Daliana Coban
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via Regulatory Electronic Submission System (RESS)

April 2, 2024

Ms. Nancy Marconi, Registrar
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: OEB File No. EB-2023-0195, Toronto Hydro-Electric System Limited ("Toronto Hydro") 2025-2029 Custom Rate Application for Electricity Distribution Rates and Charges – Evidence Update and Corrections

As indicated in prior correspondence and in the response to interrogatory 1A-Staff-01, Toronto Hydro is filing certain updates and corrections to the pre-filed evidence and interrogatory responses in advance of the upcoming Technical Conference. For ease of reference, Appendix A to this response provides a summary of the updated evidence.

Please do not hesitate to contact us if you have any questions.

Sincerely,

Daliana Coban
Digitally signed by Daliana Coban
DN: cn=Daliana Coban, c=CA, email=dcoban@torontohydro.com
Date: 2024.04.02 22:36:19 -04'00'

Daliana Coban
Director, Regulatory Applications & Business Support
Toronto Hydro-Electric System Limited

Cc: Charles Keizer and Arlen Sternberg, Torys LLP; all intervenor

Appendix A: Summary of Updated Evidence (April 2, 2024)

Updated Pre-Filed Evidence

Pre-Filed Evidence	Description of the Revisions	Numerical Differences
Table of Contents (Exhibit 1A, Tab 1, Schedule 1)	Updated the Table of Contents to reflect the evidence updates submitted on December 19, 2023; January 29, 2024; and April 2, 2024.	N/A
Administration (Exhibit 1A, Tab 3, Schedule 1)	Revised narrative on Page 3 to reflect Toronto Hydro's withdrawal of its custom labour inflation proposal as noted in its response to 1B-Staff-93.	N/A
Application Summary (Exhibit 1B, Tab 1, Schedule 3)	Updated the Capital and OM&A expenditure tables to reflect 2023 actuals and updated 2024 bridge and 2025-2029 forecasts as outlined in: (1) January 29, 2024 evidence update; (2) updated OEB models filed with interrogatory responses; and (3) updated OEB Appendices 2-AA as noted below.	

Table 8: Capital Investment Expenditures by Categories ($ Millions)

Category	Total 2020-2024 Forecast	Total 2025-2029 Forecast	Var. ($)	Var. (%)
System Access	~~630.0~~ 653.6	~~1,071.7~~ 1,052.5	~~441.7~~ 398.9	~~70%~~ 61%
System Renewal	~~1,458.2~~ 1,456.6	~~1,970.2~~ 1,970.3	~~512.1~~ 513.7	35%
System Service	~~225.6~~ 226.0	~~353.0~~ 301.7	~~127.4~~ 75.8	~~56%~~ 34%
General Plant	~~418.6~~ 419.0	562.5	~~143.9~~ 143.4	~~34%~~ 34%
Other	~~55.1~~ 85.9	~~44.3~~ 41.7	~~(10.8)~~ (44.2)	~~(20%)~~ (51%)
Total	**~~2,787.4~~ 2,841.1**	**~~4,001.8~~ 3,928.7**	**~~1,214.4~~ 1,087.5**	**~~44%~~ 38%**

Table 9: 2020-2024 Rate Base Summary ($ Millions)

	OEB Approved	Actuals			~~Bridge~~ Actuals	Bridge
	2020	**2020**	**2021**	**2022**	**2023**	**2024**
Opening PP&E NBV	4,229.4	4,233.2	4,419.2	4,628.1	4,893.9	~~5,244.3~~ 5,227.4
In-Service Additions	527.4	447.9	485.2	554.4	~~607.9~~ 594.7	~~606.3~~ 619.8
Depreciation	(265.4)	(262.0)	(276.2)	(288.7)	~~(257.4)~~ (261.2)	~~(271.8)~~ (277.8)
Closing PP&E NBV	4,491.3	4,419.2	4,628.1	4,893.9	~~5,244.3~~ 5,227.4	~~5,578.8~~ 5,569.4
Monthly Avg PP&E NBV	**4,298.6**	**4,284.3**	**4,457.7**	**4,686.3**	**~~4,954.3~~ 4,960.0**	**~~5,348.5~~ 5,327.0**
Working Capital Allowance	216.2	249.8	217.2	220.7	~~240.6~~ 216.8	~~248.0~~ 230.0
Rate Base	**4,514.8**	**4,534.1**	**4,674.9**	**4,907.0**	**~~5,194.9~~ 5,176.8**	**~~5,596.5~~ 5,557.0**

Pre-Filed Evidence	Description of the Revisions	Numerical Differences
		See Tables 10 and 11 below

Table 10: 2025-2029 Rate Base Summary ($ Millions)

	Forecast				
	2025	2026	2027	2028	2029
Opening PP&E NBV	~~5,578.8~~ 5,569.4	~~5,937.9~~ 5,931.4	~~6,335.9~~ 6,325.7	~~6,809.6~~ 6,796.1	~~7,234.4~~ 7,219.9
In-Service Additions	~~645.9~~ 653.8	~~699.4~~ 699.9	~~795.6~~ 795.1	~~769.2~~ 770.1	~~875.4~~ 860.1
Depreciation	~~(286.8)~~ (291.8)	~~(301.4)~~ (305.7)	~~(321.9)~~ (324.8)	~~(344.3)~~ (346.2)	~~(357.1)~~ (359.5)
Closing PP&E NBV	~~5,937.9~~ 5,931.4	~~6,335.9~~ 6,325.7	~~6,809.6~~ 6,796.1	~~7,234.4~~ 7,219.9	~~7,752.7~~ 7,720.4
Monthly Avg PP&E NBV	**~~5,669.8~~ 5,667.5**	**~~6,047.4~~ 6,042.1**	**~~6,472.2~~ 6,460.6**	**~~6,927.1~~ 6,912.2**	**~~7,352.5~~ 7,334.3**
Working Capital Allowance	~~231.5~~ 231.6	~~237.1~~ 237.2	~~242.5~~ 242.6	~~250.8~~ 249.8	~~255.6~~ 255.7
Rate Base	**~~5,901.2~~ 5,899.1**	**~~6,248.5~~ 6,279.3**	**~~6,714.7~~ 6,703.2**	**~~7,177.9~~ 7,162.0**	**~~7,608.2~~ 7,590.1**

Table 11: OM&A 2020-2029 Cost Drivers ($ Millions)

Programs	~~Bridge~~ **Actuals**	**Bridge**
	2023	**2024**
Reporting Basis	MIFRS	MIFRS
Opening Balance	280.4	~~301.5~~ 294.2
Distribution Operations	~~5.0~~ (0.2)	~~9.5~~ 13.2
Customer Care	~~5.6~~ 4.1	~~3.5~~ 5.0
Human Resources, Environment and Safety	~~2.2~~ 1.4	~~2.4~~ 3.2
Information Technology	~~4.0~~ 2.4	~~3.6~~ 1.7
Common Corporate Costs	~~(0.1)~~ 1.3	~~0.2~~ (1.2)
Facilities Management	~~1.0~~ 1.4	1.9 1.5
Other Various	3.4	2.9
Closing Balance	**~~301.5~~ 294.2**	**~~325.5~~ 320.5**

<table>
<tr><th>Pre-Filed Evidence</th><th>Description of the Revisions</th><th>Numerical Differences</th></tr>
<tr><td></td><td>Updated the Load Customer and Load Growth Changes for 2018-2029 based on the updated evidence in Exhibit 3 as noted below.</td><td>
<table>
<tr><th></th><th></th><th>Total Normalized GWh</th><th>Total Normalized MVA</th><th>Total Customers</th></tr>
<tr><td>2018</td><td>Actual</td><td>24,691.6 ~~24,701.0~~</td><td>39,813.3 ~~39,823.2~~</td><td>770,333</td></tr>
<tr><td>2019</td><td>Actual</td><td>24,421.7 ~~24,429.6~~</td><td>39,115.3 ~~39,126.0~~</td><td>777,369</td></tr>
<tr><td>2020</td><td>Actual</td><td>23,664.4 ~~23,674.7~~</td><td>36,801.2 ~~36,813.7~~</td><td>781,374</td></tr>
<tr><td>2021</td><td>Actual</td><td>23,564.8 ~~23,575.0~~</td><td>36,624.9 ~~36,638.0~~</td><td>786,258</td></tr>
<tr><td>2022</td><td>Actual</td><td>23,981.0 ~~23,990.1~~</td><td>37,635.2 ~~37,648.0~~</td><td>790,699</td></tr>
<tr><td>2023</td><td>Actual~~Bridge~~</td><td>23,908.0 ~~23,678.6~~</td><td>37,425.9 ~~37,199.3~~</td><td>793,465 ~~794,025~~</td></tr>
<tr><td>2024</td><td>Bridge</td><td>23,603.5 ~~23,676.2~~</td><td>36,735.8 ~~36,993.9~~</td><td>796,787 ~~797,318~~</td></tr>
<tr><td>2025</td><td>Forecast</td><td>23,412.8 ~~23,458.7~~</td><td>36,167.8 ~~36,384.5~~</td><td>800,430 ~~800,374~~</td></tr>
<tr><td>2026</td><td>Forecast</td><td>23,433.6 ~~23,416.5~~</td><td>35,949.7 ~~36,063.4~~</td><td>803,655 ~~803,344~~</td></tr>
<tr><td>2027</td><td>Forecast</td><td>23,431.4 ~~23,389.6~~</td><td>35,648.1 ~~35,698.8~~</td><td>806,407 ~~806,017~~</td></tr>
<tr><td>2028</td><td>Forecast</td><td>23,525.0 ~~23,498.8~~</td><td>35,489.2 ~~35,507.1~~</td><td>808,736 ~~808,731~~</td></tr>
<tr><td>2029</td><td>Forecast</td><td>23,393.8 ~~23,458.5~~</td><td>34,964.1 ~~35,093.4~~</td><td>811,363 ~~811,245~~</td></tr>
</table>
</td></tr>
<tr><td></td><td>Updated Table 14 DVA Summary to align with updated DVA Continuity OEB model (see below).</td><td></td></tr>
<tr><td></td><td>Included a Total Revenue Requirement (RR) table (aligned with updated evidence in Exhibit 6) and re-calculated the Performance Incentive Mechanism (PIM) based on the updated RR figures.</td><td>
Table 3: 2025 Forecast Revenue Requirement
<table>
<tr><th>Revenue Requirement Component</th><th>2025 Test Year
(April 2, 2024)</th></tr>
<tr><td>OM&A Expenses (incl. property taxes)</td><td>343.0</td></tr>
<tr><td>Amortization/Depreciation</td><td>~~285.3~~ 290.4</td></tr>
<tr><td>Income Taxes (grossed up)</td><td>~~27.9~~ 28.9</td></tr>
<tr><td>Deemed Interest Expense</td><td>~~142.2~~ 142.9</td></tr>
<tr><td>Return on Deemed Equity</td><td>220.9</td></tr>
<tr><td>Service Revenue Requirement</td><td>~~1,020.3~~ 1,026.0</td></tr>
<tr><td>Revenue Offsets</td><td>~~(47.9)~~ (48.2)</td></tr>
<tr><td>Base Revenue Requirement</td><td>~~972.4~~ 977.8</td></tr>
</table>
</td></tr>
</table>

<table>
<tr><th>Pre-Filed Evidence</th><th>Description of the Revisions</th><th>Numerical Differences</th></tr>
<tr><td></td><td></td><td>Table 4: 2020 versus 2025 Service Revenue Requirement ($ Millions)
<table>
<tr><th></th><th>2020 Approved</th><th>2025 Forecast</th><th>Variance ($)</th><th>Variance (%)</th></tr>
<tr><td>OM&A</td><td>266.7</td><td>343.0</td><td>76.3</td><td>28.6%</td></tr>
<tr><td>Depreciation</td><td>263.7</td><td>~~285.3~~
290.4</td><td>~~21.6~~
26.7</td><td>~~8.2%~~
10.1%</td></tr>
<tr><td>Deemed Interest Expense</td><td>98.5</td><td>~~142.2~~
142.9</td><td>~~44.7~~
44.4</td><td>~~45.4%~~
45.1%</td></tr>
<tr><td>Return on Equity</td><td>153.9</td><td>220.9</td><td>67.0</td><td>43.5%</td></tr>
<tr><td>PILs</td><td>9.7</td><td>~~27.9~~
28.9</td><td>~~18.2~~
19.2</td><td>~~187.6%~~
197.9%</td></tr>
<tr><td>Total Service Revenue Requirement</td><td>792.5</td><td>~~1,020.3~~
1,026.0</td><td>~~227.8~~
233.6</td><td>~~28.7%~~
29.5%</td></tr>
</table></td></tr>
<tr><td>Rate Framework
(Exhibit 1B, Tab 2, Schedule 1)</td><td>Revised narrative to reflect Toronto Hydro’s withdrawal of its custom labour inflation proposal as noted in the response to 1B-Staff-93.</td><td>N/A</td></tr>
<tr><td>Responses to Letters of Comment
(Exhibit 1B, Tab 5, Schedule 3, App A)</td><td>Revised to include Toronto Hydro’s response to letters of comment filed with the OEB.</td><td>N/A</td></tr>
<tr><td>OEB Appendix 2-AB
(Exhibit 2B, Section E4, App A)

OEB Appendix 2-AA
(Exhibit 2B, Section E4, App B)</td><td>Revised 2025-2029 AFUDC resulting from 2023 actuals and updated 2024 bridge for capital expenditures.</td><td>
<table>
<tr><th></th><th>2025</th><th>2026</th><th>2027</th><th>2028</th><th>2029</th></tr>
<tr><td>AFUDC</td><td>~~6.2~~
6.5</td><td>~~7.0~~
7.3</td><td>~~8.3~~
8.4</td><td>9.2</td><td>10.2</td></tr>
</table></td></tr>
<tr><td>Regression Model Input Data
(Exhibit 3, Tab 1, Schedule 1, Appendix A)</td><td>Revised to reflect 2023 actuals and updated forecasts of model input variables (CDM, GDP, employment, unemployment rate, customer numbers)</td><td rowspan="2">Due to the size of the information, the numerical differences from the April 2nd revisions cannot be summarized for the purposes of this table. Please refer to the updated Appendices at Exhibit 3, Tab 1, Schedule 1.</td></tr>
<tr><td>CDM Variables
(Exhibit 3, Tab 1, Schedule 1, Appendix C)</td><td>Revised to reflect 2023 Actuals and re-estimated model co-efficients</td></tr>
</table>

Pre-Filed Evidence	Description of the Revisions	Numerical Differences
2015-2022 Post-CFF Historical Savings (Exhibit 3, Tab 1, Schedule 1, Appendix D)	Revised to include remaining 2015-2022 CDM savings under CFF wind-down period and 2021-2022 Actuals under the IESO's 2021-2024 CDM framework	
Extrapolation Method (Exhibit 3, Tab 1, Schedule 1, Appendix E)	Revised to include remaining 2015-2022 CDM savings under CFF wind-down period	
Regression Model Input Data ((Exhibit 3, Tab 1, Schedule 1, Appendix H)	Revised to reflect 2021-2022 Actuals under the IESO's 2021-2024 CDM framework	
Regression Model Statistics - Customers (Exhibit 3, Tab 1, Schedule 1, Appendix I)	Revised to reflect 2023 Actuals and updated forecasts of model input variables (employment, population, reclass)	
Clearspring Report on the Integration of Revenue Forecast with EV and DER (Exhibit 3, Tab 1, Schedule 1, Appendix J)	Revised to reflect 2023 Actuals and re-estimated model co-efficients	Due to the size of the information, the numerical differences from the April 2nd revisions cannot be summarized for the purposes of this table. Please refer to the updated Appendices at Exhibit 3, Tab 1, Schedule 1.
OEB Appendix 2-IB (Exhibit 3, Tab 1, Schedule 2)	Updated model to reflect 2023 actuals and updated the 2025-2029 forecast as discussed in response to interrogatory 1B-SEC-1 part (g).	Due to the size of the information, the numerical differences from the April 2 revisions cannot be summarized for the purposes of this table. Please refer to the updated OEB Appendix 2-IB.
Other Operating Revenues (Exhibit 3, Tab 2, Schedule 2, OEB Appendix 2-H)	Revised 2025 balance for Revenue Offset Account 4220 - Other Electric Utilities to align with updates to revenue requirement and reclassification of some 2024-2029 revenues and costs within Account 4325 - Revenues from Merchandise and Account 4330 - Costs and Expenses of Merchandising.	Due to the size of the information, the numerical differences from the March 11 and April 2 revisions cannot be summarized for the purposes of this table. Please refer to the updated OEB Appendix 2-H.

<table>
<tr><th>Pre-Filed Evidence</th><th>Description of the Revisions</th><th>Numerical Differences</th></tr>
<tr><td>Human Resources and Safety
(Exhibit 4, Tab 2, Schedule 15)</td><td>Revised the narrative at page 12 to correct an administrative error regarding Toronto Hydro’s recordable injury performance as noted in its response to 4-Staff-299.</td><td>N/A</td></tr>
<tr><td>Workforce Staffing Plan and Strategy
(Exhibit 4, Tab, 4, Schedule 3)</td><td>Corrected the approximate proportion of staffing plan by skill sets.</td><td>Table 1: Skill Sets and Job Types for the Future Workforce
<table>
<tr><th>Skill Sets</th><th>Sample Jobs</th><th>Approximate Proportion of Staffing Plan</th></tr>
<tr><td>“Big Data” Analytics – Consolidation & Presentation of data to support Decision Making</td><td>Analysts – cross functional</td><td>23%</td></tr>
<tr><td>Design, operational and management of distribution grid</td><td>Power Line Technician, Engineering Technologist, Power System Controller, Meter Mechanic, Meter Data Technologist, Distribution System Technologist, Dispatcher</td><td>~~17%~~
18%</td></tr>
<tr><td>Front-line Leadership</td><td>Day-to-day operations and people management</td><td>~~16%~~
20%</td></tr>
<tr><td>Financial management, regulatory affairs management, legal management, supply chain management, operations support, human resources management</td><td>Professional & supporting skills – cross functional</td><td>~~16%~~
12%</td></tr>
<tr><td>Distribution system design and engineering to support existing and new technologies (e.g. bidirectional grid, distributed energy resources)</td><td>Engineers</td><td>11%</td></tr>
<tr><td>Customer Experience, Key Account Management, Customer Relations Management</td><td>Large Customer & Key Account Consultant
Customer Relations Representative</td><td>10%</td></tr>
<tr><td>New technical and cyber security skills to support technology advancements and innovation</td><td>IT Technical Consultant
Cyber Security Specialist</td><td>7%</td></tr>
<tr><td>TOTAL</td><td></td><td>100%</td></tr>
</table></td></tr>
<tr><td>OEB Appendix 2-N
(Exhibit 4, Tab 5, Schedule 2)</td><td>Resolved data entry error when populating “% of Corporate Costs Allocated” column for year 2020.</td><td>Due to the size of the information, the numerical differences from the April 2 revisions cannot be summarized for the purposes of this table. Please refer to the updated OEB Appendix 2-N that was filed concurrently with the response to 4-Staff-310, Appendix A.</td></tr>
<tr><td>Continuity Schedule (Excel)
(Exhibit 9, Tab 2, Schedule 1)</td><td>Updated the DVA Continuity Schedule filed on March 11, 2023 (9-Staff-347) to correct the</td><td>Please see footnotes 15 and 16 in the updated Application Summary at Exhibit 1B, Tab 1, Schedule 3 at page 18.</td></tr>
</table>

Pre-Filed Evidence	Description of the Revisions	Numerical Differences
	balance for Account 1508 – Operations Consolidation Center Program.	
Lost Revenue Adjustment Mechanism (LRAM) (Exhibit 9, Tab 2, Schedule 3, Appendix A)	Revised to include the remaining 2018-2022 CDM savings under CFF wind-down period, and CDM savings persisting into 2023-2024	Due to the size of the information, the numerical differences cannot be summarized for the purposes of this table. Please refer to the updated Exhibit 9, Tab 2, Schedule 3, Appendix A.
Third Party Evaluation Reports (Exhibit 9, Tab 2, Schedule 3, Appendices O – Q)	Additional reports; remaining 2018-2022 CDM savings under CFF wind-down period	Due to the size of the information, the numerical differences from the March 11 and April 2 revisions cannot be summarized for the purposes of this table. Please refer to the updated Appendices O – Q in Exhibit 9, Tab 2, Schedule 3.
Non-Retrofit Projects (Exhibit 9, Tab 2, Schedule 3, Appendix R)		Due to the size of the information, the numerical differences from the March 11 and April 2 revisions cannot be summarized for the purposes of this table. Please refer to the updated Appendix R Exhibit 9, Tab 2, Schedule 3.
Retrofit Projects (Exhibit 9, Tab 2, Schedule 3, Appendix S)		Due to the size of the information, the numerical differences from the March 11 and April 2 revisions cannot be summarized for the purposes of this table. Please refer to the updated Appendix S in Exhibit 9, Tab 2, Schedule 3.

Updated Interrogatory Responses

Interrogatory	Description of the Revisions	Numerical Differences
1B-Staff-12 (f)	Updated response to provide the requested revenue requirement calculation.	N/A
1B-CCC-37	Updated response to provide the requested revenue requirement calculation.	N/A
1B-SEC-23	Updated response to provide 2023 results for the 2020-2024 Custom Scorecard, EDS, and ESQRs.	N/A
2A-Staff-107	Updated to provide an updated Lead Lag study including 2023 actuals. For clarity, Toronto Hydro is not requested an updated Working Capital Allowance (WCA) rate.	
4-AMPCO-84 (f), App A	Revised 2024 Bridge for Salary and Overtime for part (f) to correct an error that was identified with respect to the allocation of shift premiums.	<table><tr><th></th><th>2024 Bridge</th></tr><tr><td>Salary</td><td>~~$ 173,141,807~~ $ 170,902,814</td></tr><tr><td>Overtime</td><td>~~$ 11,402,747~~ $ 13,641,740</td></tr><tr><td>Incentive Pay</td><td>$ 18,029,137</td></tr><tr><td>Total</td><td>$ 202,573,692</td></tr></table>
7-SEC-122	Provided bill impacts scenarios related to CSMUR cost allocation changes.	N/A

EXHIBIT LIST / TABLE OF CONTENTS

Tab	Schedule	Appendix		Excel
EXHIBIT 1A - ADMINISTRATION				
1	**Table of Contents**			
	1	Table of Contents		
2	**Legal Application**			
	1	Legal Application		
3	**Filing Requirements**			
	1	Administration		
		A	OEB Appendix 2-A: List of Requested Approvals	excel
	2	Filing Requirements Checklist		excel
	3	Certification of Evidence		
	4	Certification of Deferral and Variance Account Balances		
	5	Disclaimer		
	6	Glossary		
EXHIBIT 1B – APPLICATION OVERVIEW				
1	**Executive Summary**			
	1	Executive Summary and Investment Plan Overview		
	2	Customer Summary		
	3	Application Summary		
2	**Rate Framework**			
	1	Rate Framework		
		A	Review of Rate Framework (Scott Madden)	
		B	Jurisdictional Review of Performance Based Regulation (Scott Madden)	
3	**Performance and Productivity**			
	1	Performance Outcomes Framework		
	2	Historical Performance Results		
		A	2022 and 2017 Toronto Hydro Electricity Distributor Scorecards	
		B	Annually Reported Measures	
		C	OEB Appendix 2-G: ESQR and Reliability	excel
		D	OEB Appendix 5-A: Metrics	excel
	3	Productivity and Benchmarking		
		A	2025 Econometric Benchmarking: Cost and Reliability (Clearspring)	
		B	PEG Forecast Benchmarking	excel
		C	Unit Cost Benchmarking Study (UMS Group)	

Tab	Schedule	Appendix		Excel
4	**Innovation at Toronto Hydro**			
	1	Facilitating Innovation		
	2	Innovation Fund Proposal		
		A	Pilot Project Concepts	
		B	NRCan Letter	
5	**Customer and Stakeholder Engagement**			
	1	Customer Engagement		
		A	Customer Engagement Report (Innovative Research Group)	
	2	Stakeholder Consultations		
		A	Toronto Hydro Stakeholder Consultation (April 26 Session)	
		B	Toronto Hydro Stakeholder Consultation (October 4 Session)	
	3	Responses to Letters of Comment		
		A	Toronto Hydro Response to Letters of Comment	/C

EXHIBIT 1C – CORPORATE INFORMATION

Tab	Schedule	Appendix		
1	**Operating Environment**			
	1	Operating Environment		
	2	Toronto Hydro Service Area Map		
2	**Corporate Structure and Governance**			
	1	Corporate Structure and Governance		
3	**Financial Information**			
	1	Financial Information Overview		
	2	Accounting Standards		
	3	Audited Financial Statements		
		A	2020 Financial Statements and Notes	
		B	2021 Financial Statements and Notes	
		C	2022 Financial Statements and Notes	
	4	THC Management Discussion & Analysis		
	5	THC 2022 Annual Information Form		
	6	Public Debt Offering		
		A	Base Shelf Prospectus, 2023	
		B	15th Supplemental Trust Indenture, Nov 2019	
		C	16th Supplemental Trust Indenture, Nov 2019	
		D	17th Supplemental Trust Indenture, Oct 2020	
		E	18th Supplemental Trust Indenture, Oct 2021	
		F	19th Supplemental Trust Indenture, Oct 2021	
		G	20th Supplemental Trust Indenture, Oct 2022	
		H	21st Supplemental Trust Indenture, Jun 2023	
	7	Rating Agency Reports		
		A	Standard and Poor's, 11 May 2023	

Tab	Schedule	Appendix		Excel	
		B	DBRS, 1 May 2023		
	8	Existing Accounting Orders and Departures from USoA			
	9	THC 2022 Annual Report			
EXHIBIT 2A – RATE BASE					
1	**Rate Base**				
	1	Rate Base Overview			
		A	2020-2024 In-Service Additions by Investment Category	excel	
	2	OEB Appendix 2-BA: Fixed Asset Continuity Schedules		excel	
2	**Depreciation and Amortization**				
	1	Depreciation and Amortization			
		A	Depreciation Expenses by USofA	excel	
		B	OEB Appendix 2-C: Depreciation and Amortization Expense	excel	
		C	OEB Appendix 2-BB: Useful Life Comparison	excel	
		D	Depreciation Study by Concentric		
	2	Derecognition of Assets			
3	**Working Capital Allowance**				
	1	Working Capital Allowance			
		A	Cost of Power	excel	
	2	Working Capital Requirements Study (Guidehouse)			
4	**Capitalization**				
	1	Capitalization Policy			
		A	Toronto Hydro Capitalization Policy		
	2	Overhead Costs			
		A	OEB Appendix 2-D: Overhead Costs	excel	
5	**Eligible Renewable Generation Investments**				
	1	Cost of Eligible Investments for the Connection of Qualifying Generation Facilities			
	2	OEB Appendix 2-FA: Renewable Generation Connection Investment Summary - Energy Storage		excel	
	3	OEB Appendix 2-FB: Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments - Energy Storage		excel	
	4	OEB Appendix 2-FA: Renewable Generation Connection Investment Summary - GPMC		excel	
	5	OEB Appendix 2-FB: Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments - GPMC		excel	
	6	OEB Appendix 2-FA: Renewable Generation Connection Investment Summary – Stations Expansion		excel	/C
	7	OEB Appendix 2-FB: Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments – Stations Expansion		excel	/C

Tab	Schedule	Appendix		Excel
EXHIBIT 2B – DISTRIBUTION SYSTEM PLAN				
A	**Distribution System Plan Overview**			
	A	Distribution System Plan Overview		
B	**Coordinated Planning with Third Parties**			
	B	Coordinated Planning		
		A	Needs Assessment Report (Toronto)	
		B	Toronto Regional Infrastructure Plan	
		C	GTA North RIP (October 2020)	
		D	Toronto IRRP Report (August 2019)	
		E	Toronto Scoping Assessment Outcome	
		F	GTA North Region Needs Assessment (July 2023)	
		G	IESO Letter of Comment	
C	**Performance Measurement for Continuous Improvement**			
	C	Performance Management		
D	**Asset Management Process**			
	D1	Asset Management Process Overview		
	D2	Overview of Assets Managed		
		A	Climate Change Vulnerability Assessment by Stantec	
	D3	Asset Lifecycle Optimization Policies and Practices		
		A	TH Asset Condition Assessment Report	
		B	ACA Results Summary	excel
		C	Review of ACA Modelling Enhancements and Customisations by EA Technology	
		D	Value of Service Study (Nexant)	
	D4	Capacity Planning & Electrification		
		A	Overview of the Future Energy Scenarios	
		B	Future Energy Scenarios Report (Element Energy)	
	D5	Grid Modernization Strategy		
	D6	Facilities Asset Management Strategy		
	D7	Net Zero 2040 Strategy		
	D8	Information Technology (IT) Investment Strategy		
		A	IT/OT Cost Benchmarking and Maturity Assessment (Gartner)	
E	**Capital Expenditure Plan**			
	E1	Capital Expenditure Plan Summary		
	E2	Capital Expenditure Planning Process Overview		
	E3	System Capability Assessment for Renewable Energy and Conventional Generation		
	E4	Capital Expenditure Summary		
		A	OEB Appendix 2-AB	excel
		B	OEB Appendix 2-AA	excel

Tab	Schedule	Appendix		Excel
	E5	System Access Investments		
		E5.1	Customer and Generation Connections	
		E5.2	Externally Initiated Plant Relocations and Expansion	
		E5.3	Load Demand	
		E5.4	Metering	
		E5.5	Generation Protection, Monitoring, and Control	
	E6	System Renewal Investments		
		E6.1	Area Conversions	
		E6.2	Underground System Renewal - Horseshoe	
		E6.3	Underground System Renewal - Downtown	
		E6.4	Network System Renewal	
		E6.5	Overhead System Renewal	
		E6.6	Stations Renewal	
		E6.7	Reactive and Corrective Capital	
	E7	System Service Investments		
		E7.1	System Enhancements	
		E7.2	Non-Wires Solutions	
		E7.3	Network Condition Monitoring and Control	
		E7.4	Stations Expansion	
			A Downsview TS Business Case	/C
	E8	General Plant Investments		
		E8.1	Enterprise Data Centre	
		E8.2	Facilities Management and Security	
		E8.3	Fleet and Equipment Services	
		E8.4	Information Technology and Operational Technology Systems	
			A ADMS Business Case	
			B SAP ERP Upgrade Business Case	

EXHIBIT 3 – OPERATING REVENUE

Tab	Schedule	Appendix		Excel
1	**Load and Customers**			
	1	Load, Customers, and Revenue		
		A	Regression Model Input Data	excel
		B	Regression Model Statistics	excel
		C	CDM Variables	excel
		D	2015-2022 Post-CFF Historical Savings	excel
		E	Extrapolation Method 2019-2020 and 2021-2024 Prov. Frameworks	excel
		F	IESO EE Report	
		G	2021-2024 CDM Framework Program Plan	
		H	Regression Model Input Data - Customers	excel
		I	Regression Model Statistics - Customers	excel

Tab	Schedule	Appendix	Excel
		J Report on the Integration of Revenue Forecast and EV and DER (Clearspring)	
	2	OEB Appendix 2-IB: Customer, Connections, Load Forecast and Revenues Data and Analysis	excel
2	**Revenue Offsets**		
	1	Revenue Offsets	
	2	OEB Appendix 2H: Other Operating Revenues	excel
EXHIBIT 4 – OPERATING EXPENSES			
1	**OM&A Overview**		
	1	Overview of OM&A Expenditures	
	2	OEB Appendix 2-JA: Summary of Recoverable OM&A Expenses	excel
	3	OEB Appendix 2-JB: Recoverable OM&A Cost Driver Table	excel
	4	OEB Appendix 2-JC: OM&A Programs Table	excel
	5	OEB Appendix 2-L: Recoverable OM&A Cost per Customer and per FTE	excel
2	**OM&A Programs**		
	1	Preventative and Predictive Overhead Line Maintenance	
	2	Preventative and Predictive Underground Line Maintenance	
	3	Preventative and Predictive Station Maintenance	
	4	Corrective Maintenance	
	5	Emergency Response	
	6	Disaster Preparedness Management	
	7	Control Centre Operations	
	8	Customer Operations	
	9	Asset and Program Management	
	10	Work Program Execution	
	11	Fleet and Equipment Services	
	12	Facilities Management	
	13	Supply Chain Services	
	14	Customer Care	
	15	Human Resources, Environment and Safety	
	16	Finance	
	17	Information Technology	
	18	Public, Legal and Regulatory Affairs	
		A OEB Appendix 2-M: Regulatory Costs Schedule	excel
	19	Charitable Donations (LEAP)	
	20	Common Costs and Adjustments	
	21	Allocations and Recoveries	

Tab	Schedule	Appendix		Excel	
3	**Non-Affiliate Services**				
	1		Overview of Non-Affiliate Services		
		A	Procurement Policy		
		B	Engagements Not Originating from a Competitive Procurement Process		
4	**Workforce Staffing and Compensation**				
	1		Workforce Staffing and Compensation Overview		
	2		OEB Appendix 2-K: Employee Costs/Compensation Table	excel	
	3		Workforce Staffing Plan and Strategy		
	4		Compensation Strategy and Workforce Governance		
		A	Post-Employment Benefits for Employees of Toronto Hydro, prepared by Willis Towers Watson		
	5		Non-Executive Compensation and Benefits Review (Mercer Canada)		
5	**Shared Services**				
	1		Shared Services and Corporate Cost Allocations		
	2		OEB Appendix 2-N: Shared Services and Corporate Cost Allocation	excel	
EXHIBIT 5 – COST OF CAPITAL AND CAPITAL STRUCTURE					
1	**Capital Structure**				
	1		Cost of Capital		
	2		OEB Appendix 2-OA: Capital Structure and Cost of Capital	excel	
	3		OEB Appendix 2-OB: Debt Instruments	excel	
EXHIBIT 6 – REVENUE REQUIREMENT					
1	**Revenue Requirement**				
	1		Revenue Requirement and Sufficiency / Deficiency		
		A	Modifications to the OEB's RRWF		
	2		Revenue Requirement Workform Model 2025	excel	
	3		Revenue Requirement Workform Model 2026	excel	
	4		Revenue Requirement Workform Model 2027	excel	
	5		Revenue Requirement Workform Model 2028	excel	
	6		Revenue Requirement Workform Model 2029	excel	
	7		Revenue Requirement Workform Model 2024	excel	/C
2	**Taxes and PILs**				
	1		Corporate Taxes (PILs)		
	2		PILs Model for Bridge and Test Years	excel	
	3		Tax Information for 2022		

Tab	Schedule	Appendix		Excel
EXHIBIT 7 – COST ALLOCATION				
1	**Cost Allocation**			
	1	Cost Allocation		
	2	Sample Methodology - Demand Data for Cost Allocation Model		
	3	Cost Allocation Model		excel
EXHIBIT 8 – RATE DESIGN				
1	**Rate Design**			
	1	Rate Design		
	2	Allocation between Fixed and Variable Rates		excel
2	**Specific Service Charges**			
	1	Specific Service Charges		
3	**Rate Schedules**			
	1	Current Tariff Sheet		
	2	Proposed Tariff Sheet		excel
4	**Loss Adjustment**			
	1	OEB Appendix 2-R: Loss Adjustment Factors		excel
5	**Retail Transmission Service Rates**			
	1	Retail Transmission Service Rates Workform		excel
6	**Bill Impacts Table**			
	1	OEB Appendix 2-W: Bill Impacts		excel
EXHIBIT 9 – DEFERRAL AND VARIANCE ACCOUNTS				
1	**Deferral and Variance Accounts**			
	1	Deferral and Variance Accounts		
		A	Calculation of Useful Life Change Impacts	excel
		B	2020-2024 Approved Draft Accounting Orders	
		C	2025-2029 Draft Accounting Orders	
2	**Continuity Schedules**			
	1	Deferral and Variance Accounts		excel
	2	GA Analysis Workform		excel
	3	Lost Revenue Adjustment Mechanism (LRAM)		
		A	LRAMVA Work Form: Distribution Rates	excel
		B	IESO Final Verified Results	excel
		C	IESO Participation and Cost Reports	excel
		D	Detailed Project-Level Savings	excel
		E	Retrofit Projects (May 2019-May 2020)	excel
		F	Non-Retrofit Projects (May 2019-May 2020)	excel
		G	Non-Retrofit Projects (June 2020-May 2023)	excel

Tab	Schedule	Appendix		Excel	
		H	Retrofit Projects (June 2020-May 2023)	excel	
		I	Third Party Evaluation Reports		
		J	Third Party Evaluation Reports		
		K	Third Party Evaluation Reports		
		L	Third Party Evaluation Reports		
		M	Third Party Evaluation Reports		
		N	Third Party Evaluation Reports		
		O	Third Party Evaluation Reports		/C
		P	Third Party Evaluation Reports		/C
		Q	Third Party Evaluation Reports		/C
3	Rate Riders				
	1	Rate Riders Development		excel	

ADMINISTRATION

This Schedule provides information relating to the administration of the Application.[1]

1. PRIMARY CONTACT FOR THE APPLICATION

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2. LEGAL REPRESENTATION FOR THE APPLICATION

Charles Keizer – ckeizer@torys.com
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79 Wellington Street West
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3. INTERNET ADDRESS

Toronto Hydro's main webpage: *www.torontohydro.com*

[1] OEB Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 – Cost of Service (December 15, 2022) at section 2.1.3.

