Hydro One Networks Inc.
483 Bay Street
7th Floor South Tower
Toronto, Ontario M5G 2P5
HydroOne.com

Kathleen Burke
Director, Applications Delivery
T 416-770-0592
Kathleen.Burke@HydroOne.com

BY EMAIL AND RESS

June 16, 2022

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Marconi,

EB-2021-0110 - Custom IR Application (2023-2027) for Hydro One Networks Inc. Transmission and Distribution (Hydro One) - Undertaking Responses

Attached please find Hydro One's responses to undertakings provided at the Technical Conference held May 31 and June 1, 2022 in respect of the above-noted proceeding.

Pursuant to Rule 10.01 of the OEB's Rules of Practice and Procedure and the OEB's Practice Direction on Confidential Filings, Hydro One requests that the interrogatories listed in Appendix "A" be granted confidential treatment. The specific information for which Hydro One seeks confidential treatment and a summary of the rationale for the requests will be filed shortly by Torys LLP.

This filing has been submitted electronically using the OEB's Regulatory Electronic Submission System (RESS).

Sincerely,

Kathleen Burke

Kathleen Burke

cc. EB-2021-0110 parties (electronic)

Appendix A

Hydro One has requested confidentiality treatment for the following undertaking responses:

- JTU-1.02 Attachment 1
- JTU-1.13 Attachment 1
- JTU-1.14 Attachment 1
- JTU-1.16
- JTU-1.18 Attachment 1
- JTU-1.19

UNDERTAKING JTU-1.01

Reference:

Exhibit O-1-2, Attachment 1

Undertaking:

To provide the standard deviation in respect of the Scotia forecast for March 2022.

Response:

The standard deviation of our total CPI forecast for March 2022 is +/- 0.4%. That means that the model will accurately estimate movements in actual historical CPI inflation within a 0.8 percentage point band 95 times out of 100 in repeated sampling (ie: a so-called 95% confidence interval). This implies that there is modest model error in its ability to fit actual inflation over time.

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UNDERTAKING JTU-1.02

Reference:

Exhibit O-1-2, Attachment 1

Undertaking:

To file the engagement letter.

Response:

Please see Attachment 1.

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TORYS LLP

79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2 Canada
P. 416.865.0040 | F. 416.865.7380
www.torys.com

Charles Keizer
ckeizer@torys.com
P. 416-865-7512

BY EMAIL

CONFIDENTIAL — PRIVILEGED

Effective as of February 14, 2022

Scotia Capital Inc.
40 King Street West, 68th Floor
Toronto, ON
M5H 1H1

Re: Retainer Letter Agreement – Hydro One Networks Inc. – Inflation Trends Study

Torys LLP ("Torys" or "we") represents Hydro One Networks Inc. ("Hydro One") in connection with its planned 2023-2027 combined Distribution and Transmission rate application (the "Application") to the Ontario Energy Board (the "Board").

We confirm that, on behalf of and to assist us in providing legal advice to Hydro One in connection with the Application, Torys has agreed to retain Scotia Capital Inc. (the "Consultant" or "you"), effective as of the date first written above (the "Effective Date"), to provide consulting services as herein described. By signing back a copy of this letter, the Consultant agrees that this letter contains the agreed-upon terms and conditions of its retainer with Torys effective on the Effective Date, subject to amendment by written agreement between the parties (the "Retainer Agreement").

1. **No Conflict**

The Consultant does not have any conflict of interest or other constraints on its ability to provide expert advice in connection with this Retainer Agreement. You confirm that you are free to provide your services to Torys in connection with Torys' representation of Hydro One in the Application. You agree that during this engagement you will not provide, directly or indirectly, any services to any other party in connection with the matters at issue in the Application.

It is acknowledged that Consultant is wholly-owned by The Bank of Nova Scotia which, together with its affiliates (collectively, the "Bank"), is a full-service financial institution that conducts a full range of investment banking, merchant banking, corporate banking and securities brokerage activities. The Bank provides loans, structured products, investment banking, corporate banking and financial advisory services to governments, corporations and institutions. In addition, the Bank has an active proprietary trading book that trades securities on behalf of the Bank that are issued in a wide range of public companies. In the ordinary course of its activities and subject always to compliance with applicable securities laws, the Bank may provide, arrange or underwrite financing for Hydro One Limited, or hold long or short positions, trade or otherwise effect transactions for its own account or for the account of the Bank's clients, in debt or equity securities or related derivative securities of Hydro One Limited.

2. **Consultant Expertise**

The Consultant has been selected to provide consulting services to Torys in connection with the Application as further described in Section 3 below. The sponsor of the work of the Consultant and the person who has the relevant expertise will be:

- Derek Holt Vice President and Head of Capital Markets Economics

(referred to as the "Sponsor").

3. **Scope of Services and Work Product**

The Consultant will:

(a) carry out an independent study to analyze (i) the trends that led to the inflation in 2021 and (ii) the expected inflation and trends in 2022 and 2023 (the "Study");

(b) discuss the findings and preliminary results of the Study with Torys and Hydro One on a date and at a location to be agreed upon (the "Discussion of Findings"), which shall be no later than February 25, 2022, unless otherwise agreed to by the parties;

(c) if requested by Torys, produce a written report(s) detailing the Study's methodology, analysis performed and the Consultant's findings and recommendations (the "Report(s)"), which (i) shall be delivered to Torys no later than March 31, 2022, unless otherwise agreed to by the parties and (ii) may be filed by Torys or Hydro One with the Board in connection with the Application; and

(d) If requested by Torys, provide support during the hearing of Application ("Application Support Services" and, together with the Study, the Discussion of Findings and the Report(s), the "Services"), which may include:

    (i) assistance in responding to interrogatories applicable to the Report;

    (ii) testifying about the Report as an expert witness either orally or in writing;

    (iii) responding to undertakings (i.e., written questions during a hearing) on the Report; and

    (iv) assistance in connection with the preparation of argument (oral or written) on the issues addressed in the Report.

4. **Fees and Invoices**

By entering into this Retainer Agreement, the Consultant acknowledges that:

a) the price for the Consultant to perform the Study and participate in the Discussion of Findings shall be determined based on the hourly rates set forth in paragraph (c) below and in no event exceed [redacted] (net of HST) without prior written approval from Torys or Hydro One;

b) the price for the Consultant to prepare and deliver the Report(s) (if requested by Torys) shall be determined based on the hourly rates set forth in paragraph (c) below and in no event exceed [redacted] (net of HST) without prior written approval from Torys or Hydro One;

c) the price for the Consultant to provide Application Support Services (if requested by Torys) will be charged at the following hourly rates:

- Derek Holt [redacted]

All amounts stated herein are in Canadian dollars.

The Consultant shall direct all invoices relating to Services performed by it under this Retainer Agreement to Hydro One, to the attention of:

Ms. Eryn MacKinnon
Hydro One Networks Inc.
Regulatory Affairs Department
483 Bay St.
7th Floor, South Tower
Toronto, Ontario
M5G 2P5

with a copy to Torys, to the attention of:

Mr. Charles Keizer
Torys LLP
79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2
ckeizer@torys.com

Any disbursements for additional incidentals incurred by the Consultant in relation to this Retainer Agreement must be pre-approved by Hydro One in writing. Hydro One reserves the right to deduct any applicable non-resident withholding taxes from any amounts owing to the Consultant under this Retainer Agreement and remit such amounts to the applicable taxation authority.

5. **Confidentiality**

All work performed by the Consultant in connection with this Retainer Agreement, including all findings, opinions and conclusions the Consultant reaches in relation to this Retainer Agreement, and any communications relating thereto, are strictly privileged and confidential and shall not be disclosed to any other person or party without the prior written consent of Torys or Hydro One. The Consultant agrees to designate all written communications and material accordingly. The Consultant further agrees to promptly notify Torys in the event that the Consultant receives a request to disclose information relating to this matter by a regulatory body, governmental authority or as required by law, and agrees to cooperate with Torys, to the fullest extent permitted by law, to prevent or limit the disclosure of such material or otherwise preserve the privileged and confidential status of such material.

The Consultant agrees to hold in confidence: (a) all information provided to the Consultant, and (b) the Consultant's opinions to Torys and to Hydro One as they relate to the information, whether the information or opinions are documentary or oral (collectively, the "Confidential Information"). The Consultant will not disclose the Confidential Information to any person unless Torys or Hydro One authorizes you in writing to do so. All documents given to the Consultant in connection with this Retainer Agreement remain the property of Torys or of Hydro One and are held in trust by the Consultant as agent. The Consultant agrees to return these documents on written request.

The Consultant will not refer to Torys or to Hydro One, directly or indirectly, in connection with the promotion of its services, without obtaining the prior written consent of Torys or Hydro One, as the case may be.

Except as expressly provided herein, all advice, opinions, analysis and materials provided by Consultant in connection with the Retainer Agreement are intended solely for the benefit and internal use by Torys and Hydro One. Unless required by a regulatory body or its processes, governmental authority or applicable law (including the policies, rules or requirements of securities regulatory authorities), the amount of fees specified herein, the advice rendered by Consultant, any communication from Consultant or any information or document prepared for delivery to Torys by the Consultant in connection with the Services to be provided hereunder will not be disclosed, quoted or referred to in any public disclosure document, report or release prepared, issued or transmitted for dissemination to the public, without the prior written consent of Consultant. Notwithstanding the foregoing and anything to the contrary herein, the Consultant acknowledges and agrees that the Report(s) may be filed with the Board if Torys or Hydro One decides (in its sole and absolute discretion) to do so in connection with the Application.

6. **Intellectual Property**

Nothing in this Retainer Agreement shall be deemed to transfer, license, assign, permit the use of, or otherwise convey an interest in whole or in part to the Consultant of any intellectual property belonging to Hydro One or any of its representatives or any third party whose intellectual property is in Hydro One's custody or control, and the use by the Consultant of any such intellectual property shall be subject to the prior written approval of Hydro One.

Torys and Hydro One shall at all times have full rights and title to all works prepared, generated or created by the Consultant pursuant to this Retainer Agreement, including without limitation any reports or other documents created by the Consultant, and any related works, modifications or additions thereto (the "Work Product"), and may at all times take possession of or use any completed or partially completed Work Product, notwithstanding any provision, express or implied, to the contrary. Without limiting the generality of the foregoing, Hydro One shall own all intellectual property rights in all Work Product, and the Consultant hereby waives and assigns to Hydro One any such rights, and agrees to give Hydro One and its representatives all assistance as may be reasonably required to perfect such rights including, without limitation, obtaining waiver of moral rights from any of the Consultant's employees, partners or other representatives. Notwithstanding the foregoing, the Consultant shall retain sole and exclusive ownership of any pre-existing Consultant tools, methodologies, proprietary research and data, together will all intellectual property rights therein (the "Consultant Property"). Consultant grants to Torys and Hydro One a fully paid up, irrevocable, perpetual, non-exclusive, royalty-free license to use the Consultant Property contained within the Work Product for the purposes intended in this Retainer Agreement.

The Consultant expressly warrants that the delivery, sale or use of the Consultant's Services will not infringe any Canadian or foreign patents, trademarks, copyrights, industrial design or other intellectual property rights and the Consultant shall indemnify and save Hydro One harmless from all claims, judgments and decrees that may be entered against Hydro One or its representatives and against all damage, liability, costs and expenses (including legal fees and other attendant costs and expenses) Hydro One incurs by reason of any infringement or claim thereof.

7. **Termination**

Either party may terminate this Retainer Agreement at any time on written notice to the other party. Torys will pay, or will cause Hydro One to pay, for work performed up to the date of the notice of termination. Upon the termination or expiration of this Retainer Agreement, the Consultant shall, upon written request, return to Torys and delete any and all electronic copies the Consultant may have of all documents and materials in its possession relating to the Services or this Retainer Agreement, including all Confidential Information (defined above) and Work Product, whether completed or not, except for such Confidential Information required to be retained by your *bona fide* governance and record keeping policies (provided that the Consultant's confidentiality obligations herein shall continue to apply to any such Confidential Information retained by you). The Consultant shall, upon written request, provide Torys with a certificate of an officer of the Consultant certifying such deletion of electronic copies.

8. **Limitation of Liability**

Except for breach of confidentiality obligations under section 5, gross negligence, willful misconduct, fraud, breach of privacy laws, and the Consultant's obligation to indemnify under section 6 (Intellectual Property), in each case as determined by a court of competent jurisdiction in a final judgment, the Consultant's total liability for any claim arising out of the performance of the Services, regardless of the form of claim, will in no event exceed total fees paid to Consultant hereunder and under no circumstances will either party be liable for any damages in respect of any incidental, punitive, special, indirect or consequential loss, even if that party had been advised of the possibility of such damages including, but not limited to, loss of profits, loss of revenues, failure to realize expected savings, loss of data, loss of business opportunity, or similar losses of any kind.

9. **Independence**

By entering into this Retainer Agreement, the Consultant acknowledges and agrees that the Sponsor has received a copy of Rule 13A of the Board's *Rules of Practice and Procedure* concerning expert evidence, and agrees to accept the responsibilities that are or may be imposed on them by that rule with respect to testimony before the Board. A copy of the rule and the relevant form are attached as Schedules 'A' and 'B' hereto.

10. **Indemnity**

Consultant and its affiliates, and each of their respective directors, officers, employees, agents and shareholders (each an "Indemnified Party" and collectively the "Indemnified Parties") shall be indemnified and held harmless by Hydro One from and against all losses, claims (including shareholder actions, derivative or otherwise) damages, expenses, actions or liabilities, joint or several, of any nature (including the reasonable fees and expenses of their respective counsel and other reasonable out-of-pocket expenses) (collectively, "Losses"), incurred in investigating, defending and settling any pending or threatened action, suit, proceeding, investigation or claim that is made or threatened against any Indemnified Party or in enforcing this indemnity (collectively, the "Claims"), to which an Indemnified Party becomes subject or otherwise involved in any capacity insofar as the Claims arise out of or are based upon, directly or indirectly, the Retainer Agreement, whether arising out of or based upon the services provided by Consultant before or after the execution of the Retainer Agreement. This indemnity shall cease to apply if and to the extent that any such Losses are determined by a final non-appealable judicial determination of a court of competent jurisdiction to have resulted from the breach of contract, negligence or willful misconduct of the Consultant or the negligence or willful misconduct of any other Indemnified Party.

11. **Entire Agreement**

This Retainer Agreement, together with all Schedules attached hereto and any agreements and other documents to be delivered pursuant to this Retainer Agreement, constitute the complete agreement between Torys and the Consultant or their respective agents with respect to the subject matter hereof and supersedes any and all prior agreements and understandings. This Retainer Agreement may be amended only in a written agreement that refers to this Retainer Agreement and is signed by both parties.

12. **Governing Law**

This Retainer Agreement shall be construed and otherwise governed pursuant to the laws of the Province of Ontario and the federal laws of Canada applicable therein.

Sincerely,

TORYS LLP

Per: ______________________________
Name: Charles Keizer, Partner

Accepted and agreed to by Scotia Capital Inc.

Per: ______________________

Name (please print) Jared Steinfeld

(I have the authority to bind the Consultant)

Accepted and agreed to by Hydro One solely as to section 10 of the Retainer Agreement.

Hydro One Networks Inc.

Per: Frank D'Andrea
____

Name: Frank D'Andrea
VP, Reliability Standards and CRO

SCHEDULE ‘A’

Rule 13A of the Board’s Rules of Practice and Procedure

13A. Expert Evidence

13A.01 A party may engage, and two or more parties may jointly engage, one or more experts to give evidence in a proceeding on issues that are relevant to the expert’s area of expertise.

13A.02 An expert shall assist the Board impartially by giving evidence that is fair and objective.

13A.03 An expert’s evidence shall, at a minimum, include the following:

(a) the expert’s name, business name and address, and general area of expertise;

(b) the expert’s qualifications, including the expert’s relevant educational and professional experience in respect of each issue in the proceeding to which the expert’s evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert’s evidence relates;

(d) the specific information upon which the expert’s evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence;

(e) in the case of evidence that is provided in response to another expert’s evidence, a summary of the points of agreement and disagreement with the other expert’s evidence; and

(f) an acknowledgement of the expert’s duty to the Board in **Form A** to these Rules, signed by the expert.

13A.04 In a proceeding where two or more parties have engaged experts, the Board may require two or more of the experts to:

(a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

(b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in **Rule 13A.04** shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;

(b) the involvement of any expert engaged by the Board;

(c) the costs associated with the conduct of the activities;

(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of the activities referred to in paragraph (a) of **Rule 13A.04**; and

(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to accept, the responsibilities that are or may be imposed on the expert as set out in this **Rule 13A** and **Form A**[1].

[1] Attached as Schedule 'B' herein.

SCHEDULE ‘B’

FORM A

Proceeding: ....

ACKNOWLEDGMENT OF EXPERT’S DUTY

1. My name is ....(*name)*. I live at .... (*city)*, in the .... (*province/state*) of ....

2. I have been engaged by or on behalf of .... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date...

____
Signature

UNDERTAKING JTU-1.03

Reference:

Exhibit I-1-O-Staff-359, Attachment 1

Undertaking:

To confirm the definition of the StatsCan GDPIPI variant used with respect to GDP deflator on page 4.

Response:

The GDP price deflator shown in our forecast tables on page 4 is the implicit price index for total GDP at market prices. It is not for a subcomponent of GDP such as consumption and is instead for total GDP.

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UNDERTAKING JTU-1.04

Reference:

Exhibit I-1-O-Staff-359, Attachment 2

Undertaking:

To advise the weighting in the Ontario CPI for housing costs and for fossil fuel costs; to comment on the model and the output of the model to either implicitly or explicitly contain the same weight.

Response:

The weight on shelter costs in Ontario CPI is 32.84%. The weight on fossil fuels is 4.8% including 1.0% for natural gas, 0.2% for fuel oil and other fuels, and 3.6% for gasoline. Our top-down macroeconometric inflation models implicitly consider such weights.

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UNDERTAKING JTU-1.05

Reference:

Exhibit I-O-1-Staff-384

Undertaking:

To look into whether Hydro One is able to provide data about the degree of customer turnover that excludes customer moves within Hydro One territory. If available, quantify HONI's customer turnover on an annual basis or otherwise.

Response:

Hydro One is not able to provide the above requested data showing customer turnover (on an annual basis or otherwise), due to the manner in which Hydro One's tracking system has been set up. As discussed in Interrogatory G-VECC-094, part a):

> Account name changes have not been separately tracked and are counted within accounts opened and closed.[1] Due to the manner in which our tracking system has been set up, account openings and closures capture total number of transactions, as we are registering multiple transactions every time an account changes.[2] As the numbers stated capture the total transactions we are registering, they are not an accurate reflection of the turnover within our customer base.

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[1] When a name change occurs, a new account is opened and the old account is closed, so that is captured in both account opening and closures.

[2] When a customer moves within Hydro One's service territory, the old account is closed and a new one opened for the same customer. If tenants move in and out of a rental property, the account moves back and forth between tenants and landlord, so multiple transactions are registered in both account openings and closures.

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UNDERTAKING JTU-1.06

Reference:

Exhibit I-4-O-CME-22

Undertaking:

a) To provide the list of projects that would fall off if there was no change in the proposal based on the impacts of inflation.

b) To provide the material Hydro One looked at when making its determination that the preferred approach would be to maintain the capital program and defer the amounts to 2028, as opposed to any other option.

Response:

a) and b)

This undertaking seeks to understand a scenario where the investment plan work would be reduced to account for higher costs due to forecasted inflation. Hydro One has not proposed a reduction to its as-filed investment plans. As described in Exhibit O-01-01, Hydro One has proposed to maintain the work and the outcomes as originally filed. These investment plans reflect Hydro One's commitment to ensuring safe, reliable, and sustainable transmission and distribution systems to meet the electricity needs of its customers.

Hydro One did not re-run its prioritization process for candidate investments to understand the implications of reducing the proposed investments. Rather Hydro One utilized the existing investment plans to assess potential customer and system impacts if investments were deferred to account for inflationary pressures.

If the investment plans had not been updated for inflation in March 2022, Hydro One concluded that some "non-mandatory" investments (e.g., not driven by regulatory or compliance obligations), that are still important based on criteria used in Hydro One's investment planning process, would be deferred. Deferrals would affect System Renewal investments that are required to address poor condition and obsolete assets and System Service investments that aim to improve reliability.

To absorb the impacts of inflation (as proposed by the undertaking), Hydro One would have to reduce its proposed TSP by $381M and its DSP by $278M. To realize these reductions, Hydro One determined that non-mandatory transmission System Renewal investments would need to be reduced by approximately 6%[1], and non-mandatory distribution System Renewal[2] and System Service investments would need to be reduced by about 14%.[3]

Investment deferrals of this magnitude would negatively impact the outcomes as described in Exhibit O-01-02 and as summarized below for each of the transmission and distribution system plans.[4] These reductions are inconsistent with the outcomes underpinning these plans. If the proposed inflationary update is not approved, these types of system impacts are expected to accommodate the upward pressure.

