# UNDERTAKING JT-2.01

**Reference:**

I-03-B2-AMPCO-28

**Undertaking:**

To update the table that was shown in IR B2-AMPCO-28 for those assets which may not be included in this as replacements related to system access and system service.

**Response:**

Replacements associated with System Access and System Service investments have been included in the table below. These investments materialize in much shorter timeframes and are typically driven by customer needs or system needs.

| Projects | 2018 Actual | 2019 Actual | 2020 Actual | 2021 F/Cast | 2022 F/Cast | 2023 Test | 2024 Test | 2025 Test | 2026 Test | 2027 Test |
|---|---|---|---|---|---|---|---|---|---|---|
| **System Renewal** | | | | | | | | | | |
| Circuit Breakers | | | | | | | | | | |
| Circuit Breakers | - | 3 | 1 | - | - | - | - | - | - | - |
| Integrated Station Investment | | | | | | | | | | |
| Transformers | 28 | 24 | 10 | 21 | 19 | 30 | 18 | 27 | 21 | 24 |
| Circuit Breakers | 155 | 69 | 66 | 168 | 130 | 88 | 107 | 98 | 146 | 154 |
| Protections | 325 | 322 | 242 | 500 | 391 | 401 | 236 | 324 | 414 | 512 |
| Overhead Lines Refurbishment Projects, Component Replacement Programs | | | | | | | | | | |
| Wood Poles | 735 | 827 | 796 | 1013 | 1024 | 1076 | 1076 | 1078 | 1082 | 1084 |
| Conductors (circuit-km) | 51 | 82 | 39 | 18 | 515 | 19 | 300 | 338 | 235 | 679 |
| Insulators | 3900 | 4290 | 2794 | 3767 | 3544 | 3980 | 3980 | 3980 | 3980 | 3980 |
| Protection and Automation | | | | | | | | | | |
| Protections | - | - | - | 21 | 21 | 42 | 42 | 42 | 42 | 42 |
| Tx Transformers Demand and Spares | | | | | | | | | | |
| Transformers | 8 | 5 | 3 | 4 | 4 | 5 | 5 | 5 | 5 | 5 |
| Circuit Breakers | 1 | 0 | 1 | 3 | 2 | 2 | 2 | 2 | 2 | 2 |
| Underground Lines Cable Refurbishment & Replacement | | | | | | | | | | |
| Underground Cables (circuit-km) | 16.5 | - | 4.7 | - | - | - | - | 7.2 | - | - |
| **System Access** | | | | | | | | | | |
| Load Customer Connection | | | | | | | | | | |
| Breakers | - | - | - | - | - | - | - | 6 | - | - |
| Conductors (circuit-km) | - | - | - | 6 | - | - | - | - | - | 17 |

Witness: JESUS Bruno, REINMULLER Robert, JABLONSKY Donna, SPENCER Andrew

| Projects | 2018 Actual | 2019 Actual | 2020 Actual | 2021 F/Cast | 2022 F/Cast | 2023 Test | 2024 Test | 2025 Test | 2026 Test | 2027 Test |
|---|---|---|---|---|---|---|---|---|---|---|
| **System Service** | | | | | | | | | | |
| Inter Area Network Transfer Capability | | | | | | | | | | |
| Transformers | - | - | - | - | - | 2 | - | - | - | - |
| Conductors (circuit-km) | - | - | - | - | 24 | - | - | - | - | - |
| Local Area Supply Adequacy | | | | | | | | | | |
| Transformers | - | - | - | 2 | 2 | - | - | - | - | - |
| Circuit Breakers | - | - | - | - | 11 | - | - | - | - | - |
| Protections | - | - | - | - | 21 | - | - | - | - | - |
| Conductors (circuit-km) | 4 | - | - | - | 72 | - | - | - | 71 | - |

Witness: JESUS Bruno, REINMULLER Robert, JABLONSKY Donna, SPENCER Andrew

This page has been left blank intentionally.

# UNDERTAKING JT-2.02

## Reference:
I-09-B3-ED-017

## Undertaking:
To provide a table showing any transmission costs for DER connection projects over the last three years, estimated and actual costs, without identifying any specific customers, if it can be provided; or if it cannot be provided, to explain why not, with any necessary qualifications.

## Response:
The table below includes DER connection projects, without identifying any specific customers, for the last three years (from Q4 2018 until Q3 2021) where actual transmission costs have been finalized. These DER projects are in other LDC service territories, and therefore 100% of their Hydro One connection costs are transmission costs. Transmission costs related to DER projects connecting to Hydro One Distribution are not readily available and have not been included in the table below.

| Project | Estimated Transmission Costs[1] | Actual Transmission Costs |
|---|---|---|
| #1 | $342,000 | $171,260 |
| #2 | $12,000 | $7,462 |
| #3 | $312,000 | $370,943 |
| #4 | $20,000 | $18,699 |
| #5 | $12,000 | $17,839 |
| #6 | $12,000 | $3,414 |
| #7 | $12,000 | $9,401 |
| #8 | $371,000 | $253,318 |
| #9 | $640,000 | $536,589 |
| #10 | $480,000 | $560,431 |
| #11 | $340,000 | $173,354 |
| #12 | $40,000 | $3,450 |
| #13 | $22,000 | $16,468 |
| #14 | $369,000 | $377,120 |
| #15 | $276,000 | $199,551 |
| #16 | $17,000 | $19,236 |
| #17 | $17,000 | $12,901 |
| #18 | $40,000 | $14,584 |
| #19 | $312,000 | $119,591 |
| #20 | $440,000 | $280,866 |
| #21 | $805,000 | $571,793 |
| #22 | $279,000 | $129,372 |
| #23 | $349,000 | $164,609 |
| #24 | $266,000 | $296,826 |
| #25 | $308,000 | $112,898 |
| #26 | $415,000 | $244,799 |

*[1]The estimated cost is based on a +/- 50% estimate that was provided to the applicant as part of the interconnection process.*

# UNDERTAKING JT-2.03

## Reference:

I-01-B2-Staff-83

## Undertaking:

For the Merivale project estimate,

a) To provide the class (AACE class) and any uncertainty percentage associated with it;
b) To provide an estimate for when the decision on how to execute or deliver this project would be.

## Response:

a) The cost for the Merivale TS investment is a planning allowance, having an accuracy level of (-50%/+100%). The planning allowance was derived using historical costs based on similar projects.

b) The delivery model for each project is determined as the project progresses through the phases of the project delivery model (see TSP Section 2.10). An initial assumption on the delivery model is made during the Project Initiation phase, which is revisited during the Project Scoping phase, and finalized during the Project Planning phase. The Project Scoping phase is expected to be completed by the end of Q1 2022, and the Project Planning phase completed in Q4 2022. Presently, the project is expected to be completed through a combination of self-performed work and some outsourcing of the engineering and construction deliverables.

This page has been left blank intentionally.

# UNDERTAKING JT-2.04

## Reference:

I-22-B1-SEC-58

## Undertaking:

To provide information about a list of investments and the rationale for investments that have been flagged with a customer engagement flag.

## Response:

The investments listed below include a "Customer Engagement" flag. These investments respond to the needs, preferences and priorities identified by customers, further described in SPF Section 1.6.

**Transmission**

| ISD | Investment |
|---|---|
| T-SR-01 | Transmission Station Renewal - Network Stations |
| T-SR-02 | Transmission Station Renewal - Air Blast Circuit Breakers |
| T-SR-03 | Transmission Station Renewal - Connection Stations |
| T-SR-04 | Wood Pole Structure Replacements |
| T-SR-05 | Steel Structure Coating Program |
| T-SR-06 | Tower Foundation Assess/Clean/Coat & LIfe Extension Program |
| T-SR-07 | Transmission Line Shieldwire Replacement |
| T-SR-08 | Transmission Line Insulator Replacement |
| T-SR-09 | Transmission Station Demand and Spares and Targeted Assets |
| T-SR-13 | Transmission Line Refurbishments |
| T-SR-16 | HV UG Cable – Replace/Refurbish Pumping Plants |
| T-SR-18 | C5E/C7E Underground Cable Replacement |
| T-SS-02 | St. Lawrence TS: Phase Shifters Replacement |
| T-SS-03 | Merivale TS to Hawthorne TS: 230kV Conductor Upgrade |
| T-SS-04 | Richview x Trafalgar 230kV Conductor Upgrade |
| T-SS-05 | Merivale TS Add 230/115kV Autotransformers |
| T-SS-06 | Southwest GTA Transmission Reinforcement |
| T-SS-07 | West of Chatham Reinforcement |
| T-SS-08 | Future Transmission Regional Plans |
| T-SS-09 | West of London Reinforcement |

## Distribution

| ISD | Investment |
|---|---|
| D-SR-01 | Distribution Stations Demand Capital Program |
| D-SR-02 | Mobile Unit Substation Program |
| D-SR-03 | Distribution Station Planned Component Replacement Program |
| D-SR-04 | Distribution Station Refurbishment |
| D-SR-05 | Distribution Lines Trouble Call and Storm Damage Response Program |
| D-SR-06 | Distribution Lines PCB Equipment Replacement Program |
| D-SR-07 | Pole Sustainment Program |
| D-SS-01 | System Upgrades Driven by Load Growth |
| D-SS-02 | Reliability Improvements |
| D-SS-03 | Demand Investments |
| D-SS-04 | Energy Storage Solutions |
| D-SS-05 | Worst Performing Feeders |
| D-SS-06 | Stray Voltage |

# UNDERTAKING JT-2.05

**Reference:**

I-01-B2-Staff-42

**Undertaking:**

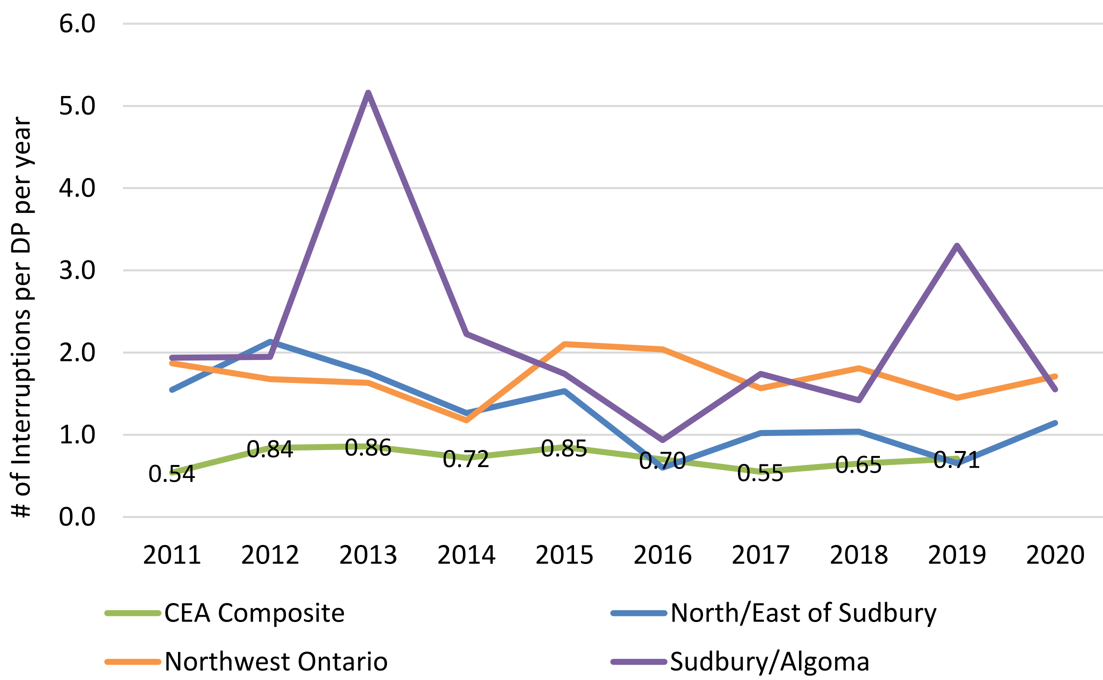
a) To provide a response to OEB STAFF IR 42;

b) To provide the spreadsheet used to produce the charts, showing all 19 regions

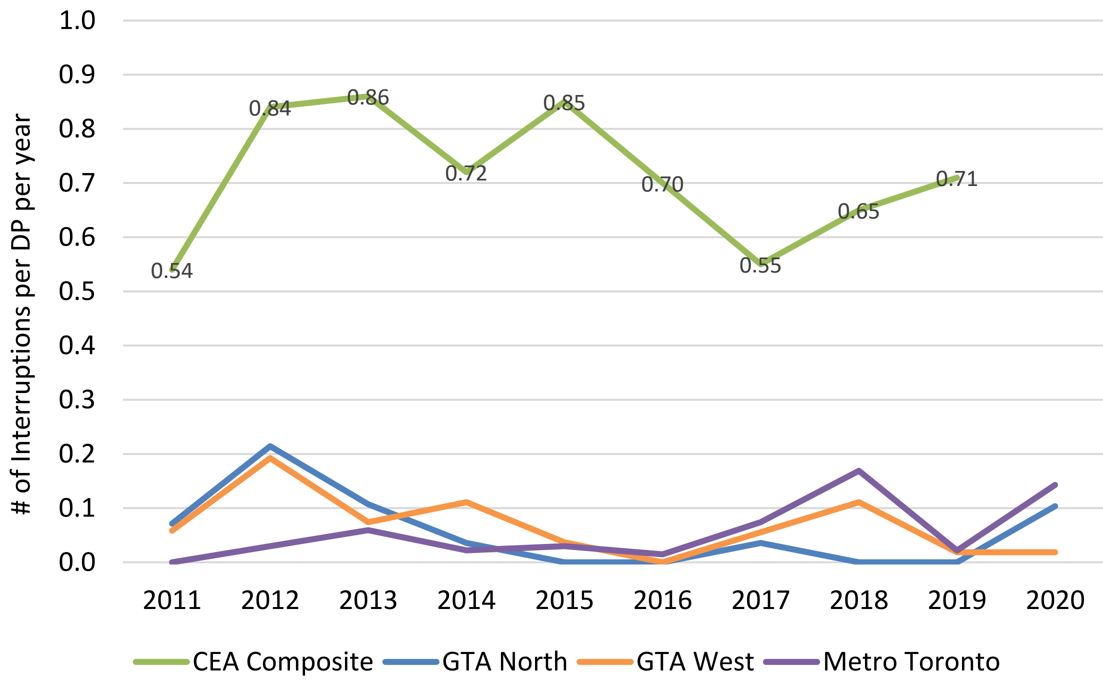
**Response:**

a) 2018 CEA values exclude the Ottawa area tornado.