Regulatory documents will be available under the Regulatory Affairs tab: *http://www.torontohydro.com/regulatory-information*

4. MEDIA ACCOUNTS

X (formerly known as Twitter) – X.com/torontohydro

Facebook – facebook.com/torontohydro

Instagram – Instagram.com/torontohydro

YouTube – youtube.com/torontohydro

LinkedIn –linkedin.com/company/toronto-hydro/

5. NOTICE OF HEARING PUBLICATION

Toronto Hydro recommends that the Notice of Hearing for its Application be published in the Toronto Star and L'Express, as well as on the utility's website, torontohydro.com.

6. FORM OF HEARING REQUESTED

Toronto Hydro requests an oral hearing.

7. EFFECTIVE REQUESTED DATE

Toronto Hydro requests new rates to be effective January 1, 2025.

8. DEVIATIONS FROM FILING REQUIREMENTS

In preparing this Application, Toronto Hydro has followed Chapters 1, 2, and 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (the "Filing Requirements").[2] Any departures from the Filing Requirements are noted in the checklist filed at Exhibit 1A, Tab 3, Schedule 2.

[2] OEB Filing Requirements for Electricity Distribution Rate Applications, Chapter 1 – Overview (April 18, 2022); Chapter 2 – Cost of Service (December 15, 2022); and Chapter 5 – Distribution System Plan (December 15, 2022).

METHODOLOGY CHANGES

The following methodology changes were applied in this application, relative to Toronto Hydro's 2020-2024 Rate Application:[3]

- A custom revenue cap model to determine the Custom Revenue Cap Index ("CRCI") to be approved in this application and applied in setting rates for the years 2026 to 2029 through annual rate update applications.[4]
- A modified X-Factor in the CRCI for a performance incentive mechanism ("PIM") that is linked to the 2025-2029 Custom Scorecard.[5]
- An Innovation Fund to be collected through a rate rider (outside of base rates) in order to provide transparency on the bill for customers and flexibility to the utility to determine the treatment (i.e. capital or operations) of innovative projects undertaken pursuant to this fund.[6] /C
- Updated asset useful lives and resulting depreciation rates in accordance with the outputs of a third-party depreciation study.[7]
- Enhanced the capacity planning process consider electrification drivers and municipal energy plans in producing the system peak load forecast that underpins the 2025-2029 Investment Plan.[8]
- Enhanced the load forecast to consider electrification drivers and changes to the availability of conservation and demand management ("CDM") savings in producing the revenue forecast that underpins to 2025-2029 rates.[9]

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[3] EB-2018-0165, Toronto Hydro-Electric System Limited Application (filed August 15, 2018, updated April 30, 2019).
[4] See Exhibit 1B, Tab 2, Schedule 1.
[5] See Exhibit 1B, Tab 3, Schedule 1.
[6] See Exhibit 1B, Tab 4, Schedule 2.
[7] See Exhibit 2A, Tab 2, Schedule 1.
[8] See Exhibit 2B, Sections D4 and E2.
[9] See Exhibit 3, Tab 1, Schedule 1.

- Refined the customer forecasting methodology to incorporate economic, demographic, and market conditions as inputs.[10]
- Modified the presentment of shared services revenues and costs to appear under Account 4375 and 4380, in accordance with the Accounting Procedures Handbook.[11]
- Increased the funding for LEAP program to 0.15% of the utility's revenue requirement and proposed exemptions from certain aspects of the LEAP Manual to modernize and enhance the effectiveness of the program in providing customers financial assistance.[12]
- Enhanced the load profile methodology to integrate electrification drivers used as the inputs in the cost allocation model.[13]

9. PREVIOUS OEB DIRECTIONS

Table 1 below summarizes how Toronto Hydro addressed OEB directions specified in the 2020-2024 Decision and Order.[14]

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[10] *Ibid*.
[11] See Exhibit 3, Tab 2 and Exhibit 4, Tab 5.
[12] See Exhibit 4, Tab 2, Schedule 19.
[13] See Exhibit 7, Tab 1, Schedule 1.
[14] EB-2018-0165, Toronto Hydro-Electric System Limited Decision and Order (December 19, 2019).

1 **Table 1: OEB Directions**

	Direction	Response
1	**General Plant – Fleet and Equipment:** *"The OEB directs Toronto Hydro to provide more detailed cost benefit analysis between EV, hybrid and combustion engines for its fleet program for future rebasing applications. In addition, the OEB directs Toronto Hydro to develop utilization measures beyond fleet use in standard hours."*[15]	Toronto Hydro addressed the OEB's direction. For specific details, please see the Fleet and Equipment capital program in Exhibit 2B, Section E8.3.
2	**Costs of Eligible Investments for the Connection of Qualifying Generation Facilities:** "*The OEB expects Toronto Hydro to provide an assessment of appropriate sharing of benefits for ESS projects as part of any future requests for funding for provincial rate protection.*"[16]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 2A, Tab 5, Schedule 1.
3	**Load Forecasting:** "*The OEB expects Toronto Hydro to enhance its approach to forecasting customers / connections for its next rebasing application. … The OEB expects there to be a greater level of documentation for future rate proceedings. … The OEB expects Toronto Hydro to do a more detailed analysis of the impact of EVs and DERs on load and load profile to be considered for any future load forecasts.*"[17]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 3, Tab 1, Schedule 1.

[15] *Ibid* at pp. 103-104.
[16] *Supra* note 4 at p. 119.
[17] *Supra* note 4 at pp. 126-127.

	Direction	Response
4	**Shared Services:** "*The OEB notes that for Account 4375 Shared Services Recovery, Toronto Hydro does not record the associated expenses in Account 4380, as required by the Accounting Procedures Handbook. Toronto Hydro disclosed this point in its evidence, however, this approach makes it more difficult to assess that there are no cross-subsidies between regulated and non-regulated activities. Toronto Hydro is expected to follow the requirements of the Accounting Procedures Handbook going forward.*"[18]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 3, Tab 2 and Exhibit 4, Tab 5.
5	**Depreciation:** "*For the next rebasing application, the OEB directs Toronto Hydro to file either the annual useful lives reviews to demonstrate that no change is required to the useful lives or a new depreciation study.*"[19]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 2A, Tab 2, Schedule 1, and Appendix D thereto.
6	**Standby Rates:** "*Given the length of time that the standby rates have been set on an interim basis, the OEB requires Toronto Hydro to file a proposal in its next rebasing application to address this situation, unless it has been otherwise superseded by a generic policy.*"[20]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 8, Tab 1, Schedule 1.
7	**Earnings Sharing Mechanism ("ESM"):** "*The 2019 ESM calculation should be filed as part of Toronto Hydro's next rebasing application.*"[21]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 9, Tab 1, Schedule 1.

[18] *Supra* note 4 at p. 131.
[19] *Supra* note 4 at p. 146.
[20] *Supra* note 4 at p. 160.
[21] *Supra* note 4 at p. 182.

	Direction	Response
8	**Other Pension and Employment Benefits ("OPEBs"):** "*The OEB requires Toronto Hydro to commence gathering the necessary information going forward to calculate the accrual OPEB amount based on the annual depreciation associated with its cumulative undepreciated capitalized OPEB costs in rate base.*"[22]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 9, Tab 1, Schedule 1.
9	**Sale of Utility Properties:** "*The OEB directs Toronto Hydro to establish the Gain on Sale of Property variance account as there is considerable variability in the gain on disposal of property. Toronto Hydro is expected to seek disposition of this symmetrical variance account in its next rebasing application.*"[23]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 9, Tab 1, Schedule 1.
10	**In-Service Additions & Capital-Related Revenue Requirement Variance Account ("CRRRVA"):** "*The approach offered by Toronto Hydro to require it to report on in-service additions by investment category for the 2020-2024 period at the time of its next rebasing is approved. … The additional information will assist in reassessing the account in the next rebasing application.*"[24]	Toronto Hydro addressed the OEB's direction. For specific details, please see the relevant evidence in Exhibit 2A, Tab 1, Schedule 1 and Exhibit 9, Tab 1, Schedule 1.

10. CONDITIONS OF SERVICE

Toronto Hydro's current Conditions of Service (Revision 22) can be found at the following link: https://www.torontohydro.com/conditions-of-service. Appendix A to this Schedule provides summaries of the following revisions Toronto Hydro made to its Conditions of Service since the last rebasing application:

[22] *Supra* note 4 at p. 187
[23] *Supra* note 4 at p. 188.
[24] *Supra* note 4 at p. 195.

- Revision 19 – January 1, 2020
- Revision 19.1 – March 1, 2020
- Revision 20 – January 1, 2021
- Revision 21 – January 1, 2022
- Revision 22 – January 1, 2023

Toronto Hydro proposes to increase its basic connection allowance for certain customer classes from $1,396 to $3,059.[25] If this proposal is approved, Toronto Hydro would update the Service Connection and Disconnection Fee column of Table 2 of its Conditions of Service as of January 1, 2025. Toronto Hydro does not expect any other proposals in this Application to result in other material changes to its Conditions of Service.

Toronto Hydro has identified five types of charges listed in the Conditions of Service that are not on its Tariff of Rates and Charges. Consistent with other similar charges that Toronto Hydro directly collects from customers, they are not recorded as a specific service charge in Toronto Hydro's OEB-approved tariff sheet. For more details, please see Exhibit 8, Tab 2, Schedule 1.

11. CORPORATE AND UTILITY ORGANIZATIONAL STRUCTURE

Toronto Hydro's organizational chart is provided in Figure 1 below. A corporate entities relationship chart showing the extent to which the parent company is represented on Toronto Hydro's Board of Directors and a description of the reporting relationships between the utility and parent company is provided in Exhibit 1C, Tab 2, Schedule 1. There are no planned changes in corporate or operational structure.

[25] Exhibit 2B, Section E5.1.

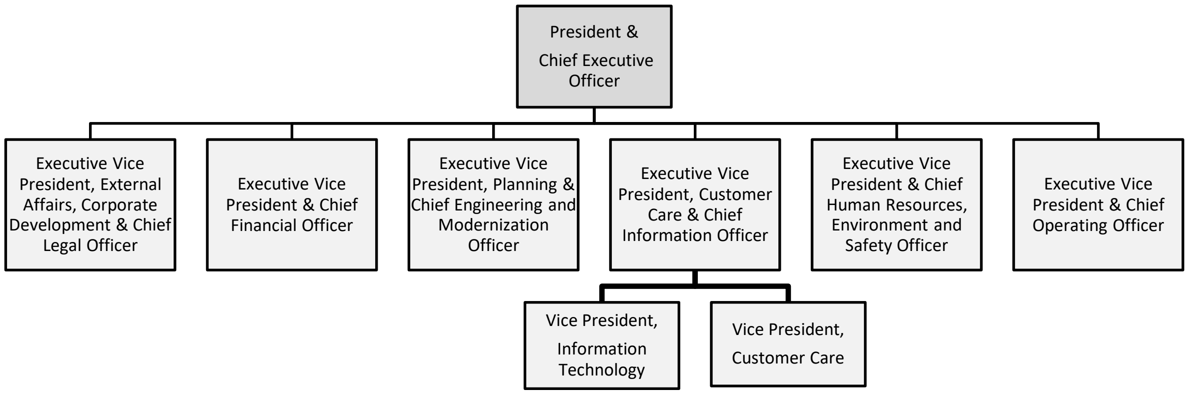

Figure 1: Toronto Hydro's Organizational Chart

12. LIST OF APPROVALS REQUESTED

The list of specific approvals that Toronto Hydro requests as part of this Application is provided in Exhibit 1A, Tab 2, Schedule 1 and OEB Appendix 2-A, and reproduced below:

Pursuant to section 78 of the *Ontario Energy Board Act, 1998*,[26] Toronto Hydro seeks the following approvals:

1) Approval of 2025 base revenue requirement as proposed in Exhibit 6, Tab 1.
2) Approval of 2025 electricity distribution rates and charges as proposed in Exhibits 8 and 9, including a number of credits to customers. In particular:
    a) Base distribution rates as set out in Exhibit 8, Tab 1, Schedule 1;
    b) Specific Service Charges as set out in Exhibit 8, Tab 2, Schedule 1; and
    c) Rate riders as set out in Exhibit 9, Tab 3, Schedule 1.
3) Approval of updated depreciation rates in accordance with Exhibit 2A, Tab 2, Schedule 1.

[26] SO 1998, c 15, Sched B.

4) Approvals related to deferral and variance accounts as proposed in Exhibit 9. In particular:
    a) To dispose of balances in existing deferral and variance accounts as detailed in Exhibit 9, Tab 1, Schedule 1;
    b) Approval of the continuation of existing deferral and variance accounts, as set out in Exhibit 9, Tab 1, Schedule 1; and
    c) Approval of new deferral and variance account as proposed in Exhibit 9, Tab 1, Schedule 1:
        i) A variance account in respect of demand-related expenditures and revenues;
        ii) A deferral account in respect of performance incentives earnings;
        (iii) A variance account in respect of the innovation fund; and
        (iv) A deferral account in respect of variable consideration from a real property sale.
5) Approval of the 2025-2029 Custom Rate Framework, including the Custom Revenue Cap Index ("CRCI") and non-CRCI elements, as proposed in Exhibit 1B, Tab 2, Schedule 1.
6) Approval of the 2025-2029 Custom Scorecard metrics, weightings and targets set out in Exhibit 1B, Tab 3, Schedule 1, including the establishment of a second phase of this proceeding to finalize the Custom Scorecard targets post the OEB's decision, as proposed therein.
7) Other items or amounts that may be requested by the Applicant in the course of the proceeding, and such other relief or entitlements as the OEB may grant.

APPLICATION SUMMARY

This schedule provides a summary of Toronto Hydro's 2025-2029 Custom Rate Application, in accordance with section 2.1.2 of the Filing Requirements.[1]

1. BILL IMPACTS

Table 1 below provides a summary of the proposed change in the monthly total bill impacts for typical customers in all rate classes.[2] Total bill impacts for all classes are below the 10 percent threshold, therefore mitigation measures are not required.

Table 1: 2025-2029 Total Bill Impacts – Proposed Change in Monthly Bill

	Change	2025	2026	2027	2028	2029
Residential	$/30 days	$0.91	$3.44	$3.77	$3.61	$2.90
	%	0.7%	2.5%	2.6%	2.4%	1.9%
Competitive Sector Multi-Unit Residential	$/30 days	-$2.10	$1.86	$2.21	$1.88	$1.66
	%	-2.8%	2.6%	3.0%	2.5%	2.1%
General Service <50 kW	$/30 days	$7.34	$9.36	$9.73	$10.39	$7.38
	%	2.0%	2.5%	2.5%	2.6%	1.8%
General Service 50-999 kW	$/30 days	-$73.44	$188.05	$197.76	$217.72	$170.01
	%	-0.5%	1.3%	1.4%	1.5%	1.2%
General Service 1,000-4,999 kW	$/30 days	-$1,565.72	$1,657.27	$1,713.81	$1,807.60	$1,560.87
	%	-1.0%	1.1%	1.1%	1.2%	1.0%
Large Use	$/30 days	-$7,459.85	$6,638.41	$9,677.61	$10,769.78	$8,543.60
	%	-1.1%	1.0%	1.4%	1.6%	1.2%
Street Lighting	$/30 days	$13,867.36	$13,873.12	$23,380.94	$13,713.23	$17,205.38
	%	4.4%	4.2%	6.8%	3.7%	4.5%
Unmetered Scattered Load	$/30 days	$1.88	$2.44	$2.52	$3.15	$2.04
	%	3.0%	3.7%	3.7%	4.5%	2.8%

[1] OEB Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 (December 15, 2022).
[2] Includes all rate riders and holding commodity rates and regulatory charges constant.

Table 2 below provides the proposed monthly distribution bill impacts per sub-total A of Tariff Schedule and Bill Impacts spreadsheet model for: (i) a typical residential customer using 750 kWh per month and for (ii) a General Service < 50kW customer using 2,000 kWh per month on time-of-use pricing, as well as other customers in all rate classes.

1 **Table 2: Proposed Distribution Bill Impacts (Per Sub-Total A of Tariff Schedule)**

	Change in Bill	2025 Proposed	2026 Proposed	2027 Proposed	2028 Proposed	2029 Proposed
Residential	$/30 days	$3.24	$3.40	$3.72	$3.97	$2.86
	%	7.6%	7.4%	7.5%	7.5%	5.0%
Competitive Sector Multi-Unit Residential	$/30 days	-$1.27	$1.84	$2.18	$2.27	$1.64
	%	-3.6%	5.4%	6.0%	5.9%	4.0%
General Service <50 kW	$/30 days	$14.18	$9.24	$9.61	$10.67	$7.29
	%	12.0%	7.0%	6.8%	7.0%	4.5%
General Service 50-999 kW	$/30 days	$235.35	$166.42	$175.01	$192.67	$150.45
	%	13.0%	8.1%	7.9%	8.1%	5.8%
General Service 1,000-4,999 kW	$/30 days	$1,993.46	$1,466.61	$1,516.65	$1,599.65	$1,381.30
	%	13.4%	8.7%	8.3%	8.0%	6.4%
Large Use	$/30 days	$10,124.44	$5,874.70	$8,564.26	$9,530.78	$7,560.71
	%	13.1%	6.7%	9.2%	9.4%	6.8%
Street Lighting	$/30 days	$15,917.30	$12,277.10	$20,691.10	$12,135.60	$15,226.00
	%	11.0%	7.6%	11.9%	6.3%	7.4%
Unmetered Scattered Load	$/30 days	$2.96	$2.41	$2.49	$3.11	$2.01
	%	9.5%	7.1%	6.8%	8.0%	4.8%

2. REVENUE REQUIREMENT

Table 3 below summarizes Toronto Hydro's 2025 forecasted revenue requirement.

Table 3: 2025 Forecast Revenue Requirement ($ Millions)

Revenue Requirement Component	2025 Test Year (April 2, 2024)
OM&A Expenses (incl. property taxes)	343.0
Amortization/Depreciation	290.4
Income Taxes (grossed up)	28.9
Deemed Interest Expense	142.9
Return on Deemed Equity	220.9
Service Revenue Requirement	**1,026.0**
Revenue Offsets	(48.2)
Base Revenue Requirement	**977.8**

/C

Table 4 below summarizes the service revenue requirement variances between the last OEB-approved year (2020) and the proposed 2025 test year. For more information about Toronto Hydro's revenue requirement, please see Exhibit 6, Tab 1.

Table 4: 2020 versus 2025 Service Revenue Requirement ($ Millions)

	2020 Approved	2025 Forecast	Variance ($)	Variance (%)
OM&A	266.7	343.0	76.3	28.6%
Depreciation	263.7	290.4	26.7	10.1%
Deemed Interest Expense	98.5	142.9	44.4	45.1%
Return on Equity	153.9	220.9	67.0	43.5%
PILs	9.7	28.9	19.2	197.9%
Total Service Revenue Requirement	**792.5**	**1,026.0**	**233.6**	**29.5%**

/C

The main drivers for the proposed increase in the 2025 service revenue requirement are:

(i) additions to rate base from capital investments undertaken in the current 2020-2024 rate period (driving increases in depreciation, deemed interest expense, and return on equity) as summarized in Exhibit 2A, Tab 2, Schedule 1 and detailed in the Distribution System Plan at Exhibit 2B, and

(ii) an increase in OM&A expenses as summarized in Exhibit 4, Tab 1, Schedule 1 and detailed in the programmatic evidence at Exhibit 4, Tab 2.

Tables 5 and 6 below summarize the 2020-2024 and the 2025-2029 revenue requirement.

Table 5: 2020-2024 Revenue Requirement ($ Millions)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2020-2024 Total
OM&A Expenses (incl. property taxes)	288.1	277.5	280.4	290.0	320.5	**1,456.5**
Amortization/Depreciation	261.0	274.7	287.0	259.9	276.6	**1,359.1**
Income Taxes (grossed up)	(3.0)	(3.1)	9.2	13.0	10.8	**26.9**
Deemed Interest Expense	99.0	102.1	107.2	113.1	121.4	**542.7**
Return on Deemed Equity	107.1	132.4	146.0	140.8	189.4	**715.7**
Service Revenue Requirement	**752.2**	**783.5**	**829.8**	**816.8**	**918.6**	**4,100.9**
Revenue Offsets	(39.3)	(40.0)	(47.4)	23.4	(46.9)	**(150.2)**
Base Revenue Requirement	**712.9**	**743.5**	**782.3**	**840.3**	**871.7**	**3,950.7**

/C

Table 6: 2025-2029 Revenue Requirement ($ Millions)

	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2025-2029 Total
OM&A Expenses (incl. property taxes)	343.0	358.0	370.1	385.5	399.6	**1,856.2**
Amortization/Depreciation	290.4	303.9	322.7	344.0	356.9	**1,618.0**
Income Taxes (grossed up)	28.9	31.1	20.7	56.5	48.3	**185.4**

	2025 Forecast	**2026 Forecast**	**2027 Forecast**	**2028 Forecast**	**2029 Forecast**	**2025-2029 Total**
Deemed Interest Expense	142.9	152.1	162.4	173.5	183.9	**814.7**
Return on Deemed Equity	220.9	235.1	251.0	268.1	284.2	**1,259.2**
Service Revenue Requirement	**1,026.0**	**1,080.2**	**1,126.9**	**1,227.6**	**1,272.8**	**5,733.5**
Revenue Offsets	(48.2)	(49.2)	(50.2)	(51.2)	(52.2)	**(251.0)**
Base Revenue Requirement	**977.8**	**1,031.0**	**1,076.7**	**1,176.4**	**1,220.6**	**5,482.5**

/C

As described in Exhibit 1B, Tab 2, Schedule 1, section 3.2.1, Toronto Hydro's rate framework proposes a proactive 0.6 percent performance incentive factor that further reduces revenues by over $65 million over the rate term, providing customers an additional upfront rate reduction.

3. LOAD FORECAST SUMMARY

Table 7 below summarizes Toronto Hydro's customer and load growth changes from 2018 to 2029. Please see Exhibit 3, Tab 1 for more information about the utility's customer and load forecast.

Table 7: Customer and Load Growth Changes for 2018-2029

Year		**Total Normalized GWh**	**Total Normalized GWh (% Change)**	**Total Normalized MVA**	**Total Normalized MVA (% Change)**	**Total Customers**	**Customer Count Change (%)**
2018	Actual	24,691.6		39,813.3		770,333	
2019	Actual	24,421.7	-1.1%	39,115.3	-1.8%	777,369	0.9%
2020	Actual	23,664.4	-3.1%	36,801.2	-5.9%	781,374	0.5%
2021	Actual	23,564.8	-0.4%	36,624.9	-0.5%	786,258	0.6%
2022	Actual	23,981.0	1.8%	37,635.2	2.8%	790,699	0.6%
2023	Actual	23,908.0	-0.3%	37,425.9	-0.6%	793,465	0.3%
2024	Bridge	23,603.5	-1.3%	36,735.8	-1.8%	796,787	0.4%
2025	Forecast	23,412.8	-0.8%	36,167.8	-1.5%	800,430	0.5%

/C

Year		Total Normalized GWh	Total Normalized GWh (% Change)	Total Normalized MVA	Total Normalized MVA (% Change)	Total Customers	Customer Count Change (%)
2026	Forecast	23,433.6	0.1%	35,949.7	-0.6%	803,655	0.4%
2027	Forecast	23,431.4	0.0%	35,648.1	-0.8%	806,407	0.3%
2028	Forecast	23,525.0	0.4%	35,489.2	-0.4%	808,736	0.3%
2029	Forecast	23,393.8	-0.6%	34,964.1	-1.5%	811,363	0.3%

Notes:
1. Total Normalized GWh are purchased GWh (before losses) and are weather normalized to the Test Year heating and cooling degree day assumptions.
2. Total Normalized MVA are weather normalized MVA.
3. Total Distribution Revenue is weather normalized and includes an adjustment for the Transformer Allowance.
4. Total Customers are an annual average and exclude street lighting devices and unmetered load connections.

4. RATE BASE AND DISTRIBUTION SYSTEM PLAN

4.1 Distribution System Plan

Toronto Hydro forecasts $2,841.1 million in net capital expenditures over the current 2020-2024 period, which is approximately five percent higher than the $2,710.7 million 2020-2024 Distribution System Plan approved by the OEB fur the purposes of setting rates in the last application. In the 2025-2029 Distribution System Plan (the "DSP"), the utility forecasts net capital expenditures of $3,928.7 million, which is $1,087.5 million or 38 percent higher than the 2020-2024 Distribution System Plan that the utility expects to deliver. Table 8 below summarizes the capital expenditures by investment category for the 2025-2029 rate period. Investments in System Access and System Service to expand and modernize the utility's grid are the biggest drivers of the 2025-2029 DSP (on a percentage basis). For more information about the utility's capital expenditures over the current and the future rate period please refer to Exhibit 2B, Section E4.

Table 8: Capital Investment Expenditures by Categories ($ Millions)

Category	Total 2020-2024 Forecast	Total 2025-2029 Forecast	Var. ($)	Var. (%)
System Access	653.6	1,052.5	398.9	61%
System Renewal	1,456.6	1,970.3	513.7	35%
System Service	226.0	301.7	75.8	34%
General Plant	419.0	562.5	143.4	34%
Other	85.9	41.7	(44.2)	(51%)
Total	**2,841.1**	**3,928.7**	**1,087.5**	**38%**

4.2 Rate Base

Table 9 below summarizes Toronto Hydro's 2020 approved and 2020 actual rate base, and presents the utility's forecasted rate base for the current 2020-2024 period. Table 10 presents the rate base for the 2025 to 2029 period.

The requested rate base for the 2025 test year is $5,899.1 million, representing an increase of approximately $1,384.3 million, or 30.7 percent from the 2020 rate base of $4,514.8 million approved by the OEB in the utility's last rebasing application. /C

Rate base variances are primarily driven by changes in Property Plant & Equipment ("PP&E") and Net Book Value ("NBV") due to in-service additions derived from the utility's actual and forecasted capital investments per the DSP. These changes are discussed in Exhibit 2A, Tab 1, Schedule 1. Other major drivers of rate variances, namely depreciation and working capital allowance ("WCA"), are discussed in Exhibit 2A, Tab 2, Schedule 1, and Exhibit 2A, Tab 3, Schedule 1, respectively.

Table 9: 2020-2024 Rate Base Summary ($ Millions)

	OEB Approved	Actuals				Bridge
	2020	**2020**	**2021**	**2022**	**2023**	**2024**
Opening PP&E NBV	4,229.4	4,233.2	4,419.2	4,628.1	4,893.9	5,227.4
In-Service Additions	527.4	447.9	485.2	554.4	594.7	619.8
Depreciation	(265.4)	(262.0)	(276.2)	(288.7)	(261.2)	(277.8)
Closing PP&E NBV	4,491.3	4,419.2	4,628.1	4,893.9	5,227.4	5,569.4
Monthly Avg PP&E NBV	**4,298.6**	**4,284.3**	**4,457.7**	**4,686.3**	**4,960.0**	**5,327.0**
Working Capital Allowance	216.2	249.8	217.2	220.7	216.8	230.0
Rate Base	**4,514.8**	**4,534.1**	**4,674.9**	**4,907.0**	**5,176.8**	**5,557.0**

/C

Table 10: 2025-2029 Rate Base Summary ($ Millions)

	Forecast				
	2025	**2026**	**2027**	**2028**	**2029**
Opening PP&E NBV	5,569.4	5,931.4	6,325.7	6,796.1	7,219.9
In-Service Additions	653.8	699.9	795.1	770.1	860.1
Depreciation	(291.8)	(305.7)	(324.8)	(346.2)	(359.5)
Closing PP&E NBV	5,931.4	6,325.7	6,796.1	7,219.9	7,720.4
Monthly Avg PP&E NBV	**5,667.5**	**6,042.1**	**6,460.6**	**6,912.2**	**7,334.3**
Working Capital Allowance	231.6	237.2	242.6	249.8	255.7
Rate Base	**5,899.1**	**6,279.3**	**6,703.2**	**7,162.0**	**7,590.1**

5. OPERATIONS, MAINTENANCE AND ADMINISTRATION ("OM&A") EXPENSE

Toronto Hydro forecasted OM&A expenses for the future 2025-2029 rate period are $1,856 million, representing an increase of $395.6 million or 27 percent from the actual and forecasted OM&A expensed of $1,461 million in the current 2020-2024 rate period. /C

Table 11 below provides a summary of the overall drivers and cost trends for operating expenditures over the current and future rate period. For more information please refer to Exhibit 4, Tab 1 and the supporting evidence at Tabs 2 through 5 of this Exhibit.

Table 11: OM&A 2020-2029 Cost Drivers ($ Millions)

Programs	Actual				Bridge	Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance	266.7[3]	288.1	277.5	280.4	294.2	320.5	343.0	358.0	370.2	385.5
Distribution Operations	4.1	(1.4)	1.8	(0.2)	13.2	15.4	7.4	6.0	6.6	7.0
Customer Care	17.2	(16.4)	-	4.1	5.0	0.2	3.0	0.9	1.9	1.7
Human Resources, Environment and Safety	-	2.1	(0.9)	1.4	3.2	1.3	0.6	1.0	1.1	1.0
Information Technology	-	2.6	2.9	2.4	1.7	5.7	2.5	2.9	3.0	3.4
Common Corporate Costs	-	(0.1)	(0.7)	1.3	(1.2)	-	-	0.1	-	-
Facilities Management	-	1.7	(1.0)	1.4	1.5	-	0.5	0.5	0.7	0.7
Other Various	0.1	0.9	0.8	3.4	2.9	(0.1)	1.0	0.8	2.0	0.3
Closing Balance	**288.1**	**277.5**	**280.4**	**294.2**	**320.5**	**343.0**	**358.0**	**370.2**	**385.5**	**399.6**

/C

Note: Toronto Hydro confirms that no costs for dedicated conservation and demand management ("CDM") staff to support IESO programs funded under the 2021-2024 CDM Framework are included in the revenue requirement.

[3] In EB-2018-0165, the OEB approved a 2020 OM&A budget of $272.2 million and directed Toronto Hydro to amend the presentation of shared services within Other Revenue, under USoA Accounts 4375 and 4380 for revenues and expenses of non-rate regulated utility operations. Normalized for this change, the 2020 OEB-approved OM&A budget was $266.7 million.

Toronto Hydro proposes a 2025-2029 LEAP funding allocation of 0.15 percent of its service revenue requirement, resulting in a total LEAP amount of $8.6 million. Please refer to Exhibit /C 4, Tab 2, Schedule 19 for more information.

6. COST OF CAPITAL

Table 12 below outlines the proposed capital structure and cost of capital parameters in /C accordance with the OEB's cost of capital parameters. The 2025 return on equity forecast, which was derived in accordance with the OEB's Cost of Capital Report (EB-2009-0084) methodology, was applied to determine the 2025-2029 revenue requirement presented in Exhibit 6, Tab 1. Toronto Hydro intends to update the return on equity forecast during the Draft Rate Order ("DRO") process to align with the return on equity approved by the OEB in the final quarter of 2024. For more information please refer to Exhibit 5, Tab 1.

Table 12: Proposed Capital Structure and Cost of Capital Parameters /C

Capital Structure			Cost Rate
Debt			
Long-term Debt	56.00%	$3,304,672,000	3.95%
Short-term Debt	4.00%	$236,048,000	5.25%
Total Debt	60.0%	$3,540,720,000	4.04%
Equity			
Common Equity	40.00%	$2,360,480,000	9.36%
Preferred Shares	0.00%	$ -	
Total Equity	40.0%	$2,360,480,000	9.36%
Total / WACC		$5,901,200,000	6.17%

7. COST ALLOCATION AND RATE DESIGN

7.1 Cost Allocation

Toronto Hydro's revenue requirement, as detailed in Exhibit 6, is allocated to rate classes in order to calculate distribution rates for the 2025 rebasing year. This is performed using the OEB's latest cost allocation model, including the OEB's policy related to the Street Lighting class[4] and subject to the adjustments noted in the Cost Allocation evidence.[5]

Consistent with the methodology relied upon in the utility's last two custom rate application (EB-2014-0116 and EB-2018-0165), Toronto Hydro completed a cost allocation study for 2025 test year, and extended the results to allocate the 2026 to 2029 revenue requirement to rate classes.

Table 13 below shows the revenue to cost ratios calculated prior to and after the proposed test year rate design in comparison with the OEB's "target ranges" (all ratios exclude revenues and costs related to transformer ownership allowance). The proposed revenue to cost ratios for all Toronto Hydro rate classes are within the OEB's guideline ranges. For more information about cost allocation, please refer to Exhibit 7, Tab 1. /C

Table 13: Revenue/Cost Ratios (%) /C

Rate Class	2020 OEB Approved	2025		OEB's Guideline Ranges
		Model	Proposed	
Residential	100.0%	102.1%	100.0%	85-115
Competitive Sector Multi-Unit Residential	100.0%	111.7%	100.0%	n/a
General Service <50kW	93.7%	97.4%	99.2%	80-120

[4] Ontario Energy Board, Issuance of New Cost Allocation Policy for Street Lighting Rate Class (June 12, 2015), "online", https://www.oeb.ca/oeb/_Documents/EB-2012-0383/LTR_CostAllocation_Streetlighting_20150612.pdf
[5] Exhibit 7, Tab 1, Schedule 1.

Rate Class	2020 OEB Approved	2025		OEB's Guideline Ranges
		Model	Proposed	
General Service 50-999kW	105.6%	96.4%	98.9%	80-120
General Service 1000-4999kW	94.8%	94.4%	98.3%	80-120
Large Use	93.6%	97.2%	99.2%	85-115
Street Lighting	111.3%	119.4%	119.4%	80-120
Unmetered Scattered Load	120.0%	121.7%	120.0%	80-120

7.2 Rate Design

In this application, Toronto Hydro requests approval of new base distribution rates and new rate riders effective January 1, 2025. Toronto Hydro calculated the rebased distribution rates for 2025 using the OEB's standard revenue requirement methodology as set out in the Filing Requirements.[6]

For the 2026-2029 rate period, Toronto Hydro calculated distribution rates using a Custom Revenue Cap Index ("CRCI").[7] For each of these years, base revenue requirements will be brought forward for final approval in Toronto Hydro's annual rate update applications, inclusive of actual inflation factors applicable to those years. In each annual rate update application, Toronto Hydro will propose new distribution rates based on the escalated base revenue requirement resulting from application of the CRCI, in accordance with the OEB's Decision in this proceeding.

Toronto Hydro proposes that for the years 2026 to 2029, the final approved base revenue requirements be allocated to each rate class based on the same allocations to rate classes established in this proceeding for 2025. Toronto Hydro will hold constant the fixed/variable revenue split for each rate class determined in 2025 for the purpose of designing rates from

[6] OEB Filing Requirements for Electricity Distribution Rate Applications, Chapter 2 (December 15, 2022), section 2.8.
[7] See Exhibit 1B, Tab 2, Schedule 1 for more information on the CRCI.