<u>Distribution</u>

Category	Investment Area	Impacts
System Renewal	Distribution Station Refurbishment (D-SR-04)	As described in DSP Section 3.2, approximately 20% of the overall transformer population is categorized as being in poor condition; these transformers are subject to an elevated risk of failure and are considered for replacement or corrective repair to address deficiencies before failures occur and impact service to distribution customers. Should current and expected inflation not be accounted for, Hydro One would adopt a more reactive approach to station transformer replacements and slow down the proposed station transformer replacement plan, which would lead to a higher risk of outages due to transformer failures, further deterioration of the condition of the transformer fleet, and additional future investment requirements.
	Pole Sustainment Program (D-SR-07)	As outlined in DSP Section 3.2, approximately 79,000 distribution poles are in poor condition and at high risk of failure. During the plan period, it is expected that an additional 50,000 poles will be added to the poor condition category due to deteriorating condition. Without an inflation adjustment, there will be reduced funding for the Pole Sustainment Program, resulting in

[1] Approximately 10% of Transmission System Renewal is mandatory, to absorb the $362M out of the remaining as-filed five-year System Renewal forecast $5,579M reflects a 6% reduction
[2] Excluding impacts to AMI 2.0
[3] Approximately 30% of Distribution System Renewal and 15% of Distribution System Service are mandatory, with a further $558M identified for the AMI 2.0 investment; to absorb the $264M out of the remaining as-filed five-year forecast $1,873M reflects a 14% reduction.
[4] General Plant cuts were not considered in this analysis due to timing but would also be included to the extent appropriate if the inflation update is not approved

		fewer poles being replaced out of the subset of poor condition poles that have been prioritized as replacement candidates under this program due to their higher consequence of failure (i.e., serving large numbers of customers). This would lead to a higher risk of customer impact due to pole failures as well as further deterioration of the condition of the wood pole fleet.
System Service	Worst Performing Feeders (D-SS-05):	As described in ISD D-SS-05, Hydro One is currently planning to address approximately 500 feeders with the highest contribution to SAIDI, through the worst performing feeders program. If inflation is not adequately accounted for, Hydro One would undertake lower volumes of grid modernization – an investment customers support. New technology allows Hydro One to more quickly detect, repair and restore power, and reducing it would lead to lower levels of reliability improvement for customers; those feeders which contribute the highest average contribution to SAIDI have been targeted over the 2023-2027 investment plan.
	System Upgrades Driven by Load Growth (D-SS-01)	System capacity constraints that are caused by regional growth result in system issues characterized by power quality complaints, system inefficiencies, or thermal constraints (where system elements are being operated near, or above, their rating). Should recent inflation not be accounted for, Hydro One would need to adopt a more reactive approach to growth investments, deferring planned investments that are needed to upgrade and enhance investments to facilitate local growth. This would in turn delay community growth and economic development, especially in rural areas, and negatively affect reliability and power quality for existing customers in the long run.

The investments that have been put forward address specific asset and system needs, and reflect mitigation measures to address high risk assets, and manage impacts to customers.

The deferral of these condition based System Renewal investments expose customers and communities to elevated levels of risk based on the vulnerability of poor condition assets to failure and the resulting consequence associated with outages as equipment is replaced on a reactive basis; several communities in Eastern Ontario, Southwest Ontario and Northern Ontario are exposed to this risk if distribution stations were deferred; severe outages to distribution stations can take over 20 hours to restore. Similarly, as noted in JT3.06, Hydro One's plan has already prioritized the pacing of wood pole replacement, leaving those poor-condition pole which impact lower numbers of customers out of the plan; as such any pole program deferrals will impact, at a minimum, mid-size clusters of customers. In the event verified, poor condition assets fail, replacements will proceed on a reactive basis, which extends outage times and increases customer exposure to this risk.

The System Service deferrals will limit the ability of the system to meet forecast customer demand in growing communities in Southwest Ontario and Eastern Ontario, as planned feeder development, station construction and system reconfigurations will not be pursued, leaving capacity constraints unaddressed; further, System Service deferrals will limit the opportunity to improve outage restoration times for communities which may have had historic reliability concerns.

Transmission

Category	Investment Area	Impacts
System Renewal	Transmission Line Refurbishment (T-SR-13):	As noted in TSP Section 2.2, regarding Hydro One's overhead conductors, investments to date have not kept pace with asset condition-driven demands. Currently, 3,874 circuit-kms or 14% of Hydro One's conductor fleet has been tested and confirmed to be in poor condition. That is an increase from 2,643 circuit-kms of poor condition conductors at the end of 2016 and 3,680 circuit-kms of poor condition conductors at the end of 2018. Without an adjustment for inflation, Hydro One would need to defer the proposed refurbishment and replacement of poor condition transmission lines which may serve both local communities and play a critical role in the overall system, transferring generation to load centres. These deferrals would adversely impact the current level of safety and reliability performance, result in further deterioration of the condition of the conductor fleet and necessitate additional future investment requirements.
	Transmission Station Renewal – Connection Stations (T-SR-03):	As noted in ISD T-SR-03, approximately 26% (152 units) of connection station transformers are rated poor condition, with an additional 63 units (11%) assessed to

		be in fair condition with some form of deterioration. Further, approximately 401 of circuit breakers (11%) at connection stations are rated poor condition, and another 1203 units (36%) in fair condition. Given that deterioration cannot be stopped or reversed, this population of fair condition assets will start migrating to the poor condition category. Should recent inflation not be accounted for, Hydro One would need to defer transmission connection station reinvestment, which would impact Hydro One's ability to maintain reliable power delivery at stations, increase performance and environmental risks, and create the need for additional investment in the future. This approach would also mean deferring investments in load serving stations in smaller communities, including those in northern and eastern Ontario.

The investments that have been put forward in the TSP address specific asset and system needs, and reflect mitigation measures to address high risk assets, and manage impacts to customers and the system.

The deferral of these condition based System Renewal would expose customers and communities to elevated levels of risk based on the vulnerability of poor condition assets to failure in Eastern Ontario, Northern Ontario, and on the outskirts of the Greater Golden Horseshoe, including areas such a Niagara and Vaughan. Failures to critical assets may result in damage to connected equipment, impacts to system stability, interruptions to customer delivery points with significant durations, employee and public safety risks and environmental impacts. Failures of critical assets at a connection station may have serious consequences as they may partially or entirely interrupt power flow to load customers as well as constrain embedded generation on the distribution network connected to a connection station.

Further, overhead line failures will impact the ability of the system to deliver power from large generation in Eastern Ontario to communities in the east GTA. Hydro One has prioritized its overhead lines investments, with only critical projects put forward in the TSP; as such, all of the projects address circuits with poor condition components that are located in publicly accessible areas where a failure would present unacceptable safety risks.

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UNDERTAKING JTU-1.07

Reference:

Exhibit I-3-O-AMPCO-132, Attachment 1

Undertaking:

a) re O-AMPCO-132 attachment 1 page 11, to reconcile the numbers shown;

b) to confirm the meaning of "planned" as referred to in part b, attachment 1, page 11.

Response:

a) The reference for interrogatory AMPCO-132 was provided as "Exhibit I-03-B3-AMPCO-087, part b)" and the interrogatory requested Hydro One to update this reference for 2021 actuals. AMPCO-087 part b) asked Hydro One to provide planned values for the 2018 to 2022 period and part c) asked Hydro One to provide the actuals expenditures for the same period.

The original request in AMPCO-132 which referenced part b) and requested Hydro One to update part b) for 2021 actuals was therefore incorrect. The correct request for 2021 actuals would be part c) – Hydro One has corrected for this in this undertaking response.

The planned value for 2021 in part b) of AMPCO-087 was originally provided as $21.27M and the Q3 actuals for 2021 in part c) were $8.09M (November 29, 2021 interrogatory responses).

When responding to I-03-O-AMPCO-132, Hydro One answered the interrogatory by updating the planned values in part b) with total capital expenditures over the life of the project up to 2021 ($12.37M), rather than providing the year-end actuals for 2021 ($11.7M).

To clarify the record:

- Attachment 1 of this response is the AMPCO-087 interrogatory response from November 29, 2021;
- Attachment 1 part b) remains as originally filed on November 29, 2021 (i.e. planned Draft Rate Order values of $21.27M);
- Attachment 1 part c) has been updated to include in-year 2021 actuals in response to I-03-O-AMPCO-132 which asked for 2021 actuals to be provided (i.e. 2021 actuals of $11.7M, in alignment with Exhibit O-02-01, Attachment 8, Appendix 2-AA).

In addition to the response above, the following notes further reconcile the data in question:

- For the year 2020, the table in AMPCO-132 part c) included a recategorization of project costs between SR-01 Distribution Station Demand Program and SR-04 Distribution Station Refurbishment for 2020, totaling $1.3M. Although this update was reflected in AMPCO-087 part c) and AMPCO-132 part c), it was not reflected in Exhibit O-02-01, Attachment 8, Appendix 2-AA. The table below provides the necessary reconciliation.

  There is no impact to the total System Renewal envelope resulting from this.

Distribution Capital Projects ($M)	2020				
	I-03-AMPCO-087	I-03-O-AMPCO-132-01	O-2-1, Attachment 8, Appendix 2AA	JTU1.7 Update	Variance
D-SR-01 Distribution Stations Demand Capital Program			$9.8	$8.5	$(1.3)
D-SR-04 Distribution Stations Refurbishment	$8.69	$8.69	$7.4	$8.69	$1.3

- Lucan Market DS was incorrectly categorized as a Distribution Stations Refurbishment and included in Hydro One's original response to AMPCO-132, part b) filed on May 16, 2022. The correct categorization for Lucan Market DS is D-SR-11 Lifecycle Optimization & Operational Efficiency Projects. There is no impact on the System Renewal envelope or on the values previously provided in Exhibit O-02-01, Attachment 8, Appendix 2-AA.

- Hydro One's response to I-03O-AMPCO-132-01, part c) correctly reported Q3 costs for 2021 of $8.09M; this was not an error. Year-end totals for 2021 of $11.7M are now shown in JTU-1.07 Attachment 1 c).

b) Planned values provided in AMPCO-087 (Attachment 1, part b) of this response) are based on the EB-2017-0049 Draft Rate Order (DRO); $21.27M of net capital expenditures were planned for 2021.

   2021 Actuals as shown in JTU-1.07 Attachment 1, part c) show a reduction in actual accomplishments and expenditures from those presented in the DRO. These reductions are largely the result of the need to defer discretionary capital investments to accommodate non-discretionary investments to manage the total capital envelope.

B3 - ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORY - 087

Reference:

DSP Section 3.11, D-SR-04, Appendix A

Interrogatory:

a) Please add the following columns to Appendix A: Number of Transformers to be Replaced and Transformer Condition Rating.

b) Please provide Appendix A Planned for the years 2018 to 2022 and include the additional columns in part (a).

c) Please provide Appendix A Actual for the years 2018 to 2022 and include the additional columns in part (a).

d) Please identify the projects in part (b) that were not completed as planned and why.

e) Please provide the number of pad-mounted distribution station (PDS) forecasted over the 2023 to 2027 period.

f) Please provide the number of pad-mounted distribution station (PDS) completed over the 2018 to 2022 period.

Response:

a)

Project Name	Project ID	Project Description	Number of Transformers to be Addressed	Transformer Condition Rating	Net Capital Investment ($ Millions)				
					2023	2024	2025	2026	2027
Brookside DS	SR-04.1	Convert 44:8.32kV 5MVA station to PDS with 2x3MVA units	1	Poor	3.1	0.0	0.0	0.0	0.0
Chesterville Bran DS	SR-04.2	Convert 44:4.16kV 2MVA station to PDS with 2x3MVA units	1	Poor	0.1	0.0	0.0	0.0	0.0
Chesterville DS #2	SR-04.3	Convert 44:4.16kV 3MVA station to PDS with 3MVA unit	1	Poor	0.1	0.0	0.0	0.0	0.0
Cobalt DS	SR-04.4	Refurbish 44:12.5kV 3MVA station to 7.5MVA unit on new site with electronic reclosers	1	Poor	2.5	0.0	0.0	0.0	0.0
Craighurst DS	SR-04.5	Replace 44:8.32kV 5MVA transformer with 7.5MVA unit	1	Poor	0.9	0.0	0.0	0.0	0.0
Disputed Road RS	SR-04.6	Replace 27.6:27.6kV 25MVA transformer with 25MVA unit	1	Poor	2.9	0.0	0.0	0.0	0.0
Goodwood DS	SR-04.7	Refurbish 44:8.32kV 5MVA station to 7.5MVA unit	1	Poor	3.1	0.0	0.0	0.0	0.0
Kenora DS	SR-04.8	Replace 115:12.5kV 7.5MVA transformer with 7.5MVA unit	2	Poor / Poor	1.0	0.0	0.0	0.0	0.0
Killaloe DS	SR-04.9	Replace 44:12.5kV 6MVA transformer with 5MVA unit, electronic reclosers and SCADA	1	Poor	0.9	0.0	0.0	0.0	0.0
Millington DS	SR-04.10	Replace 44:8.32kV 5MVA transformer with 5MVA unit	1	Poor	1.0	0.0	0.0	0.0	0.0
Pointe Au Baril DS	SR-04.11	Replace 44:12.5kV 3MVA with 5MVA unit	1	Poor	1.4	0.0	0.0	0.0	0.0

Witness: FALTAOUS Peter

Project Name	Project ID	Project Description	Number of Transformers to be Addressed	Transformer Condition Rating	Net Capital Investment ($ Millions)				
					2023	2024	2025	2026	2027
Snow Road DS	SR-04.12	Replace 44:12.5kV 3MVA transformer with 5MVA unit	1	Poor	0.9	0.0	0.0	0.0	0.0
Stratford DS	SR-04.13	Replace 27.6:8.32kV 3MVA transformer with 5MVA unit	1	Poor	0.4	0.0	0.0	0.0	0.0
Stratford Easthope DS	SR-04.14	Refurbish 27.6:8.32kV 3MVA station to 10MVA unit with SCADA	2	Poor / Poor	3.1	0.0	0.0	0.0	0.0
Wolsey Lake DS	SR-04.15	Replace 44:12.5kV 6MVA transformer to 7.5MVA unit with electronic reclosers	1	Poor	1.0	0.0	0.0	0.0	0.0
Alex Kenyon West DS	SR-04.16	Replace 44:4.16kV 2MVA transformer with 5MVA unit	1	Poor	0.1	0.9	0.0	0.0	0.0
Belmont DS	SR-04.17	Refurbish 27.6:8.32kV 3.6MVA station with 5MVA unit	1	Poor	1.8	1.3	0.0	0.0	0.0
Berwick DS	SR-04.18	Convert 44:8.32kV 3MVA station to PDS with 2x3MVA	1	Poor	0.6	0.3	0.0	0.0	0.0
Brighton Pinnacle DS	SR-04.19	Refurbish 44:4.16kV 5MVA with 5MVA unit, electronic reclosers and SCADA	1	Poor	0.5	2.6	0.0	0.0	0.0
Brockville Park DS	SR-04.20	Convert 44:4.16kV 5MVA station with breakers to PDS with 2x3MVA	2	Poor / Poor	0.0	1.1	0.0	0.0	0.0
Crozier DS	SR-04.21	Convert 44:25kV 2x6MVA station to PDS with 2x3MVA	2	Poor / Poor	0.0	1.0	0.0	0.0	0.0
Deseronto DS	SR-04.22	Replace 44:4.16kV 3MVA transformer with 5MVA unit, electronic reclosers and SCADA	1	Poor	0.1	1.0	0.0	0.0	0.0
Jellicoe DS #3	SR-04.23	Refurbish 115:12.5kV 1.5MVA station with 7.5MVA unit	1	Poor	0.0	3.2	0.0	0.0	0.0

Witness: FALTAOUS Peter

Project Name	Project ID	Project Description	Number of Transformers to be Addressed	Transformer Condition Rating	Net Capital Investment ($ Millions)				
					2023	2024	2025	2026	2027
Lily Lake DS	SR-04.24	Refurbish 44:8.32kV 2MVA station with 7.5MVA unit on new site	1	Poor	0.2	1.6	0.0	0.0	0.0
Owen Sound DS #2	SR-04.25	Convert 44:8.32kV 2MVA station to PDS 3MVA unit on new site with electronic reclosers	1	Poor	0.2	2.3	0.0	0.0	0.0
Richardson RS	SR-04.26	Replace 44:44kV 25MVA station with 25MVA unit with SCADA	1	Poor	2.8	0.3	0.0	0.0	0.0
Ringwood DS	SR-04.27	Replace 44:8.32kV 5MVA transformer with 7.5MVA unit	1	Poor	0.0	1.0	0.0	0.0	0.0
Schreiber Winnipeg DS*	SR-04.28	Refurbish 115:12.5kV 6MVA station with 7.5MVA unit	2	Good / Good	0.0	3.2	0.0	0.0	0.0
Shelburn Andrew DS	SR-04.29	Convert 44:4.16kV 5MVA station to PDS 3MVA unit	1	Poor	0.0	3.2	0.0	0.0	0.0
Simcoe Ireland DS	SR-04.30	Refurbish 27.6:8.32kV 5MVA station with 5MVA unit	1	Poor	2.8	0.3	0.0	0.0	0.0
St.Thomas Union DS	SR-04.31	Replace 27.6:8.32kV 5MVA transformer with 5MVA unit	1	Poor	0.0	1.5	0.0	0.0	0.0
Stouffvil 10 Line DS	SR-04.32	Replace 44:8.32kV 5MVA transformer with 5MVA unit	1	Poor	0.1	1.0	0.0	0.0	0.0
Thamesville North DS	SR-04.33	Refurbish 27.6:8.32kV 5MVA station with 7.5MVA unit	1	Poor	0.0	3.2	0.0	0.0	0.0
Thorold Allanport DS	SR-04.34	Replace 27.6:4.16kV 5.4MVA transformer with 5MVA unit, electronic reclosers and SCADA	1	Poor	0.0	1.5	0.0	0.0	0.0

Project Name	Project ID	Project Description	Number of Transformers to be Addressed	Transformer Condition Rating	Net Capital Investment ($ Millions)				
					2023	2024	2025	2026	2027
Thorold Ormond DS	SR-04.35	Refurbish 27.6:4.16kV 5.4MVA transformer with 5MVA unit, electronic reclosers and SCADA	1	Poor	2.3	0.8	0.0	0.0	0.0
Thorold Turner DS	SR-04.36	Refurbish 27.6:8.32kV 3.6MVA station with 5MVA unit, electronic reclosers and SCADA	1	Poor	2.8	0.3	0.0	0.0	0.0
Uxbridge DS #2	SR-04.37	Refurbish 44:8.32kV 5MVA transformer with 7.5MVA unit	1	Poor	2.6	0.5	0.0	0.0	0.0
Williamstown RS	SR-04.38	Replace 44:44kV 25MVA transformer with 25MVA unit	1	Poor	2.6	0.5	0.0	0.0	0.0
Woodland Beach DS	SR-04.39	Refurbish 44:8.32kV 5MVA station with 7.5MVA unit	1	Poor	1.5	1.6	0.0	0.0	0.0
Young JCT RS	SR-04.40	Replace 27.6:27.6kV 15MVA with 15MVA unit	1	Poor	0.1	0.6	0.0	0.0	0.0
Black Corners DS	SR-04.41	Replace 44:8.32kV 5MVA transformer with 7.5MVA unit, electronic reclosers with SCADA	1	Poor	0.0	0.1	0.8	0.0	0.0
Brighton Division DS	SR-04.42	Convert 44:4.16kV 3MVA station to PDS 2x3MVA unit with electronic reclosers and SCADA	1	Poor	0.0	0.0	3.0	0.0	0.0
Brunelle DS	SR-04.43	Refurbish 44:8.32kV 5MVA station with 7.5MVA unit	1	Poor	0.0	2.9	0.3	0.0	0.0
Burford DS	SR-04.44	Convert 27.6:8.32kV 3.6MVA station to PDS 2.5MVA with additional real estate	1	Poor	0.0	0.0	1.5	0.0	0.0
Castleton DS	SR-04.45	Replace 44:8.32kV 5MVA transformer with 5MVA unit	1	Poor	0.0	0.1	0.8	0.0	0.0

Witness: FALTAOUS Peter

Project Name	**Project ID**	**Project Description**	**Number of Transformers to be Addressed**	**Transformer Condition Rating**	**Net Capital Investment ($ Millions)**				
					2023	**2024**	**2025**	**2026**	**2027**
Devlin DS**	SR-04.46	Refurbish 44:12.5kV 2MVA station with 7.5MVA unit	2	Poor / Good	0.0	0.0	3.2	0.0	0.0
Drumbo DS	SR-04.47	Replace 27.6:8.32kV 2MVA transformer with 5MVA unit	1	Poor	0.0	0.1	0.5	0.0	0.0
Emo DS	SR-04.48	Refurbish 44:12.5kV 3MVA station with 7.5MVA unit	2	Poor / Poor	0.0	0.0	3.2	0.0	0.9
Forest Jefferson DS	SR-04.49	Convert 27.6:8.32kV 3.6MVA station to PDS 2x3MVA unit	1	Poor	0.0	0.4	1.8	0.0	0.0
Forest McNab DS	SR-04.50	Convert 27.6:4.16kV 5.6MVA station to PDS 2x3MVA unit with electronic reclosers	1	Poor	0.0	0.4	1.8	0.0	0.0
Guthrie DS	SR-04.51	Convert 44:8.32kV 3MVA station to PDS 3x3MVA unit	1	Poor	0.0	0.2	1.6	0.0	0.0
Kemptville West DS	SR-04.52	Replace 44:8.32kV 5MVA 7.5MVA unit with electronic recloser and SCADA	1	Poor	0.0	0.0	0.9	0.0	0.0
Shedden DS	SR-04.53	Replace 27.6:8.32kV 3.6MVA transformer with 7.5MVA unit	1	Poor	0.0	0.0	1.0	0.0	0.0
Thorold Front DS	SR-04.54	Replace 13.8:4.16kV 5.4MVA 5MVA unit with electronic recloser and SCADA	1	Poor	0.0	0.0	1.0	0.0	0.0
Vanastra DS	SR-04.55	Refurbish 27.6:8.32kV 3.6MVA station to 7.5MVA unit with electronic recloser and SCADA	1	Poor	0.0	0.8	2.2	0.0	0.0
Cameron DS	SR-04.56	Replace 44:12.5kV 6MVA transformer with 7.5MVA unit	1	Poor	0.0	0.0	0.0	1.0	0.0
Espanola DS	SR-04.57	Replace 44:12.5kV 6MVA transformer with 7.5MVA unit	1	Poor	0.0	0.0	0.1	0.8	0.0

