vendor transformer quotations and designs based on best overall economic benefit including losses.	Hydro One exceeds CSA C802.1-13 minimum efficiency standards for service transformers, to minimize the Total Ownership Cost (TOC) of new transformers.
Installation of Power factor Correction capacitors	Hydro One has installed HV shunt capacitor at all stations to ensure power factor is kept as high as possible, thereby reducing current and minimizing losses.	Hydro One has installed shunt capacitors on some of its feeders to improve the power factor, thereby reducing current and losses.
Line Loss Mitigation Practices at Transmission and Distribution System Operation Stage		
Re-direct Power Flows	Power flows at any given time are dependent on the connected load and generation. Losses are a factor considered in the overall optimization of the generation dispatch by the IESO.	Investments to address load growth can reconfigure feeder loadingto balance loading between available feeders, which reduces losses.
Employ Distributed Generation	This is not within Hydro One control. The IESO and relevant project proponents decide the location of distributed generation	This is not within Hydro One control. The relevant project proponents decide the location of distributed generation

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B2 - ENVIRONMENTAL DEFENCE INTERROGATORY – 008 – WORKBOOK CALCULATION

P30

Date	23-Oct-20	acf	0.0749
Planner	Planner		
Comments	Test Case - developing the workbook		
Study Title	Line Refurbishment Example		

SCREENING

Note: Use actual dollars, not $k or $M

	Least Capital Expenditures			Most Capital Expenditures	
	Option 1	Option 2	Option 3	Option 4	Option 5
Option Name	Alternative 1 – 795 kcmil	Alternative 2 – 997.2 kcmil	Alternative 3 – 1192.5 kcmil	Alternative 4 – 1443.7 kcmil	
Capital Cost	$ 7,800,000.00	$ 8,003,490.00	$ 8,515,070.00	$ 8,600,000.00	
Original rank	1	2	3	4	#N/A
Capital Cost	$ 7,800,000.00	$ 8,003,490.00	$ 8,515,070.00	$ 8,600,000.00	
Losses at Peak Flow (MW)	3.70	3.03	2.61	2.16	
Annual Losses assuming Peak (MWHR)	32,412.00	26,507.76	22,872.36	18,877.80	0.00
Incremental Annual OM&A	$ -	$ -	$ -	$ -	
HOEP ($/MWHR)	$ 30.0000	$ 30.000	$ 30.000	$ 30.000	$ 30.000
Annual Revenue Cost (ARC)	$ 584,248.02	$ 599,490.15	$ 637,809.33	$ 644,170.89	$ -
Cost of annual losses (CAL)	$ 972,360.00	$ 795,232.80	$ 686,170.80	$ 566,334.00	$ -
Preliminary Total Annual Cost	$ 1,556,608.02	$ 1,394,722.95	$ 1,323,980.13	$ 1,210,504.89	
Less Than Option One?		True	True	True	
Rank	4	3	2	1	#N/A

Losses affect Ranking of Alternatives - Detailed Analysis Required - See below

Fill in Detailed section below if Losses change Ranking

DETAILED

	Option 1	Option 2	Option 3	Option 4	Option 5
Option Name	Alternative 1 – 795 kcmil	Alternative 2 – 997.2 kcmil	Alternative 3 – 1192.5 kcmil	Alternative 4 – 1443.7 kcmil	
Capital Cost	$ 7,800,000.00	$ 8,003,490.00	$ 8,515,070.00	$ 8,600,000.00	$ -
Annual Losses (MWHR - Detail)	6,828.00	5,565.50	4,801.50	3,997.00	
Incremental Annual OM&A	$ -	$ -	$ -	$ -	$ -
HOEP ($/MWHR)	$ 30.0000	$ 30.000	$ 30.000	$ 30.000	$ -
Annual Revenue Cost (ARC)	$ 584,248.02	$ 599,490.15	$ 637,809.33	$ 644,170.89	$ -
Cost of annual losses (CAL)	$ 204,840.00	$ 166,965.00	$ 144,045.00	$ 119,910.00	$ -
Total Annual Cost	$ 789,088.02	$ 766,455.15	$ 781,854.33	$ 764,080.89	
Less Than Option One?		True	True	True	
Rank	4	2	3	1	#N/A

B2 - ENVIRONMENTAL DEFENCE INTERROGATORY – 008 – VOLTAGE PROFILES

Table of historical voltages.

- These are average voltages that occurred on July 9, 2020 which is when Ontario's 2020 system peak occurred.
- Voltages are depressed as the system loading increases, and therefore this table represents a conservative voltage profile.

Area	Nominal Voltage	July 9, 2020 Daily Average Voltage
Bruce	500	550.9
Napanee	500	546.8
Napanee	230	242.6
Niagara	230	236.5
Ottawa	115	123.2
Ottawa	230	241.9
Southwest	230	245.4
Southwest	500	544.3
Sudbury	500	535.7
Sudbury	230	245.3
Sudbury	115	126.2
Thunder Bay	230	244.3
Toronto	500	532.3
Toronto	230	245.2
Toronto	115	124.2

Hydro One Transmission Losses Assessment Tool
Version: 20Alpha

Overview and Key Assumptions

The Hydro One Transmission Losses Assessment Tool is to assist the Planner to consider Transmission Line Loss Option Analysis when a transmission line investment alternatives are being considered.

The methodology and assumptions are consistent with the Transmission Line Loss Guideline jointly developed by Hydro One and the IESO in order to satisfy the Ontario Energy Board's direction in EB-2019-0082 in respect of transmission line losses.

All inputs are entered in the Inputs tab. The Planner shall input the investment alternatives in ascending order by the Planner's estimated capital investment cost of each alternative. Once the necessary inputs are completed, the necessary calculations will be executed. If the calculations are within the required tolerances, please contact your financial advisor for a full NPV.

SCREENING

Note: Use actual dollars, not $k or $M

	Least Capital Option 1	Option 2	Option 3	Option 4	Most Capital Option 5
Option Name	Alternative 1 – 795 kcmil	Alternative 2 – 997.2 kcmil	Alternative 3 – 1192.5 kcmil	Alternative 4 – 1443.7 kcmil	
Original rank	2	3	4	5	1
Capital Cost	$ 7,800,000.00	$ 8,003,490.00	$ 8,515,070.00	$ 8,600,000.00	$ -
Losses at Peak Flow (MW)	3.70	3.03	8.61	2.16	
Annual Losses assuming Peak (MWHR)	32,412.00	26,507.76	75,432.36	18,877.80	0.00
Incremental Annual OM&A	$ -	$ -	$ -	$ -	
HOEP ($/MWHR)	$ 30.0000	$ 30.000	$ 30.000	$ 30.000	$ 30.000
Annual Revenue Cost (ARC)	$ 553,950.91	$ 568,402.63	$ 604,734.71	$ 610,766.38	$ -
Cost of annual losses (CAL)	$ 972,360.00	$ 795,232.80	$ 2,262,970.80	$ 566,334.00	$ -
Preliminary Total Annual Cost	$ 1,526,310.91	$ 1,363,635.43	$ 2,867,705.51	$ 1,177,100.38	N/A
Less Than Option One?		True	False	True	False
Revised Rank	3	2	4	1	#VALUE!

Losses affect Ranking of Alternatives - Detailed Analysis Required - See below

Fill in Detailed section below if Losses change Ranking

DETAILED

	Option 1	Option 2	Option 3	Option 4	Option 5
Option Name	Alternative 1 – 795 kcmil	Alternative 2 – 997.2 kcmil	Alternative 3 – 1192.5 kcmil	Alternative 4 – 1443.7 kcmil	
Capital Cost	$ 7,800,000.00	$ 8,003,490.00	$ 8,515,070.00	$ 8,600,000.00	$ -
Annual Losses (MWHR - Detail)	6,828.00	5,565.50	4,801.50	3,997.00	
Incremental Annual OM&A	$ -	$ -	$ -	$ -	$ -
HOEP ($/MWHR)	$ 30.0000	$ 30.000	$ 30.000	$ 30.000	$ 30.000
Annual Revenue Cost (ARC)	$ 553,950.91	$ 568,402.63	$ 604,734.71	$ 610,766.38	$ -
Cost of annual losses (CAL)	$ 204,840.00	$ 166,965.00	$ 144,045.00	$ 119,910.00	$ -
Total Annual Cost	$ 758,790.91	$ 735,367.63	$ 748,779.71	$ 730,676.38	N/A
Less Than Option One?		True	True	True	False
Detailed Rank	4	2	3	1	#VALUE!

	Option 1	Option 2	Option 3	Option 4	Option 5
Estimated Rate Base	$ 7,800,000.00	$ 8,003,490.00	$ 8,515,070.00	$ 8,600,000.00	$ -
Incremental OM&A Costs	$ -	$ -	$ -	$ -	$ -
Depreciation	$ 156,000.00	$ 160,069.80	$ 170,301.40	$ 172,000.00	$ -
LT Debt	$ 193,065.60	$ 198,102.38	$ 210,765.01	$ 212,867.20	$ -
ST Debt	$ 8,580.00	$ 8,803.84	$ 9,366.58	$ 9,460.00	$ -
Required ROE	$ 265,824.00	$ 272,758.94	$ 290,193.59	$ 293,088.00	$ -
Tax Gross up on ROE	$ 95,841.31	$ 98,341.66	$ 104,627.62	$ 105,671.18	$ -
Rough CCA Tax Shield	$ (165,360.00)	$ (169,673.99)	$ (180,519.48)	$ (182,320.00)	$ -
Annual cost factor	$ 553,950.91	$ 568,402.63	$ 604,734.71	$ 610,766.38	$ -

DISCOUNT RATE INPUTS:

Capital Structure:

Third-Party Long-term Debt Ratio	49.1%
Deemed Long-term Debt Ratio	7.0%
Short-term Debt Ratio	4.0%
Common Equity	40.0%

Allowed Return:

Third-Party Long-term Debt Ratio	4.42%
Deemed Long-term Debt Ratio	4.42%
Short-term Debt Ratio	2.75%
Return on Equity	8.52%

TAX INPUTS:

Federal Income Tax Rate	15.00%
Ontario Income Tax Rate	11.50%
Income Tax rate	26.50%
Discount Rate	5.31%

CCA Rates

Class 47	8%

B2 - ENVIRONMENTAL DEFENCE INTERROGATORY - 009

Reference:

Exhibit B-2-1, TSP Section 2.3, Attachment 4

Preamble:

In a letter dated May 14, 2021, Environmental Defence provided the following summary of its comments on the Transmission Line Loss Guideline:

1. Use forecast demand figures to estimate loss reductions, not historic figures;
2. Use a net-present-value ("NPV") calculation over the asset lifetime, not a first-year cost comparison, at least for the more detailed calculations;
3. Use accurate avoided electricity cost assumptions, not only the HOEP;
4. Use hourly or seasonal avoided electricity cost figures in the detailed calculations to account for the fact that transmission losses are highest when electricity costs are highest;
5. Consider loss reductions alongside other monetized benefits (e.g., capacity on the bulk electricity system), not in isolation, including these steps:
    a. Explore with the IESO whether there are other benefits of increased conductors that can be monetized and document the outcome of this exploration; and
    b. Ensure the detailed loss valuation calculations are completed and added to overall cost-benefit evaluations; and
6. Conduct sensitivity analysis: (a) for projects over a certain cost threshold, and (b) for all projects until the completion of the IESO-coordinated work on avoided electricity cost figures.

Interrogatory:

a) Are these comments still under consideration?

b) Please provide a response to each of those comments (for further details please see the letter of May 14, 2021).

c) Please file a copy of the May 14, 2021 letter as an attachment to this response.

d) Did Hydro One make any changes to its proposed guideline as a result of its consultation with stakeholders? If not, why not?

e) Is Hydro One still in the process of finalizing the guidelines and open to refinements?

Response:

a) Yes. These comments are under consideration.

b) These comments are being considered as part of the IESO Stakeholder Engagement process. Hydro One believes that this is the appropriate forum for considering these comments and the views of all relevant stakeholders.

c) A copy of the May 14, 2021 letter is at Attachment 1. The terms of reference of the stakeholder session provided that participation was on a without prejudice basis. Notwithstanding Environmental Defence's waiver of without prejudice in requesting the filing of the attached correspondence, all other correspondence filed by parties and commentary provided by them and Hydro One remains on a without prejudice basis.

d) Please refer to b) above.

e) Hydro One completed the Transmission Line Loss Guideline on March 1, 2021 (see TSP Section 2.6). Please refer to b) above.

Elson
Advocacy

May 14, 2021

Robert Reinmuller and Frank D'Andrea
Director, Transmission System Planning
Chief Regulatory Officer
Hydro One Networks Inc.
483 Bay Street, South Tower, 7th Floor
Toronto, ON, M5G 2P5

Dear Mr. Reinmuller and Mr. D'Andrea

Re: Comments on the Draft Transmission Line Loss Guideline

I am writing to provide comments on behalf of Environmental Defence on Hydro One's draft transmission line loss guideline. Thank you for this opportunity and for committing to consider intervenor input.

Context

Hydro One plans to replace approximately 425 km of its conductors every year.[1] If this continues, that will amount to 8,500 km over the next two decades. These assets have lives of between 60 to 90 years.[2] It is very important that Hydro One consider whether ratepayers would benefit from upsizing these conductors or replacing them with lower-loss conductor types (e.g., ACSR/TW). In appropriate cases this could reduce customer energy bills by (a) reducing line losses, (b) increasing peak capacity, and/or (c) avoiding future reinforcement project.

When a conductor is being replaced or built, there is a one-time opportunity to consider upsizing it. Once the project is complete, that opportunity is lost. It is important that time and effort be taken to ensure the right decision is made.

Overview of the Comments

Environmental Defence commends Hydro One for preparing these guidelines. This is a positive step forward. Environmental Defence also supports Hydro One's approach of having explicit screening criteria such that detailed hourly calculations are only carried out for a more limited set of projects.

[1] EB-2019-0082, Exhibit I, Tab 06, Schedule 11 ("Hydro One plans to replace 2,127 circuit-km of conductor over the 2020 to 2024 period").
[2] EB-2020-0265, Exhibit I, Tab 1, Schedule 3, Page 1.

Environmental Defence recommends that Hydro One:

1. Use forecast demand figures to estimate loss reductions, not historic figures;

2. Use a net-present-value (“NPV”) calculation over the asset lifetime, not a first-year cost comparison, at least for the more detailed calculations;

3. Use accurate avoided electricity cost assumptions, not only the HOEP;

4. Use hourly or seasonal avoided electricity cost figures in the detailed calculations to account for the fact that transmission losses are highest when electricity costs are highest;

5. Consider loss reductions alongside other monetized benefits (e.g., capacity on the bulk electricity system), not in isolation, including these steps:

    a. Explore with the IESO whether there are other benefits of increased conductors that can be monetized and document the outcome of this exploration; and

    b. Ensure the detailed loss valuation calculations are completed and added to overall cost-benefit evaluations; and

6. Conduct sensitivity analysis: (a) for projects over a certain cost threshold, and (b) for all projects until the completion of the IESO-coordinated work on avoided electricity cost figures.

1. Use forecast demand figures to estimate loss reductions, not historic figures

We recommend that Hydro One use forecast demand figures to estimate loss reductions, not historic figures. This would be more accurate and is not onerous. It can be as simple as escalating the figures at a fixed percentage each year based on approximate demand increases. This should at least be carried out for the more detailed loss reduction calculations.

The draft guidelines would account for electricity demand increases only if they are expected to be over 25% over 10 years. This approach is inaccurate because the analysis would implicitly assume 0% demand increases over a decade for a project that is forecast to have 20% demand increases over a decade. It is also biased against transmission loss reduction investments.

2. Use an NPV calculation over the asset lifetime, not a first-year cost comparison

We recommend that Hydro One use an NPV calculation over the asset lifetime, not a first-year cost comparison, at least for the more detailed calculations. We believe an NPV calculation is very much preferred because of the following factors:

(a) Almost all economic assessments set out in Board guidelines involve an NPV calculation;

(b) NPV calculations use explicit and transparent assumptions on the project time horizon and discount rate;

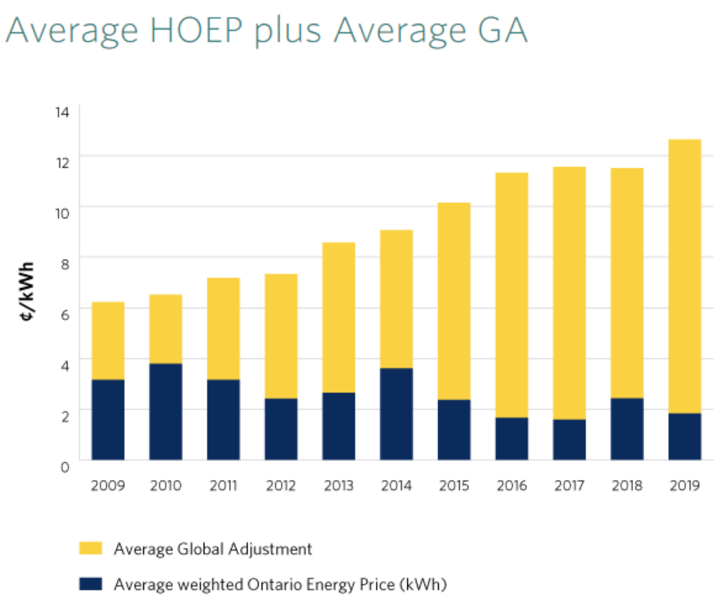
(c) NPV calculations can compare investments with varying lifetimes;

(d) NPV calculations are easy to do; and

(e) NPV assessments result in a net costs/savings figure that can be added to other benefits or subtracted from other costs to assess the overall cost-effectiveness of an alternative.

3. Use accurate avoided electricity cost assumptions, not only the HOEP

We recommend that Hydro One use accurate avoided electricity cost assumptions, not only the HOEP. As illustrated below, using just the HOEP excludes approximately 85% of the actual electricity savings benefits of transmission loss reductions. This is inaccurate. It also hugely skews the analysis against incremental investments to reduce transmission losses.



[3]

Hydro One cannot rely on the IESO as the reason it uses the HOEP. The IESO has stated under oath that it does not dictate Hydro One's loss valuation methodology.[4] The IESO also stated under oath that it *does not* take the position that the appropriate method is to use only the HOEP.[5] Instead, the IESO wishes to explore this issue further.[6]

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[3] EB-2020-0265, Evidence of Travis Lusney (updated March 18, 2021), p. 8.
[4] EB-2020-0265, Technical Conference Transcript, March 16, 2021, pp. 15-16 ("MR. ELSON: So if Hydro One wishes to use a different methodology -- well, let me put it a different way. The IESO isn't dictating that HONI use one loss methodology versus another loss valuation methodology? MS. LUND: No.").
[5] EB-2020-0265, Technical Conference Transcript, March 16, 2021, p. 21 ("MR. ELSON: I guess the IESO isn't taking the position that the appropriate method is to use only the HOEP. At this stage, you not taking a position on one method being appropriate over another method being appropriate? MR. MARIA: That's right. We want to explore this further in the stakeholder engagement.").
[6] *Ibid*.

For more details on why the HOEP is inaccurate, see Appendix A, attached. We acknowledge that this issue is being addressed in more detail by the IESO. In the meantime, if Hydro One wishes to be consistent with the IESO's current nuanced position, Hydro One should only screen out transmission losses based on an analysis that include the full avoided electricity cost, not just the HOEP.

4. Use hourly or seasonal avoided electricity cost figures

We recommend that Hydro One use hourly or seasonal avoided electricity cost figures in the detailed calculations (i.e., not for the screening) to account for the fact that transmission losses are highest when energy costs are highest.

Transmission losses are highest at peak demand.[7] Therefore, using a figure that represents total annual transmission losses and multiplying it by an average annual electricity price can undervalue the actual loss reduction benefits.[8] For example, if the line in question is a critical path, a higher amount of transmission loss reductions at the peak would allow a greater degree of firm capacity to be relied on through that wire. The most accurate way to assess losses is to examine them on an hourly basis.[9] The next best option is on-peak, mid-peak, and off-peak.[10] A number of valuation techniques can be used to account for this factor in an efficient way.[11]

5. Consider loss reductions alongside other monetized benefits

We ask that Hydro One consider loss reductions alongside other monetized benefits, not in isolation. Other benefits might include increased peak capacity, increased import/export capacity, or reducing generation bottlenecks. These will generally only arise for reinforcements to the bulk electricity system. All of the relevant costs and benefits need to be considered together.

It is worth noting that electricity demand may increase considerably within the lifetime of the assets that Hydro One is currently planning. Additional capacity in the bulk electricity system may become very important for keeping electricity costs low. In particular, almost all vehicles will likely become electric in the next one or two decades. This is a significant load. A great deal of Ontario's space and water heating may be converted to electric heat pumps over that same

[7] EB-2020-0265, Technical Conference Transcript, March 16, 2021, p. 22 ("MS. LUND: Generally, losses are higher when flows 2 across transmission facilities are higher. So at peak 3 demand, losses will be high.").
[8] *Ibid.*, p. 23 ("MR. ELSON: Using the average annual HOEP or any average annual number multiplied by the annual loss reductions wouldn't be reflecting the time when those losses occurred and the price of electricity at that time. Is that fair to say? MR. RISVAY: Correct.")
[9] *Ibid.*, ("MR. ELSON: So the most accurate way would be to look at it on an hourly basis? MR. RISVAY: Correct.")
[10] *Ibid*. ("MR. ELSON: I assume the next most accurate would be to look at it based on on-peak, mid-peak, and off-peak, perhaps? MR. RISVAY: If they were available, yes.")
[11] *Ibid*. ("MR. ELSON: I assume there may be some other ways to approximate this by looking at the loading of the lines and other ways, such that it is not either looking at the average annual or at 5-minute intervals. There's ways to do this in a more efficient way, is that fair to say? MR. RISVAY: There is a number of ways you can conduct this analysis, yes.").

time period. The benefits of increased capacity are important to consider in light of this likelihood of greatly increased electricity demand.

To provide a simplified example, an incremental upgrade could cost $5 million and bring about $4 million in avoided transmission losses (NPV) and $4 million in other system benefits (NPV). If transmission losses are considered in isolation, the incremental update is not cost-effective. However, the upgrade would save $3 million if considered holistically.

Three adjustments are needed to consider loss reductions alongside other benefits:

(a) First, Hydro One would need to explore with the IESO whether there are other benefits of increased conductor sizing that can be monetized. We recommend that this step be added to the guideline and document.

(b) Second, Hydro One would need to avoid screening out transmission losses at stage one where other benefits have been identified. The detailed loss valuation calculations would be necessary so that the outcome could be factored into the overall cost-effectiveness assessment that includes other monetized benefits.

(c) Third, this would be made much easier by using a standard NPV calculation. The system benefit calculations from the IESO will likely be expressed as an NPV figure.

6. Conduct sensitivity analysis:

The sensitivity analysis provided in Hydro One's presentation was helpful. We recommend that Hydro One update its guideline to require that a sensitivity analysis be completed for:

(a) Projects over a certain cost threshold; and

(b) All projects that are assessed prior to the completion of the IESO-coordinated work on avoided electricity cost assumptions (to address uncertainty regarding accurate avoided electricity cost figures).

Conclusion

We believe the above adjustments will provide a much more accurate and fair assessment of incremental investments to reduce transmission losses. Without these adjustments, the combined impacts of the various factors would mean that these investments are subject to a huge and inaccurate discount in Hydro One's planning processes, to the detriment of electricity customers.

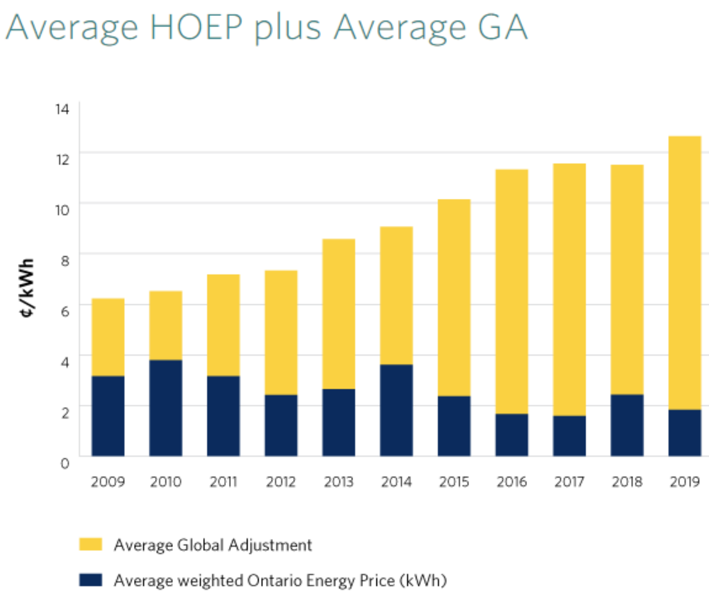
These comments have focused on customer cost savings. However, there are also significant environmental benefits. Loss reduction investments have the greatest impact at times of peak demand. Therefore, they reduce the need to rely on fossil fuel power generation facilities that are utilized at peak times. These investments also reduce overall energy and capacity needs, which will ease the transition away from fossil fuel vehicles and heating. It is important that cost-benefit comparisons be done fairly and accurately, both to minimize system costs and to combat climate change.

Yours truly,

Kent Elson

Appendix A – Avoided Electricity Cost Figures

It is critical that the valuation of loss reductions be based on actual avoided electricity costs, not only the HOEP. This is likely the most important issue with respect to transmission loss reduction valuation. Mr. Lusney's evidence in EB-2020-0265 shows that this excludes roughly 85% of the actual price of electricity in 2019.[12] This is illustrated in the following figure:



In the following lengthy excerpt, Mr. Lusney explains why the HOEP is not appropriate to value transmission loss reductions:

> *In Ontario, wholesale energy prices are determined by two components. The first component is the Hourly Ontario Energy Price (HOEP), which is partially representative of the commodity portion of wholesale electricity prices. Due in part to Ontario's hybrid market structure, the market clearing price (which is reflected in the HOEP) does not reflect the entire wholesale electricity price. Practically all generation resources receive additional payments for their energy production. The additional payments are made through contracts from IESO or for rate-regulated generation assets owned by Ontario Power Generation. The additional payments to supply resources are collected from customers through the GA.*
>
> *Over the past decade, the portion of wholesale electricity prices attributed to HOEP has fallen from ~50% in 2009 to roughly 15% in 2019 …*
>
> *The value of transmission loss reductions is derived from the price paid to generation resources in Ontario. If no transmission losses existed in the electricity grid, the price paid to generators for injecting energy into the grid would also be the price paid by electricity consumers throughout the province. The existence of transmission losses means the volume of energy used to determine payment for energy injected by generators is higher than the*

[12] EB-2020-0265, Evidence of Travis Lusney (updated March 18, 2021), p. 8.

volume of energy delivered to customers. In other words, transmission losses represent the volume of energy Ontario consumers have paid generators to inject into the grid but have lost to inefficiencies in the power system. The simple diagram below provides an illustrative example.

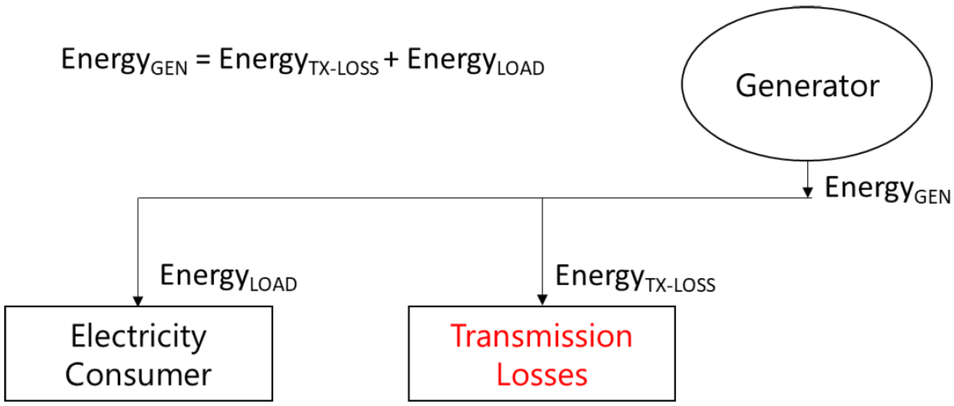


Figure 3: Illustrative Example of Transmission Losses

HOEP is an energy payment for all supply resources that inject energy into the Ontario electricity grid. Contract payments and rate-regulation funding generally take two forms: an energy payment for energy injected or a capacity payment for maintaining the participation of the generator in the Ontario electricity market. Typically, the energy payment under contracts or rate-regulation is through a Contract-For-Differences (CfD) structure where the amount paid to generators is the difference between the contract price and HOEP; thus, ensuring the generator receives the contract price regardless of variations in HOEP.

A vast majority of the generation resources in Ontario receive energy payments through their contract or rate-regulation arrangements. This includes all of Ontario's nuclear generation fleet, almost all hydroelectric facilities, all the non-hydro renewables (i.e., solar, wind and bioenergy) and some of the gas-fired generators. In total I estimate that roughly 90% of the annual energy production by supply resources in Ontario in 2020 receives a top-up payment in addition to HOEP for energy injected into the Ontario electricity grid.

Put simply, transmission losses represent energy that has been paid for by ratepayers but is unusable due to system inefficiencies. For this reason, it is incorrect to only use HOEP when valuing transmission loss reductions for the purpose of comparing alternative solutions. A much more accurate alternative is to use the total cost of wholesale electricity (i.e., HOEP + GA) to determine the value of transmission loss reductions…

The behaviour of the HOEP during times of surplus baseload provides another illustration of why it is inaccurate to rely on the HOEP alone to value loss reductions. Due in part because of oversupply and top-up payments from contracts and rate-regulated assets, Ontario experiences significantly more negative-priced hours for HOEP then the market energy price *in other jurisdictions. When looking at the HOEP alone, it appears as though generators are paying customers for the energy they produce and inject into the system. Contract & rate-regulation payments from the IESO create an offset such that generators are net-revenue-positive. More importantly, the top-up payments for generators are costs that ratepayers must fund even through the market price for electricity suggests ratepayers are being paid for energy.*

Ontario has experienced many hours of Surplus Baseload Generation that leads to negative HOEP, and the IESO expects Surplus Baseload Generation conditions to continue over the next 20 years

Using only HOEP in transmission loss analysis leads to inappropriate conclusions. Transmission losses for negative priced hours for HOEP would appear to be a net savings for customers even though energy is being lost in the transmission system. Further, when HOEP is $0/MWh the system would appear lossless even though energy is being lost throughout the system. This market dynamic significantly skews the assessment of transmission losses and does not reflect the actual cost of lost energy in the transmission system.

The year 2016, when the existing HxM path experienced the highest loading to date, is a good example of how skewed transmission loss analysis can be if only HOEP is used. The table below provides a summary of the negative priced hours (i.e., HOEP <$0/MWh), zero-dollar hours (i.e., HOEP = $0/MWh), and positive priced hours. In 2016 almost a quarter of all hours were negative or $0. That means a transmission loss assessment would view no cost for transmission losses in some hours or potentially a benefit of having transmission losses in the system. Viewing inefficiencies as a benefit to the power system for ~12% of the hours clearly shows the flaw of using HOEP only for transmission loss assessments.

Table 1: 2016 Hourly HOEP Summary[12]

2016 Hourly HOEP	Hours	% of Year
HOEP < $0 (Negative Priced Hours)	1,076	12%
HOEP = $0	920	10%
HOEP > $0	6,788	77%

It is clear from Mr. Lusney's evidence that it is inaccurate to use the HOEP to value transmission loss reductions.

Finally, we note that in EB-2020-0265 Hydro One conducted a sensitivity analysis that included what it described as a $100/MWh HOEP. This is a positive step forward, but is not sufficient because:

(a) Hydro One initially screened out the larger conductor using an analysis based on the HOEP alone.[13]

(b) The sensitivity analysis was not conducted when the initial decision to screen out the larger conductor was made. It was only conducted long afterwards, to justify the previous decision when responding to an interrogatory.[14]

Hydro One should not be valuing transmission loss reductions based on the HOEP when that excludes roughly 85% of actual electricity costs.

[13] EB-2020-0265, Technical Conference Transcript, March 16, 2021, p. 118 ("MR. ELSON: You just mentally took 600 megawatts, multiplied it by the HOEP, and based on that decided that alternative 4 was not cost-effective. Correct? MR. QURESHY: Right.").
[14] EB-2020-0265, Technical Conference Transcript, March 16, 2021, p. 114 ("MR. ELSON: So this sensitivity analysis, these numbers in table 1, you prepared sometime in February of 8 2021 for the purpose of answering this interrogatory. MR. QURESHY: Yes.").

B2 - ENVIRONMENTAL DEFENCE INTERROGATORY - 010

Reference:

Exhibit B-2-1, TSP Section 2.3, Attachment 4

Interrogatory:

a) Please list the various electricity price forecasts that Hydro One uses for various planning purposes.

b) Please provide a copy of the forecasts listed in (a).

c) Please list the various capacity price forecasts that Hydro One uses for various planning purposes.

d) Please provide a copy of the forecasts listed in (c).

Response:

a) Hydro One uses the IESO's historic Hourly Ontario Energy Price (HOEP)[1] for transmission loss evaluation.

b) Please refer to a) above.

c) Hydro One does not use a capacity forecast for transmission planning.

d) Please refer to c) above

[1] Link to IESO HOEP data
https://www.ieso.ca/en/Power-Data/Price-Overview/Hourly-Ontario-Energy-Price

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B2 - ENVIRONMENTAL DEFENCE INTERROGATORY - 011

Reference:

Exhibit B-2-1, TSP Section 2.11, T-SA-01 to T-SA-10

Interrogatory:

a) Please complete the following table for T-SA-01 to T-SA-10:

	Total Cost	Total CIAC	Total forecast incremental revenue
T-SA-01			
…			
T-SA-10			

b) Does Hydro One's application include projects that are 100% customer funded? If not, please estimate the cost of these projects over 2023-2027.

c) Please provide a table showing the system access costs for each year from 2018 (historic) to 2027 (forecast) broken down by those funded by the customers being connected and those recovered from all ratepayers through the revenue requirement.

Response:

a) The completed table is provided below. The Contribution-in-Aid-of-Construction (CIAC) is defined simply as Capital Contribution. The Capital Contribution is determined by subtracting the incremental revenue from the customer's load from the total project cost.

ISD	Investment Title	Total Project Cost ($ Millions)	Customer Capital Contribution ($ Millions)	Total Forecast Incremental Rate Revenue ($ Millions)
T-SA-01	New Customer Connection Station	100.0	73.0	27.0
T-SA-02	IAMGOLD – 115 kV Mine Connection	65.1[1]	33.3	25.8
T-SA-03	Halton TS: Build a Second 230/27.6kV Station	34.9	26.9	8.0
T-SA-04	Connect Metrolinx Traction Substations	25.3	17.4	8.0
T-SA-05	Future Transmission Load Connection Plans[2]	109.1	70.6	38.5
T-SA-06	Protection and Control Modifications for Distributed Generation[2]	18.0	18.0	0.0
T-SA-07	Secondary Land Use Projects	112.2	56.2	56.0
T-SA-08	H29/H30: Reconductor 230kV Circuits	8.0	2.7	5.3
T-SA-09	New Transformer Station in Northern York Region	35.0	23.3	11.7
T-SA-10	Build Leamington Area Transformer Stations	135.9	0.0	135.9

[1] includes $6.1M in removal costs as outlined in ISD T-SA-02
[2] reflects total project costs over the five-year test period as outlined in the referenced ISD

b) Yes, Hydro One's application includes 100% customer funded projects.

c) Please see table below for the System Access historical and future forecast costs, broken down by those funded by the connecting customers through capital contributions and those recovered through incremental rate revenue as a result of the load connected.

($ Millions)	Historical				Bridge	Test Years				
	2018 Actual	2019 Actual	2020 Actual	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast
Total Expenditures	95.3	88.7	90.8	113.8	78.3	157.6	154.3	116.6	80.8	83.8
Customer Capital Contributions	61.7	42.7	71.4	73.6	46.9	78.2	83.4	56.8	44.3	33.7
Incremental Rate Revenue	33.7	46.1	19.4	40.1	31.5	79.4	70.9	59.8	36.5	50.1

B2 - ENVIRONMENTAL DEFENCE INTERROGATORY - 012

Reference:

TSP Section 2.11, T-SR-01, Page 31

Interrogatory:

a) Please reproduce the table at page 31 removing the columns showing the annual capital investments but adding the following columns: (i) capacity pre-construction, (ii) capacity post-construction, (iii) ancillary benefits ($).

b) When Hydro One upgrades transfer stations, does it consider whether to increase their capacity? If yes, what factors are considered?

Response:

a) Please see the reproduced table below. There are no ancillary benefits where the capacity is unchanged.

ISD Ref.	Station Name	EB-2019-0082	Type	Installed Transformation Capacity (MVA)		Net Capital Investment ($ Millions)		In Service Year
				Pre-Construction	Post-Construction	23-27 Total	Proj. Total	
T-SR-01.01	Claireville TS	SR-04	E	3,000	3000	8.6	21.7	2023
T-SR-01.02	Seaforth TS	SR-03	P	500	500	20.1	54.4	2023
T-SR-01.03	Fort Frances TS	SR-03	P	250	250	11.9	20.1	2023
T-SR-01.04	Keith TS[1]	SR-03	E	230	500	11.0	36.5	2023
T-SR-01.05	Whitedog Falls SS	-	P	N/A	N/A	3.7	8.1	2023
T-SR-01.06	Milton SS	SR-04	P	N/A	N/A	12.6	19.2	2023
T-SR-01.07	Rabbit Lake SS	SR-04	P	N/A	N/A	11.0	23.1	2023
T-SR-01.08	Lakehead TS	SR-04	P	500	500	21.6	36.1	2024

ISD Ref.	Station Name	EB-2019-0082	Type	Installed Transformation Capacity (MVA)		Net Capital Investment ($ Millions)		In Service Year
				Pre-Construction	Post-Construction	23-27 Total	Proj. Total	
T-SR-01.09	Sarnia Scott TS	SR-03	P	500	500	21.4	26.4	2024
T-SR-01.10	Kenora TS	SR-04	P	125	125	13.7	15.9	2025
T-SR-01.11	Marathon TS	SR-04	P	250	250	11.6	14.7	2025
T-SR-01.12	Wawa TS	SR-02	P	250	250	36.6	44.8	2025
T-SR-01.13	Lakehead TS	-	P	500	500	24.2	29.1	2025
T-SR-01.14	Middleport TS	SR-03	P	1500	1500	29.2	29.8	2025
T-SR-01.15	Porcupine TS	SR-03	P	1170	1220	71.6	77.7	2025
T-SR-01.16	Essa TS	-	P	1500	1500	35.8	36.6	2025
T-SR-01.17	Mackenzie TS	SR-04	P	125	125	46.6	51.4	2025
T-SR-01.18	Algoma TS	SR-03	P	240	250	28.6	30.0	2026
T-SR-01.19	Des Joachims TS	-	P	250	250	6.7	6.7	2026
T-SR-01.20	Otto Holden TS	SR-03	P	120	125	61.4	65.3	2026
T-SR-01.21	Ansonville TS	-	P	125	125	8.7	8.7	2027
T-SR-01.22	Manby TS	SR-03	P	1500	1500	51.7	52.5	2027
T-SR-01.23	Fort Frances TS	-	P	250	250	20.6	20.6	2027
T-SR-01.24	Merivale TS	SR-04	P	500	500	167.8	168.4	2027
T-SR-01.25	Beach TS	SR-03	P	788	750	44.4	45.3	2028
T-SR-01.26	Lennox TS	-	P	1500	1500	31.4	34.4	2028

ISD Ref.	Station Name	EB-2019-0082	Type	Installed Transformation Capacity (MVA)		Net Capital Investment ($ Millions)		In Service Year
				Pre-Construction	Post-Construction	23-27 Total	Proj. Total	
T-SR-01.27	Buchanan TS	SR-03	P	750	750	32.8	39.8	2028
T-SR-01.28	Owen Sound TS	SR-06	P	250	250	21.6	28.1	2028
T-SR-01.29	Kenora TS	-	P	125	125	10.8	15.0	2028
T-SR-01.30	Mississagi TS	SR-04	P	N/A	N/A	22.1	32.4	2028
T-SR-01.31	Hawthorne TS	-	P	3250	3250	27.1	33.7	2028
T-SR-01.32	Cataraqui TS	-	P	500	500	24.9	31.1	2028
T-SR-01.33	Claireville TS	-	P	3000	3000	22.0	49.2	2029
T-SR-01.34	Beck 2 TS	-	P	2000	2000	9.4	16.7	2029
T-SR-01.35	Claireville TS	-	P	3000	3000	11.0	21.1	2029
	Net Investment Cost					**994.1**	**1244.6**	

[1] Ancillary benefits have not been quantified.

b) Capacity requirements for network transformer station are determined as part of the bulk and regional planning processes. Hydro One identifies transformers for replacement and works with the IESO and/or the Regional Planning Technical Working Group to determine whether a change in capacity is required. An increase in capacity would be considered if forecast flows were expected to increase.

B2 - ENVIRONMENTAL DEFENCE INTERROGATORY - 013

Reference:

TSP Section 2.11, T-SR-13, Page 22

Preamble:

Hydro One plans to spend $833.2 million on transmission line complete refurbishments.

Interrogatory:

a) Please reproduce the table at page 22 removing the columns showing the annual capital investments but adding the following columns: (i) current conductor size, (ii) proposed conductor size, (iii) maximum conductor size without tower replacement, (iii) has the transmission loss guideline analysis been undertaken for this project?, (iv) would an upsized conductor be cost-effective if losses were valued at $120/MWh, (v) has an upsized conductor been screened out? If yes, why.

b) Please provide the documentation produced in the process of applying the transmission line loss guideline to each of the projects in the table on page 22.

Response:

a) Please see Interrogatory B2-ED-005 part a)

b) Please see Interrogatory B2-ED-005 part a)

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B2 - ENVIRONMENTAL DEFENCE INTERROGATORY - 014

Reference:

Exhibit B-2-1, TSP Section 2.1, Page 21

Preamble:

Section 4.1 of the 2015 OEB CDM Guidelines states:

> *Distributors may apply to the Board for funding through distribution rates to pursue various activities such as CDM programs, demand response programs, energy storage programs and programs reducing distribution losses for the purpose of deferring the capital investment for specific distribution infrastructure. Any such application must include a consideration of the projected effects to the distribution system on a long-term basis.*
>
> *Applications can be filed at any time. The Board expects that as part of its long-term planning processes, a distributor will consider applications for CDM programs to defer distribution infrastructure. The distributor should explain the proposed program in the context of the distributor's five-year Distribution System Plan ("DSP") or explain any changes to its system plans that are pertinent to the program.*

Interrogatory:

a) Is Hydro One permitted to seek approval for CDM programs to cost-effectively defer or avoid transmission system upgrades? Please include excerpts of the applicable rules or guidelines.

b) Is Hydro One proposing any CDM programs to defer transmission infrastructure in this application? If not, why not.

c) Please describe the steps taken by Hydro One to consider CDM as an alternative to each transmission system service project over 2023-2027. Please address each project and sub-project separately.

d) What is the main entity responsible for considering non-wires-alternatives to transmission system service projects?

Response:

a) To clarify, the 2015 CDM Guidelines referenced in above preamble are no longer applicable given the end of the Conservation First Framework to which the Guidelines were to apply. Updated CDM Guidelines, including the provision for distribution rate funded CDM, are the subject of the OEB's review in EB-2021-0106. Any consideration of a distribution rate funded initiative will be subject to the completion of that process. Moreover, Hydro One notes that a utility is under no obligation to make a request for rate funded CDM.

Please note, all CDM programs are to be administered by the IESO as per the Province of Ontario 2021-2024 Conservation and Demand Management Framework[1]. Hydro One Transmission continues to work with the IESO along with the distributors to identify any CDM program that may cost effectively defer transmission system upgrade as part of the Regional Planning Process. However, at this time Hydro One Transmission does not seek approval for CDM programs.

b) Please refer to response in part (a) above.

c) Please refer to response in part (a) above. In an effort to be of assistance, Hydro One would like to note that CDM is not an option for most of the System Service investments. For the ones where CDM would have been an option, the Regional Planning Technical Working Group led by the IESO has reviewed the CDM option in the relevant IRRP and has recommended the transmission option.

ISD#	Project	Comments
T-SS-01	Nanticoke TS: Connect HVDC Lake Erie Circuits	CDM is not an option. This investment facilitates an interconnection with the US.
T-SS-02	St. Lawrence TS: Phase Shifters Replacement	CDM is not an option. This investment facilitates an interconnection with the US.
T-SS-03	Merivale TS to Hawthorne TS: 230KV Conductor Upgrade	Transmission is the preferred option. Please refer to EB-2020-0265 Exhibit I-01-02.
T-SS-04	Richview TS x Trafalgar TS 230 kV Conductor Upgrade	CDM is not an option. This investment is in response to changes in generation resources. Please refer to EB-2021-0136 Exhibit B-02-01.
T-SS-05	Merivale TS: Add 230/115kV Autotransformers	The Ottawa 115 kV System Study currently underway will confirm how CDM (or other non-wires alternatives) would be most cost effectively integrated with required wires investments.

[1] Province of Ontario 2021-2024 Conservation and Demand Management Framework - https://ero.ontario.ca/notice/019-2132

ISD#	Project	Comments
T-SS-06	Southwest GTA Transmission Reinforcement	Transmission is the preferred option. Please see the IESO 2019 Toronto IRRP which confirmed the need and recommended proceeding with the project.
T-SS-07	West of Chatham Reinforcement	CDM is one part of an integrated plan to address the area's needs, in combination with the transmission investment to meet the area's need.
T-SS-08	Future Transmission Regional Plans	CDM will be considered by the IESO as part of future IRRP Studies.

d) The IESO is the main entity responsible for considering non-wires-alternatives as outlined in Exhibit B-1-1, SPF Section 1.2.

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B3 - ENVIRONMENTAL DEFENCE INTERROGATORY - 015

Reference:

Exhibit B-3-1, DSP Section 3.4, Page 2

Preamble:

> *Hydro One continues to apply the DSC rules related to Renewable projects by funding a portion of the expansion cost (up to $90,000/MW) and 100% of Renewable Enabling Improvement (REI) investments.*

Interrogatory:

a) Please describe the eligibility criteria for the above funding. Please attach the relevant sources for the eligibility.

b) What discretion does HONI have in interpreting the eligibility criteria.

c) Does this apply to storage? If not, why not?

Response:

a) Hydro One interprets eligibility for classification as a renewable energy source according to the definition in the electricity act:

> *renewable energy source" means an energy source that is renewed by natural processes and includes wind, water, biomass, biogas, biofuel, solar energy, geothermal energy, tidal forces and such other energy sources as may be prescribed by the regulations, but only if the energy source satisfies such criteria as may be prescribed by the regulations for that energy source; ("source d'énergie renouvelable)*

b) Hydro One is obligated to comply with the Distribution System Code.

c) Energy Storage does not meet the definition of a Renewable Energy Source according to the Electricity Act, because it does not renew from natural processes.

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B3 - ENVIRONMENTAL DEFENCE INTERROGATORY - 016

Reference:

Exhibit B-3-1, DSP Section 3.4, Page 2

Preamble:

> *Since 2018, the DER applications received by Hydro One have been primarily combined heat and power/co-generation, natural gas, diesel and BESS. The cost for connecting these non-renewable energy projects to Hydro One distribution system is 100% recoverable from the DER customers.*

Interrogatory:

a) Why does Hydro One consider Battery Energy Storage Systems (BESS) to be non-renewable? Is this Hydro One's interpretation of eligibility rules? Please explain and provide sources.

b) Storage systems are also system loads and thus generate revenue for the distribution system. Are the connection costs for storage systems reduced by forecast revenues for the purposes of calculating customer capital contributions? Please explain why or why not. Please provide an answer for
   i. a stand-alone storage device and

   ii. a storage system added to an existing load customer.

Response:

a) See interrogatory response to B3-ED-015.

b) i) and ii)

Distribution revenues are only a consideration in determining the contribution required from a customer when distribution system expansion is required to accommodate the connection. If expansion is required to accommodate a customer connection or upgrade, Hydro One performs an economic evaluation as prescribed in Appendix B of the Distribution System Code. In this economic evaluation incremental distribution revenues offset expansion costs. This applies to all expansions, regardless of customer rate class or mode of operation.

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B3 - ENVIRONMENTAL DEFENCE INTERROGATORY - 017

Reference:

Exhibit B-3-1, DSP Section 3.4, Page 3-7

Interrogatory:

a) Please describe the DERs that are capacity allocation exempt, and why.

b) Please provide a table showing the forecast for each year up 2027 in DERs (total kW) for storage, fossil gas, diesel, solar, wind, and other.

c) Does the restricted DS and TS list on page 7 include all the stations that do not have capacity to connect DER? If not, please provide the complete list.

d) Please reproduce Table 4 adding columns to indicate the approximate number of customers and MW load served by each station.

e) If the restrictions on the feeders in Table 4 were eliminated, approximately how many DERs would likely apply for connections on those feeders (# and MW)? Please provide an estimate based on the average numbers of DER connections elsewhere in Hydro One's service area.

Response:

a) The DER which is "Capacity Allocation Exempt (CAE)" means an embedded generation facility which is not a micro-embedded generation facility and which has a name-plate rated capacity of 250 kW or less in the case of a facility connected to a less than 15 kV line and 500 kW or less in the case of a facility connected to a 15 kV or greater line. This is the definition of CAE projects as per the Distribution System Code.

b) Hydro One does not have information necessary to predict the composition of future DER applicants.

Based on actuals from the historical participation in the IESO ICI program, Hydro One expects the vast majority of non-renewable projects >10kW to be Battery Energy Storage, with a few Natural Gas turbines. The average size of such projects has been approximately 2.5MW.

Historical net-metering projects >10kW have largely been less than 100kW in size, but there is no size limit for net-metering.

c) Yes, with the following clarification:
Chesterville TS, Cobden TS, Pembroke TS, and Wallace TS are only partially constrained, and will accept microDER or non-exporting DER applications of any size.

d) Below, we have reproduced Table 4 and added the requested peak load and number of customers served.