2026 to 2029. Subsequently, the utility will calculate rates in each year relying on Toronto Hydro's five-year customer and load forecast as approved in this application.

Please see Exhibit 1B, Tab 4, Schedule 1 for more information about the proposed CRCI, and Exhibit 8, Tab 1 fore more information about rate design.

7.3 Specific Service Charges

For this application, Toronto Hydro proposes to leave its specific service charges unchanged, with the exception of the wireline pole attachment charge, which Toronto Hydro will update at the draft rate order stage and annually in accordance with the latest OEB rate orders. Please refer to Exhibit 8, Tab 2, Schedule 1 for more information about specific service charges.

8. DEFERRAL AND VARIANCE ACCOUNTS ("DVA")

The total net DVA balance proposed for clearance is $113.3 million (credit/refund) to customers beginning January 1, 2025. Tables 14 and 15 provide a summary of Group 1 and Group 2 DVA balances, respectively. With the exception of the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA"),[8] the amounts proposed for clearance include the balances as reflected in the audited financial statements for the fiscal year ended December 31, 2023. The amounts also include the forecasted principal activity and carrying costs calculated to December 2024. /C

[8] Toronto Hydro notes that the balances in the LRAMVA were not reported in RRR or AFS filings because, as the OEB Decision noted in EB-2022-0065, the utility did not have sufficient information at the time those filings to estimate the balances in the account.

1 **Table 14: Deferral and Variance Account Summary ($ Millions)**

Accounts		Principal Balance as of Dec 31, 2023	Carrying Charge Balance as of Dec 31, 2023	Balances as of Dec 31, 2023	Proposed for Disposition (Yes/No)	To Be Continued (Yes/No)
Group 1 Accounts						
Various	**Retail Settlement Variance Account ("RSVA")[9]**	**163.0**	**10.8**	**173.8**	**Yes**	**Yes**
1550	Low Voltage Variance Account	0.8	0.1	0.9	Yes	Yes
1580	Wholesale Market Service Charge	28.0	3.3	31.3	Yes	Yes
1580	WMS – Sub-account CBR Class A	-	-	-	Yes	Yes
1580	WMS – Sub-account CBR Class B	0.8	(0.2)	0.6	Yes	Yes
1584	Retail Transmission Network Charge	56.0	3.4	59.4	Yes	Yes
1586	Retail Transmission Connection Charge	38.0	1.7	39.7	Yes	Yes
1588	Power (excluding Global Adjustment)	35.3	1.8	37.0	Yes	Yes
1589	Global Adjustment	7.6	0.9	8.5	Yes	Yes
1551	Smart Meter Entity Charge	(3.6)	(0.1)	(3.7)	Yes	Yes
1595	**Disposition and Recovery/Refund of Regulatory Balances ("RARA")**	**(37.0)**	**(14.2)**	**(51.1)**	**No**	**Yes**
	Total Balance	**126.0**	**(3.4)**	**122.6**		

/C

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[9] Includes Account 1588 – Power ($RSVA_{Power}$) and Account 1589 Global Adjustment ($RSVA_{GA}$)

Accounts		Principal Balance as of Dec 31, 2023	Carrying Charge Balance as of Dec 31, 2023	Balances as of Dec 31, 2023	Forecasted Principal Balance as of Dec 31, 2024	Forecasted Carrying Charge Balance as of Dec 31 2024	Balances as of Dec 31, 2024	Proposed for Disposition (Yes/No)	To Be Continued (Yes/No)
Group 2 Accounts									
1508	Capital-Related Revenue Requirement (“CRRRVA”)[10]	-	-	-	-	-	-	No	No
1508	Customer Choice Initiative Costs	0.3	-	0.3	0.6	-	0.6	Yes	No
1508	Excess Expansion Deposits	(7.8)	(0.5)	(8.3)	(7.8)	(1.1)	(8.7)	Yes	Yes
1508	Externally Driven Capital Variance Account (“EDCVA”)	5.2	(0.1)	5.1	8.3	0.3	8.6	Yes	No[11]
1508	Gain on Sale of Properties[12]	(1.1)	(0.0)	(1.2)	(1.9)	(0.2)	(2.1)	Yes	Yes
1508	Impact for USGAAP Deferral Account	(9.7)	-	(9.7)	(9.7)	-	(9.7)	No	Yes
1522	Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges	-	-	-	-	-	-	No	Yes
1592	PILs and Tax Variances – CCA Changes[13]	(1.6)	(0.1)	(1.7)	(1.6)	(0.2)	(1.8)	Yes	Yes
1508	THESL Wireless Attachment Costs & Revenues	(2.4)	(0.2)	(2.6)	(3.3)	(0.3)	(3.6)	Yes	Yes[14]
1508	Wireline Pole Attachment Revenue Variance	2.7	0.1	2.8	4.0	0.3	4.3	Yes	No

/C

[10] Balance relates to 2015-2019 activity which was approved for clearance in 2020 CIR.
[11] Toronto Hydro proposes to track the types of variances that are currently captured in the EDCVA in the new the Demand Related Variance Account (“DRVA”). Please refer to section 9.2 for further details.
[12] As noted in 3-SEC-85(b), the amount was corrected from pre-filed evidence (November 17, 2023) and now includes proceeds from the sale of utility vehicles.
[13] Balance relates to 2015-2019 activity which was approved for clearance in 2020 CIR.
[14] Toronto Hydro requests this account to be converted from a deferral account to a variance account, which would track variances from the utility’s forecast of relevant revenues and costs that is incorporated in Other Revenue. This modified approach passes through the benefit of the associated revenues to ratepayers up front, rather than deferring disposition to the next rebasing. See 3-VECC-55 for a breakdown of forecasted wireless attachment revenues in 2025-2029

Accounts		Principal Balance as of Dec 31, 2023	Carrying Charge Balance as of Dec 31, 2023	Balances as of Dec 31, 2023	Forecasted Principal Balance as of Dec 31, 2024	Forecasted Carrying Charge Balance as of Dec 31 2024	Balances as of Dec 31, 2024	Proposed for Disposition (Yes/No)	To Be Continued (Yes/No)
1533	Renewable Generation Connection Funding Adder Deferral Account – Provincial Rate Protection Payment Variances	(4.7)	-	(4.7)	(7.3)	-	(7.3)	Yes	Yes
1508	Local Initiatives Program Costs	-	-	-	-	-	-	No	Yes
1568	Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA")	-	-	-	-	-	-	Yes	Yes
1508	Operating Centres Consolidation Program ("OCCP")[15]	1.8	0.2	2.0	1.8	0.3	2.1	Yes	Yes
1508	Gains on Sale of Properties related to the Operating Centres Consolidation Program ("OCCP")[16]	(23.8)	(0.9)	(24.7)	(23.8)	(2.2)	(26.0)	Yes	Yes
1508	Useful Life Changes	(61.3)	(1.4)	(62.7)	(129.2)	(6.4)	(135.6)	Yes	No
1508	Ultra-Low Overnight ("ULO") Implementation Costs	(0.6)	-	(0.6)	0.1	-	0.1	Yes	No
1508	Green Button Initiative Costs	-	-	-	(0.4)	-	(0.4)	Yes	No
1508	50/60 Eglinton Proceeds of Sale Deferral Account [16, 17]	(7.3)	(0.3)	(7.6)	(7.3)	(0.7)	(8.0)	Yes	Yes
1508	Carillion Insolvency Payments Receivable Account	0.3	-	0.3	0.3	-	0.3	No	Yes

/C

[15] This entry relates to a residual balance in relation to the Operating Centres Consolidation Program of $2.0 million (debit) in the updated Group 2 account continuity schedule and that is comprised of a $1.7 million overpayment to ratepayers and $0.3 million in related carrying charges. Please refer to interrogatory response 9-Staff-336 for more information supporting the amounts recorded in this account.

[16] The proposed claim amount per the continuity schedule has been grossed-up to include the tax savings proposed to be returned to ratepayers

[17] Toronto Hydro seeks approval to create of this deferral account to capture and dispose additional proceeds received from the sale of 50/60 Eglinton. Please refer to Exhibit 9, Tab 1, Schedule 1 at section 9.4 for more information.

Accounts		Principal Balance as of Dec 31, 2023	Carrying Charge Balance as of Dec 31, 2023	Balances as of Dec 31, 2023	Forecasted Principal Balance as of Dec 31, 2024	Forecasted Carrying Charge Balance as of Dec 31 2024	Balances as of Dec 31, 2024	Proposed for Disposition (Yes/No)	To Be Continued (Yes/No)
1508	Getting Ontario Connected Act Variance Account[18]	0.9	-	0.9	2.5	0.1	2.6	Yes	Yes
1511	Cloud Computing Incremental Implementation Costs[19]	0.5	-	0.5	4.0	0.1	4.1	Yes	No[20]
	Total Balance	**(108.8)**	**(3.0)**	**(111.8)**	**(170.8)**	**(9.7)**	**(180.5)**		

/C

[18] Please see interrogatory response 4-Staff-296(e) for supporting details for the amounts booked in this account.
[19] This account was added as part of the April 2, 2024 evidence update in accordance with OEB Letter re Accounting Order (003-2023) for the Establishment of a Deferral Account to Record Incremental Cloud Computing Arrangement Implementation Costs (November 2, 2023).
[20] For the reasons described in the response to interrogatory 2B-Staff-263(b), Toronto Hydro does not propose to continue this account.

Toronto Hydro proposes to allocate the DVA balances to the customer classes based on the methodologies described in the OEB's Deferral and Variance Account Review ("EDDVAR").[21] For accounts where the EDDVAR report indicated allocation was to be determined on a case-by-case basis, Toronto Hydro has proposed an allocator. The allocation between customer classes is set out in Table 15 below. /C

[21] EB-2008-0046, Ontario Energy Board Deferral and Variance Account Review Initiative.

Table 15: Proposed Allocators for Rate Classes /C

Allocators	Total (%)	Residential (%)	CSMUR (%)	GS < 50kW (%)	GS – 50-999 kW (%)	GS > 1,000 to 4,999 kW (%)	Large User =>5,000 kW (%)	Street Lighting (%)	USL (Connections) (%)	USL (Customer) (%)
Distribution Revenue (2022)	100.0	38.9	4.8	15.5	26.1	8.3	3.9	2.0	0.5	0.0
Revenue Offsets (2025)	100.0	35.9	4.4	15.0	17.4	4.8	1.8	20.5	0.3	0.0
LRAMVA	100.0	-0.9	-0.1	-23.9	60.4	15.6	48.9	0.0	0.0	0.0
Distribution Revenue GS>50 kW (2022)	100.0	0.0	0.0	0.0	64.0	20.3	9.6	5.0	1.1	0.0
# of RPP Customers (2022)	100.0	78.8	11.9	8.8	0.4	0.0	0.0	0.0	0.1	0.0

Toronto Hydro proposes various recovery periods for specified DVA accounts, beginning January 2025, in order to minimize the bill impacts to all affected customers set out in Table 16 below. /C

Table 16: Proposed Rate Rider Allocators and Recovery Periods /C

Rate Riders	Allocators	Proposed Recovery Period (Years)	Rate Rider Start Year	Rate Rider End Year
PILs and Tax Variance	Distribution Revenue (2022)	1.00	2025	2025
Wireline Pole Attachments Rev	Revenue Offsets (2025)	1.00	2027	2027
Gain on Property Sale	Distribution Revenue (2022)	1.00	2027	2027
Impact for USGAAP (Actuarial loss on OPEB)	Distribution Revenue (2022)	1.00	2025	2025
Customer Choice Initiative	# of RPP Customers (2022)	1.00	2027	2027
External Driven Capital	Distribution Revenue (2022)	1.00	2026	2026
Operations Center Consolidation Plan	Distribution Revenue (2022)	1.00	2025	2025
Excess Expansion Deposits	Distribution Revenue GS>50 kW (2022)	5.00	2025	2029
Change in Useful Life of Assets (2025-2026)	Distribution Revenue (2022)	2.00	2025	2026
Lost Revenue Adjustment Mechanism (LRAMVA)	LRAMVA	5.00	2025	2029
Innovation Fund	Distribution Revenue (2022)	1.00	2029	2029
Ultra-Low Overnight Rate Costs	# of RPP Customers (2022)	1.00	2025	2025
Green Button Initiative Costs	Distribution Revenue (2022)	4.00	2025	2028
Wireless pole attachments Rev	Revenue Offsets (2025)	3.00	2026	2028
50/60 Eglinton Proceeds of Sale Deferral Account	Distribution Revenue (2022)	4.00	2026	2029
Change in Useful Life of Assets (2026-2029)	Distribution Revenue (2022)	4.00	2026	2029
Change in Useful Life of Assets (2025-2027)	Distribution Revenue (2022)	5.00	2025	2029

Toronto Hydro seeks approval for the following four new Deferral and Variance Accounts: (1) the 50/60 Eglinton Proceeds of Sale Deferral Account, (2) the Performance Incentive

Mechanism Deferral Account, (3) Demand Related Variance Account, and (4) the Innovation Fund Variance Account.

Toronto Hydro requests discontinuation of the following accounts:

- Account 1508 - subaccount - Capital-Related Revenue Requirement ("CRRRVA")
- Account 1508 - subaccount - Customer Choice Initiative Costs
- Account 1508 - Subaccount - Externally Driven Capital Variance Account ("EDCVA")
- Account 1508 - subaccount - Wireline Pole Attachment Revenue Variance
- Account 1508 - subaccount - Useful Life Changes
- Account 1508 - subaccount - Ultra-Low Overnight Rate Costs
- Account 1508 - subaccount - Green Button Initiative Costs

For more information about Toronto Hydro's DVA accounts and amounts proposed for clearance, please refer to Exhibit 9, Tab 1.

RATE FRAMEWORK

This schedule outlines Toronto Hydro's 2025-2029 custom incentive rate-setting framework: an evolved rate framework (rooted in the Renewed Regulatory Framework (the "RRF"), the Rate Handbook (the "Handbook"), and performance-based regulation principles) that enables the utility to deliver customer outcomes in the context of an energy transition driven by imperatives to electrify key sectors of economy (2025-2029 Custom Rate Framework).

Toronto Hydro followed a principled approach in developing the 2025-2029 Custom Rate Framework. In this approach the utility was guided by the following principles:

- deliver customer outcomes and advance public policy objectives;
- maintain rate stability and funding predictability to enable effective multi-year utility and customer planning and decision making,
- provide flexibility to execute multi-year plans in increasingly dynamic circumstances;
- protect customers and the utility from structural forecasting risks in times of uncertainty; and
- balance the interests of customers, the utility and its shareholder.

Toronto Hydro's framework is informed by enhanced performance-based regulation ("PBR") approaches employed in other leading jurisdictions that are undergoing an energy transition. To that end, Toronto Hydro retained a third-party expert (Scott Madden) to review the 2025-2029 Custom Rate Framework against a set of elements that were derived from a jurisdictional scan. A copy of this evidence is attached as Appendices A and B to this schedule to assist the OEB in evaluating the proposed framework.

The current custom rate framework, which was established in the 2015-2019 Rate Application (EB-2014-0116), provided stability and flexibility as Toronto Hydro grappled with the significant challenge of renewing a rapidly deteriorating distribution system.

The 2025-2029 Custom Rate Framework detailed in this schedule is structurally consistent with the rate framework approved by the OEB in past applications, with purposeful evolutions to achieve the objectives summarized below.

1. Provide multi-year funding certainty and flexibility for Toronto Hydro to:
   (i) continue to sustain a reliable grid and safe and effective operations; and
   (ii) address current and emerging (externally-driven) needs and challenges that the utility faces in delivering its services and preparing the grid for the energy transition.
2. Establish an appropriate balance between customer benefit and risk to the utility and its shareholder to:
   (i) protect consumers with respect to price and service quality outcomes in the next rate period and beyond, as consumers increase their reliance on the Toronto Hydro's grid for day-to-day energy needs; and
   (ii) maintain the utility's financial integrity with sufficient funding to deliver capital and operations programs to achieve outcomes that customers need and value now, and in an electrified future.

The following elements, as further described in this schedule, make up the comprehensive 2025-2029 Custom Rate Framework:

- A cost of service rebasing in 2025, the first year of a five-year rate term.

- A Custom Revenue Cap Index ("CRCI"), applied in years two through five (i.e. 2026 to 2029), to set rates for each year based on: (i) the expected growth in revenue that is required to fund the utility's investment plan, taking into account (ii) inflation minus productivity ("I-X") escalators and (iii) expected annual growth in billing determinants in each rate class per the five-year load forecast.
- The CRCI includes a Revenue Growth Factor ("RGF") to fund Toronto Hydro's incremental capital and operational investment needs in the outer years of the rate period (i.e. 2026-2029) so that the utility can make necessary investments in the grid and its operations to deliver outcomes that customers need and value.
- Base Revenues are adjusted annually by inflation and incentive factors (I-X):
  - The inflation factor ("I") is aligned with standard OEB methodology /C
  - The incentive factor ("X") includes a 0.15 percent efficiency-factor supported by empirical total cost benchmarking evidence, and a pro-active 0.6 percent performance factor that balances risk and reward by providing:
    - customers a significant upfront rate reduction benefit of approximately $65 million over the 2025-2029 rate term; and
    - Toronto Hydro the opportunity to earn back this revenue in the next rate period through an innovative Performance Incentive Mechanism ("PIM") if the utility achieves set objectives.
- The PIM shifts cost and performance risk to the utility, ensuring greater accountability to customers for outcomes, while maintaining the utility's financial integrity by providing Toronto Hydro the opportunity (not the guarantee) to make its full rate of return by delivering performance outcomes in the areas of: (i) reliability and resilience, (ii) customer service and experience, (iii) environment, safety and governance, and (iv) efficiency and financial performance. These performance

outcomes are measured through twelve custom metrics with set targets on the utility's 2025-2029 Custom Scorecard.

- An Innovation Fund to further the OEB's objectives set out in the Framework for Energy Innovation ("FEI"), and enable Toronto Hydro to overcome practical challenges of pursuing innovation during the 2025-2029 rate period, including:
    - a prudence standard of review that requires a higher level of certainty in proving beneficial outcomes,
    - a rate term that generally requires investment plans to be developed far in advance, and
    - a revenue requirement approach that requires spending to be classified either as a capital or operating expense, with limited flexibility during the rate period to trade-off between these types of expenditures.
- A Demand-Related Variance Account ("DRVA") to protect ratepayers, the utility and its shareholder, from structural unknowns in forecasted costs and revenues related to demand growth in a time of unprecedented change and transformation in the economy and energy system.

For ease of reference, Table 1 below compares the key elements of the current 2020-2024 Custom Rate Framework and the proposed 2025-2029 Custom Rate Framework.

Table 1: Comparison of Current and Proposed Custom Rate Frameworks

	2020-2024 Custom Rate Framework	2025-2029 Custom Rate Framework
Year 1	Standard COS rebasing	Standard COS rebasing
Year 2	Custom Price Cap Index ("CPCI"): $I_n – X + C_n – S_{cap} * (I + X_{cap}) - g$	Custom Revenue Cap Index ("CRCI"): $I_n – X + RGF_n$
OM&A	One-year plan escalated by inflation less productivity (I-X)	Five-year plan funded through the Revenue Growth Factor ("RGF")
Capital	Five-year plan funded through a capital factor ("C-Factor")	Five-year plan funded through the Revenue Growth Factor ("RGF")
Inflation	OEB Inflation Factor	OEB Inflation Factor
X-Factor	0.6 percent reduction on non-capital related revenue requirement, and 0.9 percent reduction on capital related revenue requirement, resulting in a blended X-factor of 0.81-0.82 percent over the rate term	0.75 percent reduction on all revenue requirement with the opportunity to earn-back up to 0.6 percent of the X-factor through a Performance Incentive Mechanism ("PIM") by achieving results measured through custom metrics with set targets on the utility's 2025-2029 Custom Scorecard
Growth	Growth factor added to CPCI derived from five-year load and customer forecast	CRCI sets rates annually based on projected growth in billing determinants in each rate class
Deferral and Variance Accounts (DVAs)	Capital-Related Revenue Requirement Variance Account[1]	Demand-Related Variance Account
		Performance Incentive Mechanism Deferral Account
	Externally Driven Capital Variance Account[1]	Innovation Fund Variance Account
		Getting Ontario Connected Act Variance Account[2]
	Earning Sharing Mechanism	Earning Sharing Mechanism
	Property Sales	Property Sales[2]

/C

[1] Toronto Hydro proposes to discontinue these accounts. For more information about these accounts, please see Exhibit 9, Tab 1, Schedule 1 at sections 4.2 and section 5.3.

[2] For more information about these accounts, please see Exhibit 9, Tab 1, Schedule 1 at sections 4.4 and 4.16.

Toronto Hydro's proposal evolves the existing custom rate-setting approach in a manner that is consistent with the RRF and aligned with the OEB's guidance in the 2016 Rate Handbook. Specifically:

- The custom index is derived from five-year forecasts and includes financial incentives for continuous improvement, including efficiency targets.
- The proposed X-Factor is higher than the OEB-approved X-Factor under standard Price Cap Incentive Regulation.
- The framework is supported by empirical evidence of the utility's productivity, as well as internal and external benchmarking.
- Annual updates are limited to updating the inflation factor.
- The inflation factor adjusts Toronto Hydro's rates and revenues annually to reflect the prevailing economic conditions, ensuring the utility has necessary funding to execute its multi-year investment plans.
- The framework includes a comprehensive scorecard with performance metrics that are aligned with the outcomes identified in the Application.
- The framework includes an Earning Sharing Mechanism ("ESM") to protect customers in the event of utility overearning in excess of 100 basis points of its OEB-approved regulated rate of return.

The sections that follow provide context and further explanation for the evolutions that Toronto Hydro proposes in the 2025-2029 Custom Rate Framework to address the needs and challenges that the utility faces, while maintaining its financial integrity and protecting customers with respect to service quality, reliability, and price outcomes both in the near- and longer-term.

1. THE PLANNING IMPERATIVES

Over the 2025-2029 rate period, Toronto Hydro's operations and capital investment needs are growing by approximately 37.5 percent due to a number of distinct and interrelated drivers. In particular:

- Responding to the extraordinary inflationary pressures experienced over the 2020-2024 rate period, wherein the Non-Residential Construction Index in the Toronto Census Metropolitan Area rose 37.7 percent from Q1 2020 through Q2 2023.[3]
- Toronto Hydro's asset base continues to age and deteriorate requiring significant sustained investment to maintain system health during the next rate period and beyond – especially since the importance of a safe and reliable grid is only increasing as customers rely on electricity for more of their daily energy needs.[4]
- Asset maintenance requirements are increasing due to (i) evolving legal and regulatory requirements, (ii) a growing level of corrective maintenance issues that need to be rectified, and (iii) increased volumes of assets that the utility must inspect and maintain.[5]
- Investment is required to prepare Toronto Hydro's grid and operations for the energy transition to ensure customers will not be underserved or unserved when demand materializes, including investments to expand and modernize the distribution system and increase operational capacity and capabilities to:[6]
    - serve customers' growing and changing electricity needs,
    - execute higher volumes of capital and operational work,
    - meet rising customer expectations with respect to service levels,[7]

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[3] Exhibit 1B, Tab 3, Schedule 3.
[4] Exhibit 2B, Sections D2.2, E2.2, E2.4.2, E4.2.2, and E6.
[5] Exhibit 2B, Section D3.1.1.3; Exhibit 4, Tab 2, Schedules 3 and 4.
[6] For more information please refer to Exhibit 2B, Sections D4 and D5 and Exhibit 4, Tab 1, Schedule 1.
[7] For more information please refer to Exhibit 1B, Tab 5, Schedule 1.

  - plan and execute more complex work in a dense, mature and urban operating environment,[8] and
  - leverage technology and pursue innovation to modernize utility operations, increase operational efficiency, optimize the use of new and existing assets, and support the integration of distributed energy resources ("DERs").[9]
- Technological changes are shifting certain types of investments such as demand-side non-wires solutions and cloud-based software solutions from capital to operational program expenditures.
- Environmental, social and governance ("ESG") imperatives are driving key account customers to pursue zero plans that will require investment in grid expansion and modernization, as well as services to support these customers in their decarbonization-through-electrification journey.

In addition to addressing grid and operational needs and laying the foundation for the unfolding energy transition in a paced manner, Toronto Hydro's 2025-2029 investment plan aims to deliver key objectives with respect to four key areas of performance: (i) reliability and resilience, (ii) customer service and experience, (iii) environment, safety and governance, and (iv) efficiency and financial performance outcomes. These outcomes are measured through custom metrics with set targets on the utility's 2025-2029 Custom Scorecard which is filed at Exhibit 1B, Tab 3, Schedule 1.

The investment priorities and associated outcomes are aligned with customers' needs and preferences, as demonstrated by the results of Toronto Hydro's two-phased customer engagement process detailed in Exhibit 1B, Tab 5, Schedule 1 whereby:

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[8] For more information about these challenges please refer to Exhibit 1B, Tab 3, Schedule 3, section 1 at page 2.
[9] For more information about please refer to the Grid Modernization Strategy at Exhibit 2B, Section E5.

- over 33,000 customers reviewed Toronto Hydro's draft plan, and
- an average of 84 percent of the customers surveyed supported the rate increase associated with the draft plan, or one that does even more to advance outcomes.

Toronto Hydro is the steward of a mature, diverse and complex distribution system serving a dense urban territory powering Canada's largest, and North America's second fastest growing city. The last two custom rate applications, and Toronto Hydro's 2012-2014 Incremental Capital Module ("ICM") application, were marked by the need for significant multi-year capital funding in excess of what can be funded through base rates under the OEB's Price Cap Incentive Rate-Setting Mechanism ("IRM") approach.

Past rate applications predominately focused on addressing significant system renewal needs and keeping up with the City's growth and densification. These investments delivered reliability improvements and many other service quality benefits to customers, as detailed in Exhibit 1B, Tab 3, Schedule 2.

Despite these achievements, Toronto Hydro continues to face asset condition and demographic pressures across all parts its system, which necessitate continued proactive investments over the next rate period to maintain a safe and reliable grid for customers.[10] At the same time, an energy transition is gradually unfolding across key sectors of the economy with residents, businesses and institutions adopting electrified technologies such as electric vehicles ("EVs"), heat pumps, solar panels and energy storage systems. Toronto Hydro must sustain, expand and modernize the grid to be ready and equipped to serve customers' growing demand for safe and reliable electricity during this transition.

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[10] For more information please refer to Exhibit 2B, Section E2.2.2.1.

While the pace and nature of electrification required to decarbonize the economy remains unsettled, there is broad societal and public consensus that an energy transition is required to mitigate the existential and economic impacts of climate change. In order to continue to serve the needs of the customers in an electrified future, Toronto Hydro is oriented around taking responsible, least-regret and paced actions in the 2025-2029 rate period to prepare the local grid and its operations for a fundamental shift in how customers rely on electricity in the decades to come.

To gain insight into the challenge posed by the energy transition, Toronto Hydro commissioned an industry leading consumer-choice modelling Future Energy Scenarios study to assess the impacts of different energy transition scenarios on Toronto Hydro's distribution system.[11] The Future Energy Scenarios study reveals that over time, a significant increase in peak demand across all scenarios is expected to occur, including the least ambitious steady progression scenario that falls short of meeting Net Zero 2050 objectives. This outlook is consistent with other leading studies, such as the Independent Electricity System Operator's ("IESO") Pathways to Decarbonization ("P2D") report, which estimates that in a high-growth scenario, in less than 30 years, Ontario could need more than double its electricity generating capacity.[12,13]

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[11] Exhibit 2B, Section D4, Appendix A and Appendix B.

[12] Toronto Hydro's own Future Energy Scenarios forecast a doubling in Toronto's electricity demand by the year 2050 across multiple scenarios (for more information please refer to Exhibit 2B – Section D4, Appendix A). The IESO's Pathways to Decarbonization report forecasts that demand could more than double by 2050 (https://www.ieso.ca/en/Learn/The-Evolving-Grid/Pathways-to-Decarbonization)

[13] Enbridge's Pathways to Net Zero forecasts an increase in demand of over three times in its electrification scenario (https://www.enbridgegas.com/en/sustainability/pathway-to-net-zero). In the US, utilities such as National Grid (https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan-sept2023.pdf),Eversource(https://www.mass.gov/doc/gmacesmp-drafteversource/download?_gl=1%2Ako8zfs%2A_ga%2ANzUwNDI5MDE3LjE2NTA5ODEyMjQ.%2A_ga_SW2TVH2WBY%2AMTY5MzkyMDE2OS4zNi4xLjE2OTM5MjM1NzQuMC4wLjA.), and Unitil (https://unitil.com/ma-esmp/en) all published modernization plans forecasting demand increases of over 2 times by 2050. ISO New England also completed a study

The Future Energy Scenarios reveal that system peak demand could grow significantly, or more moderately, depending on technology, policy and consumer choices that will be made in the future. Toronto Hydro must both ensure that the grid is ready ahead of when demand increases (to avoid under-served or unserved customers), and also be reasonably cautious in building new capacity for the future. Building too much too soon could result in stranded assets and high rate impacts for customers, and building too late would result in the grid not being available to meet customer needs and expectations related to electrification.

To manage this uncertainty and the cost-consequences for customers, the utility must be: (i) measured-but-proactive in its investment plan (as both asset and human capital investments have long lead-times), (ii) deliberate in sustaining and modernizing its grid and operations to ensure that it is ready to serve and enable customer choice in a range of electrification scenarios, and (iii) oriented around a base of least-regret investment choices (i.e. investments that are required under most or all of the possible futures outlined in the *Future Energy Scenarios* study). Striking this important balance is at the heart of the 2025-2029 investment plan and the proposed Custom Rate Framework. In this regard, Toronto Hydro's Plan is aligned with the expanded priorities and expectations articulated by the Minister of Energy in the 2022 *Letter of Direction to the OEB*, and the recent *Powering Ontario's Growth* report.[14,15]

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which forecasts a doubling in system peak by 2050 (https://www.iso-ne.com/static-assets/documents/100004/a05_2023_10_19_pspc_2050_study_pac.pdf). National Grid ESO (Great Britain's system operator), also forecasts in an increase of about 2 times across many of it's future energy scenarios (https://www.nationalgrideso.com/document/283101/download). Electricity North West, *Distribution Future Electricity Scenarios* (December 2022) online: <https://www.enwl.co.uk/globalassets/get-connected/network-information/dfes/current/distribution-future-electricity-scenarios-2022.pdf>; National Grid ESO, *Future Energy Scenarios* (July 2023) online: <https://www.nationalgrideso.com/document/283101/download>.

[14] Ministry of Energy, *Letter of Direction from the Minister of Energy to the Chair of the OEB* (October 21, 2022) online: <https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20221021.pdf>.

[15] Ministry of Energy, *Powering Ontario's Growth: Ontario's Plan for a Clean Energy Future* (July 10, 2023) online: <https://www.ontario.ca/page/powering-ontarios-growth>.

2. THE FUNDING NEED

As illustrated in Figure 1 below, the continuation of a custom-rate setting approach is necessary for Toronto Hydro as funding derived from the OEB's standard Price Cap and IRM framework is insufficient to fund the plan's imperatives of system stewardship, growth and electrification, and modernization. Furthermore, Toronto Hydro's ability to deliver its investment plan and advance the public policy objectives and customer benefits is dependent on a rate-setting approach that builds on, and necessarily evolves the current approved custom-rate setting approach.

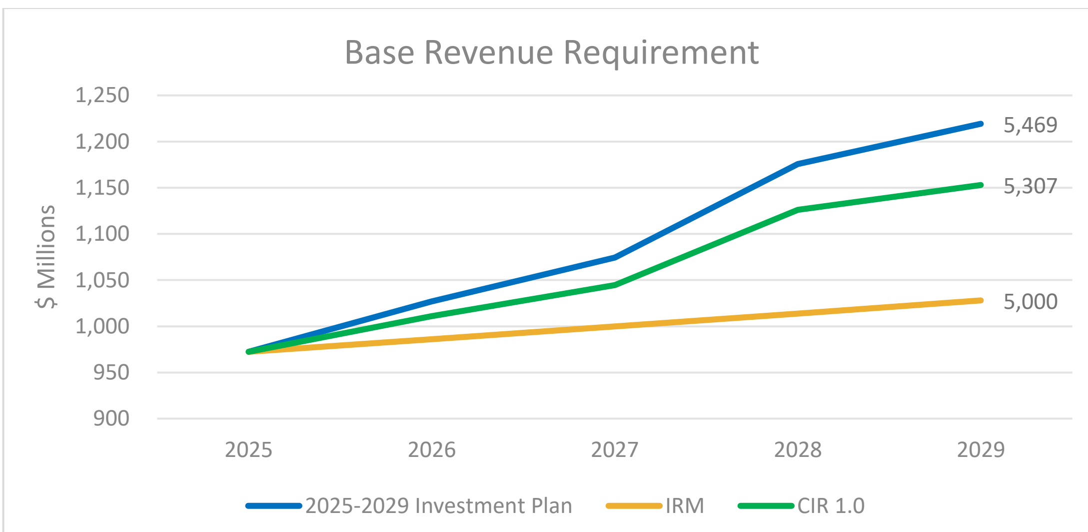

Figure 1: Cumulative 2025-2029 Base Revenue Requirement

Left unmitigated, the funding gaps depicted in Figure 1 above between IRM (the orange line), the existing custom rate-setting approach (the green line) and Toronto Hydro's 2025-2029 investment plan (the blue line) would result in hundreds of millions of dollars of underinvestment in Toronto Hydro's grid and operations. In these scenarios, system performance and customer outcomes would be adversely affected and energy transition objectives would be compromised or unmet. For the reasons detailed in the paragraphs that follow, Toronto Hydro submits that these scenarios do not serve the public interest or align with the OEB's statutory objectives.[16]

Under a standard IRM scenario, Toronto Hydro's 2025-2029 capital investment plan would be underfunded by approximately 35 percent or $1.5 billion. Adoption of a plan constrained by this funding envelope would force the utility into a sustainment plan that would be almost entirely reactive in nature, resulting in roughly an 8 percent deterioration in system reliability by the end of the rate period, along with increases in safety and environmental risks and reactive replacement costs due to increasing numbers of asset failures.[17] Such deterioration in system performance would: (i) put Toronto Hydro out of alignment with good utility practice, (ii) delay or prohibit the advancement of energy transition objectives that must be met over the 2025-2029 rate period in preparation for increasing peak demand and transition in the next decade, and (iii) harm ratepayers' interest with respect to long-term service quality and affordability outcomes.

While the gap between what standard IRM can fund and the revenue that the utility needs to execute its 2025-2029 investment plan is best addressed by a custom rate-setting approach, the needs of Toronto Hydro's 2025-2029 investment plan remain unmet under the current custom framework. Specifically, under the current framework, Toronto Hydro's 2025-2029 investment plan would be underfunded by approximately $450 million (i.e. approximately $360 million in capital expenditures and $90 million in OM&A expenses) due to a 0.9 percent stretch-factor on capital-related revenue requirement, and an approach to funding OM&A where operational budgets are rebased in the first year of the rate period

[16] Section 1(1) of the *Ontario Energy Board Act*, 1998, SO 1998, c. 15, Sched. B.
[17] For more information please review the SAIDI custom metric in Exhibit 1B, Tab 3, Schedule 1.

and then adjusted annually by a rate that is less than inflation. Table 2 presents the return on equity ("ROE") implications of the existing framework.

Table 2: ROE Implications of the Existing Custom Framework ($ Millions)

	2025	2026	2027	2028	2029
2025-2029 Investment Plan Revenue Requirement (A)	972	1,027	1,074	1,176	1,219
2025-2029 funding under the existing custom framework (B)	972	1,011	1,044	1,126	1,153
Variance (A) – (B)	-	16	30	50	66
ROE Impact (basis points) *	-	59.6	110.8	183.5	245.6

*Estimated where $27 million per year equals approximately 100 basis points.