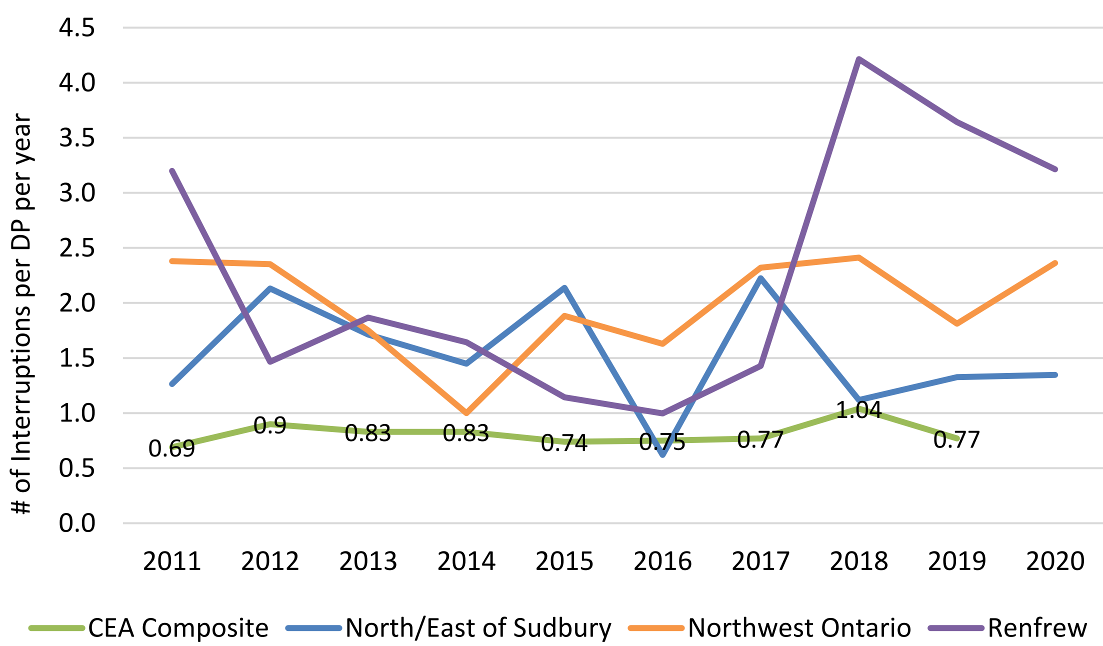
Revised TSP Section 2.4 Figure 6, T-SAIFI-M for 3 worst regions as comparison to CEA Composite



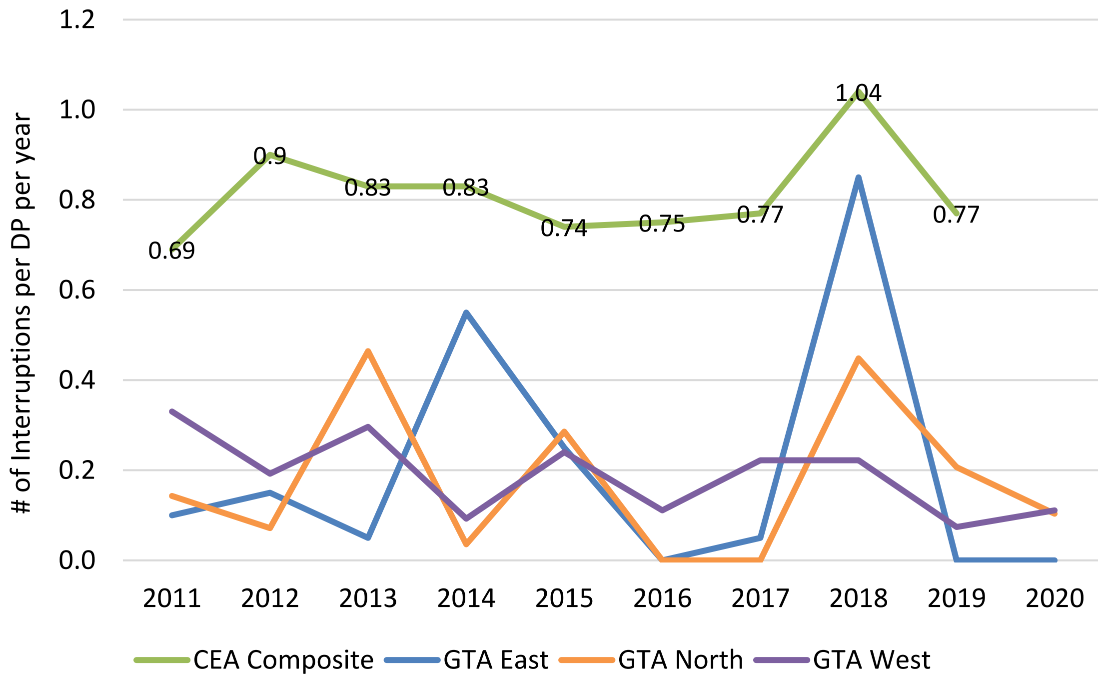
Revised TSP Section 2.4 Figure 6, T-SAIFI-M for 3 best regions as comparison to CEA Composite



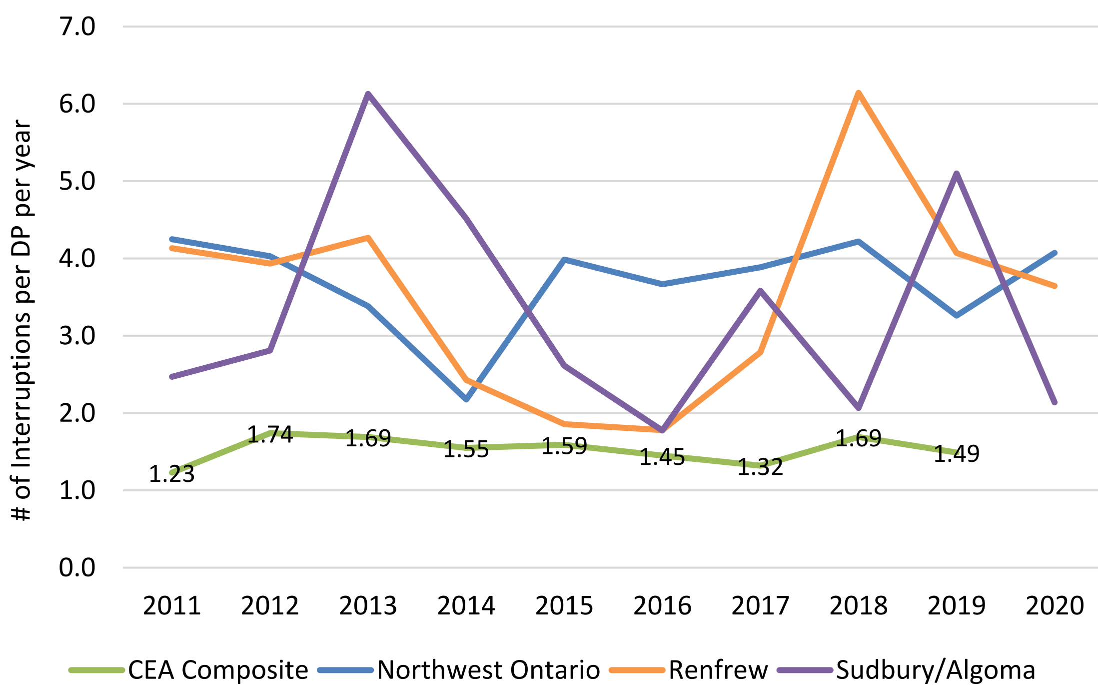

Revised TSP Section 2.4 Figure 7, T-SAIFI-S for 3 worst regions as comparison to CEA Composite



Revised TSP Section 2.4 Figure 7, T-SAIFI-S for 3 best regions as comparison to CEA Composites



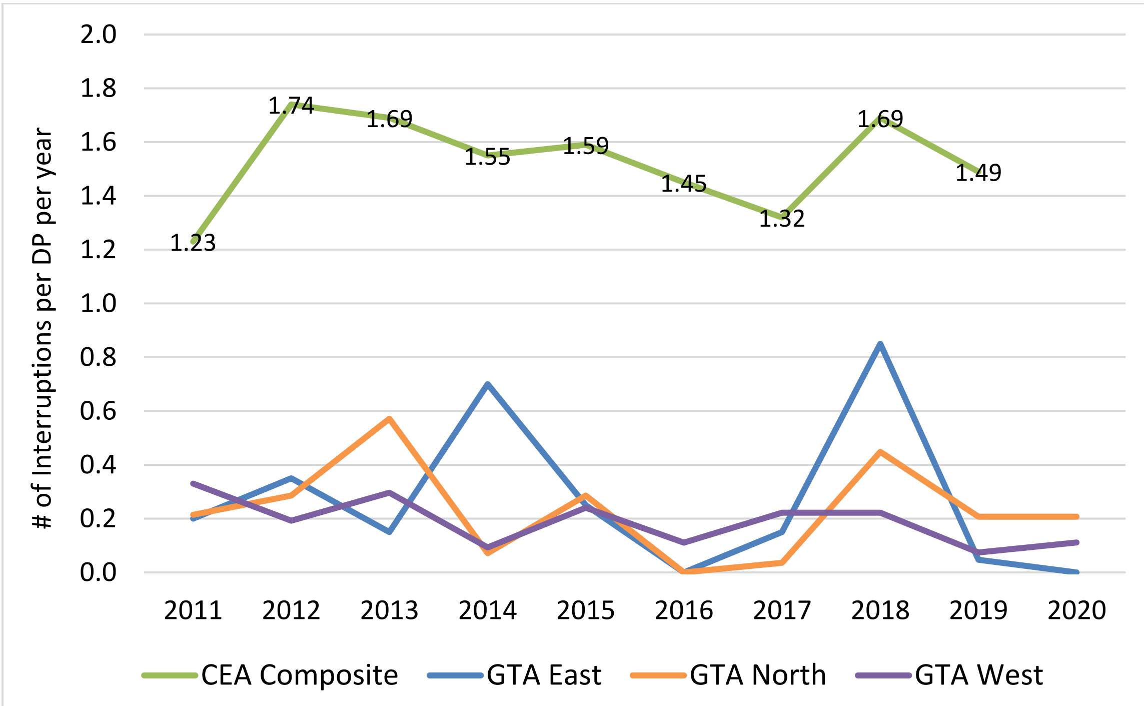

Revised TSP Section 2.4 Figure 8, T-SAIFI for 3 worst regions as comparison to CEA Composite




Witness: JESUS Bruno

1 Revised TSP Section 2.4 Figure 8, T-SAIFI for 3 best regions as comparison to CEA Composite

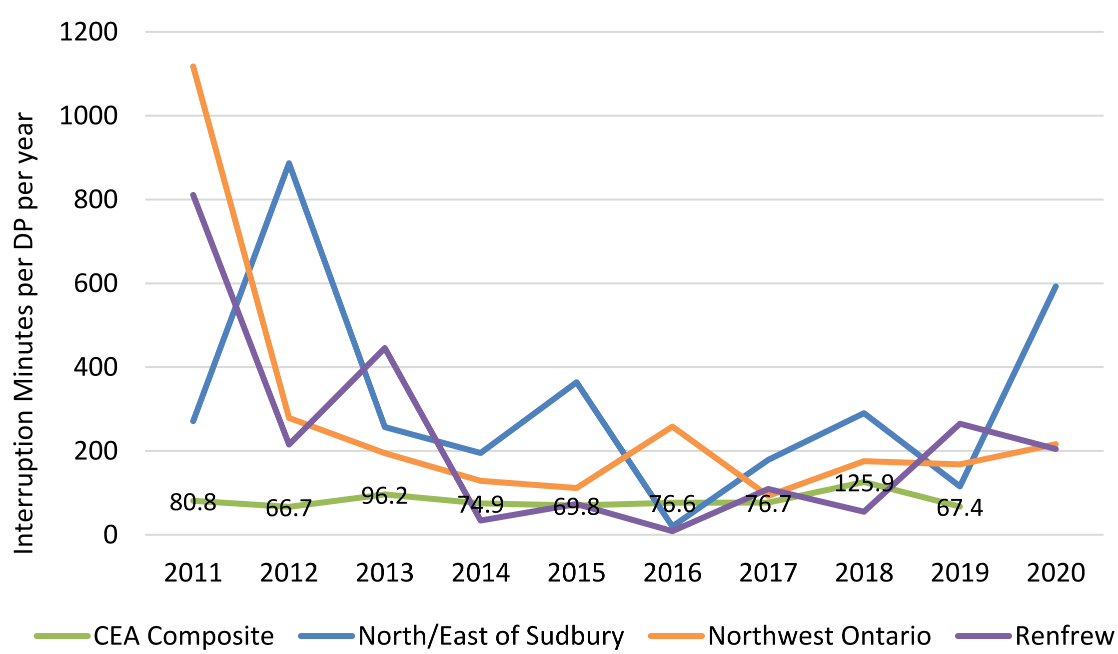
2



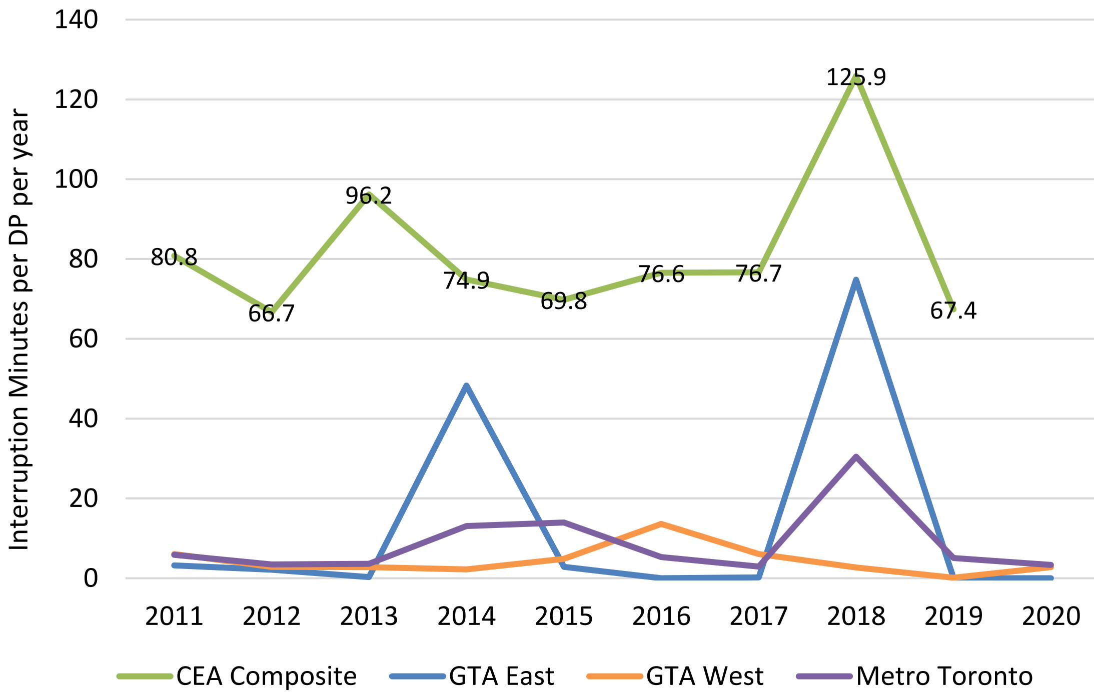

3

4 Revised TSP Section 2.4 Figure 9, T-SAIDI for 3 worst regions as comparison to CEA Composite

5



Revised TSP Section 2.4 Figure 9, T-SAIDI for 3 best regions as comparison to CEA Composite




b) Please see Attachment 1 for the spreadsheet used to produce the charts.