Project Name	Project ID	Project Description	Number of Transformers to be Addressed	Transformer Condition Rating	Net Capital Investment ($ Millions)				
					2023	2024	2025	2026	2027
Grand Valley DS #2	SR-04.58	Replace 44:12.5kV 3MVA transformer with 7.5MVA unit, electronic reclosers and SCADA	1	Poor	0.0	0.1	0.8	0.1	0.0
Lucan Market DS 8kV	SR-04.59	Replace 27.6:8.32kV 3.6MVA transformer with 5MVA unit	1	Poor	0.0	0.0	0.1	0.8	0.0
Nakina DS	SR-04.60	Refurbish 44:12.5kV 3MVA station to 7.5MVA unit with electronic reclosers and SCADA	2	Poor / Poor	0.0	0.0	0.3	3.0	0.0
Red Rock DS	SR-04.61	Refurbish 115:12.5kV 6.24MVA station to 7.5MVA unit	2	Poor / Poor	0.0	0.1	0.9	3.2	0.0
Russell DS	SR-04.62	Replace 115:8.32kV 6MVA transformer with 7.5MVA	3	Poor / Poor / Poor	0.0	0.0	0.0	1.2	0.0
Shabaqua DS	SR-04.63	Refurbish 115:25kV 6MVA and 25:12.5kV 2MVA station with 115:25kV 7.5MVA unit	2	Poor / Poor	0.0	0.0	0.3	4.6	0.0
Thedford DS	SR-04.64	Replace 27.6:8.32kV 3.6MVA transformer with 5MVA	1	Poor	0.0	0.0	0.1	0.8	0.0
Virginiatown DS	SR-04.65	Convert 44:4.16kV 2MVA station to PDS 3MVA unit on greenfield site	1	Poor	0.0	0.0	0.2	2.9	0.0
Washago DS	SR-04.66	Refurbish 44:8.32kV 5MVA transformer with 7.5MVA unit	1	Poor	0.0	0.0	0.0	3.3	0.0
Wellington DS	SR-04.67	Replace 44:8.32kV 5MVA transformer with 5MVA with SCADA	1	Poor	0.0	0.0	0.1	0.8	0.0
Aguasabon DS	SR-04.68	Refurbish 13.8:12.5kV 6MVA transformer with 12.5MVA unit	1	Poor	0.0	0.0	0.0	0.0	3.3

Witness: FALTAOUS Peter

Project Name	Project ID	Project Description	Number of Transformers to be Addressed	Transformer Condition Rating	Net Capital Investment ($ Millions)				
					2023	2024	2025	2026	2027
Colborne DS #2	SR-04.69	Replace 44:8.32kV 3MVA station with 7.5MVA unit and electronic reclosers	1	Poor	0.0	0.0	0.0	0.3	1.1
Coldstream DS	SR-04.70	Replace 27.6:8.32kV 5MVA with 5MVA unit	1	Poor	0.0	0.0	0.1	0.8	0.2
Dack DS	SR-04.71	Convert 44:12.5kV 3MVA station to PDS 3MVA unit	2	Poor / Poor	0.0	0.0	0.0	0.2	1.1
Ennismore DS	SR-04.72	Replace 44:8.32kV 5MVA transformer with 5MVA unit	1	Poor	0.0	0.0	0.0	0.1	0.0
Haycroft DS	SR-04.73	Replace 27.6:8.32kV 5MVA transformer with 7.5MVA unit	1	Poor	0.0	0.0	0.0	0.0	0.6
Hinchinbrooke DS	SR-04.74	Replace 115:12.5kV 7.2MVA transformer with 7.5MVA unit	2	Poor / Poor	0.0	0.0	0.0	0.1	1.0
Holland Centre RS	SR-04.75	Replace 44:44kV 15MVA transformer with 44MVA unit	1	Poor	0.0	0.0	0.0	0.6	0.3
Hornepayne DS	SR-04.76	Refurbish 44:4.16kV 10MVA station with 15MVA	2	Poor / Poor	0.0	0.0	0.0	2.2	1.1
Kimberley DS	SR-04.77	Replace 44:8.32kV 5MVA transformer with 7.5MVA unit	1	Poor	0.0	0.0	0.0	0.1	1.2
Longlac East DS	SR-04.78	Refurbish 44:12.5kV 3MVA station to 7.5MVA unit	1	Poor	0.0	0.0	0.0	0.3	2.9
Maxville Prince DS	SR-04.79	Refurbish 44:4.16kV 2MVA station with 5MVA unit	1	Poor	0.0	0.0	0.0	0.1	0.8
McGregor DS	SR-04.80	Replace 27.6:8.32kV 5MVA transformer with 7.5MVA unit	1	Poor	0.0	0.0	0.1	0.6	0.3
Napanee DS #2	SR-04.81	Convert 44:8.32kV 5MVA station to PDS 2x3MVA units with electronic reclosers and SCADA	1	Poor	0.0	0.0	0.0	0.1	1.0

Project Name	Project ID	Project Description	Number of Transformers to be Addressed	Transformer Condition Rating	Net Capital Investment ($ Millions)				
					2023	2024	2025	2026	2027
Picton Disraeli DS	SR-04.82	Replace 44:4.16kV 5MVA with breakers to 5MVA unit with electronic reclosers and SCADA	1	Poor	0.0	0.0	0.0	0.4	0.5
Picton DS	SR-04.83	Replace 44:8.32kV 5MVA transformer with 7.5MVA unit, electronic reclosers and SCADA	1	Poor	0.0	0.0	0.0	0.1	1.0
Port Lambton DS	SR-04.84	Replace 27.6:8.32kV 5MVA transformer with 7.5MVA unit	1	Poor	0.0	0.0	0.1	0.6	0.3
Rainy River DS***	SR-04.85	Convert 44:8.32kV 3MVA station to PDS 3MVA unit	2	Poor / Good	0.0	0.0	0.0	0.3	0.8
Reach Road RS	SR-04.86	Replace 44:44kV 25MVA transformer with 25MVA unit	1	Poor	0.0	0.0	0.1	1.0	0.5
Rondeau DS	SR-04.87	Convert 27.6:8.32kV 3MVA station to PDS 3x2.5MVA unit with additional real estate	1	Poor	0.0	0.0	0.1	0.6	0.2
Rutherglen DS	SR-04.88	Convert 44:12.5kV 2MVA station to PDS 3MVA unit	1	Poor	0.0	0.0	0.0	0.2	3.3
Sleeman DS	SR-04.89	Refurbish 44:12.5 3MVA and 44:25kV 6MVA to 44:12.5 5MVA and 44:25kV 12.5MVA unit	3	Poor / Poor / Poor	0.0	0.0	0.0	0.3	4.7
Springvale DS	SR-04.90	Replace 27.6:8.32kV 5MVA transformer with 5MVA unit	1	Poor	0.0	0.0	0.0	0.1	1.0
Stardale DS	SR-04.91	Replace 44:8.32kV 5MVA station to 7.5MVA with electronic reclosers and SCADA	1	Poor	0.0	0.0	0.0	0.0	0.1
Whitedog DS	SR-04.92	Refurbish 13.8:12.5kV 2MVA station with 5MVA unit	1	Poor	0.0	0.0	0.0	0.2	2.9

Witness: FALTAOUS Peter

*Schreiber Winnipeg DS T1 and R1: The R1 regulator failed causing a fire that damaged the station structure. Station refurbishment is required in order to address the damaged station structure and address the failed regulator with a new transformer equipped with an Under Load Tap Changer.

**Devlin DS T1 and R1: The T1 transformer in poor condition is being replaced with a new transformer that includes regulation through an Under Load Tap Changer (ULTC) thereby making the R1 regulator redundant.

***Rainy River T1 and R1: The R1 regulator is in poor condition and is to be replaced with a transformer that includes regulation through a ULTC.

b)

Year	Station Name	# Of Transformers Planned to be Addressed	Transformer Condition	Planned Cost ($M)
2018	Creemore DS	1	Poor	11.75
2018	Sowerby DS	1	Transformer condition was not the driver[1]	
2018	Bobcaygeon Anne DS	1	Transformer condition was not the driver[1]	
2019	Burford DS	1	Poor	18.65
2019	Hurondale DS	2	Poor / Poor	
2019	Thorold Allanport DS	1	Poor	
2019	Brigden DS	1	Poor	
2019	Blenheim DS	1	Poor	
2019	Ostrander DS	1	Poor	
2019	Arnprior Airport DS	1	Transformer condition was not the driver[2]	
2019	Arnprion McLachin DS	1	Poor	
2019	Meaford Vincent DS	1	Poor	
2020	Drumbo DS	1	Poor	14.18
2020	Clarence DS	2	Poor / Poor	
2020	Eugenia RS	1	Poor	
2020	La Salle RS	1	Poor	
2020	Rutherglen DS	1	Poor	

2020	Adams Point DS	1	Poor	
2020	Woodland Beach DS	1	Poor	
2020	Owen Sound DS #2	1	Poor	
2020	Vanastra DS	1	Poor	
2021	Forest Jefferson and McNab DS Padmounts	2	Poor / Poor	
2021	Stratford East Hope DS	1	Poor	
2021	Anderdon RS	1	Poor	
2021	Colpoys Bay DS	1	Poor	
2021	Jellicoe DS #3	1	Fair[4]	
2021	Cornell RS	1	Poor	
2021	Disputed Road RS	1	Poor	
2021	Rondeau Jct RS	1	Poor	
2021	Dack DS	1	Poor	
2021	Kenora DS	1	Poor	
2021	Lily Lake DS	1	Poor	
2021	Lake Vernon DS	1	Poor	21.27
2021	Washago DS	1	Poor	
2021	Ufford DS	1	Poor	
2021	Guthrie DS	1	Poor	
2021	Cobalt DS	1	Poor	
2021	Barrys Bay DS #1	2	Poor / Good[3]	
2021	Island Grove DS	1	Poor	
2021	New Sarum RS	1	Poor	
2021	Hawley DS	2	Poor/ Poor	
2021	Thorold Ormond DS	1	Poor	
2021	Thorold Turner DS	1	Poor	
2021	Rondeau DS	1	Poor	
2022	Thorold Front DS	1	Poor	
2022	Shedden DS	1	Poor	
2022	Stratford DS	1	Poor	
2022	Brighton Pinnacle DS	1	Poor	
2022	Cameron DS	1	Poor	
2022	Perth North DS	1	Poor	27.58
2022	Richardson RS	1	Poor	
2022	Williamstown RS	1	Fair[4]	
2022	Port Dover St Andrews DS	1	Poor	
2022	Simcoe Ireland DS	1	Poor	

Witness: FALTAOUS Peter

2022	Goodwood DS	1	Poor	
2022	Moosonee DS	3	Transformer condition was not the driver[1]	
2022	Tory Hill DS	1	Poor	
2022	Aguasabon DS	1	Poor	
2022	Devlin DS	2	Poor / Good[3]	
2022	Emo DS	1	Poor	
2022	Russell DS	3	Good / Good / Poor[3]	
2022	Whitedog DS	1	Fair[4]	
2022	Uxbridge DS #2	1	Fair[4]	
2022	Shelburne DS	1	Fair[4]	
2022	Nottawaga DS	1	Fair[4]	
2022	Eels Lake RS	1	Fair[4]	
2022	Commanda DS	1	Fair[4]	
2022	Tralee DS	1	Transformer condition was not the driver[1]	
2022	Haliburton DS	1	Transformer condition was not the driver[1]	
2022	Kirkfield DS	1	Poor	

[1]Station Refurbishment was driven due to poor station structures or sub standard design which necessitated addressing the transformer.
[2]Station Refurbishment was driven due to load growth expected in the area.
[3]At least one of the transformers or regulating units in poor condition is being replaced with a new transformer that includes regulation through a ULTC thereby making the regulator redundant.
[4] These transformers were expected to be in poor condition by the time they were to be addressed.

c)

Year	Station Name	# Of Transformers Addressed	Transformer Condition	Total Cost ($M)
2018	Creemore DS	1	Poor	11.75
2018	Sowerby DS	1	Transformer condition was not the driver[1]	
2018	Bobcaygeon Anne iMDS	1	Transformer condition was not a driver[1]	
2019	Hurondale PDS	2	Poor / Poor	16.54
2019	Brigden DS	1	Poor	
2019	Blenheim DS	1	Poor	
2019	Ostrander DS	1	Poor	
2019	Madsen DS	1	Poor	
2019	Meaford Vincent iMDS	1	Poor	
2019	Arnprior Airport iMDS	1	Transformer condition was not the driver [2]	
2019	Arnprior McLachin iMDS	1	Poor	
2019	Brockville Cedar iMDS	1	Transformer condition was not the driver[1]	
2020	Chatham Raleigh DS	1	Poor	8.69
2020	Joyceville DS	1	Poor	
2021	Ufford DS	1	Poor	11.7
2021	Gorrie DS	1	Poor	
2021	Hawley DS	2	Poor / Poor	
2021	Adams Point PDS	1	Poor	
2021	Troy DS	1	Poor	
2022	No Planned Stations to be In-Serviced. Forecasted spend for 2022			3.18

[1]Station Refurbishment was driven due to poor station structures or sub standard design which necessitated addressing the transformer.
[2]Station Refurbishment was driven due to load growth expected in the area.

Witness: FALTAOUS Peter

d) Please see I-03-B3-Staff-141

e) Hydro One Distribution is forecasting 21 PDS type stations over the filing period.

Year	# of PDS type stations
2023	4
2024	6
2025	5
2026	1
2027	5

f) Between 2018-2021, a total of 7 PDS type stations were placed in-service

Year	# of PDS type stations
2018	1
2019	3
2020	2
2021	1
2022	0

Witness: FALTAOUS Peter

UNDERTAKING JTU-1.08

Reference:

Exhibit I-3-O-AMPCO-132, Attachment 1
Exhibit O-2-1, Attachment 8

Undertaking:

To find the reconciliation between the 8.09 number identified in AMPCO 87 and the number it relates to in 2AA, and to do the reconciliation for the previous years.

Response:

Please refer to JTU-1.07, part a).

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UNDERTAKING JTU-1.09

Reference:

Exhibit I-22-O-SEC-264, Attachment 1
Exhibit O-2-1

Undertaking:

To reconcile the numbers in the capital program report included for 2021, as well as the previous ones included in the evidence.

Response:

The 2021 Capital Performance Report (CPR) found in I-22-O-SEC-264 Attachment 1 provides variance analysis for both program (section 3.1) and project investments (section 3.2) against the Draft Rate Order (DRO) budget.

In comparing the CPR against the values in Exhibit O-2-1, Attachment 8, Appendix 2-AA, the following should be taken into consideration:

1. The CPR **only** reports on the performance of major projects and programs, those with a total budget cost greater than $3M and planned for completion within the test year (Table 2 for programs and Table 3 for projects).
2. The ISD categorizations in the CPR are shown consistent with the ISD categorization of the **prior rate application** for the purpose of the report.
3. Appendix 2-AA contains both historical and forecast program and project expenditures consistent with the ISD categorization of the **current rate application** (i.e. prior rate period ISDs have been mapped to current rate application ISDs).
4. Some ISDs in Appendix 2-AA, such as Distribution Stations Refurbishments (SR-04 in the current rate application and respectively SR-06 in the CPR), contain both program and project investments.

When comparing the values in the CPRs against Appendix-2AA, for the Distribution Station Refurbishment ISD, the following table and notes provide some context around any differences:

- (A) Appendix 2-AA provides the summary total program and project related expenditures by ISD.
- (B) Figures reported in Table 2 of the CPR contain only those ISD program related expenditures.
- (C) Differences between values reported under the prior ISD categorization (SR-06) can either be attributed to variance thresholds or project expenditures that are not included in Table 2.

Distribution Station Refurbishment ($M)	Projects	2019	2020	2021
	(A)SR-04 - O-2-1 Attachment 8, Appendix 2-AA	$16.5	$8.7[3]	$11.7
	(B)SR-06 - Capital Performance Report(s)[1]	N/A[2]	$7.7	$9.9
	(C)Difference	N/A	$1.0[4]	$1.8[4]

[1] Figures can be found in Table 2 of I-22-O-SEC-264 Attachment 1 and Table 5 of B-3-1 Section 3.9, Attachment 2

[2] The program total spend in this ISD did not meet the variance criteria and therefore was not discussed in the CPR.

[3] Please see correction identified in JTU-1.07, part a)

[4] The difference of $1.0M and $1.8M in 2020 and 2021 is attributed to project related investment expenditures in those respective years.

UNDERTAKING JTU-1.10

Reference:

Exhibit I-03-O-AMPCO-138

Undertaking:

To complete the table in I-03-O-AMPCO-138 with respect to ISD D-SR-04 for 2021, and to indicate in the undertaking as to any reasons why Hydro One is not updating any other periods. To explain if there are any errors or inconsistencies required to clarify previous amounts.

Response:

AMPCO-138 requested an annual breakdown of transformers addressed by Investment Summary Document (ISD) ID for the years 2018-2027, which Hydro One refused as per Procedural Order Number 5. Notwithstanding, the table below provides the values as requested in AMPCO-138.

AMPCO-138 references 106 transformers to be addressed under D-SR-04 during the 2023-2027 rate period, which is the number of *poor condition* transformers and aligns with the values presented in the table below.

There are no inconsistencies or clarifications required for previous amounts.

# Station Transformer Units by ISD	2018	2019	2020	2021 Forecast[1]	2021 Actual[2]	2022 Bridge[3]	2023	2024	2025	2026	2027
D-SR-01 – Distribution Stations Demand Capital Program[4]	11	5	8	N/A	10	N/A	N/A	N/A	N/A	N/A	N/A
D-SR-04 – Distribution Station Refurbishment	4	9	3	26	6	0	17	26	14	18	31
D-SR-11 – Life Cycle Optimization & Operational Efficiency Projects	5	1	1	4	3	0	1	3	7	1	0

[1] "Forecast" values are based on DRO.
[2] 2021 Actuals are transformers addressed in 2021.
[3] 2022 Bridge are transformers anticipated to be addressed in 2022, consistent with I-3-B3-AMPCO-087, part c)
[4] Station transformers addressed under SR-01 are not forecast and have therefore been indicated as "N/A".

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UNDERTAKING JTU-1.11

Reference:
Exhibit I-22-O-SEC-264, Attachment 1
Exhibit O-2-1, Attachment 8

Undertaking:
For this proceeding, to explain why there is a difference, if any, for capital and ISA amounts for D-SR-12 and D-SR-10 in the Capital Performance Reports and other evidence in this proceeding. To take this request under advisement and to consider what can be provided.

Response:
Please refer to JTU-1.09 for an explanation on the differences.

The table below provides a summary of the differences between D-SR-12 and D-SR-10 from the Capital Performance Reports and Exhibit O-2-1, Attachment 8, Appendix 2-AA, in the context of the explanation provided in JTU-1.09.

Distribution Lines Sustainment Initiatives ($M)	Projects	2019	2020	2021
	SR-10 - O-2-1 Attachment 8, Appendix 2-AA	$8.1	$11.7	$11.7
	SR-12 - Capital Performance Report(s)[1]	$8.0	$11.2	$10.6
	Difference	$0.1	$0.5	$1.1

[1] Figures can be found in Table 2 of I-22-O-SEC-264 Attachment 1 and Tables 4 and 5 of B-3-1 Section 3.9, Attachment 2.

The difference in each of the years is attributed to project related investment expenditures in those respective years.

In explaining any differences between capital and ISA amounts for D-SR-12 in O-SEC-264, a clerical error was discovered in Table 2 for D-SR-12. The error has been corrected, and an updated 2021 Capital Performance Report has been included as Attachment 1 to this undertaking response.

Witness: NG Chong Kiat

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DISTRIBUTION - CAPITAL PROGRAM PERFORMANCE REPORT - 2021

1.0 INTRODUCTION

This distribution Capital Program Performance Report is provided in response to the Ontario Energy Board's (OEB) Decision and Order in EB-2017-0049, which directed Hydro One to submit with this application a comprehensive report detailing the Company's actual performance in the execution of its capital program relative to plan.[1]

This report is divided into two main sections. Section 2.0 focuses on performance at the overall envelope and OEB category level, demonstrating Hydro One's ability to successfully manage to the overall capital envelope in terms ISAs. Section 3.0 focuses on performance at the project and program level. That section outlines the approach used by Hydro One to manage projects and programs and provides an overview of performance. The projects and programs included in this report have material (greater than or equal to $3 million) actual or planned ISA in 2021.

2.0 PERFORMANCE AT THE OVERALL ENVELOPE AND OEB CATEGORY LEVEL

Hydro One's Distribution capital portfolio is comprised of investments designed to address existing assets as well as install new assets to address system needs. The Distribution capital envelope is predominantly program-based with smaller scale projects. Distribution is also required to respond to a high volume of demand work with short turnaround times, which can impact work completed within the capital envelope annually.

A summary of the Distribution capital envelope for 2021 is shown below in Table 1, organized according to the categories defined by the OEB Filing Requirements.

[1] EB-2017-0049, Decision and Order, March 7, 2019, Appendix 2. The TSP and GSP Capital Program Performance Reports are filed in this application as TSP Section 2.9, Attachment 2 and GSP Section 4.9, Attachment 2 respectively.

Table 1 - OEB Category Performance 2021($M)[2]

OEB Category	Capital Expenditures			In-Service Additions		
	2021			2021		
	DRO Plan	Actuals	Variance	DRO Plan	Actuals	Variance
1. System Access	150.9	228.9	52%	160.8	226.1	41%
2. System Renewal	237.3	252.0	6%	241.9	253.3	5%
3. System Service	144.1	110.7	-23%	138.8	80.5	-42%
Subtotal Categories 1, 2, and 3	**532.3**	**591.6**	**11%**	**541.4**	**559.9**	**3%**
4. General Plant Allocated to Distribution	95.3	171.1	80%	164.1	151.2	-8%
Grand Total	**627.6**	**762.8**	**22%**	**705.5**	**711.1**	**1%**

Excluding General Plant, 2021 Distribution capital totalled $591.6M, which is an overage of 11% relative to the prior plan. Distribution in-service additions were 3% higher than plan at $559.9M. Total Distribution capital expenditures including General Plant were $762.8M (22% higher than the approved envelope), and total in-service additions were $711.1M (1% higher than the approved envelope). Details on the capital and in-service additions for General Plant Allocated to Distribution are provided in the Capital Program Performance Report for General Plant in I-01-O-Staff-362, Attachment 1. The remainder of this report focuses on the capital and in-service performance of System Access, System Renewal, and System Service Investments attributable wholly to Distribution.