Since 2012, Toronto Hydro has been operating under high stretch factors and has achieved significant productivity gains by harvesting operational efficiencies such as fleet and facilities consolidation, job harmonization and process automation that have delivered significant benefits to customers. While the utility remains committed to productivity and efficiency and intends to continue on a path of achievement in this area, Toronto Hydro has already targeted and adjusted the most significant areas for productivity improvements. The various benchmarking studies filed in this application show that Toronto Hydro is a good cost performer relative to its peers, and in many cases exceeds the performance of its peers when the appropriate operating conditions (e.g. dense urban environment) are taken into consideration.[18]

After more than a decade of living under a top-down constrained funding model serving a growing urban service territory that poses significant operational challenges and material cost drivers, Toronto Hydro cannot eliminate the funding gap identified above through

[18] For more information about productivity and benchmarking, please refer to Exhibit 1B, Tab 3, Schedule 3.

productivity efforts such as absolute cost reductions or reprioritizing capital and operational work. While deferral of work may have been a viable strategy in past periods, it is not in the current circumstances where the utility must tackle both persisting and new challenges and requirements, and prepare the grid and its operations for a major transformation in how customers use electricity.

A choice to defer work planned within the 2025-2029 Distribution System Plan found at Exhibit 2B does not serve the interests of ratepayers. For example, a deferral of work contained within the Grid Modernization Strategy at Exhibit 2B, Section D5 would mean that customers can expect a deterioration in reliability performance over the next rate period, higher customer interruption costs and much higher costs in the next decade as the system becomes more heavily utilized by customers. Similarly, investments to increase grid capacity to connect new or expanded loads in a timely and efficient manner, and enable customers to adopt DERs could be compromised – jeopardizing customer choice and impeding progress towards energy transition goals.

Similarly, deferring investment in OM&A to manage within the funding provided by the current framework, would lead to attrition of up to 200 employees by the end of the rate period, putting Toronto Hydro's staffing complement at precariously low level, and setting the utility back with respect to a multitude of outcomes and risks which are summarized in section 2.1 below and further detailed in Exhibit 4, Tab 1, Schedule 1.

The funding challenges depicted above are already being felt in the current rate period given the capital and operational needs that the utility is managing, and notwithstanding the productivity achieved through various initiatives detailed in Exhibit 1B, Tab 3, Schedule 3. For example, from 2020 to 2022, Toronto Hydro's achieved regulatory ROE averaged at 6.81

percent, which is 1.71 percent lower than its deemed ROE of 8.52 percent. The funding deficiency in the current rate period is due to multiple factors including the load-related impacts of COVID-19,[19] and the need to invest in prudent operational expenditures (above what base rates can fund under the current framework) in order to: (i) to implement the 2020-2024 workforce plan and (ii) address various incremental requirements summarized in the OM&A Overview schedule at Exhibit 4, Tab 1, Schedule 1 and detailed throughout the programmatic evidence in Exhibit 4, Tab 2.

Toronto Hydro proposes a number of evolutions to the existing custom-rate setting approach that are purposefully designed to address the funding challenges described above, re-balance utility and ratepayers' risk and reward, and critically – continue to pursue outcomes that matter to customers including achieving efficiency gains. To that end, the Performance Incentive Mechanism ("PIM") and the Custom Revenue Cap Index ("CRCI") outlined in section 3 are key elements of the proposed Custom Rate Framework.

2.1 Operational Funding Needs

The paradigm of a single rebased OM&A year subject to a growth rate that is less than inflation over the rate term (i.e. an I-X approach) is incompatible with Toronto Hydro's evolving operational needs, as the utility must expand and modernize the grid and its operations to facilitate the energy transition that customers and stakeholders expect. The key drivers behind the operational need in the current period are summarized in Exhibit 4, Tab 1, Schedule 1, and throughout the programmatic evidence at Exhibit 4, Tab 2.

[19] For more information please see Exhibit 3, Tab 1, Schedule 1 and Exhibit 1B, Tab 3, Schedule 3 at section 2.1.

After a decade of realizing sustained operational efficiencies to be able to manage its operations with a workforce complement that is essentially flat from 2015 to 2024, it is no longer possible nor prudent for Toronto Hydro to meet its obligations without hiring additional resources. From 2024 through to 2029, Toronto Hydro's workforce must grow by roughly 25 percent to support the execution of an expanded capital program as detailed in Exhibit 2B, while also addressing the policy, technology and customer imperatives of a changing energy landscape. Greater volumes of capital work require more skilled trades working in the field and operating the distribution system, as well as staff executing a broad range of support functions, such as corporate services professionals administering the utility's financial processes and accounting records, and legal and regulatory professionals negotiating contracts (e.g. offers to connect) and maintaining compliance with legal and regulatory requirements in the face of increasing volumes and complexity of work outlined in the plan. Furthermore, as traditional energy consumer models evolve to a paradigm where customers are using more electricity and actively participating in energy management through new technologies such as DERs, Toronto Hydro's customer-interfacing operations must also follow suit. Customer-related utility functions need to be expanded and enhanced to successfully address emerging customer needs and requirements such as: connecting EVs, heat pumps and DERs of varying size and scale; accessing energy data and analytics and new channels of digital customer communication and interaction.

It is not possible for the utility to meet these requirements, and in particular its workforce needs, with the operational funding levels provided by the current framework. As noted in the OM&A Overview evidence at Exhibit 4, Tab 1, Schedule 1, managing workforce-related costs downwards to live within a standard IRM funding paradigm would put Toronto Hydro's staffing complement at a precariously low pre-2015 level. Since the utility already has a demonstrably lean workforce compared to other distributors in the province (as evidenced by benchmarking) such a reduction would compromise the utility's performance with respect to a multitude of outcomes and risks, including safety, customer service and efficiency.

Under a constrained operational plan, the utility would also face a reduced absorption rate of the Certified and Skilled Trades such as Distribution System Technologists ("DSTs") that are critical to the execution of Toronto's capital and operations programs. DSTs operate, install, commission, construct, repair, maintain, and decommissions all types of protective relay and control systems, distribution automation equipment, and SCADA systems that are integral to implementing key components of the utility's Grid Modernization Strategy outlined in Exhibit 2B, Section D5. Other consequences of not having the operational funding that is necessary to attract and retain the level of resourcing outlined in Toronto Hydro's workforce plan, include:

- Less efficient and effective system and capacity planning compromising:
    - (i) the execution of the 2025-2029 Distribution System Plan ("DSP") and the development of future DSPs,
    - (ii) the optimization of investments to meet future load growth and connection capacity, including the identification of non-wires solutions opportunities,
    - (iii) the integrity of regional planning and coordination efforts, and
    - (iii) the implementation of grid modernization and innovation initiatives that can provide long-term value and significant future benefits to customers;
- Safety, reliability, and poor customer service outcomes if distribution system records and data updates cannot be maintained and synchronized with equipment or system configuration changes;

- Lack of skill sets necessary to support evolution of control centre operations, including to undertake the data modelling and system analysis required to enable the self-healing grid and other distribution automation functions;
- Insufficient cyber security capacity and expertise to manage the widespread threat of advanced cyber attacks against critical infrastructure;
- Insufficient staffing levels and skill sets to meet customers service expectations, including knowledge management expertise to ensure accurate and timely responses to increasingly complex customer inquiries, as well as, data analytics to deploy and fully optimize automated quality management powered by artificial intelligence and machine learning technologies;
- Reduced governance and oversight of financial planning activities that can limit the organization's ability to maintain financial integrity outcomes;
- Ineffective or unfavourable negotiation of contract terms, resulting in substandard performance by contracted parties or foregone recourse to appropriate remedies, reducing the value to ratepayers;
- Non-compliance or incorrect implementation of new requirements, policies or programs resulting in increased customer complaints, potentially compromising the advancement of public policy objectives;
- Increased frequency of inaccurate or delayed information resulting in customer confusion and dissatisfaction; and
- A reduced ability to successfully recruit and develop the skilled and specialized resources that Toronto Hydro requires to execute its current and future investment plans.

The operational consequences highlighted compromise Toronto Hydro's ability to execute the 2025-2029 investment plan, deliver the performance results detailed in Exhibit 1B, Tab

3, Schedule 1, and advance energy transition objectives that are important to its customers and stakeholders. For these reasons, Toronto Hydro 2025-2029 Custom Rate Framework includes a mechanism (the Revenue Growth Factor further described in section 3.1.3.1 below) to fund operational investments over the rate period that exceed what can be funded under a standard IRM approach.

3. 2025-2029 CUSTOM RATE FRAMEWORK

This section describes the elements of Toronto Hydro's proposed 2025-2029 Custom Rate Framework. The information is organized to first describe the components of the rate formula known as the Custom Revenue Cap Index (the "CRCI"), followed by the non-CRCI elements of the Custom Rate Framework.

3.1 Custom Revenue Cap Index ("CRCI")

3.1.1 Revenue Cap Approach

In the last two custom rate applications (EB-2014-0116 and EB-2018-0165) Toronto Hydro proposed, and the OEB approved, a rate-setting approach centered around a modified price-cap rate model. This approach established rates in the rebasing year (2015 and 2020, respectively) after which established rates were escalated annually by an index known as the Custom Price Cap Index ("CPCI"). On completion of the rebasing year, no further consideration was given to customer billing determinants (i.e. customer count, kWh and kVa) or changes in these determinants over the rate plan.

In EB-2014-0116, where the current custom framework was first proposed and adjudicated, a growth adjustment was added to Toronto Hydro's CPCI to ensure that capital costs were not over-collected. This took the form a 0.3 percent factor – termed the growth-factor or "g-factor" – derived from the top-line of the utility's five-year customer and load forecast. A g-factor of 0.2 percent was carried forward for inclusion in the utility's current rate framework based on 2020-2024 load and customer forecast.[20]

The g-factor translates billing determinant growth across customer count, kWh, and kVa in all rate classes into a simplistic top-line figure that is applied formulaically to base rates. In doing so, it lacks specific consideration of the details embedded in the five-year customer and load forecast. In particular, it does not recognize different patterns of growth amongst the rate classes and their billing determinants.

The g-factor was adopted in 2015 at a time where the growth in billing determinants was more stable and linear. However, in the current period and looking ahead to the end of the decade, growth in demand is becoming more dynamic due to a multitude of factors (e.g. a more volatile housing market and supply mix, shifting immigration policies, and electrification-related policies, technology and consumer preferences). A more nuanced mechanism is suitable to capture billing determinant growth within this changing and more dynamic environment to ensure that rates for each of the customer classes continue to be just and reasonable.

Toronto Hydro proposes a shift in its rate-setting approach from price-cap to a revenue-cap model. Rather than escalate rates themselves each year, and use a simplistic g-factor to account for expected billing determinant growth, Toronto Hydro proposes to escalate revenue requirement each year, and design rates for each revenue requirement on the basis of forecasted customer and load growth over the rate term. This approach captures expected billing determinant growth in a more precise manner, considering shifting

[20] EB-2014-0116, Decision and Order (December 29, 2015) at pages 28-29 and EB-2018-0165, Decision and Order (December 19, 2019) at pages 41-42.

customer make-up and changes to energy usage patterns as amongst kWh and kVa in a period of energy transition.

It is also worth noting that Toronto Hydro's proposal is a true revenue cap as the utility proposes a sub-account within its Demand-Related Variance Account ("DRVA") to record revenue differences as a result of variances in weather normalized billing determinants at the rate class level. The DRVA is further described in section 3.2.3 of this schedule.

3.1.2 Year 1: Standard Rebasing

The first year of the proposed rate application is a cost of service rebasing year, consistent with the OEB's standard IRM approach. The rebasing is derived from Toronto Hydro's 2025 forecasted revenue requirement based on its capital and operational plans for the year, as further detailed in its Distribution System Plan ("DSP") at Exhibit 2B and the OM&A evidence in Exhibit 4. The revenue requirement resulting from these projections is presented in Exhibit 6, Tab 1.

With the 2025 revenue requirement established, Toronto Hydro used the OEB's cost allocation model to allocate the revenue requirement to its rate classes, maintaining revenue-to-cost ratios for each class within the guidelines set out in the OEB's 2011 Review of Electricity Cost Allocation Policy.[21] For more information about Toronto Hydro's Cost Allocation and Rate Design, please refer to Exhibits 7 and 8, respectively.

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[21] EB-2010-0219, EB-2012-0383 and OEB letter issued June 12, 2015 Issuance of New Cost Allocation Policy for Street Lighting Rate Class.

3.1.3 Years 2-5: Custom Index

In year two through five of the rate period (i.e. 2026 to 2029), rates are set by the implementation of the Custom Revenue Cap Index ("CRCI"). The CRCI produces a percentage factor by which base revenue requirement must be escalated from one year to the next during the rate term in order to fund Toronto Hydro's investment plan.

The CRCI formula to be applied in years 2 through 5 (2026 to 2029) is: **CRCI = I_n – X + RGF_n**

Where,

- **I** = an Inflation-factor to be updated annually as per the OEB's standard methodology. /C
- **X** = an X-Factor of 0.75 percent which consists of (i) a 0 percent productivity-factor, plus (ii) a 0.15 percent efficiency-factor, supported by total cost benchmarking, plus (iii) a proactive 0.6 percent performance factor that enables the PIM.
- **RGF** = a Revenue Growth Factor which represents the amount by which base revenue requirement must increase each year to fund the utility's proposed investment plan, and is adjusted as outlined in Table 3 to remove a forecast of the inflation factor so that the base revenue requirement can be escalated by the actual inflation-factor through a mechanistic annual rate update process.
- **n =** the rate year in question.

The following sections describe the components of the CRCI.

1. <u>Revenue Growth Factor</u>

The OEB's decision in EB-2014-0116 marked the establishment of a new mechanism to account for multi-year capital needs in excess of what base rates can fund under standard IRM – this mechanism is known as the Capital or "C-factor". The C-factor is an attrition relief mechanism that implements additional rate escalations each year, beyond those provided for through base rates escalated at inflation less productivity, to account for the utility's growing capital-related revenue requirement as a result of implementing the multi-year capital investment plan known as the DSP. Over the last two custom rate applications, the C-factor provided a means to fund multi-year capital investment plans beyond what could be achieved under a standard IRM approach.

As noted in this schedule and detailed in Exhibit 4, Toronto Hydro's operational funding needs are growing due to a number of distinct and interrelated factors, including the need to hire and retain more resources to deliver a larger and more complex work program, which is necessary to sustain, expand, and modernize the grid, and deliver key outcomes that customers and stakeholders value. To address the emerging need for multi-year operational funding in excess of what can be achieved under standard IRM, Toronto Hydro proposes a Revenue Growth Factor ("RGF"). The RGF, similar to the existing C-factor, enables year-over-year rate increases to fund incremental revenue requirement related to both capital and OM&A investments. As further described below, the RGF escalates revenue requirement annually by a factor that accounts for the difference between one year's revenue requirement and the next.

In Exhibit 6, Toronto Hydro submitted the revenue requirement resulting from its capital and OM&A programs and other revenue forecasts over the 2025 to 2029 rate period. To calculate the RGF, the difference between each subsequent year's revenue requirement is determined as a percentage by which revenue requirement must escalate to fund the investment plan for the upcoming year.

The forecasted capital and OM&A expenditures presented in Exhibits 2B and 4, and the resulting revenue requirement presented in Exhibit 6, include inflationary assumptions with respect to the underlying cost inputs (i.e. labour, materials, and other costs). To allow updates of the annual inflation factor in rates without double-counting the impact of inflation, Toronto Hydro adjusted the RGF by removing a 2 percent forecasted annual inflation factor for the 2026 to 2029 period, thereby presenting the RGF as an increase in revenue requirement on an inflation-adjusted basis for rate-setting purposes.

Table 3 below outlines the proposed RGF values for years two through five (2026-2029) before and after the inflation adjustment.

Table 3: 2026-2029 Revenue Growth Factor ($ Millions)

	2025	2026	2027	2028	2029
Base Revenue Requirement (BRR)	972	1,027	1,074	1,176	1,219
Difference	-	55	47	101	44
RGF before Inflation Adjustment	**-**	**5.61%**	**4.62%**	**9.43%**	**3.71%**
Forecast Inflation Factor (%)	-	(2.00%)	(2.00%)	(2.00%)	(2.00%)
RGF after Inflation Adjustment	**-**	**3.61%**	**2.62%**	**7.43%**	**1.71%**

The RGF value for each year, as determined and approved by the OEB in this application, is applied to the prior year base revenue requirement to set rates from 2026 to 2029 through the implementation of the CRCI in annual rate applications. Aside from achieving the objective of providing funding certainty and stability in rates which is necessary to enable effective multi-year planning and operations, the RGF offers the added benefit of simplicity relative to the current C-factor since the entire revenue requirement is being escalated by the same inflation and productivity factors as further detailed below.

2. *Inflation Factor*

An annual inflation adjustment based on objective economic factors is an important element of establishing just and reasonable rates under standard OEB policy.[22] This element is even more important in light of the current volatility in national and global inflation, which may or may not subside over the 2025 to 2029 rate period.

Toronto Hydro's proposed approach to account for inflation in annual rate setting is consistent with standard OEB policy. The utility proposes to use the OEB's I-factor in its CRCI. As the value for the I-factor is updated annually per the OEB's standard methodology, Toronto Hydro will incorporate the updated value in its CRCI appropriately adjust base distribution rates for the following year. /C

3. *X-Factor*

Toronto Hydro proposes an X-Factor of 0.75 percent which consists of:

- 0 percent productivity-factor consistent with OEB policy, plus
- 0.15 percent efficiency-factor supported by empirical evidence, plus
- 0.6 percent proactive performance incentive mechanism factor.

The study prepared by Clearspring Energy Advisors at Exhibit 1B, Tab 3, Schedule 3, Appendix A supports an efficiency-factor of 0.15 percent based on empirical total cost benchmarking against relevant peers accounting for known and accepted operational differences between utilities which require adjustment.[23] By the end of the rate period (i.e. in 2029) the 0.15

[22] EB-2010-0379, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (updated December 4, 2013).

[23] In the 2020-2024 Rate Application (EB-2018-0165), OEB Staff's expert Pacific Energy Group (PEG) accepted the appropriateness of a variable that accounts for urban congestion. The OEB Panel presiding over that case echoed the comment in the Decision and Order (December 19, 2019) at page 29. Similarly, in Hydro One's 2023 Joint Rate

percent efficiency-factor yields an approximate annual revenue reduction of $6.9 million relative to Toronto Hydro's forecasted revenue requirement set out in Exhibit 6.

This revenue reduction represents the annual value of the efficiency benefits that customers would reasonably expect to receive through the utility's productivity efforts over the rate term. As is customary within IRM, Toronto Hydro takes the risk of this efficiency gain upfront giving customers the benefit of the rate reduction during the rate period – a benefit that amounts to approximately $16.4 million over the entire rate period by adding up the values in the last row of Table 5 below.

Table 5: Efficiency Factor (0.15%) Revenue Reduction ($ Millions)

	2025	2026	2027	2028	2029
Revenue Requirement based on the 2025-2029 Investment Plan	972.4	1,027.0	1,074.4	1,175.7	1,219.2
Revenue Collected after 0.15% Efficiency Factor	972.4	1,025.5	1,071.3	1,170.9	1,212.2
Revenue Reduced by 0.15% Efficiency Factor	-	1.5	3.1	5.0	6.9

Note: There could be minor differences due to rounding.

Furthermore, as part of the 2025-2029 Custom Scorecard outlined in Exhibit 1B, Tab 3, Schedule 1, the utility set a goal through the Efficiency Achievements metric to sustain these benefits for customers into the next rate period by achieving quantified efficiency gains of at least $6.9 million per year by 2029. These gains can be achieved through cost avoidances, reductions or other efficiency gains that result in a lower revenue requirement at the next rebasing, than would otherwise be put forward if the efficiency gains were not achieved.

Application (EB-2021-0110), PEG through an OEB-ordered conferral process with Clearspring Energy Advisors accepted the inclusion of a substation variable within the custom total cost benchmarking study.

In addition to the efficiency-factor, Toronto Hydro's rate framework proposes a proactive 0.6 percent performance incentive factor that further reduces revenues by approximately $65 million over the rate term, providing customers an additional upfront rate reduction. This proposal (i) demonstrates Toronto Hydro's commitment to be held financially accountable to customers for key outcomes of the proposed investment plan, and (ii) gives effect to an innovative Performance Incentive Mechanism ("PIM") that provides the utility the opportunity to earn-back the foregone revenue, if it delivers the target performance results on the Custom Scorecard. The PIM proposal is further detailed in the section 3.2.1 below.

3.2 Key Custom Elements (Non-CRCI)

The following sections discuss three key elements of the 2025-2029 Custom Rate Framework that enable an evolved approach to custom incentive rate-setting: (1) the Performance Incentive Mechanism ("PIM"); (2) the Innovation Fund; and (3) the Demand Related Variance Account ("DRVA"). Together with the CRCI rate formula described above in section 3.1, and the existing Earning Sharing Mechanism ("ESM"), Off-Ramp and Z-Factor mechanisms summarized below in section 3.3, these elements form a balanced custom rate framework that is integral to the utility being able to function effectively within the operating context that it faces – a transition that is expanding the role of electricity within the energy system, and customers, communities and stakeholders who expect the utility to enable this future-state in a paced and deliberate manner.

3.2.1 Performance Incentive Mechanism (PIM)

As noted above, the PIM is a key enhancement and regulatory innovation within Toronto Hydro's 2025-2029 Custom Rate Framework. This section describes the mechanics of the PIM in further detail.

The custom total cost benchmarking study performed by Clearspring Energy Advisors supports an efficiency-factor of 0.15 percent. This reflects Toronto Hydro's productivity achievement and ordinarily should be used for purposes of setting rates. However, instead of the empirically-derived efficiency-factor of 0.15 percent, Toronto Hydro proposes the adoption of a higher factor of 0.75 percent that is composed of the 0.15 percent efficiency-factor and a proactive performance incentive of 0.6 percent. The former drives continuous improvement in efficiency consistent with benchmarking expectations, and the latter functions as an incentive mechanism to achieve outcomes and deliver customer benefits associated with the 2025-2029 investment plan.

Any combination between the empirical efficiency-factor and the performance incentive that make-up the total X-factor should be capped at 0.75 percent in order to maintain balance between the utility risk and customer reward derived from the PIM. The balance is assessed by the cost of the incentive to be paid by customers over the 2030-2034 rate period relative to the value of the direct benefits to ratepayers over that period derived from meeting the targets proposed in the 2025-2029 Custom Scorecard. This analysis is presented in Exhibit 1B, Tab 3, Schedule 1 at section 3.

Toronto Hydro carries the risk of achieving the performance outcomes since, if the targets are not achieved, Toronto Hydro cannot earn its approved return on equity ("ROE"). As such, the PIM is an asymmetrical incentive to the benefit of customers in that it provides Toronto Hydro with the opportunity (not the guarantee) to earn the approved ROE and make a fair return for its shareholder. It is aligned with the RRF, and responsive to the OEB's feedback in Toronto Hydro's 2020-2024 decision encouraging the utility to consider an alternative approach in the future that meets RRF requirements and improves the balance of risk between customers and the utility.[24]

The PIM balances efficiency and other important performance outcomes within an incentive mechanism that places greater accountability on the utility for delivering value for money and benefits to ratepayers. In the event that some (or all) of the outcomes are not achieved, the PIM is not met, which means that ratepayers keep some (or all) of the incentive that was credited to them during the 2025-2029 rate period. This approach protects ratepayers and shifts risk onto the utility to manage the funding challenge described in this schedule while balancing grid performance and service quality outcomes that are important to customers and stakeholders now and in the future.

The PIM is linked with the 2025-2029 Custom Scorecard detailed in Exhibit 1B, Tab 3, Schedule 1. The scorecard includes weighted metrics and proposed targets which capture key objectives and outcomes of Toronto Hydro's plan, including but not limited to efficiency. As it is tied to a comprehensive five-year plan, the Custom Scorecard is established on a five-year basis, covering the entire 2025-2029 rate period. Though Toronto Hydro has proposed a continuation of annual reporting against the scorecard, the targets on the scorecard are set on a five-year basis, and do not include annual targets as Toronto Hydro's application is based on an integrated five-year investment plan and not five annual plans. This is important since Toronto Hydro requires the flexibility to execute its multi-year plan and adapt to externally-driven changes and more complex operating dynamics that it may face in that regard.[25]

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[24] EB-2018-0165, Decision and Order (December 19, 2019) at page 24.
[25] For a summary of the operational and work execution challenges that the utility faces operating in a dense urban environment please refer to Exhibit 1B, Tab 3, Schedule 3 at pages 3 to 9.

The targets proposed in Exhibit 1B, Tab 3, Schedule 1 are carefully calibrated to Toronto Hydro's proposed plan, as outlined in this application. To the degree final approval of Toronto Hydro's 2025 to 2029 investment plan and rate-setting approach varies materially from what the utility proposed in pre-filed evidence, the performance results identified in the targets must be reviewed and recalibrated to align with the implications of the OEB's decision. Further, given the careful establishment of proposed targets, their relationship with top-line capital and OM&A funding in rates is dynamic and multi-dimensional, which means that a simple pro-ration of proposed targets would not yield appropriate outcomes. For these reason, Toronto Hydro proposes to defer the finalization of the targets to a second phase of this proceeding that can be run in parallel with the Draft Rate Order process. Putting in place a dedicated process to consider updated targets, armed with full knowledge of approved funding and other OEB Decision parameters, enables Toronto Hydro, intervenors and the OEB to finalize PIM targets which appropriately balance incentives, risk, achievability, and difficulty.

To implement the PIM, Toronto Hydro proposes a new deferral account – the Performance Incentive Mechanism Deferral Account (PIM-DA) – to record the PIM earnings. This account would be brought forward for review and disposition in the utility's next rebasing application, based on known (or forecasted) performance results for the 2025-2029 rate period. Only if the set performance targets are achieved (or forecasted be achieved with a high degree of confidence) by the end of the rate term would the incentive be recovered from customers in the next decade. As such, Toronto Hydro confirms that that there would be no rate recovery associated with the PIM in the 2025-2029 period.[26]

[26] Please refer to Exhibit 9, Tab 1, Schedule 1, Appendix C for a Draft Accounting order for the PIM-DA.

The earnings under the PIM, if targets are fully achieved, allow Toronto Hydro to earn its foregone revenue associated with the proactive 0.6 percent reduction provided to customers upfront through the X-factor. Earning this amount back is only sufficient to enable the utility to achieve its approved ROE. In other words, the PIM is an asymmetrical mechanism to the benefit of customers, as meeting the performance targets set out in 2025-2029 Custom Scorecard does not give rise to the possibility of utility overearnings.

3.2.2 Innovation Fund

In alignment with the OEB's statutory objective to facilitate innovation in the electricity sector, Toronto Hydro proposes to establish an Innovation Fund to support the design and execution of innovative pilot projects over the 2025-2029 rate period.[27] The pilot projects undertaken through the Innovation Fund would be focused on testing new technologies, advanced capabilities and alternative strategies that enable electrification grid readiness and are responsive to the OEB's expectations with respect to facilitating DER integration, as expressed in the Framework for Energy Innovation (FEI*)* report.[28]

The proposed Innovation Fund is an important part of Toronto Hydro's 2025-2029 Custom Rate Framework because it addresses needs that are not adequately met by existing funding mechanisms which favour investment where the beneficial outcomes are proven or certain. The Innovation Fund supports important utility work that is more early stage, exploratory and developmental in nature, and as such where the outcomes are less certain, but the potential benefits for the system and customers could be significant. While the benefits of individual projects may not be immediate or certain, and some initiatives may prove to be

[27] Please refer to Exhibit 1B, Tab 4, Schedule 2 for more information about the Innovation Fund proposal.
[28] Ontario Energy Board, Framework for Energy Innovation: Setting a Path Forward for DER Integration (January 2023) https://www.oeb.ca/sites/default/files/FEI-Report-20230130.pdf

more or less fruitful than others, this type of work is nevertheless critical to achieving real innovation during a time of unprecedented change and transformation in the energy sector.

The Innovation Fund would also assist Toronto Hydro in overcoming the challenges of pursuing innovation in the context of a rate cycle that generally requires investment planning to be carried out far in advance and that requires spending to be classified either as a capital or operating expense. It provides Toronto Hydro with operational flexibility to identify and pursue the research, development and piloting of new technologies, capabilities and strategies throughout the rate period, and to determine the types of expenditures (i.e. capital or operating) in real time based on project specific details. For these reasons, the Innovation Fund would enable the utility to be more responsive to emerging needs and technologies as they arise during the rate period, and to scope, design and implement pilot projects and other exploratory initiatives more effectively.

Toronto Hydro carefully considered the amount of funding requested for this proposal. Based on research, the utility decided to allocate 0.3 percent of the proposed revenue requirement to the Innovation Fund, which amounts to approximately $16 million over the 2025-2029 rate period. This is the low end of a range found in research of comparable ratepayer-funded initiatives aimed at facilitating innovation by utilities and regulatory bodies in other jurisdictions, as well as general data on utility spending for research and development activities.

Toronto Hydro proposes to collect the amount allocated to the Innovation Fund through a rate rider (rather than through base rates) in order to provide transparency to ratepayers on the bill and flexibility to the utility to determine how the funds should be allocated across capital and operational expenditures on the basis of the selected pilot projects. Toronto

Hydro proposes to establish a new variance account to record variances between the amounts collected by the rate rider and the actual costs incurred to execute the selected pilot projects as part of the Innovation Fund.

For more information about the Innovation Fund proposal, please refer to Exhibit 1B, Tab 4, Schedule 2, which (i) outlines the Governance Framework to administer the proposed Innovation Fund, (ii) discusses the areas of innovation targeted by the fund, and (iii) describes various pilot project concepts that are being considered as part of this proposal.

3.2.3 Demand Related Variance Account (DRVA)

This application is being filed during a time of unprecedented change and transformation, as customers, communities and governments at all levels are actively embarking on an energy transition to mitigate the existential and economic impacts of climate change. Decarbonization is expected to create new roles for electricity, including as an energy source for transportation and building heating systems. While there is certainty that fundamental change is ahead, there are degrees of uncertainty about how that change will unfold (e.g. the pace and adoption of electrified technologies such as EVs and heat pumps; the role of low-emission gas; and the scale of local vs. bulk electricity supply). To address this uncertainty within its 2025-2029 Custom Rate Framework, Toronto Hydro proposes a symmetrical variance account that protects both ratepayers and the utility from structural unknowns in forecasted costs and revenues, during this time of change and evolution with respect to the role of electricity in the energy system.

Subject to OEB approval, Account 1508 – Demand-Related Variance Account (DRVA) would record: (i) the demand-driven revenue requirement impacts arising from variances in actual versus forecast capital and operational expenditures for certain demand-based programs (the Expenditure Variance Sub-Account); and (ii) the revenue impacts arising from variances in forecast versus actual billing determinants over the rate period (the Revenue Variances Sub-Account). To that end, the account will consist of two subaccounts:

1. The Expenditure Variances subaccount would record the symmetrical revenue requirement impacts, including PILs, arising from the variance between 2025-2029 planned and actual expenditures related to the following capital and operations programs: Customer Connections, Customer Operations, Stations Expansion, Load Demand, Non-Wires Solutions, Generation Protection Monitoring and Control and Externally-Initiated Plant Relocations and Expansions (collectively the "Demand-Related Investments").
2. The Revenue Variance subaccount would record the revenue impacts resulting from weather-normalized variances in billing determinants (i.e. customer count, kWh and kVA).

The DRVA satisfies the OEB's eligibility criteria of causation, prudence and materiality.

- **Causation**: The amounts to be captured in the DRVA are outside of the base upon which the rates proposed in the current application are derived, as they relate to variances driven by external factors (e.g. customer demand, public policy and technology changes) that are clearly outside of the utility's control.
- **Prudence**: With respect to prudence, the incremental costs that would be captured in the DRVA are presumptively prudent in that they are necessary to ensure that Toronto Hydro is able meet its obligation to serve customers and provide non-discriminatory access to the grid.
- **Materiality**: While Toronto Hydro makes significant efforts to forecast cost and revenues, as discussed below and throughout the evidence, the pacing and level of

demand can deviate from the levels forecasted.[29] Given the breadth, scale and potential variability of the demand drivers considered in the plan, Toronto Hydro believes that the amounts recorded in the proposed account could be material and over time, exceed the utility's $1 million materiality threshold.

1. <u>DRVA: Expenditure Variance Subaccount</u>

The need for the Expenditure Variance Subaccount arises from Toronto Hydro's statutory obligation to serve and provide non-discriminatory access to the grid, together with the compounding effect of potential variability in Demand-Related Investments due a multitude of factors outside the utility's control that can affect the pace and type of demand growth over the period. These factors include:

- public policy changes mandating or encouraging customers to decarbonize-through-electrification,
- customer adoption rates of electrified technologies such as EVs, heat pumps, solar panels and energy storage systems, and
- technology market advancements providing customers and/or the utility access to new or more cost-effective demand-management tools.

Demand-Related Investments are tied to factors that are external to Toronto Hydro causing the need, pacing and prioritization of these investments to be externally-driven by third-parties or other factors outside of Toronto Hydro's control. For example, policy objectives related to decarbonization-through-electrification could accelerate customer adoption of EVs or other fuel switching technologies. Similarly, government policies or procurement programs could create an expanded role for Distributed Energy Resources ("DERs") in the deployment of coordinated infrastructure solutions to facilitate electrification, or other

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[29] See Capacity Planning evidence in Exhibit 2B, Section D4 and the Load Forecast evidence in Exhibit 3, Tab 1.

policy objectives. As a result of such external factors, the pacing and level of certain expenditures can unexpectedly change and materially deviate from forecasted investment levels ultimately approved for recovery in base rates. The utility risk is that, over the rate period, these investment needs could be materially higher than the forecast embedded in rates. The pace and magnitude of potential change due to the combination of organic growth volatility observed in the current rate term, and the acceleration of an unprecedented energy transition renders this risk outside of tolerance from a forecasting perspective. [30]

Toronto Hydro faced a similar, albeit less pervasive risk, a decade ago related to externally-driven plant relocations to enable major infrastructure projects including the development of new and expanded transit lines across the Greater Toronto Area. To manage this risk in the context of a multi-year plan, in the 2015-2029 rate application Toronto Hydro requested (and the OEB approved) the Externally-Driven Capital variance account recognizing that "[*a*]*s these projects are completely outside Toronto Hydro's control as to both need and timing, they are appropriate for a variance account*."[31] This account continued in the 2020-2024 rate period. For the 2025-2029 period, Toronto Hydro proposes to consolidate this account into the DRVA in order to improve regulatory efficiency by reduce the number of Group 2 accounts that the utility needs to manage.

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[30] For example, in the current rate period capital in-service additions related to System Access investments where approximately $153 million (32.5 percent) greater than the amounts included in base rates in the 2020-2024 rate period primarily due to increased expenditures in demand-driven programs such as Customer Connections (Exhibit 2B, Section E5.1) and Load Demand (Exhibit 2B, Section E5.3). Toronto Hydro had to make additional investments in these programs in order to fulfil its core obligation to connect new and expanded services to the grid, including a higher than anticipated volume of system access requests for large projects (greater than 5 MVA demand) over this period.
[31] EB-2014-0116, OEB Decision and Order (December 29, 2016) at page 50.

In the current rate period, Toronto Hydro saw a significant increase in the volume and complexity of load connections. From 2020 to 2022, high voltage connections (which often require expansion work) increased by 27.6 percent, with a substantial increase in larger commercial and multi-use projects requiring greater than 10 MVA of demand load per project, as well data centers with larger loads (e.g. 30-50 MVA) than ever before. These circumstances resulted in gross expenditures in the 2020-2024 Customer Connections program that are expected to be approximately 1.75 times greater than initially planned in order to meet these requirements and preserve other key outcomes of the 2020-2024 plan (e.g. maintain reliability, remove transformers at risk of containing PCBs from the grid by 2025).

The trend in Customer Connections is expected to continue in the 2025-2029 rate period. Projects in the City of Toronto's development pipeline from 2017 through 2022 established a new five-year record with over 717,327 residential units and 14,484,961 square meters of non-residential gross floor area planned for completion in the next rate period, or shortly thereafter. This pace could increase further as a result of *Ontario's More Homes Built Faster Act, 2022* which is intended to expedite development approvals and encourage development with tax incentives and funding mechanisms.[32] This likewise impacts the Customer Operations program which includes activities such as field work and support functions to safely, efficiently, and promptly meet customer connections related requests.