This page has been left blank intentionally.

| T-SAIFI-M | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 10-Yr Weighted Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Burlington to Nanticoke | 0.13 | 0.12 | 0.17 | 0.03 | 0.11 | 0.03 | 0.05 | 0.11 | 0.08 | 0.05 | 0.09 |
| Chatham/Lambton/Sarnia | 0.77 | 0.39 | 0.08 | 0.24 | 0.16 | 0.64 | 1.48 | 0.24 | 0.20 | 0.24 | 0.44 |
| Greater Bruce/Huron | 0.52 | 3.81 | 1.14 | 1.82 | 0.93 | 0.00 | 0.46 | 1.22 | 1.25 | 0.57 | 1.16 |
| Greater Ottawa | 0.65 | 0.28 | 0.21 | 0.12 | 0.29 | 0.10 | 0.16 | 0.00 | 0.20 | 0.08 | 0.21 |
| GTA East | 0.10 | 0.20 | 0.10 | 0.15 | 0.00 | 0.00 | 0.10 | 0.00 | 0.05 | 0.00 | 0.07 |
| GTA North | 0.07 | 0.21 | 0.11 | 0.04 | 0.00 | 0.00 | 0.04 | 0.00 | 0.00 | 0.10 | 0.06 |
| GTA West | 0.06 | 0.19 | 0.07 | 0.11 | 0.04 | 0.00 | 0.06 | 0.11 | 0.02 | 0.02 | 0.07 |
| KWCG | 1.32 | 1.28 | 1.05 | 0.50 | 0.15 | 0.17 | 0.28 | 0.03 | 0.23 | 0.18 | 0.52 |
| London Area | 0.43 | 0.33 | 0.46 | 0.48 | 0.58 | 0.37 | 0.37 | 0.24 | 0.20 | 0.35 | 0.38 |
| Metro Toronto | 0.00 | 0.03 | 0.06 | 0.02 | 0.03 | 0.01 | 0.07 | 0.17 | 0.02 | 0.14 | 0.06 |
| Niagara | 0.31 | 0.09 | 0.20 | 0.45 | 0.39 | 0.04 | 0.54 | 0.36 | 0.13 | 0.17 | 0.27 |
| North/East of Sudbury | 1.55 | 2.13 | 1.75 | 1.27 | 1.53 | 0.60 | 1.02 | 1.04 | 0.65 | 1.14 | 1.26 |
| Northwest Ontario | 1.87 | 1.68 | 1.63 | 1.18 | 2.10 | 2.04 | 1.57 | 1.81 | 1.45 | 1.71 | 1.70 |
| Peterborough to Kingston | 0.88 | 0.72 | 1.15 | 0.85 | 0.56 | 0.46 | 0.56 | 0.77 | 0.36 | 0.69 | 0.70 |
| Renfrew | 0.93 | 2.47 | 2.40 | 0.79 | 0.71 | 0.78 | 1.36 | 1.93 | 0.43 | 0.43 | 1.24 |
| South Georgian Bay/Muskoka | 0.26 | 0.45 | 0.21 | 0.50 | 0.18 | 0.00 | 0.21 | 0.18 | 0.00 | 0.05 | 0.21 |
| St. Lawrence | 1.50 | 1.56 | 1.53 | 0.41 | 0.82 | 0.24 | 0.71 | 0.71 | 2.29 | 0.71 | 1.05 |
| Sudbury/Algoma | 1.94 | 1.95 | 5.16 | 2.23 | 1.74 | 0.94 | 1.74 | 1.42 | 3.30 | 1.55 | 2.20 |
| Windsor/Essex | 0.26 | 0.33 | 0.37 | 0.44 | 0.15 | 0.30 | 0.15 | 0.34 | 0.18 | 0.18 | 0.27 |

| T-SAIFI-S | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 10-Yr Weighted Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Burlington to Nanticoke | 0.18 | 0.15 | 0.43 | 0.23 | 0.30 | 0.16 | 0.28 | 0.10 | 0.28 | 0.19 | 0.23 |
| Chatham/Lambton/Sarnia | 0.68 | 0.52 | 0.40 | 0.36 | 0.20 | 0.52 | 0.40 | 1.20 | 0.64 | 0.12 | 0.50 |
| Greater Bruce/Huron | 2.00 | 1.19 | 0.51 | 2.20 | 1.00 | 0.69 | 0.32 | 0.75 | 1.43 | 0.64 | 1.07 |
| Greater Ottawa | 0.56 | 0.62 | 0.55 | 0.82 | 0.46 | 0.31 | 0.32 | 0.72 | 0.33 | 0.31 | 0.50 |
| GTA East | 0.10 | 0.15 | 0.05 | 0.55 | 0.25 | 0.00 | 0.05 | 0.85 | 0.00 | 0.00 | 0.20 |
| GTA North | 0.14 | 0.07 | 0.46 | 0.04 | 0.29 | 0.00 | 0.00 | 0.45 | 0.21 | 0.10 | 0.18 |
| GTA West | 0.33 | 0.19 | 0.30 | 0.09 | 0.24 | 0.11 | 0.22 | 0.22 | 0.07 | 0.11 | 0.19 |
| KWCG | 0.53 | 0.66 | 1.24 | 0.30 | 0.30 | 0.27 | 0.08 | 0.18 | 0.10 | 0.05 | 0.37 |
| London Area | 0.48 | 0.83 | 0.43 | 0.92 | 0.36 | 0.46 | 0.42 | 0.89 | 0.70 | 0.30 | 0.58 |
| Metro Toronto | 0.20 | 0.13 | 0.16 | 0.34 | 0.41 | 0.24 | 0.21 | 0.56 | 0.23 | 0.24 | 0.27 |
| Niagara | 0.11 | 0.38 | 0.23 | 0.31 | 0.50 | 0.23 | 0.39 | 0.36 | 0.17 | 0.15 | 0.28 |
| North/East of Sudbury | 1.26 | 2.13 | 1.71 | 1.45 | 2.14 | 0.62 | 2.22 | 1.12 | 1.33 | 1.35 | 1.53 |
| Northwest Ontario | 2.38 | 2.35 | 1.75 | 1.00 | 1.88 | 1.63 | 2.32 | 2.41 | 1.81 | 2.36 | 1.99 |
| Peterborough to Kingston | 0.43 | 0.77 | 1.00 | 0.56 | 0.79 | 0.74 | 0.46 | 0.38 | 0.46 | 0.33 | 0.59 |
| Renfrew | 3.20 | 1.47 | 1.87 | 1.64 | 1.14 | 1.00 | 1.43 | 4.21 | 3.64 | 3.21 | 2.28 |
| South Georgian Bay/Muskoka | 0.29 | 0.34 | 0.37 | 0.37 | 0.32 | 0.11 | 0.13 | 0.13 | 0.13 | 0.24 | 0.24 |
| St. Lawrence | 0.61 | 0.22 | 0.35 | 0.29 | 0.41 | 0.53 | 0.29 | 0.18 | 0.35 | 0.29 | 0.35 |
| Sudbury/Algoma | 0.53 | 0.86 | 0.97 | 2.29 | 0.87 | 0.84 | 1.84 | 0.65 | 1.80 | 0.59 | 1.12 |
| Windsor/Essex | 0.63 | 0.56 | 0.37 | 0.41 | 0.19 | 1.11 | 0.44 | 0.34 | 0.25 | 0.21 | 0.45 |

| T-SAIFI-all | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 10-Yr Weighted Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Burlington to Nanticoke | 0.31 | 0.27 | 0.60 | 0.26 | 0.41 | 0.19 | 0.34 | 0.21 | 0.35 | 0.25 | 0.32 |
| Chatham/Lambton/Sarnia | 1.45 | 0.91 | 0.48 | 0.60 | 0.36 | 1.16 | 1.88 | 1.44 | 0.84 | 0.36 | 0.94 |
| Greater Bruce/Huron | 2.52 | 5.00 | 1.66 | 4.02 | 1.93 | 0.69 | 0.78 | 1.97 | 2.68 | 1.21 | 2.24 |
| Greater Ottawa | 1.22 | 0.90 | 0.76 | 0.95 | 0.74 | 0.41 | 0.48 | 0.72 | 0.53 | 0.39 | 0.71 |
| GTA East | 0.20 | 0.35 | 0.15 | 0.70 | 0.25 | 0.00 | 0.15 | 0.85 | 0.05 | 0.00 | 0.27 |
| GTA North | 0.21 | 0.29 | 0.57 | 0.07 | 0.29 | 0.00 | 0.04 | 0.45 | 0.21 | 0.21 | 0.23 |
| GTA West | 0.39 | 0.38 | 0.37 | 0.20 | 0.28 | 0.11 | 0.28 | 0.33 | 0.09 | 0.13 | 0.26 |
| KWCG | 1.84 | 1.94 | 2.29 | 0.80 | 0.45 | 0.44 | 0.35 | 0.20 | 0.33 | 0.23 | 0.90 |
| London Area | 0.90 | 1.17 | 0.89 | 1.40 | 0.95 | 0.83 | 0.80 | 1.13 | 0.90 | 0.65 | 0.96 |
| Metro Toronto | 0.20 | 0.16 | 0.21 | 0.36 | 0.44 | 0.25 | 0.29 | 0.73 | 0.25 | 0.38 | 0.33 |
| Niagara | 0.42 | 0.47 | 0.43 | 0.76 | 0.89 | 0.27 | 0.93 | 0.72 | 0.30 | 0.32 | 0.55 |
| North/East of Sudbury | 2.81 | 4.26 | 3.47 | 2.71 | 3.67 | 1.22 | 3.24 | 2.16 | 1.98 | 2.49 | 2.80 |
| Northwest Ontario | 4.25 | 4.03 | 3.38 | 2.18 | 3.99 | 3.67 | 3.89 | 4.22 | 3.26 | 4.07 | 3.69 |
| Peterborough to Kingston | 1.30 | 1.48 | 2.15 | 1.41 | 1.36 | 1.21 | 1.03 | 1.15 | 0.82 | 1.03 | 1.29 |
| Renfrew | 4.13 | 3.93 | 4.27 | 2.43 | 1.86 | 1.78 | 2.79 | 6.14 | 4.07 | 3.64 | 3.52 |
| South Georgian Bay/Muskoka | 0.55 | 0.79 | 0.58 | 0.87 | 0.50 | 0.11 | 0.34 | 0.32 | 0.13 | 0.29 | 0.45 |
| St. Lawrence | 2.11 | 1.78 | 1.88 | 0.71 | 1.24 | 0.76 | 1.00 | 0.88 | 2.65 | 1.00 | 1.41 |
| Sudbury/Algoma | 2.47 | 2.81 | 6.13 | 4.52 | 2.61 | 1.77 | 3.58 | 2.06 | 5.10 | 2.14 | 3.32 |
| Windsor/Essex | 0.89 | 0.89 | 0.74 | 0.85 | 0.33 | 1.41 | 0.59 | 0.69 | 0.43 | 0.39 | 0.72 |

| T-SAIDI (Load) | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 10-Yr Weighted Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Burlington to Nanticoke | 6.0 | 10.0 | 37.0 | 42.6 | 15.5 | 8.6 | 6.7 | 3.6 | 17.0 | 7.5 | 15.5 |
| Chatham/Lambton/Sarnia | 181.0 | 46.9 | 36.5 | 26.1 | 8.6 | 57.2 | 72.7 | 46.9 | 39.2 | 0.2 | 50.0 |
| Greater Bruce/Huron | 42.7 | 86.3 | 232.2 | 138.5 | 71.4 | 13.8 | 1.2 | 22.8 | 20.1 | 93.5 | 71.9 |
| Greater Ottawa | 12.1 | 22.6 | 23.8 | 32.2 | 20.0 | 422.6 | 5.7 | 8.1 | 10.9 | 3.1 | 55.3 |
| GTA East | 3.2 | 2.2 | 0.3 | 48.3 | 2.9 | 0.0 | 0.2 | 74.8 | 0.0 | 0.0 | 13.0 |
| GTA North | 5.1 | 13.9 | 131.1 | 0.1 | 0.9 | 0.0 | 0.0 | 26.4 | 0.9 | 0.2 | 17.8 |
| GTA West | 6.1 | 2.9 | 2.8 | 2.2 | 4.9 | 13.6 | 6.0 | 2.7 | 0.1 | 2.8 | 4.4 |
| KWCG | 18.8 | 42.3 | 140.0 | 12.9 | 10.3 | 9.9 | 0.3 | 0.9 | 4.3 | 1.2 | 24.3 |
| London Area | 15.0 | 5.9 | 20.2 | 47.5 | 4.0 | 30.7 | 18.4 | 48.3 | 49.5 | 3.9 | 24.0 |
| Metro Toronto | 5.8 | 3.5 | 3.6 | 13.1 | 14.0 | 5.3 | 2.9 | 30.5 | 5.0 | 3.3 | 8.7 |
| Niagara | 3.7 | 23.1 | 2.1 | 10.2 | 30.0 | 17.0 | 25.7 | 3.7 | 30.0 | 16.7 | 16.2 |
| North/East of Sudbury | 271.2 | 886.6 | 257.2 | 195.1 | 363.9 | 19.8 | 178.8 | 290.3 | 115.5 | 592.6 | 314.9 |
| Northwest Ontario | 1117.5 | 278.9 | 194.9 | 128.7 | 111.6 | 258.3 | 92.8 | 175.6 | 168.0 | 216.1 | 274.3 |
| Peterborough to Kingston | 26.5 | 7.5 | 77.0 | 18.7 | 84.1 | 33.6 | 35.5 | 40.9 | 20.1 | 21.7 | 36.5 |
| Renfrew | 810.9 | 215.5 | 445.5 | 34.0 | 73.4 | 8.6 | 109.4 | 55.0 | 265.1 | 204.6 | 227.8 |
| South Georgian Bay/Muskoka | 46.9 | 2.2 | 20.2 | 8.9 | 10.8 | 3.4 | 7.5 | 8.6 | 7.7 | 13.9 | 13.0 |
| St. Lawrence | 113.5 | 1.8 | 3.6 | 23.2 | 8.9 | 49.8 | 2.6 | 13.1 | 108.1 | 14.4 | 34.2 |
| Sudbury/Algoma | 39.8 | 75.9 | 184.3 | 75.7 | 85.7 | 34.4 | 175.2 | 19.9 | 75.1 | 57.8 | 82.4 |
| Windsor/Essex | 14.0 | 2.7 | 59.6 | 35.3 | 9.5 | 45.1 | 15.7 | 3.9 | 9.9 | 0.9 | 19.4 |

# UNDERTAKING JT-2.06

## Reference:

I-01-B2-Staff-70

## Undertaking:

To provide the historical over the past five years of how many customers connected and how much it cost to connect them -- to show how the 38.5 million was arrived at.

## Response:

The load customer connection project costs and number of load customer connected projects over the past five years are outlined in the following table:

| Load Customer Connection Projects | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Total Net Capital Expenditure ($M) | 13.6 | 42.3 | 28.5 | 40.1 | 18.4 |
| Number of Projects[1] | 6 | 5 | 6 | 4 | 7 |

*[1]Represents multi-year projects with cash flows greater than $0.5M in the given year; a project may be reflected in more than one year.*

The forecast of $38.5M for Future Transmission Load Connections (T-SA-05) represents the net capital expenditure to connect future transmission load customers, over the 2023 to 2027 period. It is based on a $5M gross capital expenditure in the first year rising to $27M in the subsequent years with customers' contributions of about 65% of the gross amount as presented in Table 2 of TSP Section 2.11, ISD T-SA-05.

This forecast is reasonable and consistent with Hydro One's forecast in EB-2019-0082 ISD SA-05 where a forecast of about $25M gross/year was included to fund future load customer requests to connect to Hydro One's transmission system.

This page has been left blank intentionally.