Station Name	Bus Name	Limitation Type	Number of Customers Served	Peak Load (MW)
BARWICK TS	BY	THERMAL	4018	14
CHESTERVILLE TS	BY	TRANSMISSION CONSTRAINT	9221	36
COBDEN TS	N/A	TRANSMISSION CONSTRAINT	8704	20.4
KLEINBURG TS	BY	SHORT CIRCUIT	7964	60
LAMBTON TS	DY	SHORT CIRCUIT	6461	69
MORRISBURG TS	JQ	THERMAL	8507	50
NORFOLK TS	BY	SHORT CIRCUIT	16509	62
PEMBROKE TS	BY	TRANSMISSION CONSTRAINT	2824	43
WALLACE TS	YQ	TRANSMISSION CONSTRAINT	14289	36.8
WANSTEAD TS	JQ	SHORT CIRCUIT	5965	43
CALSTOCK HVDS	N/A	THERMAL	415	6
CHAPLEAU HVDS	B2	THERMAL	429	7
FAUQUIER HVDS	N/A	THERMAL	1013	3.2
LAFOREST ROAD HVDS	B1	THERMAL	3882	13
SMOOTH ROCK FALLS HVDS	N/A	THERMAL	799	3
CUMBERLAND HVDS	N/A	SHORT CIRCUIT	1228	3.3
SHARBOT HVDS	N/A	SHORT CIRCUIT	2072	3.2
MANOTICK HVDS	N/A	SHORT CIRCUIT	2343	17

e) Hydro One does not have any information to predict the number of DER applications that would be made on restricted stations after the removal of restrictions.

B3 - ENVIRONMENTAL DEFENCE INTERROGATORY - 018

Reference:

DSP Section 3.11, D-SS-04

Preamble:

> *This investment involves implementing battery energy storage solutions to improve reliability for customers who experience long interruption durations. The primary trigger of the investment is reliability. The investment is expected to improve reliability for vulnerable customers at locations where traditional reliability solutions are not economically viable or practical.*

Interrogatory:

a) Will these storage systems also be used to peak shave to serve a portion of the demand at peak times? If not, why not?

b) Could these storage systems be used to peak shave during periods where the chance of outages are very low, such as times of calm weather?

c) Page 5 describes outages in Aroland First Nation. Please provide a list of these outages and the cause (e.g. storm)

d) Please provide a table showing the proposed investments and the MW capacity of each.

e) Page 6 states that "Hydro One proposes to install residential battery storage at around 2100 homes across the province over the plan period." Please describe (i) the range of capacity (kW) and average capacity of these units, (ii) the total cost of each unit, (iii) the total cost of installation and overhead, (iv) the portion of the costs covered by the customer vs. ratepayers.

f) Please confirm that the new electric Ford F150 advertises an ability to provide backup power to a home for 10 days if electricity is conserved.

g) Will Hydro One consider provide assistance for customers to purchase bi-directional electric vehicle chargers as a way to cost-effectively increase reliability?

h) For each of grid-connected the storage systems Hydro One plans to install, please calculate the benefit of using the storage system to smooth out system peaks during times of low outage risks. Please include the benefits in terms of lower energy and capacity costs as well as lower transmission losses. Please include all calculations. Please make assumptions as necessary and state every assumption.

Response:

a) The focus of the D-SS-04 Energy Storage Solutions Investment is to improve reliability for customers and peak shaving has not been considered at this time.

b) Energy storage systems can be used for peak shaving. However, the current focus of these Energy Storage Solutions is to improve reliability for customers.

c) Between 2013 and 2017, Aroland averaged 11 outages and 57 hours of power interruptions per year. Below is a list of outages that impacted Aroland First Nation community:

Interruption Time	Duration (hours)	Outage Cause
2013-06-26 22:46:26	13.80	Loss of Supply
2013-07-07 07:32:49	5.67	Planned/scheduled
2013-07-16 07:40:45	8.75	Motor Vehicle Accident
2013-07-16 11:32:37	4.89	Motor Vehicle Accident
2013-07-23 07:38:22	2.09	Tree Fallen
2013-08-21 05:17:12	3.07	Tree Branches
2013-09-28 17:10:21	11.69	Tree Fallen
2013-10-11 10:00:59	3.69	Planned/scheduled
2013-11-19 23:09:59	6.33	Tree Fallen
2014-07-21 19:14:00	4.68	Loss of Supply
2014-07-21 23:58:58	12.20	Loss of Supply
2014-09-08 14:18:37	5.64	Tree Fallen
2014-09-08 16:30:00	3.83	Tree Fallen
2014-09-23 16:55:20	3.74	Other
2014-10-05 11:07:56	5.98	Planned/scheduled
2015-03-29 20:47:31	9.16	Loss of Supply
2015-03-31 07:52:16	2.96	Planned/scheduled
2015-05-06 12:45:46	0.41	Planned/scheduled
2015-05-11 14:12:10	1.38	Tree Fallen
2015-07-29 11:55:00	3.09	Tree Fallen
2015-07-29 14:58:40	0.57	Tree Fallen
2015-08-30 13:09:34	1.86	Planned/scheduled
2015-09-21 17:38:43	3.35	Tree Fallen
2015-10-04 08:59:59	6.67	Planned/scheduled

2015-12-09 02:34:00	1.52	Tree Fallen
2015-12-09 04:05:24	1.56	Tree Fallen
2015-12-10 02:59:40	1.97	Tree Fallen
2015-12-13 12:00:00	4.07	Planned/scheduled
2016-03-08 14:53:00	5.39	Loss of Supply
2016-03-08 20:16:39	4.66	Loss of Supply
2016-03-09 00:56:26	3.41	Loss of Supply
2016-05-17 10:23:29	5.73	Motor Vehicle Accident
2016-05-17 10:23:29	0.78	Motor Vehicle Accident
2016-05-23 15:38:10	4.12	Adverse Environment
2016-05-23 16:11:09	25.46	Other
2016-05-23 19:45:31	6.18	Adverse Environment
2016-06-20 10:36:00	2.90	Tree Fallen
2016-06-25 13:05:00	0.88	Tree Fallen
2016-06-25 13:05:00	5.15	Tree Fallen
2016-06-29 16:24:17	0.51	Loss of Supply
2016-07-24 10:00:05	8.42	Planned/scheduled
2016-08-04 18:00:00	0.26	Loss of Supply
2016-08-09 17:03:40	4.43	Tree Fallen
2016-09-11 09:55:22	1.43	Planned/scheduled
2016-11-19 01:33:00	12.72	Loss of Supply
2017-03-21 21:56:58	4.79	Other
2017-04-09 03:32:18	1.73	Other
2017-04-10 10:29:03	3.67	Planned/scheduled
2017-05-28 08:00:19	5.99	Planned/scheduled
2017-06-11 02:41:32	4.06	Tree Fallen
2017-06-11 09:12:08	3.71	Tree Branches
2017-06-14 10:07:41	3.42	Tree Fallen
2017-07-09 17:59:22	4.22	Equip./ Material Failure
2017-07-27 05:49:00	8.68	Loss of Supply
2017-10-24 20:43:42	17.46	Tree Fallen
2017-11-05 08:30:28	4.69	Planned/scheduled

d) Candidates below are based on preliminary study only. Preliminary studies are in progress for candidate sites to determine storage specifications, cost, and projected in-service dates.

<table>
<tr><th>First Nation Battery Energy Storage System Candidates</th><th>Minimum Proposed output of Battery Energy Storage System (MW)</th><th>Proposed Investment ($M)</th></tr>
<tr><td>Anishinaabeg of Naongashiing</td><td>0.5</td><td>3.5</td></tr>
<tr><td>Atikameksheng Anishnawbek</td><td>0.85</td><td>6.0</td></tr>
<tr><td>Brunswick House First Nation</td><td rowspan="3">0.72</td><td rowspan="3">5.0</td></tr>
<tr><td>Chapleau Cree First Nation</td></tr>
<tr><td>Chapleau Ojibway First Nation</td></tr>
<tr><td>Dokis First Nation</td><td>0.72</td><td>5.0</td></tr>
<tr><td>Henvey Inlet First Nation</td><td>0.41</td><td>2.8</td></tr>
<tr><td>Lac La Croix First Nation</td><td>0.82</td><td>5.7</td></tr>
<tr><td>Magnetawan First Nation</td><td>0.32</td><td>2.3</td></tr>
<tr><td>Mattagami First Nation</td><td>0.75</td><td>5.2</td></tr>
<tr><td>Mishkeegogamang First Nation</td><td>1.2</td><td>8.4</td></tr>
<tr><td>Moose Deer Point</td><td>2.06</td><td>14.4</td></tr>
<tr><td>Naicatchewenin First Nation</td><td>0.78</td><td>5.5</td></tr>
<tr><td>Netmizaaggamig Nishnaabeg</td><td>1.26</td><td>8.8</td></tr>
<tr><td>Ojibway Nation of the Saugeen</td><td>0.33</td><td>2.3</td></tr>
<tr><td>Ojibways of the Pic River First Nation</td><td>1.47</td><td>10.3</td></tr>
<tr><td>Shawanaga First Nation</td><td>0.67</td><td>4.7</td></tr>
<tr><td>Sheshegwaning First Nation</td><td>0.38</td><td>2.7</td></tr>
<tr><td>Shoal Lake #40 First Nation</td><td>0.98</td><td>6.8</td></tr>
<tr><td>Temagami First Nation</td><td>0.26</td><td>1.8</td></tr>
<tr><td>Wahgoshig First Nation</td><td>0.53</td><td>3.7</td></tr>
<tr><td>Wahta Mohawk First Nation</td><td>0.8</td><td>5.6</td></tr>
<tr><td>Wasauksing First Nation</td><td>1.6</td><td>11.1</td></tr>
<tr><td>Zhiibaahaasing First Nation</td><td>0.16</td><td>1.1</td></tr>
</table>

e) Residential storage:

   i. Capacity of the unit: Each BESS unit is rated at 5 kW of power output and 13.5 kWh of energy capacity.

   ii. The cost of materials per household is approximately $21,500 which includes two BESS units.

   iii. The average total cost per home is approximately $29,500 which includes the installation and overhead costs.

   iv. There is no cost to the customer.

f) Hydro One cannot comment on statements made by another company.

g) At this time, Hydro One is not providing assistance for customers to purchase bi-directional electric vehicle chargers.

h) As described in response a), the primary purpose for these storage system investments is to improve reliability and as a result Hydro One has not performed the assessments necessary to calculate benefits of peak shaving.

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B3 - ENVIRONMENTAL DEFENCE INTERROGATORY - 019A

Reference:
Exhibit B-3-1

Preamble:
Section 4.1 of the 2015 OEB CDM Guidelines states:

> *Distributors may apply to the Board for funding through distribution rates to pursue various activities such as CDM programs, demand response programs, energy storage programs and programs reducing distribution losses for the purpose of deferring the capital investment for specific distribution infrastructure. Any such application must include a consideration of the projected effects to the distribution system on a long-term basis.*
>
> *Applications can be filed at any time. The Board expects that as part of its long-term planning processes, a distributor will consider applications for CDM programs to defer distribution infrastructure. The distributor should explain the proposed program in the context of the distributor's five-year Distribution System Plan ("DSP") or explain any changes to its system plans that are pertinent to the program.*

Interrogatory:

a) Please file any guidelines, standards, or processes that Hydro One uses to "consider applications for CDM programs to defer distribution infrastructure" as outlined in the above except from the OEB CDM guidelines.

b) Is Hydro One proposing any CDM programs to defer distribution infrastructure in this application? If not, why not.

c) Please describe the steps taken by Hydro One to consider CDM as an alternative to each of the projects listed in Exhibit B-3-1, Section 3.11, pages 1-2. Please address each project and sub-project separately with a particular focus on system service.

d) What is the main entity responsible for considering non-wires-alternatives to system service projects?

e) What steps will Hydro One take to revaluate its plans for 2023-2027 if the proposed changes to the CDM guidelines are implemented by the OEB?

Response:

a) Please see B2-ED-014.

b) Please see B2-ED-014.

c) Please see B2-ED-014.

d) Please see B1-PP-003 part c).

e) It is not clear as to what proposed changes the question is referring to. Should the OEB implement any changes to the CDM guidelines, Hydro One will review those guidelines when they are finalized and consider the appropriate approach at that time.

B3 - ENVIRONMENTAL DEFENCE INTERROGATORY - 019B

Reference:

Exhibit B-3-1, DSP Section 3.6, Page 9

Interrogatory:

a) Please elaborate on the following excerpt and confirm whether Hydro One declined to update its line loss study as directed by the OEB:

Update its distribution line loss study for consideration in its next rebasing application, which should include an assessment of the actual line losses for a five-year period.	151	Hydro One assessed the actual line losses for a five-year period and is filing the results of this assessment, which indicates that the anomalous variation that caused the OEB to require an updated study is not present in the previous five-year period.	L-06-02 L-06-02-01	Clement Li and Bijan Alagheband

b) Please file a copy of any distribution line loss studies completed by Hydro One since 2000.

c) Does Hydro One Distribution quantify and consider the potential value of distribution loss reductions for different options when procuring equipment (e.g. transformers) and deciding on the details of demand-driven capital projects (e.g. the type and sizing of conductors)? If yes, please explain how and provide documentation detailing the methodology used.

d) If Hydro One Distribution is considering the value to its customers of distribution loss reductions for planning purposes, how does it calculate the dollar value ($) of said loss reductions (kWh)? Is the value calculated based only on the HOEP or on all-in cost of electricity (e.g. including the GA)?

e) Further to the above question, Hydro Ottawa and Burlington Hydro use the all-in cost of electricity. If Hydro One Distribution's practice differs, please explain whether there are aspects of its system that would justify this.

f) Please complete the following table:

Value of Hydro One Distribution System Energy Losses –						
	2015 (historic)	…	2027 (forecast)	Historic annual average	Forecast annual average	Total
Electricity Purchases (MWh)						
Electricity Sales (MWh)						
Losses (MWh)						
Losses %						
All-In Cost of Electricity ($/MWh) – Annual Average						
Cost of Losses ($)						

g) Please complete the following table:

GHG's from Hydro One's Forecast Distribution System Energy Losses						
	2023	2024	2025	2026	2027	Total
Forecast Losses (MWh)[1]						
Carbon Intensity of Electricity[2] (CO2e/MWh)						
GHGs (CO2e)						

h) In EB-2019-0261, Hydro Ottawa agreed to, and the Board approved, the following: "Between 2021 and 2025, Hydro Ottawa shall endeavour to maintain its five-year average total system losses below the target of 3.02% set by the OEB in EB-2005-0381 through cost-effective measures." Is Hydro One willing to agree to the same terms? If not, what commitments can Hydro One make to the Board in this regard? In particular, please indicate what target Hydro One is willing to meet.

[1] If no better numbers are available, the losses from 2019 or the average over 2015 to 2019 could be used for the purpose of this row of this response.
[2] Please base this figure on the IESO's January 2020 Annual Planning Outlook - http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Annual-Planning-Outlook-Jan2020.pdf?la=en; see also the data tables at http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Annual-Planning-Outlook-Data-Tables-Jan2020.xlsx?la=en.

i) In EB-2019-0261, Hydro Ottawa agreed to, and the Board approved, the following: "In addition, over the course of 2020-2021, Hydro Ottawa shall prepare a plan to reduce distribution losses as much as possible through cost-effective measures. The utility shall file the plan with the OEB when complete. In 2022-2025, Hydro Ottawa shall implement as many of the cost-effective measures set out in its plan as possible (e.g., any changes to planning and procurement processes to better mitigate losses, investments that can be made within current budgets, operational measures, etc.). All other cost-effective measures will be incorporated into the utility's next rebasing application and DSP." Is Hydro One willing to agree to the same terms? If not, what commitments can Hydro One make to the Board in this regard.

j) In EB-2019-0261, Hydro Ottawa agreed to, and the Board approved, the following: "Finally, as described in Hydro Ottawa's response to undertaking JT 3.10, a pilot of a Grid Edge Volt/VAr Control ("VVC") solution will be complete by the end of 2020. If this pilot is successful, Hydro Ottawa shall increase the deployment of these (or equivalent) units by conducting an analysis in 2021 to identify potential suitable locations and by deploying these units in a subset of locations which are deemed to be suitable and cost-effective, with an estimated investment of up to $1.0M over the five-year test period. The cost of these investments will be accommodated within the overall approved capital budget." Is Hydro One willing to agree to implement similar technology through an equivalent commitment? If not, what commitments can Hydro One make to the Board in this regard?

k) Please complete the following table:

Distribution Losses – Correlated with Consumption and Peak Demand				
	2010	…	2020	Average
Annual distribution losses (MWh)				
Annual consumption (MWh)				
Losses as % of consumption (%)				
Peak demand (MW)				
Ratio of loss % to peak demand				

Response:

a) In the EB-2017-0049 Decision dated March 7, 2019 at page 151, the OEB approved the loss factors proposed by Hydro One for Hydro One's existing rate classes. Specifically, the OEB stated "[t]hese loss factors were previously approved by the OEB, and no party objected to their continued approval."

However, the OEB noted that it was "concerned about the variation in distribution losses from year to year; from a low of 5.3% in 2012 to a high of 10.4% in 2013 (averaging 8.3%). Hydro One is expected to update its line loss study for consideration in its next rebasing rate application, which should include an assessment of the actual line losses for a five-year period."

The OEB's concern regarding the variation in losses from year to year has been resolved because as explained in Exhibit L-6-2 pages 3 to 4, this variation was the result of changes to Hydro One billing systems at that time. After 2013, Hydro One's loss factors remained stable as demonstrated by the data in L-6-2 Attachment 1. Moreover, L-6-2 Attachment 1 provides the actual line losses for a five-year period, as requested by the OEB in EB-2017-0049.

b) As indicated in Exhibit L-06-02, at page 3, Hydro One's existing total loss factors, which it proposes to continue to use for all existing Hydro One rate classes for the 2023 to 2027 Custom IR period, are based on the methodology and recommendations of the line loss study that was filed with the OEB on January 31, 2014 as Exhibit G1-8-2, Attachment 1 in EB-2013-0416. A copy of that study is provided at B3-ED-19b-1. Hydro One has not completed additional line loss studies since the study that was filed in EB-2013-0416. Moreover, as any earlier line loss studies going back to 2000 would be irrelevant to this application and available on the OEB's website, Hydro One declines to provide copies of any such additional studies.

c) Yes, see Exhibit B-3-1 Section 3.6.4 How the Capital Plan Addresses Distribution System Losses for details. For specific Total Ownership Cost calculations for Hydro One distribution transformers, please see the study by Kinectrics, 2016 attached at B3-ED-19b-2.

d) Hydro One considers the benefits of reduced losses for planning purposes based on qualitative considerations such as system operations, and efficiency.

e) Please refer to part d) above.

f) For the purposes of this response Hydro One has included the load of embedded customers when calculating losses. For the requested information over the years 2016-2020 and forecast period, please see the following tables. The figures include Acquired Utilities. It can be observed that the historic average loss factor is 6.1%, which is the same as forecast (6.1%).

	2016	2017	2018	2019	2020
Electricity Purchases in MWh	35,938,880	35,217,571	37,457,098	37,236,502	37,523,391
Electricity Sales in MWh	33,884,932	33,193,399	35,483,132	35,112,828	35,117,034
Losses in MWh	2,053,949	2,024,172	1,973,967	2,123,675	2,406,357
Losses (%)	6.1	6.1	5.6	6.0	6.9
$/MWh	161.9	163.0	159.7	170.5	177.1
Cost of Losses ($)	332,432,909	329,901,878	315,243,457	362,129,606	426,177,346

	2021	2022	2023	2024	2025	2026	2027
Electricity Purchases in MWh	35,507,213	35,643,803	35,853,650	35,974,429	36,090,354	36,202,057	36,311,722
Electricity Sales in MWh	33,477,681	33,606,780	33,807,057	33,921,117	34,030,456	34,135,728	34,239,044
Losses in MWh	2,029,532	2,037,023	2,046,593	2,053,312	2,059,898	2,066,329	2,072,678
Losses (%)	6.1	6.1	6.1	6.1	6.1	6.1	6.1
$/MWh	179.4	182.9	186.5	190.3	194.2	198.1	202.1
Cost of Losses ($)	364,198,258	372,492,173	381,734,734	390,713,700	399,967,696	409,385,732	418,983,490

For the years 2010 to 2015, the losses are not readily available, and they would not be consistent with the figures provided above as they do not include Acquired Utilities.

g) The forecast losses are already provided in f) above. Hydro One does not have the other information requested in this interrogatory.

h) It is Hydro One's understanding that Hydro Ottawa's commitment arose as a result of a Settlement Proposal approved by the OEB. Hydro One is not aware of the basis on which Hydro Ottawa provided the commitment noted. Hydro One is not prepared to make such a commitment at this time.

i) See I-09-B3-ED-019b(h).

j) See I-09-B3-ED-019b (h). Hydro One is not aware of the details of the Ottawa Hydro pilot project with respect to costs and benefits of such technology.

k) For annual losses in MWh for the years 2016-2020 please see response to part f) above. Hydro One does not have information on peak demand losses. Actual Distribution peak values, including the Acquired Utilities, are presented in the following table in MW.

2016	2017	2018	2019	2020
6,045	5,586	5,918	6,039	6,752

Actual Distribution peak values for the years 2010-2015 would not be consistent with the figures provided above as they do not include Acquired Utilities.

NAVIGANT

DISTRIBUTION LINE LOSS STUDY

Prepared for

HYDRO ONE NETWORKS, INC.

January 28, 2014

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Executive Summary

In its Decision with Reasons on the Hydro One Networks, Inc. (Hydro One) 2010 and 2011 Distribution Rate Application, the Ontario Energy Board (OEB or the "Board") directed Hydro One to "track the dollar value of variances between the Board approved losses recovered in rates, and actual line losses, commencing January 1, 2010" and to "bring this analysis to its next cost of service proceeding so that this issue may be further examined".[1]

In response to this decision, Hydro One engaged Navigant through a competitive process to:

- develop and implement a methodology to calculate actual losses on Hydro One's distribution system and determine the variance in terms of energy (kilowatt-hours) and cost of power (dollars) between actual and approved losses for 2010, 2011 and 2012; and

- recommend a methodology for Hydro One to determine the variance between actual and approved losses on a going-forward basis.

In addition, Hydro One engaged Navigant to develop and implement a methodology to review, and if appropriate propose alternate loss factors for Hydro One's individual customer classes.

System-Wide Losses and Variances

Methodology

System-wide losses are the difference between the electricity injected and withdrawn from the Hydro One distribution network (i.e. the difference between purchases and sales). For the purpose of calculating and reporting the dollar value of variances between actual and approved losses, only the injections (purchases) and withdrawals (sales) for Hydro One customers that are not IESO market participants are considered.

Losses are characterized as technical and non-technical. Technical losses are primarily due to heat dissipation resulting from current passing through conductors and from magnetic losses in transformers. Non-technical losses occur as a result of theft, metering inaccuracies and unmetered energy.

Navigant analysed system-wide losses and variances using two methods. Throughout this report they are referred to as:

- the 'meter data' method; and

- the 'bill data' method.

1 OEB. "Decision with Reasons in the Matter of an Application by Hydro One Networks Inc. for 2010 and 2011 Distribution Rates". April 9, 2010. pp 55.

In both methods, total sales are subtracted from total purchases over a defined period to determine the total losses. The fundamental distinction between the two methods is how the total sales were determined. In the meter data method, total sales in a period were based on the sum of individual customers' smart, interval, or conventional metered consumption ("metered consumption"). In the bill data method, total sales in a period were based on the sum of the total volume billed to individual customers ("billed consumption").

The key distinction is the granularity of the underlying data. Metered consumption is available on an hourly basis for smart and interval metered customers, whereas billed consumption is only available as a single number for a customer's entire billing cycle.

The benefit of the meter data method is that the majority of the sales data is available over a defined period on an hourly basis, allowing for easy alignment with purchases. The downside is that it involves vast quantities of data. For example, one year's worth of data for Hydro One's approximately 1.2 million customers is equivalent to approximately 10.5 trillion data points. Furthermore, it requires data from multiple sources, each containing a subset of Hydro One's customers.

In the bill data method, which is consistent with the approach that other distribution companies in Ontario use to determine losses, billed consumption is used for all customers. The data used in this method is on a billing cycle basis, making the direct alignment between purchases and sales more difficult. However, in contrast to the meter data method, the bill data method leverages information from a single source, minimising any risks for double counting or omissions. The bill data method is also relatively straightforward to implement, unlike the meter data method which takes considerable time and effort to implement.

Results

Navigant analysed Hydro One's actual losses in 2012 using both methodologies. The results, including the resulting approved and actual Total Loss Factors (TLFs), are presented in Figure ES - 1. Both methods indicate that Hydro One's actual losses in 2012 were lower than the approved losses.[2] The difference in the variance determined through the two methods is small, approximately 155 GWh, or six tenths of one percent (0.006 or 0.6%) of Hydro One's total purchases.

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[2] The OEB approves Total Loss Factors (TLFs) not total losses. To calculate the total approved losses, Navigant either (i) multiplied the consumption (C) by the approved TLF ($C \times (TLF)$), or (ii) multiplied the loss adjusted consumption (LAC) by the approved TLF over one plus the approved TLF ($LAC \times (TLF/(1+TLF))$). In either case, this was done on a rate class by rate class basis, to take into account the different approved TLFs.

Figure ES - 1: Variance between Actual and Approved Losses for 2012 (Meter Data vs. Bill Data Method)

	Meter Data Method	Bill Data Method
Purchases (kWh)	25,214,927,356	25,214,927,356
Consumption (kWh)	23,917,241,601	24,060,730,736
Actual Losses (kWh)	1,297,685,755	1,154,196,620
Loss Adjusted Consumption (kWh)	25,652,307,042	25,806,884,587
Approved Losses (kWh)	1,735,065,441	1,746,153,851
Variance (kWh)	(437,379,686)	(591,957,231)
Approved TLF / Actual TLF	7.3% / 5.4%	7.3% / 4.8%

Source: Hydro One data, Navigant analysis

The principal benefit of the meter data method is the availability of hourly smart meter data. However, in 2010 and 2011, there were fewer Hydro One customers with smart meters on automated meter reads than in 2012. In 2010 less than 50% of Hydro One's RPP eligible customers had a smart meter registered with the IESO and the MDM/R for the entire year. In 2011, the number increased, but still, less than 70% of Hydro One's RPP eligible customers had a smart meter registered with the IESO and the MDM/R for the entire year. Based on this, Hydro One estimates that hourly data for 2010 and 2011 is available for less than 50% and 65% of all consumption, respectively. As such, there is much less value associated with the meter data method in prior years. Based on this, and the fact that the results of both methods in 2012 were similar, the variance between actual and approved losses for 2010 and 2011 were only analysed using the bill data method. The results of this analysis are presented in Figure ES - 2.

Figure ES - 2: Variance between Actual and Approved Losses for 2010 and 2011 (Bill Data Method)

	2010	2011
Purchases (kWh)	25,147,786,869	25,269,760,852
Consumption (kWh)	23,090,758,102	23,696,731,189
Actual Losses (kWh)	2,057,028,767	1,573,029,663
Loss Adjusted Consumption (kWh)	24,801,899,448	25,418,695,980
Approved Losses (kWh)	1,711,141,347	1,721,964,791
Variance (kWh)	345,887,420	(148,935,128)
Approved TLF / Actual TLF	7.4% / 8.9%	7.3% / 6.6%

Source: Hydro One data, Navigant analysis

Based on this analysis, in 2010, Hydro One's approved loss factors under collected by approximately 346 GWh, whereas in 2011, the approved loss factors over collected by approximately 149 GWh.

Hydro One will recognise the dollar value associated with the variance at Hydro One's effective average wholesale market cost for RPP consumers over the period.

Figure ES - 3 outlines the annual variance from 2010 to 2012 using the bill data method and the corresponding dollar values that will be reported in Account 1588 RSVA Power.

Figure ES - 3: Variance between Actual and Approved Losses and Corresponding Dollar Amounts for 2010 to 2012

	2010	2011	2012	Total
Purchases (kWh)	25,147,786,869	25,269,760,852	25,222,134,097	75,639,681,818
Consumption (kWh)	23,090,758,102	23,696,731,189	24,060,730,736	70,848,220,027
Actual Losses (kWh)	2,057,028,767	1,573,029,663	1,161,403,361	4,791,461,791
Loss Adjusted Consumption (kWh)	24,801,899,448	25,418,695,980	25,806,884,587	76,027,480,015
Approved Losses (kWh)	1,711,141,347	1,721,964,791	1,746,153,851	5,179,259,989
Variance (kWh)	345,887,420	(148,935,128)	(584,750,490)	(387,798,198)
Approved TLF / Actual TLF	7.4% / 8.9%	7.3% / 6.6%	7.3% / 4.8%	7.3% / 6.8%
RSVA Power ($)	17,234,733	(3,343,507)	(14,438,777)	547,551

Source: Hydro One data, Navigant analysis

The total purchases for 2012 reported in Figure ES - 3 are slightly different from the total purchases reported in Figure ES - 1. Since the variances and the associated dollar amounts will be used for financial reporting, Navigant accepted Hydro One's recommendation to only include purchase data information that would be available when the purchase data record is officially closed for accounting purposes. The difference in total purchases 2012 between Figure ES - 1 and Figure 14 reflects minor adjustments made to settlement invoices after the record closing date.

Class-specific Loss Factors

Methodology

Meter data alone is not sufficient to support a review and assessment of Hydro One's current class-specific loss factors because purchases cannot be linked to a particular customer or customer class. As such, Navigant developed an alternative approach that is distinct from the approach used to analyse the actual system-wide losses. The approach that Navigant developed is based on engineering calculations of technical losses on a representative sample of feeders taken from across Hydro One's service territory, plus an adjustment to account for non-technical losses.

Navigant's methodology for analysing class-specific losses included eight components:

1. power flow modeling to calculate the peak current (i.e. I2R) losses on each segment of primary distribution feeder and in transformer windings;

2. tracing of the feeder segments between each distribution transformer and the transmission station;

3. allocation of peak current losses to each distribution transformer;

4. the estimation of no load losses on distribution transformers;

5. the estimation of peak current losses on secondary distribution lines;

6. an allocation of all of the above peak losses to the individual customers served by each distribution transformer and the aggregation of individual customer losses by rate class; and

7. translation of peak load losses to average losses.

Navigant and Hydro One collaborated to undertake the first computational step, leveraging Hydro One's existing power flow models. The remaining six were undertaken by Navigant.

In an ideal situation, the entirety of Hydro One's distribution system would be modelled simultaneously and the seven computational steps discussed above would be undertaken for all Hydro One distribution customers. However, in reality the size of Hydro One's distribution network is such that modelling it in its entirety simultaneously and collecting all the necessary information to implement the methodology is not feasible. As such, the Navigant methodology was employed on a representative sample of feeders from across Hydro One's service territory.

Navigant deployed a rigorous process to select the sample feeders. A similar sampling process was used elsewhere by Navigant to identify representative feeders for large utilities with diverse network topologies. As part of the sampling process, Hydro One provided Navigant with attribute and connectivity data for its approximately 3,200 distribution feeders. The connectivity information allowed Navigant to aggregate the list of 3,200 feeders and attribute data into approximately 800 unique 'originating' feeders. The originating feeders were then arranged into 16 clusters based on the similarity of their attributes. Each cluster was assigned a weight, based on the percentage of customers in each rate class served by all of the feeders within the cluster. From each cluster, Navigant selected a representative feeder with attributes similar to the average attributes of the cluster. The results from the representative feeders were then weighted by the corresponding cluster weight and extrapolated to represent the entirety of Hydro One's customer and feeder population.

The strength of the sampling process is the clustering of similar feeders. The clusters are designed to be a unique grouping of similar feeders. That is, the feeders contained within each cluster are similar, but the feeders in one cluster are different from the feeders in every other cluster. It is this unique cluster design that allows a single feeder from each cluster to be representative of a large number of feeders, and ultimately a large number of customers.

Results

The sample feeders, each taken to be representative of the cluster it was drawn from, represent feeders that serve between 90 and 99% of the population of each rate class. The one exception is Sub-Transmission. The sample feeders represent feeders that serve only approximately 65% of the population of Sub-Transmission customers. As such, Navigant concluded that it would not be appropriate to extend the analysis to the Sub-Transmission customer class, and that the current loss factors should be maintained. The decision to not extend the results to the Sub-Transmission impacts the overall allocation of losses between Sub-Transmission customers and other customers, but not the allocation between the other classes, for example the difference between the Urban Residential and R2 Residential loss factors are not affected.

Customer connectivity data was not readily available for Hydro One's unmetered customers (e.g., street lighting). As such Navigant's study was not extended to the Street Lighting, Sentinel Lighting, and Unmetered Scattered Load rate classes. Hydro One's Distributed Generation rate class is small, in terms of number of customers and consumption (approximately 0.1% of total), making it difficult to obtain a representative sample. As such, Navigant's study was also not extended to the Distributed Generation rate class. For all of these rate classes, Navigant recommended that the current loss factors be maintained.

For the remaining classes, using the methodology described above, Navigant calculated the peak demand kW loss per customer customers on the sample feeders. These losses were then aggregated by rate class and translated into average demand kW loss per customer. To calculate a system wide-average demand loss for each rate class, individual sample feeder results for each of the clusters were weighted by the percentage of the population of the rate class served by the all feeders within the cluster. The resulting (i) weighted average kW loss per customer, (ii) average demand per customer, and (iii) technical loss factor for each rate class are presented for each rate class in Figure ES - 4.

Figure ES - 4: Average kW Losses, Demand, and Technical Loss Factors by Rate Class

	UGD	GSD	UGE	GSE	UR	R1	R2	SEASONAL
Average Losses (kW/cust)	1.358	1.749	0.140	0.181	0.030	0.059	0.126	0.037
Average Demand (kW/cust)	65.7	53.7	3.6	2.7	1.1	1.2	1.7	0.5
Technical Loss Factor	2.1%	3.3%	3.9%	6.7%	2.8%	4.8%	7.6%	7.5%

Source: Hydro One data, Navigant analysis

As evidenced from the result above, there are clear differences in the technical loss factors between the urban and non-urban rate classes. This is intuitive, as the feeders serving urban customers tend to be shorter and the distribution transformers serving urban customer tend to serve more customers, resulting in a more efficient allocation of no load losses.

Note that the above values do not account for non-technical losses, or transformation losses in the transmission stations or high voltage distribution stations.

Recommendations

System-Wide Losses and Variances

The meter data method is not the industry standard approach for calculating total sales and determining actual losses. A key reason for this is that the meter data method requires the collection and analysis of vast quantities of hourly consumption data, which only recently became available for the majority of customers with the roll out of smart meters and the implementation of automated meter reads.

Based on this and other factors, and since the results of the meter data method and the bill data method for 2012 were reasonably similar, Navigant recommends that Hydro One use the bill data method to calculate actual losses from January 1, 2010 to December 31, 2013. The actual losses can then be compared to the approved losses to determine the variance and establish the amount to report in RSVA 1588 Power. The variances between actual and approved losses from January 1, 2010 to December 31, 2012, calculated using the bill data method, and the corresponding dollar amount to be reported in RSVA 1588 Power are presented above in Figure ES - 3.

While Navigant's analysis of system-wide losses shows that actual losses have varied from approved losses over the 2010 to 2012 period, the magnitude and sign of the variance has changed considerably from year to year. As such, Navigant recommends that Hydro One maintain the absolute level of approved losses and continue to monitor variances to assess whether an across the board increase or decrease to the approved TLFs is required to reduce the magnitude of the variance.

Going forward, Navigant recommends that Hydro One use the capabilities of its new CIS to implement and improve the calculation of actual losses and the variance relative to the approved level.

Class-specific Losses

Navigant recommends that Hydro One adopt the TLFs presented in Figure ES - 5 for the residential, seasonal, and general service rate classes. The non-technical loss factor is set such that the resulting TLFs would have recovered the same losses in 2012 as the approved TLFs. As illustrated in Figure ES - 5, Navigant believes that it is appropriate to allocate non-technical losses on a pro-rata basis relative to consumption (i.e. through a fixed percentage adjustment to the technical loss factors for all rate classes). This is consistent with previous treatment.

Figure ES - 5: Proposed DLF and TLFs for the Residential, Seasonal, and General Service Rate Classes

	UGD	GSD	UGE	GSE	UR	R1	R2	SEASONAL
Technical Loss Factor	2.1%	3.3%	3.9%	6.7%	2.8%	4.8%	7.6%	7.5%
Non-Technical Loss Factor	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
Supply Facility Load Factor	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
TLF	5.0%	6.1%	6.7%	9.6%	5.7%	7.6%	10.5%	10.4%

Note: Differences between the sum of the individual values and the TLF are due to rounding.

Navigant proposes Hydro One maintain its current approved Distribution Loss Factors (DLFs) and TLFs for the Sub-Transmission, Street Lighting, Sentinel Lighting, Unmetered Scattered Load, and Distributed Generator rate classes.

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1 Introduction

1.1 Background and Objectives

In its Decision with Reasons on the Hydro One Networks, Inc. (Hydro One) 2010 and 2011 Distribution Rate Application the Ontario Energy Board (OEB or the "Board") concluded that "it is important that Hydro One calculate and report to the Board the difference between the cost of actual line losses and the amounts recovered from ratepayers".[3] The Board also recognised that "Hydro One's calculation of cost and revenue is more involved than any other distributor and that with the several deemed loss factors in Hydro One's tariff, there is the likelihood of inaccuracies that are different in nature from other distributors".[4] The Board ultimately directed Hydro One to "to track the dollar value of variances between the Board approved losses recovered in rates, and actual line losses, commencing January 1, 2010" and to "bring this bring this analysis to its next cost of service proceeding so that this issue may be further examined".[5]

In response to this decision, Hydro One engaged Navigant to:

- develop and implement a methodology to calculate actual losses on Hydro One's distribution system and determine the variance in terms of energy (kilowatt-hours) and cost of power (dollars) between actual and approved losses for 2010, 2011 and 2012; and

- recommend a methodology for Hydro One to determine the variance between actual and approved losses on a going-forward basis.

In addition, Hydro One engaged Navigant to develop and implement a methodology to review, and if appropriate proposed alternate loss factors for Hydro One's individual customer classes.

1.2 Structure of Report

This report consists of four sections. The first section is this introduction. The second section discusses the methodology, results and key findings from the system-wide losses and variance analysis. The third section discusses the methodology, results and key findings from the analysis of class-specific loss factors. The final section presents Navigant's conclusions and recommendations.

[3] OEB. "Decision with Reasons in the Matter of an Application by Hydro One Networks Inc. for 2010 and 2011 Distribution Rates". April 9, 2010. pp 55.

[4] Ibid.

[5] Ibid.

2 System-wide Losses and Variance

System-wide losses are the difference between the electricity injected into and the electricity withdrawn from the Hydro One distribution network by Hydro One customers. For the purpose of calculating the dollar value of variances between actual and approved losses, only the injections and withdrawals for Hydro One customers that are not IESO market participants are considered.

Losses are generally characterized as technical and non-technical. Technical losses are primarily due to heat dissipation resulting from current passing through conductor and from magnetic losses in transformers. Non-technical losses occur as a result of theft, metering inaccuracies and unmetered energy.

Navigant analysed system-wide losses and variances using two methodologies. Throughout this report they are referred to as:

- the 'meter data' method; and
- the 'bill data' method.

The sections that follow describe each approach in detail and summarise the results of Navigant's analysis.

2.1 Methodology

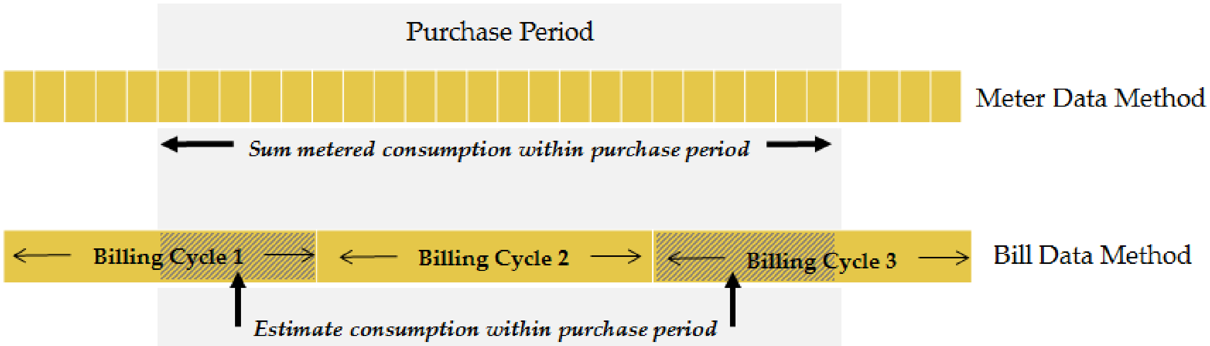
2.1.1 Overview

Navigant analysed system-wide losses and variances using two methods. In both methods, total sales are subtracted from total purchases over a defined period to determine the total losses. The fundamental distinction between the two methods is how the total sales were calculated. In the meter data method, aggregate sales in a period were based on the sum of individual customers' smart, interval, or conventional metered consumption ("metered consumption"). In the bill data method, aggregate sales in a period were based on the sum of the total volume billed to individual customers ("billed consumption").

The key distinction is the granularity of the data. Metered consumption is available on an hourly basis for smart and interval metered customers, whereas billed consumption is only available in aggregate as a single number for a customer's billing cycle.

As a result, while the metered consumption can generally be directly aligned with purchases over a period, estimation is required to determine the fraction of billed consumption that aligns with the purchases. This is illustrated in Figure 1 below.

Figure 1: Key Distinction between Meter Data and Bill Data Methods



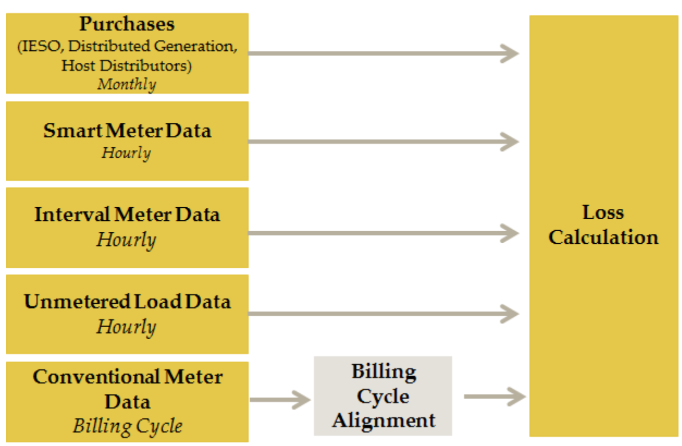
2.1.2 Meter Data Method

Overview

In the meter data method, total sales were calculated as the aggregate of metered consumption over a defined period that was directly aligned with a period of time over which total purchases were known.

The metered consumption data was segmented by the 'type' of meter -- smart meter, interval meter, conventional meter -- or in the case of unmetered load customers (e.g. street and sentinel lighting), the lack of a meter. With the proliferation of smart meters across Ontario, this method uses hourly data for most customers. For those customers with a conventional meter, the method uses billed consumption[6] and an alignment between the billing cycle and the purchase period is required.

Figure 2: Meter Data Method Overview



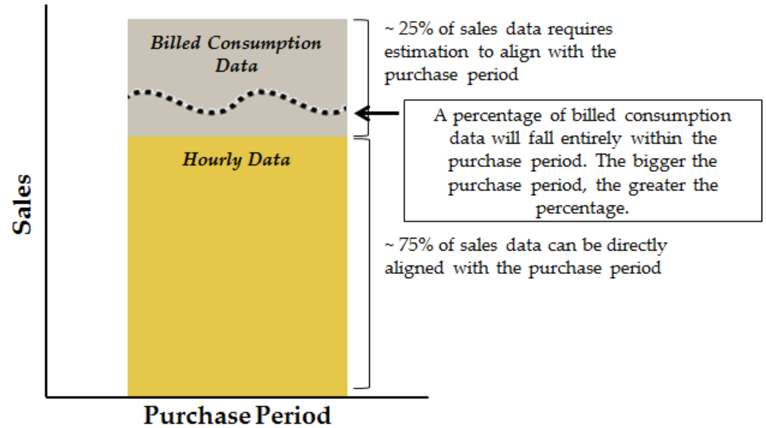
The benefit of the meter data method is that the majority of the underlying sales data is hourly, meaning that it can be directly aligned with the purchase period. The downside is that it requires vast amounts of data. For example, one year's worth of data for Hydro One's approximately 1.2

[6] Billed consumption was also relied on for some customers whose smart meters are still being read manually.

million customers is equivalent to approximately 10.5 trillion data points. Furthermore, it requires data from multiple sources within Hydro One, each containing a subset of Hydro One's customers.

As illustrated in Figure 3, the majority of the sales data in the meter data method can be directly aligned with the purchase period.

Figure 3: Meter Data Method Sales Data Alignment with Purchase Period



Data

The meter data method required the following inputs:

- IESO purchases, by month;
- purchases from distributed generators, by month;
- other purchases such as transfers from host distributors, by month;
- metered consumption for smart meter customers, by hour;
- metered consumption for interval meter customers, by hour;
- metered consumption for conventional metered customers, by billing cycle; and
- estimated consumption for unmetered loads, by hour.

Monthly purchase data was obtained from Hydro One's settlement system, hourly interval meter data was obtained from Hydro One's meter data management system (MV Star), conventional metered consumption data was obtained from Hydro One's CIS, and hourly smart meter data was collected from the IESO's Meter Data Management and Repository (MDM/R). To obtain this last piece of information, Hydro One formally requested the hourly consumption data for all of its smart meter customers from the IESO.[7]

[7] As will be discussed, the request was ultimately made for 2012 data only.

Due to the large size of the smart meter and interval meter datasets, the individual customer consumption was aggregated by zone and rate class prior to being analysed.[8]

Linking the multiple datasets required careful consideration of any customer transitions that may have occurred, for example, a customer moving from a conventional meter to a smart meter. Since the data for conventional metered customers came from the CIS, which also included the billed consumption data for all smart and interval metered customers, considerable effort was required to ensure there was no double counting or omissions.

Alignment of Purchases and Sales

The majority of the sales data used in the meter data method is easily aligned with the purchase period, because it is available on an hourly basis. To align the billed consumption data for conventional metered customers, additional steps were required.

Navigant employed three different methods to align the billed consumption data for conventional metered customers depending on the customer rate class, number of billing cycles for which data is available, and the extent to which supplemental hourly data for 'similar' customers was available.

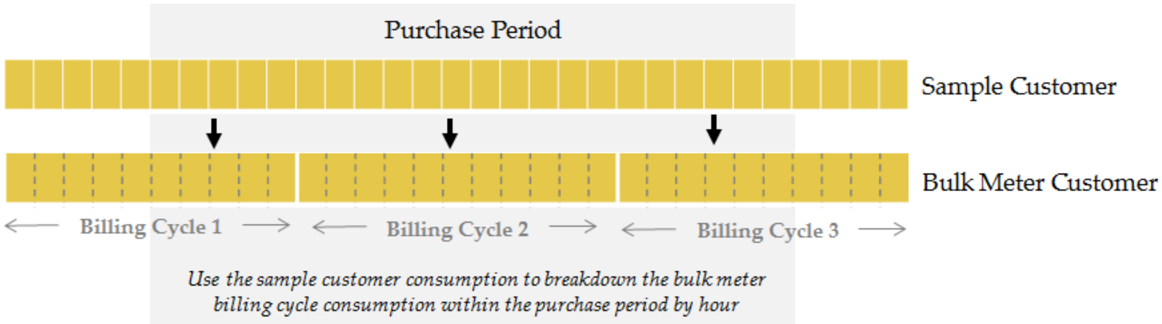
Method 1: Match to Sample Customer Profile

In the first method, conventional meter customers were 'matched' to sample customers for whom hourly data was available. The hourly profile of the matched sample customer was then used to allocate the conventional metered customer's consumption within billing cycles that did not directly align with the purchase data.

The match was made by determining which sample customers' consumption within the same zone most closely resembled the conventional metered customer's consumption across all of the available billing cycles. To make this determination, Navigant calculated the sum of the absolute value of the difference between the conventional metered customer's consumption and each sample customer's consumption across all of the available billing cycles. The sample customer with the smallest value was matched to the conventional metered customer. Once a match was made, the conventional metered customer's billed consumption was translated to an hourly profile using the hourly profile of the matched sample customer. This is illustrated in Figure 4.

[8] Hydro One's service territory is split into eight regional zones: west, west central, central, east, Georgian Bay, east central, northeast and northwest

Figure 4: Illustrative Example of Method 1 - Match to Sample Customer Profile



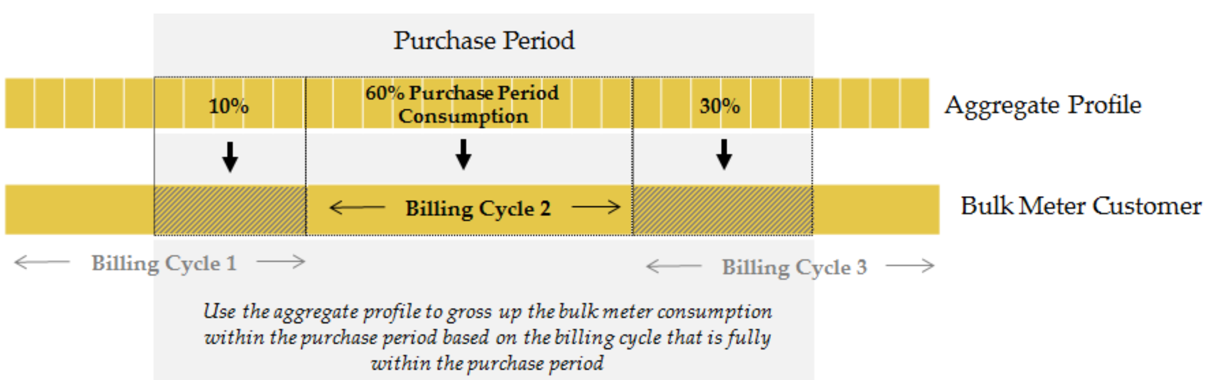
Method 2: Match to Aggregate Profile

In the second method, instead of a single sample customer with similar consumption patterns, average profiles for each zone and rate class were used to estimate the consumption within billing cycles that did not directly align with the purchase period.

Average profiles for each zone and rate class were developed by aggregating the available hourly data for all interval and smart meter customers. Each conventional meter customers' consumption was then aggregated between the first bill-from and last bill-to date within the purchase period. The conventional metered customer's consumption was then scaled up based on a profile ratio. The profile ratio was calculated as a ratio of the total purchase period consumption to consumption within the same bill-from and bill-to period for the average profile.

For example; assume the purchase period was a calendar year and a customer was on bi-monthly billing beginning February 1st of each year. The first bill-from date within the calendar year would be February 1 and the last bill-to date would be November 30. The remaining billing cycles would include bill-from dates in the prior year and bill-to dates in the subsequent year, and thus would not be included. If the conventional metered customer consumed 10,000 kWh from February 1 to November 30 and the matched aggregate profile for the same rate class and zone shows that 60% of annual consumption occurred between February 1 and November 30, then the conventional metered customer's annual consumption is estimated to be 16,667 kWh. This is illustrated in Figure 5.