In addition to the foregoing, the City is experiencing a shift to clean energy and electrification through the adoption of technologies such as EV charging, electric heat pumps and water heaters. Immediate growth areas being supported by Toronto Hydro's distribution system

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[32] *More Homes Built Faster Act*, 2022, S.O. 2022, c. 21 - Bill 23; Ontario, Backgrounder More Homes Built Faster Act, 2022 (November 28, 2022) https://news.ontario.ca/en/backgrounder/1002525/more-homes-built-faster-act-2022.

include EV charging for public streets, City fleet vehicles (including TTC), Toronto Parking Authority parking lots, residential homes, commercial and residential developments. Ongoing and other evolving areas include heating and cooling systems (i.e. heat pumps) and complete home electrification at single-family residential home and residential complex levels.

On August 24, 2023, for example, the OEB issued a Staff Bulletin on Residential Customer Connections and Service Upgrades to provide guidance as a result of OEB staff receiving questions and complaints regarding residential customer connection practices pertaining to cost responsibility.[33] Within this bulletin, OEB staff noted that with the shift to electrification currently underway in Ontario, an increasing number of prospective homeowners will likely seek residences that can readily support electrical service that can accommodate the demands of equipment such as EV chargers and heat pumps. Observing this change in consumer preferences and attitudes, OEB staff highlighted the need for distributors to ensure their distribution systems will support the increasing demand for residential electrification. OEB staff expressed that "*it is good practice for distributors to provide new residential customers with capacity (both transformation and conductor) to accommodate a 200-amp service under their Basic Connection policy*."[34] Toronto Hydro recognizes that similar policy guidance may be forthcoming requiring quick response and effective implementation to help enable decarbonization-through-electrification public policy objectives.

[33] OEB Staff Bulletin *RE: Residential Customer Connections & Service Upgrades* (August 24, 2023): https://www.oeb.ca/sites/default/files/OEB-Staff-Bulletin-Residential-Customer-Connections-20230824.pdf
[34] *Ibid* at page 2.

When faced with incremental distribution investment needs as a result of external drivers, Toronto Hydro must typically defer necessary expenditures in other investment priority areas, such as System Renewal, System Service and General Plant. Yet, to the extent Toronto Hydro does not carry out the planned investments in these areas, there could be significant reliability, safety or environmental risks that remain unmitigated, or customer needs and outcomes that are unmet.[35] The proposed Expenditure Variance Subaccount, if approved, would enable Toronto Hydro to respond to unforeseeable increases in demand-related investment needs without having to defer other priority work within the plan and put customer outcomes at risk.

Although Toronto Hydro does not expect that demand-related investments would be lower than forecast, it is possible that material changes in economic conditions, such as a recession, could slow down the pace of forecasted demand, or that a change in geopolitical dynamics affecting global supply chains could hinder the availability of electrified technologies such as EVs and heat pumps. In circumstances where demand-related investments are lower than planned, the subaccount would protect ratepayers by ensuring that (i) they do not pay for demand-driven work that can be deferred, and (ii) funds are not repurposed to manage variances in other aspects of the plan that are not driven by demand.

Unanticipated demand changes can impact the plan in different ways. The paragraphs that follow explain the nature of the Demand Related Investments programs and provide context

[35] For example, in the current rate period, Toronto Hydro decided to defer planned investments in Underground System Renewal (Exhibit 2B, Section E6.2 and E6.3) and Overhead System Renewal (Exhibit 2B, Section E6.5) programs to balanced capital funding pressures driven by the 0.9 percent capital stretch factor and by higher than forecasted expenditures in Demand-Related Investments in Customer Connections (Exhibit 2B, Section E5.1), Load Demand (Exhibit 2B, Section E5.3) and Stations Expansion (Exhibit 2B, Section E7.2). For more details please refer to Exhibit 2B, Section E4.1.2.

with respect to the unanticipated demand changes and factors that can impact actual expenditures in these programs.

a. Load Demand Program

The Load Demand program (Exhibit 2B, Section E5.3) alleviates emerging capacity constraints to ensure that there is sufficient capacity available to connect customers to Toronto Hydro's distribution system in a timely and efficient manner. To satisfy connection obligations, Toronto Hydro must maintain adequate capacity on its system to keep pace with load growth and to ensure that its assets are not overloaded. The rapid influx of dense load in the downtown core and horseshoe areas of the City pose a challenge to Toronto Hydro's ability to meet its service requirements. Over the 2025-2029 rate period, Toronto Hydro expects multiple station buses to reach their rated capacity. The forecasted growth in the distribution system is based on the System Peak Demand Forecast outlined in Exhibit 2B, Section D4. However, actual demand will vary by the actual realization of load in the system. This can depend on the above noted factors, including emerging trends such as EV uptake and pacing of heating electrification. To meet these requests in a timely and cost-effective manner and maintain reliability and service quality for existing customers, Toronto Hydro has to invest in infrastructure upgrades and load transfers to alleviate localized capacity constraints.

b. Stations Expansion Program

The Stations Expansion program (Exhibit 2B, Section E7.4) is driven by capacity constraints at the station or regional level, which can no longer be effectively managed by the Load Demand program. Uncertainty regarding increased and continued densification, population growth, and electrification could driver further need to relieve the station loading and expand system capacity. Depending on policies implemented by different levels of government, changes in customer behaviour, and ongoing societal decarbonization efforts, there are a wide range of potential impacts on Toronto Hydro's distribution system. For example, using the Future Energy Scenarios model, the impact of the high electrification/low efficiency scenario ("NZ40 – Low") projects a large increase in system load which would translate into additional investment in the Stations Expansion Program in order to meet system capacity needs in this scenario, as shown in Table 6 below.

Table 6: Incremental Stations Expansion Investment under NZ40-Low Scenario

Rate Period	Additional Investments ($ Million)[36]
2025-2029	44
2030-2034	186
2035-2039	527

c. Regional Planning Process

Another variable that could affect demand-related investments is the regional planning process described in Exhibit 2B, Section B3. While the investments planned in the Stations Expansion program are aligned to meet the needs identified in the most recent Needs Assessment at the regional planning level, Toronto Hydro is currently in the middle of a regional planning cycle that will not conclude until 2025. This process will draw from a number of options to meet the electricity needs identified in Toronto, including conservation and demand management ("CDM"), distributed generation, non-wires solutions, and traditional wires-only solutions. Outputs of this process, or additional updates during the rate term, could modify planned investments under the Stations Expansion program, or other Demand Related Investment programs, resulting in the need to change or increase the level of investment.

[36] This is the additional investment needed incremental to the 2025-2029 investment proposed in this Program, and incremental to the 2030-2034 expenditures forecasted for the Downsview TS and Scarborough TS expansion projects.

d. Connection and Integration of Distributed Energy Resources (DER)

As of 2022, Toronto Hydro connected 2,424 DERs to its grid totaling 304.9 MW in capacity. The utility forecasts DER connections (including energy storage) to reach an estimated 516.7 MW by the end of 2029.[37] Policy, economic conditions and consumer preferences, could facilitate growth in DERs beyond anticipated levels. These changes can be spurred by existing or forthcoming government action at the global, national and local levels, such as the federal clean electricity tax credit, or recent provincial regulatory changes enabling third-party ownership of net-metered generation facilities.[38]

The Generation Protection, Monitoring, and Control (Exhibit 2B, Section E5.5) program enables Toronto Hydro to fulfill its regulatory obligations to connect DER projects to its grid in a safe manner, and alleviate restrictions on the grid such as short circuit capacity constraints to enable the connection of DERs. Depending on the system location and extent of the unanticipated demand change, and the penetration of DER including renewable electricity generation ("REG") projects, Toronto Hydro could also explore additional Non-Wires Solutions ("NWS") investments in either demand-side Flexibility Services or grid-side Renewable-Enabling Battery Energy Storage Systems (Exhibit 2B, Section E7.2) as alternatives to conventional poles and wires solutions.

e. Customer Operations

Toronto Hydro receives a high volume of requests for connections and upgrades for residential and commercial developments each year, which are address through the

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[37] Exhibit 2B, Section E3 at pp. 1-3.

[38] Government of Canada, Budget 2023, *Chapter 3: A Made-In-Canada Plan: Affordable Energy, Good Jobs, and a Growing Clean Economy* (March 28, 2023) online: <https://www.budget.canada.ca/2023/report-rapport/chap3-en.html#m17>.; O. Reg. 386/22: Net Metering under *Ontario Energy Board Act*, 1998, S.O. 1998, c. 15, Sched. B

Customer Operations program (Exhibit 4, Tab 2, Schedule 8). Toronto Hydro may be required to undertake expansion and enhancement work to enable certain connections particular in the dense downtown core or rapidly growing transit corridors. Over the past three years, both the volume and average complexity of expansion work has remained high. Toronto Hydro's Key Account customers (i.e. the largest customers and those customers who have critical loads like hospitals, financial institutions, essential public services and developers), have unique needs in relation not only to complex connections and expansions, but also other priorities like power quality, resilience, ESG objectives and behind-the-meter energy solutions. A material increase in the volume or complexity of Customer Connections as described above, yields a corresponding increase in the need for operational support to address customer needs and expectations.

f. Externally Initiated Plant Relocations and Expansions

The City is experiencing a period of significant infrastructure renewal, neighbourhood revitalizations, commercial development and large transit expansions. The Externally Initiated Plant Relocations and Expansion (Exhibit 2B, Section E5.2) program captures work that the utility must undertake to relocate its infrastructure in response to third-party relocation requests and to enable third-party construction projects to proceed in a timely manner. Relocation requests by third parties are usually received from those required to maintain, upgrade, expand and improve existing public infrastructure such as roads, bridges, highways, transit systems, transmission stations and rail crossings. The timing, pace and expenditures under this program are driven by third-party projects that are entirely outside of Toronto Hydro's control, which is why in the last two rate applications the utility requested and the OEB approved the Externally-Driven Capital variance account.[39] For the

[39] EB-2014-0116, Decision and Order (December 29, 2016) at page 50 and EB-2018-0165, Decision and Order (December 19, 2019) at page 198.

2025-2029 rate period, Toronto Hydro proposes to consolidate this account into the DRVA in order to reduce the number of Group 2 accounts that the utility needs to manage and improve regulatory efficiency.

2. *Demand-Related Revenue Variance Subaccount*

The same external factors (i.e. policy, technology and consumer behaviour) that drive variances in expenditures can also yield variances in billing determinants (i.e. kVa, kWh and customer count) relative to the load and customer forecast set out in Exhibit 3, Tab 1. Such variances in billing determinants can result in lower or higher revenues than forecasted when setting base rates for 2025-2029 that can pose a risk to both ratepayers and the utility. This is a structural forecasting risk that emanates from entering a period of energy transition that results in greater uncertainty and the potential for greater variability with respect to how demand manifests in terms of revenues. To hold the utility and ratepayers harmless from this risk, Toronto Hydro proposes the Revenue Variance subaccount to symmetrically record revenue variances resulting from differences between forecasted and actual billing determinants on a weather normalized basis. The revenue variances recorded in the Revenue sub-account would be tracked at a rate class level so that they can be properly disposed to the same rates classes at the next rebasing.

With this subaccount, Toronto Hydro's CRCI becomes a true revenue cap model (subject to weather-driven variances), rather than a revenue requirement cap, with the revenue variance sub-account operating similar to a decoupling true-up mechanism.[40] Whereas in the past the merits of revenue decoupling were explored through the lens of declining use and resulting earnings attrition due to energy efficiency, Toronto Hydro sees equal merit to

[40] EB-2010-0060, Review of Distribution Revenue Decoupling Mechanisms, (March 19, 2010) at page iv: <https://www.oeb.ca/oeb/_Documents/EB-2010-0060/Report_Revenue_Decoupling_20100322.pdf>.

using revenue decoupling as a means to address energy transition forecasting challenges, including but not limited to the role of energy efficiency measures. As the pace of change in the 2025 to 2029 period remains subject to degrees of uncertainty, Toronto Hydro believes this mechanism is an appropriate means to ensure that neither ratepayers nor the utility or its shareholder are unduly burdened or rewarded by billing determinant variances during this transitional time.

3.3 Other Aspects of the Framework

3.3.1 Earnings Sharing Mechanism (ESM)

In the 2020-2024 rate application (EB-2018-0165), the OEB approved an asymmetrical earnings sharing mechanism ("ESM") with a 100-basis point dead band on a cumulative five-year basis.[41] The approved ESM represented a transition from Toronto Hydro's previous ESM over the 2015 to 2019 period; transitioning away from a symmetrical ESM to an asymmetrical ESM, and calculating ESM amounts based on ROE as opposed to a comparison of Non-Capital Related Revenue Requirement variances.[42]

Toronto Hydro proposes to continue the ESM as approved by the OEB in EB-2018-0165, including the OEB's finding that "*certain adjustments will be required for a ROE-based ESM calculation in order to account for out-of-period items and to ensure there is no double counting*."[43] Where such adjustments are required, Toronto Hydro intends to make them when evaluating ESM entries (or non-entries) at the end of the next rate term. All of the above is consistent with the methodology presented in Exhibit 9, Tab 1, Schedule 1 as it relates to Toronto Hydro's current ESM.

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[41] *Supra* note 26 at page 193.
[42] *Ibid*.
[43] *Ibid.*

With respect to the PIM Deferral Account (“PIM-DA”), under Toronto Hydro’s proposal there is no interaction between the PIMDA and ESM. Earnings under the PIM (only if targets are fully achieved) allow Toronto Hydro to earn the foregone revenue associated with the 0.6 percent portion of the X-factor that was proactively reduced from the utility’s revenue and given to customers upfront as a rate reduction. Earning this amount back is only sufficient to enable the utility to achieve its approved ROE. As such, it would not be suitable for the 2025-2029 ESM proposed in this application to include the PIM earnings associated with earning back the 0.6 percent.

To the degree Toronto Hydro’s 2030 to 2034 rate-setting approach incorporates a continuation of the ESM, or a similar ESM, Toronto Hydro expects ROE for the purpose of determining any ESM amounts would be adjusted for out-of-period transactions, consistent with the OEB’s standard practice for determining Regulated ROE.[44] Such adjustments would include earnings associated with 2025-2029 PIM amounts, as these earnings relate to investments made during the 2025 to 2029 rate period.

3.3.2 Off-ramps and Z-factor

Toronto Hydro proposes to continue to apply the OEB’s generic policy with respect to off-ramps for the 2025-2029 rate term (as outlined in the Rate Handbook), and proposes that it continue to be allowed to have Z-factor relief available based on the OEB’s generic criteria for such relief (as set out in the Report of the Board on 3rd Generation Incentive Regulation).[45]

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[44] Ontario Energy Board, *Electricity Reporting and Record Keeping Requirements* (March 8, 2023) at Section 2.1.5.6.
[45] Ontario Energy Board, *Handbook to Utility Rate Applications* (October 2016) at page 28; see also Ontario Energy Board, *Report of the Board on 3rd Generation Incentive Regulation for Ontario’s Electricity Distributors* (July 14, 2008) at pp. 35-36 and Appendix A at pp. 4-6.

Re: Toronto Hydro 2025–2029 Rate Application Letters of Comment

Dear Valued Customer,

Thank you for your letter of comment regarding Toronto Hydro's 2025–2029 rate application and investment plan. Customer letters are an important part of the rate application process and we appreciate you taking the time to provide your feedback.

The Ontario Energy Board (OEB) received 22 letters of comment in total. Many of the letters focused on similar themes, including that:

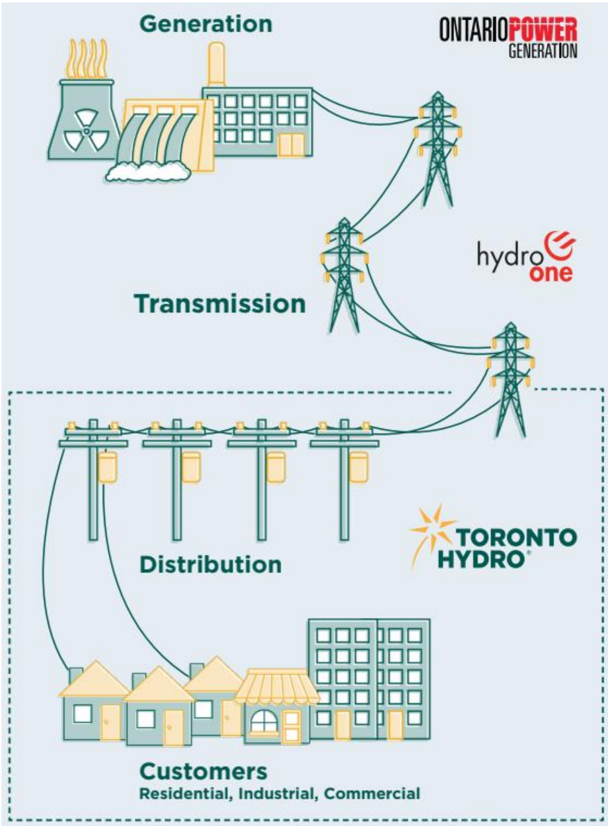
- Customers need clarity about what portion of their electricity bill goes to Toronto Hydro
- Customers believe the required electricity infrastructure already exists, so additional investment isn't required
- Customers are struggling with the cost of living and can't afford additional rate increases
- Customers want Toronto Hydro to explore other solutions rather than increasing costs

This letter represents Toronto Hydro's response to the comments raised and is divided into the following sections:

1. Electricity 101: – Toronto Hydro's Role in the Electricity System
2. Toronto Hydro Bill Breakdown
3. Toronto Hydro's Investment Needs
4. Toronto Hydro's Operating Environment
5. Customer Engagement and Business Planning
6. Timing and Pace of Investment
7. Supporting Electrification
8. Affordability and Cost-of-Living Challenges
9. Our Productivity and Performance
10. Additional Resources

1. Electricity 101: – Toronto Hydro's Role in the Electricity System

Ontario's electricity system is made up of three parts: **generation**, **transmission** and **distribution**:



Generation: Generation is the process of creating electricity from sources such as nuclear power, hydroelectric, natural gas wind and solar. Ontario Power Generation, a government-owned company, generates almost half of Ontario's electricity. The other half comes from other generators contracted by the grid operator.

Transmission: Once electricity is generated, it must be sent to urban and rural areas across the province. This happens by way of high-voltage transmission lines that serve as highways for electricity. Ontario has approximately 30,000 kilometers of transmission lines, mostly owned and operated by Hydro One.

Distribution: Toronto Hydro is responsible for the last step of the journey: distributing electricity locally to customers. Toronto Hydro does not generate or transmit electricity — we own and operate the local electricity system made up of approximately 183,620 poles, 61,300 distribution transformers, 17,060 primary switches, 15,393 kilometers of overhead wires and 13,765 kilometers of underground cables.

2. Toronto Hydro Bill Breakdown

Toronto Hydro recognizes that there is some confusion among customers about how their electricity bill is distributed among the different parties involved in the electricity system, including what portion goes to Toronto Hydro and how Toronto Hydro spends the money we receive.

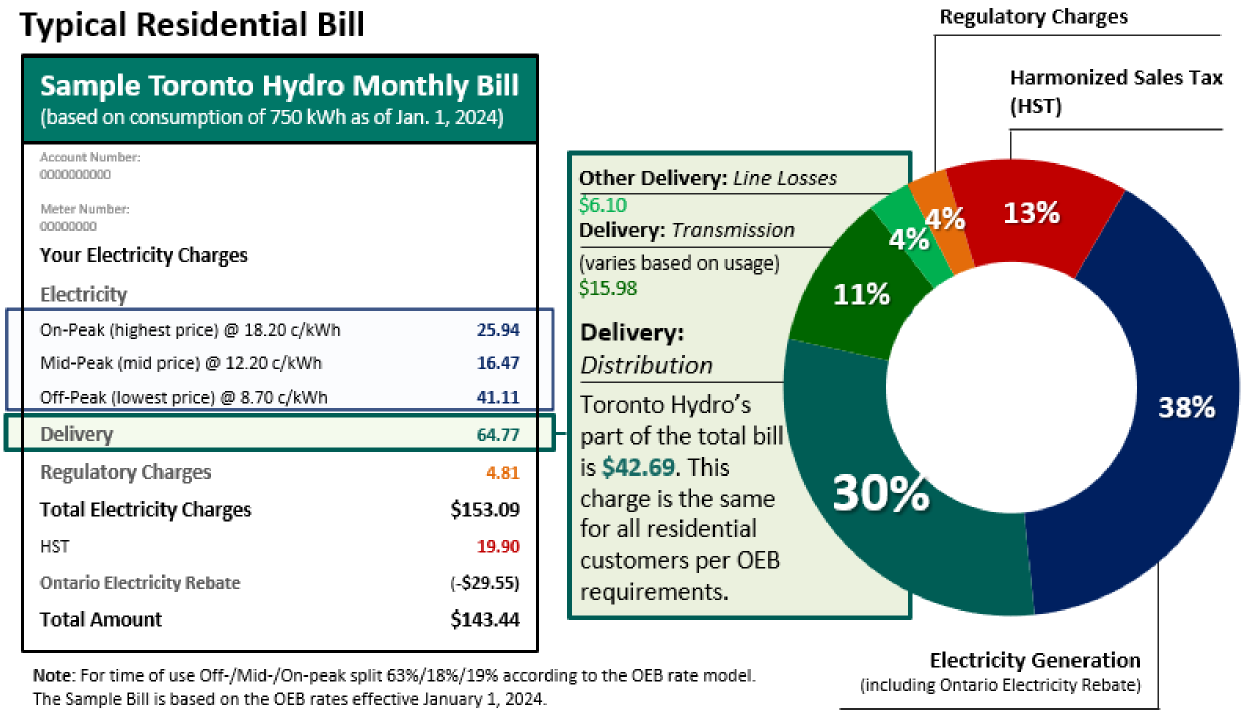
While the electricity bill you receive comes from Toronto Hydro, we actually collect payment for the entire electricity system. **Only about 30% of your electricity bill goes to Toronto Hydro** to pay for the local distribution grid. For example, if the typical monthly residential bill is $143.44**,** the **Delivery Charge** would be **$64.77** and would include:

- Toronto Hydro's Distribution: $42.69
- Hydro One's Transmission: $15.98
- Other Delivery including Line Losses (which is electricity lost during transmission): $6.10

The **remaining 70% of the bill** goes to generation companies, transmission companies, the federal and provincial governments, and regulatory agencies. Included in this amount is the 40% of your total bill that covers electricity generation costs. This is the part of your bill that changes based on your consumption. In other words, if you take steps to conserve energy, these actions will only impact 38% of your bill. For the typical residential customer, this amount is approximately $53.97.

The diagram below provides a breakdown of a typical residential bill:

Typical Residential Bill



Note: For time of use Off-/Mid-/On-peak split 63%/18%/19% according to the OEB rate model. The Sample Bill is based on the OEB rates effective January 1, 2024.

3. Toronto Hydro's Investment Needs

The Delivery Charges found on your bill help fund Toronto Hydro's distribution system. For 2025 to 2029, we developed an investment plan to get the grid ready to serve the city's evolving electricity needs, including increased development from population and economic growth, as well as increased electrification and digitization. Our plan will help ensure that our grid and operations will remain safe, reliable and environmentally responsible.

Specifically, Toronto Hydro's 2025–2029 investment priorities include:

- **Sustainment and Stewardship:** These are investments to renew aging, deteriorating and obsolete distribution equipment to maintain the foundations of a safe and reliable grid.
- **Modernization**: These are investments to develop advanced technological and operational capabilities that will make the system better and more efficient over time
- **Growth and City Electrification**: These are necessary investments to connect customers (including distributed energy resources) and build the capacity to serve a growing and electrified local economy
- **General Plant**: These are investments in our vehicles, work centres and information technology infrastructure to keep the business running and reduce our greenhouse gas emissions

4. Toronto Hydro’s Operating Environment

In developing the investment priorities that formed the basis of our 2025–2029 plan, we aimed to address certain needs and challenges of delivering safe, reliable and clean electricity, including:

- **Powering a mature and growing urban city**: We serve Canada’s largest and North America’s second fastest growing city (by population). We also operate in a dense urban environment, which makes it more complicated and more expensive for us to plan and build infrastructure. As Toronto continues to grow, we need to prepare the grid to power new condo towers, residential communities and businesses.
- **Fixing and replacing equipment in poor condition:** A large percentage of our grid was installed in the 1950s and 60s, and approximately a quarter of the utility’s grid equipment continues to operate past useful life. We need to continue monitoring the condition of our grid and replace equipment most at risk to keep it safe and reliable for customers.
- **Keeping up with how customers use electricity:** Customers are increasingly adopting electrified technologies like electric vehicles and heat pumps for their day-to-day energy needs, and using new technologies like solar panels and battery storage to manage their energy usage. We need to upgrade our equipment and modernize our grid to keep up with these changes.
- **Responding to extreme weather and cybersecurity threats:** Extreme weather events such as extreme heat, high winds, flooding and ice storms are becoming more common due to climate change. In addition, cybercrime is on the rise across Canada. We need to invest in making our grid and operations more resilient against these emerging threats.

5. Customer Engagement and Business Planning

In preparing our plan, we recognized that we needed to balance addressing the operating challenges with price and other outcomes that customers value. Toronto Hydro has a robust planning process, which ensures that customer feedback informs our multi-year investment priorities.

During our planning process, we heard from over 37,000 customers across two phases of customer engagement:

- **Phase 1:** In 2022, we started preparing our plan by asking customers about their needs and preferences for electricity distribution services. Based on the Phase 1 Engagement and system conditions, we developed an initial plan that targeted certain short and long term goals.
- **Phase 2:** In March 2023, we went back to our customers with this draft plan — via a comprehensive online survey — to get feedback and to ask customers how the plan could better meet their needs and preferences.

With unprecedented levels of participation (more than 33,000 customers completed the survey), **84% of respondents supported our proposed plan** or one that does even more to improve services.

6. Timing and Pace of Investment

We understand that there are concerns about affordability, and questions regarding whether our proposed investments can be delayed until economic conditions improve.

Toronto Hydro's investment planning and rate application process operates on a five-year cycle. This means we only go to the OEB approximately every five years with an investment plan to ask for updated rates.

As described in this letter, there are certain investments which are necessary to renew aging equipment and prepare for increased growth in the city. These investments cannot happen quickly — particularly in a densely populated and congested city like Toronto. Building new powerlines and stations takes years of planning and construction. There are also equipment and resource constraints that limit how quickly we can build a bigger grid. That's why we need to start investing now to get the grid ready for future growth.

If we were to put off these investments, this could lead to lower reliability, lower service levels for customers looking to connect to the grid, and reduced efficiency. In addition, if we wait to make these proactive investments, we will likely have to spend even more to catch up on work that needs to be done, instead of spending more gradually. That's why we need to start investing in least-regrets investments now so as not to risk the safety, security, reliability and resiliency of the grid.

In the long term, increasing the utilization of the electricity system (through increasing the number of total users as well as the amount of electricity used by individual users) could help to bring down costs for individual customers.

7. Supporting Electrification

We understand that there are concerns that increased electricity rates will disincentivize customers from switching to electric vehicles (EVs) and heating. The rates we're proposing are necessary for making the investments needed to ensure the grid is ready when increased electricity demand materializes.

In addition, as customers increasingly turn to electricity for more of their day-to-day energy needs, it's expected that they will spend less of their income on energy over the long term as increased electricity costs are more than offset by savings from reducing or eliminating their use of fossil fuels, such as gasoline and natural gas.

Finally, there are a number of financial incentives available for EVs and electric heating, such as the Government of Canada's Incentives for Zero-Emission Vehicles Program[1] and the City of Toronto's Home Energy Loan Program.[2]

8. Affordability and Cost-of-Living Challenges

While our proposed rate increases are necessary for ensuring system safety and reliability and addressing the investment needs and challenges described in this letter, we recognize that there are some customers for whom rate increases will be particularly challenging.

[1] https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/incentives-zero-emission-vehicles/program-overview

[2] https://www.toronto.ca/services-payments/water-environment/environmental-grants-incentives/home-energy-loan-program-help/help-terms-and-conditions/

A number of financial assistance programs are available to eligible customers, with support ranging from helping customers reduce their electricity usage to on-bill credits that help offset monthly charges. The following programs are available to eligible customers:

- The City of Toronto's **Emergency Energy Fund (EEF)** assists customers with energy-related emergencies to reconnect, prevent disconnection or assist in payment of energy arrears
- The OEB's **Ontario Electricity Support Program (OESP)** provides an on-bill credit each month to qualifying households
- The Independent Electricity System Operator's **Energy Affordability Program** offers support to income-eligible electricity consumers by helping them to better manage their monthly electricity costs and to increase their home comfort
- The OEB's **Low-income Energy Assistance Program (LEAP)** provides a one-time emergency grant to help customers pay their electricity bill

To learn more about these assistance programs, visit **torontohydro.com/help**.

Additionally, as part of our commitment to improving how these programs work, Toronto Hydro is requesting enhancements to the LEAP program for the 2025-2029 rate period. Through these various enhancements, we're aiming to increase the average annual number of customers assisted to approximately 1,900 per year (or more than 9,000 over the entire five-year period).

We're also committed to working with the OEB, governments and other stakeholders to find additional targeted solutions that will help customers who need it most.

9. Our Productivity and Performance

Toronto Hydro always strives to provide value to our customers. Like many companies, Toronto Hydro faces rising costs in purchasing equipment for the grid and completing construction work in the city. Despite this, we're always looking for ways to minimize costs and rate increases by finding productivity and efficiencies in our plans and work. For example, as part of reducing our facilities footprint in the city, we consolidated from seven operating centres down to four. As part of this consolidation, the utility sold properties, and are returning proceeds of close to $200 million to customers by the end of the decade resulting in an annual credit of approximately $132 on the average residential customer's bill from 2016 to 2029.

During our business planning process, we asked external experts to assess our performance, including benchmarking with respect to our productivity, reliability, and cost efficiency. The results of those studies, which were publicly filed as part of our application, demonstrate that our performance on these measures is similar or better than our peer utilities.[3]

This also applies to employee compensation. Toronto Hydro balances cost-effectiveness with the need to attract and retain the talent required to provide service in an increasingly complex and dynamic operating environment. Toronto Hydro has external consultants who benchmark our total compensation, and we've been found to be within a market-competitive range in the energy market.

[3] For more information on Productivity initiatives, please see Exhibit 1B, Tab 3, Schedule 3.

In addition, our 2025–2029 plan is focused on delivering results that matter to customers like you. To help ensure that we achieve these outcomes, we'll be holding ourselves financially accountable through a framework that tracks and reports our performance on 12 distinct measures. This performance framework provides customers with an upfront rate reduction benefit of $65 million that we will only earn back if we achieve certain objectives.

10. Additional Resources

To learn more about Toronto Hydro's 2025–2029 rate application and investment plan, please refer to the following:

- Our 2025–2029 Rate Application
- 2025–2029 Rate Application Executive Summary (PDF, 894 KB)
- 2025–2029 Rate Application Customer Summary (PDF, 1.5 MB)
- Our 2025–2029 Investment Plan

Integration of Revenue Forecast with Electric Vehicle and Distributed Energy Resource Forecasts

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1 Executive Summary

Toronto Hydro-Electric System Limited ("Toronto Hydro" or "Company") engaged Clearspring Energy Advisors, LLC ("Clearspring") to develop a model ("Integration Model") that integrates the Company's revenue forecast for the years 2025 to 2029 with forecasts for electric vehicles ("EVs") and distributed energy resources ("DERs"). The lead model developer is Mr. Steven A. Fenrick. Mr. Fenrick has developed models, provided research reports, and expert witness testimony before the Ontario Energy Board in several applications including Toronto Hydro's previous distribution rate application. Mr. Fenrick and Clearspring have been involved in several load forecasting studies. In recent years, many of these studies have begun to incorporate EV and DER forecasting into the analysis. A copy of Mr. Fenrick's summary *curriculum vitae* is attached in Appendix B.

The objective of the Integration Model is to forecast the impact on energy and billing demand by rate class resulting from the forecasted changes in EVs and DERs. Clearspring also produced an analysis on the changes to the rate class load profiles resulting from the EV and DER forecasts that is used as an input in the cost allocation model by Toronto Hydro for rate setting purposes.

The base revenue forecast is produced by Toronto Hydro. Toronto Hydro also provided Clearspring with the historical data and forecasts for the number of EVs and the nameplate capacity of DERs on its system along with other assumptions on EV consumption and DER production. Clearspring's research focused not on the EV and DER forecasts themselves but rather on building a model that estimates the impacts of those forecasts onto the billing determinants of energy and demand.

The Integration Model and the forecasted impact of the technologies onto the base revenue forecast is discussed in Sections 1 through 8. Please see Section 9 for a summary of the cost allocation model ("CAM") analysis.

1.1 Forecast Inputs

Electric vehicles and distributed energy resources are emerging technologies that have the potential to significantly influence the energy delivered by utilities and the peak demands they need to plan for. The overall impact on the kilowatt hours ("kWhs") and the timing of charging or production is relevant for forecasting the energy and demand billing determinants. EVs will increase electricity consumption and demand, whereas DERs will tend to decrease them.

Our study uses the following forecast inputs, provided by Toronto Hydro, to forecast the impacts of EVs and DERs onto the billing components of energy and demand:

1. Light-duty electric vehicles ("LDEVs")
2. Medium-duty electric vehicles ("MDEVs")
3. Heavy-duty electric vehicles ("HDEVs")
4. Customer-owned ground-mounted and roof-mounted solar photovoltaic panels ("Renewables")
5. Customer-owned non-renewable distributed energy resources ("Non-Renewable")

6. Customer-owned energy storage resources

The base revenue forecast is produced and was provided to Clearspring by Toronto Hydro's staff.[1] It is Clearspring's understanding that the dataset used to inform the econometric models of the base forecast has an end year of 2023. Therefore, the Integration Model estimates the incremental load of these technologies from their 2023 adoption levels to the forecasted levels of the future custom incentive regulation years of 2025 to 2029.

The incremental energy and billing demand from 2023 of LDEVs, MDEVs, HDEVs, Renewable, Non-Renewable DER, and energy storage are forecasted by the Integration Model and are to be added to the base revenue forecast. The technology forecasts are required because these technologies are expected to exceed historical market adoption levels. Given this anticipated acceleration, the base revenue forecast does not satisfactorily account for the anticipated future load impacts of these technologies.

1.2 Forecast Summary of EVs and DERs

The six technology inputs can be aggregated to the base revenue forecast to determine the expected forecast after accounting for these technologies. There is a balancing of impacts between the technologies as EVs will increase energy and billing demand, whereas DERs will lower energy and billing demand.

The net forecasted impacts as a percentage of the base revenue forecast on a total system basis are provided below annually.[2] Please see Appendix A for monthly breakdowns of the energy and billing demand impacts of the technology forecasts by rate class.

Table 1: Annual Forecasted Energy and Billing Demand Impacts

Year	Incremental Energy (kWh) % Increase	Incremental Billing Demand (kVA) % Increase
2025	-0.1%	-0.3%
2026	0.3%	-0.1%
2027	0.8%	0.2%
2028	1.4%	0.6%
2029	2.1%	1.0%

The net impacts are forecasted to have a minimal impact on the base revenue forecast in 2025 but this impact is projected to increase to 2.1% for energy and 1.0% for billing demand by 2029 as EV technologies mature and market adoption accelerates.

[1] The base forecast results and methodology are described in Exhibit 3.

[2] The forecasts are integrated monthly as the base revenue forecast is monthly, but we display annual impacts here for display purposes.