# UNDERTAKING JT-2.07

## Reference:
I-19-B3-PWU-006

## Undertaking:
To respond to the question, if Hydro One installs 100 poles in 2021, what is Hydro One's expectation, 62 years from now, as to how many of those poles will still be in service.

## Response:
The expected service life (ESL) for poles provides an estimated value of how long a pole is expected to last from the time it is installed. An expected service life of 62 years would suggest that 50% (50 poles) of the 100 poles installed would be expected to be in service 62 years from now, assuming factors contributing to pole replacement such as weather and externally driven work remain constant. ESL is an estimate and is only valid at the time of installation. Hydro One does not use ESL as a criteria for pole replacement. Pole replacements are based on known pole condition.

This page has been left blank intentionally.

# UNDERTAKING JT-2.08

## Reference:

No Reference Provided

## Undertaking:

To file criteria for sizing distribution assets for new subdivision builds, in their existing form.

## Response:

Sizing of distribution assets for new subdivision builds are determined using the applicable sections of Hydro One's Distribution Standards, Section 9-1-1: Transformer Sizing and Section 13-4: Secondary and Service Cable Application Data. The applicable sections are extracted below.

**Section 9-1-1: Transformer Sizing:**

The following procedure for sizing transformers takes into account the diversity peak demands of various customers.

[redacted]

[redacted]

[redacted]

[redacted]

Witness: FALTAOUS Peter

# UNDERTAKING JT-2.09

**Reference:**

D-SA-02, Table 2

**Undertaking:**

To provide on a best-efforts basis a breakdown by customer type on residential, commercial, industrial of the new connections shown in Table 1 of Exhibit B, Tab 2, Schedule 1, IDS D-SA-02, page 3 of 10; or explain why you can't if you can't.

**Response:**

Hydro One cannot provide the new connection forecast in Table 1, D-SA-02 broken down by customer type. Hydro One does not track historical new connections by customer type and as a result can only forecast new connections at an aggregate level.

This page has been left blank intentionally.

# UNDERTAKING JT-2.10

## Reference:

I-09-B3-ED-017

## Undertaking:

In reference to the table I-9-B3-ED-017, (D), p.2, to provide the number of all Hydro One Dx customers that are on a constrained facility and therefore cannot install a distributed energy resource, and to confirm that this table does include all of those customers, and then to provide a table that includes also the constraints in the distribution system.

## Response:

The below table is an update to the I-9-B3-ED-017 (D) response. It includes all facilities which are fully constrained from all DER connections. The number of customers served represent all downstream Hydro One distribution customers supplied by the constrained facilities. The total Hydro One distribution customer count for all fully constrained facilities is 65,623. This represents approximately 4.7% of Hydro One's 1.4M distribution customers.

| Station Name | Bus Name | Limitation Type | Number of Customers Served | Peak Load (MW) |
|---|---|---|---|---|
| BARWICK TS | BY | THERMAL | 4018 | 14 |
| 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 |
| WANSTEAD TS | JQ | SHORT CIRCUIT | 5965 | 43 |
| CHAPLEAU DS | N/A | THERMAL | 429 | 7 |
| LAFOREST ROAD DS | N/A | THERMAL | 3882 | 13 |
| CUMBERLAND DS | N/A | SHORT CIRCUIT | 1228 | 3.3 |
| SHARBOT DS | N/A | SHORT CIRCUIT | 2072 | 3.2 |
| MANOTICK DS | N/A | SHORT CIRCUIT | 2343 | 17 |
| BEARDMORE #2 DS | N/A | THERMAL | 366 | 2 |
| TILBURY WEST DS | N/A | THERMAL | 1411 | 19 |
| WENDOVER DS | N/A | THERMAL | 4468 | 10 |

This page has been left blank intentionally.

# UNDERTAKING JT-2.11

**Reference:**

I-09-B3-ED-017

**Undertaking:**

To undertake to confirm how many customers, if any, are restricted from installing micro non-exporting DER 10 kilowatts or under; to specify which of them are Hydro One customers.

**Response:**

Hydro One does not have a different process for non-exporting microDER because of low historical interest in non-exporting microDER connections. Hydro One will develop a specific process once Hydro One receives details about the type of equipment that customers are contemplating to install. Until such time, Hydro One will continue to evaluate such requests on a case-by-case basis as they arise.

MicroDER connections are restricted by three types of constraints:

- Short Circuit limits imposed by the Transmission System Code. Stations affected by this constraint have been listed in Table 4 of Exhibit B-3-1, section 3.4.
- Thermal and short circuit constraints on upstream assets. Stations affected by this constraint have been listed in Table 4 of Exhibit B-3-1, section 3.4, except for four stations listed in the response to ED-017 (c)

Feeder microDER penetration level limitations. The total number of Hydro One distribution customers constrained from installing microDER is approximately 142,106. This represents 10.2% of Hydro One's 1.4M distribution customers.

To further clarify the discussion made during the Technical Conference:

- Short Circuit constraints which are based on limits imposed by the Transmission System Code cannot be overcome by increasing equipment capability. The limits exist to ensure customer's equipment is adequately designed for expected short circuit levels.
- Smart Inverter settings are being tested to increase the feeder microDER penetration level limitations. These settings will not address the thermal or short circuit constraints on upstream assets or the Short Circuit limits imposed by the Transmission System Code.

This page has been left blank intentionally.

# UNDERTAKING JT-2.12

**Reference:**

I-09-B3-ED-024 (c)

**Undertaking:**

To provide the previously requested estimates of load growth from switching from fossil-fuel heating from the Greener Homes grant folks.

**Response:**

Hydro One notes that interrogatory ED 24 (c) requested as follows:

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.

As indicated in Hydro One's response to ED 24 (c), Hydro One reached out the Greener Homes Division at Natural Resources Canada to request the above information.

Hydro One has not yet received a response from the Greener Homes Division at Natural Resources Canada regarding this inquiry.

This page has been left blank intentionally.

# UNDERTAKING JT-2.13

**Reference:**

I-09-B3-ED-025

**Undertaking:**

To advise whether there are fees for micro-gen connection applications, is there an application fee for a residential customer to make a micro-gen connection application, and if there is, to describe what it's meant to cover and how much it is.

**Response:**

There are no fees for a residential customer to make a microDER connection application.

This page has been left blank intentionally.

# UNDERTAKING JT-2.14

**Reference:**

I-09-B3-ED-025

**Undertaking:**

To provide a list of fees for micro-generation and to specify which ones would apply to any micro-generation application and which one would not apply to non-exporting connections.

**Response:**

Hydro One charges a fixed fee of $800 for replacement of the meter.

Occasionally, the customer would also be required to pay for other work that is needed to enable the microDER connection such as an upgrade to the service transformer, which could range from approximately $4,000 to $6,000.

Hydro One does not currently have a different process for non-exporting microDER because of low historical interest in non-exporting microDER connections. Hydro One recognizes that some requirements are likely to be different and will develop a specific process once Hydro One receives details about the type of equipment that customers are contemplating to install. Until such time, Hydro One will continue to evaluate such requests on a case-by-case basis as they arise. It is anticipated that the above fees would not apply to a non-exporting microDER use-case.

This page has been left blank intentionally.

# UNDERTAKING JT-2.15

**Reference:**

I-09-B3-ED-019b, part c)

**Undertaking:**

To provide an example of the total ownership cost calculation where the methodology is used to determine the procurement for a transformer.

**Response:**

In a recent evaluation of two manufacturers, the following information was provided by each company in their bid to supply transformers for a commercial application:

Company A:

1) Transformer cost per unit: $39,979
2) No-Load losses = 1285W
3) Load losses = 7820W

Company A TOC = $39,979 + ($16.4x1285) + ($5.22x7820) = $101,873

Company B:

1) Transformer cost per unit: $47,699
2) No-Load losses = 542W
3) Load losses = 6822W

Company B TOC = $47,699 + ($16.4x542) + ($5.22x6822) = $92,199

Although Company A had lower manufacturing costs, Company B had the lower Total Ownership Cost (TOC).

This page has been left blank intentionally.

# UNDERTAKING JT-2.16

## Reference:

I-09-B3-ED-019b, Part f)

## Undertaking:

To confirm the calculation of the costs per megawatt hour shown in the tables at part (f) of IR ED-19B.

## Response:

The tables below provide the derivation of all-in electricity prices as provided in response to part (f) of interrogatory ED-19(B).

**Table 1 - Components of All-in Electricity Prices ($/MWh)**

| | 2016 | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|---|
| Commodity[1] | $113.2 | $115.5 | $114.9 | $125.8 | $132.1 |
| Wholesale Market Service Charges[1] | $5.1 | $4.3 | $3.9 | $3.9 | $3.4 |
| Wholesale Transmission Charges[1] | $10.2 | $10.1 | $10.8 | $10.6 | $11.2 |
| Debt Retirement Charge[1] | $7.0 | $7.0 | $1.8 | $0.0 | $0.0 |
| Distribution Service Charges[2] | $26.4 | $26.1 | $28.3 | $30.2 | $30.4 |
| **TOTAL** | **$161.9** | **$163.0** | **$159.7** | **$170.5** | **$177.1** |

*[1] Data source: Information collected from IESO Monthly Market Reports for the month of December for the respective year. This information was collected for the purpose of bill impact calculations submitted in Hydro One's Transmission Revenue Requirement Applications (For example, Exhibit A, Tab 4, Schedule 1, Table 5 in EB-2021-0185 provides the reference for 2019).*

*[2] Data source: Derived based on information from the Yearbook of Electricity Distributors for the respective year (see Table 2).*

| Table 2 - Derivation of Distribution Service Charge | | | | | |
|---|---|---|---|---|---|
| | **2016** | **2017** | **2018** | **2019** | **2020** |
| Revenues from Service - Distribution | $3,432,927,549 | $3,297,218,769 | $3,746,579,691 | $3,921,857,499 | $3,897,073,729 |
| Total kWh Delivered (excluding losses) | 130,194,306,824 | 126,378,180,878 | 132,372,503,335 | 129,764,882,800 | 128,165,623,290 |
| Total kWh Delivered on Long-Term Load Transfer | 84,433,871 | 43,445,339 | 13,091,219 | 10,742,410 | 7,317,485 |
| **Distribution Service Charge ($/MWh)** | **$26.4** | **$26.1** | **$28.3** | **$30.2** | **$30.4** |

HOEP and GA prices shown in the response are based on arithmetic averages of monthly prices from the IESO website[1]:

HOEP:
https://www.ieso.ca/-/media/Files/IESO/Power-Data/data-directory/Average-Weighted-Hourly-Price-kWh.ashx

GA:
https://www.ieso.ca/-/media/Files/IESO/Power-Data/data-directory/Global-Adjustment-Values-MWh.ashx

All-in Electricity Prices for the 2021-2027 period are derived using the growth rates from a CER forecast as shown in Table 3.

| Table 3: Growth Rate of All-in Ellectricity Prices | | | | | | |
|---|---|---|---|---|---|---|
| 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 |
| 1.3% | 1.9% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% |

[1] IESO no longer has the monthly market reports before January 2020 readily available, and so, arithmetic averages of monthly values for HOEP and GA were used.

# UNDERTAKING JT-2.17

## Reference:

I-09-B3-ED-019b-02

## Undertaking:

To advise why demand charges are not accounted for in the 2016 formula.

## Response:

Demand charges are not included because the cost of losses are solely applied to a customer's kWh consumption.

This page has been left blank intentionally.

# UNDERTAKING JT-2.18

## Reference:

I-09-B3-ED-019b-02

## Undertaking:

To advise whether the energy price at page 9 of the Kinectrics study includes the GA.

## Response:

The energy price (TOU) includes GA.

This page has been left blank intentionally.

# UNDERTAKING JT-2.19

**Reference:**

I-09-B3-ED-019b-02

**Undertaking:**

To confirm that the Kinectrics methodology is used and to advise if there are any aspects of it that are not used or have been adapted as it's applied in practice.

**Response:**

Hydro One can confirm that the Kinectrics methodology is used to evaluate the Total Ownership Cost and has not been adapted or changed.

This page has been left blank intentionally.

# UNDERTAKING JT-2.20

**Reference:**

I-09-B3-ED-023

**Undertaking:**

To provide a copy of the 2019 residential equipment survey; if you cannot, to explain why you cannot.

**Response:**

Results of the survey questions related to the requests in ED-23 are provided in Attachment 1.

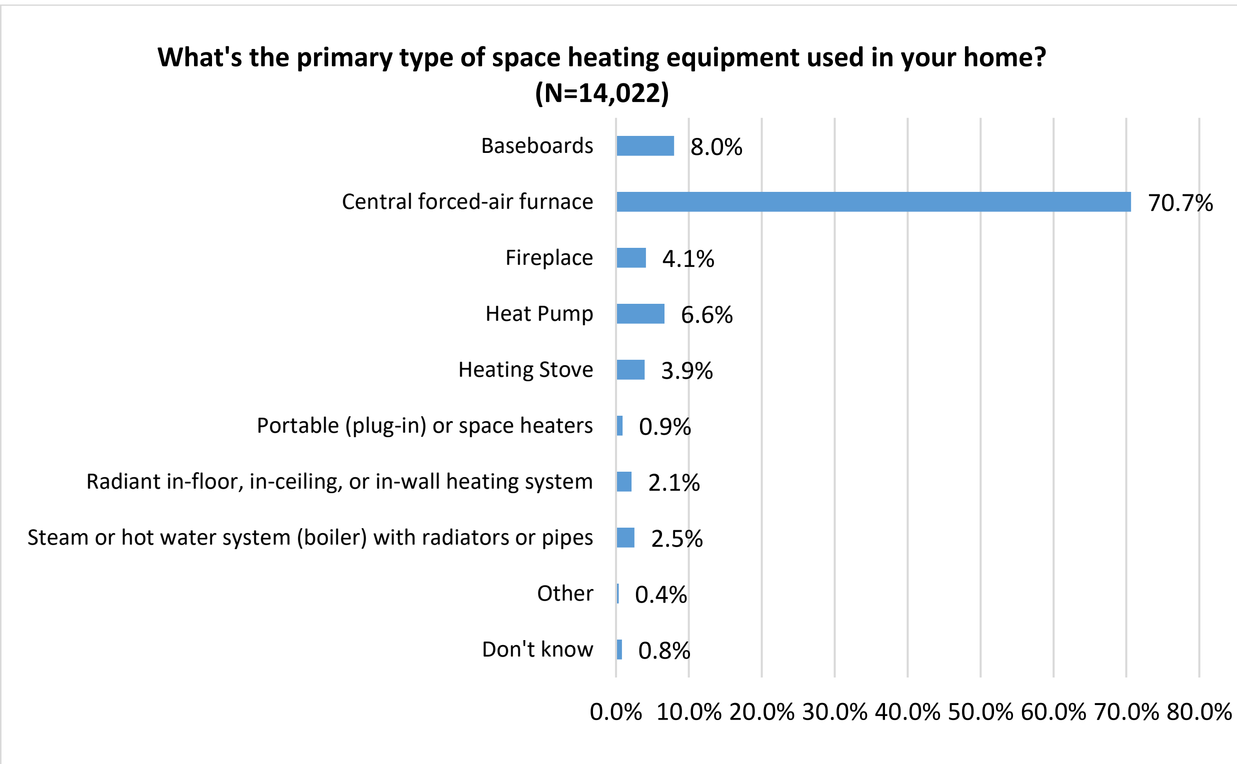
This page has been left blank intentionally.