The overall increase in Hydro One's Distribution capital expenditure was largely due to non-discretionary investments in the System Access (i.e., customer driven) and, to a lesser extent, the System Renewal (i.e., trouble calls and storm response) categories. Hydro One was able to partially offset these areas of overspending by reductions in System Service and some discretionary investments in System Renewal. Although the timing of some System Renewal and System Service work is more flexible than System Access investments, there are circumstances where work in these categories is urgently needed to address assets that pose a high risk. Accordingly, System Renewal and System Service work can require increased capital expenditure. The OEB categories and associated variance explanations are outlined below.

[2] Does not include Acquired Utilities of Haldimand, Norfolk, and Woodstock.

System Access: The largest category-level variance in 2021 was in the System Access category, with capital expenditures and in-service additions higher than budget by $78.0M or 52% and $65.3M or 41% respectively. The main driver of this overage compared to previously planned expenditures was increased demand for New Load Connections and Service Upgrades including more complex large connections projects. The increase in non-discretionary project spending also impacted costs associated with design and estimation due to increased project complexity and varying scope compared to historical requests. In addition, increased demand within the Joint Use and Relocations program was driven by an influx of requests for third party attachments primarily related to broadband internet access.

System Renewal: Capital expenditures and in-service additions for System Renewal were higher than budget by $14.7M or 6% and $11.4M or 5% respectively. The increase in expenditures was largely a result of costs incurred within the Distribution Lines Trouble Call and Storm Damage Response program, which exceeded capital expenditure budget by $32.4M and in-service additions budget by $30.7M. Hydro One was able to partially offset these increases, primarily through reductions to other planned system renewal work such as Distribution Lines Sustainment Initiatives and Lines PCB Equipment Replacements. However, due to the nature of work that is required to maintain a safe and reliable distribution network, there are limits on Hydro One's ability to make reductions within this category.

System Service: System Service capital expenditures and in-service additions were lower than budget by $33.3M or 23% and $58.2M or 42% respectively. This was primarily the result of deferring discretionary investments in response to an increase in non-discretionary externally-driven System Access and System Renewal work. This was partially offset by increased investment to modernize the worst performing feeders and demand system investments.

As shown in Table 1, and as was generally the case in previous years, the pattern of heightened non-discretionary spending was generally offset by reprioritization of other important but ultimately discretionary work. This reflects Hydro One Distribution's active management of a large capital portfolio which includes large proportion of non-discretionary, externally-driven spending. Circumstances may change throughout the year and the organization must adapt accordingly. In many cases, Hydro One is required to meet legal, contractual or statutory obligations, and as such there are no alternatives other than to fund demand work as required. As a consequence, in-year fluctuations and re-direction occurs resulting in variances between planned and actual capital expenditures.

3.0 PERFORMANCE AT THE PROGRAM AND PROJECT LEVEL

Hydro One's Distribution expenditures consist of programs and projects. Programs involve work that is repeatable in nature on a specific asset type that recurs every year and the assets are in-serviced in the same fiscal year. Projects are stand-alone jobs with a discrete beginning and end which may span over more than one fiscal year and in-service does not occur until energization occurs. Capital expenditure variances at the program-level are discussed in Section 3.1, and project-level variances are discussed in Section 3.2.

Programs and projects with a total budgeted cost of greater than $3M have been summarized in the following sub-sections along with variance explanations. The thresholds used by Hydro One to identify "material variances" were determined using the following criteria:

- **Scope Variances** – For programs, material scope variances arise if the unit accomplishment filed in the rate application varied from the actual unit accomplishment by 20%. For projects, material scope variances arise if the project required internal approval for a scope change.
- **Cost Variances** – Material cost variances were identified where the in-year variance in cost is greater than or equal to $0.5M and the cost is 10% over or under budget.
- **Date Variances** – Material date variances were identified where the actual or projected in-service year changed from the year proposed.

Capital programs and projects that met at least one of these criteria were deemed to be material variances for the purposes of this report. Material variances are presented in four categories:

- **Emergent Needs**: Emergent needs are investments that Hydro One made and in-serviced in 2021 in response to a change of priority due to equipment condition or failure, as well as customer needs.
- **Reprioritization**: Reprioritization includes investments that are accelerated or deferred. Accelerated investments can include projects or programs that need to be completed sooner than planned. As described in SPF Section 1.7, Hydro One adjusts its capital investments through annual planning and in-year redirection processes. In some cases, this results in the acceleration of work when resources are redirected from another delayed project. Alternatively, deferral can occur as a result of increased demand for non-discretionary investments and planned discretionary work is reprioritized as a result.
- **Execution Factors**: Execution factors represent delays encountered during the execution phase of work which can include timing delays that arise as a result of changing conditions, risks and priorities that need to be addressed during execution. As risks materialize, plans are adjusted to accommodate the change and mitigate the overall impact to cost, schedule and resources. This can change the year in which the project goes in-service but does not necessarily result in a material change to the in- service amount or affect the volume of work completed. Some of the main causes for delays are outage delays or cancellations, material delivery and logistics factors as well as customer needs.
- **Work Definition**: Work definition variances naturally arise as a project's scope, estimated budget and schedule are refined and the project moves from the high-level planning phase to design and estimate followed by execution. As the project is refined, there may be increases or decreases to the project cost as a result of new or changing information that becomes known during the design and estimation phase or in the execution stage of work.

As is described in the Distribution Capital Work Execution Strategy (DSP Section 3.10), Hydro One Distribution continues to improve its planning and estimating processes, tools and technology to minimize work definition issues. As a result, the in-service addition amounts and project expenditures are more accurate, although changes may still arise during the planning process. Drivers of change include:

- prudent scope changes or additions made as project plans mature;
- assumptions made in earlier project phases that are later clarified as site-specific conditions are addressed; and
- risks that either materialize or are mitigated during execution that impact the amount of contingency spent.

3.1 PROGRAM VARIANCES

A large portion of Distribution's capital work program includes investments that are driven by demand and require action in a specified period as part of Hydro One's obligations under the Distribution System Code. While Distribution makes every effort to work within its budget, there are times when an influx of demand work results in a reprioritization of resources away from planned work. Hydro One has a robust redirection process that provides the flexibility necessary to reprioritize investments to respond to fluctuations in emergent work while trying to minimize as best it can the impacts of deferring planned investments that can introduce additional risks to the system in future years. In addition, the COVID-19 pandemic continues to affect program performance in 2021. While Hydro One was able to quickly adapt to the changing work environment challenges introduced by COVID-19, certain modified work procedures implemented to maintain employee safety remained in place for much of 2021. For example, implementing one person per vehicle has a slight impact on cost per unit. This section will speak to material program variances in 2021.

Table 2 - Distribution Program Variances 2021

OEB Category	ISD[3]	ISD Description	Net DRO Plan ($M)	Net Actual ($M)	Net Variance ($M)	ISA DRO Plan ($M)	ISA Actual ($M)	ISA Variance ($M)	Units DRO Plan	Units Actual	Units Variance	Variance Type
System Access	SA-01	Joint Use and Line Relocations Program # of poles	17.7	31.5	13.8	17.7	28.7	11.0	1,475	1,355	-120	Emergent Needs
	SA-02	Meter Infrastructure Sustainment # of Devices or Meters	17.7	23.0	5.3	17.7	22.6	4.9	20,110	35,816	15,706	Emergent Needs
	SA-03	AMI Network Expansion # of Devices	9.2	0.0	-9.2	18.5	0.0	-18.5	242	0	-242	Work Definition
	SA-04	New Load Connections, Service Upgrades, Cancellations and Metering # of Connections, Designs, Upgrades, Cancellations, or Subdivisions	104.6	176.0	71.4	104.7	173.7	69.1	40,666	47,543	6,877	Emergent Needs
System Renewal	SR-01	Distribution Station Demand Program n/a	4.8	9.3	4.4	4.8	10.9	6.1	n/a	n/a	n/a	Emergent Needs
	SR-02	Mobile Unit Substations Program # of MUSs	4.8	1.5	-3.3	4.3	0.1	-4.1	2	0	-2	Execution Factors
	SR-04	Distribution Station Component Planned Replacement Program # of Components	5.2	7.0	1.8	5.1	7.8	2.7	282	257	-25	Work Definition
	SR-06	Distribution Station Refurbishments # of Stations	3.4	9.9	6.5	1.2	11.2	10.0	1	4	1	Work Definition
	SR-07[4,5]	Distribution Lines Trouble Call and Storm Damage Response Program # of poles/equipment, transformers, or occurrences	78.7	110.0	31.9	78.7	109.4	30.7	9,926	1,207,383	1,197,457	Emergent Needs
	SR-08	Distribution Lines PCB Equipment Replacement Program # of Transformers	12.4	6.0	-6.4	12.4	6.0	-6.4	3,450	1,165	-2,285	Reprioritization
	SR-09[6]	Pole Replacement Program # of Poles	58.8	60.6	1.8	58.8	60.4	1.6	9,333	5,344	-3,989	Work Definition
	SR-10	Distribution Lines Planned Component Replacement # of crossarms replaced, nest relocated, transformers, or sentinel lights	7.2	9.0	1.9	7.2	9.0	1.8	4,098	3,885	-213	Work Definition
	SR-11	Component Replacement Submarine Cable # of Submarine Cables	9.8	6.6	-3.2	9.8	6.6	-3.2	230	292	62	Reprioritization
	SR-12	Distribution Lines Sustainment Initiatives n/a	16.3	10.6	-5.7	20.4	13.5	-7.0	n/a	n/a	n/a	Reprioritization

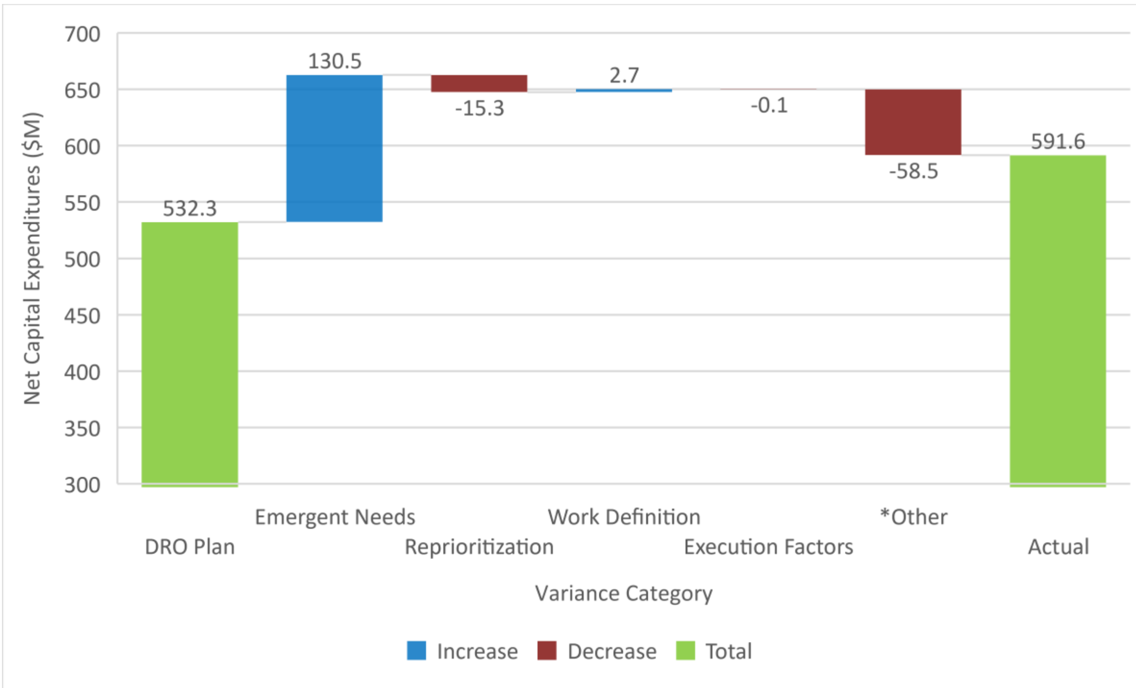
[3] The ISD numbers presented are the ISD numbers presented in the last distribution application.
[4] A portion of SR-07 funding is reported in System Service which includes Distribution Capital Post Trouble Call and Distribution Capital Power Quality & Stray Voltage.
[5] The unit of measure for storms damaged was changed from occurrences to customers impacted. Please see variance explanation SR-07.
[6] Unit of measure for this ISD expanded to include Pole Test and Treat and Pole Refurbishments.

Witness: NG Chong Kiat

System Service	SR-07[7]	Distribution Lines Trouble Call and Storm Damage Response Program # of occurrences	13.2	13.6	0.4	13.2	13.4	0.2	842	546	-296	Emergent Needs
	SS-04	Demand Investments n/a	3.5	5.2	1.7	3.5	4.1	0.6	n/a	n/a	n/a	Emergent Needs
	SS-05	Distribution System Modifications n/a	7.1	9.2	2.1	5.1	10.2	5.1	n/a	n/a	n/a	Emergent Needs
	SS-06	Worst Performing Feeders Program # Devices (Mix of Remotely Operable and Fault Location Devices)	15.2	18.4	3.2	15.2	24.2	9.1	773	716	-57	Work Execution

[7]A portion of SR-07 funding is reported in System Service which includes Distribution Capital Post Trouble Call and Distribution Capital Power Quality & Stray Voltage.

The impact of each variance category from a capital expenditure perspective is demonstrated below in Figure 1.



(*Note: Other includes non-material program variances and total project variances)

Figure 1: Waterfall chart highlighting the contributions to the 2021 Distribution capital expenditures variance by variance category

- **Joint Use and Lines Relocations Program (D-SA-01):** The Joint Use and Lines Relocations program represented a $13.8M variance to support the influx of requests to access Hydro One's support structure network for the expansion of Telecommunication attachments as well as private customer relocation requests. The variance was categorized as Emergent Needs as Hydro One is required to meet contractual obligations to third parties through Joint Use agreements and to maintain compliance with Hydro One's distributor licence.
- **Meter Infrastructure Sustainment (D-SA-02):** The Meter Infrastructure Sustainment program experienced increased capital expenditures of $5.3M compared to plan. The

Witness: NG Chong Kiat

primary driver for higher than forecast costs was higher AMI 1.0 meter failures resulting in additional material and labour cost.

- **Meter Infrastructure Expansion Program (D-SA-03):** This planned investment of $9.2M to continue to expand the AMI 1.0 network to reach additional customers through leveraging ongoing Telecommunications Carrier upgrades was cancelled. Following detailed field investigation and testing it was determined that the cost per new customer added to the network was not economic.
- **New Load Connection, Service Upgrades, Cancellations and Metering program (D-SA-04)**: The New Load Connection, Service Upgrades, Cancellations and Metering program variance accounted for the largest increase within System Access, totalling $71.4M due to higher demand compared to historical trends on which the DRO budget was based. This increase in spend was categorized as Emergent Needs. The additional capital expenditure was required to support an increased volume of connections, including more complex large connections which require additional labour hours and therefore more expensive to design and construct. There was also an increase in the volume and size of subdivision construct projects although the connections within those subdivisions will be realized over their five-year connection horizon.
- **Distribution Station Demand Program (D-SR-01):** Capital expenditures exceeded plan by $4.4M due to the demand nature of the work required. This program involves addressing equipment failures and demand-driven system upgrades that require immediate equipment replacement. As a result, the variance is categorized as emergent needs.
- **Mobile Unit Substations Program (D-SR-02):** The Mobile Unit Substations (MUS) program expenditures were underspent by $3.3M primarily due to procurement delays associated with MUS manufacturers.
- **Distribution Station Component Planned Replacement (D-SR-04):** The Distribution Station Planned Component Replacement investment addresses the need to replace individual components in distribution stations on a planned basis. Prior to 2019, this investment primarily focused on the replacement of MUS Structures and replacement of station switches. In 2019, Hydro One added the replacement of oil hydraulic reclosers

with vacuum hydraulic reclosers to this investment, which is expected to lower the lifecycle cost of these reclosers. Overall, the program was overspent by $1.8M. Most of the overage was due to the addition of the hydraulic recloser replacements to the scope.

- **Distribution Station Refurbishments (D-SR-06):** Distribution Station refurbishments aim to correct deficiencies in power transformers or other station equipment to prevent significant outages from occurring. The program incurred a $6.5M increase in 2021, primarily due to site-specific conditions not captured in early budgetary estimating stages as well as reprioritization of projects.
- **Distribution Lines Trouble Call and Storm Damage (D-SR-07)[8]:** This portion of SR-07 includes the following investments: Dx Capital Trouble Call Poles & Equipment, Dx Capital Storm Damage, Dx Capital Trouble Sub and UG Cable and Dx Capital Trouble Call Damage Claims. An increase of $31.9M to Distribution Lines Trouble Call and Storm Damage was required mainly due to significant storm activity in December totaling $32.5M, which was $27.3M above the three-year historical average for December.
- **Distribution Lines PCB Equipment Replacement Program (D-SR-08):** The PCB Equipment Replacement program was $6.4M below plan primarily due to fewer complex transformer replacements and, to a lesser extent, fewer proactive transformer replacements. Program unit costs depend on the complexity of the transformer replacement, which itself depends on individual design requirements. If a replacement transformer is functionally equivalent, unit costs are relatively low. However, if the replacement is not like-for-like (e.g., it requires replacement of the pole and transformer), the cost can be significantly higher.
- **Pole Replacement (D-SR-09):** The Pole Replacement program came within 3% of budget however the composition of units had changed significantly compared to the DRO since the introduction of Pole Test & Treat and Pole Refurbishments. Originally budgeted

[8] The unit of measure for storm damage was changed in 2020 to the number of customers impacted as opposed to number of occurrences that was used historically. The number of customers impacted in 2020 was approximately 1.1M compared to approximately 1.2M customers in 2021.

units included the replacement of 9,333 poles with no Pole Test & Treat or Pole Refurbishments. In 2021, 5,344 poles were replaced, approximately 60,280 Poles underwent Test & Treat and approximately 1,877 poles were refurbished. Like 2020, higher unit costs for pole replacements were the result of targeting replacement of high reliability impact poles.

- **Distribution Lines Planned Component Replacement (D-SR-10):** Overall program expenditures were higher than plan by $1.9M because of a change in the scope of work for sentinel lights and cross arms replacements. This was partially offset by lower spend in transformer replacements due to lower than budgeted unit costs.
- **Component Replacement Submarine Cable (D-SR-11):** Capital expenditures for submarine cable replacement was below plan by $3.2M. This was because of higher priority demand work that limited resource availability, outage limitations and emergent submarine cable replacement. Higher volume of units was completed due to a higher proportion of lower cost units compared to the budget.
- **Distribution Lines Sustainment Initiatives (D-SR-12):** This investment includes projects that have historically been categorized into a program. Expenditures for Distribution Lines Sustainment Initiatives were lower than plan by $5.7M in 2021. This was a result of reprioritization of program investments associated with relocation and/or refurbishment of distribution assets in response to increases in non-discretionary System Access expenditures.
- **Distribution Lines Trouble Call and Storm Damage (D-SR-07) – System Service:** This portion of SR-07 is reported within System Service and accounts for two work programs: Dx Capital Post Trouble Call and Dx Capital Power Quality & Stray Voltage. Post Trouble Calls involve a return trip to permanently repair a temporary fix completed during the initial trouble call. This also includes follow-up activities to field-initiated requests that field personnel have determined require replacement immediately due to potential safety or reliability concerns. Units reported in this program can vary in size and scope depending on the type of post trouble incident, power quality or stray voltage investigation.

- **Demand Investments (D-SS-04):** Demand Investments involve minor distribution system modifications that ensure adequate supply of electricity to customers by addressing system needs identified by customer power quality complaints, feeder studies and system impact assessments. Increased demand in 2021 resulted in an increase of $1.7M to program expenditures. Variances in these investments reflect an emergent need, as the work is high-priority in nature with short turn around times that require Hydro One to promptly respond to system needs related to growth and effective operation of the distribution system.
- **Distribution System Modifications (D-SS-05):** Distribution System Modifications is another investment that is driven by customer needs which is focused on correcting feeder load balance, power quality and protection coordination issues that arise due to load growth. In 2021, the program experienced higher demand than anticipated resulting in an additional $2.1M in capital expenditures associated with customer connections that had to be completed in-year.
- **Worst Performing Feeders Program (D-SS-06):** In 2021, program spend was higher than plan levels by $3.2M due to the limited historical costing data available for this program at the time of the 2018-2022 Distribution Rate Order. Some execution challenges also affected the actual cost of this work, such as defects associated with some of the newly acquired devices.

3.2 PROJECT VARIANCES

The Distribution capital envelope is predominantly program-based, with smaller scale projects. However, some large System Service investments are required to ensure the system can accommodate load growth. Accordingly, Hydro One focuses on adherence to the total project cost rather than adherence to in-year expenditures.

Table 3 summarizes the projects that met the criteria of a material variance for either timing, scope or cost with detailed explanations for each listed below. As the Distribution capital work program is largely comprised of programs and smaller projects, few projects meet the $3M variance threshold. Only those projects in Table 3 that are identified either in the Execution or

Completed phase require variance explanations. Those projects identified as Planning have yet to be approved by Asset Planning in order to proceed to Execution.