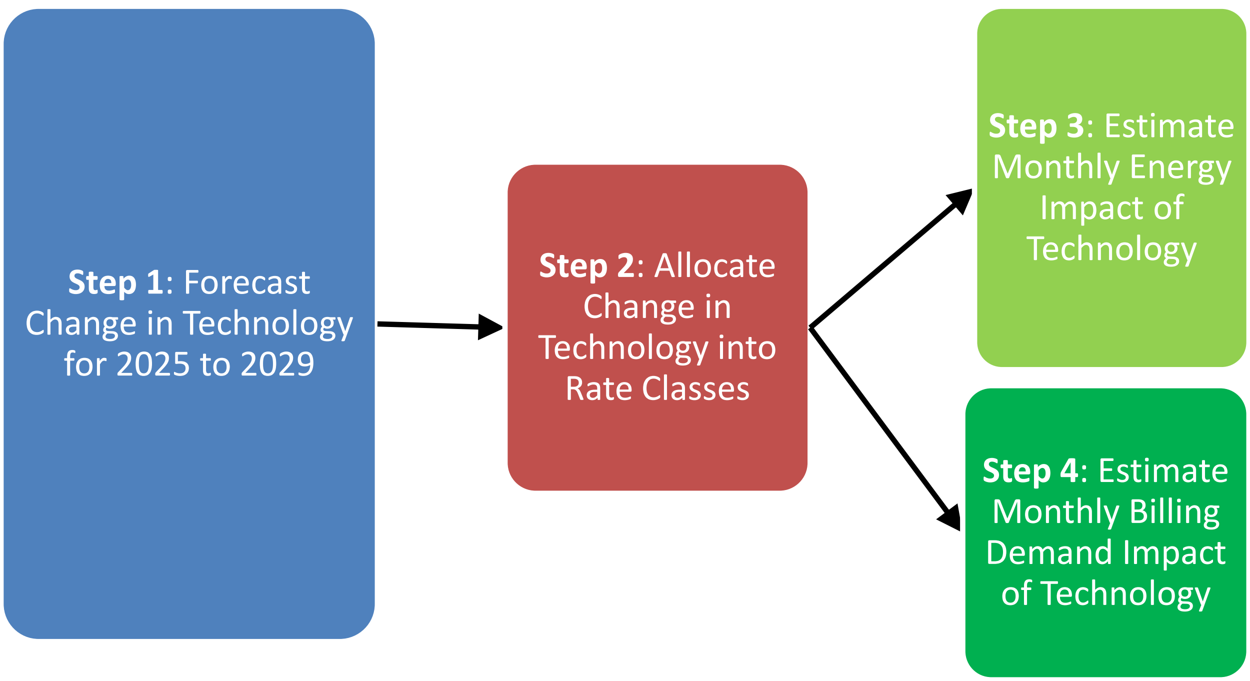
2 Integration Forecast Methodology

The 2025-2029 forecasts for the EV counts and DER nameplate capacities are provided by Toronto Hydro. The forecasts appear to be reasonable expectations of near-term technology adoption based on our experience with other clients in forecasting EVs and renewable resources.

After being provided with the forecasts for the technology counts/capacities on a system-wide basis, the Integration Model undertakes a four-step process to translate the forecasted technology count/capacity into incremental energy and billing demand.

The four steps are:

1. Calculate the change in the count/capacity forecasts from 2023.
2. Allocate the change from 2023 to a specific rate class.
3. Estimate the monthly energy (kWh) impact of each technology for the rate class in 2025 through 2029.
4. Estimate the billing demand (kVA) impact of each technology for the three rate classes that contain a billing demand component in 2025 through 2029.



2.1 Forecast Change in Technology Count

The objective of the research is to forecast how much energy and billing demand should be added to the base revenue forecast to account for the changes in the technologies included in the study. The base revenue forecast sample dataset goes through the year 2023. The load effects for each technology through 2023 will be embedded within the data used to calculate the base forecasting models.

It is, therefore, the incremental loads from their 2023 values that will drive a change to the base revenue forecast for the upcoming years of 2025 to 2029. The Integration Model calculates the change in each technology for these upcoming years from the 2023 value. These new loads will drive an incremental change in energy and billing demand to the base revenue forecast.

2.2 Allocate Incremental Change to the Rate Classes

Integrating the technology forecasts with the revenue forecast requires allocating the technology count/capacity into appropriate rate classes. The six rate classes that we allocated EVs and DERs to are:

- Residential
- CSMUR
- GS<50 kW
- GS50-999 kW
- GS 1-5 MW
- Large Use

Three of the rate classes also have a billing demand component that is calculated based on the customer's highest kVA reading during the month. The three classes with a demand rate component are the larger customer classes of GS50-999 kW, GS 1-5 MW, and Large Use. For these three rate classes, the Integration Model forecasts the impact on billing demands from the incremental additions of EVs and DERs using hourly interval data specific to individual customers within each rate class and layered on technology hourly load profiles to estimate the impact on billing demand resulting from the presence of the technology. This process is discussed further below in Step 4.

Technologies were allocated by the Integration Model to rate classes based on where the technology is most likely to be used and installed. LDEVs are more likely to be owned and charged at residences and have higher concentrations in the residential rate class, whereas HDEVs are more likely to be owned and charged at larger businesses and be concentrated in the general service or Large Use rate classes.

The following list summarizes the technology and the information used in the Integration Model to allocate each technology to the six rate classes.

Technology	Rate Class Allocation Method
Light-Duty EVs (LDEVs)	The Integration Model uses an estimate of 91% of home charging, placing 91% of LDEVs in the residential rate class.[3] The remaining 9% was apportioned to the other five rate classes based on the percentages of Level 2 EV chargers at Toronto Hydro.
Medium-Duty EVs (MDEVs)	The Integration Model uses the rate class percentage of kWh usage in the Manufacturing and Warehouse industry sector at Toronto Hydro.
Heavy-Duty EVs (HDEVs)	Same as the MDEV method but TTC kWh usage is added to the percentages.
Renewable DER	The Integration Model uses Toronto Hydro's records of customers on the net metering program and the installed kW capacity of Solar by rate class.
Non-Renewable DER	The Integration Model uses the current Non-Renewable installed nameplate capacity by rate class at Toronto Hydro.
Energy Storage	The Integration Model uses the current energy storage by nameplate capacity by rate class.

2.3 Estimate Monthly Energy Impact

Estimating the energy contribution of each technology by month to each rate class involves multiplying the expected energy required to charge the EV (or the expected production of the DER) in each month by the forecasted number of EVs/DERs in each rate class. The energy usage for EVs will vary due to temperatures impacting the battery efficiencies of the vehicles. Cold temperatures reduce battery efficiency relative to milder temperatures. The Integration Model uses a differential assumption of +/- 10 percent to adjust for this reality.[4] [5] Renewable DERs tend to produce far more energy in the summer months when sunlight is more direct than during winter months. The Integration Model inputs capacity factors for Renewables that are specific to winter and summer months. The model makes no seasonal adjustment for Non-Renewable DERs.

The average daily EV energy consumption was provided by Toronto Hydro. For LDEVs, Toronto Hydro estimated an average daily consumption of 9.4 kWh per LDEV. For MDEVs, Toronto Hydro estimated

[3] USDRIVE, Summary Report on EVs605 at Scale and the U.S. Power System, Grid Integration Tech Team and Integrated Systems Analysis Tech Team, 2019.

[4] Cold Temperatures Affect an Electric Vehicle's Driving Range - Consumer Reports

[5] May through September are designated as summer months and are reduced by 10 percent and the remaining months designated as winter months and are increased by 10 percent.

103.56 kWh per MDEV use per day. For HDEVs, Toronto Hydro estimated 319.87 kWh per HDEV use per day. Clearspring then multiplied these daily estimates by the number of days in each month and adjusted for summer/winter seasonal differences.

The Renewable and Non-Renewable average hourly capacity factors are provided by Toronto Hydro. The capacity factors are summed to estimate the daily energy production. This daily production is multiplied by the number of days in each month. The Renewable capacity factors are specific to summer and winter. Energy storage is assumed to not be actively charged and discharged, due to a current lack of evidence regarding how energy storage may be used at customer sites, and so will not have an impact on the results.

2.4 Estimate Monthly Billing Demand Impact

Three of Toronto Hydro's rate classes are billed on peak demand,[6] which is calculated as the highest kVA demand for that customer in each month. Billing demand times and amounts will vary from customer to customer and from month to month. The presence of EV charging will put upward pressure on billing demand and that pressure is a function of the number of EVs being charged at the premise, the load profiles of those EVs, and the base load profile for that customer. DERs will also have an impact on billing demand, but in the opposite direction. However, the mechanics of forecasting the change in the Integration Model are the same.

The Integration Model accounts for these factors by using hourly load profiles of the EVs and hourly capacity factors of the DERs, receiving smart meter hourly interval data for customers from Toronto Hydro from the three rate classes with a billing demand component, and then examining how the estimated number of EVs or DERs would impact billing demand for each general service customer. A load profile that estimates the hourly charging requirements (or production expectations) of an EV/DER at the general service customer premise is necessary for the analysis.[7] The load profiles are based on either Toronto Hydro analysis or external sources and are scaled to match the energy assumptions found in Step 3.[8]

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[6] These rate classes are GS 50-999, GS 1-5MW, and Large Users. The remaining rate classes do not have a billing demand rate component.

[7] Since only the three general service rate classes have a billing demand component, it is only a general service load profile that needs to be calculated. Residential home charging can be ignored when estimating billing demand impacts.

[8] The LDEV hourly profile was derived from the U.S. Department of Energy Alternative Fuels Data Center. More details on the LDEV hourly profiles are provided in Section 3. The MDEV, HDEV, and DER hourly load profiles are provided by Toronto Hydro.

The following table shows the seasonal hourly load profiles used for each EV technology in the billing demand analysis of Step 4.

Table 2: Seasonal Hourly Load Profiles by EV Technology

Hour Beginning	Summer LDEV	Winter LDEV	Summer MDEV	Winter MDEV	Summer HDEV	Winter HDEV
0	0.0	0.1	4.0	4.9	29.0	35.4
1	0.0	0.0	4.1	5.0	25.2	30.8
2	0.0	0.0	3.7	4.5	19.4	23.7
3	0.0	0.0	4.4	5.3	14.8	18.0
4	0.1	0.1	4.1	5.0	14.2	17.3
5	0.1	0.2	3.6	4.4	12.1	14.8
6	0.4	0.5	3.2	3.9	12.8	15.6
7	0.9	1.1	2.9	3.5	11.9	14.6
8	1.3	1.6	0.9	1.0	2.4	3.0
9	1.3	1.5	1.0	1.2	8.7	10.6
10	0.9	1.1	1.8	2.2	10.5	12.8
11	0.7	0.8	2.1	2.5	13.7	16.7
12	0.5	0.6	4.1	5.0	11.7	14.3
13	0.4	0.5	3.7	4.5	10.3	12.6
14	0.4	0.1	3.6	4.4	10.9	13.4
15	0.4	0.4	4.8	5.8	9.5	11.6
16	0.3	0.4	5.7	7.0	9.2	11.2
17	0.2	0.3	5.2	6.3	8.8	10.7
18	0.2	0.2	4.9	6.0	6.4	7.8
19	0.1	0.1	5.0	6.1	5.8	7.1
20	0.1	0.1	5.8	7.1	4.4	5.4
21	0.1	0.1	5.8	7.1	4.0	4.9
22	0.1	0.1	5.1	6.3	3.3	4.0
23	0.0	0.1	4.0	4.9	29.0	35.4

The following table displays the capacity factors for the DERs. A value of -0.5 means that the model assumes the DER will produce 0.5 kWh for every 1 kW of nameplate capacity in that hour.[9]

Table 3: Seasonal DER Capacity Factors

Hour Beginning	Solar Summer	Solar Winter	Energy Storage Summer	Energy Storage Winter	Non-Renewable Summer	Non-Renewable Winter
0	0	0	0	0	-0.66	-0.66
1	0	0	0	0	-0.65	-0.65
2	0	0	0	0	-0.65	-0.65
3	0	0	0	0	-0.65	-0.65
4	0	0	0	0	-0.65	-0.65
5	0	0	0	0	-0.65	-0.65
6	0	0	0	0	-0.66	-0.66
7	-0.03	-0.01	0	0	-0.67	-0.67
8	-0.13	-0.02	0	0	-0.67	-0.67
9	-0.22	-0.04	0	0	-0.67	-0.67
10	-0.28	-0.05	0	0	-0.67	-0.67
11	-0.32	-0.06	0	0	-0.67	-0.67
12	-0.33	-0.06	0	0	-0.67	-0.67
13	-0.35	-0.07	0	0	-0.67	-0.67
14	-0.34	-0.06	0	0	-0.68	-0.68
15	-0.33	-0.06	0	0	-0.68	-0.68
16	-0.32	-0.06	0	0	-0.68	-0.68
17	-0.28	-0.05	0	0	-0.67	-0.67
18	-0.2	-0.04	0	0	-0.67	-0.67
19	-0.09	-0.02	0	0	-0.67	-0.67
20	0	0	0	0	-0.67	-0.67
21	0	0	0	0	-0.66	-0.66
22	0	0	0	0	-0.66	-0.66
23	0	0	0	0	-0.66	-0.66

The Integration Model inputs 2019 hourly smart meter data for customers in the three rate classes with a billing demand component. The year of 2019 is used since 2020 and subsequent hourly load data was influenced by the Covid-19 pandemic. Using this data provides 8,760 hourly observations for each customer included in the analysis. For the rate classes of GS 1-5MW and Large Use, Clearspring received and processed the 2019 interval data for all the customers in the rate classes. Given the large number of customers in the GS 50-999 rate class, Clearspring extracted a sample of the data for that rate class to conduct the billing demand impact analysis.

Using the hourly interval data, the monthly billing demands in 2019 can be calculated for every customer in the three samples. The Integration Model adds the technology load profile to the customer load profile

[9] We assume zero for energy storage as there is not yet evidence available on if energy storage will be used to avoid billing demand or other peak demands or only be used for resiliency.

in every single hour of the year. The revised customer load profile with the new technology loads added is used to calculate what the billing demand would have been if the technology had been present for each customer.

The before and after billing demand differences for every customer are averaged in each rate class to produce an estimate of how much billing demand is predicted to change from adding the technology at the customer premise. This is used to produce the average kW impact per EV (or per DER nameplate) in each month. The average kW estimate is multiplied by the forecasts for the technology count/capacity in each rate class to determine the kW impacts for each rate class by each month. The kW estimate impacts are escalated by an assumption of a 0.95 power factor to translate from kW to kVA.[10]

Layering estimated technology load profiles to customer hourly interval data enables the analysis to adjust for when each customer is actually consuming its peak demand for the month, since customers incur their billing peaks at varying times of day. This procedure enables the model to estimate how the technology will influence the load that is specific to that specific customer's peak time. This is important since EVs are not charged uniformly through the day, nor do Renewable DERs have a constant production curve.

The second advantage of this procedure is that it gives the model flexibility to adjust the peak time after the new loads are added. The addition of EV load (or DER production) may move the peak time to an entirely different hour and the analysis accounts for this possibility.[11]

The steps in the billing demand analysis can be summarized as follows:

1. Estimate the technology hourly load profile.
2. Process the 2019 hourly interval customer data in each of the three rate classes.
3. Calculate the average billing demand in each rate class in 2019.
4. Add the technology hourly load profiles to the customer hourly interval data for every hour in the year.
5. Calculate the average billing demand in each rate class after the addition of the technology hourly load profiles.
6. Take the difference in the before and after billing demand to estimate a per unit billing demand impact for the technology.
7. Multiply the per unit billing demand impact for the rate class by the forecasted number of EVs or DER nameplate capacity for that rate class.

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[10] This assumption was provided to Clearspring from Toronto Hydro.

[11] The more EVs or DER capacity at a given customer site, the more likely it will be that the presence of the technology will shift the billing peak time to a different time that day or to a separate day. The Integration Model accounts for this by adding more EVs and more DER capacity for the larger rate class customers (GS 1-5 MW and Large Use) who are likely to have a higher number of EVs or DERs on site than those customers GS 50-999 kW.

3 Light-Duty Electric Vehicle Forecasts

Vehicles classified as Light-Duty Vehicles ("LDVs") weigh less than 4,535 kilograms according to Statistics Canada. There are two major types of Light-Duty Electric Vehicles ("LDEVs") on the market today: battery electric vehicles ("BEV") and plug-in hybrid electric vehicles ("PHEV"). For the purposes of the Integration Model, we do not distinguish between these two types of LDEVs. Given that most driving and the necessary charging will occur due to relatively short driving distances in or near the City of Toronto, both BEVs and PHEVs will add similar electric demand profiles to the grid.

The market adoption rate of LDEVs has grown but continues to be low relative to future expectations. The maturation of the technology, decreasing prices relative to internal combustion engines ("ICE"), and increasing charging opportunities are increasing sales of EVs as a percentage of total sales. However, recent supply chain issues caused by COVID have slowed down adoption rates.[12]

The LDEV forecast was provided by Toronto Hydro. The forecasts appear to be reasonable expectations of near-term technology adoption based on our experience with other clients in forecasting EVs.[13] Historic LDEV data was estimated by Toronto Hydro and is small compared to the future forecasts of LDEVs.

The electric vehicles will mostly be charged at the owner's residence. However, some of the LDEVs will be charged at alternate locations, typically at the place of work. The energy required for home charging will add to residential energy use and the alternate locational charging will add to the general service rate classes. Integration of the LDEVs into the revenue forecast requires an assumption on the rate class split of where charging will occur.

The Integration Model assumes 91% of LDEV charging in Toronto will occur at home.[14] The remaining 9% of LDEV charging is allocated to the other five rate classes based on Toronto Hydro data on the percentage of Level 2 EV chargers in those five rate classes.

For display purposes, the following table displays the annual LDEV counts for each rate class after allocating 91% to the residential class and divvying up the remaining 9% based on Level 2 EV chargers. The

[12] 'Unprecedented' global chip shortage pushing electric vehicle delays into years - National | Globalnews.ca.

[13] https://www.eia.gov/outlooks/aeo/data/browser/#/?id=48-AEO2023&cases=ref2023&sourcekey=0.

[14] USDRIVE, Summary Report on EVs605 at Scale and the U.S. Power System, Grid Integration Tech Team and Integrated Systems Analysis Tech Team, 2019.

model is, however, monthly, with the LDEV counts escalating to the annual numbers in December of each year.

Table 4: Number of LDEVs by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2019	6,772	43	143	342	128	14
2020	9,023	57	190	456	171	19
2021	11,960	76	252	604	227	25
2022	19,520	123	411	986	370	41
2023	29,972	189	631	1,514	568	63
2024	43,635	275	918	2,204	826	92
2025	59,429	375	1,251	3,001	1,126	125
2026	76,411	482	1,608	3,859	1,447	161
2027	96,006	606	2,020	4,849	1,818	202
2028	117,339	741	2,469	5,926	2,222	247
2029	140,303	886	2,952	7,086	2,657	295

3.1 LDEV Energy Forecast

Estimating the energy contribution of each LDEV by month for each rate class involves multiplying the expected energy required to charge each LDEV in each month by the forecasted number of LDEVs in each rate class. The charging energy required is a function of the average kilometres ("km") driven each day and the average EV efficiency factor. The EV efficiency factor measures how many kilowatt hours ("kWh") of electricity are required per kilometre of driving.

$$kWh\ per\ day\ for\ LDEV = average\ km\ driven\ per\ day\ (km) * EV\ efficiency\ factor\ (kWh\ /\ km)$$

Toronto Hydro estimated that an average Toronto LDEV driver will average 40.3 km/day. The EV efficiency factor is estimated by Toronto Hydro at .233 kWh/km. Multiplying these two components together produces the estimate of each LDEV requiring 9.4 kWh per day, which appears reasonable to Clearspring based on our experience and other external sources.[15]

[15]https://ecocostsavings.com/average-electric-car-kwh-per-mile/.

The following table displays the forecasted annual LDEV energy contribution for each rate class.

Table 5: Annual LDEV Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2019	2,168,435	13,689	45,630	109,512	41,067	4,563
2020	27,822,885	175,641	585,471	1,405,131	526,924	58,547
2021	36,954,088	233,285	777,617	1,866,281	699,855	77,762
2022	55,886,731	352,804	1,176,013	2,822,430	1,058,411	117,601
2023	87,660,678	553,387	1,844,625	4,427,100	1,660,162	184,462
2024	130,109,415	821,359	2,737,865	6,570,875	2,464,078	273,786
2025	181,707,014	1,147,087	3,823,622	9,176,693	3,441,260	382,362
2026	238,948,815	1,508,445	5,028,149	12,067,558	4,525,334	502,815
2027	303,011,373	1,912,861	6,376,204	15,302,889	5,738,583	637,620
2028	374,527,806	2,364,333	7,881,109	18,914,661	7,092,998	788,111
2029	451,895,366	2,852,741	9,509,138	22,821,931	8,558,224	950,914

The forecasts are translated into monthly forecasts using the monthly LDEV counts found in Table 4 and multiplying the average daily kWh charging by the number of days in each month. An additional monthly adjustment is made to account for the reality that EV batteries perform worse in cold temperatures.[16] To adjust for this, the Integration Model adds 10 percent to the energy totals in winter months and subtracted 10 percent to the energy totals in summer months.[17]

To integrate the LDEV forecasted energy into the revenue forecast, the incremental load of LDEVs for each rate class from their 2023 adoption levels are added to the revenue forecast. The incremental load in each month in 2025 to 2029 is the difference between that month's forecasted LDEV load and the same month in 2023.

For display purposes, the following table displays the annual LDEV incremental energy impact from 2023 levels for each rate class. The model is, however, monthly. Also shown is the average increase in LDEV energy from the base revenue forecast for each rate class.

Table 6: Annual Incremental Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	94,046,336	593,699	1,978,997	4,749,593	1,781,097	197,900
2026	151,288,137	955,057	3,183,524	7,640,458	2,865,172	318,352
2027	215,350,695	1,359,474	4,531,579	10,875,789	4,078,421	453,158
2028	286,867,128	1,810,945	6,036,484	14,487,561	5,432,835	603,648
2029	364,234,688	2,299,354	7,664,513	18,394,831	6,898,062	766,451

[16] https://cleantechnica.com/2022/12/19/how-temperature-affects-electric-car-range-charging-performance/.

[17] Summer months are defined as May through September with the remaining months designated as winter months.

3.2 LDEV Billing Demand Forecast

A load profile that estimates the hourly charging requirements of an LDEV at the general service customer premise is necessary to forecast the impact of LDEVs on billing demand.[18] Most of this charging will be from commuters who are working at the place of business. The Integration Model uses a load profile that estimates "at work" charging behavior per LDEV from the U.S. Department of Energy (DOE) Alternative Fuels Data Center.[19]

The DOE profile is scaled to match the LDEV energy charging assumptions that were provided to Clearspring by Toronto Hydro. The model scales the profile to match the energy use estimate of 9.4 kWh and adjusts for summer and winter differences in battery efficiency. The winter and summer LDEV load profiles for "at work" charging used in the analysis are provided in the following table.

[18] Since only the three general service rate classes have a billing demand component, it is only a general service load profile that needs to be calculated. Residential home charging can be ignored when estimating billing demand impacts.

[19] The DOE profile tool can be found here: https://afdc.energy.gov/evi-pro-lite/load-profile/. The profile used a location of Chicago, which is also on a Great Lake and has similar weather to Toronto, and 25 commuting miles.

Table 7: Summer and Winter LDEV Work Charging Load Profile

Hour	Summer LDEV Load	Winter LDEV Load
0	0.04	0.05
1	0.03	0.04
2	0.03	0.03
3	0.02	0.02
4	0.05	0.06
5	0.14	0.18
6	0.41	0.50
7	0.88	1.08
8	1.33	1.62
9	1.25	1.53
10	0.94	1.15
11	0.65	0.80
12	0.47	0.57
13	0.42	0.52
14	0.40	0.14
15	0.35	0.43
16	0.29	0.35
17	0.22	0.27
18	0.16	0.19
19	0.12	0.14
20	0.08	0.10
21	0.06	0.07
22	0.05	0.07
23	0.05	0.06

For display purposes, the following table displays the annual LDEV incremental billing demand impact from 2023 levels for each rate class. The model is, however, monthly.

Table 8: Incremental Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	10,594	4,076	412
2026	17,043	6,557	663
2027	24,260	9,334	944
2028	32,316	12,434	1,258
2029	41,032	15,788	1,597

Shown in the following table is the average percentage increase in LDEV billing demand from the base revenue forecast for each rate class.

Table 9: LDEV Percentage Increase from Base Demand by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.0%
2026	0.1%	0.1%	0.0%
2027	0.1%	0.1%	0.0%
2028	0.1%	0.1%	0.0%
2029	0.2%	0.2%	0.0%

4 Medium-Duty and Heavy-Duty Electric Vehicle Forecasts

Vehicles classified as Medium-Duty Vehicles ("MDVs") weigh between 4,535 and 11,793 kilograms according to Statistics Canada. Vehicles classified as Heavy-Duty Vehicles ("HDVs") weigh more than 11,793 kilograms. Medium-Duty Electric Vehicles ("MDEVs") and Heavy-Duty Electric Vehicles ("HDEVs") are forecasted separately by Toronto Hydro.

The MDEV and HDEV count forecast was provided to Clearspring by Toronto Hydro. The forecasts appear to be reasonable expectations of near-term technology adoption based on our experience with other clients in forecasting EVs.

The table below provides the historic and forecasted MDEVs and HDEVs in Toronto.

Table 10: Forecast for the Number of MDEVs and HDEVs in Toronto

Year	Total MDEVs in Toronto	Total HDEVs in Toronto
2022	0	0
2023	82	147
2024	210	479
2025	413	964
2026	674	1,560
2027	1,007	2,284
2028	1,502	3,095
2029	2,120	3,908

The MDEVs and HDEVs count forecasts for Toronto Hydro are allocated to the rate classes. The Integration Model uses the Manufacturing and Warehouse kWh usage percentages by rate class provided by Toronto Hydro to allocate the MDEVs by rate class. For the HDEV rate class allocations, the model uses the same Manufacturing and Warehouse kWh usage percentages plus the Toronto Transit Commission ("TTC") garage kWh usage. The TTC garage usage, which was provided by Toronto Hydro, and was added to the HDEV allocations because of TTC's Green Bus Program, is forecasted to purchase and add several electric buses to its fleet, which would be classified as HDEVs.

For display purposes, the following table displays the annual MDEV counts for each rate class. The model is, however, monthly with the MDEV and HDEV counts escalating to the annual numbers in December of each year.

Table 11: Forecasted Number of MDEVs by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-000 kW	GS 1-5 MW	LU
2022	0	0	0	0	0	0
2023	0	0	6	28	25	22
2024	0	0	16	73	64	56
2025	0	0	32	144	127	111
2026	0	0	51	235	207	181
2027	0	0	77	351	309	270
2028	0	0	115	523	461	403
2029	0	0	162	739	651	569

The following table displays the annual HDEV counts for each rate class.

Table 12: Forecasted Number of HDEVs by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-000 kW	GS 1-5 MW	LU
2022	0	0	0	0	0	0
2023	0	0	11	51	45	40
2024	0	0	36	166	145	132
2025	0	0	72	334	293	266
2026	0	0	116	540	474	430
2027	0	0	170	791	693	630
2028	0	0	230	1,072	940	854
2029	0	0	290	1,353	1,186	1,078

4.1 MDEV & HDEV Energy Forecast

Estimating the energy contribution of each MDEV and HDEV by month for each rate class involves multiplying the expected energy required to charge each vehicle in each month by the forecasted number of MDEV and HDEVs in each rate class. The Integration Model assumes that MDEVs require 103.56 kWh per day and HDEVs require 319.87 kWh of electricity per day. Both of these assumptions were provided from Toronto Hydro.

The following table displays the forecasted annual MDEV energy contribution for each rate class.

Table 13: Annual MDEV Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2022	0	0	0	0	0	0
2023	0	0	92,292	421,300	371,586	324,412
2024	0	0	315,744	1,441,332	1,271,252	1,109,863
2025	0	0	669,510	3,056,232	2,695,591	2,353,377
2026	0	0	1,159,758	5,294,152	4,669,433	4,076,634
2027	0	0	1,787,311	8,158,854	7,196,095	6,282,528
2028	0	0	2,667,883	12,178,551	10,741,461	9,377,799
2029	0	0	3,843,691	17,545,972	15,475,517	13,510,852

The following table displays the forecasted annual HDEV energy contribution for each rate class.

Table 14: Annual HDEV Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2022	0	0	0	0	0	0
2023	0	0	498,747	2,326,961	2,039,258	1,853,621
2024	0	0	2,052,675	9,576,983	8,392,895	7,628,877
2025	0	0	4,661,915	21,750,688	19,061,454	17,326,262
2026	0	0	8,091,377	37,751,224	33,083,701	30,072,043
2027	0	0	12,274,950	57,270,151	50,189,328	45,620,519
2028	0	0	17,126,372	79,905,004	70,025,630	63,651,094
2029	0	0	22,234,906	103,739,441	90,913,202	82,637,239

The energy forecasts are translated into monthly forecasts using the monthly MDEV and HDEV counts found in Table 11 and multiplying the average daily kWh charging by the number of days in each month. Similar to LDEVs, an additional monthly adjustment is made to account for the reality that EV batteries perform worse in cold temperatures. To adjust for this, the Integration Model adds ten percent to the energy totals in winter months and subtracted ten percent to the energy totals in summer months.

To integrate the MDEV/HDEV forecasted energy into the revenue forecast, the incremental load of MDEV and HDEVs for each rate class from their 2023 adoption levels are added to the revenue forecast. The incremental load in each month in 2025 to 2029 is the difference between that month's forecasted MDEV/HDEV load and the same month in 2023. The incremental load is used since the base revenue forecast uses a dataset through 2023 and, therefore, already has the 2023 MDEV/HDEV load embedded into the forecast.

Tables 16 and 17 below display the annual MDEV and HDEV incremental energy impacts from 2023 levels for each rate class. The model is, however, monthly.

Table 15: Annual MDEV Incremental Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0	0	577,219	2,634,931	2,324,005	2,028,965
2026	0	0	1,067,467	4,872,852	4,297,847	3,752,222
2027	0	0	1,695,020	7,737,553	6,824,509	5,958,116
2028	0	0	2,575,591	11,757,251	10,369,875	9,053,387
2029	0	0	3,751,400	17,124,672	15,103,931	13,186,440

Table 16: Annual HDEV Incremental Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0	0	4,163,168	19,423,726	17,022,196	15,472,641
2026	0	0	7,592,630	35,424,263	31,044,442	28,218,421
2027	0	0	11,776,202	54,943,190	48,150,070	43,766,898
2028	0	0	16,627,625	77,578,043	67,986,372	61,797,472
2029	0	0	21,736,159	101,412,480	88,873,944	80,783,617

Shown in Tables 18 and 19 are the average percentage increase in MDEV and HDEV energy from the base revenue forecast for each rate class.

Table 17: Annual Percentage MDEV Impact from Revenue Base Forecast by Rate Class

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.0%	0.0%	0.1%	0.1%
2026	0.0%	0.0%	0.0%	0.1%	0.1%	0.2%
2027	0.0%	0.0%	0.1%	0.1%	0.2%	0.3%
2028	0.0%	0.0%	0.1%	0.1%	0.3%	0.5%
2029	0.0%	0.0%	0.2%	0.2%	0.4%	0.7%

Table 18: Annual Percentage HDEV Impact from Revenue Base Forecast by Rate Class

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.2%	0.2%	0.4%	1.0%
2026	0.0%	0.0%	0.3%	0.4%	0.8%	1.8%
2027	0.0%	0.0%	0.5%	0.6%	1.2%	2.9%
2028	0.0%	0.0%	0.7%	0.8%	1.7%	4.2%
2029	0.0%	0.0%	0.9%	1.1%	2.3%	5.8%

4.2 MDEV & HDEV Billing Demand Forecast

MDEVs and HDEVs will put upward pressure on Toronto Hydro's three rate classes with billing demand, and that pressure is a function of the number of EVs being charged at the premise, the load profiles of those EVs, and the base load profile for that customer. The model accounts for these factors by using hourly load profiles of the MDEV and HDEVs, analyzing smart meter interval data for customers from Toronto Hydro, and then examining how the estimated number of MDEV and HDEVs would impact billing demand for each general service customer.

The following table displays the hourly load profile used for MDEVs and HDEVs for both the summer and winter. This load profile is layered onto the customer-specific hourly interval data to calculate the difference in the before and after technology billing demands.

Table 19: Summer and Winter MDEV and HDEV Charging Load Profiles

Hour Beginning	Summer MDEV	Winter MDEV	Summer HDEV	Winter HDEV
0	4.023	4.917	28.98	35.42
1	4.113	5.027	25.236	30.844
2	3.663	4.477	19.35	23.65
3	4.356	5.324	14.76	18.04
4	4.104	5.016	14.166	17.314
5	3.6	4.4	12.141	14.839
6	3.177	3.883	12.798	15.642
7	2.862	3.498	11.907	14.553
8	0.855	1.045	2.421	2.959
9	1.008	1.232	8.694	10.626
10	1.8	2.2	10.467	12.793
11	2.052	2.508	13.653	16.687
12	4.086	4.994	11.673	14.267
13	3.663	4.477	10.332	12.628
14	3.564	4.356	10.944	13.376
15	4.761	5.819	9.459	11.561
16	5.697	6.963	9.171	11.209
17	5.166	6.314	8.784	10.736
18	4.932	6.028	6.417	7.843
19	5.013	6.127	5.823	7.117
20	5.778	7.062	4.419	5.401
21	5.805	7.095	4.032	4.928
22	5.13	6.27	3.285	4.015
23	4.023	4.917	28.98	35.42

For display purposes, the following table displays the annual MDEV incremental billing demand impact from 2023 levels for each rate class.

Table 20: MDEV Incremental Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2023	-	-	-
2024	1,996	1,584	1,408
2025	5,156	4,091	3,637
2026	9,538	7,567	6,721
2027	15,147	12,015	10,668
2028	23,014	18,257	16,213
2029	33,525	26,592	23,607

For display purposes, the following table displays the annual HDEV incremental billing demand impact from 2023 levels for each rate class.

Table 21: HDEV Incremental Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2023	-	-	-
2024	14,434	12,280	13,100
2025	38,730	32,947	35,149
2026	70,696	60,137	64,160
2027	109,695	93,310	99,554
2028	154,940	131,796	140,617
2029	202,618	172,350	183,889

Shown in the following table is the average percentage increase in MDEV billing demand from the base revenue forecast for each rate class.

Table 22: MDEV Percentage Demand Impact from Revenue Forecast by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.1%
2026	0.0%	0.1%	0.2%
2027	0.1%	0.2%	0.3%
2028	0.1%	0.2%	0.5%
2029	0.2%	0.3%	0.7%

Shown in the following table is the average percentage increase in HDEV billing demand from the base revenue forecast for each rate class.

Table 23: HDEV Percentage Demand Impact from Revenue Forecast by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	0.2%	0.4%	0.9%
2026	0.3%	0.7%	1.7%
2027	0.5%	1.2%	2.7%
2028	0.7%	1.7%	4.0%
2029	1.0%	2.2%	5.5%

5 Renewable DER Forecast

Toronto Hydro provided the Renewable nameplate capacity forecast, and historical, data to Clearspring. It is Clearspring's understanding that the Renewable forecast is entirely driven by solar. The forecasts appear to be reasonable expectations of near-term technology adoption based on our experience with other clients in forecasting solar resources.[20]

The table below provides the 2022 to 2029 forecast for the Renewable capacity for Toronto Hydro.

Table 24: Annual Renewable Capacity Forecast by Year

Year	Total Renewable Nameplate kW
2022	100,366
2023	110,610
2024	117,616
2025	127,593
2026	139,278
2027	152,669
2028	167,768
2029	184,574

The Renewable capacity forecasted for Toronto Hydro is allocated to the different rate classes. The Integration Model uses the 2022 participation percentages in Toronto Hydro's net metering program by rate class to estimate the rate class allocations.

The following table displays the annual Renewable Capacity for each rate class.