# 2019 Hydro One Residential Energy Consumption Survey Results

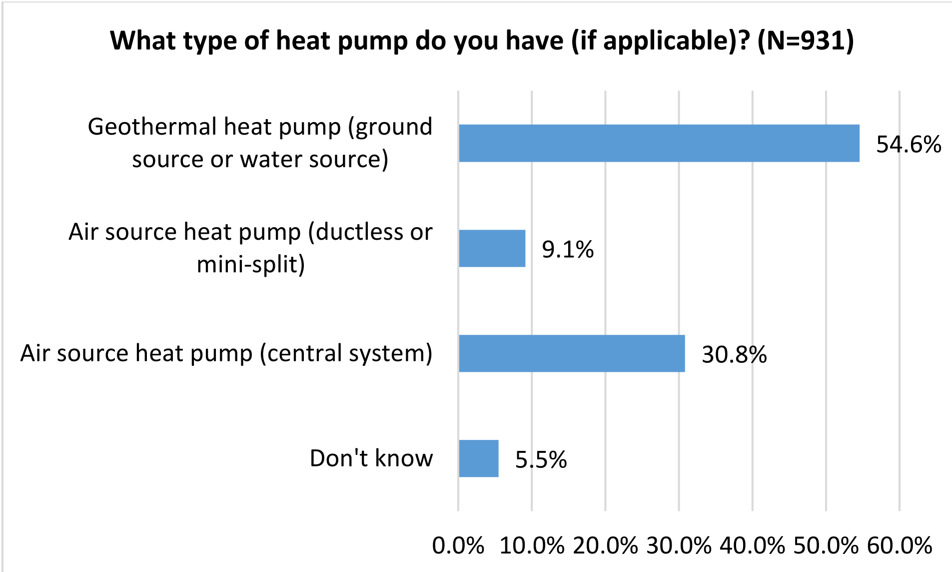
Date of survey: **November 14th to December 1st, 2019**
Total surveys sent out to year-round residential customers: **361,680**
Open rate: **31.6%** (114,363 opened emails)
Total number of unique responses from year-round residential customers: **14,541**
Response rate: **4%** (or 12.7% of opened emails)

## Section 2: Household Equipment

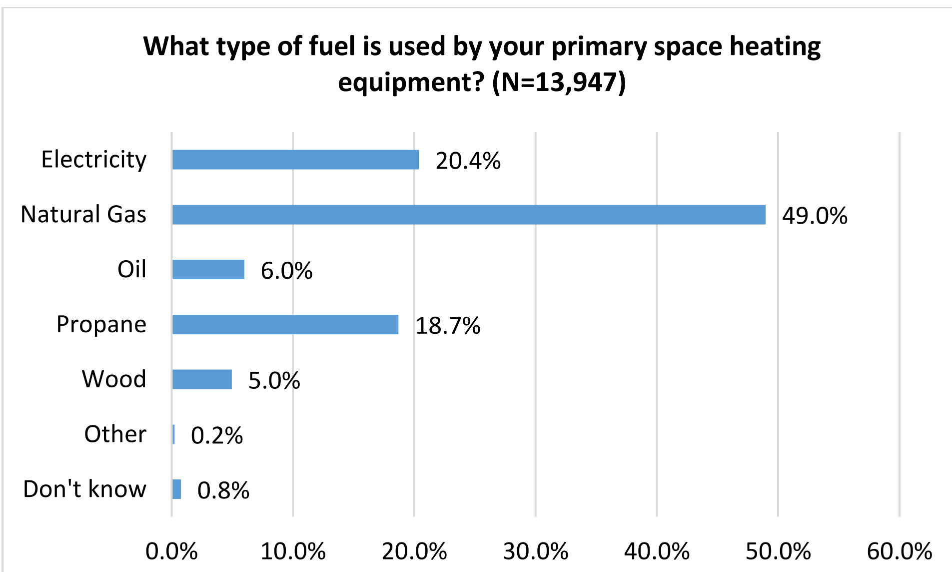
**Question 16: What's the primary type of space heating equipment used in your home?**



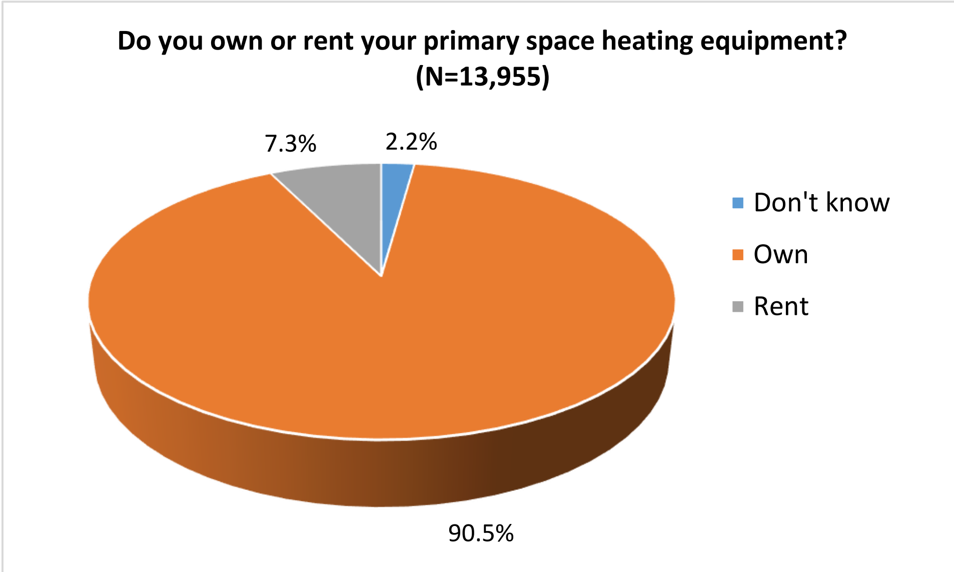

**Question 17: If you have a heat pump, what type do you have?**



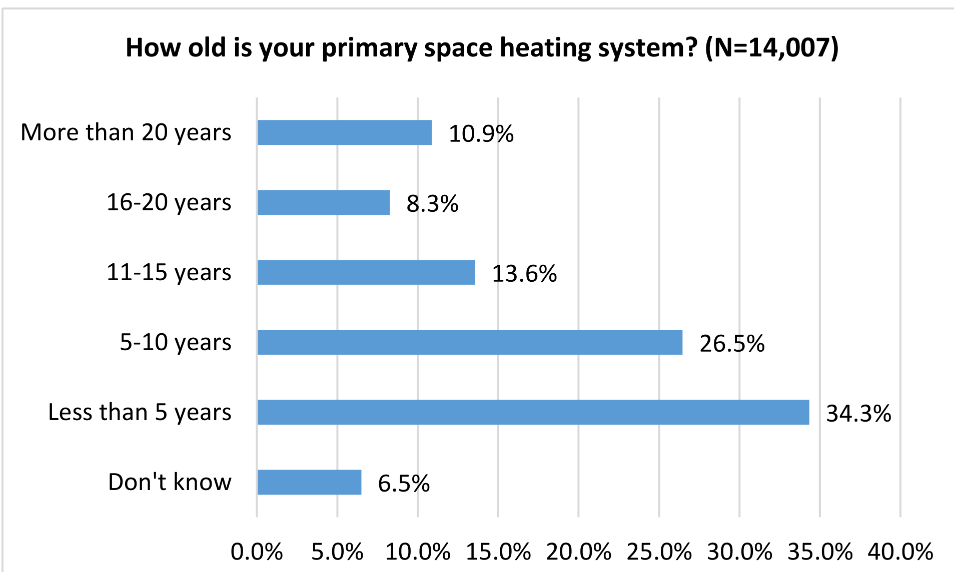

**<u>Question 18:</u> What type of fuel is used by your primary space heating equipment?**



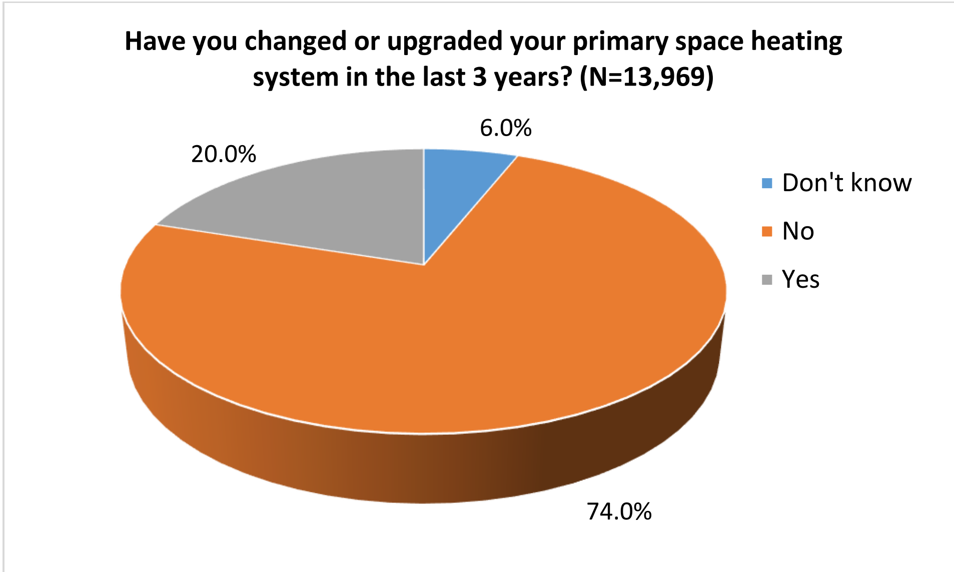
**<u>Question 19:</u> Do you own or rent your primary space heating equipment?**



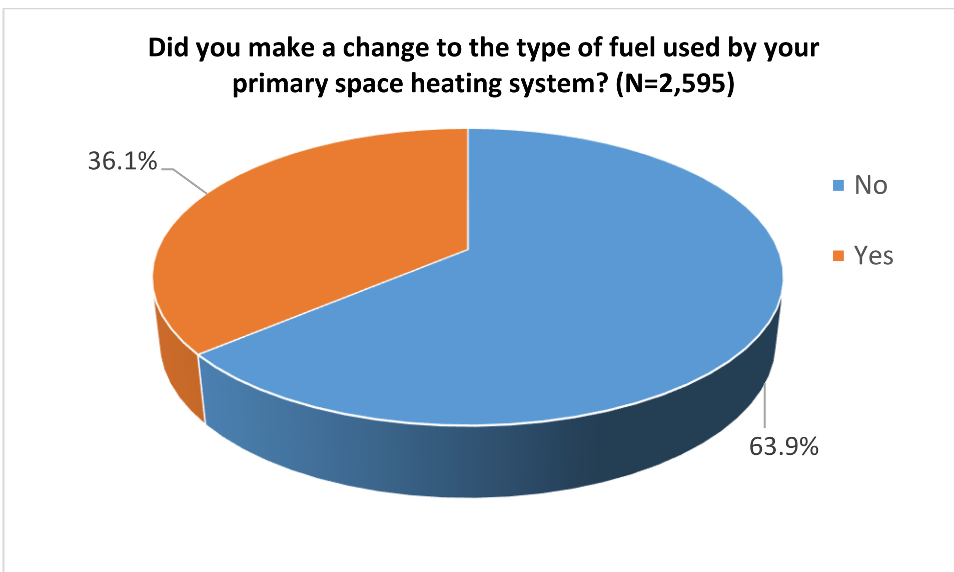

**<u>Question 20:</u> How old is your primary space heating system?**



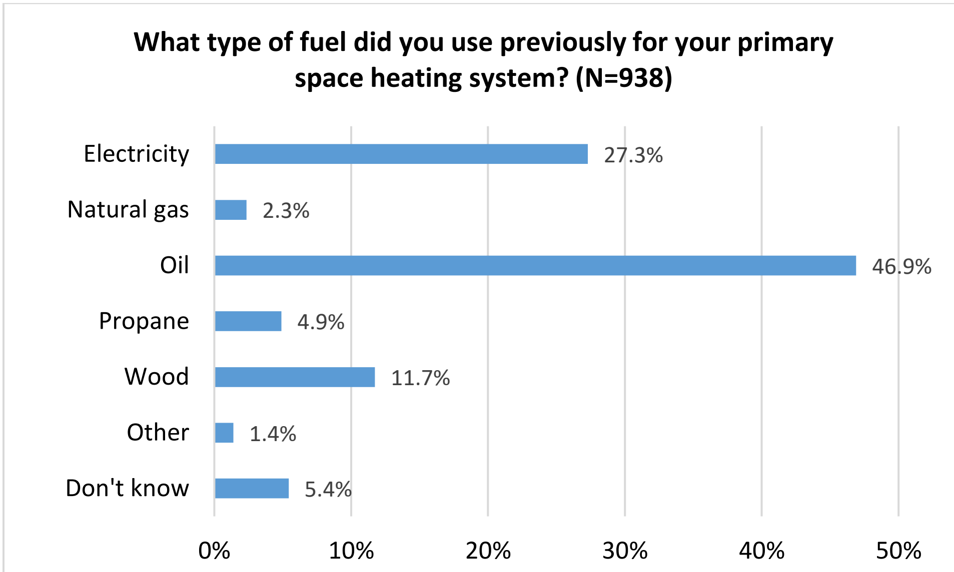
**<u>Question 21:</u> Have you changed or upgraded your primary space heating system in the last 3 years?**



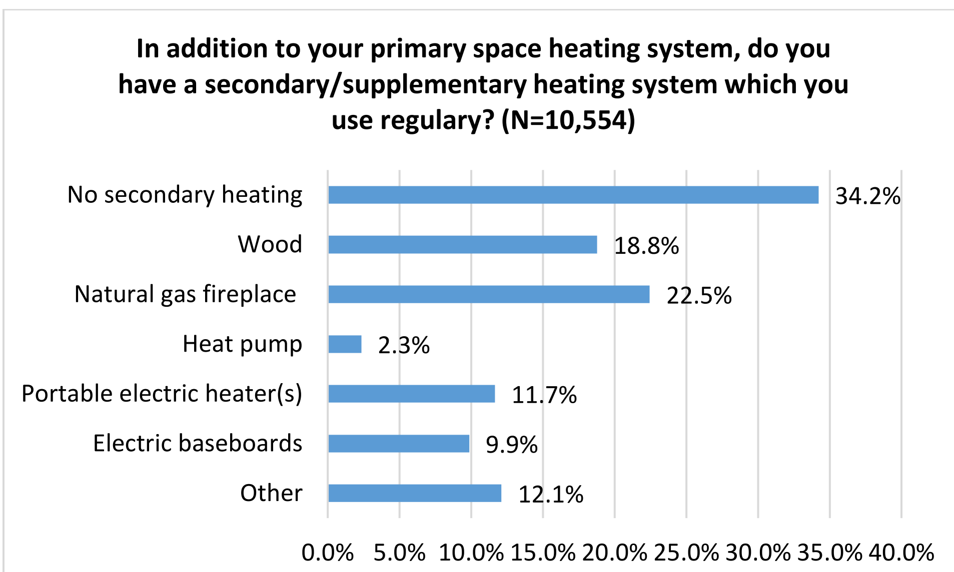

**<u>Question 22a:</u> If you changed or upgraded your primary space heating system, did you make a change to the type of fuel used?**



**<u>Question 22b:</u> If you changed fuels, what type of fuel did you use previously for your primary space heating system?**