Figure 5: Illustrative Example of Method 2 - Match to Aggregate Profile



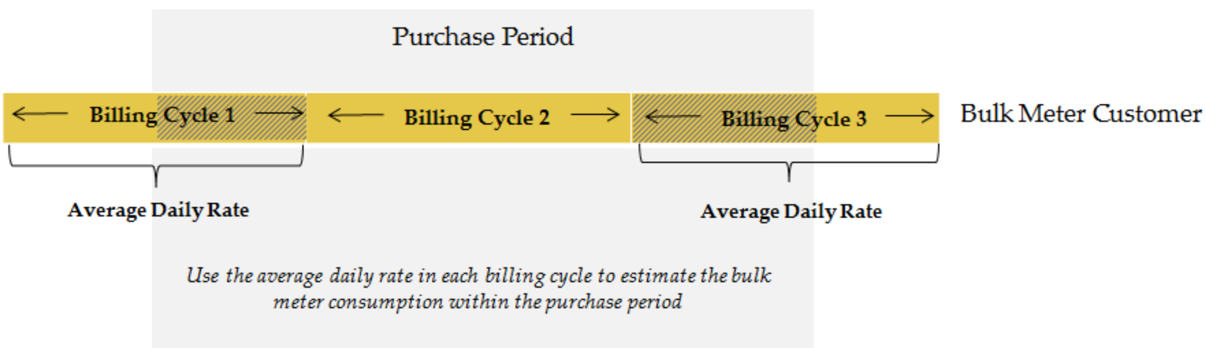
Method 3: Average Daily Consumption

In the third method, average daily consumption for the conventional metered customer between two actual meter reads was used to estimate consumption within billing cycles that did not directly align with the purchase period. The average daily consumption and the number of days are used to allocate the billing cycle consumption.

Average daily consumption was calculated for billing cycles that overlap the start or end of a purchase period. This rate was applied to the number of days in the purchase period that require estimation. Not all billing cycles are based on actual meter reads and a customer may be billed based on estimated kilowatt hour consumption for a given billing cycle. If this was the case, the kilowatt hour consumption was summed between two actual meter reads and the same process was followed.

For example; if a billing cycle contained only four days in the purchase period in question, the average daily rate for that individual billing cycle is multiplied by four to estimate the consumption within the purchase period. This is illustrated in Figure 6.

Figure 6: Illustrative Example of Method 3 - Average Daily Consumption



Note that in all three methods, additional adjustments were made in instances where customer accounts either initiated or terminated in the purchase period.

The method used for each conventional metered customer was determined based on the decision logic outlined below:

- customers were first segmented based on the answer to the following question: "is there at least one full billing cycle within the purchase period (i.e., is there at least one pair of actual bill-from and bill-to dates that are within the same purchase period)". If the answer was no, the customer was assigned to method three.

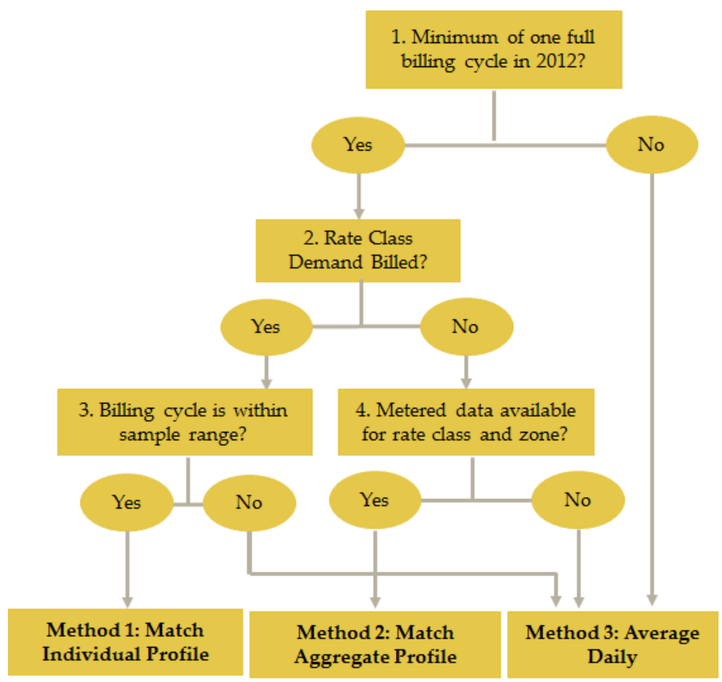
- customers with at least one full billing cycle within the purchase period were then separated into two groups: those that are energy billed and those larger customers that are demand billed.

- the third step was to segment the demand billed customers based on the following question: "are the customer's billing cycles within the sample range[9]". Larger customers' usage patterns and levels of consumption can vary widely based on many factors. Method one matches each individual customer to a sample customer with hourly meter data. To employ method one, the billing cycles for the conventional metered customer must fall within the sample range. If the customer billing cycle is outside of this range, method three must be used.

- the final step was to segment the energy billed customers based on the question: "is aggregate meter data available for the customer's rate class and zone". Method two matches conventional metered customers to an aggregate hourly profile for their zone and rate class. Thus, metered data must be available for their rate class and zone. If this data is unavailable, method three must be used.

Figure 7 illustrates the logic that decided the segmentation and treatment of conventional metered customers in the meter data method.

Figure 7: Decision Logic for Treatment of Conventional metered Customers in Meter Data Method



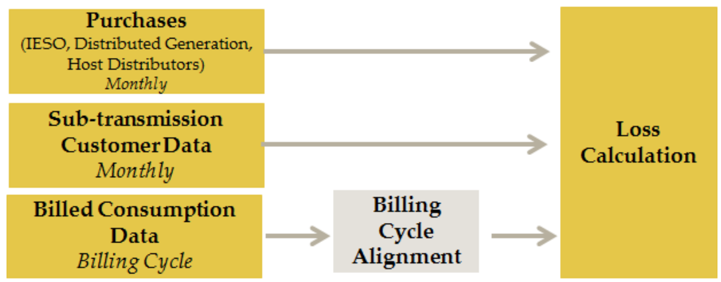
[9] The sample range includes a random selection of GSD and UGD customers within each zone with hourly data from July 1, 2011 until December 31, 2012.

2.1.3 Bill Data Method

Overview

In the bill data method, which is consistent with the approach other distributors in Ontario use to determine actual losses, total losses are calculated as the aggregate of all customers. Average daily consumption is used to estimate consumption within billing cycles that do not directly align or are not fully contained within the purchase period. Sub-transmission customers are billed on a calendar month basis and estimates are not required to align consumption with the purchase period.

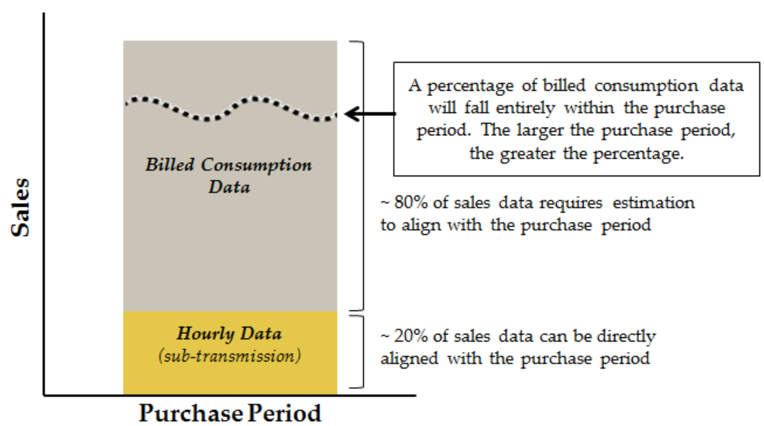
Figure 8: Bill Data Method Overview



In contrast to the meter data method, the bill data method leverages withdrawal information from a single source, minimising the risk for double counting or omitting customers. Unlike the meter data method, which takes considerable time and effort to implement, the bill data method is relatively straightforward to implement.

As illustrated in Figure 9, only a small percentage of total sales directly align with the purchase period. However, provided the purchase period is sufficiently long (i.e. one or more years), a large percentage of the billing cycle data will be entirely contained within it.

Figure 9: Bill Data Method Sales Data Alignment with Purchase Period



Data

The bill data method required the following inputs:

- IESO purchases, by month;
- Purchases from distributed generators, by month;
- other purchases such as transfers from host distributors, by month; and
- billed consumption for all customers, by billing cycle.

Billing Cycle Alignment

In the bill data method, average daily consumption is used to estimate consumption within billing cycles that do not directly align with the purchase period or are not entirely contained within it. This approach is consistent with the third method used to align billing cycle data in the meter data method described in the meter data method section. While at first glance this would appear to be a significant disadvantage of the bill data method, when the purchase period is a calendar year, the percentage of electricity consumed within billing cycles that overlap the beginning and end of a year can be small. The percentage is even smaller when the purchase period is multiple years. For example, in this report the cumulative variance over the three year period from 2010 to 2012 is analysed.

2.2 Results

This section outlines the results of both the meter data and bill data method for 2012, as well as the results of the bill data method for 2010 and 2011.

Losses are determined by subtracting total sales from total purchases. The variance is determined by comparing actual losses to the approved losses. To calculate the total approved losses, Navigant either (i) multiplied the consumption (C) by the TLF$(C\ \times (TLF))$, , or (ii) multiplied the loss adjusted consumption (LAC) by the TLF over one plus the TLF $(LAC\ \times (TLF/(1+TLF)))$. In either case, this was done on a rate class by rate class basis, to take into account the different approved TLFs.

2.2.1 2012

The results of the meter data method for 2012 are presented in Figure 10.

Figure 10: Meter Data Method Results (2012)

	2012
Purchases (kWh)	25,214,927,356
Consumption (kWh)	23,917,241,601
Actual Losses (kWh)	1,297,685,755
Loss Adjusted Consumption (kWh)	25,652,307,042
Approved Losses (kWh)	1,735,065,441
Variance (kWh)	(437,379,686)
Approved TLF / Actual TLF	7.3% / 5.4%

Source: Hydro One data, Navigant analysis

The results of the bill data method for are presented in Figure 11.

Figure 11: Bill Data Method Results (2012)

	2012
Purchases (kWh)	25,214,927,356
Consumption (kWh)	24,060,730,736
Actual Losses (kWh)	1,154,196,620
Loss Adjusted Consumption (kWh)	25,806,884,587
Approved Losses (kWh)	1,746,153,851
Variance (kWh)	(591,957,231)
Approved TLF / Actual TLF	7.3% / 4.8%

Source: Hydro One data, Navigant analysis

Both methods indicate that in 2012 Hydro One's actual distribution losses were lower than the amount of losses recovered through the approved TLFs.

Figure 12 compares the results of both the meter data and the bill data methods.

Figure 12: Comparing Results of Meter Data and Bill Data Methods

	Meter Data Method	Bill Data Method
Purchases (kWh)	25,214,927,356	25,214,927,356
Consumption (kWh)	23,917,241,601	24,060,730,736
Actual Losses (kWh)	1,297,685,755	1,154,196,620
Loss Adjusted Consumption (kWh)	25,652,307,042	25,806,884,587
Approved Losses (kWh)	1,735,065,441	1,746,153,851
Variance (kWh)	(437,379,686)	(591,957,231)
Approved TLF / Actual TLF	7.3% / 5.4%	7.3% / 4.8%

Source: Hydro One data, Navigant analysis

The difference in the variance determined through the two methods is approximately 155 GWh, or six tenths of a percent (0.006 or 0.6%) of total purchases.

2.2.2 2010 and 2011

In 2010 and 2011, there were fewer Hydro One customers with smart meters on automated meter reads than in 2012. In 2010 less than 50% of Hydro One's RPP eligible customers had a smart meter registered with the IESO and the MDM/R for the entire year. In 2011, the number increased, but still, less than 70% of Hydro One's RPP eligible customers had a smart meter registered with the IESO and the MDM/R for the entire year. Based on this, Hydro One estimates that hourly data for 2010 and 2011, is available for less than 50% and 65% of all consumption, respectively. As a result, there is much less value associated with the meter data method in prior years. Based on this, and the fact that the results of both methods in 2012 were similar, actual losses for 2010 and 2011 were only analysed using the bill data method. The results of this analysis are presented in Figure 13.

Figure 13: Bill Data Method Results (2010 and 2011)

	2010	2011
Purchases (kWh)	25,147,786,869	25,269,760,852
Consumption (kWh)	23,090,758,102	23,696,731,189
Losses (kWh)	2,057,028,767	1,573,029,663
Loss Adjusted Consumption (kWh)	24,801,899,448	25,418,695,980
Approved Losses (kWh)	1,711,141,347	1,721,964,791
Variance (kWh)	345,887,420	(148,935,128)
Approved TLF / Actual TLF	7.4% / 8.9%	7.3% / 6.6%

Source: Hydro One data, Navigant analysis

Based on this analysis, in 2010, Hydro One's approved loss factors under collected by approximately 346 GWh, whereas in 2011, the approved loss factors over collected by approximately 149 GWh.

2.2.3 Dollar Value of Variance

Hydro One will recognise the dollar value associated with the variance at Hydro One's effective average wholesale market cost for RPP consumers over the period.

Figure 14 outlines the annual variance from 2010 to 2012 using the bill data method and the corresponding dollar values that will be reported in Account 1588 RSVA Power. While the values in Figure 14 are reported on an annual basis, the calculation was done on a monthly basis to reflect the variation in monthly unit costs.

Figure 14: Loss Variance (2010 to 2012)

	2010	2011	2012	Total
Purchases (kWh)	25,147,786,869	25,269,760,852	25,222,134,097	75,639,681,818
Consumption	23,090,758,102	23,696,731,189	24,060,730,736	70,848,220,027
Actual Losses (kWh)	2,057,028,767	1,573,029,663	1,161,403,361	4,791,461,791
Loss Adjusted Consumption (kWh)	24,801,899,448	25,418,695,980	25,806,884,587	76,027,480,015
Approved Losses (kWh)	1,711,141,347	1,721,964,791	1,746,153,851	5,179,259,989
Variance (kWh)	345,887,420	(148,935,128)	(584,750,490)	(387,798,198)
Approved TLF / Actual TLF	7.4% / 8.9%	7.3% / 6.6%	7.3% / 4.8%	7.3% / 6.8%
RSVA Power ($)	17,234,733	(3,343,507)	(14,438,777)	547,551

Source: Hydro One data, Navigant analysis

The total purchases for 2012 reported in Figure 14 are slightly different from the total purchases reported in Figure 11. Since the variances and the associated dollar amounts will be used for financial reporting, Navigant accepted Hydro One's recommendation to only include purchase data information that would be available when the purchase data record is officially closed for accounting purposes. The difference in total purchases 2012 between Figure 11 and Figure 14 reflects minor adjustments made to settlement invoices after the record closing date.

3 Class-Specific Losses

Meter data alone is not sufficient to support a review and assessment of Hydro One's current class-specific loss factors because purchases cannot be linked to a particular customer or customer class. As such, Navigant developed an alternative approach that is distinct from the approach used to analyse the actual system-wide losses. The approach that Navigant developed is based on engineering calculations of technical losses on a representative sample of feeders taken from across Hydro One's service territory, plus an adjustment to account for non-technical losses. The methodology that Navigant developed and the results of the analysis are presented in the sections that follow.

Hydro One's current approved loss factors for each rate class are listed in Figure 15 below.

Figure 15: Hydro One's Current Approved Loss Factors

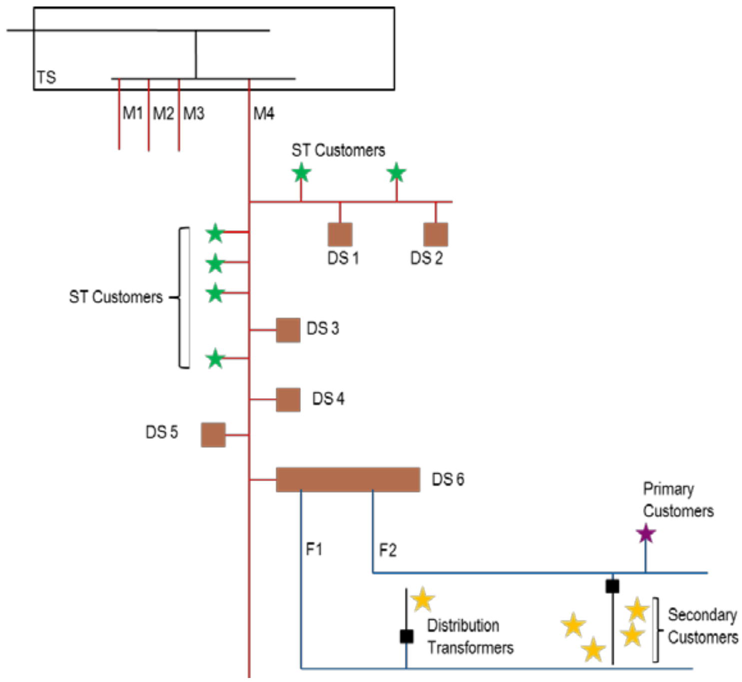
Rate Class	Supply Facility Loss Factor (SFLF)	Distribution Loss Factor (DLF)	Total Loss Factor (TLF)
Urban Residential (UR)	0.6%	7.2%	7.8%
R1 Residential (R1)	0.6%	7.9%	8.5%
R2 Residential (R2)	0.6%	8.6%	9.2%
Seasonal (SEASONAL)	0.6%	8.6%	9.2%
Urban General Service Demand (UGD)	0.6%	5.5%	6.1%
General Service Demand (GSD)	0.6%	5.5%	6.1%
Urban General Service Energy (UGE)	0.6%	8.6%	9.2%
General Service Energy (GSE)	0.6%	8.6%	9.2%
Street Lighting (STR)	0.6%	8.6%	9.2%
Sentinel Lighting (SEN)	0.6%	8.6%	9.2%
Distributed Generation (DGEN)	0.6%	5.5%	6.1%
Sub-Transmission (ST) - Primary Metered	0.6%	2.8%	3.4%
Sub-Transmission (ST) - TS Metered	0.6%	0.0%	0.6%

Source: Hydro One

Navigant's analysis did not include a review of the loss factors for Hydro One's Street Light, Sentinel Light, and Unmetered Scattered Load classes because of the lack of geographic and connectivity data for these customers. Distributed Generation customers were also not considered due to the relatively small volume and variable nature of this class. Sub-transmission customers were included in the review, however, it was later concluded that the number of customers in the sample was insufficient.

An illustrative schematic of a radial distribution network is provided below in Figure 16. In this example, the M-Class feeder, M4, serves six distribution stations (DS). One of those distribution stations, DS 6, has two F-Class feeders, F1 and F2, each of which feeds a single distribution transformer which serves multiple secondary service customers. The F2 feeder also serves one primary customer. In reality, the F-Class feeders feed a larger number of distribution transformers and serve a larger number of customers. Figure 16 is intended to introduce some language and illustrate a typical configuration.

Figure 16: Illustrative Example of Distribution Network Radial



3.1 Methodology

3.1.1 Overview

Navigant's approach and use of engineering calculations was designed to answer "to what extent are the losses incurred to serve different classes of customers different" instead of attempting to answer "what are the total losses incurred across Hydro One's distribution network".

Navigant's methodology for analysing class-specific losses included eight components:

- power flow modeling to calculate the peak current (or I^2R) losses incurred on each segment of primary distribution feeder and transformer;
- tracing of the feeder segments between each distribution transformer and the transmission station;
- allocation of peak current (or I^2R) losses to each distribution transformer;
- the estimation of no load losses on distribution transformers;
- the estimation of I^2R losses on secondary distribution lines;

- an allocation of all of the above peak losses to the individual customers served by each distribution transformer and the aggregation of individual customer losses by rate class; and

- translation of peak load losses to average losses.

The first computational step was undertaken by Hydro One. The remaining six were undertaken by Navigant.

Ideally, the entirety of Hydro One's distribution system would be modelled simultaneously, and the elements of the methodology outlined above would be implemented for all feeders and all of Hydro One distribution customers. However, in reality the size of Hydro One's distribution network is such that modelling it in its entirety simultaneously and collecting all the necessary information to implement the methodology is not feasible. Instead, Navigant's methodology was deployed for a representative sample of feeders from across Hydro One's service territory. The results from the representative feeders were then extrapolated to reflect the entirety of Hydro One's distribution network.

3.1.2 Sample Design and Selection

This section describes Navigant's sample design and representative feeder selection process.

Overview

Hydro One provided Navigant with attribute and connectivity data for its approximately 3,200 distribution feeders. The approximately 3,200 distribution feeders included feeders Hydro One classifies as 'M-Class' or sub-transmission as well as 'F-Class' or primary distribution. The connectivity information allowed Navigant to aggregate the list of 3,200 feeders and attribute data into approximately 800 unique 'originating' feeders. For example, if one M-Class feeder served two downstream distribution stations and there were two F-Class feeders originating from each distribution station, Navigant aggregated the attribute data for the four F-Class feeders (two distribution stations x two feeders per station) as well as any unique attribute data for the M-Class feeder into one record.

The attribute data Hydro One provided to Navigant for each feeder included:

- voltage;

- length (km);

- number of customers, by rate class;

- provincial lines zone; and

- distributed generation (kW).

Navigant removed feeders from the list for which customer and attribute data was not available. This resulted in in a final list of 676 feeders. In total, the 676 feeders serve over 80% of Hydro One customers. The 676 originating feeders were then arranged into 16 clusters based on the similarity of their attributes. A representative feeder was then selected from each of the 16 clusters.

Figure 17: Clustering of Hydro One Distribution Feeders

Clustering

Fundamental to the clustering process was the notion of 'similarity' between two feeders. Navigant defined 'similarity' as the Euclidian distance between two feeders in an 'n' dimensional attribute space. Based on this definition, the distance between two feeders could be calculated based on the following formula:

$$Distance = \sqrt{(a_1 - b_2)^2 + (a_2 - b_2)^2 + \cdots + (a_n - b_n)^2}$$

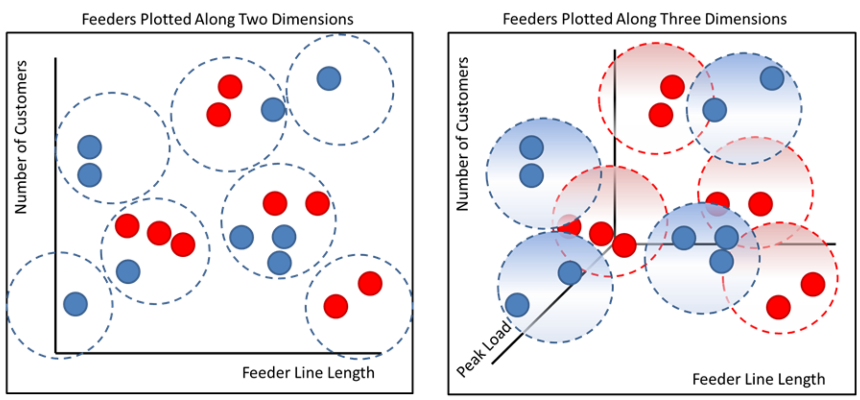
Where:

a_i is the value of attribute 'i' for feeder 'a'; and

b_i is the value of attribute 'i' for feeder 'b'.

This concept of similarity and distance is illustrated below in Figure 18. In the graphic on the left, feeders (represented by dots) are plotted on two dimensions (or attributes). Feeders that are close together on the two-dimensional surface are similar and hence grouped into a single cluster. In the graphic on the left, a third dimension (or attribute) is added. Adding the third dimension (or attribute) allows for greater distinction to be made between feeders.

Figure 18: Feeder Selection Process



Navigant's clustering considered a total of eight attributes, and hence eight dimensions:

- originating line voltage;
- total feeder length;
- number of urban customers;[10]
- number of ST customers;
- number of GSD and GSE customers;
- number of R1 customers,
- number of R2 customers; and
- number of SEAS customers.

The clustering algorithm included four steps. In the first step, data for each attribute was normalised to a range from zero to one. This was done so that initially the distances between feeders was determined based on equal treatment of attributes (i.e. attributes with large nominal differences in values, for example, total feeder length does not dominate over attributes with small nominal differences in values, for example number ST customers served).

In the second step feeders were grouped into preliminary clusters. The clustering process employed was heuristic. It started by creating a new cluster for the first feeder. Then, the second and each subsequent feeder, was compared to all of the existing clusters. If the feeder was 'sufficiently similar' to an existing cluster it was added to that cluster, otherwise, it was placed in a new cluster. Once all feeders were assigned to a cluster, the process ended. In this step, the 'sufficiently similar' threshold was kept fairly strict, so as to identify clusters of feeders that were extremely similar.

Using the tight clusters as a starting point, the process was repeated with a slightly relaxed similarity condition. More feeders were added to the clusters identified in the first run and some new clusters were formed from feeders that were distinct from the tight clusters identified in the first iteration.

The algorithm produced approximately three dozen clusters. In reviewing the results Navigant applied professional judgement, excluding clusters containing feeders that served only a very small number of customers and combined some clusters in instances where the underlying feeders were similar. Ultimately, this resulted in a total of 16 clusters.

The average values of the attributes for each cluster are presented in Figure 19.

[10] Inclusive of UR, UGE, and UGD.

Figure 19: Average Attributes of Feeder Clusters

Cluster	Originating Voltage (kV)	Total Length (km)	Number of Urban Customers	Number of ST Customers	Number of GSD Customers	Number of R1 Customers	Number of R2 Customers	Number of SEASONAL Customers
1	11	4	0	0	0	2	6	2
2	11	30	2	0	3	328	109	51
3	13	116	1	0	2	66	360	209
4	13	21	1,345	0	1	109	4	2
5	26	127	10	1	7	207	394	100
6	26	40	29	1	6	151	120	41
7	27	8	3	1	0	1	1	3
8	27	261	3	1	18	833	906	157
9	28	24	2,661	1	4	78	40	5
10	44	11	0	1	0	1	3	0
11	44	55	4	0	9	435	32	7
12	44	112	34	1	10	876	438	145
13	44	119	1	3	4	48	512	41
14	44	426	21	1	21	1,466	1,473	846
15	44	68	2,557	2	8	314	69	11
16	44	223	2,068	0	22	1,698	919	51

Clusters 4, 9 and 15 include feeders that predominantly serve urban customers. One of the key differences between them is the originating voltage. Feeders in Cluster 16 serve a mix of urban and non-urban customers, whereas the remaining clusters consist of feeders that serve predominantly non-urban customers.

Clusters 8, 14, and 16 consist of feeders that on average have a total circuit length of greater than 200 km. Clusters 3, 5, 12, and 13 consist of feeders that on average have a total circuit length of between 100 and 200 km. The remaining clusters consist of feeders that on average have a total circuit length of less than 50 km. These broader characteristics of the clusters are summarised in Figure 20 below.

Figure 20: Broad Characteristics of Clusters

Cluster	Voltage	Length	Number of Customers	Urban / Rural / Mixed
1	Low	Short	Low	Rural
2	Low	Short	Medium	Rural
3	Low	Medium	Medium	Rural
4	Low	Short	Low	Urban
5	Medium	Medium	Medium	Rural
6	Medium	Short	Medium	Rural
7	Medium	Short	Low	Rural
8	Medium	Long	High	Rural
9	Medium	Short	Medium	Urban
10	Medium	Short	Low	Rural
11	Medium	Short	Medium	Rural
12	Medium	Medium	High	Rural
13	Medium	Medium	Medium	Rural
14	Medium	Long	High	Rural
15	High	Short	Medium	Urban
16	High	Long	High	Mixed

Representative Feeder Selection

Within each cluster, Navigant identified two feeders with attributes similar to the average attributes of the cluster. These feeders were provided to Hydro One as suitable representative feeders. Hydro One then identified which of the two feeders could be analysed given readily available CYMDIST models.[11] A complete list of the feeders that were selected is provided in Figure 21. The feeder is designated by the originating feeder name. However, the models included all downstream distribution stations and primary feeders.

The strength of the sampling process is the clustering of similar feeders. The clusters are designed to be a unique grouping of similar feeders. That is, the feeders contained within each cluster are similar, but the feeders in one cluster are different from the feeders in every other cluster. It is this unique cluster design that allows a single feeder from each cluster to be representative of a large number of feeders, and ultimately a large number of customers. Navigant has deployed similar clustering techniques in other jurisdictions where utilities are attempting to identify a reasonable number of representative feeders from a very large radial network.

[11] CYMDIST is discussed in more detail in Section 3.1.3.

Figure 21: List of Representative Feeders

Cluster	Originating Feeder	Downstream Distribution Stations
1	Sapawe DS F2	N/A
2	Manotick DS F4	N/A
3	Verner DS F1	N/A
4	Petawawa DS F5	N/A
5	Murillo DS F3	N/A
6	Margach DS F1	N/A
7	Jarvis TS M7	N/A
8	Highbury TS M11	N/A
9	Timmins TS M10	Dorchester DS, Thorndale DS
10	Pembroke TS M3	N/A
11	Dryden TS M3	Dryden Government DS
12	Trout Lake TS M3	Callander DS
13	Palmerston TS M4	Harriston DS
14	Havelock TS M14	Campbellford Alma DS, Campbellford Front DS, Campbellford King DS, Petherwick Corner DS, Rylstone DS
15	Brockville TS M3	Brockville Cedar DS, Brockville Park DS, Brockville Schofield DS, Brockville Water DS
16	Wilson TS M16	Park Road DS

3.1.3 Loss Analysis

This section describes Navigant's methodology to analyse class-specific losses across the sample feeder.

Overview

As indicated above in Section 3.1.1, there are nine major elements to Navigant's methodology to analyse class-specific losses. Each of these components is discussed in more detail in the sections below.

Power Flow Modeling

Hydro One uses CYME International T&D's CYMDIST Distribution System Analysis platform to simulate the behaviour of its distribution network. The CYMDIST platform is used to perform load flow, short-circuit, and network optimization analysis to support planning and other engineering studies. A component of the load flow analysis is the estimation of current based losses under given system configurations and loading.

Hydro One provided Navigant with the CYMDIST model outputs for each of the 16 representative feeders under peak load conditions and Hydro One's standard modeling assumptions. The models capture the power flow downstream from the transmission station (TS) to the distribution transformers. Loads downstream of the distribution transformers, i.e. secondary service customers, are modelled as a single aggregate load.

For each of the CYME models, Hydro One provided Navigant with a number of key outputs. For feeder segments, the outputs included:

- segment ID;
- GPS coordinates;
- node-to-node connectivity;
- length (km);
- cumulative length from the TS to the segment (km)
- number of phases;
- load (kW);
- segment losses (kW); and
- cumulative losses downstream from the segment (kW).

For transformers, the outputs included:

- transformer ID;
- 'from node';
- rated capacity (kVA); and
- load (kW).

In addition to the CYME model outputs, Hydro One provided Navigant with customer connectivity information for each distribution transformer and the geographic coordinates of each customer's meter. As will be discussed in further detail, the customer connectivity data and the geographic coordinates is what enables the estimate of losses on secondary lines and the allocation of losses to individual customers and hence customer classes.

Tracing Pathways

A key step in Navigant's methodology was to trace the feeder segment pathway from each distribution transformer to the transmission station. Each transformer ID was traced to a feeder segment based on the transformer's 'from node.' The feeder segment was then traced to the next feeder segment upstream, and so on and so forth, all the way up to the first segment of the feeder originating in the transmission station. An example of the results of this tracing exercise for five distribution transformers on the Sapawe DS F2 feeder is provided in Figure 22 below. In this case, the distribution transformers are less than six segments away from the top of the feeder. In other instances there were several hundred segments between the distribution transformer and the transmission station.

Figure 22: Illustrative Example of Pathway from Distribution Transformer to TS

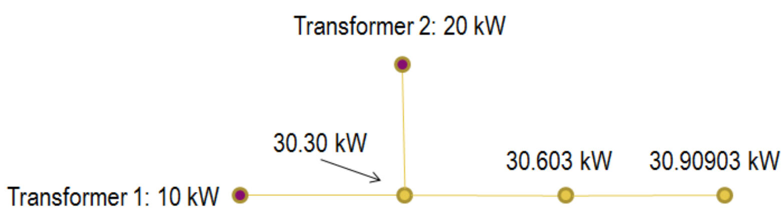
TransformerID	FromNode	Path -1	Path -2	Path -3	Path -4	Path -5	Path -6	Path -7
5405	45551_5405	SAPAWE_DS-3086	N/A	N/A	N/A	N/A	N/A	N/A
2006	45551_2006	467478.469_12476545	45551_404	467335.719_12476603	45551_5405	SAPAWE_DS-3086	N/A	N/A
2101	45551_2101	45551_2006	467478.469_12476545	45551_404	467335.719_12476603	45551_5405	SAPAWE_DS-3086	N/A
3298	45551_3298	467478.469_12476545	45551_404	467335.719_12476603	45551_5405	SAPAWE_DS-3086	N/A	N/A
2005	45551_2005	45551_3298	467478.469_12476545	45551_404	467335.719_12476603	45551_5405	SAPAWE_DS-3086	N/A

Allocation of Losses to Distribution Transformers

After the pathway from the distribution transformer to the TS was traced, incremental losses on each segment were allocated to the distribution transformers. The methodology for allocating segment losses to distribution transformers is best described through an example.

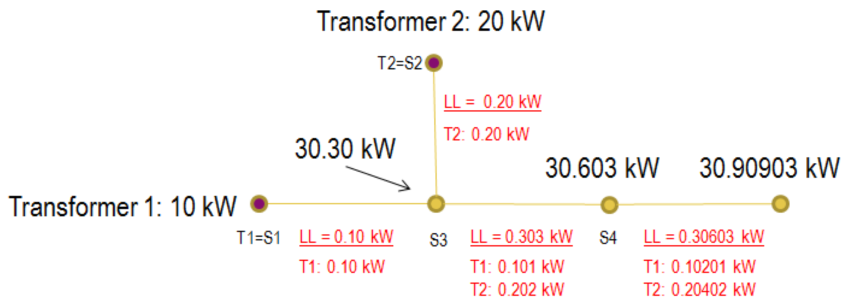
In the example, there are two distribution transformers; one has a peak load of 10kW and the other has a peak load of 20 kW. Assume for simplicity that the losses generated in each feeder segment are equal to 1% of the load in that segment. Thus, each segment has to provide 101% of the total load (including losses) downstream of it. Figure 23 illustrates the transformer loads and the losses on each segment based on the assumed 1% loss factor.

Figure 23: Illustrative Example of Transformer and Segment Load



The pathway from each transformer all the way up to the head of the feeder was found in step one and the load behind each transformer and each feeder segment is also known. Therefore, the losses can be proportionally allocated in each segment between the loads downstream based on the ratio of those loads and the accumulated losses. Figure 24 demonstrates the calculation for this example, where total line losses (LL) and the allocation to each distribution transformer are shown in red.

Figure 24: Illustrative Example of Loss Allocation



The general formula that extends this concept is as follows:

$$T1\ LL_{TOTAL} = \underbrace{\frac{T1}{S1}}_{(T1_{LL1})} LL_{S1} + \underbrace{\frac{(T1 + T1_{LL1})}{S3}}_{(T1_{LL3})} LL_{S3} + \underbrace{\frac{(T1 + T1_{LL1} + T1_{LL3})}{S4}}_{(T1_{LL4})} LL_{S4}$$

Navigant used this formula to allocate all of the feeder segment losses to downstream distribution transformers.

No Load Losses

To simplify the modeling, no load losses were estimated as a fixed percentage of the size of the transformer. For distribution transformers no load losses were estimated to be 0.25% of the rated capacity.

Secondary Line Losses

Secondary losses were estimated for each individual customer based on the estimated contribution of each customer to the load on the transformer, the voltage of the secondary, the distance from the transformer to the customer meter, and typical secondary conductor types. Knowing the estimated load of a given customer, and the voltage on the secondary, Navigant estimated the current in the conductor. The resistivity was estimated based on standard resistivity/length specifications for typical secondary conductors, such as Triplex 3/0 and the length of the secondary. The length of the secondary was estimated based on the straight-line distance between the geographic coordinates of each customer's meter and the geographic coordinates of the distribution transformer that served the customer.

Allocation of Losses to Customers

In instances where the distribution transformer served only customers from one class, the current (i.e. I^2R) losses were allocated to the distribution transformer were evenly allocated to each customer. In instances where the distribution transformer served customers of different classes, Navigant estimated the peak load contribution of each type of customer and used this as the basis for allocating current (i.e. I^2R) losses.

Navigant used a regression to estimate the contribution of each type of customer to the peak load on a distribution transformer. The dependent variable in the regression was the load on each of the distribution transformers on a sample feeder. The independent variables were the number of customers from each class served by the distribution transformer. The form of the model was:

$$Load_t = \alpha_1 \times ST_t^{Cust} + \alpha_2 \times UDG_t^{Cust} + \alpha_3 \times GSD_t^{Cust} + \alpha_4 \times UGE_t^{Cust} + \alpha_5 \times GSE_t^{Cust} + \alpha_6 \times UR, R1, R2_t^{Cust} + \alpha_7 \times SEASONAL_t^{Cust} + \varepsilon_t$$

Where:

t denotes a single distribution transformer, and

α_1, α_2, etc. represent the average peak load contribution of a customer in each class.

The model coefficients, α_1, α_2, etc., were estimated using data for all the distribution transformers on a sample feeder. While the results of the estimation varied across the sample feeders, they were generally consistent with typical peak loads for the different types of customers.

No load losses on the distribution transformer and secondary losses were allocated in a different manner. No load losses were allocated on an equal basis to each customer. Losses on the secondary were estimated for each individual customer and hence further allocation was not required.

Peak to Average Losses

The approach outlined above results in an allocation of losses at peak load to each individual customer on a feeder. The peak load losses for individual customers were then aggregated by rate class. The peak load losses were translated to average losses using an estimate of the load loss factor (LLF). The LLF is defined as the ratio of average power loss to peak load loss. The LLF is a function of load factor (LF), which is defined as the average demand over a period of time to the maximum demand within that period for the particular network. Where hourly or more granular demand recordings exist, the LF and LLF can be calculated. For the purpose of this study, actual data for 2012 was used to determine the load factors for different classes of customers and the following empirical formula was used to estimate the LLF:

$$LLF = k * LF + (1 - k) * LF^2 \qquad LLF = \frac{Averge\ Power\ Loss}{Peak\ Load\ Loss}$$

Where:

k is a constant, 0.2 for medium voltage feeders and distribution stations or 0.3 for sub-transmission systems.

3.2 Results

The sample feeders selected for this study serve between one and five percent of the customers within each rate class (see Figure 25).

Figure 25: Customers Served by Sample Feeders

	ST	UGD	GSD	UGE	GSE	UR	R1	R2	SEASONAL
Customers Served by Sample Feeder	25	25	108	588	1,503	8,624	8,197	5,373	1,544
Total Customers (2012)	795	1,185	6,550	12,308	98,513	167,672	403,304	370,995	153,653
Percent of Total	3%	2%	2%	5%	2%	5%	2%	1%	1%

The percentage of Hydro One's customers in each rate class served by each cluster of feeders is provided in Figure 26. A blank cell indicates that the feeders in the corresponding cluster do not serve customers in the rate class. A value of 0.0% indicates that the percentage of customers in the rate class served by feeders in that cluster is very small, less than one tenth of a percent. The bolded values highlight the clusters for which the sample feeders serve customers in a particular rate class. For example, the sample feeder selected from Cluster 4 served urban residential customers, whereas the sample feeder selected from Clusters 2 and 3 did not. Given the small number of UR customers served by feeders within Cluster 2, this is not surprising.

Figure 26: Percent of Hydro One Customers Served by Feeders in each Cluster

Cluster	ST	UGD	GSD	UGE	GSE	UR	R1	R2	SEASONAL
1					0.1%		0.0%	0.0%	0.0%
2			3.7%	0.3%	4.5%	0.1%	7.0%	2.4%	2.6%
3			1.3%		3.8%	0.0%	1.0%	6.0%	7.9%
4		3.8%	0.1%	6.1%	0.1%	6.0%	0.2%	0.0%	0.0%
5	8.3%		8.6%	0.5%	7.5%	0.4%	4.0%	7.8%	4.6%
6	7.4%	1.5%	5.2%	1.4%	2.7%	0.9%	2.1%	1.8%	1.4%
7	9.3%			1.2%	0.1%		0.0%	0.0%	0.1%
8	14.6%		20.1%	0.3%	17.0%	0.1%	15.7%	17.6%	7.0%
9	3.2%	29.5%	1.4%	23.5%	1.0%	36.3%	0.4%	0.2%	0.1%
10	13.6%				0.2%		0.0%	0.1%	
11			0.9%	0.1%	0.6%	0.0%	0.7%	0.1%	0.0%
12	4.9%		5.3%	0.7%	5.3%	0.7%	7.7%	4.0%	3.0%
13	3.7%		0.5%		0.5%	0.0%	0.1%	1.2%	0.2%
14	27.3%	1.0%	45.1%	1.8%	51.2%	1.7%	52.8%	54.9%	72.4%
15	7.6%	56.3%	2.7%	53.9%	1.2%	34.6%	1.9%	0.4%	0.2%
16		7.9%	5.1%	10.3%	4.0%	19.0%	6.4%	3.6%	0.5%
Population Represented by Sample Feeders	65%	94%	99%	94%	98%	96%	100%	99%	90%

The sum of the bolded values, presented in the last row of Figure 26 is the population of customers in each rate class represented by the sample feeders. In total, the sample feeders represent feeders that serve between 90 and 99% of the population of customers in each rate class. The one exception is the ST customer class. Because of the small number of ST customers within Hydro One, the sample feeders selected from Clusters 5, 6, 8, and 12 did not include ST customers. However, each of these clusters includes feeders that serve, in aggregate, 5% or more of the total ST customers. Given the diversity of ST customers and this low representation amongst the sample feeders, Navigant concluded that it would not be appropriate to extend the analysis to the ST customer class. As such, the remainder of the discussion focuses on the general service and residential customer classes.

The decision to not extend the results to the Sub-Transmission impacts the overall allocation of losses between Sub-Transmission customers and other customers, but not the allocation between the other classes, for example the difference between the Urban Residential and R2 Residential loss factors are not affected.

The peak demand kW losses per customer for each rate class and sample feeder is presented in Figure 27.

Figure 27: Peak Losses (kW) per Customer

Sample Feeder	UGD	GSD	UGE	GSE	UR	R1	R2	SEASONAL
Sapawe DS F2				0.17			0.08	0.04
Manotick DS F4		1.02		0.15		0.15	0.15	
Verner DS F1				0.39		0.06	0.19	0.11
Petawawa DS F5			0.12		0.03	0.11		0.03
Murillo DS F3		1.62		0.24		0.09	0.17	0.09
Margach DS F1		2.71		0.13		0.05	0.07	0.15
Jarvis TS M7								
Highbury TS M11		2.35		0.29		0.16	0.22	
Timmins TS M10	0.60	0.86	0.09	0.12	0.01	0.01	0.01	0.01
Pembroke TS M3								
Dryden TS M3		2.17		0.35		0.06		
Trout Lake TS M3		2.95		0.35		0.12	0.29	0.34
Palmerston TS M4		1.92		0.92			0.56	
Havelock TS M14		3.54		0.34		0.11	0.30	0.09
Brockville TS M3	1.68	0.43	0.21		0.05	0.06		0.05
Wilson TS M16	14.55	8.66	0.94	0.76	0.20	0.19	0.43	

The average demand kW losses per customer for each rate class and sample feeder are presented in Figure 28.

Figure 28: Average Losses (kW) per Customer

Sample Feeder	UGD	GSD	UGE	GSE	UR	R1	R2	SEASONAL
Sapawe DS F2				0.11			0.05	0.03
Manotick DS F4		0.70		0.09		0.08	0.08	
Verner DS F1				0.21		0.03	0.09	0.04
Petawawa DS F5			0.08		0.02	0.06		0.02
Murillo DS F3		1.02		0.14		0.06	0.09	0.03
Margach DS F1		2.44		0.10		0.04	0.05	0.07
Jarvis TS M7								
Highbury TS M11		1.28		0.17		0.08	0.11	
Timmins TS M10	0.32	0.43	0.04	0.06	0.01	0.01	0.01	0.01
Pembroke TS M3								
Dryden TS M3		1.34		0.21		0.04		
Trout Lake TS M3		1.56		0.18		0.06	0.13	0.10
Palmerston TS M4		1.09		0.46			0.24	
Havelock TS M14		1.93		0.18		0.05	0.14	0.03
Brockville TS M3	1.08	0.29	0.13		0.03	0.04		0.03
Wilson TS M16	7.17	4.79	0.46	0.40	0.08	0.08	0.19	

The sample feeders were selected to be representative of the clusters that they are drawn from. The clusters represent 16 archetype feeders across Hydro One's distribution network. Figure 26 highlights the percentage of the population of each rate class served by the feeders within each cluster. For example, approximately six percent of UR customers are served by feeders within Cluster 4, 36% by feeders in Cluster 9, 35 % from feeders in Cluster 15, and 19% by feeders in Cluster 16. As such, to determine the average kW loss for a typical UR customer across Hydro One's entire system, the sample feeder results were weighted by the percentage of the population of each rate class served by feeders within each cluster. The formula used to weight the individual results was:

$$Weighted\ Average^{rc} = \sum_{c} Average\ Loss_{sf}^{rc} \times \frac{Percent\ of\ Customers\ Served_{c}^{rc}}{Total\ Population\ Represented\ by\ Sample\ Feeders^{rc}}$$

Where:

rc denotes an individual rate class;

c denotes an individual clusters; and

sf denotes the sample feeder within an individual cluster.

The resulting weighted average kW losses per customer by rate class, average demand per customer by rate class, based on 2012 actuals, and resulting loss factors are presented in Figure 29.

Figure 29: Average Losses, Demand, and Technical Loss Factors by Rate Class

	UGD	GSD	UGE	GSE	UR	R1	R2	SEASONAL
Average Losses (kW/cust)	1.358	1.749	0.140	0.181	0.030	0.059	0.126	0.037
Average Demand (kW/cust)	65.7	53.7	3.6	2.7	1.1	1.2	1.7	0.5
Technical Loss Factors	2.1%	3.3%	3.9%	6.7%	2.8%	4.8%	7.6%	7.5%

As evidenced from the result above, there is a clear difference in the loss factor between the urban and non-urban rate classes. This is intuitive, as the feeders serving urban customers tend to be shorter. The distribution transformers serving urban customer also tend to serve more customers, resulting a smaller allocation of no-load losses to an individual customer.

Note that the above values do not account for non-technical losses, or transformation losses in the transmission stations or high voltage distribution stations.

To determine whether the resulting technical loss factors were statistically different from each other, Navigant conducted a difference of means test on the underlying sample data. The test results are reported for the 'sub-classes' only (i.e. UGD vs. GSD, UGE vs. GSE, UR vs. R1, R1 vs. R2, and UR vs. R2). The results of this test are provided in Figure 30 below.

The test demonstrates that the null hypothesis (i.e. that the means of the two samples are the same) can be rejected at the 95% confidence interval for year round residential customers and at the 90% confidence interval for energy billed general service customers. Given the small number of demand billed general service customers in the sample, the null hypothesis cannot be rejected at a meaningful confidence interval. However, the results for the energy billed general service and residential customers clearly demonstrate that there is a meaningful difference in loss factors between urban and non-urban customers. The results for the more limited sample of GSD and UGD customers indicate a similar relationship. As such, Navigant believes it is appropriate to adopt the study results for the UGD and GSD rate classes.

Figure 30: Results of Difference of Means Test (95% Confidence Interval)

	UGD vs. GSD	UGE vs. GSE	UR vs. R1	R1 vs. R2	UR vs. R2
p-values	0.506	0.097	0.000	0.000	0.000

4 RECOMMENDATIONS

4.1 System-wide Losses and Variance

The meter data method is not the standard approach used in the industry. In general, utilities rely on an approach comparable to the bill data method to calculate actual losses. A key reason for this is that the meter data method requires the collection and analysis of vast quantities of hourly consumption data, which only recently became available for the majority of customers with the roll out of smart meters and the implementation of automated meter reads. The amount of hourly metered consumption data available to implement the meter data declines prior to 2012. The further back in time, the more the meter data method approaches the bill data method.

Based on these factors, and since the results of the meter data method and the bill data method for 2012 were reasonably similar, Navigant recommends that Hydro One use the bill data method to calculate actual losses from January 1, 2010 to December 31, 2013. The actual losses can then be compared to the approved losses to determine the variance and establish the amount to report in RSVA 1588 Power. The variance between actual and approved losses from January 1, 2010 to December 31, 2012, calculated using the bill data method is presented in this report (see Figure 14). Once the final settlement data becomes available, Hydro One will be able to perform a similar analysis for the period from January 1, 2013 to December 31, 2013.

While Navigant's analysis of system-wide losses shows that actual losses have varied from approved losses over the 2010 to 2012 period, the magnitude and sign of the variance has changed considerably from year to year. As such, Navigant recommends that Hydro One maintain the absolute level of approved losses and continue to monitor variances to assess whether an across the board increase or decrease to the approved TLFs is required to reduce the magnitude of the variance.

Going forward, Navigant recommends that Hydro One use the capabilities of its new CIS to improve the calculation of actual losses. Hydro One's new CIS includes an industry leading unbilled consumption module. The CIS uses individual customer's historic consumption data to estimate unbilled consumption and revenue as of a given date and time. The system develops a kilowatt-hour per day metric during a specified base period and applies it to unbilled period. With this module, the CIS is capable of determining total sales as well as unbilled consumption for each of Hydro One's ~1.2 million customers as of December 31 of each year.

4.2 Class-specific Losses

The results of Navigant's review and analysis of losses for the year-round residential, seasonal, and general service classes, suggest there is wider variability in the losses incurred to serve each class of customers than is currently reflected in the approved loss factors.

Navigant's analysis explicitly estimated the technical losses and corresponding loss factors for the year-round residential (i.e. UR, R1, and R2), seasonal, and general service (i.e. UGD, GSD, UGE, and GSE) rate classes.

In order to translate the technical loss factors estimated for the rate classes above into DLFs, non-technical losses need to be considered. To determine the TLF, further accounting for transformation losses in the transmission station and high voltage distribution station is required.

The non-technical loss factor should be set such that the variance between approved and actual system-wide losses is close to zero. Based on the total consumption by rate class for 2012, the calculated technical loss factors for the residential, seasonal, and general service classes would have resulted in a system-wide average loss factor of 5.4%. The system-wide average of the approved DLFs in 2012 for the residential, seasonal, and general service classes was 7.7%, a difference of 2.3%.

As mentioned above, based on the system-wide loss and variance analysis, Navigant recommends that Hydro One continue to monitor actual losses before determining whether adjusted the absolute level of the approved loss factors. Based on this recommendation, the non-technical loss factor would be set at 2.3%, such that the proposed TLFs for the residential, seasonal, and general service classes recover the same losses as the approved TLFs.

To account for transformation losses in the transmission and high voltage distribution stations, the current approved Supply Facility Load Factor (SFLF) of 0.6% is added to the DLFs to determine the TLF.

Figure 31 below presents Navigant's recommended DLFs and TLFs for Hydro One's residential, seasonal, and general service rate classes.