Table 25: Forecasted Renewable Capacity by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-000 kW	GS 1-5 MW	LU
2022	14,262	0	11,141	66,302	8,662	0
2023	15,718	0	12,278	73,069	9,546	0
2024	16,713	0	13,055	77,697	10,150	0
2025	18,131	0	14,163	84,288	11,011	0
2026	19,791	0	15,460	92,007	12,020	0
2027	21,694	0	16,946	100,853	13,175	0
2028	23,840	0	18,622	110,828	14,478	0
2029	26,228	0	20,488	121,930	15,929	0

5.1 Renewable Energy Forecast

Renewables are not able to produce the same amount of electricity continuously and consistently during every hour of the day. For instance, solar will produce substantially more electricity during summer

[20] https://www.iea.org/reports/renewables-2022/renewable-electricity#abstract

months and during the mid-day while sunlight is most direct. Toronto Hydro provided the hourly capacity factors to Clearspring for both summer and winter months. The table below provides the hourly capacity factors of a one kW nameplate capacity solar array for both summer and winter.

Table 26: Summer and Winter Renewable Production Hourly Profiles

Hour Beginning	Summer	Winter
0	0	0
1	0	0
2	0	0
3	0	0
4	0	0
5	0	0
6	0	0
7	-0.03	-0.01
8	-0.13	-0.02
9	-0.22	-0.04
10	-0.28	-0.05
11	-0.32	-0.06
12	-0.33	-0.06
13	-0.35	-0.07
14	-0.34	-0.06
15	-0.33	-0.06
16	-0.32	-0.06
17	-0.28	-0.05
18	-0.20	-0.04
19	-0.09	-0.02
20	0	0
21	0	0
22	0	0
23	0	0

The hourly capacity factors can be summed to estimate the average production per day of a one kW solar array.[21] In the summer, the sum of the production factors is -3.22, meaning that for every one kW nameplate capacity, a solar array will have an average production of 3.22 kWh's during the summer months. In the winter, the sum of the production factors is -0.60, meaning a 0.6 kWh production expectation during winter months. The Integration Model multiplies the average daily production by the number of days in each month to estimate the energy contribution of Renewables based on the estimated nameplate capacity in each rate class.

[21] These production factors are for "average" summer and winter days. Cloudy days will have lower production and clear days will have higher production.

The table below provides the annual Renewable energy contribution by rate class and year. The annual totals are provided below for display purposes; however, the model disaggregates the forecasts into monthly contributions to match and integrate with the base revenue forecast.

Table 27: Annual Renewable Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LS
2022	-8,761,942	0	-6,844,303	-40,732,855	-5,321,292	0
2023	-9,353,911	0	-7,306,714	-43,484,823	-5,680,806	0
2024	-10,093,938	0	-7,884,779	-46,925,089	-6,130,238	0
2025	-10,859,950	0	-8,483,142	-50,486,158	-6,595,452	0
2026	-11,824,330	0	-9,236,457	-54,969,403	-7,181,138	0
2027	-12,939,083	0	-10,107,236	-60,151,711	-7,858,148	0
2028	-14,204,210	0	-11,095,477	-66,033,082	-8,626,484	0
2029	-15,619,711	0	-12,201,181	-72,613,517	-9,486,144	0

To integrate the Renewable forecasted energy into the revenue forecast, the incremental production of Renewables for each rate class from their 2023 adoption levels are added to the revenue forecast. The incremental production forecasted in each month in 2025 to 2029 is the difference between that month's forecasted production and the same month in 2023. The incremental production is used since the base revenue forecast uses a dataset through 2023 and, therefore, already has the 2023 Renewable production embedded into the forecast.

Table 28: Annual Incremental Renewable Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	-1,818,949	0	-1,420,854	-8,456,000	-1,104,682	0
2026	-2,783,328	0	-2,174,169	-12,939,244	-1,690,368	0
2027	-3,898,081	0	-3,044,947	-18,121,552	-2,367,378	0
2028	-5,163,208	0	-4,033,189	-24,002,924	-3,135,713	0
2029	-6,578,709	0	-5,138,893	-30,583,358	-3,995,374	0

Shown below is the average percentage impact from Renewables from the base revenue forecast for each rate class.

Table 29: Renewable Energy Percentage of Base Forecast by Rate Class

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	-0.1%	-0.1%	0.0%	0.0%
2026	-0.1%	0.0%	-0.1%	-0.1%	0.0%	0.0%
2027	-0.1%	0.0%	-0.1%	-0.1%	-0.1%	0.0%
2028	-0.1%	0.0%	-0.2%	-0.3%	-0.1%	0.0%
2029	-0.1%	0.0%	-0.2%	-0.3%	-0.1%	0.0%

5.2 Renewable Billing Demand Forecast

Renewables will put downward pressure on Toronto Hydro's three rate classes regarding billing demand, and that pressure is a function of the nameplate capacity producing at the premise, the production profiles of those Renewables (provided in the table in the prior subsection), and the base load profile for that customer. The Integration Model accounts for these factors by using the hourly Renewable capacity factors, analyzing smart meter interval data for customers from Toronto Hydro, and then examining how the estimated production of the Renewables would impact billing demand for each general service customer.

The following table provides the forecasted incremental billing demand reductions by rate class of Renewables.[22]

Table 30: Incremental Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	(12,821)	(2,816)	-
2026	(19,614)	(4,309)	-
2027	(27,465)	(6,034)	-
2028	(36,375)	(7,991)	-
2029	(46,344)	(10,182)	-

Shown below is the average percentage impact from Renewables from the base revenue forecast for each rate class.

Table 31: Renewable Billing Demand Percentage of Base Forecast by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	-0.1%	0.0%	0.0%
2026	-0.1%	0.0%	0.0%
2027	-0.1%	-0.1%	0.0%
2028	-0.2%	-0.1%	0.0%
2029	-0.2%	-0.1%	0.0%

[22] The forecast is monthly but annual numbers are provided for display purposes.

6 Non-Renewable DER Forecast

Toronto Hydro provided the behind-the-meter Non-Renewable nameplate capacity forecast and historical data to Clearspring. It is Clearspring's understanding that these Non-Renewable DERs will be actively dispatched by the IESO. The forecasts increase substantially until 2024 and then grow by less than two percent thereafter.

The table below provides the 2022 to 2029 forecast for Non-Renewable capacity for Toronto Hydro.

Table 32: Annual Non-Renewable Capacity Forecast by Year

Year	Total Nameplate kW
2022	170,013
2023	198,186
2024	212,056
2025	215,566
2026	218,717
2027	221,597
2028	224,297
2029	226,817

The Non-Renewable capacity forecasted for Toronto Hydro is then allocated to the different rate classes. The Integration Model uses the current nameplate capacity of non-renewable generation by rate class to estimate the rate class allocations.

For display purposes, the following table displays the annual Non-Renewable capacity for each rate class.

Table 33: Forecasted Non-Renewable Capacity by Rate Class and Year

Year	Residential	CSMUR	GS<50 kW	GS50-000 kW	GS 1-5 MW	LU
2022	0	0	95	32,026	70,748	67,145
2023	0	0	110	37,333	82,471	78,271
2024	0	0	118	39,946	88,243	83,749
2025	0	0	120	40,607	89,704	85,135
2026	0	0	122	41,201	91,015	86,379
2027	0	0	123	41,743	92,214	87,517
2028	0	0	125	42,252	93,337	88,583
2029	0	0	126	42,726	94,386	89,579

6.1 Non-Renewable DER Energy Forecast

Unlike Renewables, Non-Renewables can continuously and consistently produce the same amount of electricity in any hour of the day and are not significantly impacted by winter/summer conditions. Toronto Hydro provided the capacity factors by hour for the existing Non-Renewable generation on its system that are dispatched by the IESO. These capacity factors are for an average day and are the same for both winter and summer months.

The table below provides the hourly production factors of a one kW Non-Renewable nameplate capacity.

Table 34: Non-Renewable Production Hourly Profile

Hour Beginning	Non-Renewable
0	-0.66
1	-0.65
2	-0.65
3	-0.65
4	-0.65
5	-0.65
6	-0.66
7	-0.67
8	-0.67
9	-0.67
10	-0.67
11	-0.67
12	-0.67
13	-0.67
14	-0.68
15	-0.68
16	-0.68
17	-0.67
18	-0.67
19	-0.67
20	-0.67
21	-0.66
22	-0.66
23	-0.66

The hourly capacity factors can be summed to estimate the average production per day of a one kW Non-Renewable resource. The sum of the production factors is -15.96. This means that on an average day, for every one kW of Non-Renewable nameplate capacity, 15.96 kWh's will be generated. The Integration Model multiplies this sum by the number of days in each month to estimate the energy contribution of Non-Renewables based on the estimated nameplate capacity in each rate class. The table below provides the annual Non-Renewable energy contribution by rate class and year.

The annual Non-Renewable energy contributions by rate class are provided below for display purposes; however, the model disaggregates the forecasts into monthly contributions to match and integrate with the base revenue forecast.

Table 35: Annual Non-Renewable Energy Contribution by Rate Class and Year (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LS
2022	0	0	-550,179	-186,298,506	-411,547,347	-390,586,651
2023	0	0	-600,616	-203,377,196	-449,275,454	-426,393,211
2024	0	0	-666,709	-225,757,248	-498,714,663	-473,314,410
2025	0	0	-693,400	-234,795,282	-518,680,357	-492,263,223
2026	0	0	-704,142	-238,432,497	-526,715,237	-499,888,875
2027	0	0	-713,875	-241,728,342	-533,996,005	-506,798,824
2028	0	0	-722,892	-244,781,589	-540,740,858	-513,200,151
2029	0	0	-731,325	-247,637,294	-547,049,324	-519,187,318

To integrate the Non-Renewable forecasted energy into the revenue forecast, the incremental production of Non-Renewables for each rate class from their 2023 adoption levels are added to the revenue forecast. The incremental production forecasted in each month in 2025 to 2029 is the difference between that month's forecasted production and the same month in 2023.

Table 36: Annual Incremental Non-Renewable Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0	0	-92,784	-31,418,086	-69,404,903	-65,870,012
2026	0	0	-103,526	-35,055,300	-77,439,783	-73,495,664
2027	0	0	-113,259	-38,351,145	-84,720,552	-80,405,613
2028	0	0	-122,276	-41,404,393	-91,465,404	-86,806,940
2029	0	0	-130,709	-44,260,098	-97,773,870	-92,794,107

Shown below is the average percentage impact from Non-Renewables from the base revenue forecast for each rate class.

Table 37: Non-Renewable Energy Percentage of Base Forecast by Rate Class

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	0.0%	0.0%	0.0%	-0.3%	-1.7%	-4.1%
2026	0.0%	0.0%	0.0%	-0.4%	-1.9%	-4.6%
2027	0.0%	0.0%	0.0%	-0.4%	-2.1%	-5.2%
2028	0.0%	0.0%	0.0%	-0.4%	-2.3%	-5.8%
2029	0.0%	0.0%	0.0%	-0.5%	-2.5%	-6.6%

6.2 Non-Renewable DER Demand Forecast

Non-Renewables will put downward pressure on billing demand and is a function of the nameplate capacity producing at the premise, the production profiles of those Non-Renewables (provided in the table in the prior subsection), and the base load profile for every customer. The Integration Model accounts for these factors by using the hourly Non-Renewable capacity factors provided by Toronto Hydro, receiving smart meter interval data for customers from Toronto Hydro, and then analyzing how the estimated production of the Non-Renewables would impact billing demand for each general service customer.

The following table provides the forecasted incremental billing demand reductions by rate class of Non-Renewables.[23]

Table 38: Incremental Non-Renewable Demand from 2023 Levels by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	-43,383	-95,783	-90,780
2026	-48,397	-106,855	-101,272
2027	-52,941	-116,887	-110,778
2028	-57,150	-126,180	-119,585
2029	-61,087	-134,871	-127,822

Shown below is the average percentage impact from Non-Renewables from the base revenue forecast for each rate class.

Table 39: Non-Renewable Billing Demand Percentage of Base Forecast by Rate Class

Year	GS50-999 kW	GS 1-5 MW	LU
2025	-0.2%	-1.1%	-2.3%
2026	-0.2%	-1.3%	-2.5%
2027	-0.2%	-1.4%	-2.9%
2028	-0.3%	-1.5%	-3.2%
2029	-0.3%	-1.7%	-3.6%

[23] The forecast is monthly but we show annual numbers for display purposes.

7 Energy Storage Forecast

Energy storage can be used for multiple purposes. One viable option may be for back-up power when outages are encountered. Another possible purpose is to reduce billing peaks or shift energy use from on-peak to off-peak. If energy storage is actively used to reduce billing demands, this could have the impact of reducing demands but increasing energy use at the premise through energy losses that result from the inefficiency in the discharge/charging cycle. Under the back-up option, there would be minimal impacts on demand and energy.

It is unclear how energy storage will be used in the future on Toronto Hydro's system. There is no evidence yet that reveals how energy storage may be used on the system and if its presence will result in meaningful energy or billing demand changes. Given this current lack of evidence, it is assumed that energy storage will only be used for back-up power through the forecast period meaning that energy storage is assumed to have zero kWh and zero kW impacts.

The forecasted energy storage nameplate kW, provided by Toronto Hydro, are presented in Table 40 below.

Table 40: Annual Energy Storage Nameplate kW

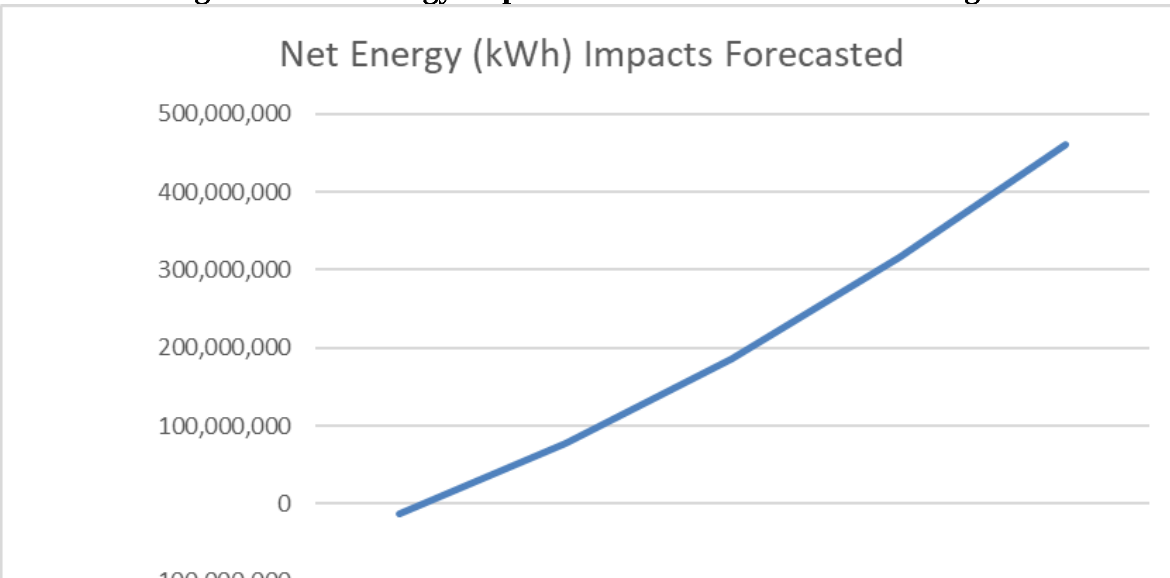
Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LS
2019	12	0	0	803	3,338	4,926
2020	24	0	0	1,553	6,457	9,531
2021	25	0	0	1,609	6,692	9,876
2022	25	0	0	1,656	6,883	10,159
2023	77	0	0	5,003	20,800	30,699
2024	82	0	0	5,309	22,073	32,578
2025	100	0	0	6,487	26,969	39,804
2026	105	0	0	6,842	28,446	41,984
2027	111	0	0	7,198	29,927	44,171
2028	116	0	0	7,554	31,408	46,357
2029	122	0	0	7,912	32,897	48,553

8 Net Results

The six technology inputs can be aggregated and layered onto the base revenue forecast to determine the expected forecast after accounting for the incremental impacts of the technologies. There is a balancing of impacts between the technologies, as EVs will increase energy and billing demand, while DERs will lower energy and billing demand.

The net forecasted energy impacts are provided below annually.[24]

Figure 1: Net Energy Impacts Forecasted for Six Technologies

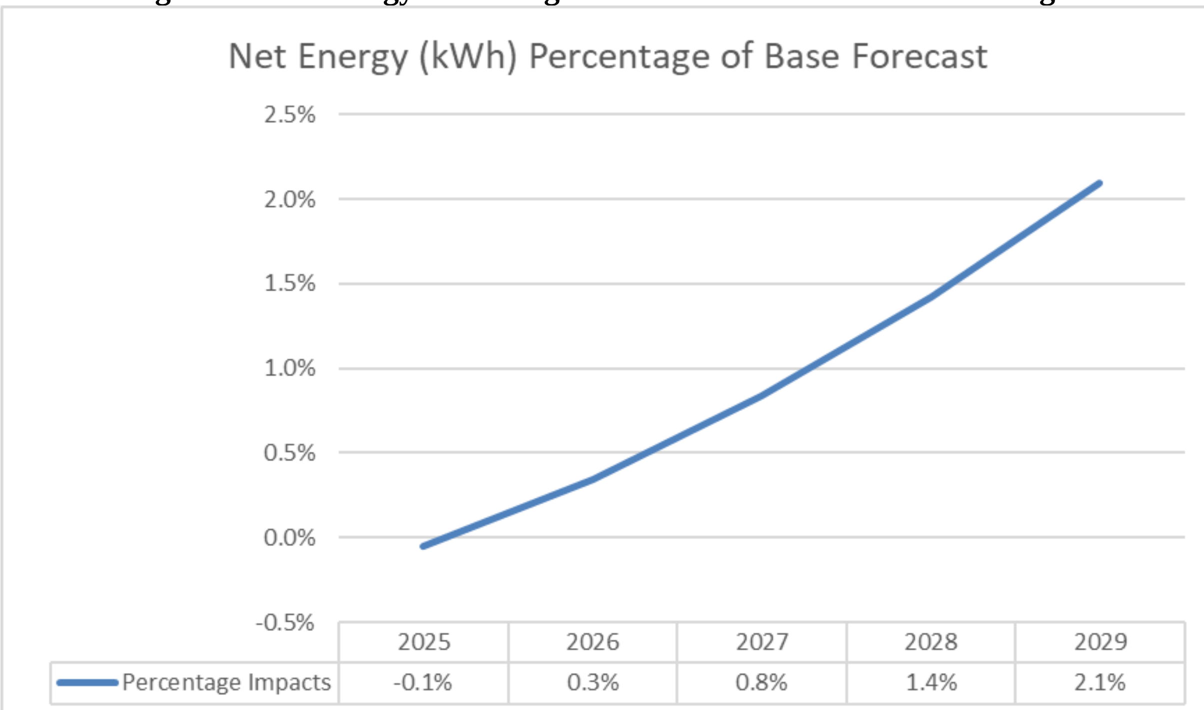


	2025	2026	2027	2028	2029
Net kWh Impacts	-12,591,796	76,839,461	186,478,145	316,850,172	460,975,421

[24] The forecasts are integrated on a monthly basis as the base revenue forecast is monthly, but we display annual impacts here for display purposes.

The following graph displays the percentage difference of the net energy impacts, in kWh's, relative to the total energy for that same year in the base revenue forecast.

Figure 2: Net Energy Percentage of Base Forecast for Six Technologies



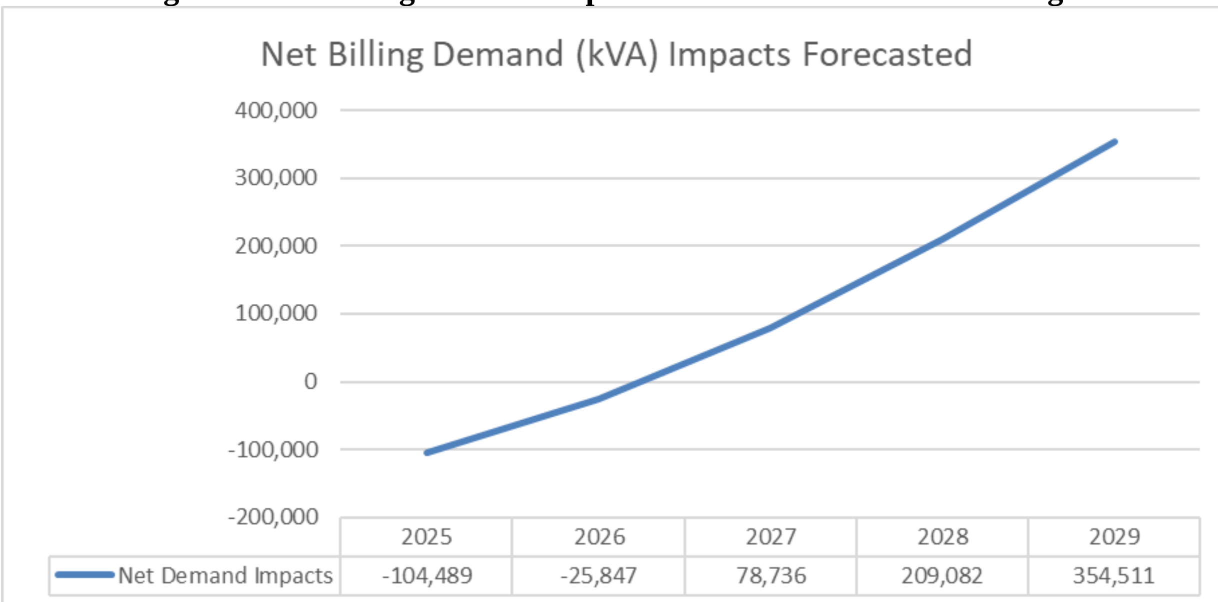
The following table displays, annually, the forecasted net energy by rate class that is projected to be added in 2025 to 2029.

Table 41: Annual Incremental Net Energy by Rate Class (kWh)

Year	Residential	CSMUR	GS<50 kW	GS50-999 kW	GS 1-5 MW	LU
2025	92,227,387	593,699	5,205,746	-13,065,835	-49,382,286	-48,170,506
2026	148,504,808	955,057	9,565,925	-56,972	-40,922,689	-41,206,668
2027	211,452,614	1,359,474	14,844,594	17,083,835	-28,034,931	-30,227,441
2028	281,703,920	1,810,945	21,084,234	38,415,539	-10,812,035	-15,352,432
2029	357,655,979	2,299,354	27,882,469	62,088,527	9,106,692	1,942,401

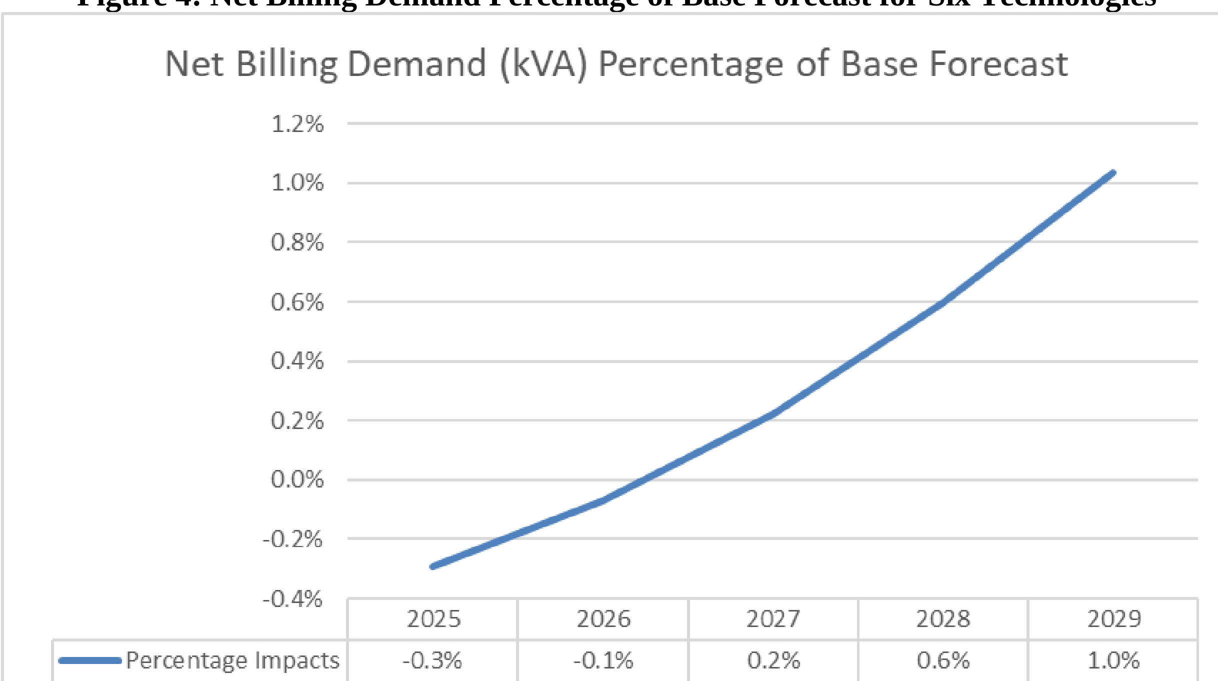
The net forecasted billing demand impacts are provided below annually.

Figure 3: Net Billing Demand Impacts Forecasted for Six Technologies



The following graph displays the percentage difference of the net demand impacts, in kVA, relative to the total billing demand in the base revenue forecast.

Figure 4: Net Billing Demand Percentage of Base Forecast for Six Technologies



The following table displays, annually, the forecasted net billing demand by rate class that is projected to be added in 2025 to 2029.

Table 42: Annual Incremental Net Billing Demand by Rate Class (kVA)

Year	GS50-999 kW	GS 1-5 MW	LU
2025	587	-55,536	-49,540
2026	33,489	-33,339	-25,997
2027	75,266	-2,718	6,188
2028	126,111	36,214	46,757
2029	182,172	80,147	92,192

9 Load Profiles

To assist with the cost allocation model ("CAM") study used for rate setting purposes by Toronto Hydro, Clearspring performed a detailed comparison between hourly 2019 rate class load profiles and hourly 2019 load profiles modified with 2025 EV and DER forecasted load impacts (LDEVs, MDEVs, HDEVs, Renewable, and non-renewable DERs). This analysis provides Toronto Hydro with the changes in the rate class allocators used within the CAM due to the anticipated changes in the technologies studied in the Integration Model.

The 2025 hourly EV/DER loads were constructed by multiplying the expected LDEV, MDEV, and HDEV counts by the same kW load profiles used in the Integration Model. Similarly, for Renewable and Non-Renewable DERs, the 2025 loads were forecasted by multiplying the total nameplate capacities by the kW load profiles used in the Integration Model.

One load profile needed to be added to the analysis: a residential LDEV load profile. For the Integration Model, it was not necessary to include a residential LDEV load profile because billing demand is not a component of residential rates. However, how LDEV's may impact the cost allocations between the residential and other classes in the CAM is pertinent.

The residential LDEV load profile assumed that EV owners would typically "smart charge" their vehicles in response to time-of-use pricing such as the Ultra-Low Overnight ("ULO") rate offering. The ULO provides a steep reduction in the electricity rate if consumers use electricity during off-peak, night-time hours. Our analysis assumes that consumers are typically charging vehicles during this time by using an LDEV load profile derived from the Alternative Fuels Data Center of the U.S. Department of Energy ("DOE") that estimates the load shape of residential LDEVs in the presence of smart charging.[25] This DOE load shape was then scaled to match the energy assumptions for the City of Toronto used in the Integration Model. The seasonal adjustment of adding ten percent for winter months and subtracting ten percent for summer months consistent with the Integration Model is also implemented for the CAM analysis.

[25] https://afdc.energy.gov/evi-pro-lite/load-profile/. The load shape used Chicago as the target city, 25 miles of travel per day in a shoulder month, and Level 1 charging.

The following table displays the residential LDEV load profiles used for the analysis.

Table 43: Residential, Smart Charging LDEV Load Profile for Toronto Hydro

Hour Beginning	Summer LDEV	Winter LDEV
0	1.319	1.612
1	1.023	1.250
2	0.782	0.956
3	0.587	0.717
4	0.390	0.476
5	0.251	0.306
6	0.141	0.173
7	0.086	0.105
8	0.057	0.070
9	0.043	0.052
10	0.041	0.050
11	0.047	0.057
12	0.052	0.064
13	0.059	0.072
14	0.085	0.104
15	0.124	0.151
16	0.170	0.208
17	0.217	0.265
18	0.245	0.299
19	0.271	0.332
20	0.295	0.360
21	0.307	0.375
22	0.305	0.373
23	1.556	1.902

The CAM input tables are compiled by calculating the yearly, quarterly, and monthly noncoincident ("NCP") and coincident peaks ("CP") and comparing the percent differences between the peaks that did not include the impacts of the six technologies and the peaks that did have the 2025 loads added.[26] Ultimately, adding the EV and DER loads to 2019 load data increases the NCP and CPs for the residential, CSMur, and GS<50 rate classes, while it decreases the NCP and CPs for the GS50-999, GS1-5MW, and LU rate classes. The increases are due to EVs having a larger impact on peaks for the lower-use rate classes, whereas the forecasted increase in DERs by 2025 causes peaks to drop for the larger use rate classes.

[26] The NCP or CP impacts of the CAManalysis will not match the demand impacts found in the Integration Model because of the different definitions of demand being analyzed. In the Integration Model, it is billing demand that is relevant which is based on each individual customer's own peak during the month. For the CAM analysis, the relevant peak demand is either the rate class non-coincident peak or the system coincident peak.

The following table displays the annual, quarterly, and monthly NCPs for the 2019 data prior to adding 2025 technology impacts and then the NCPs after adding in the impacts.[27]

Table 44: NCPs Before and After 2025 Technology Impacts by Rate Class

	RES	CSMUR	GS<50	GS50-999	GS1-5MW	LU	SL	USL	**Total**
1NCP: 2025Baseline	1,202,242	81,697	642,970	1,577,135	645,935	310,050	31,389	6,323	**4,497,741**
1NCP: 2025Net	1,212,328	81,797	642,961	1,566,120	625,420	290,411	31,389	6,323	**4,456,749**
% Increase	0.8%	0.1%	0.0%	-0.7%	-3.2%	-6.3%	0.0%	0.0%	-0.9%
4NCP: 2025Baseline	4,364,424	300,589	2,502,247	6,194,492	2,516,961	1,195,740	121,365	24,249	**17,220,066**
4NCP: 2025Net	4,410,788	300,966	2,502,763	6,152,751	2,432,341	1,115,494	121,365	24,249	**17,060,716**
% Increase	1.1%	0.1%	0.0%	-0.7%	-3.4%	-6.7%	0.0%	0.0%	-0.9%
12NCP: 2025Baseline	10,817,700	831,752	6,753,047	17,271,260	6,912,953	3,347,378	348,075	70,127	**46,352,293**
12NCP: 2025Net	10,981,253	832,870	6,763,953	17,168,462	6,666,153	3,115,743	348,075	70,127	**45,946,635**
% Increase	1.5%	0.1%	0.2%	-0.6%	-3.6%	-6.9%	0.0%	0.0%	-0.9%

The following table displays the annual, quarterly, and monthly CPs for the 2019 data prior to adding 2025 technology impacts and then the CPs after adding in the impacts.

Table 45: CPs Before and After 2025 Technology Impacts by Rate Class

	RES	CSMUR	GS<50	GS50-999	GS1-5MW	LU	SL	USL	**Total**
1CP: 2025Baseline	884,507	46,895	642,970	1,571,419	641,174	290,102	-	4,429	**4,081,498**
1CP: 2025Net	913,274	48,766	638,780	1,551,590	615,798	255,329	-	4,437	**4,027,973**
% Increase	3.3%	4.0%	-0.7%	-1.3%	-4.0%	-12.0%		0.2%	-1.3%
4CP: 2025Baseline	3,551,046	218,023	2,344,649	6,117,966	2,355,768	1,037,809	28,111	19,135	**15,672,506**
4CP: 2025Net	3,603,754	220,065	2,341,719	6,064,921	2,266,427	942,752	28,111	19,142	**15,486,890**
% Increase	1.5%	0.9%	-0.1%	-0.9%	-3.8%	-9.2%	0.0%	0.0%	-1.2%
12CP: 2025Baseline	8,757,869	644,093	6,321,104	16,957,736	6,682,659	3,037,182	140,169	59,368	**42,600,180**
12CP: 2025Net	8,891,672	646,676	6,324,315	16,834,621	6,425,229	2,781,677	140,169	59,376	**42,103,735**
% Increase	1.5%	0.4%	0.1%	-0.7%	-3.9%	-8.4%	0.0%	0.0%	-1.2%

[27] The following tables include metered and unmetered street lighting but there are zero impacts of the technologies assumed on those rate classes.

Appendix A: Monthly Projected Impacts by Technology by Rate Class from the Integration Model

The following tables provide the forecasted monthly impacts for each technology resulting from the Integration Model.