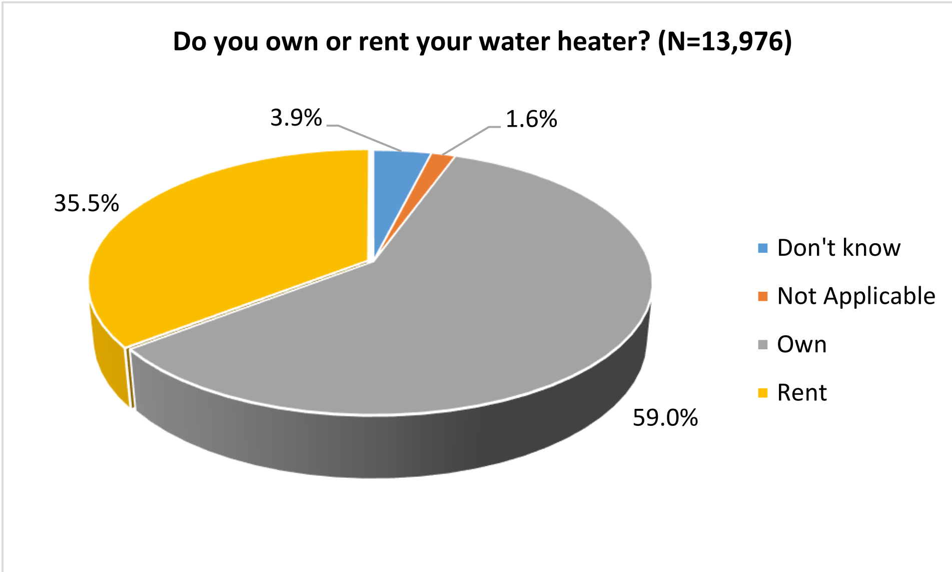



**<u>Question 23:</u> In addition to your primary space heating system, do you have a secondary or supplementary heating system which you use regularly?**

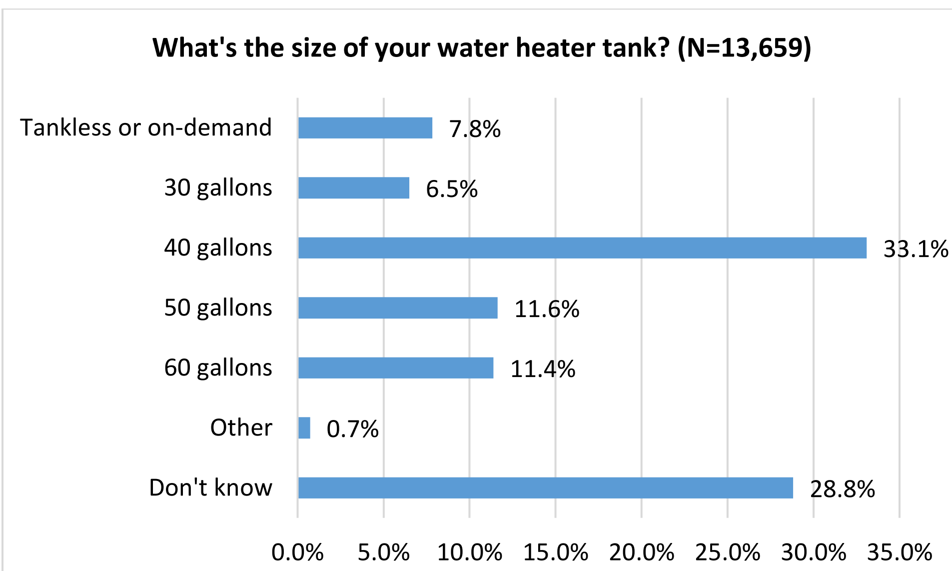



*Note: Respondents can select multiple responses so percentages do not add to 100%*

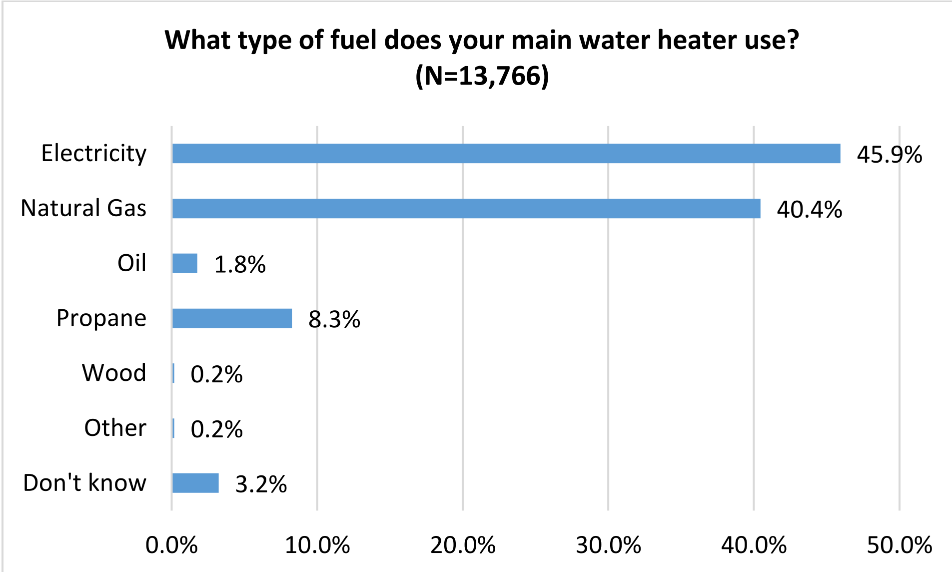
**Question 24:** **Do you own or rent your water heater?**



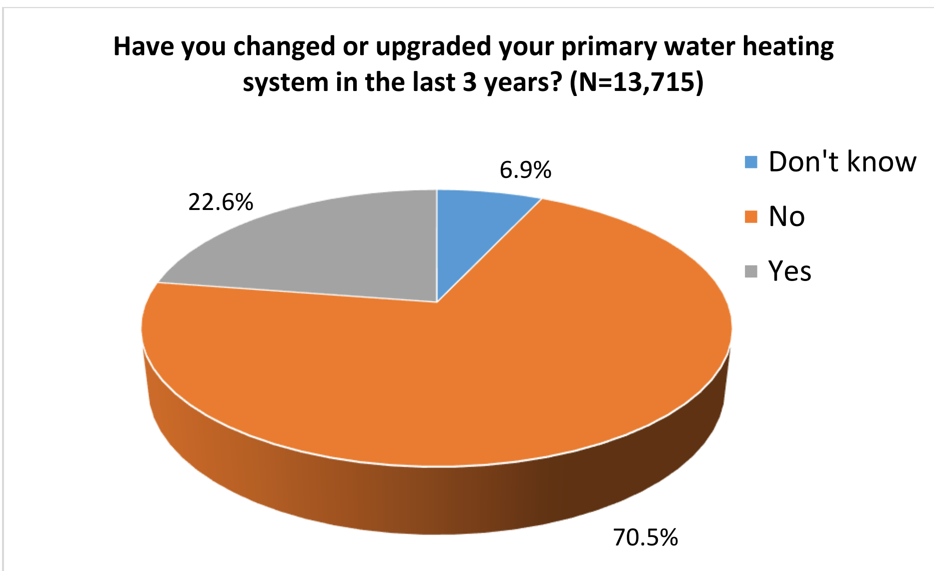

**Question 25:** **What's the size of your water heater tank?**



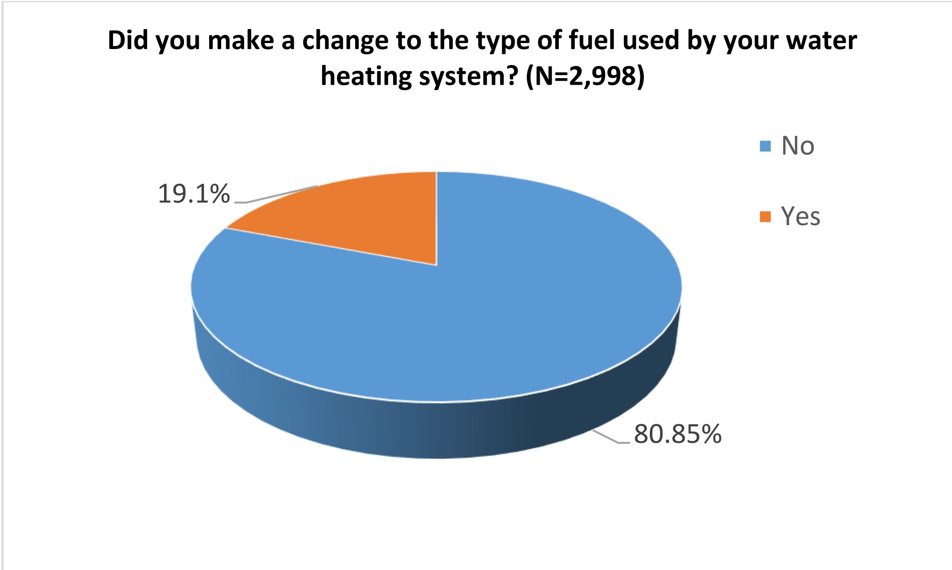
**Question 26:** **What type of fuel does your main water heater use?**



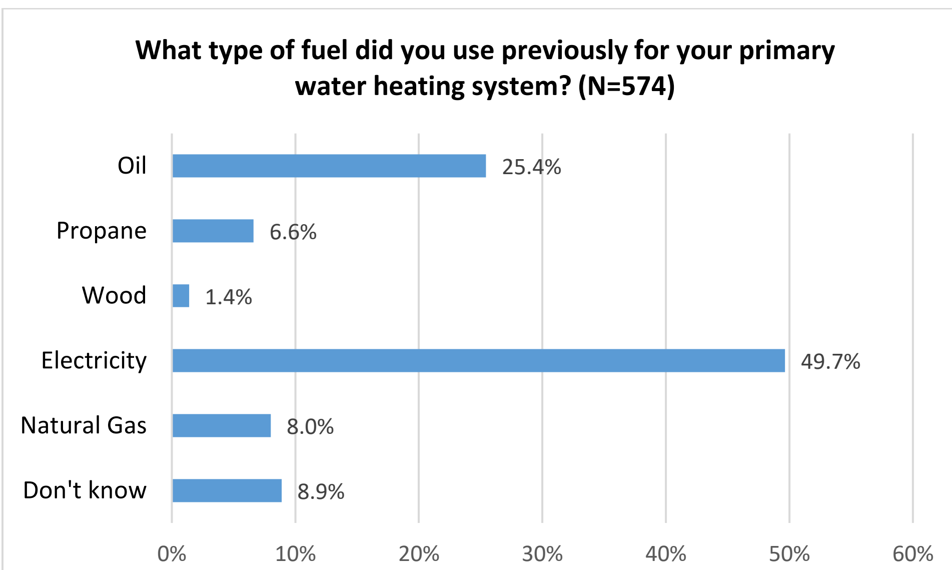

**Question 27:** **Have you changed or upgraded your primary water heating system in the last 3 years?**



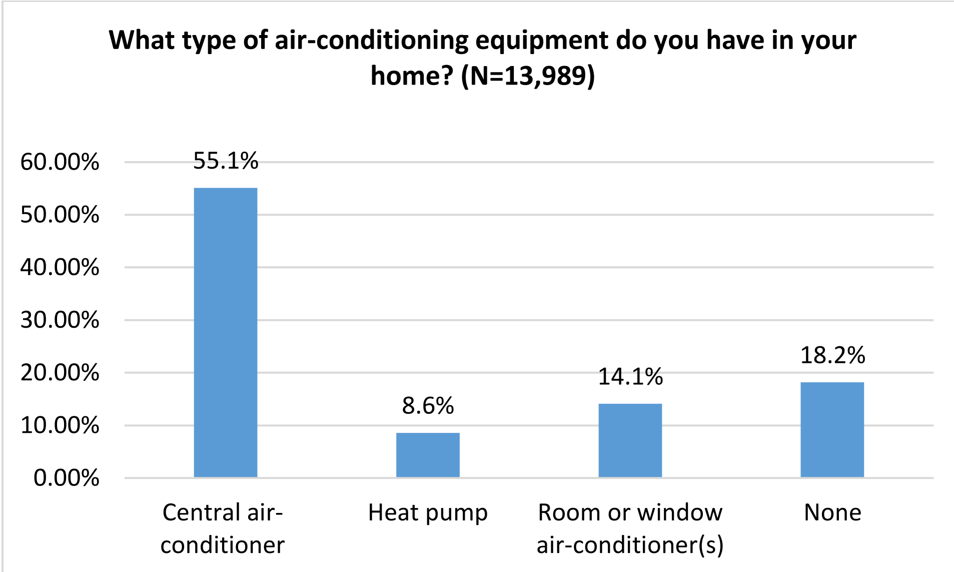
**<u>Question 28a:</u> If you changed or upgraded your primary water heating system, did you make a change to the type of fuel used?**




**<u>Question 28b:</u> If you changed fuels, what type of fuel did you use previously for your primary water heating system?**

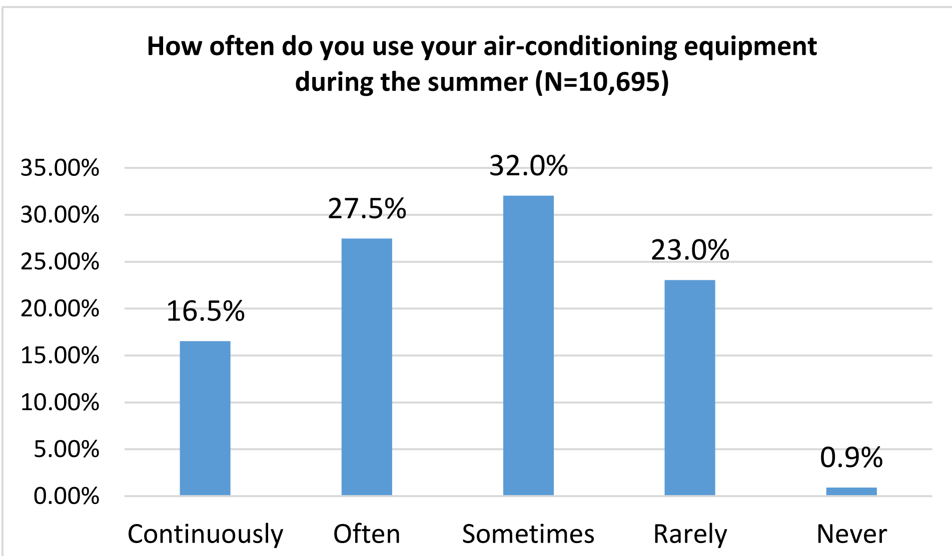


**<u>Question 29:</u> What type of air-conditioning equipment do you have in your home?**

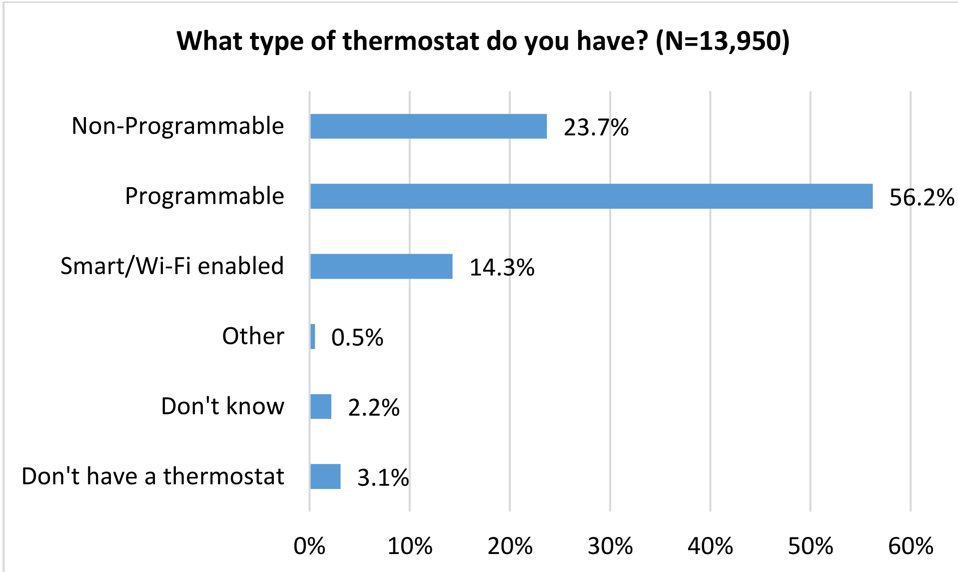



*Note: Respondents can select multiple responses so percentages do not add to 100%*