Figure 31: Proposed Loss Factors for the Residential, Seasonal, and General Service Classes

	UGD	GSD	UGE	GSE	UR	R1	R2	SEASONAL
Technical Loss Factor	2.1%	3.3%	3.9%	6.7%	2.8%	4.8%	7.6%	7.5%
Non-Technical Loss Factor	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%	2.3%
SFLF	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
TLF	5.0%	6.1%	6.7%	9.6%	5.7%	7.6%	10.5%	10.4%

Note: Differences between the sum of the individual values and the TLF are due to rounding.

Navigant proposes Hydro One maintain its current approved DLFs and TLFs for the Sub-Transmission, Street Lighting, Sentinel Lighting, Unmetered Scattered Load, and Distributed Generator rate classes.

KINECTRICS

2016 TRANSFORMER COST-OF-LOSSES FORMULAE FOR HYDRO ONE

K-418982-REPT-0001- R01

Prepared for:

Hydro One Networks Inc.
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2016 TRANSFORMER COST-OF-LOSSES FORMULAE FOR HYDRO ONE

Kinectrics Report: K-418982-REPT-0001-R01

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SUMMARY

Distribution transformer Cost-of-Losses formulae, to be used in the transformer purchasing process, have been computed for Hydro One Networks Inc. and are provided in this report along with information on their development.

The formulae allow evaluation of the Total Ownership Cost of transformer designs. Specifically, the formulae can be used to compute the lifetime costs of the inherent energy losses of the transformers. The formulae were derived utilizing transformer load profile projections and predicted economic factors from the year 2016 forward. Of significant difference from previous Hydro One cost-of-losses formulae, the 2016 formulae consider on-peak, mid-peak and off-peak energy costs, applied to 5 daily time-periods, as well as different rate allocations for summer and winter periods. Further, some actual measured residential load profiles were used to validate the theoretical load profiles used in the computations.

The 2016 distribution transformer cost-of-losses formulae were developed for transformers that will be used in either rural, urban, or commercial transformer applications. The resultant formulae are shown in the Table below.

Cost-of-Losses Formulae for Distribution Transformers in Rural, Urban and Commercial Applications

Application	Transformer Cost-of Losses Formulae
Transformers for Rural Application	TOC =CAPCOST + **$18.15***NLL + **$2.72*** LL
Transformers for Urban Application	TOC =CAPCOST + **$18.15***NLL + **$5.44*** LL
Transformers for Commercial Application	TOC =CAPCOST + **$16.40***NLL + **$5.22*** LL

where:
TOC = Total Ownership Cost (net present value in $)
CAPCOST = Capital cost of the transformer
NLL = No-load losses in Watts
LL = Load losses in Watts

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1 INTRODUCTION

The transformer purchasing process often employs a "cost-of-losses" formula, which provides a tool to minimize the Total Ownership Cost (TOC) of the transformer purchased. The cost-of-losses formula determines the operating cost of the transformer over its lifetime and sums it with the capital cost to produce a Net Present Value for the lifetime cost of the transformer. The TOC of alternative transformer designs can be compared so that the utility can select those with the lowest TOC. This allows the utility to assess whether or not there is economic benefit in paying a higher capital cost in order to obtain a transformer with reduced losses and lower operating costs.

Transformer losses can be reduced by design or loading changes. Design changes can be achieved by using lower loss steel in the transformer core, or by using windings with lower resistance, either by using copper instead of aluminum or by using larger wire, or both. Since some transformer losses are load dependent, changing the utilization of existing transformers is also a means of controlling losses.

The transformer loss evaluation formula also indicates to a manufacturer the dollar value that the utility associates with load and no-load losses. The design can them be adjusted to minimize the transformer lifetime cost by optimizing the load and no-load losses.

The 2016 cost-of-losses formulae, developed for Hydro One, consider on-peak, mid-peak and off-peak energy costs applied to 5 daily time-periods, as well as different rate allocation for summer and winter periods. Further, some measured residential load profiles were used to validate the theoretical load profiles used in the computations. Appropriate period-specific loss factors were applied to each of the 5 daily time categories (as opposed to using a single loss factor for the entire daily profile).

1.1 Objectives and Scope

This project had the objective of developing the cost-of-losses purchasing formula for evaluating the total ownership cost of distribution transformers purchased by Hydro One Networks Inc. Formulae were to be developed for transformers to be applied in urban, rural, and commercial applications.

The three formulae required, and the type of transformers for which they are to be applicable, are described in Table 1.

Table 1
Required Cost-of-Losses Formulae and their Application

Formula	Transformer Type	Transformer Rating	Load Type	Economic Parameters
Formula 1	**Rural – Residential** **Polemount and Padmount**	5 – 25kVA Single-phase units 120/240 V	Single residential load profile	3 tier residential TOU energy rates No peak demand rate
Formula 2	**Urban – Residential** **Polemount and Padmaount**	50kVA to 167kVA Single-phase units For 120/240 V and 120/208V applications	Multiple residential load profile	3 tier residential TOU energy rates No peak demand rate
Formula 3	**Commercial** **Polemount and Padmount**	All 3-phase padmounts up to 1000kVA without forced cooling All single phase polemount units with secondaries of 347/600V	Commercial load profile	Average commercial energy rates No peak demand rate

2 COMPUTATION OF COST-OF-LOSSES FORMULAE

Losses in distribution transformers are categorized as load and no-load losses. Load losses vary with the square of the load on the transformer whereas no-load losses are continuous and constant regardless of load.

When transformers are lightly loaded the no-load losses form a large percentage of the power utilized and therefore the efficiency is low. As the transformer is loaded to higher levels the load losses dominate the efficiency. The maximum efficiency point is the optimal point of lowest load and no-load losses. It is determined by the design of the transformer and theoretically could be designed to occur at any load percentage. It typically is designed to occur at 50% rated load because the average load tends to be about 50% of the peak load. Transformers with high no-load losses are most efficient at 60-80% load and transformers with low no-load losses are most efficient at about 40% load [1].

Transformer no-load losses are constant and depend on the size of the transformer installed and are likely related to the loss formula used when the transformer was purchased. Decreasing the transformer rating will decrease the no-load losses.

The total ownership cost of a transformer has two major components: the capital cost and the cost of losses. Inherent in transformer design is the fact that if the materials are held constant, then when no-load losses are decreased the load losses will increase. If load losses are decreased then no-load losses will increase. Therefore, utilities use the cost-of-losses formula to indicate to transformer manufacturers the optimal ratio of load to no-load losses that would minimize the total lifetime or ownership cost at their particular utility. For urban applications with high load levels on transformers, the utility would buy transformers with low load losses and these may inherently have higher no-load losses. Rural applications often require transformers with low no-load losses because the loading and load losses would be generally low.

The following paragraphs provide the basic formulation of the cost-of-losses formulae. Appendix A provides additional details and advancements in the accuracy of the basic formulation. Previous cost-of-losses equations had been developed using flat rate demand and energy charges and fixed economic factors such as interest rate. The concepts of load factor and loss-factor were used to describe the loads on the transformer for the entire year and thus to evaluate the load losses. For the 2016 Hydro One cost-of-losses formulae, Time-of-Use energy charges are accommodated by the computation and different daily, weekly and monthly load profiles are used to simulate the typical load changes. Load factors and loss factors were developed for each period of the daily load profile (as opposed to using one loss-factor for the entire year).

Loss evaluation formulae have the form:

$$TOC = CAPCOST + NLL*CNLL + LL *CLL$$

Where:
TOC = Total Ownership Cost (net present value in $)
CAPCOST = Capital Cost (in $)
NLL = No-load losses for the transformer design (Watts)
CNLL = Cost of no-load losses ($)
LL = Load losses for the transformer design (Watts)
CLL = Cost of load losses ($)

A brief description of each of these terms is provided in the following paragraphs:

No-Load Losses (NLL)
No-load losses occur continuously when the transformer is energized, regardless of the loading. The no-load losses are due primarily to hysteresis and eddy currents.

Cost of No-Load Losses (CNLL)
The cost of no-load losses is independent of the loading and dependent on the demand charges, the on-peak, mid-peak and off-peak energy charges, and the amount of time that these rates apply. In the simplest form, if there was a constant energy rate all year, the cost of no-load losses would be:

$$CNLL = [(\frac{12}{1000} \text{ x } D) + (\frac{8760}{1000} \text{ x } \frac{E}{100})] \text{ x } PVF$$

D = Demand charge ($/kW)
E = Energy charge (cents/kWh)
PVF = Present value factor

In the 2016 cost-of-losses formulae, rather than a constant energy rate, the Time of Use rates are applied for the appropriate number of hours in the year (as defined in Table 2 and Table 3).

Load Losses at Rated Load (LLR)
Load losses are primarily due to the I^2R heating of the copper or aluminum windings. The value of load losses at rated load is a measured parameter and load losses at other loadings are derived from this value.

Cost of Load Losses (CLL)
The cost of the load-losses depends on the demand and energy charge rates as well as on the loading of the transformer throughout its life. The cost of load-losses formula, given a constant Demand and Energy rate throughout the year, would be as follows:

$$CLL = [UF^2 \text{ x } \frac{12}{1000} \text{ x D x RF}) + (UF^2 \text{ x } \frac{8760}{1000} \text{ x } \frac{E}{100} \text{ x LSF})] \text{ x PVF}$$

UF = Utilization factor (peak load/rated load)
D = Demand charge ($/kW)
RF = Responsibility factor (load at system peak/peak load)^2
E = Energy charge (cents /kWh)
LSF = Loss factor (average load loss/peak load loss)
PVF = Present value factor

In the 2016 cost-of-losses formulae, rather than a constant energy rate, Time-of-Use rates are applied for the appropriate number of hours in the year (details in Table 2 and Table 3).

Table 2
Time-of-Use Energy Charges Used in the 2016 Cost-of-Losses Formulae

	Daily Period 1 Hours	**Daily Period 2 Hours**	**Daily Period 3 Hours**	**Daily Period 4 Hours**	**Daily Period 5 Hours**
	0:00 to 7:00	**7:00 to 11:00**	**11:00 to 17:00**	**17:00 to 19:00**	**19:00 to 24:00**
Residential - Winter (November 1 to April 30)	Off-peak	On-peak	Mid-peak	On-peak	Off-peak
Energy price: cents per kWhr	8.7	18	13.2	18	8.7
Residential - Summer (May 1 to October 31)	Off-peak	Mid-peak	On-peak	Mid-peak	Off-peak
Energy price: cents per kWhr	8.7	13.2	18	13.2	8.7
Residential - Weekends and Statutory Holidays	Off-peak	Off-peak	Off-peak	Off-peak	Off-peak
Energy price: cents per kWhr	8.7	8.7	8.7	8.7	8.7
Commercial	Average	Average	Average	Average	Average
Energy price: cents per kWhr	10	10	10	10	10

Table 3
Duration for Which the Time-of-Use Energy Charges are Applicable in a Year

	Number of Days	Business Days	Weekend Days	Statutory Holidays	On-peak Hours	Mid-Peak Hours	Off-Peak Hours	Hour Total
Winter	182	125	52	5	750	750	2868	
Summer	183	126	52	5	756	756	2880	
Total	365	251	104	10	1506	1506	5748	8760

Utilization Factor (UF)
The utilization factor is the ratio of the peak load to the transformer rated load. It represents the portion of the transformer rated load that is being utilized. In the 2016 cost-of-losses formulae, the utilization factor is varied from month to month depending on a monthly load profile.

Responsibility Factor (RF)
The responsibility factor is the ratio of the transformer load at system peak to the peak load, all squared. It indicates how much the load loss of the transformer contributes to the total demand.

Loss Factor (LSF)
The loss factor is the ratio of the average loss to the peak loss. The loss factor is dependent on the load factor. The load factor is the ratio of the average load to the peak load. The load factor is a single value which characterizes the load profile. Similarly the loss factor characterizes the losses. There are at least three categories of loading profile, industrial/commercial, urban residential and rural residential. Commercial loads are generally flatter over the working hour period throughout the week.

The relationship between loss factor and load factor is dependent on the shape of the load profile. Theoretically, the loss factor may have a value between the value of the load factor and the load factor squared [2]. Field measurements of transformer loads and losses have indicated that the expression **Loss Factor = $0.85*LDF^2+0.15*LDF$**, where LDF is the load factor of the daily load profile, most accurately represents field conditions. This formula is often used by utilities for calculating loss factor for cost-of-losses purposes.

In the 2016 Hydro One cost-of-losses formulae, however, a more precise method was used to determine the loss-factor for each Time-of-Use rate period. A specific daily load profile was developed for each of the rural, urban and commercial transformer types (see Appendix C). The urban residential load profiles were verified by comparison to some measured load profiles (see Appendix B). The associated loss profiles were then developed for each application. These loss profiles were then segmented into the time-of-day periods and a specific loss factor (average loss/peak loss) was computed for each segment (see Appendix D).

Present Value Factor (PVF)
The present value factor accounts for the changing value of money and expresses the present worth of dollars spent in the future. The present value factor for a year is calculated as follows:

$$\mathrm{PVF} = \sum_{y=1}^{NY} \frac{[1+p(y)]^{y-1}}{[1+i(y)]^{y-1}}$$

PVF = Present value factor
p(y) = Growth of power costs for year "y"
i(y) = Interest rate for year "y"
NY = Number of years in the economic study period

The total cost of a distribution transformer includes the capital cost plus the present value of the losses over its expected lifetime. A typical distribution transformer lifetime is considered to be 30 years. Appendix E shows the numerical computation of the PVF for the 2016 cost-of-losses formulae. As the no-load losses are constant over the life of the transformer, a purely economic PVF is used. As there is likely a year-over-year increase in transformer load, a load growth factor is combined into the PVF used for the Load Losses (see Appendix E).

Capital Cost (CAPCOST)
Capital cost is the initial cost or purchase price of the transformer.

The input values and the results of the cost-of-losses computations for rural, urban and commercial transformers are provided in Table 4, Table 5, and Table 6 respectively. Each Table indicates the prior 2006 formulae, where available, and the 2016 computation results. The majority of the economic parameters for the 2016 formulae were stipulated by Hydro One.

Table 4
Rural Cost-of-Losses Formulae

Parameter	Units	2006 Formula based on OEB Total Resource Cost Guide [1]	2006 Formula based on H1 "average" rates [1]	2016 Formula
Demand Charge				
Winter	**$/kW**	(TRC)	5.24	0
Summer	**$/kW**	(TRC)	5.24	0
Energy Charge				
Winter- On-peak	**Cents/kWh**	(TRC)	6.24	18
Winter– Mid–peak	**Cents/kWh**	na	na	13.2
Winter– Off–peak	**Cents/kWh**	(TRC)	6.24	8.7
Summer– On-peak	**Cents/kWh**	(TRC)	6.24	18
Summer– Mid-peak	**Cents/kWh**	na	na	13.2
Summer–Off-peak	**Cents/kWh**	(TRC)	6.24	8.7
Weekend		na	na	8.7
Rate of Return (after tax)	**%**	5.8%	5.8	5.72
Load growth factor	**%**	1	1	1
Cost of Power growth / Inflation	**%**	(TRC)	4	2
Utilization factor		0.61	0.61	0.61
Responsibility Factor		1	1	1
Load Factor		0.5	0.5	Load profile (App. C) Average LDF = 0.56
Loss Factor		0.29	0.29	Loss Profile (App. C) Average LSF= 0.35
Monthly Load Scalar		na	na	Winter & summer peaks Shoulder months peak at 0.75 * UF
Weekend Load Scalar		na	na	Weekends peak at 1.1* UF
Evaluation Period	**years**	30	30	30
Present value factor		(TRC)	23.65	18.72
Cost-of-Losses Formula CNLL	**$**	13.60	14.42	18.15
Cost-of-Losses Formula CLL	**$**	2.17	2.56	2.72
Ratio of CNLL to CLL		6.3	5.6	6.7

Table 5
Urban Cost-of-Losses Formula

Parameter	Units	2006 Formula based on OEB Total Resource Cost Guide [1]	2006 Formula based on H1 "average" rates [1]	2016 Formula
Demand Charge				
Winter	**$/kW**	(TRC)	5.24	0
Summer	**$/kW**	(TRC)	5.24	0
Energy Charge				
Winter- On-peak	**Cents/kWh**	(TRC)	6.24	18
Winter– Mid–peak	**Cents/kWh**	na	Na	13.2
Winter– Off–peak	**Cents/kWh**	(TRC)	6.24	8.7
Summer– On-peak	**Cents/kWh**	(TRC)	6.24	18
Summer– Mid-peak	**Cents/kWh**	na	Na	13.2
Summer–Off-peak	**Cents/kWh**	(TRC)	6.24	8.7
Weekend	**Cents/kWh**	na	na	8.7
Rate of Return (after tax)	**%**	5.8%	5.8	5.72
Load growth factor	**%**	1	1	1
Cost of Power growth / Inflation	**%**	(TRC)	4	2
Utilization factor		0.8	.8	0.8
Responsibility Factor		0.7	0.7	0.7
Load Factor		0.6	0.6	Load profile (App. C) Average LDF = 0.65
Loss Factor		0.4	0.4	Loss Profile (App. C) Average LSF= 0.45
Monthly Load Scalar		na	Na	Winter & summer peaks Shoulder months peak at 0.80 * UF
Weekend Load Scalar		na	Na	Weekends peak at 0.90* UF
Evaluation Period	**years**	30	30	30
Present value factor		(TRC)	23.65	18.72
Cost of Losses Formula CNLL	**$**	13.60	14.42	18.15
Cost of Losses Formula CLL	**$**	4.66	5.21	5.44
Ratio of CNLL to CLL		2.92	2.76	3.33

Table 6
Commercial Cost-of-Losses Formula

Parameter	Units	2006 Formula based on OEB Total Resource Cost Guide [1]	2006 Formula based on H1 "average" rates [1]	2016 Formula
Demand Charge				
Winter	**$/kW**	na	na	0
Summer	**$/kW**	na	na	0
Energy Charge		na	na	
Winter- On-peak	**Cents/kWh**	na	na	10
Winter– Mid–peak	**Cents/kWh**	na	na	10
Winter– Off–peak	**Cents/kWh**	na	na	10
Summer– On-peak	**Cents/kWh**	na	na	10
Summer– Mid-peak	**Cents/kWh**	na	na	10
Summer–Off-peak	**Cents/kWh**	na	na	10
Rate of Return (after tax)	**%**	na	na	5.72
Load growth factor	**%**	na	na	1
Cost of Power growth / Inflation	**%**	na	na	2
Utilization factor		na	na	0.9
Responsibility Factor		na	na	0.7
Load Factor		na	na	Load profile (App. C) Average LF = 0.68
Loss Factor		na	na	Loss Profile (App. C) Average LSF= 0.5
Monthly Load Scalar		na	na	Winter & summer peaks Shoulder months peak at 0.8 * UF
Weekend Load Scalar		na	na	Weekends peak at 0.7* UF
Evaluation Period	**years**	na	na	30
Present value factor		na	na	18.72
Cost of Losses Formula CNLL	**$**	na	na	16.40
Cost of Losses Formula CLL	**$**	na	na	5.22
Ratio of CNLL to CLL		na	na	3.14

3 CONCLUSIONS

1. Total Ownership Cost approach is effective for assessing the impact of the cost of losses when choosing between alternative transformer assets. Utilities have typically purchased transformers using a total ownership cost approach. A cost-of-losses formulae is used to assign a dollar value to the load and no-load losses experienced over the life of the transformer. This cost of losses can be compared with the transformer capital cost. A more efficient, higher cost transformer can be justified if it allows an off-setting reduction in the lifetime cost of losses.

2. Of significant difference over previous cost-of-losses formulae, the 2016 formulae considers on-peak, mid-peak and off-peak energy costs applied to 5 daily time-periods, as well as different rates for summer and winter periods. Further, some measured urban residential load profiles were used to validate the theoretical load profiles used in the computations. Appropriate loss factors were applied to each of the 5 daily time categories (as opposed to using a single loss factor for the entire period).

3. It is recommended that Hydro One adopt the use of three cost-of-losses formulae; one for transformers used in rural settings, another for transformers used in urban areas, and one for transformers to be used in commercial applications. This will ensure that no-load losses are minimized for rural transformers, urban, and commercial transformers.

4. Results of the distribution transformer cost-of-losses computations conducted in this study are provided in Table 4, Table 5, and Table 6 of this report.

.

4 REFERENCES

[1] Cress, S.L., 2006 Distribution Transformer Cost-of-Losses Formula, Kinectrics Report K-013337-001-RA-0001-R01, November 27,2008.

[2] Cress, S.L., Economic Loading of Distribution Transformers, CEA Report 161 D 456A, January 1993.

Appendix A Transformer Loss Evaluation Methodology

A basic form of the transformer cost of losses formula is presented in the body of this report and has a similar form as Equation 1 below:

Equation 1

$$TOC = CAPCOST + NLL * CNLL + LL * CLL$$

In the actual computation of the 2016 loss-evaluation formulae, numerous extensions to the basic formula were made simulate the variability of the economic and load inputs and thus increase the accuracy of the computation. The end result of the calculation is the present value of the lifetime cost of the transformer. The fixed factors that enter the above equation are the capital cost, and the transformer losses: the no-load loss (NLL) and the load loss at rated load (LL), expressed in watts (W). A more complex version of the formula is provided in this Appendix and includes the following symbols.

Definition of Symbols

CAPCOST	Capital cost ($)
CLL	Present value of cost of load losses ($/W)
CLL(m)	Cost of load losses for month “m” ($/kW)
CNLL	Present value of cost of no-load losses ($/W)
CNLL(m)	Cost of no-load losses for month “m” ($/kW)
D	Demand charge, monthly ($/kW)
D(m)	Demand charge for month “m” ($/kW)
E	Energy charge, monthly (¢/kWh)
EOP(m)	Energy charge off-peak for month “m” (¢/kWh)
EP(m)	Energy charge on-peak for month “m” (¢/kWh)
FYG(y)	Factor for yearly load growth accumulated to year “y”
g(y)	Growth of load for year “y” (%/100)
HOP(m)	Hours off-peak for month “m” (h)
HP(m)	Hours on-peak for month “m” (h)
i(y)	Interest rate for year “y” (%/100)
j(y)	Inflation rate for year “y” (%/100)
TOC	Present value of lifetime cost ($)
LL	Load losses (W)
LSF	Loss factor (average loss/peak loss)
NLL	No-load losses (W)
NY	Number of years in economic study period
p(y)	Growth of power costs for year “y” (%/100)
PVF	Present value factor for a period of years
PVF(y)	Present value factor for year “y”
RF	Responsibility factor (load at system peak/peak load)^2
UF	Utilization factor (peak load/rated load)
UF(m)	Utilization factor for month “m” (monthly peak load/rated load)

The formulation below takes into account the fact that energy and demand charges may depend on time of use, either on-peak or off-peak. The economic factors, including the load growth, may vary from year to year. Note that either *p(y)* or *j(y)* must be set to zero for all years *y*.

Equation2

$$CLL = \left[\frac{1}{1000} * \sum_{m=1}^{12} CLL(m)\right] * \sum_{y=1}^{NY} \left\{\left[UF * FYG(y)\right]^2 * PVF(y)\right\}$$

(Note: in the 2016 computation, the UF value was also modified monthly by a day-of- the-week and month-of- the- year factor to account for weekly and seasonal load variations – see Appendix C).

Equation3

$$CLL(m) = D(m) * RF + \left[HP(m) * \frac{EP(m)}{100} + HOP(m) * \frac{EOP(m)}{100}\right] * LSF$$

(Note: in the 2016 computation, mid-peak pricing was also enabled in the computation. Also a separate value of LSF was used for each of the Time-of-Use periods – see Appendix D)

Equation4

$$CNLL = \left[\frac{1}{1000} * \sum_{m=1}^{12} CNLL(m)\right] * PVF$$

Equation5

$$CNLL(m) = D(m) + HP(m) * \frac{EP(m)}{100} + HOP(m) * \frac{EOP(m)}{100}$$

Equation6

$$PVF(y) = \frac{[1 + p(y)] * [1 + j(y)]}{[1 + i(y)]} * PVF(y-1)$$

Equation7

$$PVF(1) = \frac{\left[1 + p(1)\right] * \left[1 + j(1)\right]}{\left[1 + i(1)\right]}$$

Equation8

$$PVF = \sum_{y=1}^{NY} PVF(y)$$

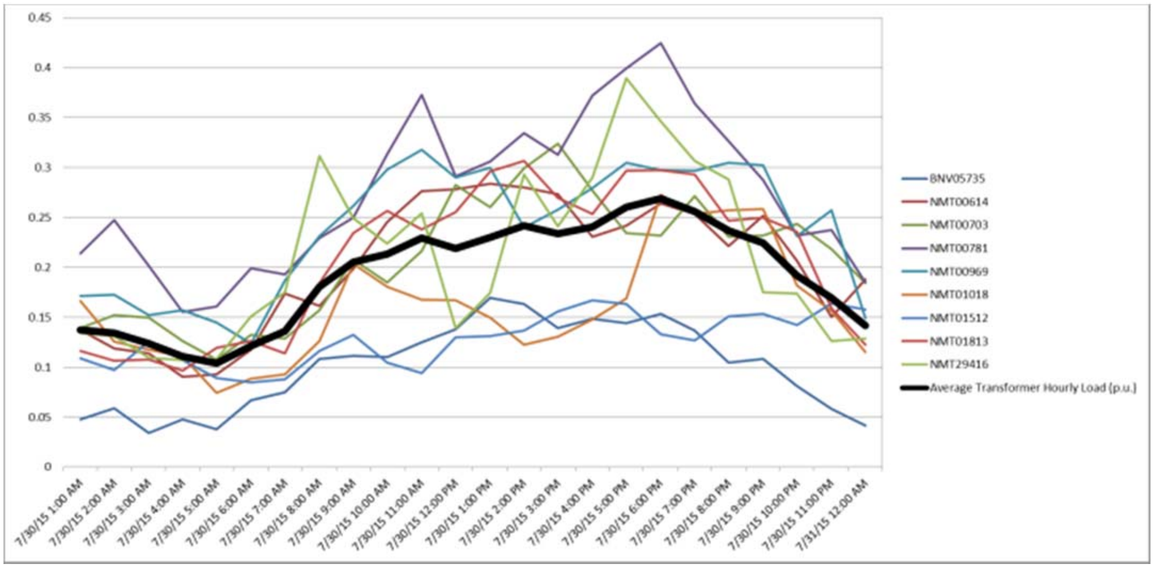
Equation9

$$FYG(y) = [1 + g(y)] * FYG(y-1)$$

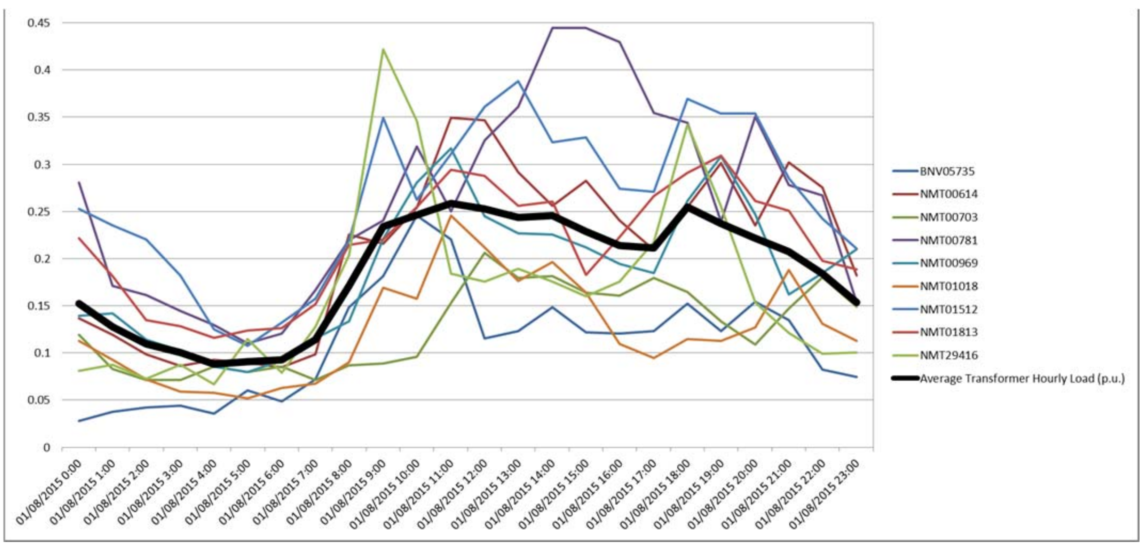
Equation10

$$FYG(1) = 1 + g(1)$$

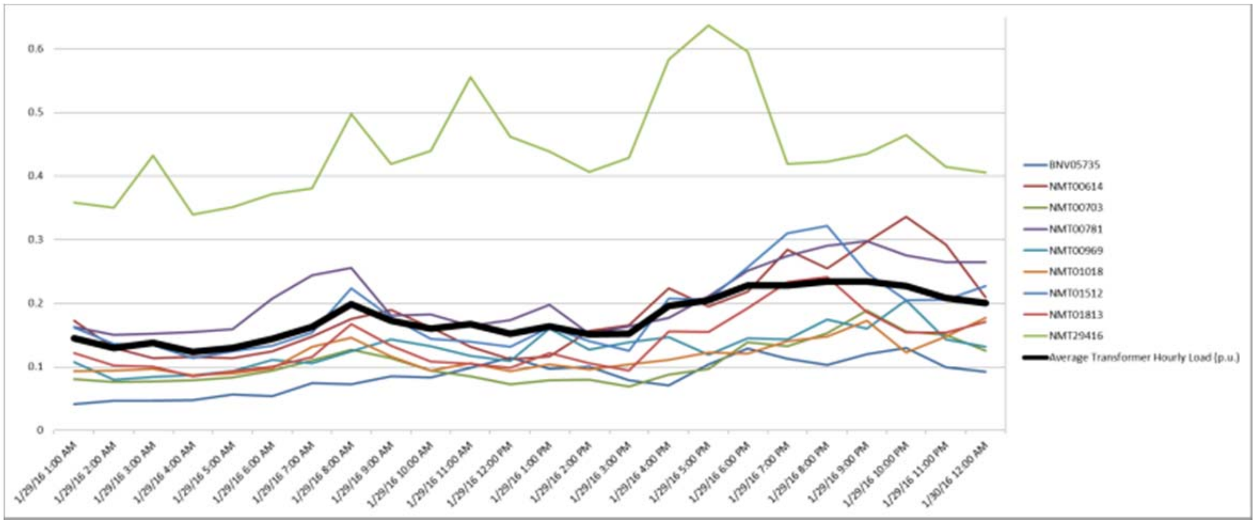
Appendix B Example Measured Load Profiles for Urban Residential Distribution Transformers Provided by Hydro One



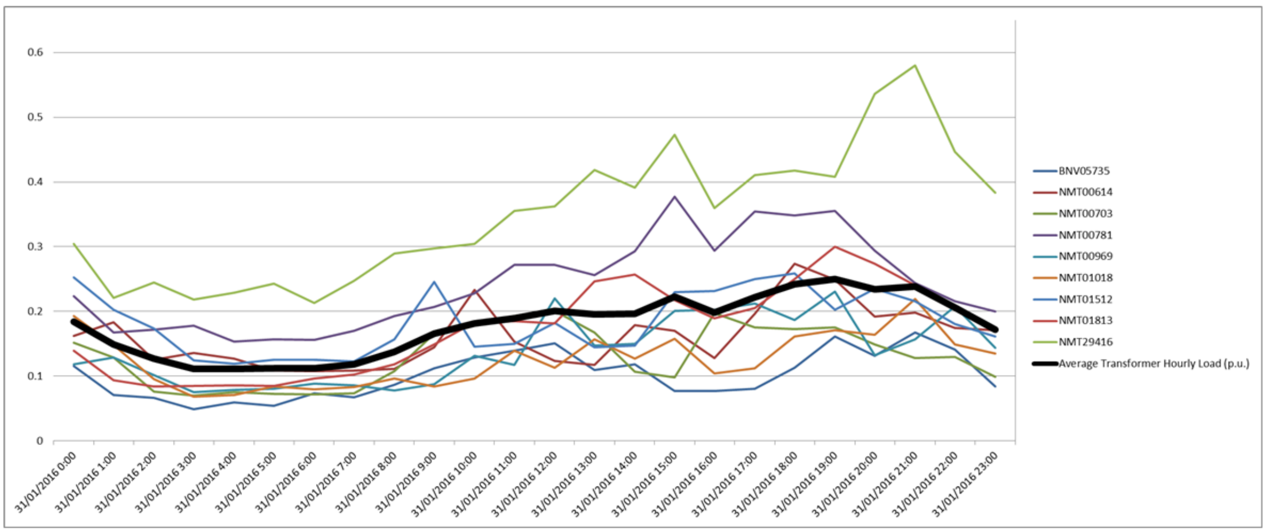
Summer Weekday Daily Load Profiles (pu Rated Load for Urban Residential Distribution Transformers, 50kVA to 100kVA, most with 10 to 15 customers per Transformer, Thursday July 30, 2015)



Summer Weekend Daily Load Profiles (pu Rated Load for Urban Residential Distribution Transformers, 50kVA to 100kVA, most with 10 to 15 customers per Transformer, Saturday August 1, 2015)

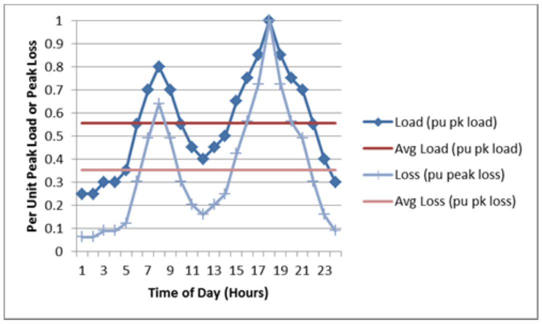


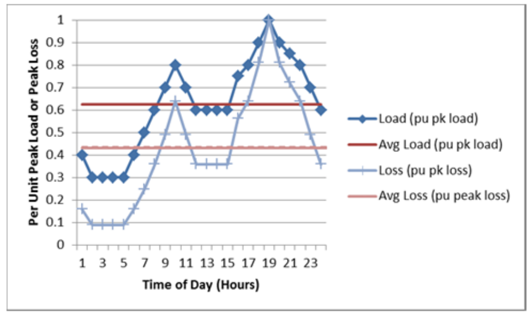
Winter Weekday Daily Load Profiles (pu Rated Load for Urban Residential Distribution Transformers, 50kVA to 100kVA, most with 10 to 15 customers per Transformer, Friday January 29, 2016)



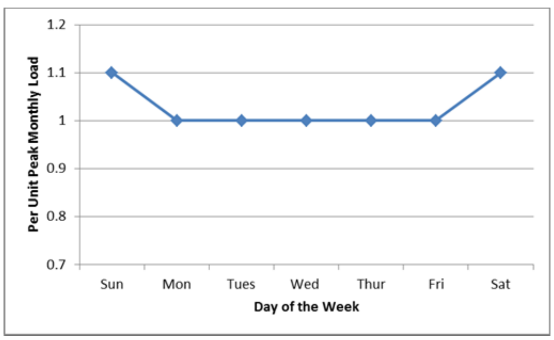
Winter Weekend Daily Load Profiles (pu Rated Load for Urban Residential Distribution Transformers, 50kVA to 100kVA, most with 10 to 15 customers per Transformer, Sunday January 31, 2016))

Appendix C Sample Load Profiles used for Transformer Loss Formulae Development

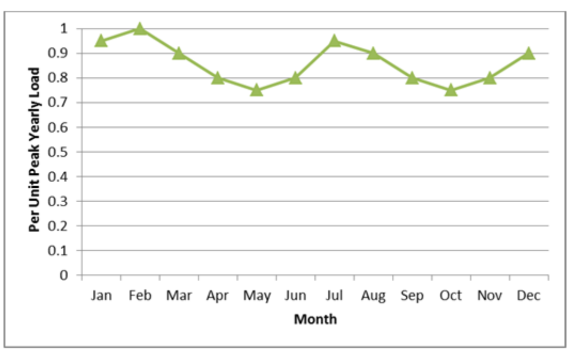




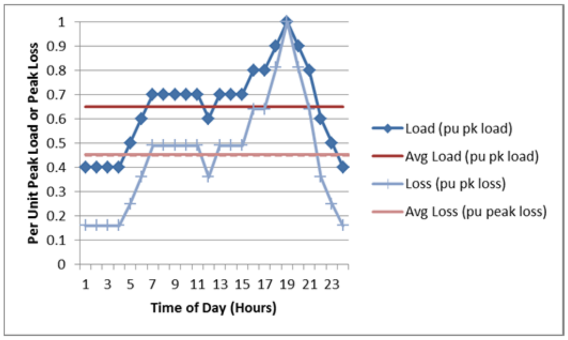
Modeled Daily Load and Loss Profiles for Rural Distribution Transformer (Left – Weekday: Load Factor=.56 Loss Factor=.35. Right – Weekend: Load Factor=.63 Loss Factor=.43)

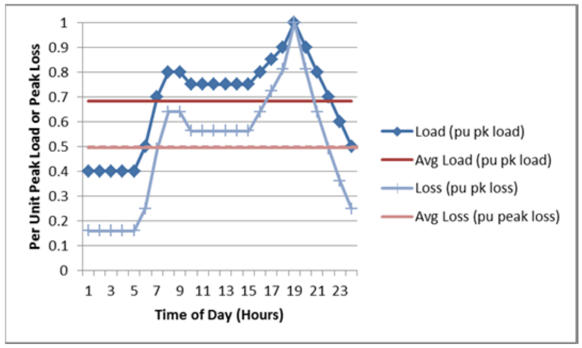


Modeled Day-of –the Week Load for Rural Distribution Transformer

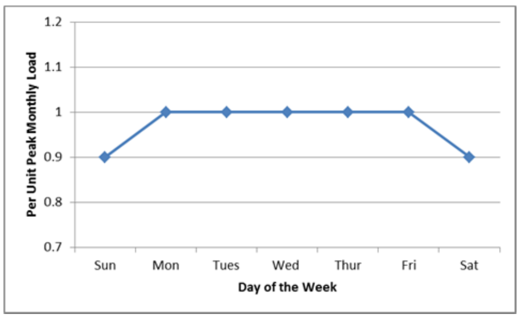


Modeled Monthly Load Variation for Rural Distribution Transformer

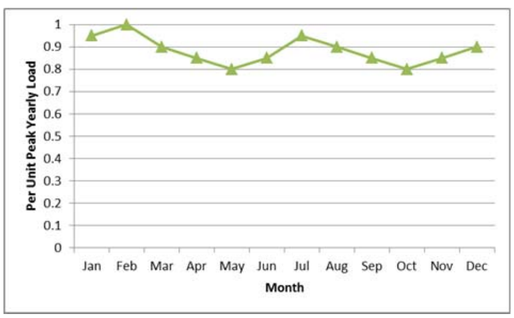




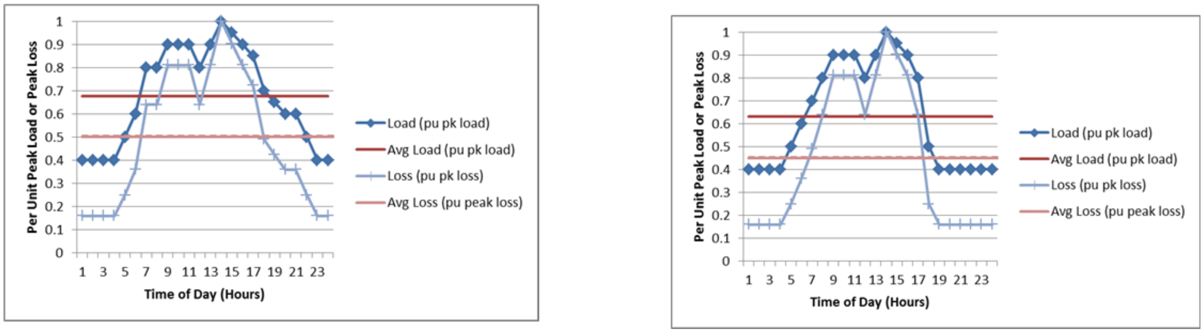
Modeled Daily Load and Loss Profiles for Urban Distribution Transformer (Left – Weekday: Load Factor=.65, Loss Factor=.45. Right – Weekend: Load Factor=.68 Loss Factor=.5)



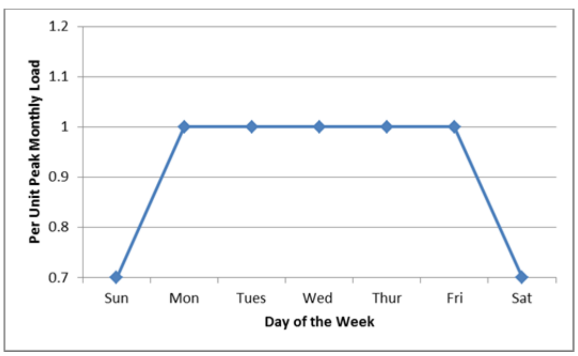
Modeled Day-of –the Week Load for Urban Distribution Transformer



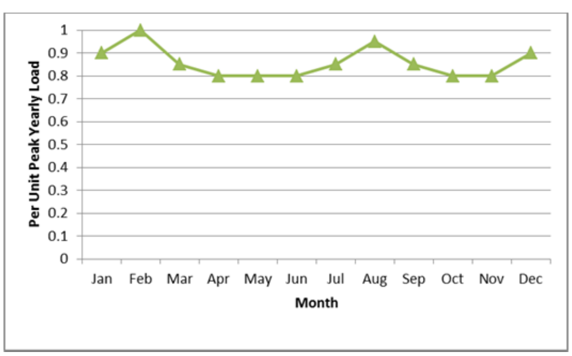
Modeled Monthly Load Variation for Urban Distribution Transformer



Modeled Daily Load and Loss Profiles for Commercial Distribution Transformers (Left – Weekday: Load Factor=.68 Loss Factor=.5. Right – Weekend: Load Factor=.63 Loss Factor=.45)

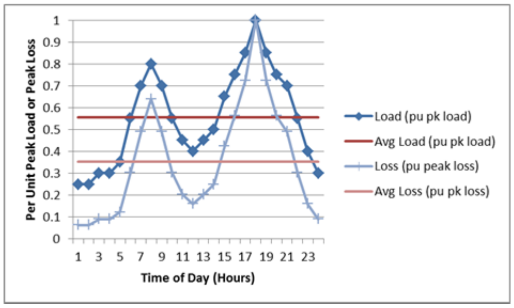


Modeled Day-of –the Week Load for Commercial Distribution Transformer

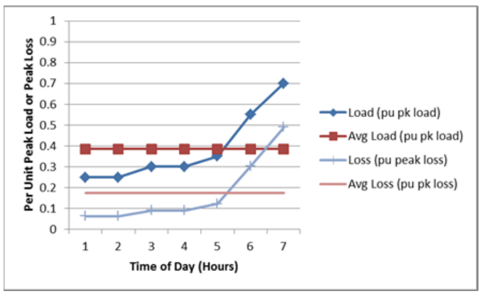


Modeled Monthly Load Variation for Commercial Distribution Transformer

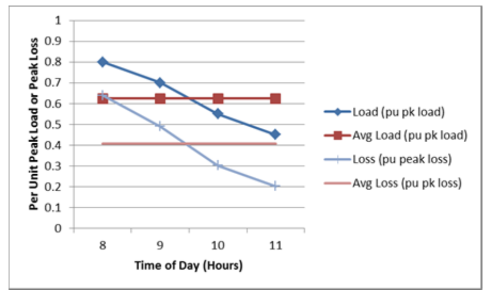
Appendix D Example of Unique Loss Factors for Each TOU Period



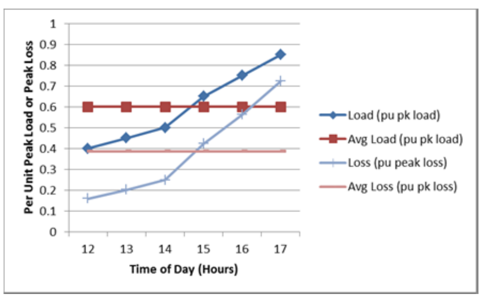
Modeled Daily Load and Loss Profiles for Rural Distribution Transformer (Load Factor=.56 Loss Factor=.35)



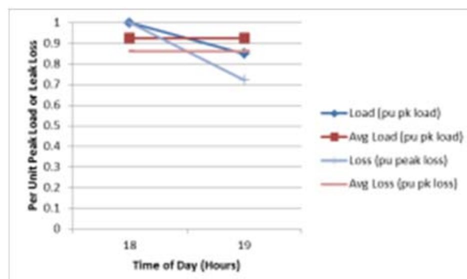
Period 1 Load and Loss Profiles (LDF=.39, LSF=.17)



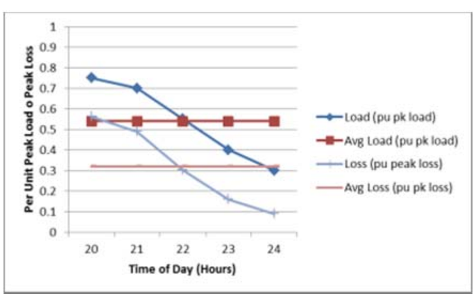
Period 2 Load and Loss Profiles (LDF=.63, LSF=.41)



Period 3 Load and Loss Profiles(LDF=.60, LSF=.39)



Period 4 Load and Loss Profiles (LDF=.93, LSF=.86)



Period 5 Load and Loss Profiles (LDF=.54, LSF=.32)

Appendix E Example of Present Value Factor Computation

Year	Inflation Rate	Rate of Return on Investment	Yearly Load Growth (pu)	Yearly Loss Growth (pu)	Annual Factor - with Loss Growth	Present Value Factor - with Loss Growth – applied to Load Losses	Annual Factor - no Loss Growth	Present Value Factor - no Loss Growth – applied to No-Load Losses
0	0.020	0.057	0.01	0.02	1	1.00	1.00	1
1	0.020	0.057	0.01	0.02	0.98	1.98	0.96	1.96
2	0.020	0.057	0.01	0.02	0.97	2.95	0.93	2.90
3	0.020	0.057	0.01	0.02	0.95	3.91	0.90	3.79
4	0.020	0.057	0.01	0.02	0.94	4.84	0.87	4.66
5	0.020	0.057	0.01	0.02	0.92	5.77	0.84	5.50
6	0.020	0.057	0.01	0.02	0.91	6.68	0.81	6.30
7	0.020	0.057	0.01	0.02	0.89	7.57	0.78	7.08
8	0.020	0.057	0.01	0.02	0.88	8.45	0.75	7.83
9	0.020	0.057	0.01	0.02	0.87	9.32	0.72	8.56
10	0.020	0.057	0.01	0.02	0.85	10.17	0.70	9.26
11	0.020	0.057	0.01	0.02	0.84	11.01	0.67	9.93
12	0.020	0.057	0.01	0.02	0.83	11.84	0.65	10.58
13	0.020	0.057	0.01	0.02	0.81	12.65	0.63	11.21
14	0.020	0.057	0.01	0.02	0.80	13.45	0.61	11.81
15	0.020	0.057	0.01	0.02	0.79	14.24	0.58	12.40
16	0.020	0.057	0.01	0.02	0.78	15.01	0.56	12.96
17	0.020	0.057	0.01	0.02	0.76	15.78	0.54	13.51
18	0.020	0.057	0.01	0.02	0.75	16.53	0.52	14.03
19	0.020	0.057	0.01	0.02	0.74	17.27	0.51	14.54
20	0.020	0.057	0.01	0.02	0.73	17.99	0.49	15.03
21	0.020	0.057	0.01	0.02	0.72	18.71	0.47	15.50
22	0.020	0.057	0.01	0.02	0.70	19.41	0.45	15.95
23	0.020	0.057	0.01	0.02	0.69	20.11	0.44	16.39
24	0.020	0.057	0.01	0.02	0.68	20.79	0.42	16.81
25	0.020	0.057	0.01	0.02	0.67	21.46	0.41	17.22
26	0.020	0.057	0.01	0.02	0.66	22.12	0.39	17.62
27	0.020	0.057	0.01	0.02	0.65	22.77	0.38	17.99
28	0.020	0.057	0.01	0.02	0.64	23.41	0.37	18.36
29	0.020	0.057	0.01	0.02	0.63	**24.04**	0.35	**18.72**

D - ENVIRONMENTAL DEFENCE INTERROGATORY - 020

Reference:

Exhibit D-4-1

Interrogatory:

a) Please provide Hydro One Transmission's best estimate of the following data for the *average* electrically heated MURB customer, per building and per unit if possible:
   i. Total kWh demand;
   ii. Peak kW demand for each month;
   iii. Total kWh demand for space heating only; and
   iv. Peak kW demand for each month for space heating only.

b) Please provide Hydro One's best estimate of the following data for all electrically heated MURB customers:
   i. Total kWh demand;
   ii. Peak kW demand for each month;
   iii. Total kWh demand for space heating only;
   iv. Peak kW demand for each month for space heating only;
   v. Number of customers; and
   vi. Number of units.

Response:

a) This information is not available.

b) This information is not available.

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D - ENVIRONMENTAL DEFENCE INTERROGATORY - 021

Reference:

Exhibit D-5-1

Interrogatory:

a) Please provide Hydro One Distribution's best estimate of the following data for the *average* electrically heated MURB customer, per building and per unit if possible:

   i. Total kWh demand;

   ii. Peak kW demand for each month;

   iii. Total kWh demand for space heating only; and

   iv. Peak kW demand for each month for space heating only.

b) Please provide Hydro One's best estimate of the following data for all electrically heated MURB customers:

   i. Total kWh demand;

   ii. Peak kW demand for each month;

   iii. Total kWh demand for space heating only;

   iv. Peak kW demand for each month for space heating only;

   v. Number of customers; and

   vi. Number of units.

Response:

a)

i.

	KWh In 2020
Average KWh per building	424,926
Average KWh per unit	16,703

ii.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AverageKW Per building in 2020	121	87	105	61	61	59	59	57	66	59	69	79
AverageKW Per Unit in 2020	4.77	3.41	4.15	2.39	2.40	2.32	2.32	2.22	2.61	2.33	2.71	3.12

iii. We don’t have enough information to estimate the space heating energy consumption.

iv. We don’t have enough information to estimate the space heating peak demand.

b)

i. Total metered kWh in 2020 is 164 GWh.

ii. The total monthly peak demand in 2020 was

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
KW	46,798	33,470	40,720	23,429	23,551	22,830	22,748	21,811	25,650	22,912	26,597	30,632

iii. The information of total kWh demand for space heating only is not available.

iv. The information of peak KW demand for each month for space heating only is not available.

v. Total number of electrically heated MURB customers in 2020 is 386.

vi. The total number of electrically heated MURB units in 2020 is 9820.
Note that we don’t have the primary heating type for all MURB customers. The above information was estimated based on customers’ consumption data and load profile.