Table 3 - Capital Project Variances 2021

OEB Category	AR Name	Project Phase ($M)	2021 Net DRO Plan ($M)	2021 Net Actual ($M)	2021 ISA DRO Plan ($M)	2021 ISA Actual ($M)	Net DRO Plan Project Total ($M)	Net Project End Forecast ($M)	Project End Variance ($M)	Net LTD Actual ($M)*	DRO Plan IS Year	Forecast/Actual IS Year	Date Variance (Years)
System Renewal – SR-12 Distribution Lines Sustainment Initiatives	Douglas Point TS 44kV U/G Cables 25721	Planning	4.0	0	4.3	0	4.3	2.5	0	0	2021	2025	4
	Dymond TS M3 Rebuild - Stage 2 25907	Planning	2.6	0	5.5	0	5.5	6.7	1.2	0	2021	2028	7
System Service – Unassigned	Nakina DS F2 BESS 25451	Completed	0	3.3	0	9.5	8.1	10.2	2.1	9.5	2019	2021	2
System Service – SS-02 System Upgrades Driven by Load Growth	Kirkland Lake Voltage Conversion - Stage 1 23080	Completed	0	1.3	0	6.4	4.6	6.4	1.8	6.1	2019	2021	2
	Stouffville 10th Line DS New T3 & feeders 23273	Execution	8.3	1.8	9.5	0	9.6	7.3	-2.3	3.1	2021	2022	1
	Armitage TS M12 Load Relief 23667	Completed	0	1.2	0	4.7	2.0	4.7	2.7	4.7	2020	2021	1
	Dundas TS #2 New Feeders 24420	Planning	7.1	0	7.3	0	7.3	7.3**	0	0	2021	After 2027	N/A
	Dresden Area Load Relief 25283	Planning	10.2	0	10.2	0	10.2	11.1	0.9	0	2021	2026	5
	Ancaster Area Load Relief 25288	Planning	4.9	0	4.9	0	4.9	8.4	0	0	2021	2028	7
	Listowel Load Relief - Load Growth 25701	Execution	4.9	0	5.2	0	5.2	3.5	-1.7	0.1	2021	2023	2
	Saugeen Shores DS and Port Elgin Load Growth 25719	Planning	4.7	0	5.1	0	5.1	5.3	0.2	0	2021	2024	3
	Elmhurst Beach DS 25861	Planning	4.8	0	4.8	0	4.8	5.4	0.6	0	2021	2025	4
	Pelham Load Relief 25282	Planning	7.9	0	7.9	0	7.9	7.9**	0	0	2021	After 2027	N/A
System Service – SS-03 Demand System Modifications	Muskoka TS M1-M5 New Tie Line 25791	Planning	5.7	0	5.9	0	5.9	10.6	4.7	0	2021	2024	3

Notes: *All forecast and LTD (Life to Date) values are as of December 2021
**Cost will be updated if project is within the planning period.

Witness: NG Chong Kiat

Nakina DS F2 BESS: This project investment is a pilot initiative for a Hydro One owned and operated Battery Storage facility in rural Ontario which is intended to provide backup power to the Aroland First Nation community where the community has been susceptible to prolonged outage durations. The project incurred increased costs as a result of complexities in finalization of the engineering design, COVID-19 restrictions, construction, commissioning and in-servicing which has also resulted in delays to the original in-service date.

Kirkland Lake Voltage Conversion Stage 1: The overall project scope involves the conversion of the Goodfish Distribution Station feeders and refurbishment of the existing station to meet load growth needs in the area and address end-of-life assets. After the completion of a detailed design, Hydro One determined that the project costs would be higher than the approved investment as outlined in the 2018-2022 Distribution Rate Order due to site specific design requirements. Given the significant forecasted load growth and condition of existing assets, the increased costs of the investment were addressed through Hydro One's redirection process to minimize the risk of overloading feeders, unsupplied load and reliability issues.

Stouffville 10th Line DS New T3 & feeders: Since the time of the 2018-2022 Distribution Rate Order, Hydro One revised this investment's scope of work to lower the project cost and address additional load growth expected to materialize in the area. This change in scope has resulted in a capital expenditure and ISA variance to budget as well as an in-service date deferral to 2022.

Armitage TS M12 Load Relief: This project was completed and in-serviced in 2021, with minor clean up and demobilization planned for 2022. The majority of the project work consisted of overhead construction and was completed in 2020. The assets did not enter service until 2021 due to the timing of permits required to complete the underground construction portion of the project. After the completion of a detailed design, Hydro One determined that the project costs would be higher than the approved investment as outlined in the 2018-2022 Distribution Rate Order due to site specific design requirements.

Listowel Load Relief - Load Growth: This project is currently in the detailed design stage. The project requires the construction of a new sub transmission line through the town of Listowel and the installation of a new 44kV pad-mounted distribution station. Due to delays associated with land acquisition and reprioritization, the forecast in-service date for this project has been revised to 2023.

4.0 CONCLUSION

Hydro One Distribution has demonstrated the ability to deliver a large and complex capital work program and has the capability of adjusting to meet the needs of its customers. The overage in capital expenditures over approved levels in 2021 was the result of non-discretionary, externally-driven spending associated with new customer connections, trouble calls, storm damage, and joint use and relocations. The organization adapted to the significant increases in demand requests and weather events to minimize the overall impact to the capital portfolio. This required prioritization of planned work to maintain a safe and reliable distribution network within the year while addressing future year risk and opportunities. As demand investments continue to experience fluctuating volumes, the organization remains focused on improving its planning strategies while leveraging flexibility within its workforce. Through its robust oversight over the distribution work portfolio, Hydro One Distribution has and will continue to execute the work portfolio in a safe and efficient manner.

UNDERTAKING JTU-1.12

Reference:
Exhibit I-3-O-AMPCO-142

Undertaking:
For I-03-O-AMPCO-142, to take the request to complete the table under advisement or to provide something different.

Response:
In its response to I-03-B3-AMPCO-103, Hydro One provided the forecast km for line rebuilds and relocations over the 2018-2027 period, and actual line kms over the 2018-2020 period, with actuals up to and including Q3-2021.

In its response for I-03-B3-AMPCO-104, Hydro One provided planned and actual capital expenditures for the D-SR-10 Distribution Line Sustainment Initiatives.

In its response to I-03-O-AMPCO-142, Hydro One subsequently updated the actual line km data from B3-AMPCO-103 for total 2021 year-end actuals.

To clarify the record:

- Parts a) and b) of AMPCO-104 did not correctly report planned and actual SR-10 expenditures. Attachment 1 of this response provides revised planned and actual capital expenditures values, which align with Exhibit O-02-01, Attachment 8, Appendix 2-AA, and which reported the capital expenditures correctly.
- AMPCO-142 did not correctly report actual km for 2021. Attachment 2 of this response provides revised 2021 actual km line rebuild and relocations for D-SR-10.

The correction provided in Attachments 1 and 2 of this response do not result in any impact to the total System Renewal envelope.

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UNDERTAKING JTU-1.12 - ATTACHMENT 1

Reference:

DSP Section 3.11, D-SR-11, Page 12, Appendix A

Interrogatory:

a) Please provide Appendix A Planned for the years 2018 to 2022.

b) Please provide Appendix A Actual for the years 2018 to 2022.

c) Please identify the projects in part (a) that were not completed as planned and why.

Response:

For this response we assumed the reference to SR-11 was incorrect and that the intent was to reference SR-10 as SR-11 does not have a page 12.

a) Below is a summary of planned investments for the years 2018 to 2022 based on the Draft Rate Order (EB-2017-0049) for Hydro One's 2018 to 2022 Distribution Revenue Requirement.

Year	Project Name	Total Net Planned ($M)
2018	Brockville TS 24M2 Feeder Rehab Phase 5	7.8
	City of Owen Sound Line Refurbish - PH 2	
	Projects <$1M	
2019	Sidney TS M7 Reconductor and Relocate	6.8
	Dymond TS M3 Rebuild - Stage 1	
	Otonabee TS 128M28 Phase 3 - Part 1	
	Projects <$1M	
2020	Palmerston TS M1 Relocation	16.6
	Muskoka TS M1 Relocation - Part 1 of 5	
	Manitoulin TS M25 - Relocate Line	
	G3K Towerline Relocate - Part 1	
	Otonabee TS 128M28 Phase 3 – Part 2 of 2	
	Wanstead TS M4 Bridgen Rebuild Stage 2	
	Projects <$1M	
2021	Wallace TS M6 Madawaska Relocate	22.0
	Douglas Point TS 44kV U/G Cables	

	Muskoka TS M1 Relocation - Part 3 of 5	
	Muskoka TS M1 Relocation - Part 2 of 5	
	Dymond TS M3 Rebuild - Stage 2	
	Owen Sound TS M24 Refurbishment - Stage 2	
	Cobden TS M6 Relocation	
	Havelock TS M2 Rebuild Part 2	
	Duart TS M5 Relocation	
	Margach DS F3 Line Relocate (SD 3201)	
	Projects <$1M	
2022	Gardiner TS M14 Relocation	33.8
	Morrisburg TS M23 Relocate	
	Napanee TS M2 Relocate	
	Kent TS M16 Relocation	
	Fergus TS M8 Relocation Eden Mills	
	Tillsonburg TS M4 Relocation	
	Muskoka TS M1 Relocation - Part 4 of 5	
	Val Caron DS - Maple Elms Street Rebuild	
	Weston Lake DS F1 – Kukatush Line Section Relocate	
	Town of Schreiber Rebuild Phase 2	
	Owen Sound TS M24 Refurbishment - Stage 3	
	Aguasabon DS F1 F2 - Terrace Bay Town Rebuild	
	Brant TS M22 Relocation Line Relocate	
	Dobbin TS 20M4 M6 M8 Reconstruction-Ackinson Rd	
	G3K Towerline Refurbishment - Part 2	
	Havelock TS M2 Rebuild Part 1	
	Longueuil TS M23 Relocate	
	Minden TS 87M2 Feeder Relocation Phase 2 Line Relocate	
	Muskoka TS M3 Relocate	
	Norfolk M3 Tillsonburg M10 Tie Relocation	
	Palmerston TS M3 Relocation	
	Projects <$1M	

Witness: FALTAOUS Peter

b) Below is a summary of actuals incurred in the year 2018-2021 and forecasted values for 2022.

Year	Project Name	Total Net Actuals ($M)
2018	Brockville TS 24M2 Feeder Rehab Phase 5	7.8
	City of Owen Sound Line Refurbish - PH 2	
	Projects <$1M	
2019	Dymond TS M3 Rebuild - Stage 1	8.1
	Otonabee TS 128M28 Phase 3 - Part 1	
	Turkey Point - Vittoria DS F2 Relocation	
	Wanstead TS M4 Oil Springs	
	Projects <$1M	
2020	Haldimand-Jarvis TS M6 Lakeshore Rebuild	11.7
	Murillo DS F2 assets upgrade and acquisition	
	Crysler DS F2 Future Proof Pilot Project	
	Dryden Wilde DS F2-Dryden Downtown East	
	Otonabee TS 128M28 Phase 3 – Part 2 of 2	
	Wanstead TS M4 Brigden Rebuild Stage 2	
	WPF - Muskoka TS M9 Section Reconductor	
	Projects <1M	
2021	Lake TS M4M6 Rebuild	11.7
	Dryden Town Rebuild Ph. 4 -Dryden Downtown East	
	Allanburg TS M7 Rebuild	
	Brant TS M22 Relocation	
	Woodstock OPC Conversion-NorthEast 4kV	
	Duart TS M5 Relocation - Kent	
	Sidney TS 12M7 Reconductor	
	Cote Boulevard Rebuild - Hanmer DS	
	Errington Street Rebuild	
	Fairchild TS M12 LV Cable Replacement	
	Projects <$1M	
2022	Underground Cable Injection Program	13.7*
	Virginiatown DS - HWY 66 Rebuild	
	Projects <$1M	

Note: **Fairchild TS – M12 LV Cable Replacement was originally planned for 2022 but was completed in 2021.*

c) Please see response to B3-Staff-146.

Witness: FALTAOUS Peter

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UNDERTAKING JTU-1.12 - ATTACHMENT 2

Reference:

DSP Section 3.11, D-SR-11, Page 12, Appendix A

Interrogatory:

Please complete the following table:

D-SR-11	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Planned Line Rebuild (km)										
Planned Line Relocation (km)										
Total										

a) Please provide the total km of actual line rebuild for the period 2018 to 2021.

b) Please provide the total km of actual line relocation for the period 2018 to 2021.

c) Please provide the total number of poles replaced for the period 2018 to 2022.

d) Please provide the forecast number of poles to be replaced for the period 2023 to 2027.

e) Please provide the average quantity of conductors and insulators per km of line.

Response:

For this response it was assumed the reference to SR-11 was incorrect and that the intent was to reference SR-10 as SR-11 does not have a page 12.

Planned line work is as follows:

D-SR-10*	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Planned Line Rebuild (km)	25	1	11	11	26	0	10	1	10	40
Planned Line Relocation (km)	30	8	47	66	83	41	23	56	17	10
Planned Line Rebuild/ Relocation (km) projects < $1M**	12	3	12	7	7	49	52	55	57	60
Total	67	12	70	84	116	90	85	112	84	110

**kms of overhead distribution line rebuilds/relocations only include 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.*

a) and b) actual line work is as follows:

D-SR-10	**2018**	**2019**	**2020**	**2021**
Actual Line Rebuild (km) *	25	21	22	18
Actual Line Relocation (km) *	30	4	2	10
Total	55	25	24	28

**kms of overhead distribution line only include material investments that were part of the ISD D-SR-10, as km accomplishments for projects less than $1M are not tracked.*

c) & d) The number of pole replacements is not tracked by projects completed under this investment.

e) The quantity of conductors and insulators per km of line are not tracked by projects completed under this investment. For information on Hydro One's Distribution Lines assets, see B-3-1 Section 3.2.3.

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UNDERTAKING JTU-1.13

Reference:
Exhibit I-22-O-SEC-242

Undertaking:
To provide the IHS global insight economic forecast, April 2022.

Response:
Please see attachment 1 (filed on a confidential basis).

Witness: ALAGHEBAND Bijan, VETSIS Stephen

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IHS GLOBAL INSIGHT – ECONOMIC FORECAST (APRIL 2022)

A copy of this Attachment has been filed confidentially with the OEB in accordance with the *Practice Direction on Confidential Filings*.

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UNDERTAKING JTU-1.14

Reference:

No Reference Provided

Undertaking:

To provide the reports on inflationary cost modelling with respect to supply chain.

Response:

Hydro One is providing two sets of analysis in response to this undertaking, as follows:

1. **Internal analysis and modelling performed by Hydro One to estimate the impacts of inflation on the company in 2022, for materials and third-party services (Attachment 1 - Filed on a confidential basis)**

   Hydro One's model estimates a 10% inflationary impact for 2022 materials and services.

   There is a lagging effect between the changes in commodity pricing and the impact on Hydro One's sourceable spend.[1] This is due to factors such as the measures described in Interrogatory O-Staff-363 b). However, these measures cannot completely shelter Hydro One from the inflationary pressures described in the updated evidence. For example, as contracts come to the end of their term and new agreements are sourced, new terms and conditions will reflect current market conditions. Similarly, pricing updates occur under existing and continuing contracts in accordance with their terms.

   Hydro One's model does not immediately capture the new inflationary pressures that are materializing in 2022. As such, the model understates actual inflation in 2022. For example, Aluminum saw an increase of 31% from Dec 2020 to Dec 2021 and a 30% increase from Dec 2021 to Mar 2022.[2] Similarly, gasoline has seen an increase of 35% from Dec 2021 to Mar 2022.[3]

   As 2022 progresses these inflationary price increases will be reflected in the model and in Hydro One's current work program forecast.

[1] Sourceable spend includes all materials and third-party services procured by Hydro One. It excludes taxes, regulatory body fees, utilities and payments to municipalities or charitable contributions.
[2] Based on the following index for aluminum: Aluminum N. America.
[3] Based on the following index for fuel: Gasoline: Reformulated Gasoline Blendstock N. America.

2. **Independent validation of Hydro One's model by Wood Mackenzie (Attachment 2)**

   Wood Mackenzie reviewed Hydro One's model structure to validate the methodology used and the key cost drivers.

   Wood Mackenzie validated Hydro One's model structure by comparing Hydro One's model inflation result of 10% to Wood Mackenzie's model for a typical electric utility. Wood Mackenzie's inflation result was 11% for a typical electric utility.

INTERNAL ANALYSIS AND MODEL OVERVIEW

An excel copy of this Attachment has been filed confidentially with the OEB in accordance with the *Practice Direction on Confidential Filings*.

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Wood Mackenzie
A Verisk Business

Inflationary Cost Model Review
Hydro One

May - 2022

The Engagement

Wood Mackenzie has performed an independent study to review Hydro One's cost model structure to validate the methodology being used and validate the key cost drivers.

Hydro One currently assumes a base 2% increase per year. Market dynamics over the last year have created higher than expected inflation across both materials and services. As such, Hydro One is proposing an incremental 8% increase, for a total of 10% increase, to reflect the current market volatility and the resulting impact on Hydro One sourceable spend.

Wood Mackenzie is a global research and consulting firm that provides energy clients with data, analytics, and insights that they rely on for their decision making. Wood Mackenzie Supply Chain Consulting (SCC), formerly PowerAdvocate, utilizes proprietary cloud-based software solutions and bespoke consulting services to enable our clients to leverage data analysis and assist them in navigating an ever-changing marketplace.

Qualifications

Wood Mackenzie Supply Chain Intelligence is a suite of cloud-based software solutions that includes a product, Cost Intelligence, which enables our clients to identify market-based risks and opportunities. Cost Intelligence includes hundreds of cost models and indices that enable users to understand what a project or item should cost in a dynamic market. Wood Mackenzie Cost Intelligence models support our energy market clients. The Wood Mackenzie team starts with industry specifications, technical drawings, supplier 10ks and other industry information to develop detailed items that tie cost inputs to dynamic market indices. Wood Mackenzie weights the indices and loads the models to the cloud-based platform. Items are combined into subcategories and categories that reflect total spend for a company or project.

Model Review

Hydro One provided SCC with a model based on Hydro One supply chain taxonomy with individual spend items that have been assigned to specific categories and subcategories. The model reflects the 2021 spend for each item. Hydro One has been monitoring seventeen (17) key indices that impact yearly spend. The indices' values are from December 2020 to December 2021 and the yearly percent change was calculated. As appropriate for a specific item, the indices were allocated to the item and weighted for the exposure each item would have to that index. The Canadian Consumers Price Index (CPI) was the only index applied to every line item, with a weighting that was the net of the 100% weight less the other applicable cost drivers.

Hydro One subtracted the base amount of 2% inflationary rate from each of the index inflation values. The net inflationary number was applied to the percentage of item spend that had been allocated to each specific index. This established the inflated item spend budget. Hydro One summed each item value to estimate the inflationary impact to the entire spend portfolio. The incremental inflationary impact is 8%, for a total of 10% inflation.

Conclusion

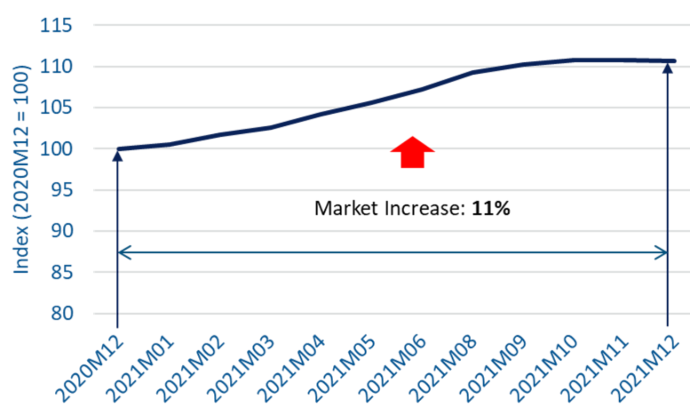
SCC compared Hydro One's inflationary methodology to our Cost Intelligence models to compare the underlying methodology, selected indices, and overall inflation. The overall approach utilized in the Hydro One model is consistent with the methodology that Wood Mackenzie has utilized in the development of our cost models. Wood Mackenzie utilizes a three-level schema for the models that include a taxonomy[1]of item, subcategory, and category. Indices are assigned at the item level with allocations weighted on how much each index influences the cost of the item. An aggregate spend value is assigned to each item that rolls up into the subcategories and categories, so that an aggregated portfolio level inflation value can be measured over a defined period.

The differences in the Hydro One approach to the Wood Mackenzie approach are two areas. The first is in the number of indices in the Hydro One model. Wood Mackenzie leverages hundreds of market indices (i.e.: Spot Market Price, Bureau of Labor Statistics) in the creation of our models as well as custom indices that Wood Mackenzie developed to reflect industry margins and overheads. This provides a more granular approach to modeling as compared to the Hydro One model.

The second difference is that Wood Mackenzie does not utilize the CPI in our models. Our reasoning is that the CPI is reflective of general inflation for all goods and services and may not capture the monthly volatility of a specific market, especially in a very dynamic market where commodity prices are rapidly changing. Wood Mackenzie's Cost Intelligence models are used to support vendor negotiations where granular visibility of monthly impact of labor and commodities are essential. The CPI historically tended to be consistent each month; during a volatile market, this tends to soften the impact of the daily/monthly volatility in the commodity market. Wood Mackenzie models use indices such as Producer Price Index (PPI), Average Hourly Earnings (AHE), Average Weekly Earnings (AWE), and commodity pricing such as Spot Price Metal (SPM) and others.

Since the pandemic, the CPI has dramatically increased reflecting the overall inflationary market. As a result, we believe that Hydro One's use of the CPI as a proxy for the overall market inflation is appropriate. Wood Mackenzie was able to validate this by comparing the Hydro One model inflation result of 10% (the incremental 8% plus the 2% baseline budget) to a Canadian specific Wood Mackenzie Cost Intelligence model for a typical electric T&D utility spend portfolio including all services, material, and equipment. The Wood Mackenzie inflation from December 2020 to December 2021 was 11% (Figure 1). While there will be variations in the spend amounts, this validates Hydro One's methodology and key cost indices.

Figure 1. Wood Mackenzie Canadian Electric T&D Cost Model



[1]*Models are built using a hierarchical order that includes 3 levels where categories are broken down into subcategories and subcategories are broken down into items.*

UNDERTAKING JTU-1.15

Reference:

Exhibit I-22-O-SEC-254

Undertaking:

To provide a sense of magnitude of contracts under fixed price or fixed escalator, at the time prior to inflationary increases, with numbers as available or easy to provide.

Response:

Contracts with a fixed price or fixed price escalator make up approximately 12 to 15% of "sourceable spend" (defined in JTU 1.14). This includes contracts that have been in place since January 2020 and will remain effective until Q4 2022 or beyond. Hydro One notes that the term of many of these contracts will expire in the next 6 to 12 months and anticipates the new or renegotiated contracts will reflect current market prices.