**<u>Question 30:</u> How often do you use your air-conditioning equipment during the summer?**



**Question 31:** What type of thermostat do you have?




**Question 32:** To what temperature do you normally set your thermostat during each of the following time periods?

| | Less than 16°C | 16°C to 18°C | 19°C to 20°C | 21°C to 22°C | 23°C to 24°C | 25°C or higher |
|---|---|---|---|---|---|---|
| A winter day when someone is home | 2% | 14% | 41% | 36% | 6% | 1% |
| A winter day when no one is home | 15% | 40% | 29% | 14% | 2% | 0% |
| A winter night | 11% | 40% | 30% | 15% | 3% | 0% |
| A summer day when someone is home | 17% | 9% | 17% | 24% | 24% | 9% |
| A summer day when no one is home | 19% | 10% | 14% | 16% | 21% | 19% |
| A summer night | 18% | 12% | 19% | 24% | 20% | 7% |

# UNDERTAKING JT-2.21

## Reference:

D-SS-02

## Undertaking:

To advise the peak demand for the lines in question of the seven project IDs shown in DSP section D-SS-02, page 10.

## Response:

Please see the table below:

| Project Name | Project ID | Project Description | Peak Loading |
|---|---|---|---|
| Orillia TS M2-M6 New Tie Line | SS-02.1 | Construct 7km of 44kV line and install 2 remote operable switches to enable sectionalizing and backfeed capabilities between Orillia TS M2 and M6. | Orillia M2: 19.1 MW<br>Orillia M6: 17.5 MW |
| Muskoka TS M1-M5 New Tie Line | SS-02.2 | Construct 15km of 44kV line and install 3 remote operable switches to enable sectionalizing and backfeed capabilities between Muskoka TS M1 and M5. | Muskoka M1: 36.7 MW<br>Muskoka M5: 8.5 MW |
| Guthrie F1 x Medonte F2 44kV tie-line | SS-02.3 | Construct 8km of 44kV line and install 3 remote operable switches to tie Midhurst TS - M4 and M9 circuits for backfeed capabilities | Midhurst TS M4: 12.1 MW<br>Midhurst TS M9: 21.3 MW |
| Muskoka TS M1 Reconductor | SS-02.4 | Reconductor 11km of existing 3/0 ACSR on the Muskoka TS M1 feeder to 556AL to increase feeder loading limits and allow for improved backfeed capabilities | Muskoka M1: 36.7 MW<br>Waubaushene TS M1: 19.9 MW<br>Parry Sound TS M2: 13.0 MW |
| Curve Inn, Park Rd and Wilson TS M11 Tie Line | SS-02.5 | Construct 3km of 44kV line and install 4 remote operable switches to tie Wilson TS M11 and M13 circuits for backfeed capabilities. | Wilson M11: 19.0 MW<br>Wilson M13: 9.4 MW |
| Palmerston TS M2-M4 Tie line | SS-02.6 | Construct 12km of 44kV line and install 2 remote operable switches to tie Palmerston TS M2 and M4 circuits for backfeed capabilities | Palmerston TS M2: 22.9 MW<br>Palmerston TS M4: 17.9 MW |
| Kent TS M18-M23 Tie | SS-02.7 | Construct 6km of 27.6kV line and install 3 remote operable switches to tie Kent TS M18 and M23 circuits for backfeed capabilities. | Kent M18: 12.1 MW<br>Kent M23: 8.9 MW |

This page has been left blank intentionally.

# UNDERTAKING JT-2.22

**Reference:**

I-09-B3-EP-036

D-SR-10

**Undertaking:**

To provide a detailed explanation of the calculation of risk spend efficiency shown in Energy Probe 36(b); to then show detailed calculations of two projects from the list included in the IR response as representative examples; or, if this cannot be done, to explain why not.

**Response:**

Please note that the original response to EP-36, part b, contained a transposition issue from the underlying data to the interrogatory response when mapping Project Names to their Risk Mitigated and Risk Spend Efficiency; the corrected mapping is included in the table below. To assist with the response to JT3.01, the list has been sorted based on Risk Spend Efficiency from high-to-low, revised from the prior sorting based on Project ID.

| Project Name | Project ID | Risk Mitigated | Risk Spend Efficiency |
|---|---|---|---|
| Lambton TS M2 and M4 off road relocation | SR-10.27 | 2,690,924 | 455,825 |
| Owen Sound TS M25 Rebuild Hepworth x Sauble | SR-10.30 | 1,084,955 | 242,386 |
| Commerce Way M2 Offroad Relocation | SR-10.33 | 246,017 | 214,383 |
| Waubaushene TS M1 Rebuild | SR-10.19 | 341,332 | 178,080 |
| Manitoulin TS M25 - Relocation | SR-10.13 | 264,247 | 162,011 |
| Dymond TS M3 Rebuild - Stage 2 | SR-10.23 | 1,043,643 | 155,579 |
| Douglas Point TS 44kV U/G Cables | SR-10.22 | 359,655 | 144,459 |
| Owen Sound TS M24 Rebuild - Stage 2 | SR-10.15 | 324,337 | 120,412 |
| Lindsay M7 Line Relocation Stage 3 | SR-10.03 | 224,804 | 113,851 |
| Waubaushene TS M1 Rebuild Part 2 | SR-10.32 | 323,281 | 104,701 |
| Owen Sound TS M24 Rebuild - Stage 3 | SR-10.16 | 248,163 | 87,832 |
| Lindsay M7 Line Relocation Stage 1+2 | SR-10.02 | 505,209 | 80,863 |
| Muskoka TS M1 Relocation - Part 6 | SR-10.14 | 412,183 | 74,568 |
| Meaford TS M1 Relocate – Lower Valley Road | SR-10.28 | 94,275 | 62,359 |
| Muskoka TS M1 Relocation - Part 2 of 5 | SR-10.18 | 169,138 | 35,418 |
| Kent TS M16 Relocation within Town | SR-10.26 | 140,016 | 29,952 |
| Underground Cable Injection | SR-10.34 | 670,495 | 29,237 |
| Napanee TS M2 Relocation | SR-10.09 | 79,787 | 26,285 |
| Waubaushene TS M3/M7 Line Relocation | SR-10.20 | 30,244 | 26,087 |

| | | | |
|---|---|---|---|
| Kingsville M1 and M5 Relocation In Town | SR-10.08 | 27,151 | 23,849 |
| Town of Schreiber Relocation Phase 3 | SR-10.11 | 21,782 | 19,740 |
| Herridge Lake - Rebuild | SR-10.25 | 27,727 | 17,676 |
| Angus 44 kV Backlot Relocate, Barrie Line Relocate | SR-10.01 | 32,883 | 13,589 |
| Owen Sound Line Rebuild - Part 4 | SR-10.05 | 15,793 | 13,242 |
| Gardiner TS M14 Relocation | SR-10.06 | 25,026 | 12,569 |
| Owen Sound Line Rebuild - Part 3 | SR-10.04 | 25,270 | 11,556 |
| Tillsonburg TS M4 Relocation | SR-10.10 | 24,580 | 10,793 |
| Errington Street Rebuild | SR-10.24 | 26,239 | 10,230 |
| Napanee TS M4 Relocation Phase 1 to Marysville | SR-10.29 | 14,679 | 9,296 |
| Stayner TS M2 Supply Rebuild | SR-10.31 | 32,996 | 9,081 |
| Weston Lake DS F1 – Kukatush Line Section Relocation | SR-10.12 | 15,202 | 8,706 |
| Clarke TS M2 Towerline Relocation | SR-10.17 | 57,527 | 8,419 |
| Crosby TS M6 Line Relocation | SR-10.21 | 41,896 | 5,799 |
| Kent TS M16 Relocation | SR-10.07 | 4,564 | 3,759 |

The total risk mitigated is calculated by summing the mitigated risk score for each taxonomy (i.e. safety, reliability and environmental). The risk spend efficiency calculation is calculated by dividing the risk mitigation benefits that will be achieved by undertaking the investment by the implementation cost. To clarify, the implementation cost used in the calculation may reflect costs that are outside of the 2023-27 period, either because work is initiated before the current period, or is anticipated to be completed beyond 2027.

The references to SR-10.09 and SR-10.10 from the table above have been extracted below, with the cost details appended, to include references A, B, C, D to illustrate the components of the calculation.

| | | A | B | C = A/B |
|---|---|---|---|---|
| **Project Name** | **Project ID** | Risk Mitigated | Implementation Cost ($M) | Risk Spend Efficiency (per $M) |
| Napanee TS M2 Relocation | SR-10.09 | 79,787 | 3.0 | 26,285 |
| Tillsonburg TS M4 Relocation | SR-10.10 | 24,580 | 2.3 | 10,793 |

# UNDERTAKING JT-2.23

**Reference:**

D-SR-10

I-09-B3-EP-036

**Undertaking:**

To provide a list of candidate investments that form part of SR-10; if not representative, to explain why, and to provide more information about when there would be situations where you would pick another project, etc.

**Response:**

The table below provides a list of material candidate investments, ordered from high to low based on risk-spend efficiency for SR-10.

| Project | Risk Mitigated | RSE | Status (In/Out of Plan) | Reference |
|---|---|---|---|---|
| Lambton TS M2 and M4 off road relocation | 2,690,924 | 455,825 | In | 10.27 |
| Owen Sound TS M25 Rebuild Hepworth x Sauble | 1,084,955 | 242,386 | In | 10.30 |
| Commerce Way M2 Offroad Relocation | 246,017 | 214,383 | In | 10.33 |
| Waubaushene TS M1 Rebuild | 341,332 | 178,080 | In | 10.19 |
| Manitoulin TS M25 - Relocation | 264,247 | 162,011 | In | 10.13 |
| Dymond TS M3 Rebuild - Stage 2 | 1,043,643 | 155,579 | In | 10.23 |
| Douglas Point TS 44kV U/G Cables | 359,655 | 144,459 | In | 10.22 |
| Owen Sound TS M24 Rebuild - Stage 2 | 324,337 | 120,412 | In | 10.15 |
| Lindsay M7 Line Relocation Stage 3 | 224,804 | 113,851 | In | 10.03 |
| Waubaushene TS M1 Rebuild Part 2 | 323,281 | 104,701 | In | 10.32 |
| Owen Sound TS M24 Rebuild - Stage 3 | 248,163 | 87,832 | In | 10.16 |
| Lindsay M7 Line Relocation Stage 1+2 | 505,209 | 80,863 | In | 10.02 |
| Muskoka TS M1 Relocation - Part 6 | 412,183 | 74,568 | In | 10.14 |
| Meaford TS M1 Relocate – Lower Valley Road | 94,275 | 62,359 | In | 10.28 |
| Muskoka TS M1 Relocation - Part 2 of 5 | 169,138 | 35,418 | In | 10.18 |
| Kent TS M16 Relocation within Town | 140,016 | 29,952 | In | 10.26 |
| Underground Cable Injection | 670,495 | 29,237 | In | 10.34 |
| Napanee TS M2 Relocation | 79,787 | 26,285 | In | 10.09 |
| Waubaushene TS M3/M7 Line Relocation | 30,244 | 26,087 | In | 10.20 |
| Kingsville M1 and M5 Relocation In Town | 27,151 | 23,849 | In | 10.08 |
| Town of Schreiber Relocation Phase 3 | 21,782 | 19,740 | In | 10.11 |
| Herridge Lake - Rebuild | 27,727 | 17,676 | In | 10.25 |
| Angus 44 kV Backlot Relocate, Barrie Line Relocate | 32,883 | 13,589 | In | 10.01 |
| Owen Sound Line Rebuild - Part 4 | 15,793 | 13,242 | In | 10.05 |
| Gardiner TS M14 Relocation | 25,026 | 12,569 | In | 10.06 |
| Owen Sound Line Rebuild - Part 3 | 25,270 | 11,556 | In | 10.04 |
| Tillsonburg TS M4 Relocation | 24,580 | 10,793 | In | 10.10 |
| Errington Street Rebuild | 26,239 | 10,230 | In | 10.24 |
| Napanee TS M4 Relocation Phase 1 to Marysville | 14,679 | 9,296 | In | 10.29 |
| Stayner TS M2 Supply Rebuild | 32,996 | 9,081 | In | 10.31 |
| Weston Lake DS F1 – Kukatush Line Section Relocation | 15,202 | 8,706 | In | 10.12 |
| Clarke TS M2 Towerline Relocation | 57,527 | 8,419 | In | 10.17 |
| Crosby TS M6 Line Relocation | 41,896 | 5,799 | In | 10.21 |
| Kent TS M16 Relocation | 4,564 | 3,759 | In | 10.07 |
| Havelock TS M2 Rebuild Part 1 | 13,836 | 3,459 | Out | Out |
| Longwood M25 Off-road Relocation | 11,853 | 3,387 | Out | Out |

| | | | | |
|---|---|---|---|---|
| Minden TS M2 - Part 2 of 2, Minden | 21,996 | 3,384 | Out | Out |
| Minden M4 Line Relocate | 7,042 | 3,364 | Out | Out |
| Kirkland Lake TS - G3K Towerline: Refurbishment | 21,439 | 3,298 | Out | Out |
| Havelock TS M4 Relocate | 7,104 | 3,229 | Out | Out |
| Martindale TS M6 - Transmission Line Refurb | 20,950 | 3,223 | Out | Out |
| Forest Jura DS F1 off-road Relocation | 5,779 | 3,211 | Out | Out |
| Brant TS M22 Offroad Relocation | 9,460 | 3,153 | Out | Out |
| Longueuil TS M23 Relocate | 15,993 | 3,076 | Out | Out |
| Dundas TS M1 Rebuild | 5,104 | 2,712 | Out | Out |
| Stratford TS M7 - Feeder Egress Relocation | 10,113 | 2,528 | Out | Out |
| Muskoka TS M2 Relocate | 2,763 | 2,477 | Out | Out |
| Hanover TS M4 – Rebuild Tap to Paisley | 9,581 | 2,375 | Out | Out |
| Zorra DS Load Relief | 3,057 | 2,352 | Out | Out |
| Centralia TS - M2 - Line Upgrade | 8,141 | 2,326 | Out | Out |
| Wanstead TS M4 Relocation - Brigden Tap | 10,206 | 2,209 | Out | Out |
| Lindsay M7 Line Upgrade Stage 2 | 3,998 | 2,159 | Out | Out |
| Hinchinbrooke DS Echo Lake Relocate | 1,993 | 2,005 | Out | Out |
| Marthaville Off Road M2 Relocation | 959 | 1,565 | Out | Out |
| Allanburg TS M7 Rebuild - Class C Estimate Line Relocate | 637 | 1,199 | Out | Out |
| Kent TS M24 Relocation Phase 1 | 4,828 | 1,178 | Out | Out |
| Tilbury West DS F2 and Belle River TS M2 Relocatio | 4,756 | 960 | Out | Out |
| Port Arthur TS M6 Rebuild-West Loon Lake Ph.1&2 | 3,010 | 944 | Out | Out |
| Craighurst DS F1 - Orr Lake Line Upgrade | 1,117 | 922 | Out | Out |
| Ingersoll TS M46 Relocation | 395 | 494 | Out | Out |
| Longwood M26 Offroad Relocation | 878 | 358 | Out | Out |
| Palmerston TS M3 Relocation | 810 | 131 | Out | Out |
| Dobbin TS 20M4 M6 M8 Reconstruction-Ackinson Rd | 263 | 84 | Out | Out |

This page has been left blank intentionally.