E - ENVIRONMENTAL DEFENCE INTERROGATORY - 022

Reference:

Exhibit E-3-3, Page 10

Preamble:

> *A potential key contributor to energy demand growth in Ontario will be the electrification of transportation. Hydro One is actively monitoring developments related to electric vehicles, and participating in a variety of industry forums such as Electric Power Research Institute (EPRI) and the Centre for Energy Advancement through Technological Innovation (CEATI). In addition to electric vehicles (cars), it is expected that other forms of electric transportation will emerge quickly, such as electric buses. If transit authorities in the province decide to deploy a large number of electric buses, significant demands on lines and station assets will result.*

Interrogatory:

a) Please file a copy of any reports in Hydro One's possession containing forecasts for the numbers of electric vehicles in Ontario and/or Hydro One's service area.

b) Please file a copy of any reports in Hydro One's possession on the impacts of electric vehicles on (i) utility revenue and (ii) utility costs.

c) What is Hydro One's best estimates of the number of electric cars in its service area total and incremental between now and 2030?

d) Please describe all steps that Hydro One is taking or considering to encourage customers to charge their cars at off-peak times.

e) Please describe all steps that Hydro One is taking or considering to encourage customers to use their car batteries to off-set the peak load of their building via bi-directional chargers.

f) Please estimate the impact on Hydro One's revenues and costs as a result of electric vehicles over 2023-2027. Please consider whether Hydro One will experience additional revenues than costs as described in the following Synapse energy study: https://www.synapse-energy.com/sites/default/files/EVs-Driving-Rates-Down-8-122.pdf. Please explain the response.

g) Please describe Alectra's optional EV rate pilot project.

h) Is Hydro One open to offering an optional EV rate structure to encourage EV owners to charge at off-peak times? What regulatory applications and approvals would be necessary to do so?

<u>Response:</u>

a) Aside from the IESO's Annual Planning Outlook 2020 attached as Attachment 1 to this interrogatory, Hydro One does not have a specific report containing a forecast of the number of EVs in Ontario or Hydro One's service area.

b) Hydro One does not have a specific report on the impacts of EVs on utility revenues and costs. Hydro One does not meter electric vehicle energy consumption separately, therefore there is no data currently available on the specific impacts of electric vehicles on Hydro One's revenue. Hydro One is actively working on assessing the overall impact of integrating electric vehicles into the system and the best approach to minimize future upgrade costs to ratepayers. Please also refer to response in h).

c) Please see response to D-Staff-190.

d) Hydro One is not taking steps at this time to encourage customers to charge off peak time.

e) Please see response to B3-ED-028, part a).

f) Please refer to response in b).

g) Hydro One is not in a position to describe the pilot project of another utility.

h) Hydro One believes that EVs and any associated rate structures are a system-wide consideration that are likely to impact all distributors in Ontario and their customers. As such, any determination of EV-related rate structures or incentives would be most appropriately determined by the OEB in the form of a generic policy consultation rather than a utility-specific proposal in a rate application. Once such policy direction was provided, Hydro One expects that it would have to subsequently file a rate application to seek specific approvals arising from the OEB's direction. Hydro One notes that its rates only represent a portion of the customer's total bill. Hydro One does not have any control over the rate structures for the cost of electricity generation (e.g., RPP Time-of-use rates, Global Adjustment rates) which typically make up a significant portion of the customer's total bill.

Hydro One notes that on November 15 and 16, 2021, the Minister of Energy issued letters to the OEB on the OEB's Mandate and sector priorities. The November 15 Mandate letter included direction to the OEB to consider how to facilitate the efficient integration of EVs into the provincial electricity system, including "providing guidance to LDCs on system investments to prepare for EV adoption." The November 16 letter instructed the OEB to report back to the Ministry on new Regulated Price Plan rate design options, including consideration of the decarbonization potential of low overnight rate structures for EV owners.

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Annual Planning Outlook

Ontario's electricity system needs: 2022-2040

December 2020

ieso
Connecting Today.
Powering Tomorrow.

Executive Summary

To help ensure the reliability and cost-effectiveness of Ontario's power system, the Independent Electricity System Operator (IESO) regularly evaluates future demand and supply, using the resulting forecasts as the basis to assess near-, medium- and long-term resource and transmission requirements. Informed by ongoing feedback from stakeholders, and taking into account demand drivers, the transmission system and other inputs, the IESO's Annual Planning Outlook (APO) provides a long-term demand forecast, and an assessment of whether resources will be ready and sufficient to meet that demand.

With the emergence of the COVID-19 global pandemic, greater emphasis is placed on the importance of effective planning for a reliable electricity system. Electricity demand forecasting anticipates future requirements for electricity services and is affected by many factors, including historical demand patterns, demographics, energy prices and, increasingly, energy-efficiency programming and distributed energy resources. While forecasts are, by definition, inexact, in 2020 the ongoing uncertainties associated with the duration and impact of COVID-19 have introduced an entirely new layer of complexity to the development process.

COVID-19 Scenarios Reflect Role of Pandemic in Electricity Planning

Given the unprecedented nature of the pandemic, the 2020 APO forecasts demand using two scenarios based on assumptions about the pace of economic recovery during the outlook period. In each scenario, demand is expected to be lower than 2019 APO forecasted levels in the early years of the outlook.

Scenario 1 assumes a shallow economic recession in 2020 and early 2021 followed by a rapid economic recovery in 2021 and 2022, with demand expected to reach pre-pandemic levels by the end of 2022. Under this scenario, net energy demand is expected to be 142 TWh in 2022, and to increase an average of approximately 1 per cent per year over the outlook period to 174 TWh in 2040, an overall increase of 32 TWh.

In contrast, Scenario 2 assumes a deep economic recession until the end of 2021, followed by a slow multi-year economic recovery starting in 2022, with demand not expected to reach pre-pandemic levels until 2024. The demand forecast for Scenario 2 projects annual net energy demand to be 138 TWh in 2022, and to increase an average of approximately 1 per cent per year over the outlook period to 166 TWh in 2040, an overall increase of 28 TWh.

In both scenarios, longer-term demand will exceed 2019 APO forecast levels for a number of reasons. These include the resiliency and stability of the industrial sector, an increase in residential usage reflecting work-from-home arrangements, and rapid growth in indoor agriculture, particularly in southwestern Ontario. Robust near-term growth in the mining sub-sector, new rail transit electrification projects and decreasing electricity prices will also contribute to increased demand over this time period.

As Ontario recovers from the COVID-19 pandemic, and helping consumers manage their energy costs becomes even more important, government has directed a new four-year electricity conservation and demand management (CDM) framework to come into effect January 1, 2021. The 2021-2024 CDM framework will be centrally delivered by the IESO under the Save on Energy brand and will focus on cost-effectively meeting customer needs and the needs of Ontario's electricity system, including achieving provincial peak demand reductions, as well as targeted approaches to address regional and/or local system needs.

Overall, savings from all energy-efficiency programs[1] in Ontario are forecast to grow to 8.3 TWh in 2040 in Scenario 1, and to 7.9 TWh in 2040 in Scenario 2, from a base year of 2019.

Nuclear Refurbishments, Retirements and Contract Expirations Increase Needs

Ontario's diverse supply mix – nuclear (28%), gas (26%), hydroelectric (23%), wind (14%), solar (7%), demand response (2%) and bioenergy (1%) – means that the province is generally well positioned to meet future resource adequacy needs. However, throughout the 2020s, many existing contracts will expire, nuclear refurbishments will be underway, and Pickering Nuclear Generating Station (NGS) will retire.

The capacity adequacy outlook indicates that needs continue to emerge through 2022, without assuming the continued availability of existing resources. Needs are largely summer driven, while winter needs are dependent on growth in the agricultural sector. These needs increase again in the late 2020s and through the 2030s, driven by the Pickering NGS retirement, nuclear refurbishments, expiring contracts, and demand growth. With the continued availability of existing resources, the needs can be met until 2024. The capacity need eventually becomes an energy need, driven by resources with contracts expiring in the late 2020s and early 2030s.

The energy adequacy outlook indicates that Ontario is expected to have a sufficient supply of energy, providing existing resources continue to be available post-contract expiry. That said, the ability of existing resources to remain available will depend on a number of factors, including asset age and condition, need for capital investment, market conditions and available acquisition tools.

Surplus baseload generation is forecast to decrease due to rising demand and the retirement of Pickering NGS, and can continue to be managed through existing market tools.

In 2019, Ontario imported 6.6 TWh of energy and exported 19.8 TWh. While increasing exports in the wake of falling demand in the early months of COVID-19 has significantly reduced costs for consumers, energy exports are expected to decrease sharply in the early 2020s with the retirement of Pickering NGS by 2026 and ongoing refurbishment outages.

In fact, Ontario is projected to become a net importer for the first time since 2005, with the balance of trade expected to return to exports following the completion of nuclear refurbishments in the 2030s. This will mean that the province will need to address transmission constraints at interties that hinder the province's ability to import more electricity.

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[1] Includes existing and committed IESO-funded energy-efficiency programs, programs funded by the federal government and the assumption of continued delivery of IESO-funded energy-efficiency programs at current savings levels through the outlook period.

With nuclear retirements, refurbishments and contract expirations driving the need for capacity, reinforcing transmission in key areas of the province will be essential to maintaining reliability. Over the next five years, several major transmission projects to improve the transfer capability of bulk transmission interfaces to and from neighbouring jurisdictions, and ties between the province's 10 electricity zones,[2] will come into service.

Innovation, New Procurement Options to Play Role in Meeting Future Needs

After a postponement as a result of COVID-19, the IESO held its first capacity auction in December 2020. These auctions, which will evolve over time to reflect lessons learned and open participation to more resource types, are expected to drive down costs through competition, and give the IESO the flexibility to adjust to changing system conditions. While capacity auctions will meet short-term needs, to keep off-contract resources in the market and procure new capacity, the IESO is currently exploring other acquisition tools as part of a Resource Adequacy engagement – target capacities for these will be informed by this APO and future editions.

Established, in part, as a result of stakeholder feedback on the limitations of having a one-size-fits-all procurement mechanism, the Resource Adequacy engagement will develop a robust framework of competitive mechanisms to meet Ontario's resource adequacy needs in the short, medium and long term. In addition to better balancing ratepayer and supplier risk, the framework is expected to support competition and produce efficiencies that will benefit suppliers, the system and ratepayers.

At the same time, the IESO and other system operators are continuing to explore the role of distributed energy resources (DERs) in addressing future energy and capacity needs. In addition to releasing a series of white papers, including two that focus on expanding DER participation in the IESO-administered markets, the IESO has supported a number of DER demonstration projects as outcomes of recommendations made in the IESO's Integrated Regional Resource Plans (IRRPs). The latter includes a York Region Non-Wires Demonstration Project, which is using a local electricity market to test the effectiveness of DERs in meeting escalating regional needs, while reducing costs.

As part of its commitment to address barriers to DERs, the IESO has also made headway in its efforts to integrate storage in the system. In September, the IESO released its long-term vision for energy storage and the interim Market Rule amendments will clarify the opportunities for storage in today's markets.

[2] Visit the IESO's zonal map illustrating the 10 electrical zones.

How to Read the Outlook

Grounded in data and market intelligence, the IESO's Annual Planning Outlook (APO), which addresses future system needs – and the factors that influence them – provides insights to help readers understand what is required to prepare for a reliable and affordable energy future. The findings will be key inputs into the target-setting process for the next capacity auction, and also inform the development of the IESO's Resource Adequacy Framework. The APO is intended to provide market participants with the data and analyses they need to make informed decisions, and communicate valuable information to policy-makers and others interested in learning more about the developments shaping Ontario's electricity system.

With the pace of economic recovery identified as the primary consideration influencing the level of electricity demand over the outlook period, Chapter 1 (Demand Forecast) explores long-term demand using a faster-recovery and a slower-recovery scenario. This chapter walks readers through the changing composition of demand by sector – and the resulting effect on overall demand – as well as the projected impact of energy-efficiency programs, evolving codes and standards and the Industrial Conservation Initiative, on reducing that demand.

Chapter 2 (Supply and Transmission Outlook) assesses the availability of resources over the outlook period, and on the ability of existing bulk transmission interfaces and interties to continue to supply electricity where it is needed. This chapter also looks at the transmission projects expected to come into service within the outlook period that are considered in the base case for resource adequacy and transmission security assessments.

Chapter 3 (Resource Adequacy) compares the demand forecast with anticipated resource performance, while taking into account transmission constraints and risks such as extreme weather conditions and equipment outages. This chapter also looks at Ontario's energy adequacy, the impact of energy production on imports and exports, and the implications of the evolving fuel mix on fuel security.

Chapter 4 (Transmission Security) explores system needs arising from the requirement to meet transmission planning standards. These needs will be referred to as transmission security needs in this report and could be more restrictive or less restrictive than the resource adequacy needs.

Building on the outcomes and findings of previous chapters, Chapter 5 (Integrating Electricity Needs) summarizes the system needs over the outlook period that were discussed in Chapter 3 and 4.

Chapter 6 (Meeting Electricity Needs) explores the potential role of imports, distributed energy resources, storage, energy efficiency, the current Resource Adequacy engagement and transmission expansion – to address a local or zonal need, or to improve access to resources located within a transmission-limiting region – in meeting future needs.

Chapter 7 (Outcomes and Other Considerations) concludes with a discussion on marginal resources and marginal costs, the impacts of carbon pricing in Ontario and neighbouring jurisdictions, and the expected increase in greenhouse gas emissions resulting from decreased nuclear production, increased gas-fired generation and growing demand.

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1. Demand Forecast

As the COVID-19 pandemic and the response to it evolve, the IESO continues to monitor and interpret electricity demand drivers and other factors to develop and update demand forecasts. Key uncertainties over the next few years relate to the:

- Impacts of the pandemic, including its magnitude and duration, subsequent waves, work-from-home arrangements, social distancing, travel restrictions, birthrates and exurban growth
- Economic environment, including recovery in the commercial and industrial sectors, pandemic-specific support policies, international trade relations and immigration levels
- Energy rate forecast for both electricity and natural gas in all sectors, as well as price and cost subsidies

1.1 Overview

Ensuring Ontarians have access to affordable power when and where they need it is at the heart of the IESO's mandate to promote a reliable and cost-effective electricity system. The long-term demand forecast sets the context for the Annual Planning Outlook (APO) and the bulk power system planning process. The demand forecast informs system reliability and investment decisions by anticipating future needs, which are affected by many factors, including the state of the economy, population, demographics, technology, energy prices, input fuel choices, equipment purchasing decisions, consumer behaviour, policy, conservation and other considerations.

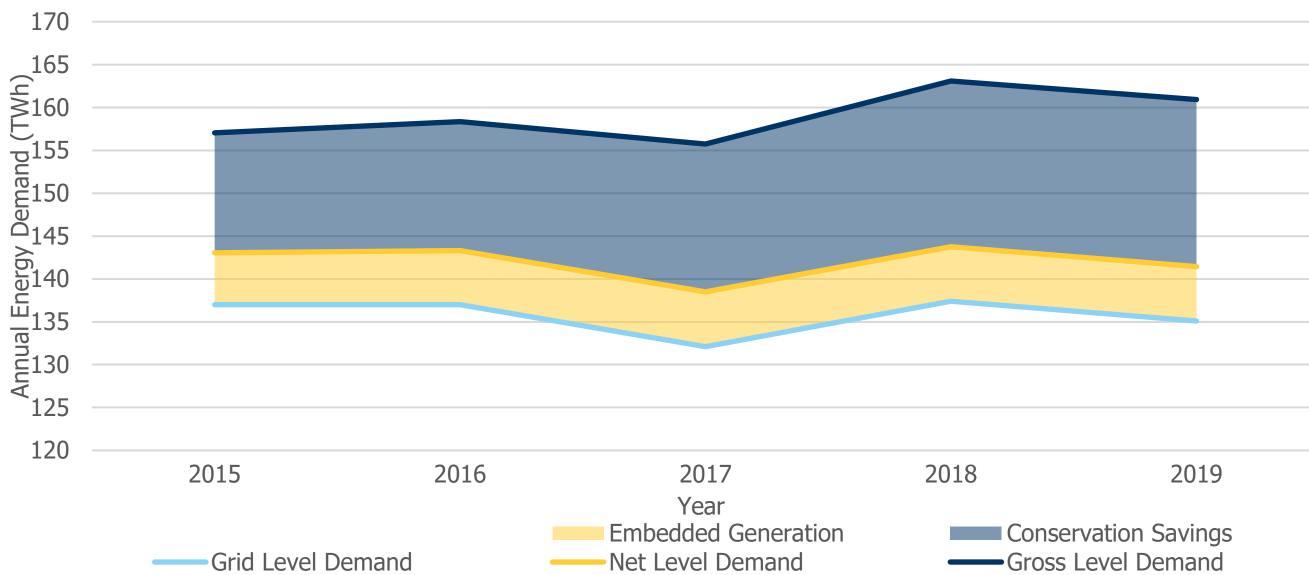
In 2020, Ontario's electricity demand experienced significant fluctuations as a result of the COVID-19 pandemic and its containment measures. Some of these resulted in near-term demand reductions. As the pandemic and its impacts on the grid evolve, the IESO continues to monitor and interpret the factors that affect the system, provide updated information to the market and regularly engage with stakeholders to enable them to make more informed decisions and investments.

Electricity demand is highly dependent on the state of the economy and has been greatly influenced by the pandemic, which has led to high levels of uncertainty. To address the uncertainties associated with the economic recovery, the APO includes two scenarios that reflect a potential range of economic conditions and resulting impacts on the electricity system over the outlook period.

To forecast demand, it is important to understand the composition of Ontario's electricity customers. For nearly the last decade, demand in Ontario has been driven primarily by the commercial (35%), residential (34%), and industrial (25%) sectors, and remaining (6%) being other sectors. In the wake of the pandemic, the traditional drivers of demand – the residential and commercial sectors – will be overshadowed by near-term recovery in the industrial sector, robust growth in agriculture and the adoption of electric vehicles.

Grid-level demand[3] has been mostly flat – ranging between 132 and 137 terawatt-hours (TWh) over the past five years, as shown in Figure 1. This is primarily the result of changes in the economy, conservation program savings, and embedded generation,[4] which reduce the need for grid-supplied energy. At between 138 and 144 TWh, net-level demand, which also includes embedded generation, has been approximately 6 TWh higher each year than grid-level demand.

Figure 1 | Historical Energy Demand



While historical energy demand has been presented on an actual weather basis and shown at the grid, net and gross levels, the demand forecasts subsequently presented are on a weather-normalized basis and at the net level.

1.2 Demand Forecast Scenarios

Demand forecasting anticipates future requirements for the services that electricity provides, and is affected by many factors. Analysis centres on understanding what is causing the changes in demand by focusing on end-uses and sector trends. That said, electricity demand forecasts are, by definition, inexact. They incorporate inherent uncertainty and reflect many dependencies, such as the impact of the pandemic on the economy, as well as future stimulus and policy frameworks. The uncertainties associated with any forecast will increase with the length of the outlook period and reflect the interdependencies of underlying assumptions.

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[3] Gross-level demand is the total demand for electricity services in Ontario prior to the impact of conservation (including programs and regulations), but including the effects of naturally occurring conservation (energy savings that occurs without the influence of incentives or education programs, and regulations). Net-level demand is gross-level demand minus the impact of conservation. Grid-level demand is net-level demand minus the demand met by embedded resources. It is equal to the energy supplied by the bulk power system to wholesale customers and local distribution companies.

[4] Embedded generation describes generators that are not registered participants in the IESO-administered wholesale electricity market, that are typically but not necessarily distribution system-connected, and reduces demand through the bulk electricity system.

To help acknowledge and mitigate uncertainties in the 2020 demand forecast, the IESO introduces the development of two demand forecast scenarios that reflect different assumptions regarding the rate of recovery from the effects of the pandemic on the electricity system. In each scenario, demand is expected to be lower than 2019 APO forecasted levels in the near term because of the pandemic and resulting economic slowdown. The pace of economic recovery is a primary factor in forecasting the level of electricity demand over the outlook period.

Table 1 summarizes the highlights in each of the two demand forecast scenarios in the 2020 APO.

Table 1 | Demand Scenarios Highlight Summary

#	Characteristic	Scenario 1	Scenario 2
1	Economic recession period	2020 - early 2021	2020 - end of 2021
2	Economic recovery period	2021 - 2022	2022 - 2024
3	Date demand returns to 2019 levels	End of 2022	Mid-2024
4	Residential sector	Slow demand growth in near term, accelerating in long term	Flat demand in the near and medium terms, slow growth in the long term
5	Commercial sector	Slow recovery	Demand lower than Scenario 1
6	Industrial sector	Swift recovery in near term, flat demand in medium term, growth in long term	Mild recovery in the near term Slow growth in long term
7	Agricultural sector	Strong growth in near and medium terms	Growth slower than Scenario 1
8	Electric vehicles	Strong growth over the outlook period	Growth slower than Scenario 1
9	Conservation energy savings	3 - 16 TWh	2 - 15 TWh
10	Annual energy demand	141 - 174 TWh	138 - 166 TWh
11	Summer peak demand	23,130 - 27,270 MW	22,470 - 25,970 MW
12	Winter peak demand	22,080 - 26,540 MW	21,690 - 25,280 MW

1.2.1 Scenario 1

Scenario 1 assumes a shallow economic recession in 2020 and early 2021, with a small-scale re-implementation of **temporary** restrictions and business closures in early 2021, followed by an economic recovery later in 2021 and 2022. While overall electricity demand is expected to recover to pre-pandemic levels by the end of 2022, the composition of that demand will have changed.

Overall growth in electricity demand in Scenario 1 is characterized by:

- Slow growth in the **residential sector** in the near term, accelerating in the long term, driven by increased household counts and decreasing electricity rates
- Strong growth in the **agricultural sector** in the near and medium terms, which will primarily impact winter energy and peak demand requirements
- Consistent growth in **electric vehicle** utilization over the outlook period
- A slow recovery in the **commercial sector** over the outlook period, after a significant decrease from the current economic recession
- A swift recovery in the **industrial sector** in the near term, primarily fueled by the mining sub-sector, followed by a period of flat demand and a return to overall growth in the long term

Scenario 1 accounts for conservation program frameworks divided into the current, near-term and long-term periods, as well as regulations. In total, energy savings are projected to be 16 TWh in 2040, with an average annual growth rate of 9.6 per cent.

Scenario 1 projects net energy demand to be 141 TWh in 2022, and to increase an average of approximately 1 per cent per year over the outlook period to 174 TWh in 2040, an increase of 33 TWh.

Summer and winter peak demands are expected to experience an average growth rate of approximately 1 per cent, which is similar to the energy demand growth rate. Summer peak demand is projected to be about 23,130 megawatts (MW) in 2022, increasing to 27,270 MW in 2040, while winter peak demand is projected to be 22,080 MW in 2022, and 26,540 MW in 2040.

Figure 2 illustrates the energy demand over the planning horizon and Figure 3 shows the summer and winter peak demand[5] under Scenario 1.

[5] The summer season is from June 1 to September 30; the winter season runs from November 1 of the prior year to April 30.

Figure 2 | Scenario 1 – Energy Demand

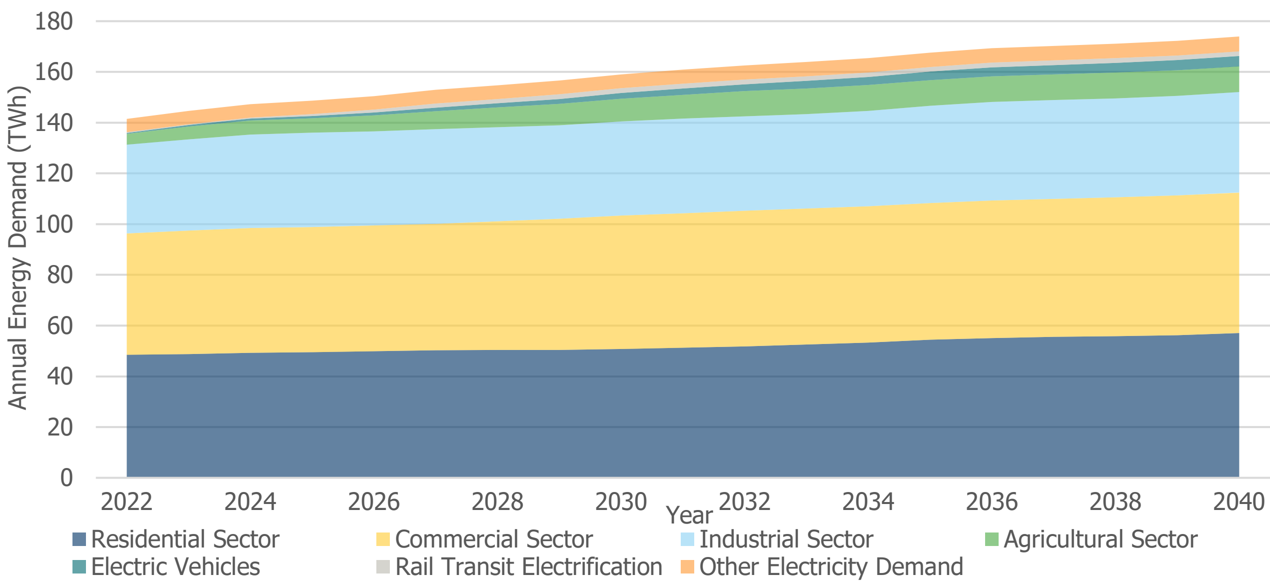
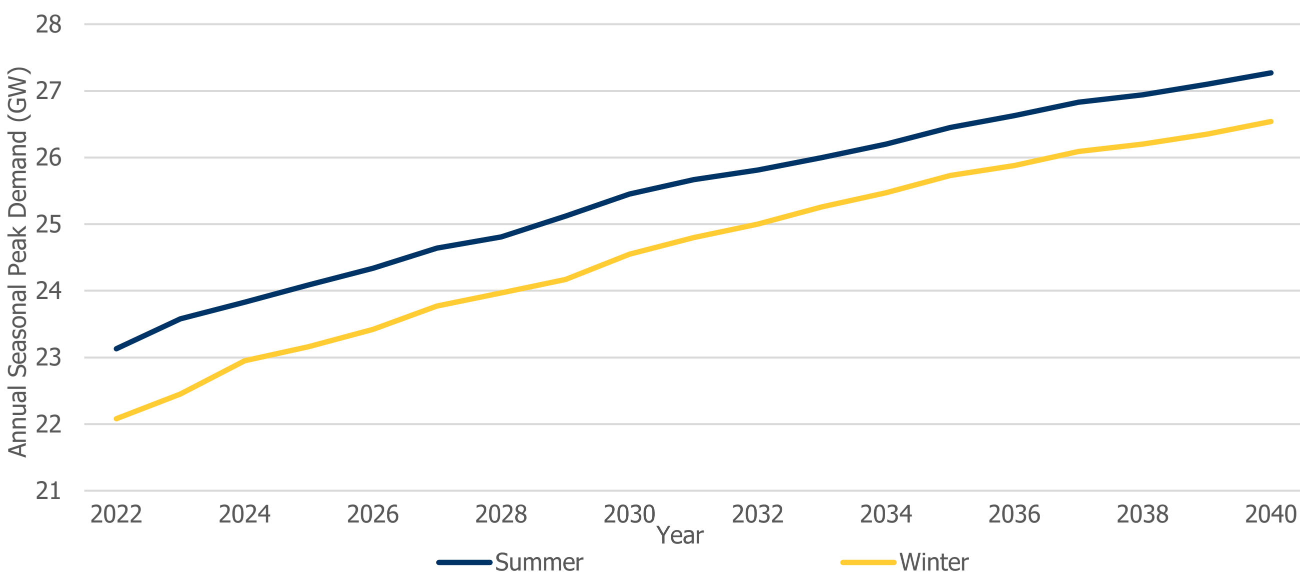


Figure 3 | Scenario 1 – Seasonal Peak Demand



1.2.2 Scenario 2

Scenario 2 assumes a deeper economic recession from 2020 to the end of 2021. Prolonged and significant pandemic impacts in this period will be followed by a slow, multi-year economic recovery starting in 2022. Overall electricity demand is expected to be lower than Scenario 1 in the near term and grow at a slower rate than Scenario 1 over the course of the outlook period.

Overall growth in electricity demand in Scenario 2 is characterized by:

- Flat demand in the **residential sector** in the near and medium terms, returning to slow growth in the long term

- Strong growth in the **agricultural sector** in the near and medium terms, though growth in this area will be slower than in Scenario 1
- Moderate growth in **electric vehicles** over the outlook period, though lower than the consistent growth in Scenario 1
- A slow recovery in the **commercial sector** over the outlook period, after a significant decrease from the current economic recession and less of a rebound prior to the start of the outlook period than Scenario 1
- A mild recovery in the **industrial sector** in the near term, followed by a period of flat demand and a return to slow growth in the long term
- Scenario 2 accounts for the same conservation categories and assumptions as Scenario 1. Current and near-term conservation program frameworks are projected to achieve the same levels of energy savings as Scenario 1, but long-term framework and regulations energy-savings projections are a function of the scenario-specific gross demand forecast. As the gross demand forecast is lower in Scenario 2, so are the energy savings attributed to the long-term framework and regulations. In total, energy savings are projected to be 15 TWh in 2040, with an average annual growth rate of 9.2 per cent.

In Scenario 2, annual net energy demand is projected to be 138 TWh in 2022, and to grow an average of approximately 1 per cent per year over the outlook period to 166 TWh in 2040, an increase of 28 TWh. Over the long term, despite lower electricity demand in a given year, demand growth rates return to near-2019 APO forecasted levels.

Summer and winter peak demands are expected to experience an average growth rate of approximately 1 per cent, similar to the energy demand growth rate. Summer peak demand is projected to be approximately 22,470 MW in 2022, increasing to 25,970 MW in 2040, while winter peak demand is projected to be 21,690 MW in 2022, and 25,280 MW in 2040.

Figure 4 illustrates the energy demand over the planning horizon and Figure 5 shows the summer and winter peak demand under Scenario 2.

Figure 4 | Scenario 2 – Energy Demand

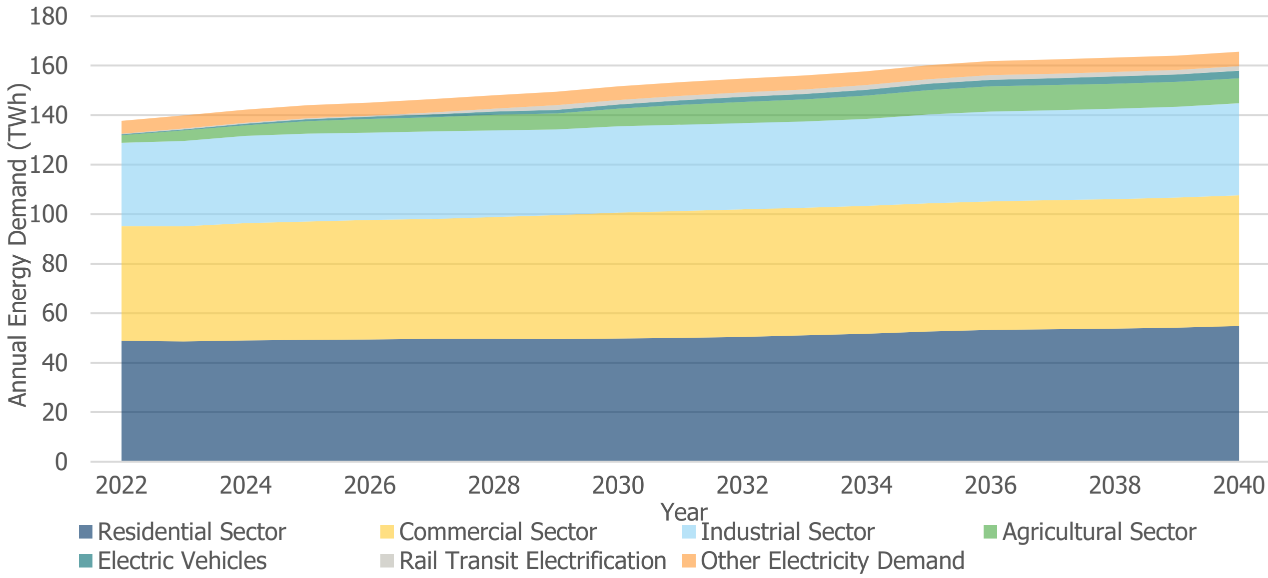
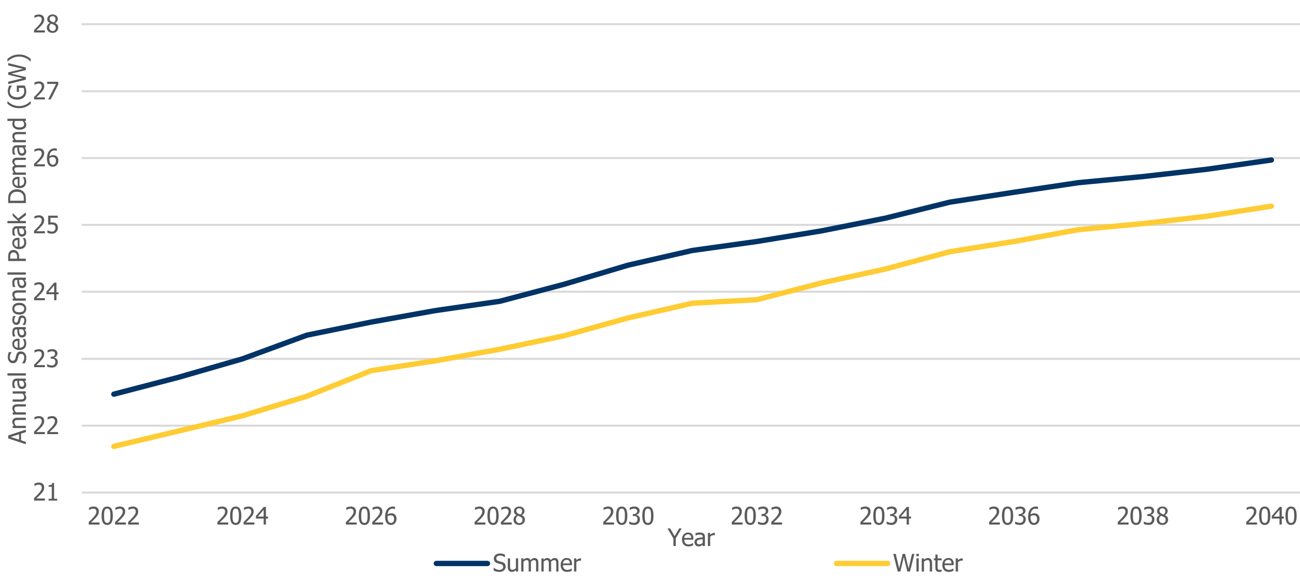


Figure 5 | Scenario 2 – Seasonal Peak Demand



1.3 Drivers of Demand

All electricity users – residential, commercial, institutional, industrial, agricultural and others – contribute to province-wide energy demand. This demand forecast has been developed using sector-level segmentation and corresponding individual assessments. Overall, an expected increase in demand over the outlook period will be largely driven by slow demand growth in the residential sector, emerging growth in the agricultural sector and electric vehicle utilization, and slow economic recovery in the commercial sector. This increase in consumption is supported by favourable electricity rates over the outlook period.

1.3.1 Residential Sector

Electricity demand from the residential sector continues to grow slowly in each scenario over the outlook period. In Scenario 1, household counts are lower in the near term and higher in the long term relative to projections in the 2019 APO. In Scenario 2, a prolonged economic recession is projected to result in a sustained lower household count relative to Scenario 1. High-level trends include a recovery in immigration rates concurrent with each scenario's recovery timeline. Emerging suburban and exurban migration is expected to lead to an increase in single-family homes with higher energy-intensity rates and changes in IESO zonal demands, lower electricity rates in the longer term (in real dollars), growth in both household occupancy and work-from-home arrangements, and the increasing adoption of electronics. All of these have been considered and integrated into the forecast, contributing to slowly growing sector demand over the outlook period.

Overall, residential sector electricity demand in Scenario 1 is forecast to grow from 48 TWh in 2022 to 57 TWh in 2040, an average annual growth rate of 0.8 per cent. In Scenario 2, demand is forecast to increase from 49 TWh in 2022 to 55 TWh in 2040, an average annual growth rate of 0.6 per cent.

1.3.2 Commercial Sector

Similar to the 2019 APO, electricity demand from the commercial sector continues to grow modestly in both scenarios over the outlook period. The shift to a digital economy is accelerating, impacting electricity demand in many sub-sectors. Remote working leads to decreases in electricity demand in offices; meal preparation and delivery services reduce electricity demand in restaurants; and e-commerce results in a decrease in bricks-and-mortar electricity demand in retail, but an increase in warehouses. The impacts of the current economic recession are especially evident in the commercial sector, with social distancing practices and travel restrictions reducing near-term electricity demand for the office, education, retail, restaurant and lodging hospitality sub-sectors. The magnitude of this reduction is especially evident in Scenario 2, but the commercial sector will experience a slow recovery in both scenarios.

Overall, commercial sector electricity demand in 2022 is reduced by about 3 TWh in Scenario 1 and by about 5 TWh in Scenario 2 relative to the 2019 APO. Commercial sector electricity demand is forecast to grow in Scenario 1, from 48 TWh in 2022 to 55 TWh in 2040, an average annual growth rate of 0.8 per cent, and in Scenario 2, from 46 TWh in 2022 to 53 TWh in 2040, an average annual growth rate of 0.8 per cent.

1.3.3 Industrial Sector

Ontario's industrial sector is expected to rebound from the current economic recession in the near term, remain flat for the medium term and grow slowly over the last third of the outlook period. This rebound is characterized by a return to 2019 APO levels by 2024 in Scenario 1, and a plateau at 2 TWh below 2019 APO levels by 2024 in Scenario 2. Average annual growth between 2032 and 2040 is expected to reach 0.7 per cent in both scenarios, which is in line with sub-sector-level GDP projections.

The top five sub-sectors[6] will continue to account for roughly 60 per cent of the total sector load. In the mining sub-sector, concentrated in northern Ontario, electricity demand is expected to grow robustly in the near term supported by favourable resource prices, then slowly decline as various mines reach end of life. Apart from mining, the primary metal sub-sector, spread across the Southwest (Hamilton, Cambridge, and Nanticoke) and Northeast (Sault Ste. Marie) Zones, is expected to grow steadily, while all other sub-sectors grow slowly. In general, the industrial sector is expected to be influenced by emerging de-globalization trends and support for increasing local industrial production capability.

Overall, total industrial sector electricity demand is forecast to grow, in Scenario 1, from 35 TWh in 2022 to 40 TWh in 2040, an average annual growth rate of 1 per cent, and in Scenario 2, from 34 TWh in 2022 to 37 TWh in 2040, an average annual growth rate of 0.8 per cent.

1.3.4 Agricultural Sector

Demand for electricity from Ontario's agricultural sector continues to grow, driven primarily by greenhouse expansion and the proliferation of artificial lighting in greenhouses. Grow lights enhance production and crop yields of various fruits, vegetables, flowers and cannabis.

Demand growth, incremental to the 2019 APO, has been identified in the West Zone, including the Kingsville-Leamington and Dresden areas. This growth is included in both scenarios and is outlined in the reference scenario in the West of London Bulk Study. Overall, sector electricity demand growth increases energy and peak demand primarily in the winter season, which is projected to increase by about 950 MW by 2033 in Scenario 1 and by 2036 in Scenario 2, accounting for potential timeline extensions of various major infrastructure construction projects needed to support the growth.

Overall, total sector electricity demand is forecast to grow, in Scenario 1, from 4 TWh in 2022 to 10 TWh in 2040, an average annual growth rate of 7 per cent, and in Scenario 2, from 3 TWh in 2022 to 10 TWh in 2040, an average annual growth rate of 7 per cent

1.3.5 Electric Vehicles

The number of electric vehicles (EVs), including mass transit buses and their electricity charging requirements, is currently relatively small, but will increase significantly over the outlook period. Government policy is a key driver for EV adoption. Policy measures include purchase incentives; tax benefits for business vehicles; and support for EV charging infrastructure, automobile manufacturers, and automobile parts suppliers. The federal government has set a long-term target to sell 100 per cent zero-emission vehicles by 2040, with interim sales goals of 10 per cent by 2025 and 30 per cent by 2030.

[6] The top five industrial sub-sectors in Ontario, by electricity demand are: 1) mining; 2) primary metals; 3) paper manufacturing; 4) chemical manufacturing; and 5) petroleum refining.

Many factors affect EV adoption and a wide range of EV adoption forecasts are available. The IESO's EV adoption forecast is based on historical trends and available information, such as industry sales data, government vehicle registration data and forecasts from other reputable organizations. The profile of EV charging is as important as the total charging electricity, when considering the impact on the demand forecast. Real-world charging data from the *Charge the North* project, the world's largest electric vehicle charging study, was used to develop the charging profile and EV hourly demand forecast.

The state of the economy has a compound effect on EV charging demand. Both EV sales and driving distance dropped in 2020 as a result of social distancing practices, temporary business closures, travel restrictions and the increase in people working from home. Each of the two scenarios reflects the various levels of EV charging demand growth.

The 2020 APO EV forecast is an adjustment of the 2019 APO EV forecast which projected the number of EVs in Ontario to reach approximately 0.7 million by 2030 and 1.2 million by 2040 with an annual charging demand of 4 TWh. In Scenario 1, EV charging demand rebounds fast, reaching the level of the 2019 APO in 2030. In Scenario 2, EV charging demand rebounds slower, reaching 75 per cent of the Scenario 1 level in the medium and long terms.

Overall, electric vehicle electricity demand is forecast to grow in Scenario 1, from 0.4 TWh in 2022 to 4.1 TWh in 2040, an average annual growth rate of 15.2 per cent, and in Scenario 2, from 0.3 TWh in 2022 to 3.1 TWh in 2040, an average annual growth rate of 14.5 per cent.

1.3.6 Rail Transit Electrification

Broad rail transit electrification is underway in Ontario, including:

- The GO rail system serving the Greater Toronto Area
- Local light rail transit (LRT) systems throughout the province
- Multiple subway expansion projects

Eight LRT projects and three subway projects are being planned or are at various stages of construction. The ION project connecting Kitchener and Waterloo and the Confederation Line in Ottawa have been in service since 2019. Early work on new subway projects, including the proposed Ontario Line and two subway line extensions in the GTA, is underway, as is the procurement process for the multi-year electrification of GO rail corridors.

Demand projected for new rail transit electrification is based on the most recent available information. Two scenario projections have been developed with the only variance being the GO rail electrification implementation timeline. Some rail transit electrification projects are at the early planning stage with little information on electricity requirements. The IESO will update the associated electricity demand projection, both in terms of magnitude and timing, when more information becomes available.

Overall, electricity demand associated with rail transit electrification is forecast to grow, in both Scenarios 1 and 2, from 0.3 TWh in 2022 to 1.8 TWh in 2040, an average annual growth rate of 15.5 per cent.

1.3.7 Other Electricity Demand

This demand forecast accounts for all electricity energy and peak demand in the province. However, certain loads do not fall under any of the previously discussed sectors and are classified as "other". These include:

- Connection of remote communities
- Electricity generators[7]
- Street lighting
- Municipal water treatment

Compared to the 2019 APO, over the course of the outlook period the IESO estimates an additional annual energy demand of less than 0.1 TWh by 2040.

Overall, "other sector" electricity demand is forecast to grow, in both Scenarios 1 and 2, from 5.2 TWh in 2022 to 5.9 TWh in 2040, an average annual growth rate of 0.7 per cent.

1.3.8 Energy-Efficiency Programs

Energy-efficiency program frameworks incorporated into the demand forecast include:

- Existing IESO-funded conservation frameworks
- Committed IESO-funded conservation framework
- Programs funded by the federal and municipal governments
- Assumed long-term conservation framework

On March 21, 2019, the 2015-2020 Conservation First Framework (CFF) and Industrial Accelerator Program (IAP) Framework were discontinued and replaced with an Interim Framework. Projects contracted under the CFF, IAP and Interim Framework are required to be in service by the end of 2022. Collectively, the wind-down of the CFF and IAP initiatives, and the Interim Framework, is expected to result in annual electricity savings of 2.5 TWh in 2023.

On September 30, 2020, the Minister of Energy, Northern Development and Mines directed the IESO to implement a new 2021-2024 Conservation and Demand Management Framework.[8] The forecasted annual savings are 3 TWh in 2026.

In addition to the Ontario electricity rate-funded programs, those funded and/or delivered by the federal and municipal governments, including the Green Municipal Fund and the Climate Action Incentive Fund, are expected to result in additional electricity savings in Ontario. That said, the amount is difficult to estimate in the absence of program details.

[7] Electricity generators such as nuclear and gas/oil generating stations can have electricity demand when: 1) commencing operation of generating units; and 2) generating units are not in operation; for example, the facility would have electricity demand for lighting and HVAC loads.

[8] For more information, refer to the Ministerial Directive.

Beyond existing and near-term committed energy-efficiency program frameworks, there are potential opportunities to achieve greater electricity savings. Continued delivery of energy-efficiency initiatives after the new 2021-2024 Framework is assumed and projected savings are included in both demand forecast scenarios. Annual savings are estimated to be 0.46 per cent of gross demand (varying between Scenario 1 and 2), which is informed by the savings level of the 2021-2024 Framework. This will be updated when a post-2024 conservation framework policy decision is made.

Overall, electricity demand savings resulting from all energy-efficiency programs in Ontario are forecast to grow in Scenario 1 and Scenario 2 to 8.3 TWh and 7.9 TWh, respectively, from 2019 to 2040.

1.3.9 Codes and Standards Regulations

Building codes and equipment standards are an effective energy-efficiency tool, as they have no ratepayer cost, broad reach and a relatively high level of certainty when forecasting results. Codes and standards savings estimates are based on the expected improvement in the codes for new and renovated buildings and for specified end-uses through the regulation of minimum-efficiency standards for equipment. The IESO estimates savings attributable to codes and standards by comparing the demand forecast at the gross level to the demand forecast adjusted for the impacts of regulations. Most savings from improved codes and standards will come from the residential and commercial sectors.

Overall, electricity demand savings from codes and standards are forecast to grow, from a base year 2019, in Scenario 1, to 7.8 TWh in 2040, and in Scenario 2, to 7.2 TWh in 2040.

1.3.10 Industrial Conservation Initiative

The demand forecasts include the impact of the Industrial Conservation Initiative (ICI), a form of demand response that enables eligible large-consumption customers to reduce their electricity costs when they curtail electricity consumption during periods of peak electricity demand. While participant eligibility criteria have been revised several times since the ICI was introduced in 2011, current eligibility rules have been in effect since 2017 with ICI response relatively stable from 2017 to 2019. However, with the onset of the pandemic, the Ontario government introduced a one-year hiatus on the program, allowing consumers to focus on economic recovery rather than responding to system peaks (i.e., curtailing). During the hiatus, government released the 2020 Ontario provincial budget,[9] which included a reduction in electricity rates, resulting in a dampened price signal for curtailment.

This increases uncertainty in the future impact of the ICI, which is expected to contribute less than in previous years. The IESO forecasts ICI top five system peak-day, system peak-hour demand reduction impacts to be 1,000 MW, a reduction from 2019 APO levels, and does not forecast increased ICI response over the outlook period.

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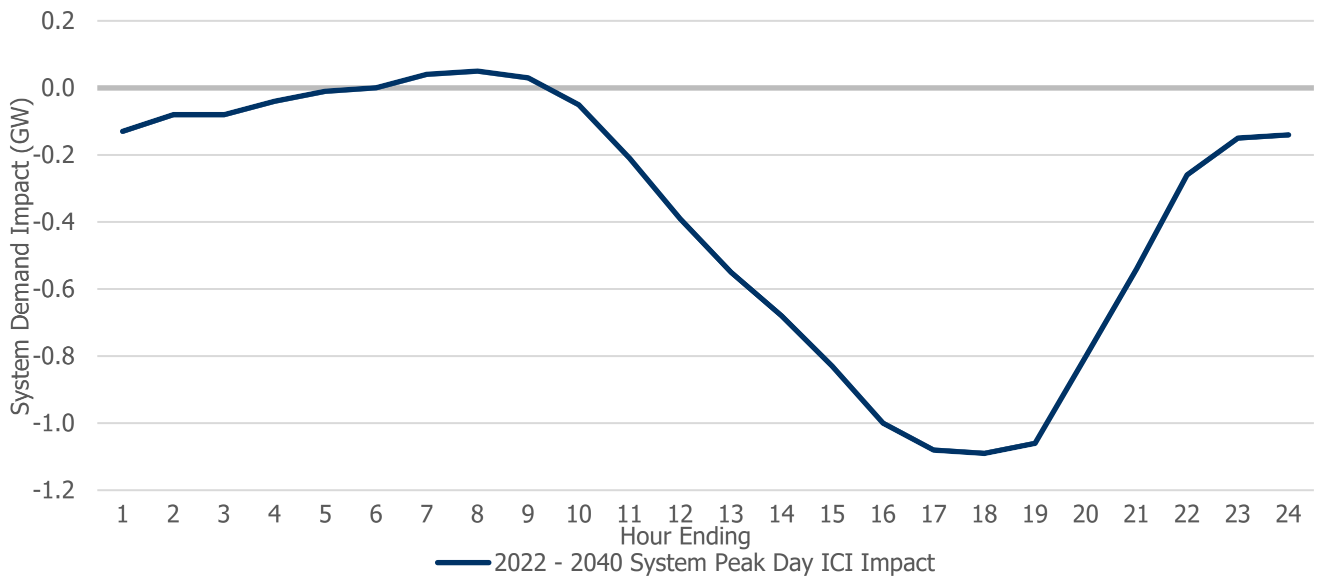
[9] The 2020 Budget includes "a plan to reduce the burden on employers of Ontario's high-cost contracts with non-hydroelectric renewable energy producers…Starting on January 1, 2021, a portion of the cost of these contracts entered into under the previous government, will be funded by the province, not the ratepayers." For more information, refer to the November 5 news release, Ontario's Action Plan: Protect, Support.

ICI drivers, including customer ICI program investment and Global Adjustment levels, will inevitably change over the course of the outlook period and the ICI impacts on the demand forecast methodology will be reassessed on an annual basis.

The projected impact from all ICI participants on the system peak day for each year in the outlook period is shown in Figure 6.

Figure 6 | Industrial Conservation Initiative Impact



2. Supply and Transmission Outlook

The majority of Ontario's installed supply capacity comes from nuclear, gas, and hydroelectric resources, with the remainder from wind, solar, demand response, and bioenergy. While most of Ontario's capacity is provided by transmission-connected market participants, Ontario also has a significant and growing number of distributed energy resources connected at the distribution level.

Nuclear refurbishments continue throughout the 2020s. The retirement of the Pickering NGS in the mid-2020s is a driver of incremental capacity needs looking ahead. Over the course of the outlook period, many resources with contracts or commitments with the IESO or the Ontario Electricity Financial Corporation will reach the end of their term. Most contracts or commitments expiring throughout the 2020s are with gas-fired generation and demand-response resources, while those with renewable resources begin to reach the end of their term in the 2030s.