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UNDERTAKING JTU-1.16

Reference:

Exhibit I-22-O-SEC-250

Undertaking:

For the contracts identified, identify the mechanics of the price escalating clauses related to the price adjustment clauses shown in that last column of the table to the extent it can be done, and if it cannot be done publicly, to set it out in confidence.

Response:

The price escalating clauses described in O-SEC-250 are provided below for each of the following contracts:

1. Transformers and Components – Power Transformers 100 MVA - 750 MVA – Highest Spend Contract in Category
2. Transformers and Components - Power Transformers 41.7 MVA - 125 MVA – Second Highest Spend Contract in Category
3. Transformers and Components – Distribution Transformers
4. Construction Materials – Wood Poles
5. Construction Materials – Wire and Cable

1. <u>Transformers and Components</u> – Power Transformers 100 MVA - 750 MVA – Highest Spend Contract in Category

Category	Contract Description	Contract Price Adjustment Timing	Price Adjustment Formula Index Inputs
Transformers and Components	Power Transformers 100 MVA - 750 MVA – Highest Spend Contract in Category	Quarterly	• Copper • Core Steel • Tank Steel • Winding Insulation • Labour • CPI Transportation • EUR to CAD Foreign Exchange

[redacted]

[redacted]

2. <u>Transformers and Components</u> – Power Transformers 41.7 MVA - 125 MVA – Second Highest Spend Contract in Category

Category	Contract Description	Contract Price Adjustment Timing	Price Adjustment Formula Index Inputs
Transformers and Components	Power Transformers 41.7 MVA - 125 MVA – Second Highest Spend Contract in Category	Quarterly	• Copper • Core Steel • Tank Steel • Winding Insulation • US CPI

[redacted]

[redacted]

Witness: BERARDI Rob

[redacted]

[redacted]

3. <u>Transformers and Components</u> – Distribution Transformers

Category	Contract Description	Contract Price Adjustment Timing	Price Adjustment Formula Index Inputs
Transformers and Components	Distribution Transformers	Annually	• Core Steel • Copper • Aluminum • Fabricated Steel • Oil • Labour • USD to CAD Foreign Exchange

[redacted]

[redacted]

4. Construction Materials – Wood Poles

Category	Contract Description	Contract Price Adjustment Timing	Price Adjustment Formula Index Inputs
Construction Materials	Wood Poles	Annually	• Whitewood • Chemical and Chemical Additive • Transportation-inbound actual costs • CAD CPI

[redacted]

[redacted]

5. <u>Construction Materials</u> – Wire and Cable

Category	Contract Description	Contract Price Adjustment Timing	Price Adjustment Formula Index Inputs
Construction Materials	Wire and Cable	Annually	• Copper • Aluminum • Ethylene • Propylene • US Producer Price Index (PPI) • US to CAD Foreign Exchange Rate

[redacted]

[redacted]

Witness: BERARDI Rob

[redacted]

UNDERTAKING JTU-1.17

Reference:
Exhibit I-22-O-SEC-261

Undertaking:
To break down into capital and OM&A for each of Tx and Dx the figures in the table that broke down procurement spend and procurement spend before inflation.

Response:

2021 Inflation Impact on Materials & Services ($M)

	2021 Procurement Spend	2021 Procurement Spend Before Inflation	Inflation Impact	Impact %
Transmission Capital	886.9	857.1	29.8	3%
Transmission OMA	178.7	176.3	2.5	1%
Total Transmission	**1,065.7**	**1,033.4**	**32.3**	**3%**
Distribution Capital	333.1	325.2	7.9	2%
Distribution OMA	250.5	247.9	2.5	1%
Total Distribution	**583.6**	**573.1**	**10.5**	**2%**

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UNDERTAKING JTU-1.18

Reference:

No Reference Provided

Undertaking:

To file updated actuals for the 2021 scorecard, team and corporate, and to file the 2022 corporate scorecard.

Response:

The 2021 Corporate Scorecard (including actual performance) was provided as an updated undertaking response (JT-4.25) filed on April 22, 2022 as part of Hydro One's response to the Ontario Energy Board Decision on Confidentiality requests and Procedural Order No. 5 dated April 14, 2022.

The 2022 Corporate Scorecard is provided as Attachment 1 to this response.

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2022 Team Scorecard

2022 Team Scorecard						
Corporate Goal	Component Weight	Measure & Definition	Sub Component Weight	Performance Levels		
				Threshold	Target	Exceeds
Health and Safety	20%	High Energy Serious Injury and Fatality Rate*: Incidents per 200,000 hours	50%	0.105	0.066	0.053
		Recordable Incidents: Incidents per 200,000 hours	50%	0.965	0.877	0.833
Work Program	20%	Transmissions (Tx) Reliability – average length of unplanned interruptions to multi-circuit supplied delivery points (SAIDI): Minutes per Delivery Point	25%	8.5	7.5	5.2
		Distribution (Dx) Reliability – average length of outages in hours that a customer experiences (SAIDI): Hours per Customer	25%	7.2	5.4	4.7
		Tx In Service Additions - Delivery Accuracy: Variance (%) to approved in-year budget of $1,391M (2022)	25%	+/- 5.0%	+/-2.0%	+/-1.0%
		Dx In Service Additions - Delivery Accuracy: Variance (%) to approved in-year budget of $646 (2022)	25%	+/- 3.0%	+/-2.0%	+/-1.0%
Productivity	10%	Productivity Savings: in $M	100%	$310.7M	$365.5M	$402.1M
Financial	30%	Net Income to Common Shareholders: in $M	100%	[redacted]	[redacted]	[redacted]
Customer	20%	Overall Favourable Impression	100%	78%	80%	84%

** If the company has a fatality, the High Energy Serious Injury and Fatality Rate measure will be reduced to 0% based on the findings of the System Investigation.*

UNDERTAKING JTU-1.19

Reference:

I-01-O-Staff-365

Undertaking:

To provide an explanation of the 20-year capacity and pricing agreement with its vendor AMI 2.0 program, how it differed both with respect to pricing and the units complete and other relevant information, as compared to what is filed in the application. As some of the information may be commercially sensitive, the response may seek confidentiality through the normal process.

Response:

[redacted]

- [redacted]
- [redacted]

[redacted]

[redacted]

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UNDERTAKING JTU-1.20

Reference:

Exhibit I-14-O-LPMA-37

Undertaking:

To provide the closing 2022 PP&E and depreciation continuity figures from the DRO in the prior applications.

Response:

As part of the Draft Rate Order (DRO) process for both Transmission and Distribution in the prior rebasing applications, Hydro One filed the updated, Rate Base and Depreciation schedules, which included the average Gross Utility Plant and average Accumulated Depreciation to derive the rate base calculations together with Working Capital Allowance.[1] Further rate base analysis is provided in Exhibit C-01-01.

The conforming year-end balances for 2021 and 2022 Gross Fixed Assets and Accumulated Depreciation as requested in the undertaking, which align to the approved 2021 and 2022 rate bases for each of Transmission and Distribution, are summarized below. These closing balances are presented in a consistent manner with Exhibit C-04-02 (Continuity of Property, Plant and Equipment: Gross Fixed Assets) and Exhibit C-04-03 (Continuity of Property, Plant and Equipment: Accumulated Depreciation) filed in the current proceeding.[2]

Transmission – Year-End Balances

$M	2021 OEB Approved	2022 OEB Approved
Gross Fixed Assets	20,937	22,153
Accumulated Depreciation	7,738	8,150

Distribution – Year-End Balances

$M	2021 OEB Approved	2022 OEB Approved
Gross Fixed Assets	13,957	14,504
Accumulated Depreciation	5,557	5,887

[1] For Distribution, the OEB-approved amounts were presented in EB-2017-0049 Exhibit 1.2 filed on April 5, 2019 and the associated impact for the reduction of $13.5M outlined in DRO Reply Submission which was filed on May 19, 2019. For Transmission, the OEB-approved amounts were presented in EB-2019-0082 Exhibit 1.2 filed on May 28, 2020.

[2] 2023-2027 tests years in Exhibits C-04-02 and C-04-03 were subsequently updated to reflect the inflation update on March 31, 2022 in Exhibit O-01-02 Attachments 06B and 06C respectively.

As part of Hydro One's response to O-LPMA-037, 2021 actuals were added to the originally filed Exhibits C-04-02 and C-04-03 as a separate line (prior to the inflation impact presented in Exhibit O-01-02). Consistent with the OEB's approach outlined in PO No. 5, 2021 actuals were included for information purposes only and did not impact the 2022 forecast. This is consistent with Hydro One's approach to maintaining the 2023 opening rate base as outlined in O-LPMA-037 and Exhibit O-02-01.

UNDERTAKING JTU-1.21

Reference:

Exhibit I-24-O-VECC-149

Undertaking:

As a follow-up to the response to VECC-149: to consider and advise of Hydro One's position in respect of how the 10% inflation cap concept is to be interpreted in the future when one looks back at the capital programs, in the scenarios where (i) inflation is significantly above 10%, and (ii) inflation is significantly below 10%.

Response:

As noted in Exhibit O-01-02, page 17, Hydro One has proposed an inflation forecast cap of 10%, reflecting the cumulative inflation cap over the 2022 and 2023 period. As part of the proposal, Hydro One will update the OM&A and capital amounts to reflect the latest inflation information at the time of the DRO, expected to be based on 2022-year end actuals and an updated 2023 forecast. The threshold provides ratepayers with mitigation of inflation risk as part of the approved Plans and provides the OEB with certainty on the upper limit of any inflation adjustment at the draft rate order stage.

The undertaking question posed appears to assert that the 10% threshold is a cap on capital expenditures. The 10% threshold and its relevance to Hydro One's capital plans must be considered in the proper context. It is first and foremost an assumption related to inflation and is no different than any other assumption used to establish a forecast level of capital. In this regard, in Hydro One's original filing, it proposed a flat annual 2% inflation rate over the bridge years and the plan period. Subject to any changes to the proposed plan arising from the OEB's decision, the resulting approved plan with the 2% inflation assumption would have resulted in a capital envelope to which Hydro One would manage to and, in doing so, where necessary, employ its investment reprioritization and redirection process. The circumstance is identical with respect to the 10% threshold. The revised inflation assumption includes the cumulative inflation for 2022 (actual) and 2023 (forecast) period up to the 10% threshold for the 2023 rebasing year and an expected to experience a 2% annual inflation rate over the remaining years of the Plan period. Identical to the original filing, subject to the OEB's consideration, capital envelopes incorporating the assumed inflation will be approved by the OEB, and Hydro One will work to remain within those envelopes.

As in any forecast including one based on the 10% threshold, actual circumstances can vary from forecast amounts. If Hydro One experiences inflation levels higher than included in the forecast (for any part of the 5 year plan period), Hydro One will strive to manage its capital work program within the approved envelopes, including fluctuations in actual inflation rates relative to forecast. However, the Company will make prudent investment decisions based on real-time factors through the application period. These decisions, which may include external cost pressures outside of Hydro One's control, will be documented and disclosed during the next rate application period, per normal course.

Likewise, if actual inflation over the Plan period was less than the assumed 2%/year for each of 2024 through 2027, Hydro One would be in a position to allocate resources to complete the Plan and potentially additional work while remaining within approved envelopes.

UNDERTAKING JTU-1.22

Reference:
Exhibit I-24-O-VECC-174

Undertaking:
To clarify why the differences in the 2 tables noted in interrogatory O-VECC-174 do not equal to the adjustments shown in interrogatory O-VECC 173 Table 1 for each of 2018 to 2020.

Response:
The 2013 to 2020 principal adjustments shown in response to interrogatory O-VECC-173 reflect the net revenues that were recorded in the External Station Maintenance, E&CS and Other External Revenues Variance account to correct for the inadvertent exclusion of actual revenues related to internal work performed by Hydro One Transmission for its affiliates, including Hydro One Distribution and Acronym (formerly Hydro One Telecom). As described in Exhibit O-01-05, the 2013 to 2020 principal adjustments, totaling a credit balance of $25.8M, were recorded in the variance account as a life-to-date adjustment in 2021. That total credit balance is being requested for disposition to return to ratepayers.

To align with the approach determined in Hydro One's internal review, actual 2018 to 2020 Transmission External Revenues (original Exhibit D-02-01, Table 1) were updated to reflect various changes, including additional internal work revenues within the Other External Revenues category that were previously excluded and minor corrections to the groupings/re-classifications within certain line items.[1] These updates were reflected in Table 2 of Exhibit O-01-05. These updates would reflect only a subset of the principal adjustments shown in the response to interrogatory O-VECC-173.

As such, a comparison of changes between Tables 1 and 2 in the preamble to interrogatory O-VECC-174 will not correlate to the table in the interrogatory response to O-VECC-173.

[1] See O-VECC-175

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UNDERTAKING JTU-1.23

Reference:

Exhibit I-24-O-VECC-151

Undertaking:

Re VECC 40b, to confirm what are the updated historical values.

Response:

Hydro One confirms that the correct number, 12.8 TWh, was used in its model in the updated response to I-24-D-VECC-040 as filed March 31, 2022. Hydro One clarifies that the reference to 12.39 TWh, which appears in row iv for 2015 in the first table shown in the response to I-24-O-VECC-151(a) is a typo and should instead be 12.8 TWh. Hydro One further clarifies that the figure 13.97 TWh which appears in the last row for 2015 in the third table shown in response to I-24-O-VECC-151(a) should have been 12.8 TWh, as shown in the corrected table below.

	2015	2016	2017	2018	2019	2020
C&S	4.52	5.17	6.28	7.07	7.37	7.37
EE	8.28	9.86	10.96	12.27	13.03	13.53
Total	12.80	15.03	17.24	19.34	20.40	20.90

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UNDERTAKING JTU-1.24

Reference:

I-24-O-VECC-158

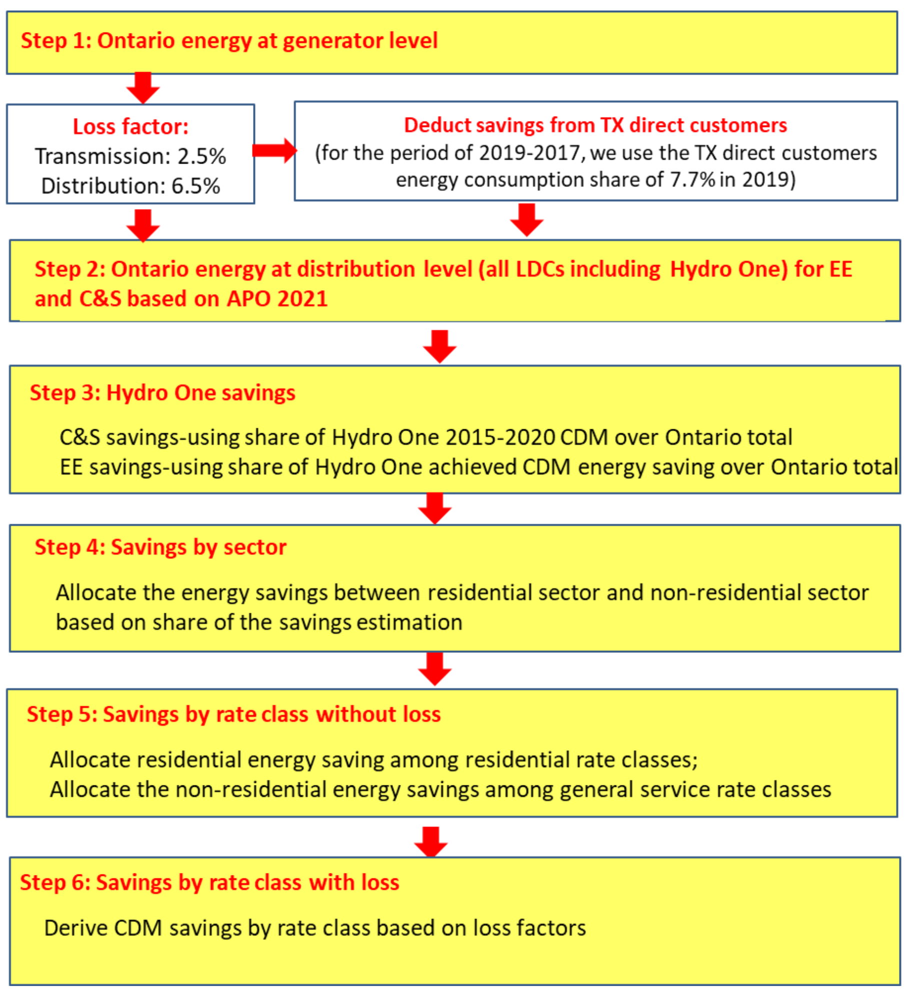
Undertaking:

To show how the 3,986 from the 1,907 was derived using the methodology set out in TCQ 13 from VECC.

Response:

The following flow chart describes in more granular detail the steps for deriving Hydro One distribution's CDM savings based on the total savings for Ontario. A detailed numerical derivation is provided in live Excel format as Attachment 1 to this response.

The attached table shows the details for deriving the total of 3,986 GWh energy savings in 2020.



Witness: ALAGHEBAND Bijan

Hydro One also provides the following correction to the question asked at the technical conference which forms the basis for this undertaking:

- VECC asked for an undertaking in which Hydro One shows how it derived total distribution savings (3,986 GWh) from 19.07 TWh in the updated evidence. Hydro One notes that 19.07 TWh is not the correct figure. The correct figure is 20.90 TWh.

NUMERICAL DERIVATION – DISTRIBUTION CDM SAVINGS

This exhibit has been filed separately in MS Excel format.

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UNDERTAKING JTU-2.01

Reference:

Exhibit I-14-O-LPMA-029

Undertaking:

To advise, in the case of Scotiabank specifically, what experience or other factors left them qualified for the project.

Response:

As discussed in the response to O-Staff-357, Hydro One is seeking to update the planning parameter of Ontario CPI for 2022 and 2023. As noted in O-LPMA-029, Hydro One is not aware of a third-party that publishes a consensus of other provincial forecast providers for Ontario CPI. As a result, Hydro One concluded that an economic forecaster needed to be selected to update the Ontario CPI planning parameter for 2022 and 2023.

Scotiabank was selected because:

Scotiabank publishes CPI Ontario forecasts on a regular basis, which are disclosed on an equal dissemination basis and are in the public domain, as discussed in the response to O-Staff-359.

Scotiabank employs highly experienced econometricians who have built a proprietary model to forecast inflation, which was recently updated to account for supply side impacts to inflation. As referenced in Exhibit O-01-02 Attachment 1, page 2, footnote 1, these econometricians are René Lalonde and Nikita Perevalov. Prior to joining Scotiabank in 2016, René Lalonde worked in modeling and forecasting with the Bank of Canada, as a Research Director, and with the International Monetary Fund. He holds a Master of Science degree in Economics from École des Hautes Études Commerciales in Montréal. Prior to joining Scotiabank in 2017, Nikita Perevalov worked at the Bank of Canada, most recently as a Research Advisor in the International Economic Analysis department focusing on model development. Prior to that Mr. Perevalov held senior positions in the projection teams, also at the Bank of Canada, focused on Canadian and global economies. Mr. Perevalov holds a Master of Arts in economics and a Master of Science in mathematics from the University of Toronto.

Derek Holt is Vice President and Head of Capital Markets Economics at Scotiabank where he is responsible for leading the team in the application of economic and financial market forecasts and research. He has over fourteen years of professional experience at Scotiabank and thirteen years at RBC (where he was the Assistant Chief Economist for over seven years). In addition to a Master of Arts degree in Economics from the University of Toronto, Mr. Holt also earned a Master of Business Administration degree in Finance from the Schulich School of Business at York University, and he holds the Chartered Financial Analyst (CFA) designation.

UNDERTAKING JTU-2.02

Reference:
Exhibit I-14-O-LPMA-029

Undertaking:
To review what internal documents are available that record discussions concerning the decision to choose Scotia over the other possibilities and to the extent they are relevant and not privileged, produce them. If Hydro One takes the position that the documents are not properly producible, to advise.

Response:
With respect to any internal documents concerning other possibilities, Hydro One believes that this material would be irrelevant to, and would not assist the OEB in deciding, the matters at issue in this application. It is that evidence that is relevant to the matters at issue and will be considered by the OEB. The evaluations Hydro One made in determining which proponent to select, are irrelevant to a consideration of the evidence filed in the application. Further, the retainer letter agreement entered into with Scotiabank, which set out the mandate or scope of work they were engaged to perform, is produced in response to JTU-1.02.

Please refer to JTU-2.01 for further discussion with respect to the decision to select Scotiabank.

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UNDERTAKING JTU-2.03

Reference:

Exhibit I-14-O-LPMA-029

Undertaking:

To the extent Hydro One is able to provide a response that is responsive and not privileged, to confirm no data or other substantive information was provided to Scotia both before and after the initial instructions, and also to confirm that there was no discussion that would constitute a potential change in instructions, once those initial instructions had been provided. To the extent there were privileged discussions, to advise.

Response:

Hydro One did not provide data or substantive information to Scotiabank before or after initial instructions.

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UNDERTAKING JTU-2.04

Reference:

Exhibit I-14-O-LPMA-29

Undertaking:

To the extent Hydro One is able to provide a response that is not privileged, to confirm whether there were any discussions internal to Hydro One in around this period on whether an external report that would address the impact of everything going on in the world, the impact on Hydro's specific costs and Hydro's specific business, would be helpful. To the extent the information being sought involves privileged discussions with counsel, to advise.

Response:

Please refer to JTU-1.14. That undertaking response includes: (i) Hydro One's analysis of the impacts of inflation on its materials and third-party services; and (ii) Wood Mackenzie's independent review and validation of Hydro One's analysis.

Please refer to O-Staff-381 (confidential). That interrogatory response discusses Hydro One's expectations for compensation costs in 2023.

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UNDERTAKING JTU-2.05

Reference:

Exhibit I-14-O-LPMA-29

Undertaking:

To the extent Hydro One is able to provide a response that is not privileged, to advise what consideration, if any, has been given to an analysis of how inflationary increases affect Hydro One's costs specifically, and then why was Scotia not asked to consider this. To the extent the response is privileged (based on discussions with counsel), to advise.

Response:

Please refer to JTU-1.14. That undertaking response includes: (i) Hydro One’s analysis of the impacts of inflation on its materials and third-party services; and (ii) Wood Mackenzie’s independent review and validation of Hydro One’s analysis.