# UNDERTAKING JT-2.24

**Reference:**

I-22-B3-SEC-145

**Undertaking:**

On a best-efforts basis and under the same caveats as provided in JT-1.12 for the transmission, to complete the tables on a forecast basis.

**Response:**

Table 5 (Exhibit B-3-1, Section 3.9, Attachment 2, page 17) in the evidence captures the 2020 plan and actual values for programs. Full year 2021 capital and ISA information for programs will not be available until after the fiscal year end.

Please see below for an updated version of Table 7 (Exhibit B-3-1, Section 3.9, Attachment 2, page 27) with project total and project in-service date information as of Q3 2021. The five projects with material changes in project total and/or in-service date compared to as filed evidence are projects that are in the Planning phase.

Any variances will be managed at the portfolio level via the redirection process. The overall capital envelope spend for the Distribution 2018-2022 rate period will be consistent with the evidence.

| OEB Category | AR Name | Project Phase | Net DRO Plan ($M) | Net Actual ($M) | ISA DRO Plan ($M) | ISA Actual ($M) | Net DRO Plan Project Total ($M) | Net Project End Forecast ($M) | Project End Variance ($M) | Net Project End Forecast at Q3 2021 ($M) | Net LTD Actual ($M) | DRO Plan IS Year* | Forecast/ Actual IS Year | Date Variance (Years) | Forecast/Actual IS Year at Q3 2021 | Variance Req'd |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **System Renewal - SR-13 Life Cycle Optimization and Operational Efficiency Projects** | Eugenia RS - 44kV Pole Mount Regulators | Planning | 3.3 | 0.0 | 4.3 | 0.0 | 4.3 | 1.1 | -3.2 | 1.1 | 0.7 | 2020 | 2022 | 2 | 2022 | Yes |
| **System Service - SS-02 System Upgrades Driven by Load Growth** | Awenda DS F1 Upgrade Supply to Christian Island | Planning | 2.8 | 0.0 | 3.5 | 0.0 | 3.5 | 0.3 | -3.2 | 0 | 0.3 | 2020 | 2022 | 2 | Project Cancelled | Yes |
| | New Old School DS and feeders | Planning | 11.2 | 0.8 | 11.6 | 0.0 | 11.6 | 0.1 | -11.5 | 4.7 | 0.8 | 2020 | 2021 | 1 | 2022 | Yes |
| | Enfield TS Feeder Development | Execution | 3.3 | 3.2 | 11.2 | 10.4 | 11.2 | 10.7 | -0.5 | 10.5 | 10.4 | 2020 | 2020 | 0 | 2020 | Yes |
| | Brockville 44kV Load Growth | Planning | 9.1 | 0.3 | 10.0 | 0.0 | 10 | 0.5 | -9.5 | 6.4 | 0.5 | 2020 | 2022 | 2 | 2023 | Yes |
| | Leamington TS DESN2 Feeder Development | Execution | 10.5 | 29.3 | 41.1 | 40.2 | 41.1 | 53.6 | 12.5 | 53.0 | 52.1 | 2020 | 2020 | 0 | 2020 | Yes |
| **System Service - SS-02 System Upgrades Driven by Load Growth** | Wikwemikong Supply - Station & Line Work | Planning | 6.1 | 0.2 | 6.3 | 0.0 | 6.3 | 1.0 | -5.3 | 5.2 | 0.3 | 2020 | 2022 | 2 | 2023 | Yes |
| | Barrie TS - Construct new feeders | Planning | 5.6 | 0.1 | 5.8 | 0.0 | 5.8 | 0.1 | -5.7 | 6.2 | 0.1 | 2020 | 2022 | 2 | 2023 | Yes |

*DRO Plan In-Service (IS) Year was updated for certain projects above to correct a data error. In addition, the DRO IS Year for Kirkland Lake Voltage Conversion - Stage 1, included at Table 6: "Capital Project Variances (2019)" in DSP Section 3.9, Attachment 2, should be modified from 2021 to 2019.

# UNDERTAKING JT-2.25

**Reference:**

I-22-B3-SEC-124

**Undertaking:**

To provide the underlying raw data for the report entitled "Guidehouse and First Quartile distribution poles replacement program benchmarking report 2020".

**Response:**

Response by Guidehouse and First Quartile:

Please see Attachment 1 for the raw data set underlying the Distribution Poles and Substations Benchmarking Report. Certain portions of the data set are not being supplied (as indicated in Attachment 1) due to Guidehouse and First Quartile’s confidentiality obligations to survey participants, as the data contained therein can be cross-referenced with publicly available information to identify the relevant peer utilities and the data associated with each of them.

This page has been left blank intentionally.

# UNDERTAKING JT-2.26

## Reference:

I-22-B3-SEC-124, part j)

## Undertaking:

To reconcile the numbers in the response to B-SEC-124, attachment 3, the excel file, or to provide an appropriate explanation.

## Response:

Hydro One scorecard outlined in Section 3.5, Page 35, shows a Gross $ Pole replacement cost of $12,499 for 2019.

Utilizing the Spreadsheet, B-SEC-124, Attachment 3, adding cells 144 to 149, then dividing by cell 137, produces a unit cost of $12,499.

Row 150 should not be included in the calculation.

This page has been left blank intentionally.

# UNDERTAKING JT-2.27

**Reference:**

I-22-B3-SEC-124

**Undertaking:**

To explain the discrepancy between the Guidehouse spreadsheet at row 136 and the numbers in the board staff interrogatory, part (j).

**Response:**

The response to question DP3700.1 in the benchmarking survey included pole replacements within Woodstock, Haldimand, and Norfolk. The value provided in I-01-B3-Staff-144 excluded the acquired LDC pole replacements due to the deferred rebasing of the acquired LDCs.

This page has been left blank intentionally.

# UNDERTAKING JT-2.28

**Reference:**

I-22-B3-SEC-124

**Undertaking:**

To advise if planned pole replacements outside of the pole replacement program were included in the study; if not, to advise how many were replaced for 2018, 2019, 2020; or, if the data doesn't exist, to advise of that.

**Response:**

Unit costs in the study are only for the planned pole replacement program and question AM0350.2 in SEC124, Attachment 3 represents only the planned pole replacement program values.

Some graphs include estimates of pole replacements across other projects and programs, for example Figure 11 of the benchmarking study includes poles replaced across all planned and demand projects and programs. The data for poles replaced under planned programs aside from the pole replacement program is not available. The data provided for Figure 11 is based on the number of poles purchased across the system while removing an estimated number of poles due to system growth. This data is on aggregate across the entire system for all planned and demand work.

This page has been left blank intentionally.

# UNDERTAKING JT-2.29

**Reference:**

I-03-B1-AMPCO-014

**Undertaking:**

To make best efforts to provide project-level and portfolio-level metrics or a scorecard to some tracking that exists at the distribution level for 2018, 2019, 2020 to Q3 of 2021, similar to what was provided for the transmission system in B1-AMPCO-14;

**Response:**

Please see below for the project and portfolio metric results prepared on a best effort basis as of Q4 2019, Q4 2020 and Q3 2021 for Distribution.

| **Power System Distribution Project Level Metrics** | **Q4 2019** | **Q4 2020** | **Q3 2021** |
|---|---|---|---|
| On-time: Project In-Service Date Forecast versus Current Approved (Note 1) | 76% | 83% | 77% |
| On-time: Project In-Service Date Forecast versus Original Approved (Note 1) | 76% | 88% | 77% |
| On-budget: Gross Project Total Forecast versus Current Approved (Note 2) | 81% | 100% | 96% |
| On-budget: Gross Project Total Forecast versus Original Approved (Note 2) | 76% | 77% | 92% |
| | | | |
| **Distribution Portfolio Level Metrics** | **Q4 2019** | **Q4 2020** | **Q3 2021** |
| In-Service Additions: Annual Forecast versus Budget (Note 3) | 105% | 99% | N/A |
| Capital Expenditures: Annual Forecast versus Budget (Note 3) | 99% | 107% | N/A |
| Power System Project Portfolio Risk: Number of Projects Forecasting a Major Variance (+10% and +$500K) to Budget | 5 of 21 | 4 of 18 | 3 of 26 |
| Power System Project Portfolio Risk: Value of Projects Forecasting a Major Variance (+10% and +$500K) to Budget (Note 4) | 8% | 12% | 1% |
| Power System Project Cost Performance: Number of Projects complete within Class A Estimate Range documented in original approval (+/-10%) (Note 5) | 4 of 7 | 0 of 3 | 1 of 3 |
| Power System Project Cost Performance: Value of Projects complete within Class A Estimate Range documented in original approval (+/-10%) (Note 6) | 29% | 0% | 25% |
| Power System Project Cost Variance Distribution (Note 5) | 57% | 0% | 33% |
| Power System Project Cost Variance: Standard Deviation of Project Cost Performance represented as a percentage of original Budgets (Note 7) | 11% | 13% | 3% |
| Power System Project Schedule Variance (Note 8) | 28% | 33% | 33% |
| Power System Project Schedule Variance: Standard Deviation of Schedule Variance in Days | 229 | 275 | 258 |

Notes/Metric Definitions:

1. Percentage of active projects forecasting an in-service date variance of less than one year.
2. Percentage of active projects forecasting variance to be less than (+10% variance and +$500K over the approved budget).
3. For Q3 2021 please see Hydro One’s response to SEC-002.

4. Calculated as the total gross forecast for projects with cost variances divided by the total gross value of the active distribution projects.
5. Projects completed in the trailing 12 months (Oct 2020-Sept 2021) within the range of the Class A expected outcomes (+10% of estimated value) relative to original funding approval for projects greater than $3M.
6. Calculated as the gross value of projects completed in the trailing 12 months (Oct 2020-Sept 2021) within the range of the Class A expected outcomes (+10% of estimated value) relative to original funding approval for projects greater than $3M divided by total gross value of all projects completed in trailing 12 months (Oct 2020-Sept 2021) for projects greater than $3M.
7. Standard deviation calculation weighted by project cost for projects greater than $3M completed in the trailing 12 months (Oct 2020-Sept 2021)
8. Project Completed in trailing 12 months within 1 year of the originally approved in-service date for projects greater than $3M.

# UNDERTAKING JT-2.30

**Reference:**

I-22-B3-SEC-150, part d)

**Undertaking:**

To clarify the tracking of emergency pole replacement.

**Response:**

In reference to I-22-B3-SEC-150 part d, the number of pole replacements are recorded for activities “Emergency pole and equipment replacements” and “Post-trouble response” which are under the D-SR-05 investment. Values provided to Guidehouse for "number of poles replaced -- emergency replacement" were not based on this data. Rather, an estimate was derived from pole purchase records for all activities within D-SR-05 in an effort to provide the requested data for the benchmarking survey.

This page has been left blank intentionally.

# UNDERTAKING JT-2.31

## Reference:

I-22-B4-SEC-162

## Undertaking:

With reference to the response to IR B4-SEC-162 part (a), to ask Gartner to provide a list of Hydro One's peer companies.

## Response:

Response from Gartner:

Gartner is not able to provide the list of peer companies. Gartner's standard agreement with clients regarding benchmarking services is as follows: "with respect to any benchmarking services performed by Gartner, Gartner will only use Client's data in an aggregate and anonymous format".

This page has been left blank intentionally.

# UNDERTAKING JT-2.32

**Reference:**
I-22-B4-SEC-162

**Undertaking:**
To respond to IR B4-SEC-162 part (c).

**Response:**
Response from Gartner:

All 8 organizations within the custom peer group have generation, transmission and distribution operations. For the 114 organizations contained within the IT Key Metrics Data peer set, Gartner does not have the distribution across the stated categories available as it does not capture this data point. Providing this insight would take considerable work to conduct research into each of the 114 organizations, and, as explained in response to I-B4-SEC-162(c), would provide little additional value given the significant efforts already undertaken in the course of the study to establish a custom Peer Group that closely aligns with Hydro One’s size and nature of operations for purposes of enabling an appropriate comparison.

This page has been left blank intentionally.

# UNDERTAKING JT-2.33

## Reference:

I-22-B4-SEC-162

## Undertaking:

To respond to IR B4-SEC-162 part (d).

## Response:

Response from Gartner:

Without conducting the supporting quantitative analysis, Gartner is not in a position to offer an opinion on potential differences in benchmarking results across the categories (i.e. distribution only vs. transmission only, etc.).

This page has been left blank intentionally.

# UNDERTAKING JT-2.34

## Reference:
I-01-B4-Staff-167, Part b)

## Undertaking:
a) To provide an estimate for the sale amounts realized on the sale of Peterborough and Lindsay facilities

b) To advise whether there are other facilities planned for sale between 2023 and 2027

c) To provide the forecast and not whether there are amounts built into the application as a revenue offset.

## Response:
a) The estimated sale amounts for the Peterborough and Lindsay facilities to be realized are as follows:

| Facility | Estimated Sale Value ($)[1] | Net Book Value (2021) | Estimated Proceeds from Sale | Forecasted Year of Sale |
|---|---|---|---|---|
| Peterborough Operations Center (OC) | $1.3-$1.7M | $5.0M | ($3.7M) - ($3.3M) | 2026 |
| Lindsay Service Centre (SC) | $3.0 - $3.9M | $1.8M | $1.2M - $2.1M | 2026 |

b) Yes, the other potential facilities planned for sale between 2023-2027 are:

| Facility | Estimated Sale Value ($)[2] | Net Book Value (2021) | Estimated Proceeds from Sale | Forecast Year for Sale |
|---|---|---|---|---|
| Picton Work Centre (WC) | $0.2M - $0.3M | $0.1M | $0.1M - $0.2M | To be Determined |
| Simcoe Field Business Centre (FBC) | $2.6M - $3.3M | $0.9M | $1.7M - $2.4M | To be Determined |

c) The above estimated amounts have not been built into the JRAP application as a revenue offset. At the present time, there is too much uncertainty in the sale value for each property and the year for sale.

[1] Based on 2016 Municipal Property Assessment Corporation valuations, escalated by 2% per year to 2021.
[2] *Ibid*.

This page has been left blank intentionally.