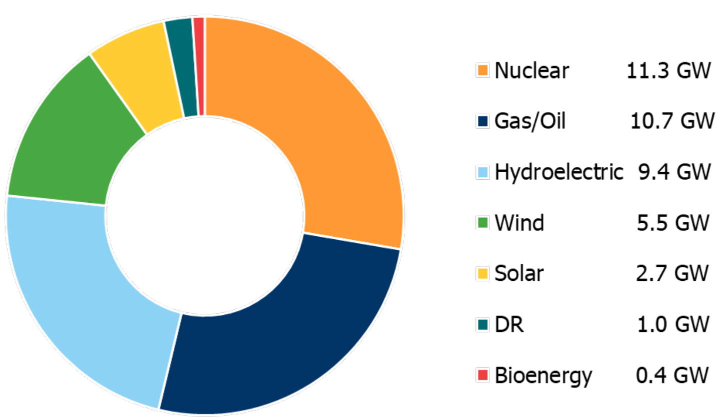
The bulk transmission system is critical to ensuring power can be delivered from the supply resource to the customer. The ability of the transmission system to transfer power across the province is defined by the capability of key interfaces.

Transmission reinforcements in the West of Chatham, Ottawa, eastern Ontario (near Napanee), and areas of northern Ontario are anticipated to come into service within the next five years, and will assist in maintaining a reliable transmission system.

2.1 Installed Capacity 2021

Ontario has 40.9 gigawatts (GW) of installed capacity made up of a diverse mix of resources.

Figure 7 | 2021 Installed Capacity by Fuel Type



As shown in Figure 7,[10] the majority of Ontario's installed capacity comes from nuclear (28%), gas (26%), and hydroelectric (23%) resources, with the remainder from wind (14%), solar (7%), demand response (DR) (2%) and bioenergy (1%). Most of Ontario's capacity is supplied by transmission-connected market participants and the rest is supplied by embedded generators. Both types of resources are included in the capacity assessment. The IESO did not consider scenarios in the supply outlooks, as information provided by asset owners to date has reinforced the IESO's confidence in their ability to continue to manage their assets during the pandemic.

2.2 Supply Outlook: Installed and Effective Capacity

There is a fundamental difference between installed capacity and effective capacity. No resource is capable of producing energy at maximum output levels at all times due to fuel availability, ambient conditions, or outages, making effective capacity a more meaningful measure of the amount of resources available to meet reliability needs in each season. Table 2 shows Ontario's effective capacity projected for each fuel type at the end of 2021, for the summer and winter seasons.[11] Going into the outlook period, total installed capacity for the entire fleet is about 40.9 GW, while summer and winter effective capacities are 28.2 GW and 30.4 GW, respectively. This supply outlook excludes the capacity acquired through the IESO's December 2020 capacity auction; this capacity will be included in future outlooks. More detail by fuel type is provided in the data tables.

[10] This chart is inclusive of both transmission- and distribution-connected resources that are either market participants and/or contracted by the IESO and excludes energy storage. For further information, please see the 2020 APO Supply, Adequacy and Energy Outlook module.

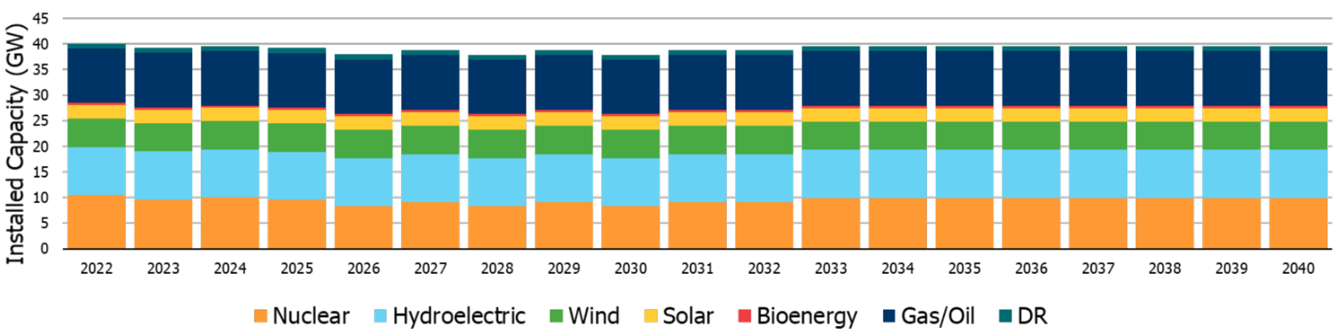
[11] Summer months are from May to October, and winter months are from November to April.

Table 2 | Ontario's Summer and Winter Effective Capacity by End of 2021

Fuel	2021 Installed GW	2021 Summer Effective GW	2021 Winter Effective GW
Nuclear	11.3	10.7	10.7
Gas/Oil	10.7	8.6	9.3
Hydroelectric	9.4	6.5	7.1
Wind	5.5	0.7	2.1
Solar	2.7	0.9	0.1
DR[12]	1.0	0.4	0.6
Bioenergy	0.4	0.4	0.4
Total	40.9	28.2	30.4

Figure 8 shows the installed capacity by fuel type for the outlook period (2022-2040). This reflects the continued availability of resources following the end of their contract term or commitment. Total installed capacity varies between 38 and 40 GW during the 2020s, due to the refurbishment and retirement of the nuclear fleet, before levelling off at 40 GW in the 2030s.

Figure 8 | Installed Capacity 2022-2040



[12] These reflect the results of the IESO's 2019 Demand-Response Auction.

Figure 9 and Figure 10 show the summer effective and winter effective capacities, by fuel type, for the outlook period. Summer effective capacity varies between 25 and 27 GW during the 2020s, due to the refurbishment of the nuclear fleet, and then levels off at 27 GW in the 2030s. Similarly, winter availability of the fleet ranges between 27 GW and 30 GW, plateauing at 29 GW in the long term. The supply mix over the course of the outlook generally reflects the supply mix shown in Table 2.

Figure 9 | Summer Effective Capacity 2022-2040

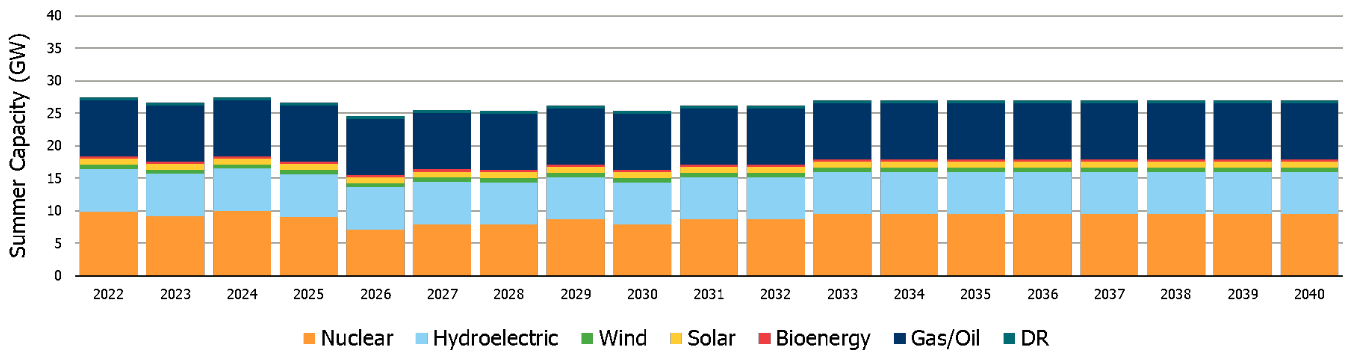
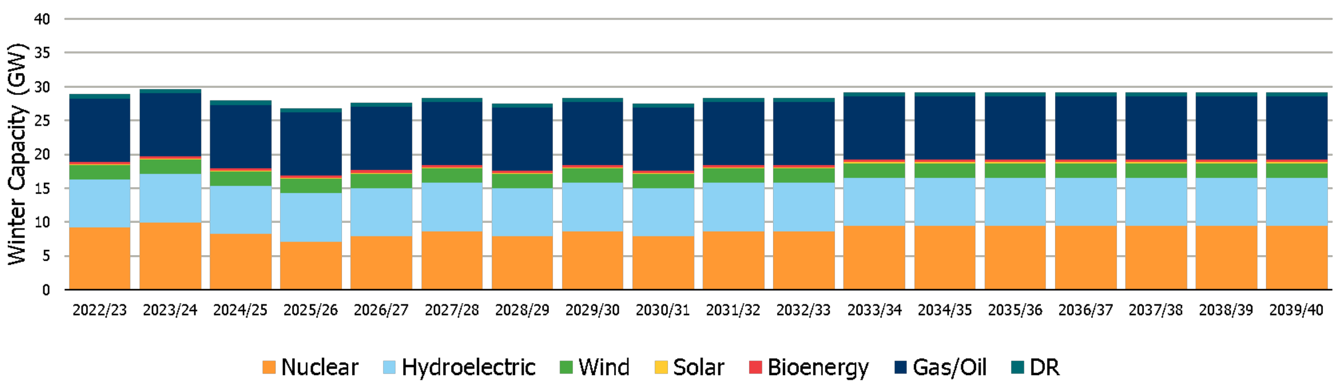


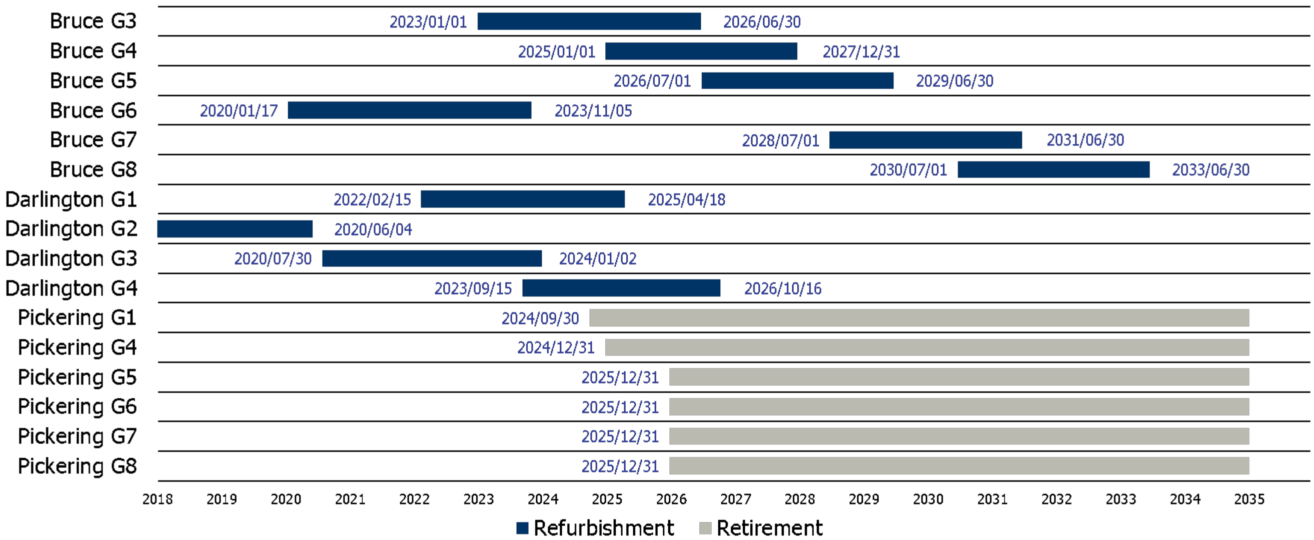
Figure 10 | Winter Effective Capacity 2022-2040



2.3 Nuclear Refurbishments and Retirements

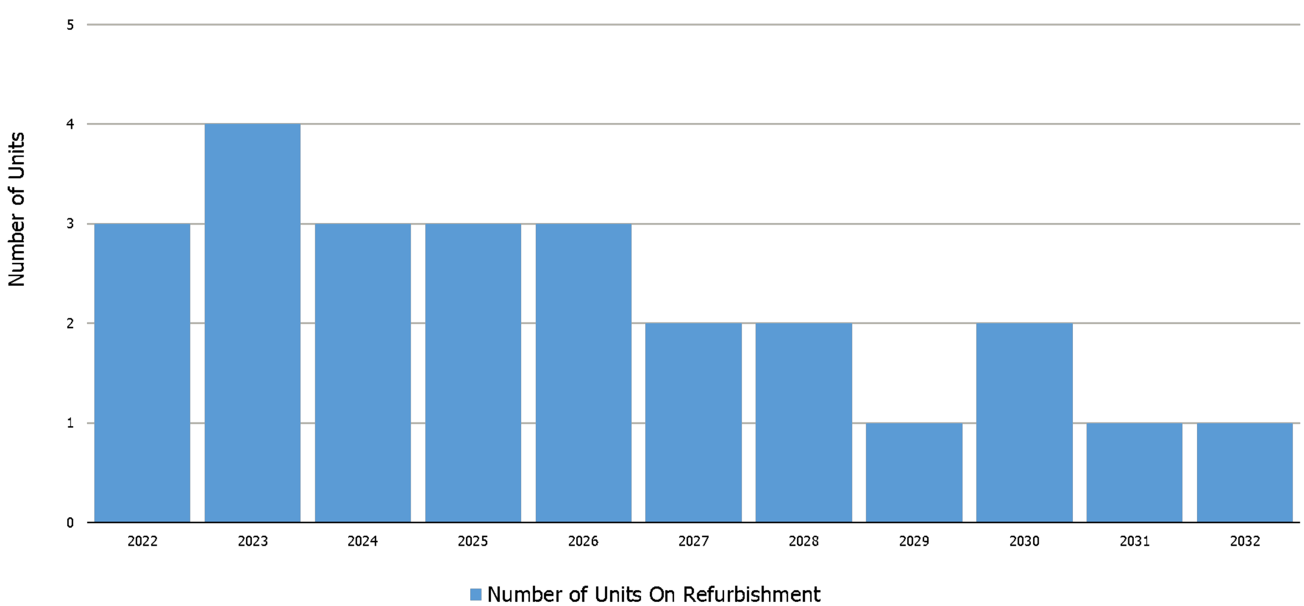
Throughout the 2020s, Ontario's electricity system will see significant change in the available capacity from its nuclear fleet, driven by nuclear refurbishments and retirements, as shown in Figure 11. The current schedule was provided to the IESO by Ontario Power Generation (OPG) and Bruce Power.

Figure 11 | Nuclear Refurbishment and Retirement Schedule



Long-term refurbishment outages at the Darlington and Bruce nuclear generating stations (NGS) will increase resource needs and introduce greater uncertainty in the resource outlook. By 2033, a total of 7.5 GW of nuclear capacity will undergo refurbishment. The first Darlington unit went offline for refurbishment in 2016 and returned to service in June 2020. Darlington and Bruce refurbishments are expected to be complete in 2026 and 2033 respectively. Figure 12 shows that refurbishment activity will increase in the 2020s, with between two and four units undergoing refurbishment concurrently over the summer period and an increase in the number of outages until 2026.

Figure 12 | Summer Refurbishment Outages

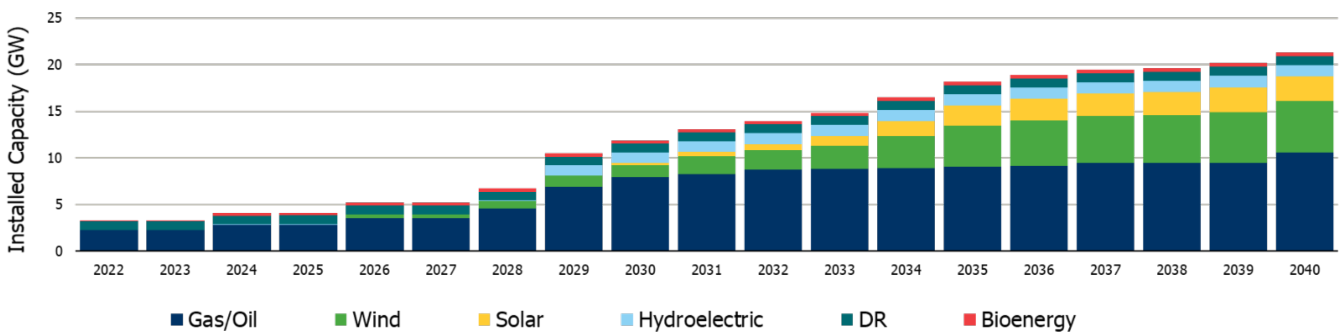


Pickering NGS is expected to retire in the mid-2020s, reducing Ontario's installed nuclear capacity by 3.1 GW. The two Pickering A units are scheduled to go out of service toward the end of 2024, with the remaining four units at Pickering B following in 2025. The Pickering NGS retirement is among the largest contributors to upcoming resource needs.

2.4 Contracts and Commitments Ending

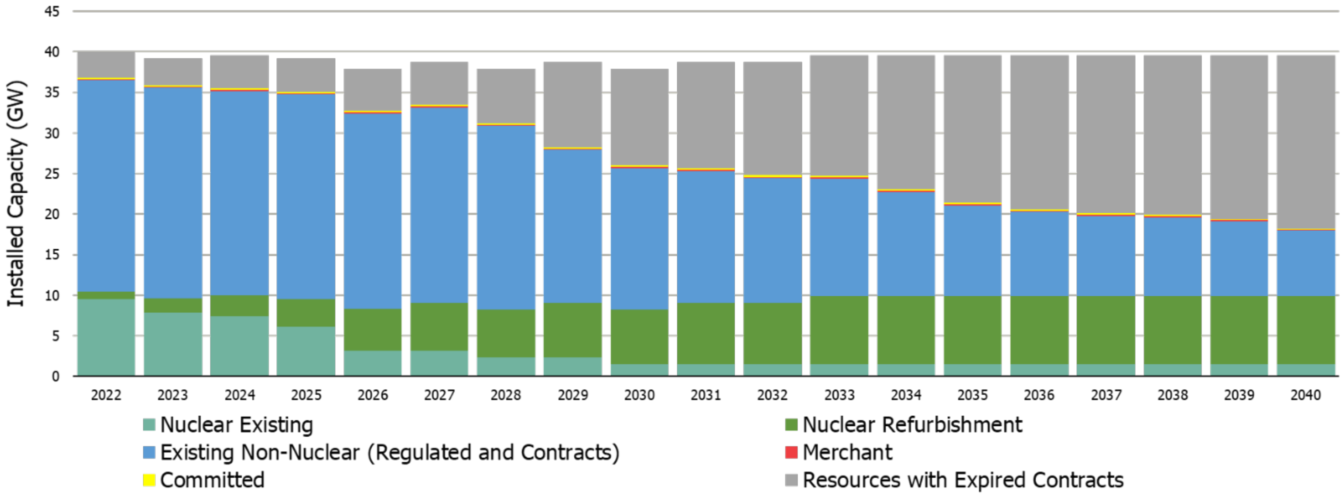
Over the course of the outlook, many commitments and generation contracts held by the IESO or the Ontario Electricity Financial Corporation will expire. The IESO is developing a Resource Adequacy Framework that will allow these resources to compete alongside new capacity to meet Ontario's needs. As shown in Figure 13, contracts begin to expire in the early 2020s, and expirations become more significant by the end of the decade. Contracts and commitments that expire in the 2020s are primarily with gas-fired generation and DR resources. Most wind, hydroelectric, and solar contracts begin to expire in the 2030s. Later in this report, scenarios with and without existing resources post-contact/commitment expiry will be examined.

Figure 13 | Existing Resources Post-Contract Expiry 2022-2040 by Fuel Type



The resource outlook includes considerable change through the 2020s and early 2030s due to the combined effect of nuclear retirements, refurbishment outages, and expiring contracts/commitments. The installed capacity outlook by contract/commitment type in Figure 14 illustrates the growing role of resources with expired contracts/commitments and units expected to complete nuclear refurbishment.

Figure 14 | Installed Capacity by Contract/Commitment Type: 2022-2040



2.5 Existing Bulk Transmission Interfaces and Interties

The ability of supply resources to meet system demand relies on the transmission system to transport the electricity to where it is needed. Within Ontario, bulk transmission interfaces form the boundaries of the 10 IESO electrical zones. The primary purpose of these interfaces is to describe power flows across the system, and associated phenomenon which may limit these transfers.

The bulk transmission system is also used to import power from or export power to neighbouring jurisdictions through a series of interties at specific points on the Ontario border. These interfaces and interties are shown in Figure 15.

Figure 15 | Ontario's Major Internal Transmission Interfaces

The maximum amount of power that these interfaces and interties can deliver is known as their transfer capability, which reflects constraints to ensure system stability, voltage performance, and acceptable thermal loading.

Interface transfer capabilities are used in resource adequacy and transmission security assessments, discussed later in Chapter 3 and Chapter 4. Resource adequacy assessments are probabilistic studies that consider interface transfer capabilities with all transmission facilities in-service, with regard to the impact of planned outages on transfer capabilities and the most limiting contingency (sudden, unplanned outage). Transmission security assessments are conducted at the zonal level and consist of deterministic assessments of various transmission system disturbances, as defined according to various regulatory obligations. Zonal adequacy or security assessments may be more restrictive than resource adequacy, depending on the characteristics of the zone(s) being investigated.

Intertie transfer capabilities are treated as interfaces in reliability assessments. Interties provide a number of system benefits, including stability, frequency support and voltage support following a contingency, and the opportunity to consider imports and exports to manage resource needs where cost-effective.

Each interface and intertie is described further in Section 2.5.1.

2.5.1 Bulk Transmission Interfaces

2.5.1.1 Buchanan Longwood Input (BLIP) and Negative Buchanan Longwood Input (NBLIP)

The BLIP interface comprises the circuits that connect the West Zone and the Southwest Zone, near London. This includes the three 500-kV circuits into Longwood TS, and the five 230-kV circuits into Buchanan TS. The NBLIP interface is defined identically to the BLIP interface, but the power transfer is measured in the opposite direction. BLIP transfer capability is important to reliably supply demand in the West Zone and facilitate exports to Michigan, while NBLIP transfer capability is important to deliver supply in the West Zone and imports from Michigan to the rest of the province.

Both transfers are generally thermally limited by circuits between Scott and Buchanan, Lambton and Longwood, or Chatham and Buchanan/Longwood, located west of where BLIP and NBLIP are measured.

2.5.1.2 Flow Away from Bruce Complex and Wind (FABCW)

The FABCW interface is the sum of all power flows away from the Bruce 230-kV and Bruce 500-kV stations (six circuits each), plus wind generation in the area. This transfer capability is important to deliver supply from the Bruce Zone, including nuclear generation from Bruce GS and surrounding wind plants, to the rest of the province.

FABCW transfers are not normally limited when all transmission facilities are in-service and are effectively managed through the Bruce Remedial Action Scheme under outage conditions.

2.5.1.3 Queenston Flow West (QFW)

The QFW interface comprises the circuits that connect the Niagara Zone and the Southwest Zone. This includes the four 230-kV circuits out of Beck 2 TS and three 230-kV circuits into Middleport TS. The QFW transfer capability is important to deliver supply from the Niagara Zone and imports from New York at Niagara to the rest of the province.

The QFW transfer capability was increased following completion of the Niagara reinforcement project in August 2019. QFW transfers are generally thermally limited, but are not expected to be restrictive under typical conditions, such as normal weather, expected imports, and all transmission facilities in-service.

2.5.1.4 Flow East Towards Toronto (FETT)

The FETT interface comprises the circuits that connect the Southwest Zone and the Toronto and Essa Zones. This includes the four 500-kV circuits into Claireville TS, two 230-kV circuits out of Orangeville TS to Essa TS, and four 230-kV circuits out of Trafalgar TS to Richview TS and Hurontario SS. FETT transfer capability is important for reliably supplying demand in the Toronto, Essa, East, Ottawa, Northeast and Northwest Zones and to deliver supply from the West, Southwest, Bruce and Niagara Zones.

FETT transfers are thermally limiting by the Richview TS to Trafalgar TS corridor in Mississauga, and can be critically binding with a transmission circuit initially out of service during summer peak demand periods, when the line ratings are low and demands are high. FETT transfer capability is highly dependent on the distribution of power that flows along the limiting path from Richview TS to Trafalgar TS, which will be affected by nuclear retirements and refurbishments, causing flows to increase and the distribution of flows to further restrict transfer capability.

2.5.1.5 Transfer East of Cherrywood (TEC)

Cherrywood TS is located in Pickering. The TEC interface comprises the circuits that connect the Toronto Zone and the East Zone. This includes the four 500-kV circuits out of Bowmanville SS, four 230-kV circuits – with one each into Dobbin TS, Almonte TS, Belleville TS and Havelock TS – and two 230-kV circuits into Chats Falls GS. TEC transfer capability is important for reliably supplying demand in the East and Ottawa Zones.

TEC transfers are generally thermally limited, but are not expected to be normally binding.

2.5.1.6 Flow into Ottawa (FIO)

The FIO interface comprises the circuits that connect the East Zone and Ottawa Zone. This includes two 500-kV circuits out of Lennox TGS, one 230-kV circuit into St. Isidore TS, one 230-kV circuit out of St. Lawrence TS, one 230-kV circuit out of Chats Falls TS and one 230-kV circuit into Merivale TS. The FIO interface is considered an open interface because the underlying lower-voltage 115-kV circuits that connect the East and Ottawa Zones are not measured by the interface. This is because flows on the 115-kV circuits do not materially impact the ability to transfer bulk quantities of power into the Ottawa Zone. FIO transfer capability is important for reliably supplying demand in the Ottawa Zone and facilitating exports to Quebec.

FIO transfers are not generally limiting with all transmission facilities in service. With one transmission circuit out of service, FIO transfers are limited to ensure acceptable voltage performance.

2.5.1.7 Claireville North (CLAN) and Claireville South (CLAS)

The CLAN interface comprises the circuits that connect the Toronto Zone and Essa Zone. This includes two 500-kV circuits and two 230-kV circuits north from Claireville TS, located in the Toronto Zone. The CLAS interface is defined identically to the CLAN interface, but the power transfer is measured in the reverse direction.

The CLAN and CLAS interfaces are generally not limiting.

2.5.1.8 Flow North (FN) and Flow South (FS)

The FN interface comprises the circuits that connect the Essa Zone and Northeast Zone. This includes the two 500-kV circuits north from Essa TS and one 230-kV circuit north into Otto Holden TS. The FS interface is defined identically to the FN interface, but the power transfer is measured in the reverse direction. FN transfer capability is important to reliably supply demand in the Northeast and Northwest Zones, as well as facilitate exports to Manitoba, Minnesota and Quebec; FS transfer capability is important to deliver imports and supply from the Northwest and Northeast Zones to the rest of the province.

FN and FS transfers can be limited under certain conditions to ensure acceptable voltage and stability performance (e.g., FN can be limiting under low water conditions and sensitive to demand; and FS can be limiting under heavy water conditions).

2.5.1.9 East-West Transfer East (EWTE) and East-West Transfer West (EWTW)

The EWTW interface comprises the circuits that connect the Northeast Zone and Northwest Zone. This currently includes the two 230-kV circuits into Wawa from Marathon, and will include the two additional 230-kV circuits into Wawa from Marathon that form part of the East-West Tie Reinforcement project. The EWTE interface is defined identically to the EWTW interface, but the power transfer is measured in the reverse direction. EWTW transfer capability is important to reliably supply Northwest Zone demand, while EWTE transfer capability is important for the delivery of Northwest supply and imports to the rest of the province.

EWTE and EWTW transfers are limited by voltage performance and the thermal capability of the underlying 115-kV path, and will be improved following implementation of the East-West Tie Reinforcement project. At that point, facilities that restrict transfers between Northwest Ontario and Northeast Ontario will be upstream and downstream of the EWTE and EWTW interfaces, notably the Mississagi East (MISSE) and West (MISSW) interfaces, as well as the Transfer West of Mackenzie (TWM) interface. Following the East-West Tie Reinforcement project, changes to the Northern Ontario zonal demarcations may be appropriate to align with these more limiting interfaces.

2.5.2 Bulk Transmission Interties

2.5.2.1 The Ontario-Manitoba Interconnection

The Ontario-Manitoba interconnection consists of two 230-kV circuits and one 115-kV circuit. The transfers on the 230-kV interconnection points are under the control of phase angle regulators (PARs)[13] and defined as Ontario-Manitoba Transfer East (OMTE) and Ontario-Manitoba Transfer West (OMTW). Ontario and Manitoba are synchronously connected[14] at 230-kV, while the 115-kV interconnection is operated normally open (i.e., no power flows) except under rare or emergency conditions.

[13] A PAR is a specialized transformer that alters power angle to control the flow of power through paths different than how it would naturally flow.

[14] Synchronously connected means direct AC to AC connection, which allows for matching frequencies between the two connecting systems.

2.5.2.2 The Ontario-Minnesota Interconnection

The Ontario-Minnesota interconnection consists of one 115-kV interconnection point. The transfers on this interconnection are the Minnesota Power Flow North (MPFN) and the Minnesota Power Flow South (MPFS). The interconnection is under the control of a PAR. Ontario and Minnesota are synchronously connected.

2.5.2.3 The Ontario-Michigan Interconnection

The Ontario-Michigan interconnection consists of two 230/345-kV interconnection points, one 230/115-kV interconnection point, and one 230-kV interconnection point. The interconnection is under the control of PARs. Ontario and Michigan are synchronously connected.

2.5.2.4 The Ontario-New York Niagara Interconnection

The Ontario-New York Niagara interconnection consists of two 230/345-kV interconnection points and two 230-kV and one 115-kV interconnection points, the latter of which is used for emergency services only. The interconnection is free-flowing.

The Queenston Flow West (QFW) interface is downstream of the New York Niagara interconnection. All flows entering Ontario on the New York Niagara interconnection will impact flows on the QFW interface, including imports and unscheduled flows. Ontario and New York Niagara are synchronously connected.

2.5.2.5 The Ontario-New York St. Lawrence Interconnection

The Ontario-New York St. Lawrence interconnection consists of two 230-kV circuits. The interconnection is under the control of PARs. The failure of the PAR connected to the Ontario-New York 230-kV interconnection circuit L33P in early 2018 reduces the province’s ability to import electricity from New York through the New York-St. Lawrence interconnection and from Quebec through the Beauharnois interconnection. The PARs are expected to be replaced in 2022/2023, restoring import capability and improving the ability to control flow on the intertie.

Ontario and New York are synchronously connected at St. Lawrence.

2.5.2.6 The Ontario-Quebec Interconnection

The Northeast Zone contains two radial[15] 115-kV interconnection points with Quebec. The East Zone contains four 230-kV and one 115-kV radial interconnection points with Quebec. The Ottawa Zone has one HVDC (non-synchronous) interconnection (consisting of two 230-kV circuits), as well as one 230-kV and one 115-kV radial interconnection points.

[15] A radial interconnection is a type of non synchronous connection where one or more generator(s) electrically is separated from the rest of the system to which it belongs, and supplies customers in the other jurisdiction.

2.6 Anticipated Transmission Projects

A number of major transmission projects are expected to come into service within the outlook time frame. These are considered in the base case for resource adequacy and transmission security assessments. The geographical locations of these anticipated transmission projects are shown in Figure 16 and a summary of each appears in Table 3.

Figure 16 | Transmission Zones and Anticipated Projects

Table 3 | Major Anticipated Transmission Project Details

Project	Description	Expected In-Service Date
West of Chatham Area Reinforcement	• Growth in the agricultural sector is one of the main drivers of increasing demand in Ontario, as discussed in Section 1.3.4, and has resulted in the need for additional electrical supply capacity to serve the Windsor-Essex region • The reinforcement project consists of: a new switching station at Leamington Junction (Lakeshore SS); and a new, double-circuit, 230-kV transmission line, approximately 50 km in length, from Chatham SS to Lakeshore SS	• Q4 2022 for Lakeshore SS • Q4 2025 for new line
Hawthorne - Merivale Reinforcement	• The Hawthorne-Merivale transmission path supplies load in western Ottawa and delivers eastern Ontario resources and imports from Quebec to southern Ontario load centres • The reinforcement consists of upgrading the two 230-kV circuits between Merivale TS and Hawthorne TS, a length of 12 km	• Q4 2022
Lennox Reactors	• Operational challenges due to high voltages in eastern Ontario and the GTA continue to occur during low-demand periods, and have recently been exacerbated due to impacts on minimum demand from COVID-19 • Two 500-kV line-connected shunt reactors will be installed at Lennox TS (near Napanee)	• Q1 2021 - Q4 2021
East-West Tie Reinforcement	• To provide long-term, reliable electricity supply to Northwest Ontario to enable forecast demand growth and changes to the supply mix in the region • New 230-kV transmission line roughly paralleling the existing East-West Tie Line between Wawa and Thunder Bay	• Q1 2022

3. Resource Adequacy

In Scenario 1, summer capacity needs continue to emerge through 2022 and long-term needs continue to be driven by the Pickering NGS retirement. Without the continued availability of existing generation and demand-side resources post contract/commitment, needs emerge in the winter of 2022/2023, influenced by strong growth in the agricultural sector. Should these resources continue to be available in the market, the need would be smaller and emerge later.

Major planned generator outages affect the need for capacity. The nuclear refurbishment program is particularly important, with two and four nuclear units out of service each summer until 2030. Major refurbishment activity occurs in summer 2023, when two to four nuclear units will be out of service over the summer.

Transmission limitations can restrict capacity from being delivered to where it is needed and will need to be considered when locating new capacity to meet future needs.

A component of power system reliability is resource adequacy, which describes the balance of supply and demand in the system. There are risks to every power system, such as extreme weather and generator outages, which could result in demand exceeding supply for a period of time. An adequate system has enough capacity to mitigate these risks. The IESO calculates capacity requirements by performing a resource adequacy assessment.

The probabilistic risk assessment compares the demand forecast with anticipated resource performance to simulate the range of possible future system conditions. Loss of load expectation (LOLE) is a measurement of resource adequacy, defined as the average number of days per year during which supply is expected to be insufficient to meet demand. Reliability standards[16] require that the IESO maintain enough capacity such that the LOLE is no greater than 0.1 days/year. Probabilistic assessments are standard practice across North America and are part of the IESO's regulatory requirements. Over time, as forecasted demand changes or resources enter and exit the market, the IESO's capacity requirements will change.

The IESO considers a number of risks in resource adequacy assessments. For example, actual demand may be higher or lower than forecast depending on weather conditions. Resources may be unavailable in real-time due to planned maintenance or equipment failures. Variable generators – like wind and solar – may provide relatively low levels of effective capacity since they are dependent on environmental conditions and cannot always produce energy when required. Finally, major projects, such as ongoing nuclear refurbishments, may face return-to-service delays and experience a higher failure rate after they return.[17]

[16] For additional information, refer to NPCC's Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System, Section R4, page 6; and the IESO's Ontario Resource and Transmission Assessment Criteria, Section 8.

[17] Consult the 2020 APO Resource Adequacy and Energy Assessment Methodology for additional information.

Resources are assessed in terms of effective capacity,[18] which is typically lower than installed capacity, as was discussed in the previous chapter. The capacity requirements in this section are in the same units (MW). The total resource requirement is the amount of effective capacity needed to meet resource adequacy standards, and the reserve margin requirement is the amount by which the total resource requirement exceeds peak demand under normal weather conditions.

In Ontario, summer capacity needs are generally much higher than winter capacity needs. The main driver of this difference is demand, with summer peaks tending to be higher and more variable than winter peaks. Existing resources, particularly gas, hydroelectric, and wind, also provide less effective capacity in the summer than in the winter.

3.1 Reserve Margin

The IESO maintains an adequate reserve margin to ensure there is enough electricity available to compensate for volatility in factors that impact supply and demand. Continued availability of existing resources is assumed in the reserve margin. Through the Resource Adequacy engagement, the IESO will work with stakeholders to develop a framework for competitive mechanisms to meet Ontario's resource adequacy needs.

In accordance with Section 8.2 of the Ontario Resource and Transmission Assessment Criteria (ORTAC), the IESO annually publishes a five-year forecast of reserve margin requirements at the time of projected annual peak. Requirements are compared to the amount of effective capacity available from existing resources. The reserve margin requirements for the next five years are shown in Table 4.

There are various reasons for year-to-year variations in the reserve margin requirement. The IESO includes additional reserve to account for risks associated with nuclear refurbishments, with the amount varying depending on the refurbishment schedule. A year with higher-than-average planned outages will also have a higher reserve margin requirement. The methodology to calculate effective capacity for each resource type also affects the reserve margin. The reserve margin requirements for the full outlook horizon are shown in Table 4 and Figure 17. The table reflects continued availability of existing resources post-contract/commitment. Should these resources become unavailable, the Reserve Margin Available would be less than what is shown.

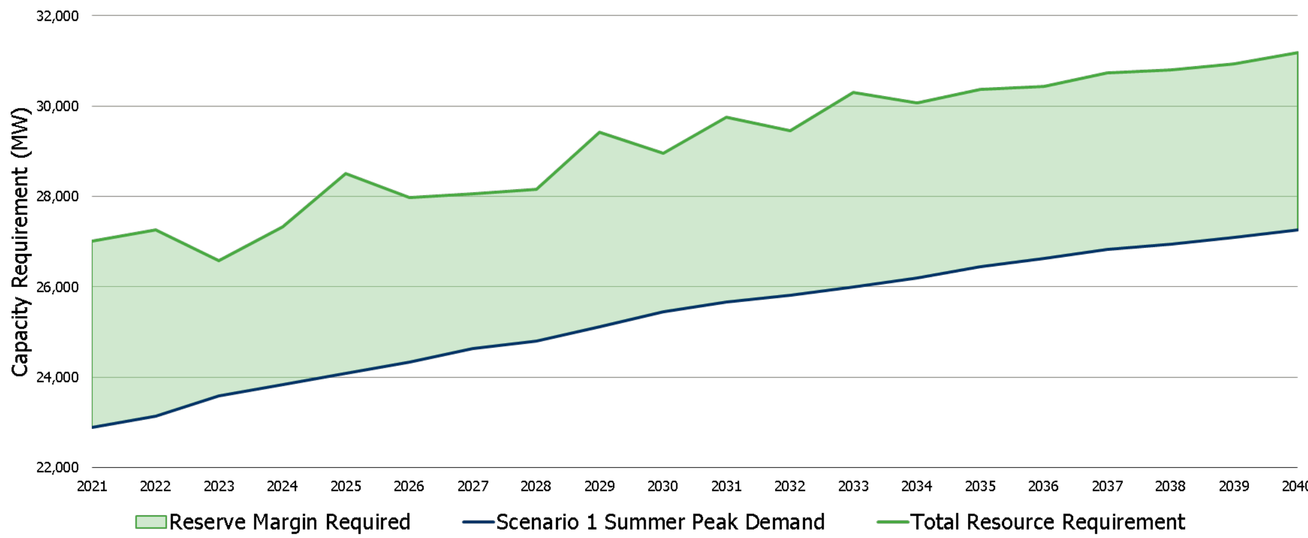
Table 4 | Five-Year Reserve Margin, with Continued Availability of Existing Resources

Five-Year Reserve Margin	2021	2022	2023	2024	2025
Scenario 1 Summer Peak Demand (MW)	22,882	23,131	23,583	23,833	24,093
Existing Summer Effective Capacity (MW)	28,207	27,388	26,659	27,446	26,588
Total Resource Requirement (MW)	27,019	27,262	26,587	27,334	28,505

[18] A resource's effective capacity is equivalent to its UCAP.

Five-Year Reserve Margin	2021	2022	2023	2024	2025
Reserve Margin Available (MW)	5,325	4,257	3,076	3,613	2,495
Capacity Surplus/Deficit (MW)	1,188	126	72	112	-1,917
Reserve Margin Available (%)	23%	18%	13%	15%	10%
Reserve Margin Requirement (%)	18%	18%	13%	15%	18%

Figure 17 | Reserve Margin Requirement, 2021-2040



3.2 Provincial Capacity Adequacy Outlook

Capacity adequacy can be understood in terms of surplus or deficit, relative to a set of demand and resource assumptions. Resource adequacy is assessed for the summer and winter seasons using the two demand forecasts outlined in Chapter 1, and the supply and transmission outlook presented in Chapter 2.

In this chapter, the capacity deficit represents the total amount of capacity, on an effective capacity or UCAP basis, that the IESO must acquire to satisfy LOLE requirements. Capacity needs calculated in this manner will inform target capacity for the capacity auction and future acquisition processes. The capacity surplus/deficits for summer and winter periods without availability of existing resources post-contract/commitment are shown in Figure 18 and Figure 19. In Scenario 1, summer capacity needs continue to emerge through 2022 and long-term needs are driven by the Pickering NGS retirement. Without the continued availability of existing generation and demand-side resources, needs emerge in the winter of 2022/2023.[19]

[19] Refer to the 2020 APO Supply, Adequacy and Energy Outlook Module for additional information on capacity needs and available options to meet these needs.

Figure 18 | Summer Capacity Surplus/Deficit, without Continued Availability of Existing Resources

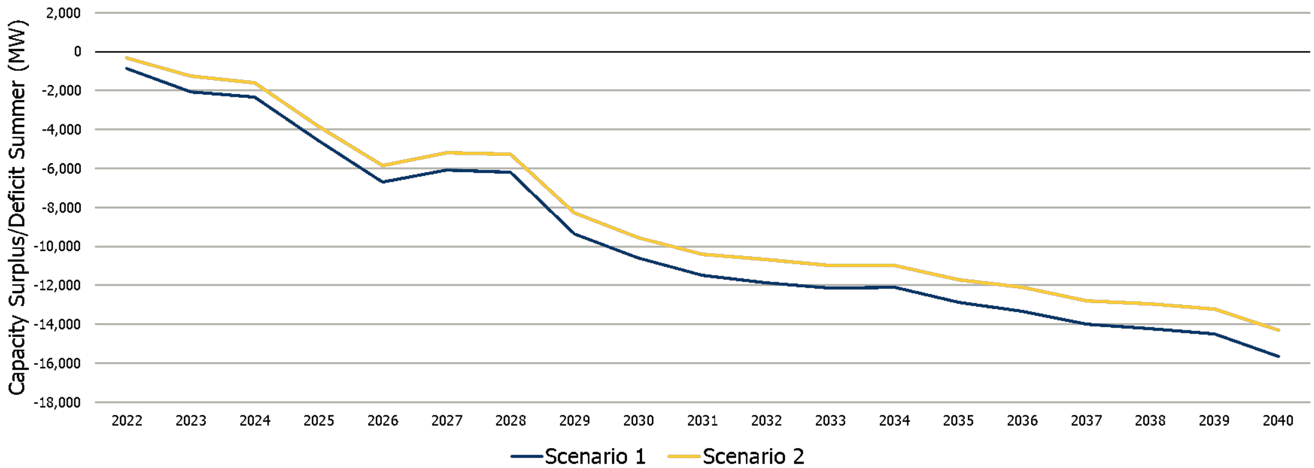
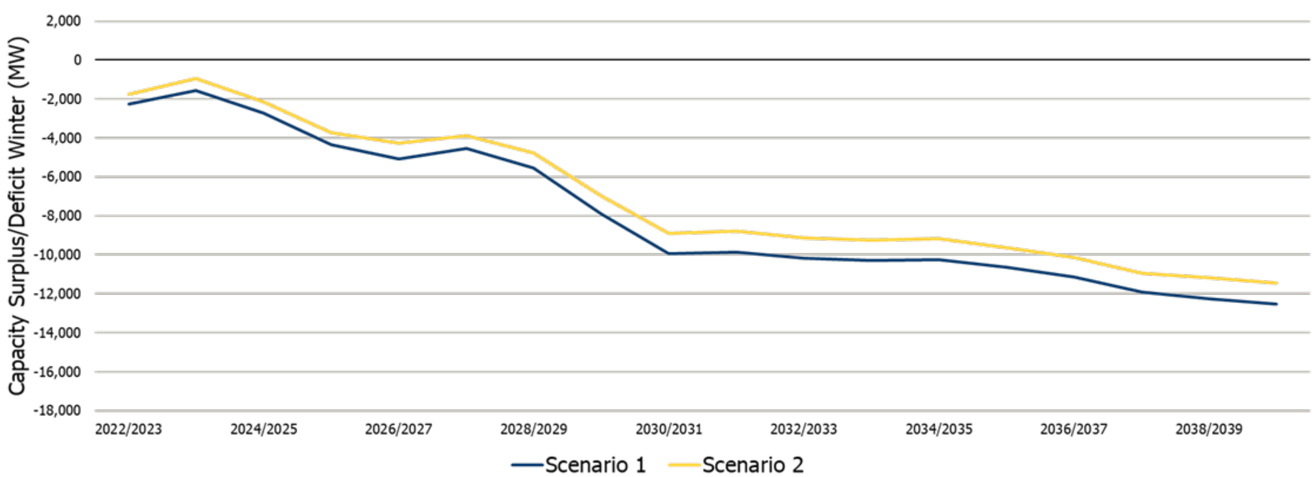


Figure 19 | Winter Capacity Surplus/Deficit, without Continued Availability of Existing Resources



The Lennox GS contract expected to expire at the end of 2022 along with major planned generator outages – such as the nuclear refurbishment program, with two and four units out of service each summer – greatly impact the capacity need. In the summer of 2023, at the height of refurbishment activity, four nuclear units (totaling 3,364 installed MW) will be out of service. The IESO will be negotiating an extension of the Lennox GS contract as a transition measure to reduce and delay this need.

Current forecasted ICI contributions to resource adequacy show an average reduction of 700 MW in the need over the course of the outlook. Potential changes to the ICI program could affect the timing of the need by a year or two.[20]

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[20] Refer to the 2020 APO Supply, Adequacy and Energy Outlook Module for additional information on the impact of ICI on resource adequacy.

3.2.1 Zonal Capacity Adequacy Outlook

The capacity requirements presented in this chapter are the total amount needed to reliably meet provincial demand for electricity. However, the location of resources on the system also affects resource adequacy. Transmission limitations can prevent capacity from being delivered to where it is needed. To manage the impact of major transmission limitations on capacity acquisition, the IESO applies minimum or maximum incremental capacity limits to certain regions of the province.

Transmission constraints in the resource adequacy assessment are modelled using the major transmission interfaces between the 10 IESO electrical zones as described in Chapter 2. Additional limits are presented for groups of zones that share a common limiting interface.[21] A zonal minimum represents the minimum required capacity in a zone necessary to meet provincial resource adequacy criteria. A zonal maximum represents the maximum amount of capacity that can be located in a zone, while still contributing to provincial resource adequacy criteria. The summer and winter zonal minimums and maximums for select future years are shown in Table 5 and Table 6, respectively.[22] The years chosen represent the main inflection points in capacity need growth over the next decade.

Given the existing transmission infrastructure, zonal constraint studies show that location-specific capacity needs will emerge in the mid-2020s, mainly in the GTA and eastern Ontario (i.e., Toronto, Essa, East, and Ottawa Zones). With the retirement of Pickering NGS and the Darlington refurbishment, this area will have less generation capacity available. Towards the end of the decade, some additional capacity will be required in the West Zone.

Capacity bottling on the Flow South interface will limit the amount of capacity that can be added in northern Ontario (i.e., Northwest and Northeast Zones). The Flow East Towards Toronto interface is also a key consideration. There are limits on the amount of capacity that can be accommodated in southwest Ontario (i.e., Southwest, West, Niagara and Bruce Zones).

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[21] The 2020 APO Resource Adequacy and Energy Assessment Methodology provides a description on the methodology on zonal limits. Also refer to the 2020 APO Supply, Adequacy and Energy Outlook Module for additional information on the zonal capacity adequacy assessments.

[22] For Table 5 and Table 6, a maximum limit of N/A indicates that the actual maximum is not expected to be practically limiting.

Table 5 | Incremental Summer Zonal Constraints, without Continued Availability of Existing Resources

Zone	2023 Min (MW)	2023 Max (MW)	2025 Min (MW)	2025 Max (MW)	2029 Min (MW)	2029 Max (MW)
Bruce	0	2,800	0	2,750	0	2,150
East	0	N/A	0	N/A	0	N/A
Essa	0	N/A	0	N/A	0	N/A
Niagara	0	900	0	900	0	900
Northeast	0	150	0	250	0	250
Northwest	0	50	0	100	0	100
Ottawa	0	N/A	0	N/A	0	N/A
Southwest	0	N/A	0	N/A	0	N/A
Toronto	0	N/A	0	N/A	0	N/A
West	0	1,000	0	1,450	400	3,900
Toronto+Essa+East+Ottawa	0	N/A	1,600	N/A	4,550	N/A
Northeast+Northwest	0	150	0	250	0	250
Bruce+West+Niagara+Southwest	0	2,250	0	2,550	0	4,150

Table 6 | Incremental Winter Zonal Constraints, without Continued Availability of Existing Resources

Zone	2023/2024 Min (MW)	2023/2024 Max (MW)	2025/2026 Min (MW)	2025/2026 Max (MW)	2029/2030 Min (MW)	2029/2030 Max (MW)
Bruce	0	N/A	0	5,000	0	2,300
East	0	N/A	0	N/A	0	N/A
Essa	0	N/A	0	N/A	0	N/A
Niagara	0	800	0	1,700	0	800
Northeast	0	600	0	1,800	0	1,550
Northwest	0	150	0	1,100	0	350
Ottawa	0	N/A	0	N/A	0	N/A
Southwest	0	N/A	0	N/A	0	N/A
Toronto	0	N/A	0	N/A	0	N/A
West	0	850	0	2,450	450	4,300
Toronto+Essa+East+Ottawa	0	N/A	200	N/A	4,200	N/A
Northeast+Northwest	0	600	0	1,800	0	1,550
Bruce+West+Niagara+Southwest	0	1,100	0	4,050	0	3,400

3.3 Provincial Energy Adequacy Outlook

The purpose of the energy adequacy outlook is to assess Ontario's ability to meet its own electricity needs and better characterize the nature of future needs. The energy adequacy assessment does not include any economic imports or exports across Ontario's interconnections. Contracted energy imports are included.

Ontario is expected to have an adequate supply of energy in the near term. In the long term, the extent to which an energy adequacy need emerges will depend on the availability of existing resources post-contract expiry, as existing renewable and gas-fired generation can continue to meet Ontario's energy needs. The energy adequacy outlooks for Scenarios 1 and 2 are shown in Figure 20 and Figure 21, respectively.