Please refer to O-Staff-381 (confidential). That interrogatory response discusses Hydro One’s expectations for compensation costs in 2023.

Regarding why Scotia was not asked to consider Hydro One’s costs specifically, please refer to the Technical Conference Transcript, Vol. 1, p. 29, ln. 4-20 where Mr. Holt indicated that they are macroeconomists who forecast CPI. They do not project the impact of inflation on a specific client. More specifically, Scotia was asked to provide a high-level report on what is currently driving inflation and what they expect in the future for inflation, leveraging forecasts that are disclosed on an equal dissemination basis and are in the public domain, as discussed in the response to O-Staff-359.

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UNDERTAKING JTU-2.06

Reference:
Exhibit I-14-O-LPMA-29

Undertaking:
To the extent Hydro One is able to provide a response that is not privileged, to advise what consideration, if any, has been given to whether certain aspects of Hydro One's prospective work in the future is more exposed to the cost increases it currently faces, and why was Scotia not asked to consider this. To the extent the response is privileged (based on discussions with counsel), to advise.

Response:
Please refer to JTU-1.14. That undertaking response includes: (i) Hydro One's analysis of the impacts of inflation on its materials and third-party services; and (ii) Wood Mackenzie's independent review and validation of Hydro One's analysis.

Please refer to O-Staff-381 (confidential). That interrogatory response discusses Hydro One's expectations for compensation costs in 2023.

Please refer to JTU-2.05 for why Scotia was not asked to consider this.

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UNDERTAKING JTU-2.07

Reference:

Exhibit I-14-O-LPMA-29

Undertaking:

To the extent Hydro One is able to provide a response that is not privileged, to advise what consideration, if any, has been given to whether certain potential projects will become relatively less expensive as compared with other projects more subject to inflation. Why was Scotia not asked to consider this. To the extent the response is privileged (based on discussions with counsel), to advise.

Response:

Please refer to JTU-1.14. That undertaking response includes: (i) Hydro One's analysis of the impacts of inflation on its materials and third-party services; and (ii) Wood Mackenzie's independent review and validation of Hydro One's analysis.

Please refer to O-Staff-381 (confidential). That interrogatory response discusses Hydro One's expectations for compensation costs in 2023.

Please refer to JTU-2.05 for why Scotia was not asked to consider this.

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UNDERTAKING JTU-2.08

Reference:
Exhibit I-2-O-Anwaatin-8, Part C

Undertaking:
To advise whether there was any general comparison, general analysis, given to the various entities in the financial sector, their general positions and conclusions on recent inflationary trends.

Response:
As indicated in O-SEC-244, Hydro One receives various third party economic and price forecasts and is aware of various forecast levels for inflation. Instead of a further analysis to support its Inflation Update, Hydro One sought an expert who could speak to historical inflation, provide a forecast for Ontario CPI and could provide rationale for that forecast, as noted in O-LPMA-029.

The rationale for the selection of Scotiabank has been provided in JTU-2.01.

Hydro One recognizes that forecasts change over time. As described in O-Staff-357, Ontario CPI assumptions as provided by Scotiabank will be updated for 2022 actuals and the most recent 2023 forecast at the draft rate order stage.

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UNDERTAKING JTU-2.09

Reference:

Exhibit KTU2.1 – New York Times Article

Undertaking:

If and when Scotia updates its analysis, in the event Scotia does not consider the EU's near-total ban on Russian fossil fuels, to consider requesting Scotia to undertake a further analysis considering this factor. If Hydro One is not prepared to ask Scotia to undertake such further analysis, to advise.

Response:

The forecast that underpins the Scotia report provided in Exhibit O-01-02 Attachment 1, is Scotia's forecast that is publicly available and was not developed specifically for Hydro One. The request is asking for an entirely different bespoke analysis which was outside the scope of Scotia's engagement.

To the extent that the EU fossil fuel ban is a factor, its impact will be reflected in future forecasts issued by Scotiabank, to be incorporated by Hydro One at the time of the DRO under the current proposal as outlined in Exhibit O-01-02 Section 2.5.2 (Confirmation and Adjustment of Inflation Forecast).

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UNDERTAKING JTU-2.10

Reference:
Exhibit I-2-O-Anwaatin-1, Attachment 2

Undertaking:
To confirm that Exhibit I-2-A-Anwaatin 1, Attachment 2, is still the applicable Indigenous Relations Policy.

Response:
In response to the above specific undertaking Hydro One gave, we confirm that Interrogatory O-Anwaatin-001, Attachment 2 is the latest Indigenous Relations Policy.

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UNDERTAKING JTU-2.11

Reference:

Exhibit I-2-O-Anwaatin-7

Undertaking:

To advise of Hydro One's position as to how the Indigenous Relations Policy informs conversations of the kind described in O-Anwaatin-007.

Response:

As noted in O-Anwaatin-007, Hydro One's approach is consistent with, and took into account, the results of the customer engagement activities performed as part of this application. This includes the First Nations Chiefs Engagement Report (Phase II), which reflects the needs and preferences of Indigenous communities.[1] This is aligned with our Indigenous Relations Policy which notes that *"Our engagement, advocacy and strategic direction are set by the Indigenous Relations Policy and led in collaboration with the Indigenous communities (First Nations, Inuit and Métis Nation) we work with every day*."[2]

[1] Exhibit I-02-O-Anwaatin-007, Page 2, Lines 17 to 23
[2] Exhibit I-02-A-Anwaatin-001, Attachment 2, Page 1

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UNDERTAKING JTU-2.12

Reference:

Exhibit I-2-O-Anwaatin-7

Undertaking:

To further consider the following question: how any seven-generation approach brought to bear in Indigenous decision-making affects the kinds of conversations described in the response to O-Anwaatin-007. In the event Hydro One objects to answering this question, to advise.

Response:

The response to Interrogatory O-Anwaatin-007 describes the customer engagement activities, including survey results, that were taken into account in determining Hydro One's approach to the inflation update. Hydro One is unclear what specifically is being referred to by the "seven-generation approach" in this question (and which definition Anwaatin is using for this term), or how it is relevant to or seeks clarification regarding the inflation update and the response to O-Anwaatin-007.

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UNDERTAKING JTU-2.13

Reference:

Exhibit I-2-O-Anwaatin-7

Undertaking:

To further consider the following question: whether consideration of intergenerational impacts, how that should or did inform the kind of conversations and consultations described in the answer to Anwaatin 7. In the event Hydro One objects to answering this question, to advise.

Response:

The response to Interrogatory O-Anwaatin-007 describes the customer engagement activities, including survey results, that were taken into account in determining its approach to the inflation update. Hydro One is unclear what specifically is being referred to by the "intergenerational impacts" in this question (and the way/context in which Anwaatin is using this term), or how it is relevant to or seeks clarification regarding the inflation update and the response to O-Anwaatin-007. If this question is referring to ratemaking intergenerational equity, please see the response to Interrogatory O-Staff-384, part a).

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UNDERTAKING JTU-2.14

Reference:

Exhibit I-18-O-PP-24

Undertaking:

With reference to forecast for assumed fuel prices as shown in PP-024(b), to provide documents that set out the position and the expectation of increase.

Response:

To determine the forecast for fuel prices, Hydro One reviewed the U.S. Energy Information Administration's (EIA) Short Term Energy Outlook report from March 2022.[1]

Hydro One's forecast did not separate gasoline and diesel but looked at a blended pricing model which included bulk fuel purchases and other fuel products required by company assets. The values in the two tables identified in PP-024 (Table 1 – Unleaded Gasoline – Ontario In-Month Average Price and Table 2 – Diesel – Ontario In-Month Average Price ($/L)) are the actual average price at the pump as provided by the Government of Ontario.[2]

Given recent geo-political events including the Russian invasion of Ukraine and the associated impact to fuel prices, Hydro One's forecast was revised in March 2022 based on the U.S. Energy Information Administration's (EIA) updated analysis of crude oil prices, as shown in Figure 1.

[1] U.S. Energy Information Administration, Short-Term Energy Outlook (March 2022) – (https://www.eia.gov/outlooks/steo/archives/mar22.pdf)

[2] Government of Ontario, Fuels price survey information – (https://data.ontario.ca/dataset/fuels-price-survey-information)

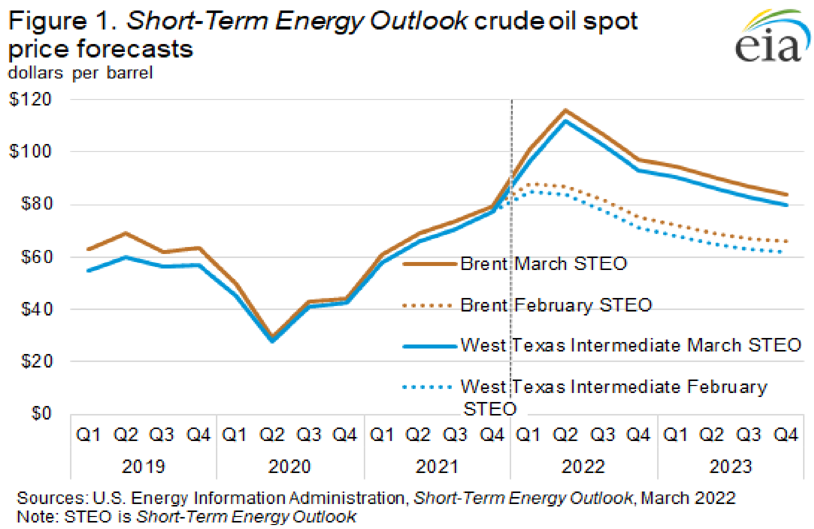

Figure 1: Short Term Energy Outlook Crude Oil Spot Price Forecasts from the U.S. EIA[3]

At that time, the EIA had revised its forecasting with the expectation that crude pricing would peak in Q2 of 2022 and then start to recede. Hydro One's assumed blended fuel price forecast was adjusted in accordance with that trend with the assumption that the blended fuel price would also peak in Q2 of 2022 as illustrated in the chart below (Figure 2). The resulting annualized average blended fuel price for 2022 was $1.68/Litre (before HST) or $1.90/Litre (including HST).

[3] U.S. Energy Information Administration, This Week in Petroleum - Crude oil prices forecast to average more than $100 per barrel in 2022 (March 9, 2022) – Figure 1 (https://www.eia.gov/petroleum/weekly/archive/2022/220309/includes/analysis_print.php)

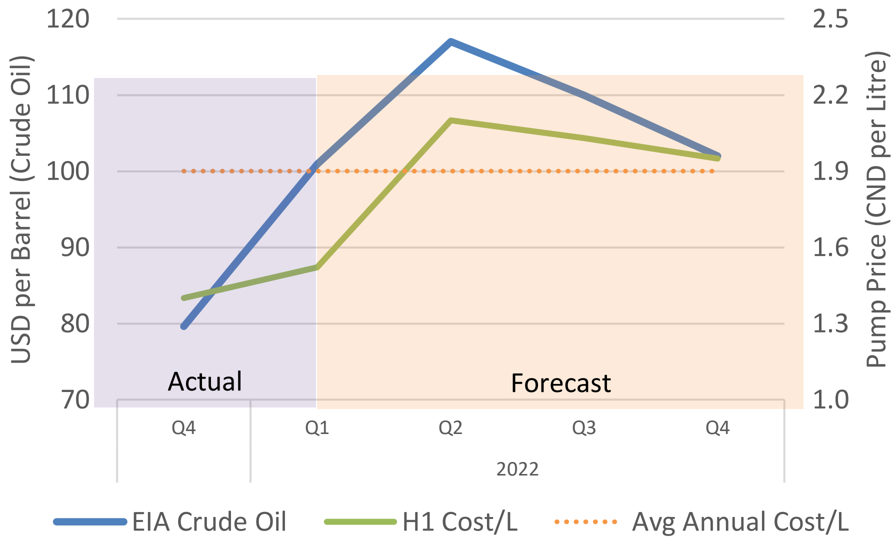

Figure 2: Hydro One Fuel Forecast vs EIA Crude Spot Price Forecast[4]

Hydro One's internal Fleet has an estimated blended fuel consumption of 26M Litres for 2022. At the annualized average blended fuel price of $1.68/litre (before HST), the 2022 fuel cost forecast was increased to $44M.

[4] Quarterly data points represent the average values of the respective quarter.

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UNDERTAKING JTU-2.15

Reference:
Exhibit I-18-O-PP-24

Undertaking:
To explain the calculation of the break-even price for fuel, where it becomes economical to move to EVs; to advise whether there are different break-even price points for different types of vehicles.

Response:
The break-even price for fuel was calculated to be $1.59 (excludes HST). This assumes the cost of an electric vehicle to be $44,800 (Chevrolet Bolt) plus $6,250 for the charger vs $28,000 for a comparable conventional fossil fueled light duty vehicle (Ford Fusion/Escape), both pre-tax.

Hydro One is unable to provide a break-even price for fuel for different types of vehicles as currently there are no suitable vehicle options for Hydro One other than sedan/SUV type assets.

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UNDERTAKING JTU-2.16

Reference:

Exhibit I-8-EnergyProbe-85, Attachment 1

Undertaking:

a) to provide a live excel version with formulas;

b) to include five-year totals for each of transmission and distribution;

c) to include a five-year CAGR (compound annual growth rate) for each of transmission and distribution;

d) to include a footnote on the inflation escalator, being the proration factor that we utilize in our evidence;

e) to include explanatory notes on any key items related to the four previous additions to the tables.

Response:

a) to e) Please refer to Attachment 1 provided in Excel format to this response.

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TRANSMISSION AND DISTRIBUTION DEFERRED REVENUE REQUIREMENT FROM INFLATION UPDATE, 2023-2027

This exhibit has been filed separately in MS Excel format.

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UNDERTAKING JTU-2.17

Reference:

Exhibit I-1-O-Staff-381, Part b
Exhibit O-2-1, Attachment 11

Undertaking:

In respect of calculating the total compensation amount for 2023: to clarify the calculation using the approach applied in the application, i.e. de-escalating and re-escalating forward using the pro-ration factor applied in the application. To clarify the base compensation amount to which the escalation is applied.

Response:

As described in Section 2.3 of Exhibit O-01-02, Hydro One updated its Capital and OM&A envelope levels by replacing the annual inflation escalation assumption used in the investment plan (2.0% per year) with actual 2021 inflation of 3.5% and forecasted 2022 and 2023 inflation of 4.5% and 3.3%, respectively. The update was conducted mechanistically by de-escalating the original inflation assumption to the base year of 2020, and re-escalating using the above noted inflation rates, and by 2.0% for 2024-2027.

The table below applies the outlined approach explained above to the as-filed compensation levels in Exhibit E-06-01 Attachment 02A, resulting in a relative increase consistent with the pro-ration factor.

		2023	
		Distribution	**Transmission**
(A)	Compensation - as-filed	$ 797,709	$ 693,847
(B)	Compensation - inflation update	$ 839,578	$ 730,265
	Relative increase (B/A)	1.0525	1.0525

While Hydro One is unable to determine the specific negotiated wage increases (or how these will be applied across the Exhibit 2-K/payroll table cost categories) which will occur after collective bargaining with key union partners in 2023, Hydro One has filed a conservative approach overall given that the Company is experiencing inflationary pressures in respect of various costs that are well above Ontario CPI forecasts, as outlined in Section 2.2 of Exhibit O-01-02 and as evident from the forecast provided in response to JTU-1.14.

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UNDERTAKING JTU-2.18

Reference:

Exhibit I-18-O-PP-22, Part d
Exhibit A-3-1, Attachment 1

Undertaking:

To reconcile the difference between the 3.0% (increase of 0.5%) for distribution as noted in PP-22, with the A-3-1, attachment 1 value of 2.2% which would represent an increase of 0.8%.

Response:

As mentioned in Note 6 under the "Distribution Revenue Requirement and Rate Impacts" table in O-PP-022, part d, the 2023 distribution load impact of -1.4%, as quoted in the as filed evidence table[1], was incorrect. Using the correct 2023 load impact of -0.1% results in 5-year average annual rate impact of 2.5% (compared to 2.2% shown in the as filed evidence), and hence, the variance between the updated and as filed evidence is 0.5% (3.0% – 2.5%).

[1] EB-2021-0110, Exhibit A, Tab 3, Schedule 1, Attachment 1, Page 11

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UNDERTAKING JTU-2.19

Reference:

Exhibit I-18-O-PP-24

Undertaking:

To provide a response to tables 1 and 2 for light duty vehicles in IR O-PP-024.

Response:

The requested tables for representative light duty vehicles are provided below. Table 1 provides the net cash flows for owning two vehicle types: Electric Vehicle (EV) and Conventional Fossil Fueled/Internal Combustion Engine (ICE). Table 2 provides a summary of the financial impacts of purchasing an EV as an alternative to an ICE vehicle.

Based on inflationary pressures and fuel pricing increases, the current analysis favours Hydro One's paced yet flexible electrification strategy. Hydro One is committed to purchasing additional EVs each year which will contribute to productivity commitments. However practical limitations of available supply, charging infrastructure, and suitable vehicle options may prevent the acceleration of fleet electrification in the near term.

Electric vehicle values are based on the costs of the Chevrolet Bolt. Hydro One does not have the data available to perform an analysis for plug-in hybrid electric vehicles (PHEV).

Table 1 - Representative Light Duty Vehicle (After Tax Cost)[1]

Year	Electric vehicle w/charging station	Conventional fossil fueled
TO	($51,050)	($28,000)
1	11,102*	($776)*
2	($871)	($2,972)
3	($900)	($3,420)
4	($928)	($3,762)
5	($956)	($4,028)
6	($984)	($4,243)
7	($1,011)	(4,417)
End of 7	$6,272**	$3,706**

** Due to Capital Cost Allowance (CCA) impact*
*** Terminal value of vehicle and tax shield.*

[1] Provides the net cash flow for each scenario

Table 2 - Representative Light Duty Vehicle

Description	Electric vs conventional fossil fueled vehicle
Incremental cost	$16,800 per vehicle plus $6,250 per EV station (fast charger)
Incremental resale value of vehicle in year 7	$2000 ($5,800 vs $3,800)
Simple Payback (years)	5 years
NPV discounted @ WACC	$3,285
IRR	~10%

UNDERTAKING JTU-2.20

Reference:

Exhibit I-22-O-SEC-242, Attachment 1

Undertaking:

To provide the membership of the board election readiness advisory group.

Response:

The membership of the Election Readiness Advisory Group goes beyond the scope of what is relevant to the matters in issue in this application, but Hydro One is providing the members' names in any event, which are as follows: Tim Hodgson, Susan Wolburgh Jenah, Jessica McDonald, David Hay.

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UNDERTAKING JTU-2.21

Reference:

Exhibit I-22-O-SEC-242, Attachment 1

Undertaking:

To advise whether Hydro One provided the advisory group with briefing materials; if so, to file them.

Response:

Hydro One's Chief Legal Officer prepared a presentation for the Election Readiness Advisory Group, a sub-committee of Hydro One's Board of Directors, on Hydro One's inflation update and its application in connection with and for purposes of providing legal advice. These are subject to legal privilege and the content goes beyond the scope of what is relevant to the matters in issue in this application, and the presentation has not been produced.

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UNDERTAKING JTU-2.22

Reference:

Exhibit I-3-B1-AMPCO-11
Exhibit B-1-1, SPF Section 1.7, Page 30

Undertaking:

To advise whether, during the 2021 reprioritization, there was a need for the redirection committee to communicate with the ELT and, if so, to provide that communication.

Response:

Attached please find excerpts of presentations from the Redirection Committee to the Executive Leadership Team for approval of investments exceeding the authority of the Redirection Committee's typical power system investment threshold of $20M. These may be summarized as follows:

Date	Investment	Variance	Forecast
May 3, 2021	Transport and Work Equipment (TWE) – Heavy Duty Equipment Replacement	$7.8	$34.1
July 30, 2021	Tx Lines Insulator Replacement Program - PWU	$3.6	$38.3
	Tx Lines Insulator Replacement Program - BTU	$4.9	$43.6
	Tx Wood Pole Replacements - PWU	$4.9	$30.9
	Tx Wood Pole Replacements - BTU	$3.0	$30.0
	Dx Customer Upgrade - Construct	$11.3	$40.8
	Dx Joint Use and Relocation >$75k	$6.5	$44.1
	Dx Subdivisions	$6.2	$40.6
	Dx Capital Trouble Call	$3.7	$29.8
	Dx Load Connections - Design	$6.1	$23.6
	Dx Disconnect / Reconnect	$7.1	$22.5
October 29, 2021	Dx Subdivisions	$16.4	$50.8
	Transport and Work Equipment (TWE) – Heavy Duty Equipment Replacement,	$0.3	$25.9
	Dx Disconnect / Reconnect	$11.0	$26.4
January 24, 2022	CIP-014 Implement Remaining 24 sites	$3.7	$24.3
	Dx Joint Use and Relocations <75k	$2.5	$21.3
	Dx Capital Storm Damage	$26.8	$80.8
	Transport and Work Equipment (TWE)	-$13.5	$12.7

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Q1 2021 Review

May 3rd, 2021

Appendix: Transport and Work Equipment (TWE)

<table>
<tr><th>Capital Program Name</th><td colspan="5">Transport and Work Equipment (TWE) – Heavy Duty Equipment Replacement, AR 21087</td></tr>
<tr><th>Variance Type</th><td colspan="5">Scope Variance</td></tr>
<tr><th>Budget $</th><th>Forecasted $</th><th>Variance $</th><th>Budgeted Units</th><th>Forecasted Units</th><th>Unit Variance</th></tr>
<tr><td>$26.2M</td><td>$34.1M</td><td>($7.8M)</td><td>207
# of Vehicles</td><td>326
# of Vehicles</td><td>119
# of Vehicles</td></tr>
<tr><th>Capital Program Description</th><td colspan="5">To ensure adequate fleets to meet the Lines of Business work program requirements, as well as to ensure the safety standard and regulatory requirements are met on our core fleet.</td></tr>
<tr><th>Explanation</th><td colspan="5">Program variance of $7.8M due to accelerate TWE acquisitions for replacing old TWEs from the field. The need for more TWEs due to increase in Work Program requirements and maintain the assets at an optimum level to ensure public and employee safety. Work Program requirements have also been impacted by COVID requirements, including the safety protocol for number of passengers in a light duty vehicle.</td></tr>
</table>

hydroOne

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Q2 2021 Review

July 30, 2021

Transmission Capital Program Variances - June

Program Name	Tx Lines Insulator Replacement Program - PWU, N.T.C.1.12, AR 18438				
Variance Type	Cost				
Current Budget	Forecast $	$ Variance	Current Budgeted Units	Forecast Units	Unit Variance
$34.7M	$38.3M	+$3.6M	1,778	1,778	0
Program Description	Replace transmission line insulators to promote reliable and safe system operation, focusing on defective porcelain and polymer that is at/near end-of-life & premature degradation of all insulator types				
Explanation	Capex Forecast exceeds budget as a result of productivity savings ($2.0M) that will not be achieved in 2021 and to accommodate the opportunity on D501P and P502X to complete additional torqueing and tensioning work ($1.6M) that posed a high risk to safety and reliability.				