Figure 20 | Scenario 1 – Energy Adequacy Outlook, with Continued Availability of Existing Resources

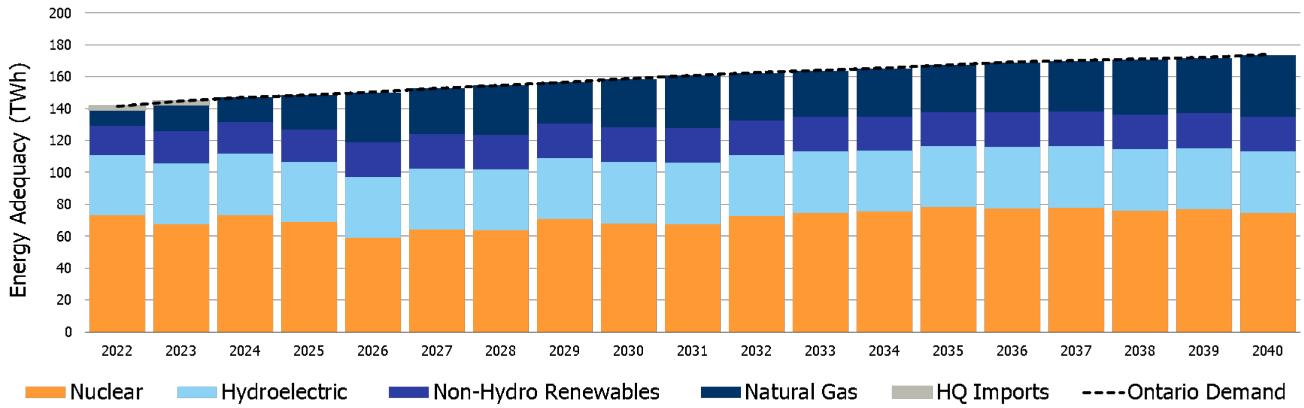
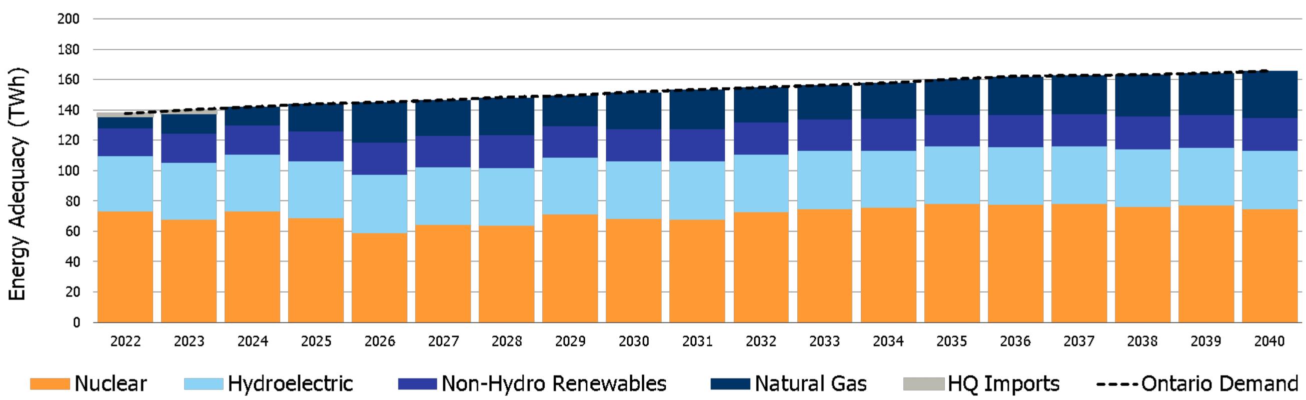


Figure 21 | Scenario 2 – Energy Adequacy Outlook, with Continued Availability of Existing Resources

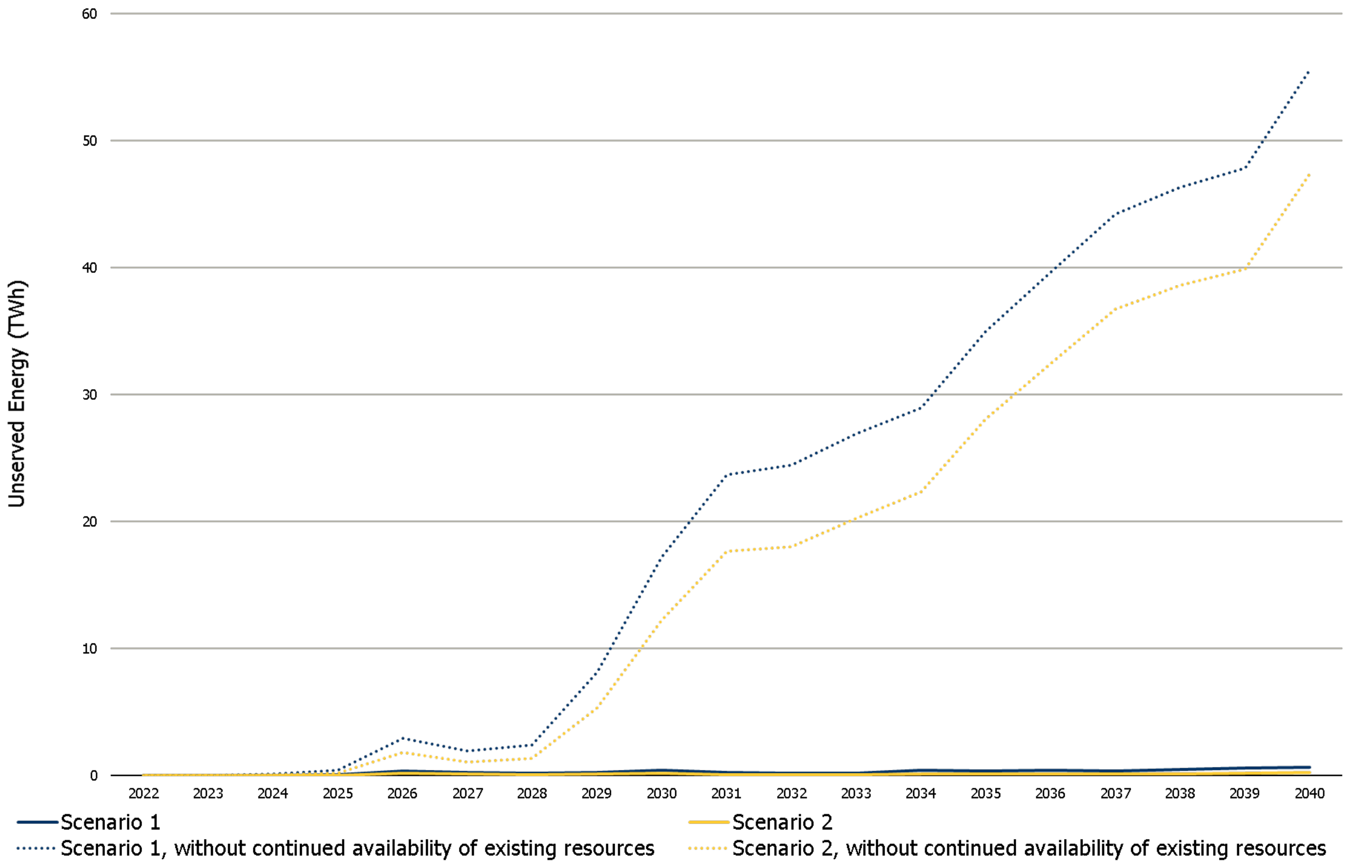


The energy adequacy outlook indicates that Ontario's supply needs over the next decade are principally for managing risks to the reliability of the grid. Existing resources can meet energy demands in most circumstances. The capacity requirement is peaking in nature and is required to help the system respond to lower probability events, such as extreme conditions (e.g. higher than expected demand or outages).

If existing resources exit the market post-contract expiry and the capacity shortfall grows, the potential for unserved energy begins in 2026. This would increase sharply after 2029, surpassing 56 TWh by the late 2030s in Scenario 1 and 47 TWh in Scenario 2, as shown in Figure 22. With a capacity need exceeding 10,000 MW, this resource scenario has considerable energy shortfalls through the 2030s, as combined gas cycle generation and renewable contracts expire.

Throughout the forecast period, the capacity need eventually becomes an energy need that is fairly dense, driven by resources with contracts expiring. However, if existing resources continue to be available, Ontario is generally expected to have enough energy to meet demand throughout the forecast period.

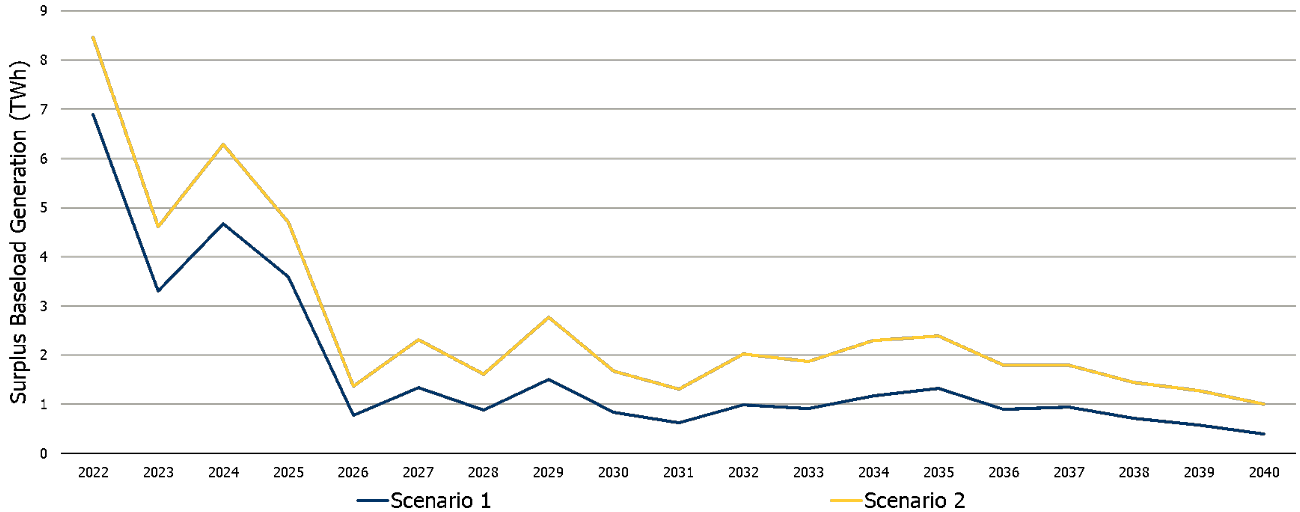
Figure 22 | Potentially Unserved Energy



Although existing resources are sufficient to meet future energy needs, new resources will have the opportunity to compete with existing resources in the energy markets. Resources can earn revenue by offering energy at a lower price than the marginal resource. Flexible, dispatchable resources can also quickly react to short-term energy price spikes or provide operating reserve.

Surplus baseload generation (SBG), as shown in Figure 23, occurs when output from baseload resources exceeds demand, and is a normal outcome of electricity markets with high portions of non-dispatchable (i.e., baseload and intermittent) resources. Periods of SBG require the IESO to use market mechanisms, such as exports, variable generation curtailment, and nuclear manoeuvers/ curtailment, to correct the imbalance. By the mid-2020s, SBG continues to fall as more nuclear units undergo refurbishment and Pickering NGS retires. Through the outlook period, SBG is expected to continue to be managed using existing market tools.

Figure 23 | Surplus Baseload Generation, with Continued Availability of Existing Resources



3.4 Provincial Energy Production Outlook

The IESO-administered energy markets are linked to Ontario's neighbours through interconnections. Imports and exports are scheduled in the real-time energy market to take advantage of price differences between jurisdictions. In 2019, Ontario imported 6.6 TWh of energy and exported 19.8 TWh. The model used to create this energy production outlook includes representations of Ontario's trading partners in order to more closely represent expected conditions and market outcomes. While the energy adequacy outlook is useful for characterizing resource needs, the energy production outlook is needed to forecast market outcomes, as illustrated in Figure 24 and Figure 25.

Figure 24 | Scenario 1 – Energy Production Outlook

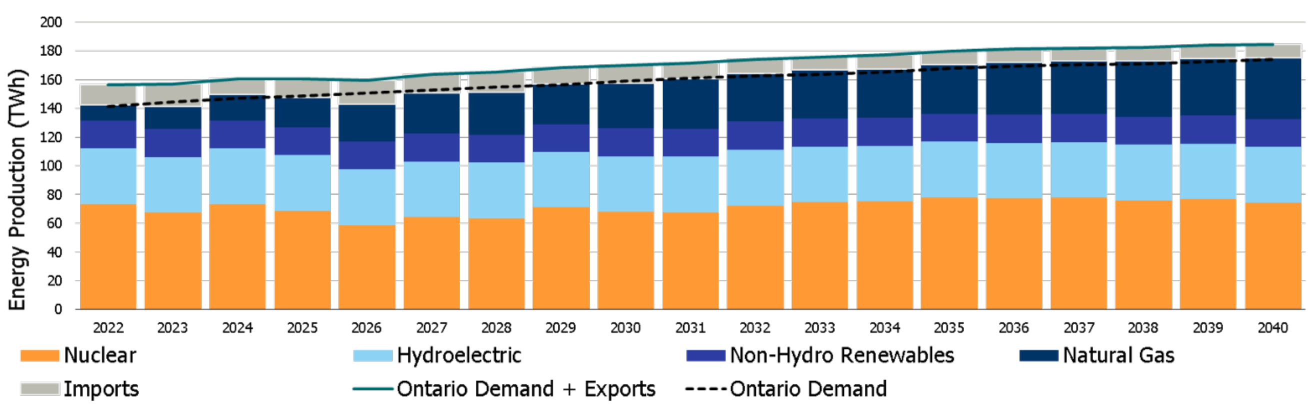
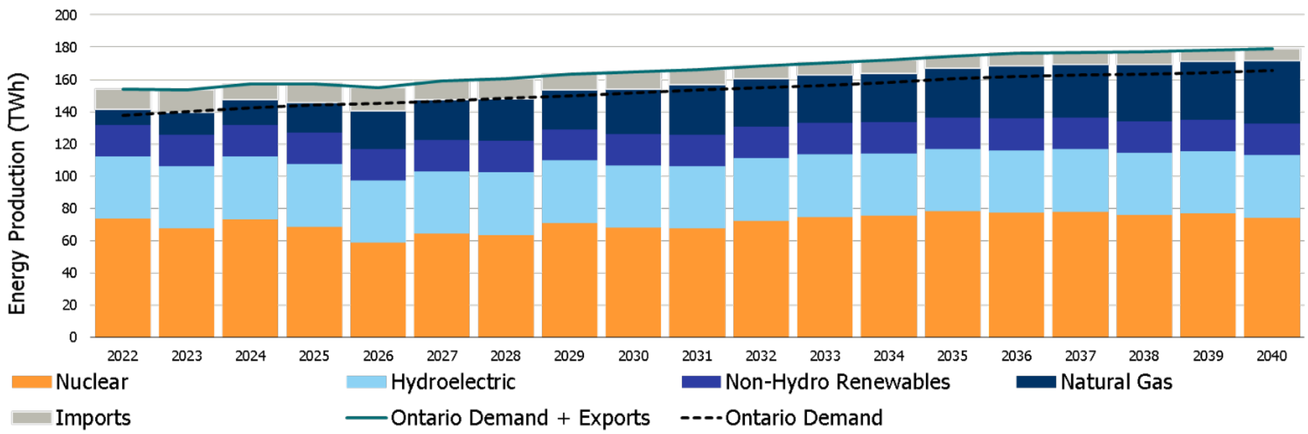


Figure 25 | Scenario 2 – Energy Production Outlook



Production by fuel type is similar to the energy adequacy outlook because production from baseload resources is generally insensitive to market prices. Gas production, which acts as a swing resource in the system, can vary depending on the extent to which these resources are more economic than imports in the real-time market. In addition, where opportunities exist, energy from Ontario's electricity fleet can also be exported.

In Figure 26 and Figure 27, energy exports decrease sharply in the early 2020s with the retirement of Pickering NGS and more nuclear generators on refurbishment outage. Coincidentally, imports increase from historic levels and Ontario becomes a net energy importer throughout the refurbishment period. The balance of trade is expected to shift back toward exports in the 2030s, following the conclusion of the nuclear refurbishment program.

Figure 26 | Energy Production Outlook, Imports[23]

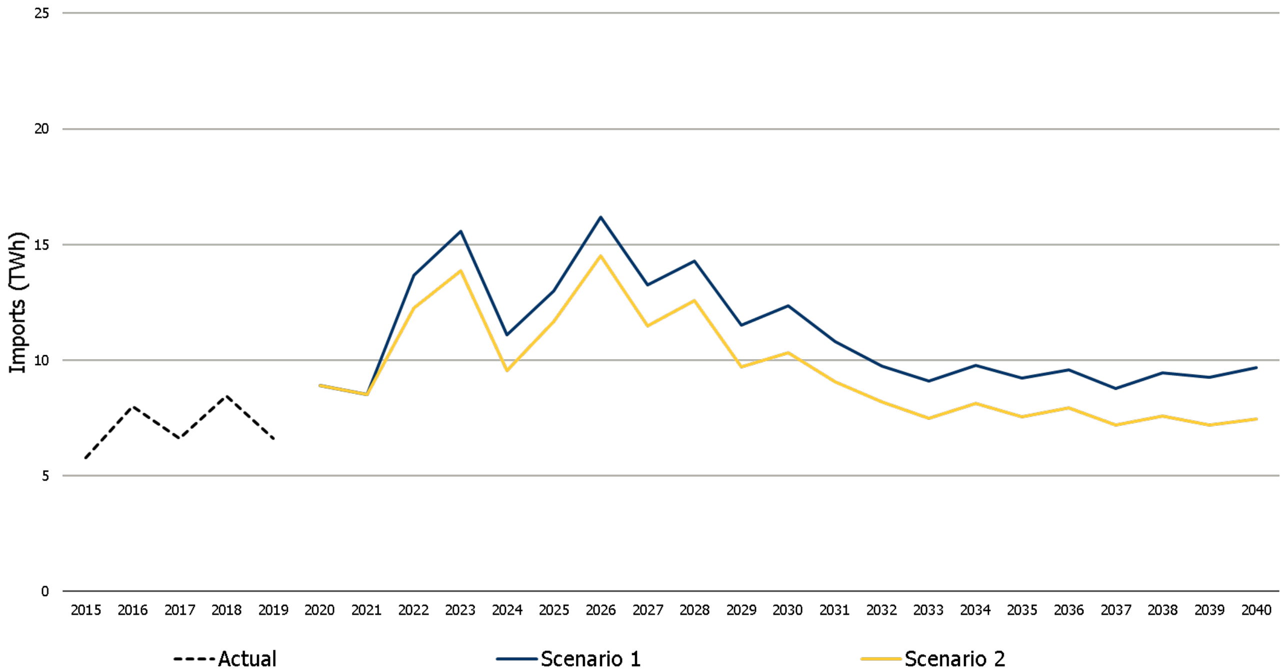
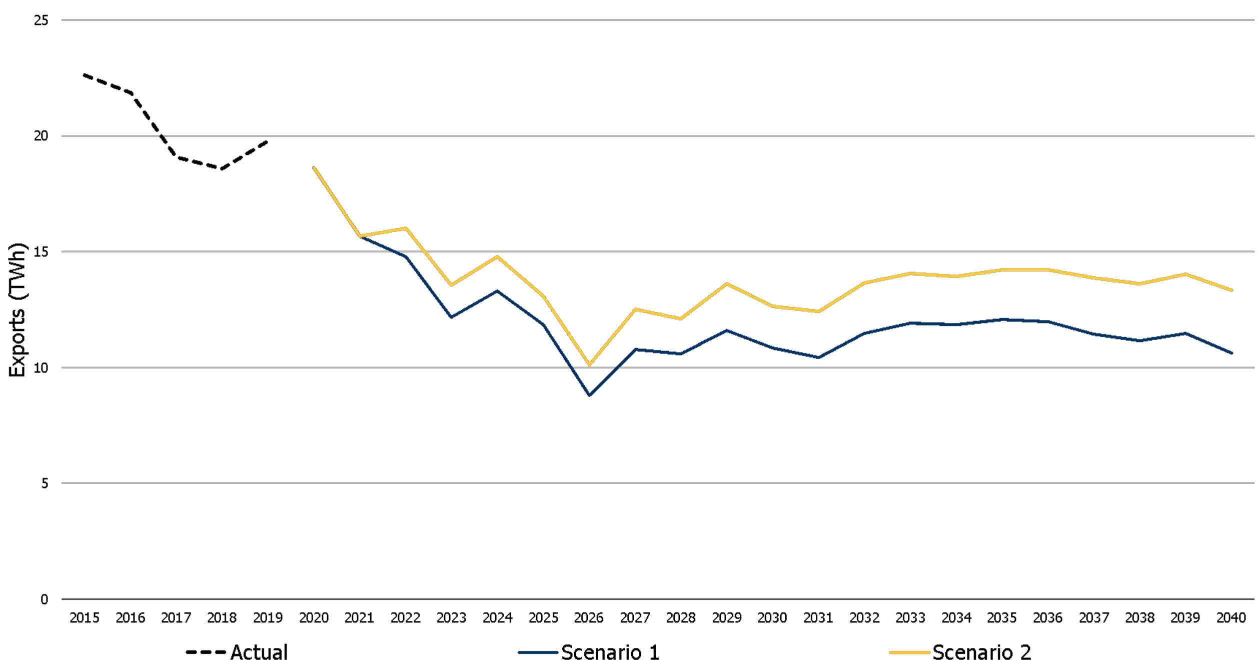


Figure 27 | Energy Production Outlook, Exports[24]



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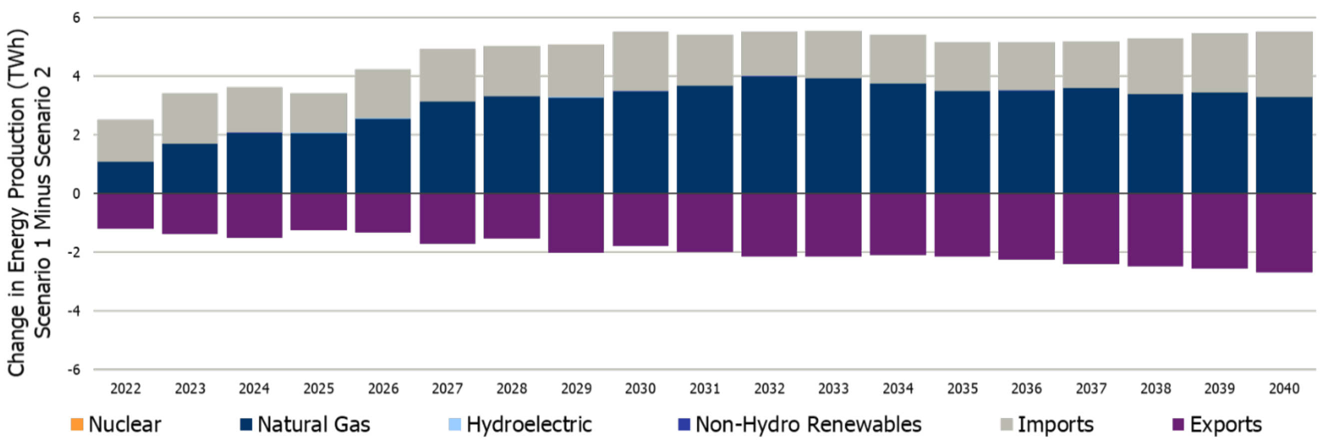
[23] For 2020 and 2021, the 2019 APO forecast values are shown.

[24] For 2020 and 2021, the 2019 APO forecast values are shown.

In Scenario 1, demand recovers to pre-pandemic levels in 2022 and steadily grows faster than previous forecasts. In Scenario 2, demand is expected to reach pre-pandemic levels in 2024. Electricity demand levels grow more slowly, with demand up to 8.2 TWh lower than that in Scenario 1 over the outlook period. This decreased demand leads to differences in the energy production outlook between the two cases. Scenario 2 sees decreased production from Ontario-based gas-fired generators, as well as fewer imports and more exports. Production from nuclear, hydroelectric, wind and solar resources is unchanged. This is illustrated in Figure 28.

Figure 28 | Change in Energy Production Outlook Between Scenario 1 and Scenario 2



Cost and emission outcomes from the energy production outlook, including avoided costs and emissions resulting from energy efficiency, are discussed in Chapter 7.

3.5 Fuel Security Considerations

Ontario has a diverse fuel mix, with nuclear and hydroelectric resources providing the majority of energy through the planning horizon. During the 2020s, nuclear refurbishments and the Pickering NGS retirement are projected to increase capacity factors of the combined cycle gas fleet to the 40 to 60 per cent range. As the fuel mix evolves through this period, interdependencies between the gas and electric systems will need to be monitored.

Fuel security risk reflects the possibility that thermal units will not have or be able to get the fuel (primarily natural gas) required to run. This could be due to the season (i.e., during winter, generating capacity may become unavailable due to priority demand for natural gas from building space heating), unexpected pipeline outages, or because increased utilization of the gas fleet creates uncertainty about whether power plants can arrange for fuel when needed.

Natural gas pipelines can become constrained during peak pipeline conditions, potentially limiting the use of natural gas-fired generation to meet Ontario's supply needs. Gas-fired generation is typically fuelled using just-in-time transportation and delivery with limited storage, and might be subject to interruption, depending on the gas delivery product. In constrained natural gas markets, these units may not be served during peak pipeline conditions. Natural gas pipeline constraints have serious implications for reliability and price volatility. Power generation facilities can mitigate these risks through the use of adequate firm transportation and storage capacity.

Fuel deliverability is of concern relative to the operating reliability of the infrastructure that delivers natural gas to the generating stations. In some areas, deliverability to the generation fleet is limited during winter months due to higher demand from space heating. As such, the risk of unavailability needs to be factored into the evaluation of the overall operational and planning reliability of the electricity system.

Following the Pickering NGS retirement and during the nuclear refurbishment period, incremental energy needs will be met primarily by the increased utilization of the gas fleet. Ontario currently benefits from having a diverse supply mix with no one dominant fuel source. With existing resources, fuel security is not expected to be a concern over the outlook as Ontario has robust gas supply. However, it will be important to consider fuel security in long-term planning as the demand and supply outlook evolves and as new resources enter the market.

4. Transmission Security

Under certain supply and demand conditions, transfer capability may become constrained between 2025 and 2030 along three major interfaces: Flow East Towards Toronto (FETT), Flow Into Ottawa (FIO) and Buchanan Longwood Input (BLIP).

Planning is underway in these areas to identify preferred solutions to address needs. Solutions must consider the impacts on reliability and security for local customers, and the broader impacts on resource adequacy resulting from potential changes to zonal transfer limits.

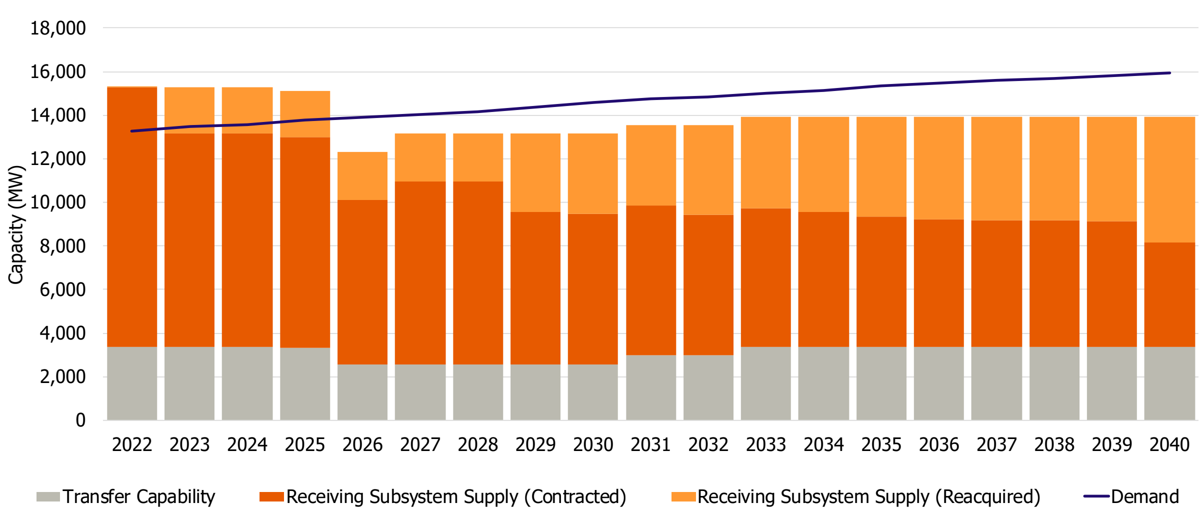
4.1 Transmission Outlook

Beyond meeting the provincial resource adequacy needs described in Chapter 3, capacity may need to be sited within specific zones to meet transmission planning standards. This transmission outlook focuses on the FETT, FIO and BLIP interfaces, since limitations to deliver power over these interfaces may result in additional requirements to site capacity in specific zones, over and above what was discussed in Section 3.2.1. To illustrate the need for local capacity, in each of the outlooks below, peak demand in the zones/subsystem that receive power from the interface under study is shown; this peak demand is compared to the amount of generation in the zones/subsystem and/or electricity transferred by the interface. The local supply need is the difference and will be referred to as the transmission security requirement.

4.1.1 Flow East Towards Toronto

Figure 29 illustrates the outlook for the system east of the FETT interface with respect to transmission security requirements.

Figure 29 | FETT Security Outlook



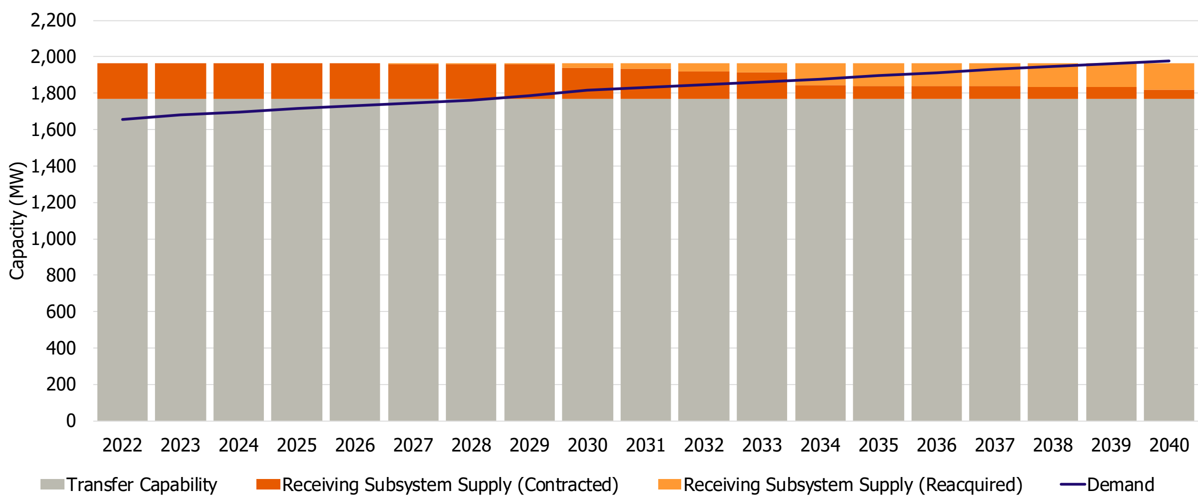
The FETT security outlook shows:

- If resources with expiring contracts are not re-acquired, a need for additional or reinforced capacity to supply the east of FETT portion of the system emerges, beginning with approximately 300 MW in 2023
- If resources with expiring contracts are re-acquired at the end of their contract terms, a need for additional or reinforced capacity to supply the east of FETT portion of the system of approximately 1,600 MW emerges in 2026
- This need for additional or reinforced capacity persists throughout the planning horizon, and increases, depending on demand growth and the future of firm supply resource acquisition. Proposed upgrades to address this need are described in Chapter 6.2.2.1.

4.1.2 Flow Into Ottawa

Figure 30 illustrates the outlook for the system east of the FIO Interface (Ottawa Zone) with respect to transmission security requirements.

Figure 30 | FIO Security Outlook



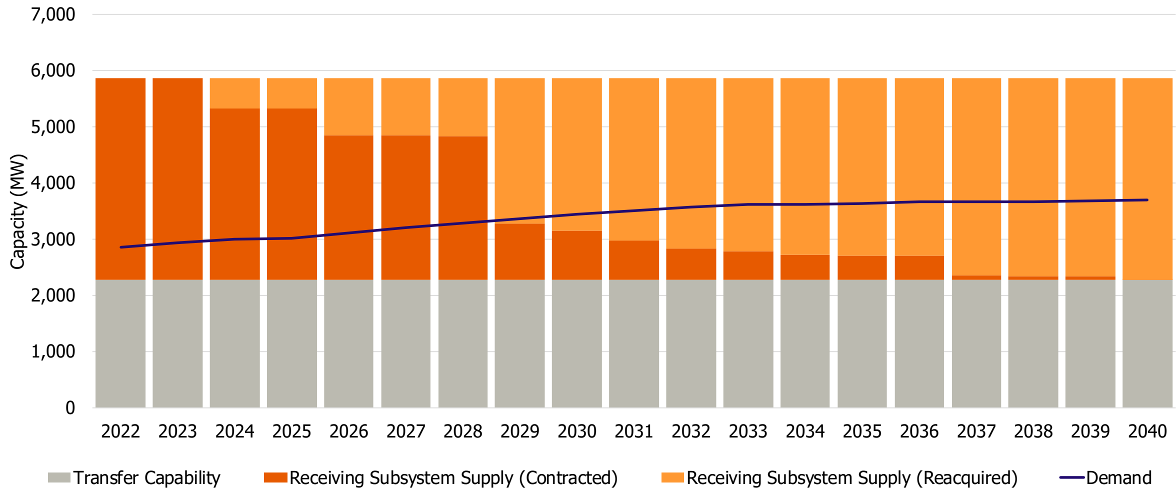
The FIO security outlook shows:

- The existing system is marginally secure
- A need for additional or reinforced capacity to supply the Ottawa Zone is highly sensitive to local demand scenarios, and is currently expected to emerge near the end of the planning horizon

4.1.3 Buchanan Longwood Input

Figure 31 illustrates the outlook for BLIP with respect to transmission security requirements.

Figure 31 | BLIP Security Outlook



The BLIP security outlook shows:

- A transmission security need in the West Zone may emerge in 2029, if resources with expiring contracts are not considered to be re-acquired
- Demand in the West Zone is largely driven by agricultural growth in the area, as described in Section 1.3.4.

5. Integrating Electricity Needs

Summer capacity needs continue to emerge through 2022 and, with continued availability of existing resources, these needs can be met until 2024. The capacity need eventually becomes an energy need that is fairly dense, driven by resources with contracts expiring in the late 2020s and early 2030s.

From a locational requirement, the Pickering NGS retirement and the Darlington refurbishment result in summer zonal capacity needs emerging in the mid-2020s in the GTA and eastern Ontario. Generation reaching the end of contract in the West Zone, along with significant growth in the agricultural sector in the Windsor-Essex and Chatham area, results in a zonal capacity need over the mid to long term. Load growth in the Ottawa area will contribute to a marginal capacity need in the Ottawa Zone over the medium term.

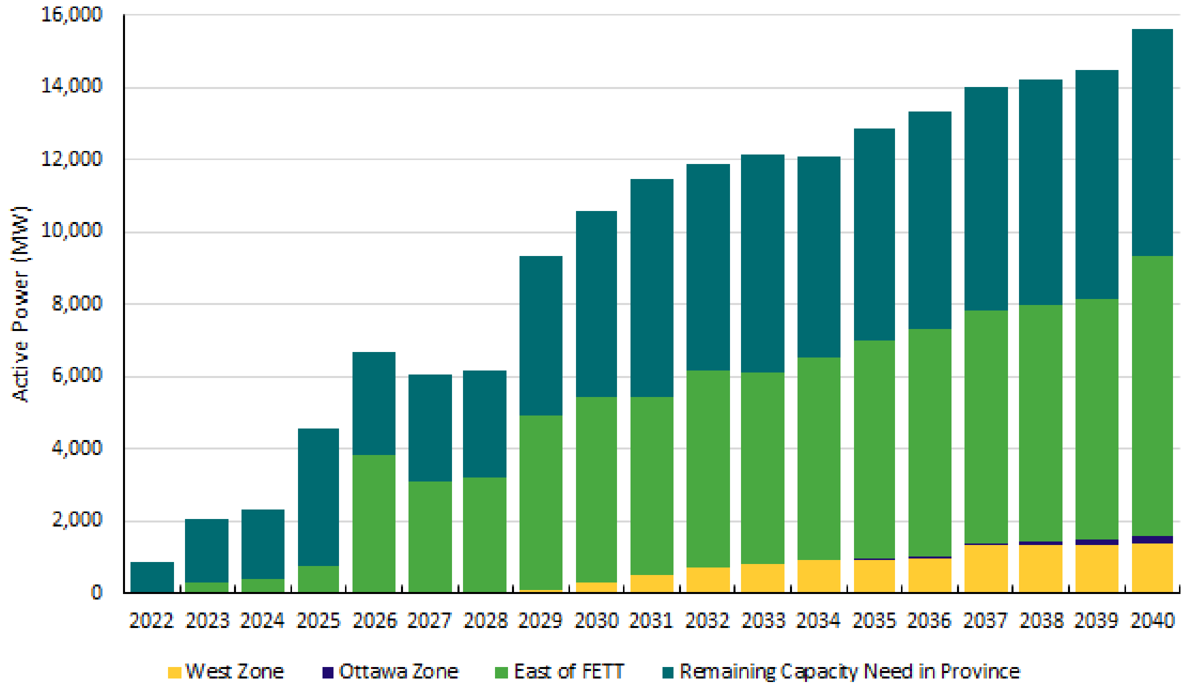
5.1 Overview

Chapter 3 and Chapter 4 presented the resources required to meet provincial resource adequacy and transmission planning standards. This chapter highlights the major outcomes and findings of those chapters, summarizing the magnitude of Ontario's needs, and when and where those needs occur.

5.2 Capacity Needs

Figure 32 summarizes the capacity need without considering re-acquisition of contracted resources once their term expires for Scenario 1, including the locational requirements arising from the need to meet transmission planning and resource adequacy standards.

Figure 32 | Scenario 1 - Summary of Summer Capacity Needs including Locational Requirements, without Continued Availability of Existing Resources[25]



The significant increase in the capacity need emerging in 2023 is primarily due to Lennox GS reaching the end of its contract term. In the 2024-2025 period, Pickering NGS is expected to retire. The nuclear refurbishment program will continue through the 2020s and into the 2030s, with between two- and four- nuclear unit refurbishments taking place concurrently during the summer until 2026. Over the next two decades, the majority of contracts with natural gas-fired and renewable generation are expected to expire. Continued availability of existing resources can address needs until 2024, after which incremental resources are required. Most of Ontario's natural gas-fired generation facilities are located in the West Zone and Toronto Zone. Less significant than Ontario's changing supply outlook, but still important, is that, in both Scenarios 1 and 2, the forecast growth in demand over the planning horizon contributes to capacity needs.

As Lennox GS, Pickering NGS and Darlington NGS are all located east of the FETT interface, the majority of Ontario's capacity needs are expected to emerge east of the FETT interface. Contracted natural gas-fired generation reaching the end of contract in the Toronto Zone exacerbates capacity needs east of the FETT interface. This results in a need to acquire new resources or re-contract existing resources east of FETT; or reinforce the interface and acquire new resources or re-contract existing resources west of FETT. Section 6.2.2.1 outlines the IESO's current planning activities to address capacity needs east of FETT.

[25] As the Ottawa Zone is located east of FETT, any additional capacity in that zone would contribute towards the amount required east of FETT.

Load growth in the Ottawa area will contribute to a marginal capacity need in the Ottawa Zone over the medium term. Plans to address asset replacement needs of existing infrastructure supplying eastern Ontario and ensure adequate supply to the Ottawa and Peterborough area will impact the future capability of the FIO interface. Section 6.2.2.2 outlines the IESO's current plans to address asset and reliability needs in eastern Ontario, specifically along the Gatineau transmission corridor.

Generation facilities reaching the end of their contracts in the West Zone result in a zonal capacity need over the mid to long term. Significant load growth in the Windsor-Essex and Chatham area in the agricultural sector is also contributing to this capacity need. Local constraints impacting the Windsor-Essex and Chatham area are common and restrict the ability to transport power into the entire West Zone. As a result, plans and acquisitions to support the Windsor-Essex and Chatham regional supply are closely linked to supply needs in the entire West Zone, and coordinated planning is being conducted in this area. Section 6.2.2.3 outlines the IESO's current plans to address the Windsor-Essex and Chatham area needs.

6. Meeting Electricity Needs

Supply, transmission, imports, distributed energy resources, storage and energy efficiency are all ways to meet the needs identified in the previous chapter.

In anticipation of future capacity shortfalls, the IESO will work with stakeholders through its Resource Adequacy engagement to enable a framework of competitive mechanisms to meet Ontario's resource adequacy needs in the short, medium and long term.

Reinforcing the transmission system can also address reliability needs and improve access to resources located within a transmission-limiting part of the system.

6.1 Overview

The APO is a technical document that describes the current demand, supply and transmission outlook, identifies future system needs, and highlights areas that may require greater attention.

This chapter presents a qualitative discussion of ways in which Ontario can meet its electricity needs. Depending on the location of these resources, transmission expansion may also be required to ensure resources are able to supply demand where needed.

6.2 Meeting Capacity Needs

Chapter 5 discussed Ontario's electricity needs from the perspective of resource adequacy and transmission security. Some of the needs identified can be met by the continued availability of existing Ontario resources once their contracts expire. Expansion of transmission may still be required to address transmission security needs within the next five years. Investment in increased zonal transfer capability, can also help address capacity needs by enabling resources located elsewhere to contribute towards resource adequacy needs. Firm and non-firm imports, distributed energy resources, storage and energy-efficiency can also provide benefits.

6.2.1 Continued Availability of Existing Ontario and New Resources

The extent to which resources with expired contracts/commitments will remain available depends on a number of factors, including asset age and condition, the need for capital investment, market conditions, and available acquisition tools. The IESO will work with stakeholders through its Resource Adequacy engagement to implement a framework of competitive mechanisms to meet Ontario's resource adequacy needs in the short, medium and long term. There are resources that are coming off contract over the next five years that impact the reliability and flexibility of the system due to their geographic location and capacity contribution to the system. Lennox GS contract will expire at the end of 2022. This resource is critical to system reliability due to its position in relation to the Greater Toronto Area load centre and the flexibility it provides for the electricity grid. With limited competition of resources to address needs, the IESO will be negotiating an extension of the Lennox GS contract as a transition measure until there is sufficient uncommitted capacity later in the decade for it to compete with. Figure 33 and Figure 34 illustrate the summer and winter capacity surplus and deficit, and the need that can be met with continued availability of existing resources.

Figure 33 | Summer Capacity Surplus/Deficit, with Continued Availability of Existing Resources

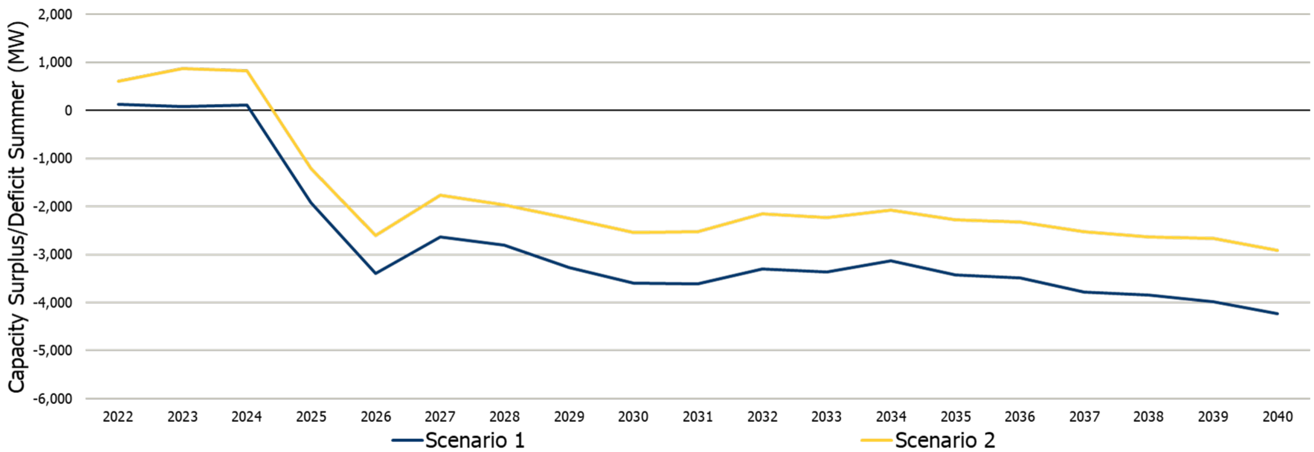
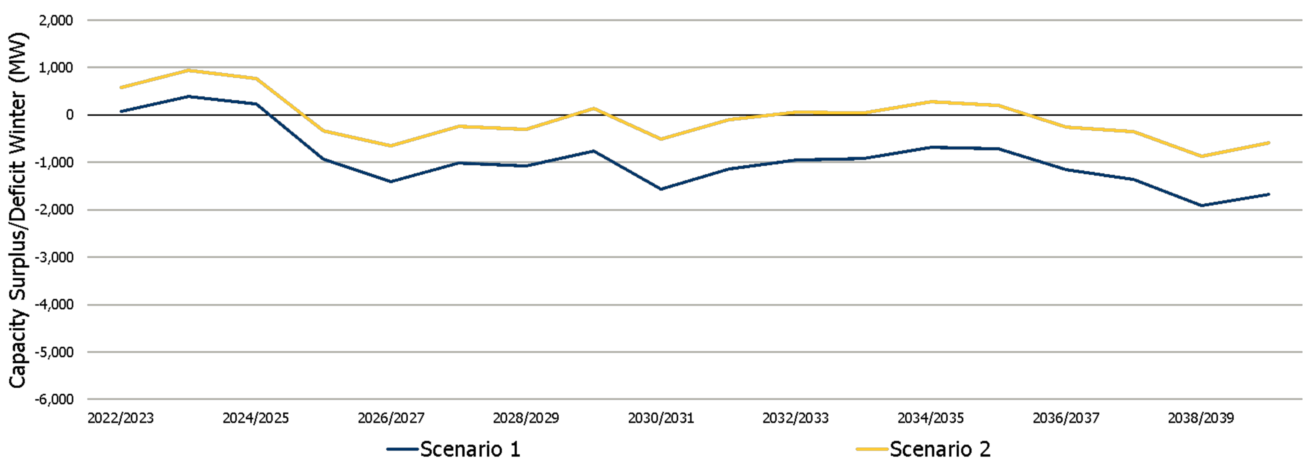


Figure 34 | Winter Capacity Surplus/Deficit, with Continued Availability of Existing Resources



6.2.2 Transmission Expansion

A number of transmission studies are currently underway to identify preferred solutions to address potential transmission reliability needs. Since the outcomes of these studies may affect interface transfer capabilities, they can impact provincial and local capacity adequacy. Reinforcing or expanding the transmission system is generally undertaken to address a local or zonal reliability need, or to improve access to resources located within a transmission-limiting region. The studies below have been selected as they are able to meet the transmission security and zonal adequacy needs identified earlier.

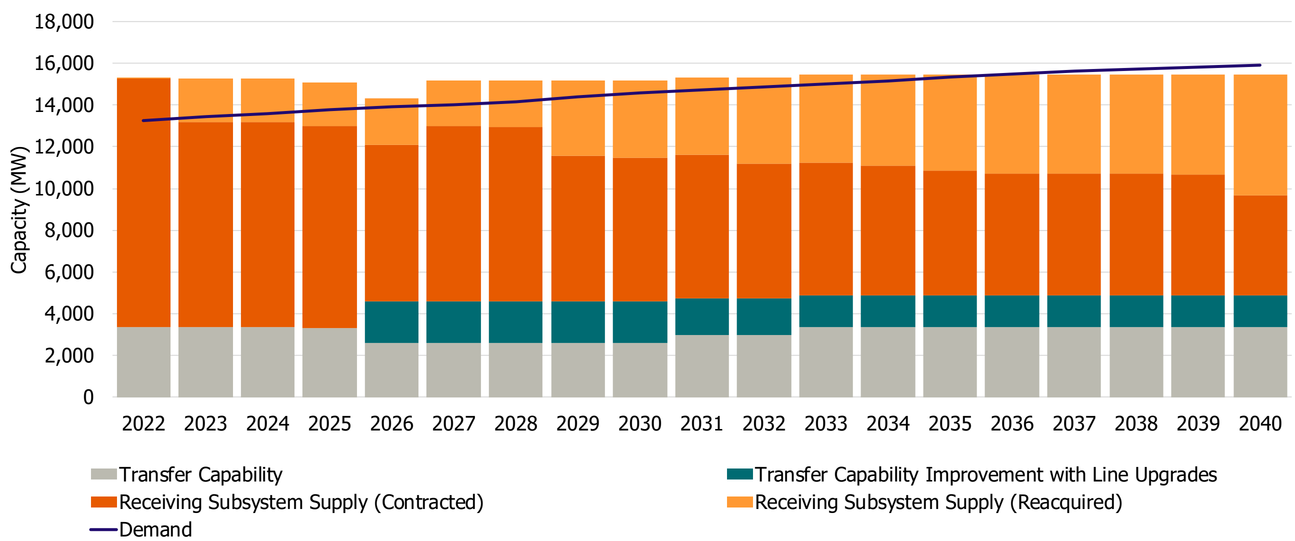
6.2.2.1 Planning for the FETT Transfer Capability Need

The FETT interface is located at the boundary between the Southwest and Toronto and Essa Zones. As described in Chapter 5, a significant amount of capacity must be sited east of the interface over the outlook period due to constraints on the FETT interface. Transmission enhancements that increase the transfer capability along the limiting section of FETT would reduce the amount of capacity that must be sited in that part of the province.

FETT transfer capacity can be increased by approximately 2,000 MW through an upgrade to a section of the Trafalgar TS x Richview TS 230-kV lines at an estimated cost of $50M and with an implementation timeline of four to five years. The IESO has requested that Hydro One carry out development work to confirm project feasibility and provide an updated cost estimate.

The resulting security outlook with this line upgrade is shown in Figure 35.

Figure 35 | FETT Security Outlook following Line Upgrade



The proposed line upgrade is a flexible solution, in that additional transmission upgrades to further increase transfer capability across FETT can be incorporated in a staged manner at a later date. While not currently anticipated in the near to medium term, the need in the second stage may be triggered depending on future resource acquisitions or other bulk and local transmission needs.

6.2.2.2 Planning for the Ottawa Zonal Supply Capacity Need

The need to address the Ottawa zonal supply capacity is currently being reviewed as part of the Gatineau Corridor End-of-Life Study. The major transmission corridor in eastern Ontario, the Gatineau Corridor consists of five transmission lines that total approximately 1,300 km, and run roughly between Pickering and Ottawa. Large portions of the corridor (many over 80 years old) will reach their end of life in the late 2020s, and refurbishment or decommissioning options will impact the FIO transfer capability, which is critical to the supply of the Ottawa Zone.

Without these circuits, the reliability of bulk and regional supply, generation incorporation, and imports from Quebec would be greatly impacted. However, even with the refurbishment of these circuits, the transmission system in eastern Ontario requires reinforcement to meet new needs, including the security of the bulk supply to the Ottawa region (FIO) in the medium term, a near-term requirement to improve supply to the Peterborough area and the ability to meet growing load demand in west Ottawa.