Transmission Capital Program Variances - June

Program Name	Tx Lines Insulator Replacement Program - BTU, N.T.C.1.12, AR 20325				
Variance Type	Cost				
Current Budget	Forecast $	$ Variance	Current Budgeted Units	Forecast Units	Unit Variance
$38.7M	$43.6M	+$4.9M	1,989	1,989	0
Program Description	Replace transmission line insulators to promote reliable and safe system operation, focusing on defective porcelain and polymer that is at/near end-of-life & premature degradation of all insulator types				
Explanation	Capex Forecast exceeds budget as a result of productivity savings ($2.3M) that will not be achieved in 2021 and to accommodate the opportunity on D501P and P502X to complete additional torqueing and tensioning work ($2.6M) that posed a high risk to safety and reliability.				

Transmission Capital Program Variances - June

Program Name	Tx Wood Pole Replacement Program - PWU, N.T.C.1.12, AR 20045				
Variance Type	Cost				
Current Budget	Forecast $	$ Variance	Current Budgeted Units	Forecast Units	Unit Variance
$26.0M	$30.9M	+$4.9M	501	492	-9
Program Description	Planned Wood Pole structure component replacement work addresses the condition of end of life wood pole structure components in order to maintain the reliability and safety of wood poles structure transmission lines in a cost effective manner.				
Explanation	Capex Forecast exceeds budget as a result of productivity savings ($1.5M) that will not be achieved in 2021. The remaining $3.4M is due to higher unit cost on multiple circuits (i.e. W2C and T61S) due to complexity (civil access requirements, equipment availability, rock drilling, helicopter use and travelling crews) and environmental activities, including additional monitoring and Indigenous consultations.				

Transmission Capital Program Variances - June

Program Name	Tx Wood Pole Replacement Program - BTU, N.T.C.1.12, AR 24081				
Variance Type	Cost				
Current Budget	Forecast $	$ Variance	Current Budgeted Units	Forecast Units	Unit Variance
$27.0M	$30.0M	+$3.0M	521	521	0
Program Description	Planned Wood Pole structure component replacement work to address the condition of end of life wood pole structure components in order to maintain the reliability and safety of wood poles structure transmission lines in a cost effective manner.				
Explanation	Capex Forecast exceeds budget as a result of productivity savings ($1.6M) that will not be achieved in 2021. The remaining $1.4M is due to higher unit cost on multiple circuits (i.e. M2D, S2B, T1M, K3D and X6) due to execution issues (civil access requirements, helicopter use, inclement weather, cancelled outages and equipment breakdowns) and environmental activities, including additional monitoring and Indigenous consultations.				

Distribution Lines Program Variances

Program Name	Customer Upgrade - Construct, AR 20026				
Variance Type	Scope				
Budget	Forecasted $	$ Variance	Budgeted Units	Forecasted Units	Unit Variance
$29.5M	$40.8M	$11.3M	4,260 Upgrades	5,688 Upgrades	1,428 Upgrades
Program Description	This investment funds work associated with service upgrade connections, meter field tests and line expansions.				
Explanation	Program experienced higher demand for customer upgrades than what was budgeted.				

Distribution Lines Program Variances

Program Name	Joint Use and Relocations >$75k, AR 24701				
Variance Type	Scope				
Budget	Forecasted $	Variances	Budgeted Units	Forecasted Units	Unit Variance
$37.6M	$44.1M	$6.5M	N/A	N/A	N/A
Program Description	This investment funds projects (greater than $75K) required to meet contractual obligations to third parties through Joint Use Agreements and to meet occupational agreements with Provincial and Municipal Road Authorities. This includes changes and enhancements to Joint Use Partners systems and road type work/relocation work. Units and unit costs for this program are not accurate due to accomplishments claiming upon project closure, while costs accumulate throughout.				
Explanation	Program experienced higher demand for joint use and relocation work than what was budgeted.				

Distribution Lines Program Variances

Program Name	Subdivisions, AR 25381				
Variance Type	Cost & Scope				
Budget	Forecasted $	Variances	Budgeted Units	Forecasted Units	Unit Variance
$34.4M	$40.6M	$6.2M	6,803 KM Designed	9,991 KM Designed	3,188 KM Designed
Program Description	This investment funds work associated with design, construction and connection of subdivision customers.				
Explanation	Program experienced higher demand for subdivision connections than what was budgeted, with a lower average unit cost.				

Distribution Lines Program Variances

Program Name	Distribution Capital Trouble Call Poles & Equipment, AR 17371				
Variance Type	Cost & Scope				
Budget	Forecasted $	Variances	Budgeted Units	Forecasted Units	Unit Variance
$26.1M	$29.8M	$3.7M	3,426 Pieces of Equipment	3,529 Pieces of Equipment	103 Pieces of Equipment
Program Description	This investment funds labour, equipment, and material costs for capital related work associated with Distribution's trouble call response.				
Explanation	Program experienced slightly higher volume of units with a higher average unit cost.				

Distribution Lines Program Variances

Program Name	Load Connections - Design, AR 19979				
Variance Type	Cost & Scope				
Budget	Forecasted $	Variances	Budgeted Units	Forecasted Units	Unit Variance
$17.5M	$23.6M	$6.1M	10,889 Connections	13,696 Connections	2,807 Connections
Program Description	This program includes all work associated with design and estimating for New Connections. In particular it includes engineering investigations, design of expansions (including subdivisions), preliminary work and Class C estimates for Large Projects, Asset Sale Data Collection, System Impact Assessment/Discounted Cash Flow.				
Explanation	Program experienced higher demand for new connection designs and estimates than what was budgeted, with a slightly higher average unit cost.				

Distribution Lines Program Variances

Program Name	Distribution Disconnects / Reconnects, AR 17368				
Variance Type	Cost & Scope				
Budget	Forecasted $	Variances	Budgeted Units	Forecasted Units	Unit Variance
$15.4M	$22.5M	$7.1M	17,807 Dis/Reconnects	24,714 Dis/Reconnects	6,907 Dis/Reconnects
Program Description	This investment funds all work associated with disconnects and reconnects at the customer's request to perform work on or near their equipment. This could include disconnect at the meter, secondary service or primary service.				
Explanation	Program experienced higher demand for disconnects and reconnects than what was budgeted.				

Q3 2021 Review

October 29, 2021

Distribution Lines Program Variances

Program Name	Subdivisions, AR 25381				
Variance Type	Cost & Scope				
Budget	Forecasted $	$ Variance	Budgeted Units	Forecasted Units	Unit Variance
$34.4M	$50.8M	$16.4M	6,803 KM Designed	10,812 KM Designed	4,009 KM Designed
Program Description	This investment funds work associated with design, construction and connection of subdivision customers.				
Explanation	Program experienced higher demand for subdivision connections than what was budgeted, with a lower average unit cost.				

Distribution Lines Program Variances

<table>
<tr><td>Program Name</td><td colspan="5">Distribution Disconnects / Reconnects, AR 17368</td></tr>
<tr><td>Variance Type</td><td colspan="5">Cost & Scope</td></tr>
<tr><td>Budget</td><td>Forecasted $</td><td>$ Variance</td><td>Budgeted Units</td><td>Forecasted Units</td><td>Unit Variance</td></tr>
<tr><td>$15.4M</td><td>$26.4M</td><td>$11.0M</td><td>17,807 Dis/Reconnects</td><td>27,101 Dis/Reconnects</td><td>9,294 Dis/Reconnects</td></tr>
<tr><td>Program Description</td><td colspan="5">This investment funds all work associated with disconnects and reconnects at the customer’s request to perform work on or near their equipment. This could include disconnect at the meter, secondary service or primary service.</td></tr>
<tr><td>Explanation</td><td colspan="5">Program experienced higher demand for disconnects and reconnects than what was budgeted.</td></tr>
</table>

Transport and Work Equipment (TWE) Program Variances

Program Name	Transport and Work Equipment (TWE) – Heavy Duty Equipment Replacement, AR 21087				
Variance Type	Schedule Variance				
Budget	Forecasted $	$ Variance	Budgeted Units	Forecasted Units	Unit Variance
$26.2M	$25.9M	$0.3M	207 # of Vehicles	303 # of Vehicles	96 # of Vehicles
Program Description	To ensure adequate fleets to meet the Lines of Business work program requirements, as well as to ensure the safety standard and regulatory requirements are met on our core fleet.				
Explanation	Program variance due to a forecast reduction of $8.2M in Q3 due to current year TWE deliveries (Heavy Duty Equipment Replacement) being delayed at chassis manufacturers such as Ford and Freightliner as result of semi-conductor and parts shortages. Fleet is continuously monitoring the TWE delivery impact on a weekly basis.				

Q4 2021 Review

January 24th, 2022

Transmission Program Variances

Program Name	CIP-014 Implement Remaining 24 sites, AR 25176				
Variance Type	Cost & Scope				
Budget	**Actual $**	**$ Variance**	**Budgeted Units**	**Actual Units**	**Unit Variance**
$20.6M	$24.3M	$3.7M	6 sites	11 sites	5 sites
Program Description	The NERC CIP-014 Physical Security standard applies to Transmission Owners and dictates physical security requirements to identified 27 facilities with voltages exceeding 200kV. The Threat Risk Assessment (TRA) identified physical security risks and vulnerabilities, documenting recommendations for each station. Hydro One has committed to NERC to have implemented the required physical security controls to mitigate TRA findings at all 27 stations.				
Explanation	2021 increase in spend can be mainly attributed to the carryover of work for 5 sites from 2020, and expedited material purchases for the 2022 sites to mitigate the risk of global supply chain slowdown. Program is on track to complete all remaining sites from the initial release by end of 2022 per external commitments. Installations at Evergreen and Ashfield will be completed in 2023 as part of secondary release.				

Distribution Lines Program Variances

Program Name	Joint Use & Relocations <$75k, AR 25154				
Variance Type	Cost				
Budget	Actual $	$ Variance	Budgeted Units	Actual Units	Unit Variance
$18.8M	$21.3M	$2.5M	N/A	N/A	N/A
Program Description	This investment funds work necessary for Hydro One Networks to meet contractual obligations to third parties through Joint Use Agreements and also to meet occupation agreements with Provincial and Municipal Road Authorities for our Distribution facilities located on their road allowances.				
Explanation	Variance in Joint Use & Line Relocations program mostly due to higher volume of project work than budget.				

Distribution Lines Program Variances

Program Name	Distribution Capital Storm Damage, AR 17368				
Variance Type	**Cost**				
Budget	**Actual $**	**$ Variance**	**Budgeted Units**	**Actual Units**	**Unit Variance**
$54.0M	$80.8M	$26.8M	N/A	N/A	N/A
Program Description	This program funds emergency category work for storm restoration on Distribution assets following major storms. Once the work is deemed storm (i.e. OGCC deems a storm scenario) all restoration costs are reported/charged to the applicable Storm work orders.				
Explanation	Program experienced higher demand for storm restorations than what was budgeted mostly due to wind storm that started on December 11, 2021.				

Transport and Work Equipment (TWE) Program Variances

Program Name	Transport and Work Equipment (TWE), AR 21087				
Variance Type	Schedule Variance				
Budget	**Actuals $**	**$ Variance**	**Budgeted Units**	**Actual Units**	**Unit Variance**
$26.2M	$12.7M	$13.5M	207 # of Vehicles	144 # of Vehicles	63 # of Vehicles
Program Description	To ensure adequate fleets to meet the Lines of Business work program requirements, as well as to ensure the safety standard and regulatory requirements are met on our core fleet.				
Explanation	Program variance due to current year TWE deliveries (Both Light and Heavy Duty Equipment Replacement) being delayed at chassis manufacturers such as Ford and Freightliner as result of semi-conductor and parts shortages. The variance quantity and amount is deferred to 2022 and is expected to be received by Q2 2022.				

UNDERTAKING JTU-2.23

Reference:

Exhibit I-3-B1-AMPCO-11
Exhibit SPF 1.7, Page 30

Undertaking:

To consider and enquire whether there is any memo or document regarding 2022 from the redirection committee. If there is and Hydro One accepts that it is relevant and not privileged, Hydro One will provide it, and if Hydro One objects to providing it on any basis, Hydro One will advise so.

Response:

To date, in 2022, the Redirection Committee has not communicated variances that exceed the committee's authority to the ELT. However, as discussed during the May 2022 Technical Conference, Hydro One continues to experience significant cost pressures in 2022 including inflation and demand pressures related to system access; i.e., new connections.[1]

To compound the upward inflationary and demand pressures, on May 21, 2022, destructive storms swept across the Central, Southern and Eastern regions of the province, causing damage across both the transmission and distribution systems, and significant power outages. This affected approximately half of Hydro One's distribution customers. Hydro One had to rapidly respond to restore power to customers by mobilizing Hydro One crews from across the province, and a large contingent from mutual aid partners including contractors and other utilities to assist with restoration efforts.

Restoration efforts lasted over 10 days, with over 1,000 poles replaced and entire feeders rebuilt to restore supply to communities. Hydro One's response to the widespread and significant damage caused by the storms resulted in significant expenditures. Initial estimates indicate that these restoration efforts for this single event will be well over the total annual capital storm budget, and could exceed 10% of the as-filed Distribution Capital forecast.

Hydro One continues to assess the financial implications of the May 2022 storms, however given the timing of these storms and the spending that has already occurred year-to-date, Hydro One currently has limited ability to redirect other Distribution capital work to offset the May 2022 storm costs.

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[1] EB-2021-0110, Technical Conference Transcript, Day 2, June 1, 2022, p110.

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UNDERTAKING JTU-2.24

Reference:

Exhibit F-1-4

Undertaking:

Hydro One to consider the request and if we do not object, with reference to Exhibit F, Schedule 1, Tab 4, Page 6 and 12, to update the tables for distribution and transmission to reflect actuals and revised forecast, given the recent change in interest rates, including any revised forecasts for 2023; to include the excel files for the two tables.

Response:

Please see attachment 1 to this undertaking in Excel format.

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EXHIBIT F, SCHEDULE 1, TAB 4, PAGE 6 AND 12

This exhibit has been filed separately in MS Excel format.

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UNDERTAKING JTU-2.25

Reference:

Exhibit JTU-1.14 Follow up

Undertaking:

To provide the cost model for 2022 showing the increased inflationary pressures in 2022 for materials and services for our procurement spend and how that relates to transmission and distribution.

Response:

The cost model is provided in response to JTU 1.14-01.

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UNDERTAKING JTU-2.26

Reference:

Exhibit JTU-1.14 Follow up

Undertaking:

To include in undertaking No. JTU1.14 the latest forecast, as far out as they go, from pro purchaser, specifically the non-labour piece, the material and services.

Response:

The inflationary model is provided in response to JTU1.14-01. The 2021 index data used to create the inflationary model is provided in Table 1. Table 2 provides the index data for 2022 year-to-date.

For clarification, ProPurchaser is an online resource that provides index data from various sources.

Table 1 - December 2020 to December 2021 ProPurchaser Index Data

Product	Unit of Measure	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Cdn Consumer Price Index all items	index	137	138	139	140	140	141	141	142	143	143	144	144	144
Cdn Raw Material Price Index all items	index	101	106	113	115	116	120	125	128	124	127	133	133	130
Gasoline:Reformulated Gasoline Blendstock N. America	gallon (U.S.)	138	158	173	195	209	219	234	232	249	249	240	260	224
Container Rate Index - Asia to North America	index	127	141	145	139	143	170	201	226	253	267	265	262	275
Trucking Cost Index (FL) Canada	index	112	114	116	119	119	120	122	123	124	123	125	127	123
Trucking Cost Index (FL) USA	index	109	110	112	114	114	115	116	117	117	117	119	120	117
Aluminum N. America	lb	91	90	90	100	100	111	109	114	117	123	129	122	120
Copper (New York)	lb	342	351	357	409	400	448	468	430	448	436	409	438	428
Nickel N. America & EU	metric ton (2205 lbs)	16,343	16,540	17,727	18,607	16,098	17,477	17,811	18,450	19,892	19,513	18,178	19,478	20,185
Steel Plate N. America	cwt	35	43	51	54	55	63	70	75	82	87	89	89	91
PET Bottle Resin N. America	lb	97	98	101	104	108	110	110	110	112	112	112	112	120
PVC N. America - smaller volumes	lb	138	138	142	145	152	152	156	159	160	160	161	163	168
Cdn Unit Labor Costs	index	141	142	142	142	147	147	147	150	150	150	149	149	149
Red Oak N. America	1000 b.f	650	710	820	825	835	890	935	950	950	950	940	940	940
Softwood Lumber 2x4 SPF N. America	1000 b.f	605	900	910	1020	1040	1410	1610	795	515	390	530	620	645
General freight trucking long-distance TL - PCU484121484121	index	148	146	151	155	159	162	159	160	165	170	174	184	185
Commercial Machinery Repair and Maintenance	index	142	144	145	145	145	147	147	149	149	149	150	150	154

Table 2 - 2022 Year-to-Date ProPurchaser Index Data

Product	Unit of Measure	Jan-22	Feb-22	Mar-22	Apr-22	May-22
Cdn Consumer Price Index all items	index	145	147	149	150	
Cdn Raw Material Price Index all items	index	138	147	164	161	
Gasoline:Reformulated Gasoline Blendstock N. America	gallon (U.S.)	243	273	302	368	374
Container Rate Index - Asia to North America	index	286	283	271		
Trucking Cost Index (FL) Canada	index	125	129	131	137	142
Trucking Cost Index (FL) USA	index	118	121	123	127	130
Aluminum N. America	lb	127	139	156	159	138
Copper (New York)	lb	446	432	444	474	440
Nickel N. America & EU	metric ton (2205 lbs)	20,913	22,798	25,235	33,388	32,425
Steel Plate N. America	cwt	91	92	90	93	96
PET Bottle Resin N. America	lb	124	136	136	144	144
PVC N. America - smaller volumes	lb	168	165	165	165	168
Cdn Unit Labor Costs	index	154	154	154		
Red Oak N. America	1000 b.f	940	940	925	925	925
Softwood Lumber 2x4 SPF N. America	1000 b.f	1140	1185	1360	1200	1085
General freight trucking long-distance TL - PCU484121484121	index	190	194	208	222	
Commercial Machinery Repair and Maintenance	index	157	160	164	164	

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UNDERTAKING JTU-2.27

Reference:

Exhibit KTU1.1 – OEB Staff Compendium

Undertaking:

To provide any more information on local or regional programs that are active or completed, or planned, delivering energy savings not captured in the IESO provincial conservation forecast.

Response:

The IESO includes energy conservation in its APO demand forecast – that is, it will count energy conservation as a reduction to demand. In contrast, resources such as demand response are counted by the IESO on the supply side – that is, even though a demand response resource will reduce peak demand on the transmission system, it is not counted on the demand side by the IESO in the APO forecast but is instead counted as a resource that will help the IESO meet demand, i.e., a supply resource.

In the case of the resources forecasted as part of integrated regional planning, the IESO has not yet determined what category these will fall under – that is, whether they will be conservation (counted as demand) or demand response (counted as supply), or a combination of both. This lack of definitive categorization does not mean that these savings are not real savings that the IESO expects will be achieved. It is appropriate to recognize the impacts of these activities in Hydro One's load forecast for the test period of the application as they will impact Hydro One's transmission load forecast regardless of the category of program (i.e., demand side or supply side).

All regional plans in the regional planning process are based on assessing needs after deducting provincial CDM allocated to the regions. Additional load savings over and above the region's share of provincial savings is also considered as part of any integrated planning processes.

The IESO's regional planning group provided the following explanation regarding the use of incremental CDM:

> In the regional planning process, the IESO currently assesses the opportunity for additional system cost-effective CDM to meet/address local needs when evaluating non-wires alternatives for these specific needs. The following completed IRRPs have assessed incremental CDM options, and in some instances have identified or recommended opportunities for further CDM to cost-effectively contribute to meeting local needs.

- 2019 Windsor Essex IRRP
- 2020 Ottawa IRRP
- 2020 York Region IRRP
- 2021 Greater Bruce Huron (Southern Huron Perth) IRRP
- 2021 Peterborough to Kingston IRRP
- 2022 South Georgian Bay Muskoka (Parry Sound Muskoka) IRRP
- 2022 South Georgian Bay Muskoka (Barrie Innisfil) IRRP

The IESO also confirmed that during the first cycle of regional planning some LDCs, with support from the IESO, undertook Local Achievable Potential Studies where the ongoing or recently completed regional planning activities indicated there may be potential for CDM to help meet medium or long-term needs ahead of the second cycle. Local Achievable Potential Studies were undertaken by Alectra for a subset of the Barrie Innisfil Subregion, by Lakeland for a subset of the Parry Sound Muskoka Subregion, and by Hydro Ottawa for a subset of the Ottawa sub-region.

Hydro One notes that, in an integrated planning process, the incremental achievable conservation potential is identified by the participants in the process and, where available, Local Achievable Potential studies.

Consequently, the type of incremental achievable conservation programs is determined during the regional planning process so that it is not known *a priori* in APO 2021.