Since the need to refurbish the existing transmission facilities arises in the late 2020s, an integrated plan to address end-of-life and reliability needs is required in the near term (as any new transmission facilities recommended as part of the plan could require five to seven years of lead time).

The final recommendations for the Gatineau Corridor End-of-Life Bulk Study are expected to be complete by Q2 2021.

6.2.2.3 Planning for the West Zonal Supply Capacity Need

The BLIP interface is located between the boundaries of the Southwest and West Zones. As described in Chapter 5, capacity needs to be sited in the West Zone by 2029.

Further, there is a local need, not discussed in this report, to site capacity west of Chatham (a sub-region of the West Zone) to address limitations of interfaces within the West Zone. While the BLIP interface limits supply to the West Zone, interfaces within the West Zone further limit supply to pockets of load behind the BLIP interface. This need for local supply west of Chatham was not discussed earlier in this report, but is relevant because simultaneously considering both the local supply need west of Chatham and zonal supply need in the larger West Zone may lead to a lower-cost solution.

As such, the ongoing West of London Bulk Study that is underway to address the local supply need west of Chatham will also consider the need and options to increase BLIP transfer capability. In addition, the bulk study will:

- Ensure the bulk transfer capability to supply significant greenhouse growth forecast in the Kingsville-Leamington and Dresden areas in the near to mid term (2020-2035)
- Enable existing resources to operate efficiently for local supply and system adequacy to the rest of Ontario
- Maintain existing interchange capability on the entire Ontario-Michigan interconnection in Windsor and Lambton-Sarnia
- Address operability concerns related to the increasing complexity of the interim measures required to connect more loads in advance of transmission reinforcement

In fall 2020, a set of short-listed transmission, generation and storage options were developed, focusing on the first two near-term needs specified above. More information on the project can be found on the Southwest Ontario Bulk Planning web page. Information on engagement sessions (both those held to date and planned), can be found on the Windsor-Essex Regional Planning web page.

The final recommendations for the West of London Bulk Study are expected to be complete by the end of Q1 2021.

6.2.3 Imports and Interconnections

Electricity imports, either firm or non-firm, can help meet the need for capacity.

Firm imports are the result of a contractual agreement guaranteeing a reliable amount of imports when needed. The IESO currently has a firm import agreement with Quebec, with 500 MW of summer capacity to be delivered when requested before 2030. Non-firm imports are assumed capacity contributions from expected flow through the interties during peak periods that are not backed up with firm capacity contracts.

Enabling capacity imports from neighbouring jurisdictions will provide access to non-domestic resources that would reduce the need for additional capacity in Ontario. Firm imports can take three forms: system-backed, where the capacity is ensured by an entire power system (e.g., a province or state); portfolio-backed, where the capacity is ensured by a collection of resources; and resource-backed, where the capacity is being provided by a specific resource in another jurisdiction. The IESO is enabling firm imports for system-backed resources through its capacity auction and is investigating options for resource-backed imports.

Non-firm imports are currently not considered in the capacity assessment. As part of its Reliability Standards Review, the IESO is proposing a methodology for including some amount of non-firm imports in future resource adequacy assessments. The inclusion of non-firm imports is expected to reduce overall resource requirements.

In Ontario, the failure of the phase angle regulator (PAR) – a specialized transformer that alters power angle to control the flow of power – connected to the Ontario-New York 230-kV circuit L33P in early 2018 continues to hinder the province's ability to import electricity from New York through the New York-St. Lawrence interconnection and from Quebec through the Beauharnois interconnection. This has required enhanced coordination with affected parties and more focused management of St. Lawrence-area resources in real-time. Careful coordination of transmission and generation outages will continue to be required in the area.

PARs are unique pieces of equipment and replacements are not readily available. Replacement options for the unit are being investigated by the IESO, in conjunction with Hydro One, the New York Independent System Operator and the New York Power Authority. The replacement will provide greater flexibility to control both current and future intertie flows with New York. The return-to-service date is expected to be between March 2022 and March 2023.

6.2.4 Distributed Energy Resources

Most of Ontario's generation is connected to the high-voltage transmission system, but a growing number of smaller resources are connecting at the distribution level. Distributed energy resources (DERs) can provide an opportunity for the IESO to address future energy and capacity needs if they are effectively integrated into the IESO-administered markets (IAMs). Over 34,000 DERs are currently under contract with the IESO, the majority of which are small-scale solar projects, contracted through the microFIT program.[26] With the potential for further deployment of these resources in the province, DERs can be harnessed to reduce system costs, improve reliability, and enhance resilience.

The IESO is examining potential models to expand DER participation in the IAMs and identifying challenges and next steps through two white papers – one that looks at conceptual models for DER participation and the other that assesses the merits of various options to enhance participation in Ontario.[27] Following publication of the second paper in November 2020, the IESO will clarify next steps for DER integration, including potential market enhancements and demonstration opportunities, through the development of a DER roadmap/vision.

As outlined in integrated regional resource plans, communities and customers have been exploring opportunities to meet their own regional electricity system needs with DERs and community-based solutions. The IESO, with support from NRCan and Alectra Utilities, is undertaking a demonstration project in York Region to explore market-based approaches to secure energy and capacity services from DERs for local needs, while coordinating across the electricity system. This will allow the IESO to better understand the potential of using DERs in place of traditional infrastructure by enabling them to operate in real-world applications. The IESO is also exploring how DERs can contribute to meeting local and system needs in areas with rapidly growing greenhouse load through projects supported by the Grid Innovation Fund.

6.2.5 Storage

In September 2020, the IESO marked the conclusion of its Storage Design Project (SDP) with the publication of the long-term design vision for energy storage. Interim Market Rule amendments, set to take effect in Q1 2021, will clarify the opportunities for storage in today's IAMs. The IESO is also committed to updating the interim Market Rules and Market Manuals for storage in advance of the Market Renewal Program go-live date to ensure the progress made through the SDP endures. The IESO is reviewing the potential for further storage enhancements alongside other market development opportunities as part of its business planning process.

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[26] The microFIT program consists of over 31,000 contracts and represents about 260 MW.

[27] These papers are part of the IESO's Innovation and Sector Evolution White Paper Series, included in the Innovation Roadmap work plan, released in 2019. The IESO's white paper series aims to deepen the understanding of emerging economic, technical, environmental and social issues that could transform the future of the electricity markets in Ontario.

6.2.6 Energy Efficiency

Additional energy-efficiency programs, beyond those described in Section 1.3.8, can help meet future capacity needs by reducing electricity demand. The 2019 Conservation Achievable Potential Study (APS) identified cost-effective electricity savings attainable through energy-efficiency programs between 2019 and 2038. The APS identified potential peak demand[28] savings of 2,000 to 3,000 MW in 2038[29] and energy savings of 18 to 24 TWh in 2038, two to three times more than the savings included in the APO demand forecasts. The opportunity for increased energy-efficiency savings will be considered as part of the mid-term review of the 2021-2024 CDM Framework and through the development of future CDM Frameworks.

6.3 Bulk Planning Process Development

During a review of system planning activities, the IESO recognized a need to increase transparency and predictability in the development of power system plans. In response, the IESO is undertaking an initiative to formalize the bulk system planning process to move to a more consistent approach to identifying and addressing needs.

This renewed process will enable more consistent forecasting and reporting on system conditions to identify bulk power system needs, provide transparent signals to the market, and enable sector participants to plan ahead, prepare for, and participate in solutions. The bulk system planning process will help ensure solutions are identified transparently as needs materialize, opportunities for integrated solutions are pursued, and analyses are carried out as efficiently as possible.

A stakeholder engagement meeting was held in November 2020 to provide information on the status of the Bulk System Planning Process review. More information on the initiative can be found on the Bulk System Planning Process webpage.

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[28] Peak demand potential in the APS study is defined as the average demand reduction during the period from 1 p.m. through 7 p.m. on non-holiday weekdays in June, July and August as per the IESO Evaluation, Measurement and Verification Protocols.

[29] The potential for savings is based on the cumulative adoption of measures over time (e.g., savings in 2038 represent the potential savings in 2038 of measures adopted in 2019 through 2038).

7. Outcomes and Other Considerations

Both the marginal cost of electricity production and electricity sector emissions are forecast to increase over the outlook period, as a result of growing demand, nuclear refurbishments and retirements, and the resulting increase in the use of Ontario's gas-fired generation fleet. In spite of increasing sector emissions, electricity remains a source of low-carbon energy in Ontario, and increased electrification of emissions-intensive sectors provides an opportunity to reduce province-wide emissions.

The results presented in this chapter are outcomes of the energy production outlook described in Section 3.4 and are based on the supply mix discussed in Chapter 2, which reflects the continued availability of existing resources following the end of their contract term or commitment. Should the supply mix change over the outlook period, the outcomes described below would also change.

7.1 Marginal Resources and Their Importance

Long-term power system plans use an economic dispatch model that schedules resources to meet system needs based on least cost. This considers each resource's production or variable costs, which typically include fuel costs and variable operating and maintenance costs. The most expensive resource scheduled is the marginal resource. This is important because costs associated with the marginal resource provide an indication of market price. This model is not meant to forecast prices but, given future conditions, the marginal resources scheduled indicate trends in energy production from different resources.

Supply resources are categorized as baseload (operating essentially constantly, e.g., nuclear), dispatchable (operating as needed, e.g., gas), or intermittent (operating when fuel is available, e.g., wind or solar). The variable cost required to produce a unit of energy is referred to as the production cost and typically consists of fuel costs, carbon costs, and variable operating and maintenance costs. Usually, baseload and intermittent resources have lower marginal energy costs than dispatchable resources.

The IESO strives to ensure Ontario's energy needs are met at the lowest cost. Resources are generally dispatched from lowest-production-cost baseload to higher-production-cost dispatchable resources that can adjust their output according to fluctuations in demand or supply of baseload and intermittent electricity.[30]

Marginal resources provide the next unit of energy needed on the system. For example, during the peak demand hours of hot summer days, the marginal resource is usually a natural gas-fired generator; overnight during autumn, gas-fired generation is less likely to be the marginal resource.

[30] Factors such as congestion or security constraints can lead to scenarios where this generalization does not hold.

7.2 Marginal Costs

The data underpinning this outlook are based on an economic dispatch model that simulates each hour of the outlook period. This model dispatches units in order of their production costs and identifies the marginal resource in each hour. The marginal cost in each hour is the production cost of the marginal resource.

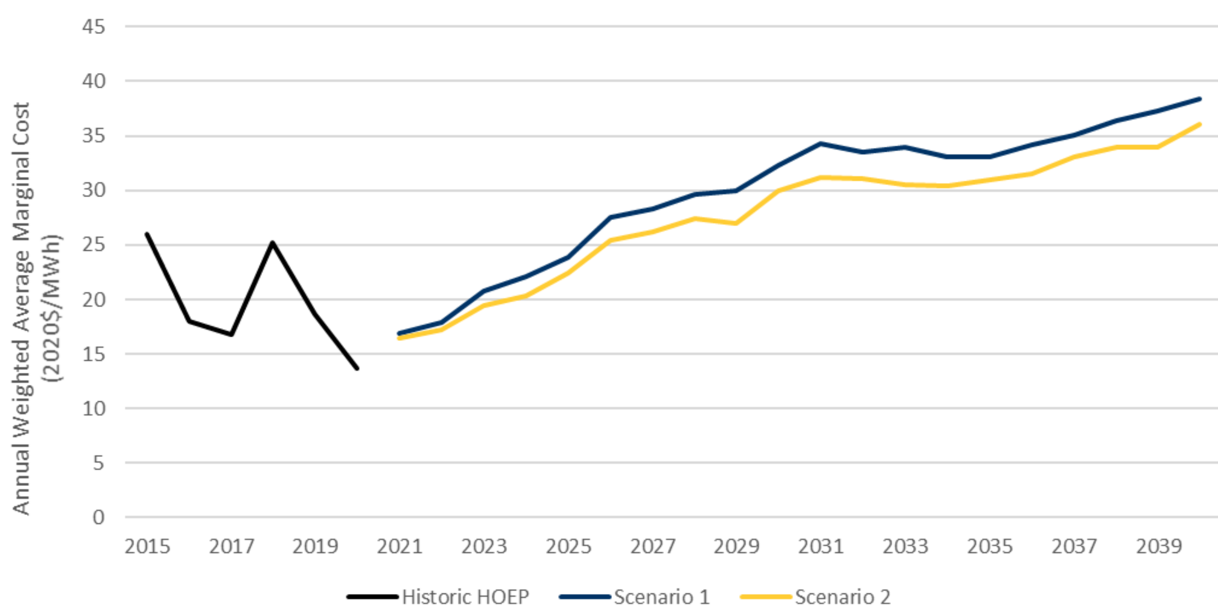
Marginal costs are not intended to be a forecast of market prices, such as the Hourly Ontario Energy Price or locational marginal prices, but can provide a directional indicator of where these prices may head over the outlook. Market prices are the wholesale prices for electricity and can differ widely due to market participant behaviour, congestion and other factors.

Marginal costs provide the trajectory of market prices. When a fundamental change to the supply mix occurs – such as the retirement or refurbishment of nuclear units – marginal costs illustrate the expected impact on the factors underpinning market prices as other higher-marginal-cost resources would need to be dispatched to meet load requirements. They provide an indication of the change in production costs due to variations in both supply and demand.

With the refurbishment of nuclear units and demand increases in the long term, marginal costs are expected to increase as gas-fired generation becomes the marginal resource more often.

Figure 36 illustrates the weighted average marginal costs forecast and the historical HOEP. The average marginal costs can also be found in the data tables.

Figure 36 | Weighted Average Marginal Costs Forecast, and Historical HOEP[31]



[31] 2020 Actual HOEP is year-to-date as of November 26, 2020

7.3 Carbon Pricing

Currently, the electricity sectors in Ontario and in neighbouring jurisdictions are subject to carbon pricing. This section details the carbon pricing policies currently in effect within the northeastern portion of the Eastern Interconnection, and how carbon pricing was modelled for this outlook.

Ontario imports from and exports to its five neighbours every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity.

The carbon pricing assumptions used in this outlook are based on the federal carbon pricing backstop, which was effective in Ontario as of January 1, 2019. The Ontario government recently announced a transition to a made-in-Ontario Emissions Performance Standards (EPS) program as an alternative to the federal output-based pricing system (OBPS); future editions of this report will reflect this change in carbon pricing policy.

The federal backstop has two components: the carbon levy applied to fossil fuels (effective April 1, 2019) and the OBPS for industrial facilities (effective January 1, 2019).

The OBPS applies a regulatory charge above an industry-specific benchmark emission rate for emission-intensive, trade-exposed (EITE) industry. The federal government considers the electricity sector as EITE and, as such, applies a benchmark emission rate to the sector for large emitters (those exceeding the threshold, with voluntary opt-in).

Having a benchmark applied to the electricity sector means there will be no charge associated with emissions up to a specific rate based on fuel type (e.g., 370 t CO_2e/GWh for natural gas). As such, the carbon pricing applied with the OBPS acts as a pro-rated carbon price. As different gas-fired generation facilities have different emission rates, each facility will be charged an amount based on its emissions and electricity production, leading to facility-specific carbon pricing. In order to more accurately forecast the impact of carbon prices on trade, the IESO has modelled the carbon pricing policies applied in neighbouring jurisdictions where there is a material impact on electricity sector emissions.[32] These include Nova Scotia,[33] New Brunswick,[34] and parts of the United States through the Regional Greenhouse Gas Initiative.[35]

7.4 Greenhouse Gas Emissions

Electricity sector emissions are forecast to increase to 12.2 megatonnes CO_2e by 2030 in Scenario 1 and 10.9 MT CO2e in Scenario 2, still well below 2005 levels, as shown in Figure 37. This expected increase is due to reduced nuclear production and growing demand, resulting in increased production from gas-fired generation.

---

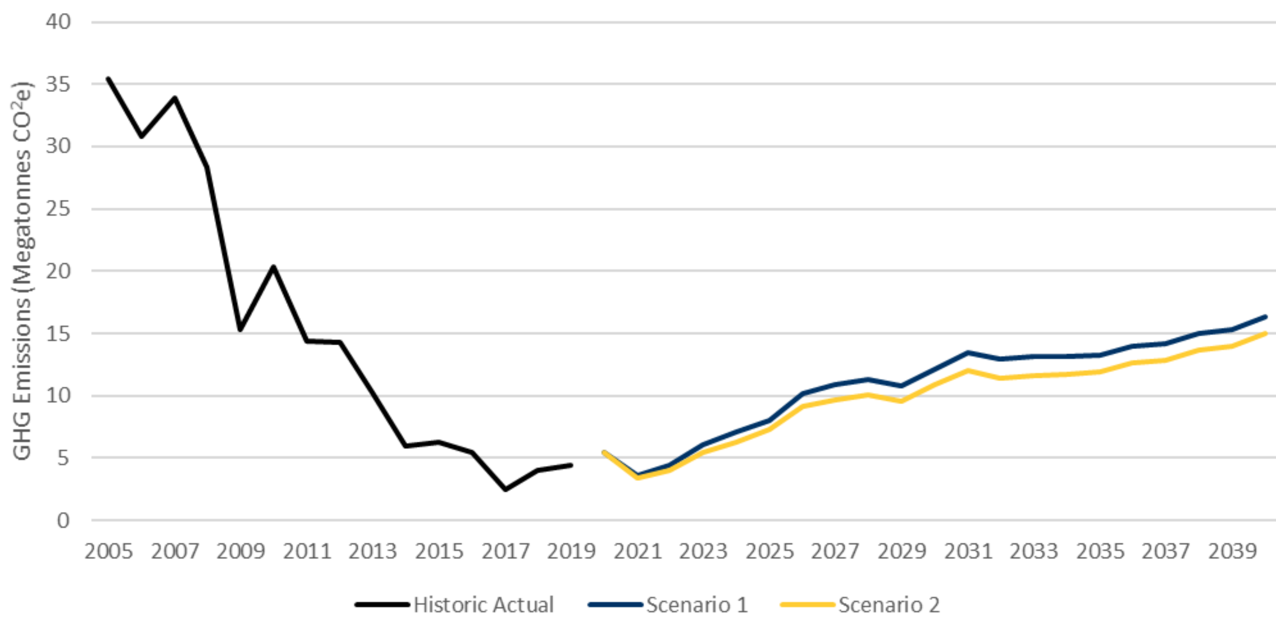
[32] Although carbon pricing is in effect in Manitoba and Quebec, these jurisdictions are considered essentially non-emitting.

[33] Nova Scotia's cap-and-trade program took effect January 1, 2019. More information is available at Nova Scotia's Cap-and-Trade Program.

[34] The federal output-based pricing system was in effect in New Brunswick as of January 1, 2019. For more information, see the Regulations Amending Part 1 of Schedule and Schedule 2 to the Greenhouse Gas Pollution Pricing Act.

[35] For more information, see the Regional Greenhouse Gas Initiative, currently in effect in 10 northeastern states.

Figure 37 | Electricity Sector Greenhouse Gas Emissions, Historical and Forecast[36]



An increase in electricity sector emissions does not necessarily mean an increase in economy-wide emissions. The carbon intensity of electricity remains far below that of other fuels, such as gasoline for automotive transportation or fuel oil for space heating. Switching from higher-emission fuels to low-carbon electricity could increase electricity sector emissions, while reducing province-wide emissions. As electricity consumption increases, the attendant rise in electricity sector emissions could be reduced by increased energy efficiency, or the entry of non-emitting resources (if successful) to the Ontario market.

7.5 Avoided Costs

The IESO's avoided-cost analysis considers the avoided energy and capacity costs from a reduction in demand. These avoided costs are considered benefits, and can be compared to the cost of other measures that would reduce demand. Any measures that are implemented should be cost-effective and lead to lower overall customer costs.

Marginal costs are used to estimate the avoided costs associated with changes in electricity consumption. To understand the impact of avoided generation, the hourly profile of the measures being considered is compared to the hourly profile of marginal costs.

In the near term, Ontario will have an abundance of resources with low production costs, meaning few system costs can be avoided.

In the medium and long terms, however, increased system costs can be avoided due to increased demand, decreased nuclear generation, and increased gas-fired generation.

[36] Emissions data is not available for 2020; values for 2020 are from the 2019 APO, Energy Efficiency case forecast.

The avoided energy costs change as demand and supply changes. Energy data are provided to show the changes during the day, during the seasons, and from year to year over the outlook period.

The avoided capacity costs reflect the cost of capacity in years where there is a capacity deficit, plus the avoided cost of additional resources to meet reserve margin requirements.

The avoided cost data can be found in the data tables.

7.6 Avoided Emissions

Similar to the avoided costs, the avoided emission factors consider the avoided emissions associated with a reduction in demand for electricity.

In order to estimate the avoided greenhouse gas emissions associated with lower consumption levels, the IESO considers emissions reflective of the marginal resource. Based on the hour and year being considered, a different mix of generators with different emission rates will represent the incremental increase or decrease in generation.

Similar to the avoided costs, there are fewer emissions to be avoided in the near term, when more non-emitting resources will be operating, and greater opportunities for emission reductions in the medium and long terms due to increased demand, decreased nuclear generation and increased gas-fired generation.

8. Conclusion

In 2020, with the outbreak of COVID-19, Ontario is experiencing major shifts in electricity demand. Resulting changes to the energy landscape have reinforced the importance of a reliable electricity system, and added further complexity and uncertainty to forecasting efforts, requiring the IESO to rethink existing assumptions.

To help account for the range of possibilities, the IESO forecast demand using two different scenarios based on the pace of economic recovery. The first, a faster-recovery version, assumes electricity demand will reach pre-pandemic levels by 2022, and steadily grow faster than previous forecasts; the second assumes a more protracted economic downturn, with demand not expected to recover until the end of 2024. In both scenarios, demand will be lower in the near term.

After a decade in which the composition of demand by sector remained relatively unchanged, COVID-19 shifted consumption patterns – particularly in the hard-hit commercial sector – but so too did other factors, including the shift to a digital economy. Work-from-home arrangements, and business closures reduced economic activity and resulted in fundamental shifts in demand in the near term. Demand drivers are expected to continue to evolve over the longer term as future consumption patterns – reflected in more rapid growth in agriculture, the residential household sector and electric vehicle adoption – contribute to a rebound in demand that will eventually outpace 2019 levels.

The supply mix over the course of the outlook remains fairly stable, with nuclear refurbishments continuing throughout the 2020s and early 2030s. Summer capacity needs continue to emerge through 2022 and long-term needs continue to be driven by Pickering NGS retirement. Ontario is expected to have adequate energy, provided existing resources continue to be available post-contract and production from gas-fired generators increases to meet growing demand. Supply needs for the next decade are principally for managing risks to grid reliability.

Given the existing transmission infrastructure, location-specific capacity needs emerge in the mid-2020s, mainly in the GTA and in eastern Ontario. Generation facilities reaching end of contract in the West Zone result in a locational capacity need in the mid to long term. Load growth in the Ottawa area will contribute to a marginal capacity need over the medium term. Work to resolve transmission constraints along three major interfaces – the Flow East Towards Toronto, the Flow into Ottawa, and the Buchanan Longwood Input – will address the need for additional or reinforced capacity to supply these zones.

Depending on how future capacity requirements are met, forecasts continue to show that surplus baseload generation (SBG) will decline as a result of rising demand and the retirement of Pickering Nuclear Generating Station. As SBG declines, energy exports will decrease sharply – and imports will increase until the conclusion of refurbishments in the early 2030s.

Ontario can meet its needs through continued use of existing resources, the expansion of transmission, imports, the growing use of distributed energy resources (DERs), storage, and incremental energy-efficiency savings. Efforts to enable new entrants to compete on a level playing field with existing generation, and to pilot or support projects to meet changing needs are underway, and can all play a role in meeting future needs.

In December 2020, with the launch of its first capacity auction, the IESO marked a milestone in its efforts to create a more competitive marketplace, by enabling resources to compete to meet fluctuating demand in the short term. Today, as part of its focus on better balancing supplier and ratepayer risk, and meeting resource adequacy needs in all time frames, the IESO is working with stakeholders to enable other competitive mechanisms.

That said, the transition to a more competitive environment will not happen overnight, and will require interim measures to maintain reliability until a resource adequacy framework is fully implemented. The IESO will be negotiating an extension of the Lennox generating station contract as a transition measure until there is sufficient competition in the area.

The electricity sector – and what it will look like in the future – is always transforming, whether in response to a pandemic, the enablement of new resources, such as energy storage, shifts in public policy, or efforts to create a more competitive and efficient marketplace. Grounded in the IESO's expert planning and stakeholder input, the Annual Planning Outlook provides a regular and predictable source of data and insights and sheds light on the issues – current and emerging – that present challenges and opportunities to system reliability and efficiency.

Whether revisiting reliability requirements to enable non-firm imports to meet capacity needs, or exploring the role of DERs in addressing local needs, the IESO will use the findings and outcomes outlined in this – and future editions of the Outlook – to meet its reliability requirements, and help build a more cost-effective and reliable energy future for all Ontarians.

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Connecting Today.
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B3 - ENVIRONMENTAL DEFENCE INTERROGATORY - 023

Reference:
Exhibit B
Exhibit G-1-2, Page 35

Preamble:
Hydro One states as follows:

> *Additionally, objectives related to decarbonisation and electrification may result in increased adoption of electric vehicle or fuel switching, which are likely to drive changes to forecasts for service upgrades.*

For all of the below questions, please provide an answer on a best efforts basis and please make and state any assumptions and caveats as necessary.

Interrogatory:
a) Please complete the following table:

Hydro One Customers – Characteristics by Sector			
	2022	...	2027
Total Customers			
Residential			
Commercial			
Industrial			
Customers with Electrical Space Heating			
Residential			
Commercial			
Industrial			
Annual Consumption (kWh) for Resistance Space Heating for Average Customer			
Residential			
Commercial			
Industrial			
Peak Demand (kW) for Resistance Space			

Heating for Average Customer			
Residential			
Commercial			
Industrial			
Annual Consumption (kWh) for Resistance Water Heating for Average Customer			
Residential			
Commercial			
Industrial			
Peak Demand (kW) for Resistance Water Heating for Average Customer			
Residential			
Commercial			
Industrial			

b) Please complete the following table:

Electricity Use – Typical Customer After Conversion to Heat Pumps									
	Average Annual Electricity Consumption – Resistance Heating (kWh)			Average Annual Electricity Consumption (ccASHP & HPWP, HSPF Region 5=10[1]) (kWh)			Average Annual Electricity Consumption (GSHP & HPWP, sCOP=5) (kWh)		
	Total – Space/Water	Space Heating	Water Heating	Total – Space/Water	Space Heating	Water Heating	Total – Space/Water	Space Heating	Water Heating
Average or Typical Single-Family Residential Customer									

[1] Equivalent to ~sCOP=2.9 (2.96516)

c) Please complete the following table:

Winter Peak Demand – Typical Customer After Conversion to Heat Pumps									
	Average Peak Demand – Resistance Heating (kW)			Average Peak Winter Demand (ccASHP & HPWP, HSPF Region 5=10[2]) (kW)			Average Peak Winter Demand (GSHP & HPWP, sCOP=5) (kWh)		
	Total – Space/Water	Space Heating	Water Heating	Total – Space/Water	Space Heating	Water Heating	Total – Space/Water	Space Heating	Water Heating
Average or Typical Single-Family Residential Customer									

d) Please complete the following table:

Summer Peak Demand – Typical Customer After Conversion to Heat Pumps									
	Average Peak Demand – Traditional Central AC (kW)			Average Peak Winter Demand (ccASHP & HPWP, HSPF Region 5=10[3]) (kW)			Average Peak Winter Demand (GSHP & HPWP, sCOP=5) (kWh)		
	Total – Space/Water	Space Cooling	Water Heating	Total – Space/Water	Space Cooling	Water Heating	Total – Space/Water	Space Cooling	Water Heating
Average or Typical Single-Family Residential Customer									

e) Please complete this table of cooling efficiencies:

Cooling Efficiencies of Various Equipment Types			
		SEER	EER
Central air conditioners	Average of current stock (best estimate, Hydro One customers or Ontario average)		
	Standard unit		
	Energy Star rated		
	Energy Star – Most efficient of 2021		
Air source heat pumps	Standard unit		

[2] Equivalent to ~sCOP=2.9 (2.96516)
[3] Equivalent to ~sCOP=2.9 (2.96516)

	Energy Star rated		
	Energy Star – Most efficient of 2021		
Air source heat pumps in hybrid systems (if different)	Standard unit		
	Energy Star rated		
	Energy Star – Most efficient of 2021		
Ground source heat pumps – closed loop	Standard unit		
	Energy Star rated		
	Energy Star – Most efficient of 2021		
Ground source heat pumps – open loop	Standard unit		
	Energy Star rated		
	Energy Star – Most efficient of 2021		
Cold climate heat pumps – variable speed	Standard unit		
	Energy Star rated		
	Energy Star – Most efficient of 2021		

<u>Response:</u>

Hydro One notes that the preamble to this interrogatory is taken from the description of Hydro One's proposed Externally Driven Distribution Projects Variance Account. For context, the full paragraph excerpt is as follows:

> *In addition, the [Externally Driven Distribution Projects Variance Account] will capture variances resulting from new externally driven work requirements that may arise during the 2023-2027 period, but which were not contemplated in the investment plan. As an example Hydro One Distribution could be required to respond to enable increasing DER connections, new DER procurement programs or assume a new or expanded role in the deployment of coordinated infrastructure solutions to facilitate electrification, transportation or other policy objectives. Additionally, objectives related to decarbonisation and electrification may result in increased adoption of electric vehicle or fuel switching, which are likely to drive changes to forecasts for service upgrades.*

a)

Hydro One Customers – Characteristics by Sector						
	2022	**2023**	**2024**	**2025**	**2026**	**2027**
Total Customers	1,343,110	1,353,017	1,362,940	1,372,696	1,381,838	1,390,870
Residential	1,196,059	1,205,957	1,215,831	1,225,515	1,234,570	1,243,487
Commercial	NOT AVAILABLE					
Industrial						
Customers with Electrical Space Heating						
Residential	238,016	239,985	241,950	243,877	245,679	247,454
Commercial	NOT AVAILABLE					
Industrial						
Annual Consumption (kWh) for Resistance Space Heating for Average Customer						
Residential&&**	17,767	17,767	17,767	17,767	17,767	17,767
Commercial	NOT AVAILABLE					
Industrial						
Peak Demand (kW) for Resistance Space Heating for Average Customer						
Residential **	11.15	11.15	11.15	11.15	11.15	11.15
Commercial	NOT AVAILABLE					
Industrial						
Annual Consumption (kWh) for Resistance Water Heating for Average Customer						
Residential						
Commercial						
Industrial						
Peak Demand (kW) for Resistance Water Heating for Average Customer						
Residential						
Commercial						
Industrial						

***Assuming no change in technology and conservation.*

b)

Electricity Use – Typical Customer After Conversion to Heat Pumps									
	Average Annual Electricity Consumption – Resistance Heating (kWh)			Average Annual Electricity Consumption (ccASHP & HPWP, HSPF Region 5=10[1]) (kWh)			Average Annual Electricity Consumption (GSHP & HPWP, sCOP=5) (kWh)		
	Total – Space/ Water	Space Heating	Water Heating	Total – Space/ Water	Space Heating	Water Heating	Total – Space/ Water	Space Heating	Water Heating
Average or Typical Single-Family Residential Customer	17,767	Not Available	Not Available	18,958	Not Available	Not Available	20,815	Not Available	Not Available

Notes:
1) Values provided based on responses to Hydro One's 2019 Residential Equipment Survey
2) Figures provided represent total average household energy consumption for customers who identified having electric resistance heating, ASHP or GSHP. Equipment specific load information is not available.

c)

Winter Peak Demand – Typical Customer After Conversion to Heat Pumps									
	Average Peak Demand – Resistance Heating (kW)			Average Peak Winter Demand (ccASHP & HPWP, HSPF Region 5=10[2]) (kW)			Average Peak Winter Demand (GSHP & HPWP, sCOP=5) (kWh)		
	Total – Space/ Water	Space Heating	Water Heating	Total – Space/ Water	Space Heating	Water Heating	Total – Space/ Water	Space Heating	Water Heating
Average or Typical Single-Family Residential Customer	10.7	Not Available	Not Available	13.4	Not Available	Not Available	12.0	Not Available	Not Available

Notes:
1) Values provided based on responses to Hydro One's 2019 Residential Equipment Survey
2) Figures provided represent total average household energy consumption for customers who identified having electric resistance heating, ASHP or GSHP. Equipment specific load information is not available.

d)

Summer Peak Demand – Typical Customer After Conversion to Heat Pumps									
	Average Peak Demand – Traditional Central AC (kW)			Average Peak Winter Demand (ccASHP & HPWP, HSPF Region 5=10[3]) (kW)			Average Peak Winter Demand (GSHP & HPWP, sCOP=5) (kWh)		
	Total – Space/ Water	Space Cooling	Water Heating	Total – Space/ Water	Space Cooling	Water Heating	Total – Space/ Water	Space Cooling	Water Heating
Average or Typical Single-Family Residential Customer	6.3	Not Available	Not Available	7.4[3]	Not Available	Not Available	7.4[3]	Not Available	Not Available

Notes:
1) Values provided based on responses to Hydro One's 2019 Residential Equipment Survey
2) Figures provided represent total average household energy consumption for customers who identified having electric resistance heating, ASHP or GSHP. Equipment specific load information is not available.
3) Only Heat Pump information is available (no further breakdown between ASHP vs. GSHP).

1 e)

Cooling Efficiencies of Various Equipment Types			
		SEER	EER
Central air conditioners	Average of current stock (best estimate, Hydro One customers or Ontario average)	Not Available	Not Available
	Standard unit	Not Available	Not Available
	Energy Star rated	Not Available	Not Available
	Energy Star – Most efficient of 2021	Not Available	Not Available
Air source heat pumps	Standard unit	Not Available	Not Available
	Energy Star rated	Not Available	Not Available
	Energy Star – Most efficient of 2021	Not Available	Not Available
Air source heat pumps in hybrid systems (if different)	Standard unit	Not Available	Not Available
	Energy Star rated	Not Available	Not Available
	Energy Star – Most efficient of 2021	Not Available	Not Available
Ground source heat pumps – closed loop	Standard unit	Not Available	Not Available
	Energy Star rated	Not Available	Not Available
	Energy Star – Most efficient of 2021	Not Available	Not Available
Ground source heat pumps – open loop	Standard unit	Not Available	Not Available
	Energy Star rated	Not Available	Not Available
	Energy Star – Most efficient of 2021	Not Available	Not Available
Cold climate heat pumps – variable speed	Standard unit	Not Available	Not Available
	Energy Star rated	Not Available	Not Available
	Energy Star – Most efficient of 2021	Not Available	Not Available

[1] *Equivalent to ~sCOP=2.9 (2.96516)*
[2] *Equivalent to ~sCOP=2.9 (2.96516)*
[3] *Equivalent to ~sCOP=2.9 (2.96516)*

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B3 - ENVIRONMENTAL DEFENCE INTERROGATORY - 024

Reference:

Exhibit B
Exhibit G-1-2, Page 35

Preamble:

Hydro One states as follows:

> *Additionally, objectives related to decarbonisation and electrification may result in increased adoption of electric vehicle or fuel switching, which are likely to drive changes to forecasts for service upgrades.*

Interrogatory:

a) What investments is Hydro One making over 2023-2027 to accommodate an expansion of electric vehicles? Please describe these and provide the dollar total.

b) What investments is Hydro One making over 2023-2027 to accommodate fuel switching over that period? Please describe these and provide the dollar total.

c) Please confer with staff for the Canada Greener Homes Grant to obtain estimates of: (i) the number of customers in Ontario that will use the grant to switch from fossil fuel heating to an electric heat pump and (ii) the number of customers that will use the grant to switch from electric resistance heating to an electric heat pump. Please provide a response on an annual basis if possible.

Response:

Hydro One notes that the preamble to this interrogatory is taken from the description of Hydro One's proposed Externally Driven Distribution Projects Variance Account. For context, the full paragraph excerpt is as follows:

> *In addition, the [Externally Driven Distribution Projects Variance Account] will capture variances resulting from new externally driven work requirements that may arise during the 2023-2027 period, but which were not contemplated in the investment plan. As an example Hydro One Distribution could be required to respond to enable increasing DER connections, new DER procurement programs or assume a new or expanded role in the deployment of coordinated infrastructure solutions to facilitate electrification, transportation or other policy objectives. Additionally, objectives related to decarbonisation and electrification may result in increased adoption of electric vehicle or fuel switching, which are likely to drive changes to forecasts for service upgrades.*

a) In respect of planned investments being made by Hydro One over 2023-2027 to accommodate an expansion of electric vehicles, the projected investment in electric vehicles for 2023-2027 is $85.1M. Additional investments will be made by Facilities and Real Estate to install new EV charging infrastructure thereby supporting the roll out of electric vehicles at various Hydro One sites. Based on the need for infrastructure over the past years, the expected annual estimated costs for electric vehicle charger installations is $0.7M across 10 sites for the current planning period of 2023-2027.

   As the EV load projection for consumers is embedded within Hydro One's load forecasts, there is no specific investment for consumer EV load at this time. However, Hydro One is proactively assessing the overall impact of increasing EV penetration and the best approach to minimize future upgrade costs to rate payers.

b) Fuel switching is embedded within Hydro One's load forecasts; there is no specific investment for fuel switching at this time.

c) Hydro One has reached out the Greener Homes Division at Natural Resources Canada to request this information, however we did not receive any data from them yet. Conservation savings from the Canada Greener Homes Grant program are included in IESO's total CDM savings assumption which is used for the purposes of this filing. Program specific information is not available.

B3 - ENVIRONMENTAL DEFENCE INTERROGATORY - 025

Reference:

Exhibit B
Exhibit G-1-2, Page 35

Interrogatory:

a) Does a residential customer need to notify or seek approval from Hydro One before installing a high-speed electric vehicle charger? Please explain and provide any relevant excerpts from the relevant document containing said requirement.

b) Does a residential customer need to notify or seek approval from Hydro One before installing a high-speed bi-directional electric vehicle charger (under 10 kW) that does not export to the grid? Please explain and provide any relevant excerpts from the relevant document containing said requirement.

c) How many applications to install bi-directional EV charges has Hydro One received?

d) Can Hydro One require a residential customer to make a financial contribution toward distribution system upgrades necessary to allow the customer to install a high-speed one-directional EV charger? If yes, would Hydro One do so? Please explain.

e) Can Hydro One require a residential customer to make a financial contribution toward distribution system upgrades necessary to allow the customer to install a high-speed bi-directional EV charger (non-exporting)? If yes, would Hydro One do so? Please explain.

f) Generally speaking, what protective devices would be needed for a residential customer to install a bi-directional EV charger that is not meant to export to the grid to ensure that there is no damage in the event of a grid outage?

g) Is Hydro One obligated to undertake the upgrades necessary for residential customers to install EV chargers if they choose to do so?

h) How many electric vehicles will Hydro One buy over 2023-2027?

i) How many electric vehicle chargers will Hydro One buy over 2023-2027?

j) Please provide all data and estimates that Hydro One has on the number of EV chargers on its network and their charging rates (kW) and a breakdown by customer class.

Response:

a) A residential customer does not need to notify Hydro One to install a Level 2 charger if the charger can be accommodated by their existing service. Hydro One approval is required if the customer is upgrading the size of their service or location of their service entrance.

b) Yes, customers are currently expected to notify Hydro One. The conditions of service state that customers planning to install a Load Displacement Generation Facility and/or Energy Storage Facility are required to consult with Hydro One during the planning process and prior to installation. Section 3.4 Embedded Generation Facilities of the Conditions of Service also applies.

c) Hydro One has not received any applications for bi-directional EV chargers.

d) Residential customers that are increasing the capacity of their service panel may be required to contribute towards the cost of distribution system upgrades necessary to supply the increased service size, in accordance with Hydro One's Conditions of Service Section 2.1.1 and 3.1.4. Hence, if the customer's service must be upgraded to accommodate the EV charger that the customer has chosen to install, the customer may be required to make a financial contribution. If a service upgrade is not required to accommodate the EV charger, then the customer will not be required to make a financial contribution to Hydro One.

e) See the response to question d) above.

f) The customer may be required to install a device such as a transfer switch.

g) Where a customer requests a service upgrade and executes a service upgrade contract, Hydro One will undertake the distribution system upgrades necessary to supply the increased service size.

h) See interrogatory response B4-Energy Probe-050.

i) The number of electric vehicle chargers installed by Hydro One Facilities for use by Hydro One employees and Fleet vehicles in any given year primarily depends on the adoption rate of EV vehicles within the Hydro One fleet within a certain geographic region or location.

j) Hydro One does not track information on the EV chargers connected to its network. For residential customers, Hydro One conducts an annual energy consumption survey that inquires about the number of electric vehicles owned or leased per household. Based on the 2021 survey results, between 1-2% of households have at least one electric vehicle in Hydro One's service territory.

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L - ENVIRONMENTAL DEFENCE INTERROGATORY - 026

Reference:

Exhibit L-2-1, Page 10

Interrogatory:

a) Please complete the following table for all non-residential metered customers (GSe, GSd, UGe, UGd, DGen, ST, AUR, AUGe, AUGd, AR, AGSe & AGSd). Please provide a copy in a live excel spreadsheet.

Fixed Charges – Actual and Estimated vs. OEB Maximum			
	2010 (actual)	…	2027 (estimated)
Fixed Charge			
Gse			
…			
AGSd			
Maximum Fixed Charge (minimum system with PLCC adjustment)			
Gse			
…			
AGSd			
Number of Customers			
Gse			
…			
AGSd			
Revenue from Fixed Charges			
Gse			
…			
AGSd			
Total			
Revenue if Fixed Charge Set at Maximum			
Gse			
…			
AGSd			
Total			

b) Please reproduce the above table for 2023 to 2027 as if Hydro One were to set its fixed rates in accordance with the following ruling in Hydro Ottawa's rates case: "[T]he OEB finds that fixed charges should be set by comparing the fixed charge resulting from Hydro Ottawa's standard rate design approach with the previous year's level for the five year rate term. In years where maintaining the current fixed/variable revenue split results in a higher fixed charge than the previous year, Hydro Ottawa shall maintain the fixed charge at the previous year's level. In years where maintaining the current fixed/variable revenue split results in a lower fixed charge than the previous year, Hydro Ottawa shall maintain the fixed charge at the lower value."

<u>Response:</u>

a) The requested information is publicly available and has been consolidated by Hydro One for the years 2018 to 2027, covering the rate period for two Custom IR applications. This can be found in Excel Attachment I-09-L-ED-026-01 to this interrogatory response (Tab ED-26 (a)).

b) The requested information can be found in Excel Attachment I-09-L-ED-026-01 to this interrogatory response (Tab ED-26(b)).

B3 - ENVIRONMENTAL DEFENCE INTERROGATORY - 027

Reference:

Exhibit B-03-01

Interrogatory:

a) If Hydro One determines that an infrastructure need can be met more cost-effectively through a non-wires-alternative (NWA) during the 2023-2027 period, is Hydro One able to use the revenue requirement approved in this application to undertake that NWA? Please explain if additional OEB approval is required, why, and the trigger for any such requirement. If the answer depends on a number of factors, please describe those factors.

Response:

a) The approved revenue requirement is not prescribed on a project specific basis. Projects undertaken during the CIR term are those that fit within the capital envelopes for System Access, System Service, System Renewal and General Plant, consistent with the approved System plan. Whether a NWA solution is undertaken would depend (in addition to economics, efficiency, and technical feasibility) on whether such a NWA was consistent with Hydro One's statutory restrictions as to the activities that it is permitted to undertake, as well as the prevailing OEB policies at the time. Unless otherwise required by statute or regulation, any OEB approval would be as part of Hydro One's next rebasing request and the addition of in-service amounts to rate base.

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B3 - ENVIRONMENTAL DEFENCE INTERROGATORY - 028

Reference:
Exhibit B, G-01-02 p. 35

Interrogatory:

a) Please comment on the potential for car batteries to be used to reduce building loads with bi-directional chargers at the time of distribution peaks and thus reduce the need for distribution infrastructure.

b) Please describe all steps Hydro One is taking to (a) assist its customers in installing or purchasing electric vehicle chargers and (b) install electric vehicle chargers for its own use.

c) With respect to Hydro One's efforts to install electric vehicle chargers, what proportion will be bi-directional chargers?

d) Nova Scotia Power is undertaking a bi-directional charger pilot project involving 20 bi-directional chargers of 4 different types. David Landrigan, vice-president of commercial for Nova Scotia Power stated as follows: "I think we can call it a game-changing resource". Would Hydro One consider a similar pilot? Would this require additional regulatory approvals if it were to occur prior to 2027?

e) The following utilities are piloting bi-directional chargers:
   - San Diego Gas & Electric in California (10 V2G busses, 25 kW/bus, 250 kW)
   - Con Edison in New York (5 V2G busses, 10 kW/bus, 50 kW)
   - EDF Energy in the UK (Customer-facing V2G program based on ABB equipment)
   - National Grid in Rhode Island (Fermata V2G bidirectional pilot, 15-20 kW)
   - Roanoke Electric Cooperative in N. Carolina (Fermata V2G system, 15-20 kW)
   - Green Mountain Power in Vermont (Fermata V2G bidirectional pilot, 15-20 kW)
   - Austin Energy in Texas (V2G/V2B pilot)
   - Snohomish County Public Utility District in Washington State (V2G pilot)

   Is Hydro One considering similar pilots? If not, why not. Would this require additional regulatory approvals if it were to occur prior to 2027? Please explain.

f) Please provide 6 examples of bi-directional charges available in North America (3 AC and 3 DC) and list their charge/discharge rate (kW) and approximate price. This could include chargers from wallbox, dcbel, ABB, Fermata, Siemens, etc.

g) Please compare the price of bi-directional chargers to one-directional chargers. Is this price differential expected to decrease?

h) Please comment on the following potential non-wires-alternative to traditional infrastructure and whether Hydro One would consider pursuing this if cost-effective:
- School bus companies incentivized to install V2G bi-directional chargers
- The bus batteries can be used to serve the grid during distribution peaks
- Busses have big batteries
- Commercial DC chargers are very fast (e.g. 125 kW – see right)
- School buses usually plugged in at peak times
- Can help pay for fleet electrification
- 20,000+ school buses in Ontario

i) Please comment on the following potential non-wires-alternative to traditional infrastructure and whether Hydro One would consider pursuing this if cost-effective:
- Incentivize municipalities to use grid-connected bi-directional chargers when electrifying on-street parking and city lots
- Low incremental cost because a new grid connection is likely required regardless
- Grid connection and protection simplified b/c the connection is not shared with other loads
- Can leverage existing connections between LDCs and municipalities
- Can be piloted and then implemented at scale
- Can help to support electrification of on-street parking and city lots

j) Please comment on the following potential non-wires-alternative to traditional infrastructure and whether Hydro One would consider pursuing this if cost-effective:
- Key design elements:
    - Consumers offered a $X discount on a bi-directional charger
    - Participants must opt-into an EV rate structure
    - The strong TOU price signal increases the incentive to charge off-peak and to discharge to offset household demand on-peak
    - Equipment is pre-set with optimal settings (e.g. discharge threshold levels, timing for charging/discharging, etc.)

    - Consumer has full control over equipment settings and when to charge/discharge
    - Charger is vehicle-to-building (i.e. not exporting to the grid)
- Consumer take-up driven by:
    - Desire for back-up power
    - Desire for high-speed charger (at a discount)
    - Reduced household electricity charges from load shifting and load offsetting
    - Upfront incentive payment (i.e. discount on bidirectional charger)
    - Marketing and technical advice
    - Ability to retain full control over vehicle charging/discharging times
- Utility considerations:
    - Reduces distribution peaks and increases reliability
    - Very low cost
    - No need for expensive or complicated communication equipment, grid connection, active control, or ongoing contractual arrangements/payments
    - Demand reductions must be modelled in aggregate, similar to CDM programs because the resource is not dispatchable

k) Please comment on the following reasons why bi-directional chargers should be a priority and could be a lost opportunity if not pursued early:
    - It is cheaper to incentivize bi-directional charging sooner, before millions of “dumb” and “one-directional” chargers are purchased
    - About 1 million customers will start charging EVs at home between now and 2030; many commercial EV chargers will be purchased over that time
    - The opportunity to upgrade to bi-directional chargers is greatest before the initial purchase (i.e., the incremental cost is lowest)
    - The lead time for a vehicle-to-building/grid program is likely long (needs OEB policy changes, LDC program development, program approval by OEB, etc.)

l) Does Hydro One have akin to this one from Hydro Quebec: https://www.hydroquebec.com/data/electrification-transport/pdf/technical-guide.pdf? If not, why not? Is one under consideration?

Response:

a) Hydro One is interested in exploring the viability, benefits, and risks of using car batteries and bi-directional chargers to reduce distribution peaks. However, further analysis and study is needed and Hydro One cannot comment on the ability of car batteries and bi-directional chargers to reduce distribution peaks at this time. Hydro One is currently participating in a Vehicle-to-Home pilot project with Peak Power and the IESO. The pilot will allow Hydro One to evaluate the potentials of leveraging EV batteries for grid benefits through bi-directional chargers.

b) Customers who wish to install an electric vehicle charger are subject to the requirements detailed in Hydro One's Condition of Service under Section 2.1: Connections, and must satisfy Electrical Safety Authority (ESA) requirements. For Hydro One's own use, the number and location of electric vehicle chargers installed by Hydro One Facilities is to support the deployment of the EV vehicles in the Hydro One fleet within a certain geographic region or location.

c) Notwithstanding Ivy Charging Network, which is part of Hydro One Limited's unregulated business, Hydro One Networks does not provide electric vehicle charger installation services for its customers.

d) Hydro One is interested in exploring the viability, benefits, and risks of incorporating bi-directional chargers to the grid for the purpose of addressing distribution concerns and identifying grid benefits. Hydro One is currently participating in a pilot with Peak Power and the IESO to evaluate the potential for EVs to inject power to support the grid. In Hydro One's view, additional approvals would not be required to undertake a bi-directional charger pilot if the pilot provided grid benefits. Hydro One also notes that the OEB is currently undertaking the Framework for Energy Innovation: Distributed Resources and Utility Incentives consultation (EB-2021-0118) where issues such as utility use of third party DERs to address distribution system need and are being considered by numerous stakeholder groups.

e) Please refer to response for d).

f) Hydro One is unable to address this question. Please refer to the manufacturers' websites for information on the chargers.

g) Please refer to response for f).

h) Hydro One would consider a non-wires-alternative if it is feasible and cost-effective.

i) Please refer to response for h).

j) Please refer to response for h).

k) Please refer to response for d).

l) Hydro One does not have an EV Charging Station Technical Installation Guide. The connection of an EV charging stations must follow Hydro One's Condition of Service, Section 2.1: Connections and satisfy the Electrical Safety Authority (ESA) requirements.

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