LDEV Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	7,864,340	49,646	165,488	397,170	628	148,939	326	16,549	33
Feb-25	7,232,014	45,655	152,182	365,236	921	136,964	352	15,218	29
Mar-25	8,149,405	51,446	171,486	411,567	1,086	154,338	352	17,149	38
Apr-25	8,024,456	50,657	168,857	405,257	1,034	151,971	328	16,886	32
May-25	6,900,930	43,564	145,215	348,516	803	130,693	288	14,521	32
Jun-25	6,791,175	42,872	142,905	342,973	744	128,615	329	14,291	33
Jul-25	7,134,165	45,037	150,123	360,295	720	135,110	316	15,012	36
Aug-25	7,250,782	45,773	152,577	366,184	706	137,319	311	15,258	38
Sep-25	7,129,742	45,009	150,030	360,071	854	135,027	318	15,003	31
Oct-25	9,147,132	57,744	192,481	461,955	993	173,233	357	19,248	39
Nov-25	8,989,998	56,752	189,175	454,019	1,084	170,257	376	18,917	31
Dec-25	9,432,197	59,544	198,480	476,351	1,022	178,632	422	19,848	39
Jan-26	12,953,184	81,771	272,571	654,171	1,034	245,314	537	27,257	55
Feb-26	11,857,010	74,851	249,505	598,811	1,510	224,554	577	24,950	48
Mar-26	13,301,624	83,971	279,903	671,768	1,773	251,913	574	27,990	62
Apr-26	13,041,139	82,327	274,422	658,613	1,681	246,980	533	27,442	51
May-26	11,168,233	70,503	235,011	564,026	1,299	211,510	466	23,501	52
Jun-26	10,945,913	69,100	230,333	552,798	1,199	207,299	531	23,033	54
Jul-26	11,453,320	72,303	241,010	578,423	1,155	216,909	507	24,101	58
Aug-26	11,595,864	73,203	244,009	585,622	1,129	219,608	497	24,401	61
Sep-26	11,359,749	71,712	239,041	573,698	1,361	215,137	507	23,904	49
Oct-26	14,521,162	91,670	305,566	733,358	1,576	275,009	566	30,557	61
Nov-26	14,221,337	89,777	299,257	718,216	1,714	269,331	595	29,926	50
Dec-26	14,869,601	93,869	312,898	750,955	1,611	281,608	665	31,290	61
Jan-27	18,460,325	116,537	388,457	932,296	1,474	349,611	766	38,846	78
Feb-27	16,894,190	106,650	355,501	853,202	2,152	319,951	823	35,550	69
Mar-27	18,948,238	119,617	398,724	956,937	2,525	358,851	818	39,872	88
Apr-27	18,573,091	117,249	390,830	937,991	2,394	351,747	759	39,083	73
May-27	15,902,305	100,389	334,629	803,109	1,849	301,166	664	33,463	74
Jun-27	15,582,489	98,370	327,899	786,958	1,707	295,109	756	32,790	76
Jul-27	16,301,506	102,909	343,029	823,270	1,644	308,726	722	34,303	83
Aug-27	16,501,106	104,169	347,229	833,350	1,606	312,506	708	34,723	87
Sep-27	16,161,974	102,028	340,093	816,223	1,937	306,084	721	34,009	70
Oct-27	20,655,931	130,398	434,658	1,043,180	2,242	391,193	806	43,466	87
Nov-27	20,225,697	127,682	425,605	1,021,452	2,438	383,045	847	42,561	70
Dec-27	21,143,844	133,478	444,925	1,067,821	2,290	400,433	946	44,493	87
Jan-28	24,780,945	156,438	521,460	1,251,504	1,978	469,314	1028	52,146	105
Feb-28	22,645,026	142,954	476,514	1,143,635	2,884	428,863	1103	47,651	92
Mar-28	25,361,613	160,104	533,679	1,280,830	3,380	480,311	1095	53,368	118
Apr-28	24,824,465	156,713	522,376	1,253,702	3,200	470,138	1015	52,238	98
May-28	21,225,502	133,993	446,644	1,071,945	2,468	401,979	886	44,664	99
Jun-28	20,770,692	131,122	437,073	1,048,976	2,276	393,366	1007	43,707	102
Jul-28	21,700,594	136,992	456,641	1,095,938	2,189	410,977	961	45,664	110
Aug-28	21,938,140	138,492	461,640	1,107,935	2,135	415,476	941	46,164	116
Sep-28	21,460,341	135,476	451,585	1,083,805	2,572	406,427	957	45,159	93
Oct-28	27,393,950	172,934	576,445	1,383,468	2,974	518,801	1069	57,645	116
Nov-28	26,791,242	169,129	563,762	1,353,030	3,229	507,386	1122	56,376	93
Dec-28	27,974,618	176,599	588,664	1,412,793	3,030	529,798	1252	58,866	115
Jan-29	31,655,232	199,834	666,114	1,598,674	2,527	599,503	1313	66,611	134
Feb-29	28,893,361	182,399	607,997	1,459,192	3,680	547,197	1407	60,800	117
Mar-29	32,322,924	204,049	680,164	1,632,395	4,308	612,148	1396	68,016	151
Apr-29	31,603,326	199,507	665,022	1,596,053	4,073	598,520	1292	66,502	124
May-29	26,992,323	170,398	567,994	1,363,185	3,139	511,194	1127	56,799	126
Jun-29	26,385,939	166,570	555,234	1,332,561	2,891	499,710	1280	55,523	129
Jul-29	27,538,617	173,847	579,489	1,390,774	2,778	521,540	1219	57,949	140
Aug-29	27,811,764	175,571	585,237	1,404,569	2,707	526,713	1193	58,524	147
Sep-29	27,178,946	171,576	571,921	1,372,610	3,257	514,729	1212	57,192	118
Oct-29	34,659,849	218,802	729,340	1,750,416	3,763	656,406	1352	72,934	146
Nov-29	33,864,866	213,783	712,611	1,710,267	4,082	641,350	1418	71,261	118
Dec-29	35,327,541	223,017	743,390	1,784,136	3,827	669,051	1581	74,339	145

MDEV Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	0	0	42,318	193,177	405	170,382	314	148,751	260
Feb-25	0	0	39,992	182,560	417	161,018	316	140,576	281
Mar-25	0	0	46,236	211,063	415	186,157	336	162,524	284
Apr-25	0	0	46,641	212,909	430	187,786	357	163,946	319
May-25	0	0	41,036	187,322	366	165,218	308	144,243	273
Jun-25	0	0	41,263	188,360	397	166,134	293	145,042	264
Jul-25	0	0	44,241	201,956	440	178,125	314	155,511	262
Aug-25	0	0	45,844	209,273	426	184,579	337	161,146	280
Sep-25	0	0	45,917	209,603	424	184,870	338	161,400	313
Oct-25	0	0	59,950	273,664	532	241,372	464	210,729	392
Nov-25	0	0	59,912	273,491	603	241,219	465	210,595	435
Dec-25	0	0	63,868	291,550	571	257,147	465	224,501	465
Jan-26	0	0	82,427	376,269	789	331,869	611	289,737	507
Feb-26	0	0	77,037	351,663	804	310,166	609	270,790	542
Mar-26	0	0	88,154	402,414	791	354,928	641	309,869	542
Apr-26	0	0	88,082	402,083	812	354,637	673	309,615	602
May-26	0	0	76,812	350,639	684	309,263	577	270,001	510
Jun-26	0	0	76,602	349,678	737	308,416	544	269,261	490
Jul-26	0	0	81,498	372,030	811	328,129	579	286,472	482
Aug-26	0	0	83,841	382,725	779	337,563	616	294,708	512
Sep-26	0	0	83,404	380,730	770	335,803	614	293,172	569
Oct-26	0	0	108,200	493,920	960	435,636	838	380,331	708
Nov-26	0	0	107,481	490,637	1,082	432,741	835	377,803	780
Dec-26	0	0	113,927	520,064	1,019	458,696	829	400,463	830
Jan-27	0	0	133,663	610,157	1,280	538,157	991	469,837	822
Feb-27	0	0	124,378	567,770	1,298	500,773	983	437,198	875
Mar-27	0	0	141,745	647,049	1,271	570,696	1,031	498,245	872
Apr-27	0	0	141,083	644,028	1,301	568,031	1,078	495,918	964
May-27	0	0	122,586	559,588	1,092	493,556	920	430,898	815
Jun-27	0	0	121,831	556,143	1,173	490,517	865	428,244	779
Jul-27	0	0	129,198	589,773	1,285	520,179	918	454,140	764
Aug-27	0	0	132,504	604,865	1,232	533,490	974	465,762	809
Sep-27	0	0	131,429	599,959	1,213	529,163	967	461,984	896
Oct-27	0	0	170,031	776,172	1,508	684,582	1,317	597,672	1,113
Nov-27	0	0	168,457	768,985	1,696	678,244	1,308	592,138	1,223
Dec-27	0	0	178,113	813,064	1,593	717,121	1,296	626,080	1,298
Jan-28	0	0	200,435	914,959	1,919	806,992	1,486	704,542	1,232
Feb-28	0	0	187,023	853,735	1,952	752,993	1,478	657,398	1,316
Mar-28	0	0	213,687	975,455	1,917	860,350	1,554	751,126	1,314
Apr-28	0	0	213,207	973,261	1,967	858,415	1,630	749,436	1,457
May-28	0	0	185,678	847,597	1,654	747,579	1,394	652,671	1,234
Jun-28	0	0	184,935	844,205	1,780	744,587	1,312	650,060	1,182
Jul-28	0	0	196,521	897,094	1,955	791,235	1,396	690,785	1,162
Aug-28	0	0	201,942	921,842	1,877	813,063	1,484	709,842	1,233
Sep-28	0	0	200,675	916,055	1,853	807,959	1,477	705,386	1,369
Oct-28	0	0	260,071	1,187,192	2,307	1,047,101	2,014	914,169	1,702
Nov-28	0	0	258,094	1,178,168	2,599	1,039,142	2,005	907,220	1,874
Dec-28	0	0	273,324	1,247,688	2,445	1,100,459	1,989	960,752	1,992
Jan-29	0	0	297,632	1,358,654	2,850	1,198,331	2,207	1,046,199	1,830
Feb-29	0	0	276,609	1,262,686	2,887	1,113,687	2,186	972,301	1,946
Mar-29	0	0	314,859	1,437,293	2,824	1,267,690	2,289	1,106,752	1,937
Apr-29	0	0	313,038	1,428,979	2,888	1,260,357	2,393	1,100,351	2,140
May-29	0	0	271,707	1,240,307	2,421	1,093,949	2,040	955,069	1,806
Jun-29	0	0	269,762	1,231,430	2,596	1,086,119	1,914	948,233	1,724
Jul-29	0	0	285,801	1,304,648	2,843	1,150,697	2,030	1,004,613	1,689
Aug-29	0	0	292,849	1,336,818	2,722	1,179,071	2,152	1,029,385	1,787
Sep-29	0	0	290,222	1,324,828	2,679	1,168,496	2,136	1,020,151	1,979
Oct-29	0	0	375,153	1,712,527	3,328	1,510,446	2,905	1,318,690	2,455
Nov-29	0	0	371,387	1,695,336	3,740	1,495,283	2,885	1,305,452	2,697
Dec-29	0	0	392,380	1,791,166	3,510	1,579,805	2,855	1,379,244	2,860

HDEV Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	-	-	293,308	1,368,463	3,124	1,199,268	2,464	1,090,097	2,708
Feb-25	-	-	279,647	1,304,722	2,989	1,143,408	2,745	1,039,322	2,981
Mar-25	-	-	325,909	1,520,565	3,370	1,332,564	2,727	1,211,258	2,854
Apr-25	-	-	331,170	1,545,112	3,509	1,354,076	2,869	1,230,812	3,004
May-25	-	-	293,326	1,368,545	2,641	1,199,340	2,254	1,090,162	2,473
Jun-25	-	-	296,770	1,384,615	2,656	1,213,422	2,364	1,102,963	2,365
Jul-25	-	-	319,999	1,492,992	2,777	1,308,400	2,565	1,189,294	2,802
Aug-25	-	-	333,336	1,555,215	2,824	1,362,930	2,637	1,238,860	2,667
Sep-25	-	-	335,489	1,565,263	3,052	1,371,735	2,695	1,246,864	2,885
Oct-25	-	-	440,011	2,052,920	4,057	1,799,099	3,582	1,635,324	3,775
Nov-25	-	-	441,591	2,060,294	4,976	1,805,561	3,788	1,641,198	4,282
Dec-25	-	-	472,611	2,205,021	4,794	1,932,395	3,992	1,756,486	4,204
Jan-26	-	-	579,105	2,701,881	6,169	2,367,823	4,865	2,152,276	5,347
Feb-26	-	-	542,642	2,531,756	5,799	2,218,732	5,327	2,016,758	5,784
Mar-26	-	-	622,459	2,904,150	6,437	2,545,084	5,209	2,313,401	5,450
Apr-26	-	-	623,357	2,908,341	6,606	2,548,756	5,399	2,316,739	5,655
May-26	-	-	544,755	2,541,617	4,906	2,227,374	4,185	2,024,613	4,592
Jun-26	-	-	544,346	2,539,706	4,871	2,225,700	4,336	2,023,091	4,338
Jul-26	-	-	580,226	2,707,110	5,035	2,372,406	4,650	2,156,442	5,082
Aug-26	-	-	597,962	2,789,857	5,066	2,444,922	4,730	2,222,357	4,784
Sep-26	-	-	595,836	2,779,939	5,421	2,436,230	4,786	2,214,456	5,124
Oct-26	-	-	774,195	3,612,095	7,138	3,165,499	6,302	2,877,339	6,642
Nov-26	-	-	770,199	3,593,448	8,679	3,149,158	6,607	2,862,485	7,468
Dec-26	-	-	817,549	3,814,364	8,292	3,342,760	6,905	3,038,464	7,272
Jan-27	-	-	930,161	4,339,771	9,908	3,803,206	7,814	3,456,995	8,588
Feb-27	-	-	865,251	4,036,925	9,247	3,537,804	8,495	3,215,752	9,223
Mar-27	-	-	985,752	4,599,135	10,193	4,030,502	8,250	3,663,600	8,631
Apr-27	-	-	980,852	4,576,274	10,394	4,010,468	8,496	3,645,390	8,898
May-27	-	-	852,007	3,975,135	7,672	3,483,654	6,546	3,166,532	7,183
Jun-27	-	-	846,531	3,949,586	7,575	3,461,263	6,743	3,146,179	6,746
Jul-27	-	-	897,491	4,187,342	7,788	3,669,624	7,193	3,335,572	7,860
Aug-27	-	-	920,232	4,293,446	7,796	3,762,608	7,280	3,420,093	7,362
Sep-27	-	-	912,555	4,257,628	8,303	3,731,219	7,330	3,391,561	7,848
Oct-27	-	-	1,180,319	5,506,909	10,882	4,826,040	9,608	4,386,719	10,126
Nov-27	-	-	1,169,143	5,454,765	13,174	4,780,344	10,030	4,345,182	11,336
Dec-27	-	-	1,235,909	5,766,273	12,535	5,053,337	10,438	4,593,324	10,993
Jan-28	-	-	1,352,787	6,311,580	14,410	5,531,223	11,364	5,027,708	12,490
Feb-28	-	-	1,250,830	5,835,889	13,368	5,114,346	12,280	4,648,779	13,334
Mar-28	-	-	1,416,909	6,610,746	14,652	5,793,400	11,858	5,266,018	12,406
Apr-28	-	-	1,402,229	6,542,254	14,859	5,733,376	12,146	5,211,459	12,721
May-28	-	-	1,211,752	5,653,564	10,912	4,954,563	9,310	4,503,542	10,215
Jun-28	-	-	1,198,049	5,589,629	10,720	4,898,533	9,542	4,452,613	9,547
Jul-28	-	-	1,264,215	5,898,336	10,971	5,169,072	10,132	4,698,524	11,072
Aug-28	-	-	1,290,446	6,020,722	10,933	5,276,326	10,209	4,796,015	10,323
Sep-28	-	-	1,274,205	5,944,944	11,593	5,209,917	10,236	4,735,650	10,958
Oct-28	-	-	1,641,334	7,657,827	15,132	6,711,021	13,361	6,100,107	14,081
Nov-28	-	-	1,619,414	7,555,558	18,248	6,621,396	13,892	6,018,641	15,702
Dec-28	-	-	1,705,455	7,956,992	17,298	6,973,198	14,404	6,338,417	15,169
Jan-29	-	-	1,822,353	8,502,390	19,412	7,451,163	15,308	6,772,873	16,826
Feb-29	-	-	1,674,971	7,814,766	17,900	6,848,557	16,444	6,225,122	17,855
Mar-29	-	-	1,886,513	8,801,736	19,508	7,713,498	15,788	7,011,327	16,518
Apr-29	-	-	1,856,703	8,662,653	19,675	7,591,612	16,083	6,900,536	16,843
May-29	-	-	1,596,005	7,446,339	14,372	6,525,681	12,262	5,931,639	13,455
Jun-29	-	-	1,569,921	7,324,644	14,048	6,419,032	12,504	5,834,698	12,510
Jul-29	-	-	1,648,499	7,691,258	14,305	6,740,319	13,212	6,126,738	14,437
Aug-29	-	-	1,674,747	7,813,718	14,189	6,847,638	13,249	6,224,287	13,398
Sep-29	-	-	1,646,123	7,680,172	14,977	6,730,603	13,223	6,117,907	14,156
Oct-29	-	-	2,111,073	9,849,446	19,463	8,631,670	17,184	7,845,916	18,111
Nov-29	-	-	2,074,019	9,676,566	23,371	8,480,165	17,792	7,708,203	20,110
Dec-29	-	-	2,175,233	10,148,791	22,063	8,894,005	18,372	8,084,371	19,348

Renewable Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	(46,909.61)	0	(36,642.98)	(218,075.22)	(401)	(28,489.09)	(66)	0	0
Feb-25	(43,558.79)	0	(34,025.51)	(202,497.79)	(403)	(26,454.07)	(67)	0	0
Mar-25	(49,541.99)	0	(38,699.23)	(230,312.74)	(373)	(30,087.78)	(70)	0	0
Apr-25	(49,217.60)	0	(38,445.84)	(228,804.68)	(446)	(29,890.77)	(76)	0	0
May-25	(280,002.48)	0	(218,721.15)	(1,301,686.39)	(1,534)	(170,050.76)	(426)	0	0
Jun-25	(277,805.84)	0	(217,005.27)	(1,291,474.58)	(1,977)	(168,716.71)	(446)	0	0
Jul-25	(294,129.59)	0	(229,756.40)	(1,367,361.08)	(1,924)	(178,630.43)	(442)	0	0
Aug-25	(301,193.15)	0	(235,274.03)	(1,400,198.42)	(1,981)	(182,920.26)	(461)	0	0
Sep-25	(298,312.95)	0	(233,024.19)	(1,386,808.81)	(2,114)	(181,171.06)	(492)	0	0
Oct-25	(58,755.33)	0	(45,896.14)	(273,144.06)	(659)	(35,683.22)	(93)	0	0
Nov-25	(58,133.73)	0	(45,410.58)	(270,254.34)	(472)	(35,305.71)	(88)	0	0
Dec-25	(61,387.71)	0	(47,952.40)	(285,381.58)	(537)	(37,281.91)	(90)	0	0
Jan-26	(73,655.97)	0	(57,535.63)	(342,414.72)	(630)	(44,732.65)	(103)	0	0
Feb-26	(68,056.42)	0	(53,161.59)	(316,383.32)	(629)	(41,331.94)	(105)	0	0
Mar-26	(77,040.39)	0	(60,179.33)	(358,148.35)	(580)	(46,788.08)	(109)	0	0
Apr-26	(76,192.84)	0	(59,517.28)	(354,208.22)	(690)	(46,273.34)	(117)	0	0
May-26	(431,613.14)	0	(337,150.31)	(2,006,499.95)	(2,365)	(262,126.77)	(656)	0	0
Jun-26	(426,478.72)	0	(333,139.60)	(1,982,630.82)	(3,035)	(259,008.54)	(684)	0	0
Jul-26	(449,776.20)	0	(351,338.20)	(2,090,937.08)	(2,943)	(273,157.54)	(676)	0	0
Aug-26	(458,857.73)	0	(358,432.15)	(2,133,155.64)	(3,018)	(278,672.92)	(703)	0	0
Sep-26	(452,844.44)	0	(353,734.93)	(2,105,200.84)	(3,209)	(275,020.94)	(747)	0	0
Oct-26	(88,885.86)	0	(69,432.31)	(413,216.04)	(997)	(53,982.05)	(140)	0	0
Nov-26	(87,656.20)	0	(68,471.77)	(407,499.54)	(712)	(53,235.26)	(133)	0	0
Dec-26	(92,270.28)	0	(72,076.01)	(428,949.67)	(807)	(56,037.48)	(135)	0	0
Jan-27	(104,914.56)	0	(81,952.96)	(487,730.87)	(897)	(63,716.58)	(147)	0	0
Feb-27	(96,629.61)	0	(75,481.26)	(449,215.50)	(893)	(58,684.98)	(149)	0	0
Mar-27	(109,051.02)	0	(85,184.12)	(506,960.60)	(821)	(66,228.73)	(154)	0	0
Apr-27	(107,534.75)	0	(83,999.70)	(499,911.75)	(974)	(65,307.88)	(165)	0	0
May-27	(607,439.46)	0	(474,495.28)	(2,823,888.14)	(3,328)	(368,909.40)	(924)	0	0
Jun-27	(598,586.09)	0	(467,579.56)	(2,782,730.25)	(4,260)	(363,532.58)	(960)	0	0
Jul-27	(629,638.45)	0	(491,835.81)	(2,927,087.71)	(4,119)	(382,391.26)	(946)	0	0
Aug-27	(640,737.95)	0	(500,506.07)	(2,978,687.49)	(4,214)	(389,132.20)	(981)	0	0
Sep-27	(630,810.44)	0	(492,751.29)	(2,932,536.07)	(4,470)	(383,103.03)	(1,041)	0	0
Oct-27	(123,528.62)	0	(96,493.16)	(574,264.67)	(1,385)	(75,021.25)	(195)	0	0
Nov-27	(121,545.34)	0	(94,943.93)	(565,044.71)	(987)	(73,816.77)	(184)	0	0
Dec-27	(127,665.08)	0	(99,724.31)	(593,494.40)	(1,117)	(77,533.40)	(187)	0	0
Jan-28	(140,685.38)	0	(109,894.98)	(654,023.66)	(1,203)	(85,440.87)	(197)	0	0
Feb-28	(129,278.37)	0	(100,984.51)	(600,994.33)	(1,195)	(78,513.19)	(200)	0	0
Mar-28	(145,573.88)	0	(113,713.58)	(676,749.50)	(1,096)	(88,409.75)	(205)	0	0
Apr-28	(143,243.35)	0	(111,893.11)	(665,915.24)	(1,298)	(86,994.38)	(220)	0	0
May-28	(807,481.41)	0	(630,756.07)	(3,753,850.96)	(4,424)	(490,398.63)	(1,228)	0	0
Jun-28	(794,127.95)	0	(620,325.14)	(3,691,772.87)	(5,652)	(482,288.83)	(1,274)	0	0
Jul-28	(833,716.35)	0	(651,249.23)	(3,875,812.97)	(5,454)	(506,331.61)	(1,252)	0	0
Aug-28	(846,833.82)	0	(661,495.81)	(3,936,793.97)	(5,569)	(514,298.09)	(1,297)	0	0
Sep-28	(832,210.93)	0	(650,073.28)	(3,868,814.49)	(5,897)	(505,417.33)	(1,374)	0	0
Oct-28	(162,683.62)	0	(127,078.69)	(756,289.93)	(1,824)	(98,800.82)	(256)	0	0
Nov-28	(159,801.16)	0	(124,827.09)	(742,889.86)	(1,298)	(97,050.25)	(242)	0	0
Dec-28	(167,572.12)	0	(130,897.29)	(779,015.77)	(1,466)	(101,769.70)	(246)	0	0
Jan-29	(180,968.43)	0	(141,361.69)	(841,293.08)	(1,548)	(109,905.53)	(254)	0	0
Feb-29	(166,002.70)	0	(129,671.35)	(771,719.79)	(1,534)	(100,816.56)	(256)	0	0
Mar-29	(186,608.97)	0	(145,767.74)	(867,515.03)	(1,406)	(113,331.13)	(263)	0	0
Apr-29	(183,318.62)	0	(143,197.51)	(852,218.71)	(1,661)	(111,332.84)	(282)	0	0
May-29	(1,031,739.02)	0	(805,932.66)	(4,796,388.42)	(5,652)	(626,594.49)	(1,569)	0	0
Jun-29	(1,013,104.31)	0	(791,376.35)	(4,709,758.69)	(7,210)	(615,277.29)	(1,625)	0	0
Jul-29	(1,062,009.90)	0	(829,578.46)	(4,937,112.87)	(6,948)	(644,978.57)	(1,595)	0	0
Aug-29	(1,077,145.34)	0	(841,401.35)	(5,007,475.09)	(7,083)	(654,170.60)	(1,649)	0	0
Sep-29	(1,057,045.91)	0	(825,700.89)	(4,914,036.11)	(7,490)	(641,963.85)	(1,745)	0	0
Oct-29	(206,350.85)	0	(161,188.91)	(959,291.84)	(2,314)	(125,320.75)	(325)	0	0
Nov-29	(202,423.66)	0	(158,121.23)	(941,034.98)	(1,644)	(122,935.69)	(307)	0	0
Dec-29	(211,991.38)	0	(165,594.96)	(985,513.78)	(1,854)	(128,746.35)	(311)	0	0

Non-Renewable Monthly Impacts

	RES	CSMUR	GS<50	GS 50-999		GS 1-5MW		Large Users	
Date	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA	Distribution kWh	Distribution kVA
Jan-25	0	0	(11,006)	(3,726,862)	(5,028)	(8,232,918)	(11,117)	(7,813,604)	(10,545)
Feb-25	0	0	(9,430)	(3,193,191)	(4,778)	(7,053,998)	(10,548)	(6,694,728)	(10,000)
Mar-25	0	0	(9,875)	(3,343,775)	(4,513)	(7,386,648)	(9,972)	(7,010,436)	(9,450)
Apr-25	0	0	(9,009)	(3,050,546)	(4,256)	(6,738,884)	(9,406)	(6,395,663)	(8,915)
May-25	0	0	(8,744)	(2,960,687)	(4,010)	(6,540,379)	(8,850)	(6,207,268)	(8,397)
Jun-25	0	0	(7,914)	(2,679,816)	(3,757)	(5,919,913)	(8,280)	(5,618,403)	(7,841)
Jul-25	0	0	(7,612)	(2,577,599)	(3,492)	(5,694,109)	(7,697)	(5,404,100)	(7,299)
Aug-25	0	0	(7,047)	(2,386,055)	(3,234)	(5,270,974)	(7,129)	(5,002,515)	(6,764)
Sep-25	0	0	(6,272)	(2,123,720)	(2,973)	(4,691,457)	(6,558)	(4,452,514)	(6,197)
Oct-25	0	0	(5,915)	(2,002,967)	(2,714)	(4,424,704)	(5,984)	(4,199,347)	(5,673)
Nov-25	0	0	(5,177)	(1,752,990)	(2,442)	(3,872,486)	(5,409)	(3,675,255)	(5,123)
Dec-25	0	0	(4,784)	(1,619,879)	(2,188)	(3,578,434)	(4,833)	(3,396,179)	(4,577)
Jan-26	0	0	(11,964)	(4,051,229)	(5,466)	(8,949,468)	(12,085)	(8,493,659)	(11,463)
Feb-26	0	0	(10,288)	(3,483,641)	(5,212)	(7,695,625)	(11,507)	(7,303,675)	(10,910)
Mar-26	0	0	(10,816)	(3,662,548)	(4,943)	(8,090,844)	(10,923)	(7,678,765)	(10,351)
Apr-26	0	0	(9,912)	(3,356,331)	(4,683)	(7,414,385)	(10,349)	(7,036,760)	(9,808)
May-26	0	0	(9,668)	(3,273,868)	(4,434)	(7,232,219)	(9,786)	(6,863,872)	(9,286)
Jun-26	0	0	(8,801)	(2,980,188)	(4,178)	(6,583,459)	(9,208)	(6,248,154)	(8,719)
Jul-26	0	0	(8,521)	(2,885,188)	(3,908)	(6,373,595)	(8,615)	(6,048,979)	(8,170)
Aug-26	0	0	(7,947)	(2,690,847)	(3,647)	(5,944,283)	(8,040)	(5,641,532)	(7,628)
Sep-26	0	0	(7,135)	(2,415,975)	(3,382)	(5,337,069)	(7,460)	(5,065,244)	(7,050)
Oct-26	0	0	(6,799)	(2,302,167)	(3,120)	(5,085,659)	(6,878)	(4,826,639)	(6,520)
Nov-26	0	0	(6,024)	(2,039,832)	(2,841)	(4,506,142)	(6,295)	(4,276,638)	(5,962)
Dec-26	0	0	(5,651)	(1,913,486)	(2,584)	(4,227,035)	(5,709)	(4,011,746)	(5,407)
Jan-27	0	0	(12,825)	(4,342,739)	(5,859)	(9,593,436)	(12,954)	(9,104,828)	(12,287)
Feb-27	0	0	(11,060)	(3,745,047)	(5,603)	(8,273,088)	(12,371)	(7,851,728)	(11,728)
Mar-27	0	0	(11,665)	(3,949,864)	(5,331)	(8,725,546)	(11,780)	(8,281,141)	(11,163)
Apr-27	0	0	(10,727)	(3,632,349)	(5,068)	(8,024,130)	(11,200)	(7,615,450)	(10,615)
May-27	0	0	(10,505)	(3,556,989)	(4,817)	(7,857,656)	(10,633)	(7,457,454)	(10,089)
Jun-27	0	0	(9,604)	(3,252,147)	(4,559)	(7,184,236)	(10,049)	(6,818,333)	(9,515)
Jul-27	0	0	(9,344)	(3,164,115)	(4,286)	(6,989,766)	(9,448)	(6,633,767)	(8,959)
Aug-27	0	0	(8,764)	(2,967,677)	(4,022)	(6,555,821)	(8,867)	(6,221,924)	(8,413)
Sep-27	0	0	(7,920)	(2,681,845)	(3,754)	(5,924,396)	(8,281)	(5,622,658)	(7,826)
Oct-27	0	0	(7,604)	(2,574,802)	(3,489)	(5,687,931)	(7,693)	(5,398,237)	(7,292)
Nov-27	0	0	(6,797)	(2,301,644)	(3,206)	(5,084,503)	(7,102)	(4,825,542)	(6,727)
Dec-27	0	0	(6,444)	(2,181,928)	(2,947)	(4,820,041)	(6,510)	(4,574,550)	(6,165)
Jan-28	0	0	(13,614)	(4,609,782)	(6,219)	(10,183,354)	(13,751)	(9,664,701)	(13,043)
Feb-28	0	0	(11,769)	(3,984,984)	(5,962)	(8,803,128)	(13,163)	(8,354,772)	(12,480)
Mar-28	0	0	(12,445)	(4,214,111)	(5,687)	(9,309,287)	(12,568)	(8,835,151)	(11,909)
Apr-28	0	0	(11,478)	(3,886,718)	(5,423)	(8,586,051)	(11,984)	(8,148,752)	(11,358)
May-28	0	0	(11,277)	(3,818,440)	(5,172)	(8,435,220)	(11,414)	(8,005,602)	(10,830)
Jun-28	0	0	(10,347)	(3,503,811)	(4,912)	(7,740,180)	(10,826)	(7,345,962)	(10,251)
Jul-28	0	0	(10,108)	(3,422,769)	(4,636)	(7,561,153)	(10,221)	(7,176,052)	(9,692)
Aug-28	0	0	(9,524)	(3,224,933)	(4,371)	(7,124,119)	(9,635)	(6,761,278)	(9,142)
Sep-28	0	0	(8,651)	(2,929,449)	(4,100)	(6,471,373)	(9,046)	(6,141,777)	(8,548)
Oct-28	0	0	(8,355)	(2,829,262)	(3,834)	(6,250,052)	(8,453)	(5,931,728)	(8,013)
Nov-28	0	0	(7,520)	(2,546,542)	(3,547)	(5,625,502)	(7,858)	(5,338,987)	(7,442)
Dec-28	0	0	(7,187)	(2,433,591)	(3,286)	(5,375,985)	(7,261)	(5,102,178)	(6,876)
Jan-29	0	0	(14,353)	(4,860,048)	(6,557)	(10,736,209)	(14,497)	(10,189,398)	(13,751)
Feb-29	0	0	(12,432)	(4,209,767)	(6,298)	(9,299,691)	(13,906)	(8,826,045)	(13,184)
Mar-29	0	0	(13,176)	(4,461,580)	(6,021)	(9,855,965)	(13,306)	(9,353,986)	(12,609)
Apr-29	0	0	(12,182)	(4,124,851)	(5,755)	(9,112,106)	(12,718)	(8,648,013)	(12,054)
May-29	0	0	(11,999)	(4,063,113)	(5,503)	(8,975,721)	(12,146)	(8,518,574)	(11,524)
Jun-29	0	0	(11,043)	(3,739,238)	(5,242)	(8,260,257)	(11,554)	(7,839,550)	(10,940)
Jul-29	0	0	(10,822)	(3,664,646)	(4,964)	(8,095,476)	(10,943)	(7,683,162)	(10,377)
Aug-29	0	0	(10,234)	(3,465,412)	(4,697)	(7,655,354)	(10,354)	(7,265,456)	(9,824)
Sep-29	0	0	(9,335)	(3,160,818)	(4,424)	(6,982,483)	(9,760)	(6,626,855)	(9,223)
Oct-29	0	0	(9,057)	(3,066,945)	(4,156)	(6,775,110)	(9,163)	(6,430,044)	(8,686)
Nov-29	0	0	(8,196)	(2,775,204)	(3,865)	(6,130,634)	(8,564)	(5,818,392)	(8,111)
Dec-29	0	0	(7,881)	(2,668,477)	(3,604)	(5,894,866)	(7,962)	(5,594,632)	(7,540)

Appendix B: Summary Curriculum Vitae

STEVEN A. FENRICK

SUMMARY OF EXPERIENCE AND EXPERTISE

- I have directed project teams and engaged in research in the fields of performance based regulation, performance benchmarking, DSM, load research and forecasting, and survey design and implementation.
- I have been a expert witness in a number of cases involving incentive regulation and other utility research topics.

PROFESSIONAL EXPERIENCE

Clearspring Energy Advisors, LLC (2019 to Present)

Principal Consultant

Responsible for providing consulting services and expert witness testimony to utilities and regulators in the areas of reliability and cost benchmarking, productivity studies and other empirical aspects of performance-based ratemaking and incentive regulation. Direct activities in the areas of demand-side management programs, peak time rebate programs, load forecasting, and market research.

Power System Engineering, Inc.– Madison, WI (2009 to 2018)

Director of Economics

Responsible for providing consulting services to utilities and regulators in the areas of reliability and cost benchmarking, incentive regulation, value-based reliability planning, demand-side management including demand response and energy efficiency, ran peak time rebate programs, load research, load forecasting, end-use surveys, and market research.

Pacific Economics Group – Madison, WI (2001 - 2009)

Senior Economist

Co-authored research reports submitted as testimony in numerous proceedings in several states and in international jurisdictions. Research topics included statistical benchmarking, alternative regulation, and revenue decoupling. Managed and supervised PEG support staff in research and marketing efforts.

EDUCATION

University of Wisconsin - Madison, WI

Bachelor of Science, Economics (Mathematical Emphasis)

University of Wisconsin - Madison, WI

Master of Science, Agriculture and Applied Economics

Publications & Papers

- "Peak-Time Rebate Programs: A Success Story", *TechSurveillance*, July 2014 (with David Williams and Chris Ivanov).
- "Demand Impact of a Critical Peak Pricing Program: Opt-In and Opt-Out Options, Green Attitudes and other Customer Characteristics:, *The Energy Journal*, January 2014. (With Lullit Getachew, Chris Ivanov, and Jeff Smith).
- "Evaluating the Cost of Reliability Improvement Programs", *The Electricity Journal*, November 2013. (With Lullit Getachew)
- "Expected Useful Life of Energy Efficiency Improvements", Cooperative Research Network, 2013 (with David Williams).
- "Cost and Reliability Comparisons of Underground and Overhead Power Lines", *Utilities Policy*, March 2012. (With Lullit Getachew).
- "Formulating Appropriate Electric Reliability Targets and Performance Evaluations, *Electricity Journal*, March 2012. (With Lullit Getachew)
- "Enabling Technologies and Energy Savings: The Case of EnergyWise Smart Meter Pilot of Connexus Energy", Utilities Policy, November 2012. (With Chris Ivanov, Lullit Getachew, and Bethany Vittetoe)
- "The Value of Improving Load Factors through Demand-Side Management Programs", Cooperative Research Network, 2012 (with David Williams and Chris Ivanov).
- "Estimation of the Effects of Price and Billing Frequency on Household Water Demand Using a Panel of Wisconsin Municipalities", *Applied Economics Letters*, 2012, 19:14, 1373-1380.
- "Altreg Rate Designs Address Declining Average Gas Use", *Natural Gas & Electricity*. April 2008. (With Mark Lowry, Lullit Getachew, and David Hovde).
- "Regulation of Gas Distributors with Declining Use per Customer", *Dialogue*. August 2006. (With Mark Lowry and Lullit Getachew).
- "Balancing Reliability with Investment Costs: Assessing the Costs and Benefits of Reliability-Driven Power Transmission Projects." April 2011. *RE Magazine*.
- "Ex-Post Cost, Productivity, and Reliability Performance Assessment Techniques for Power Distribution Utilities". Master's Thesis.
- "Demand Response: How Much Value is Really There?" *PSE whitepaper.*
- "How is My Utility Performing" *PSE whitepaper*.
- "Improving the Performance of Power Distributors by Statistical Performance Benchmarking" *PSE whitepaper*.
- "Peak Time Rebate Programs: Reducing Costs While Engaging Customers" *PSE whitepaper*.
- "Performance Based Regulation for Electric and Gas Distributors" *PSE whitepaper*.
- "Revenue Decoupling: Designing a Fair Revenue Adjustment Mechanism" *PSE whitepaper.*

Expert Witness Experience

- Docket EB-2021-0110, Hydro One Networks, Joint Rate Application for Transmission and Distribution. Custom Incentive Regulation Benchmarking and Productivity research.
- Case No. 2020-00299, Big Rivers Electric Corporation, Integrated Resource Plan. Testimony on load forecast research.
- Docket EB-2019-0261, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket EB-2019-0082, Hydro One Networks Transmission, TFP and Econometric Benchmarking research.
- Docket EB-2018-0165, Toronto Hydro Electric System Limited, Econometric Benchmarking research.
- Docket EB-2018-0218, Hydro One Transmission Sault St. Marie, TFP and Econometric Benchmarking research.
- Docket EB-2017-0049, Hydro One Distribution, TFP and Benchmarking research.
- Docket EB-2015-0004, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket 15-SPEE-357-TAR, Application for Southern Pioneer Electric Cooperative, Inc., Demand Response Peak Time Rebate Pilot Program.
- Docket EB-2014-0116, Toronto Hydro, Custom Incentive Regulation Application.
- Docket EB-2010-0379, The Coalition of Large Distributors in Ontario regarding “Defining & Measuring Performance”.
- Docket No. 6690-CE-198, Wisconsin Public Service Corporation, “Application for Certificate of Authority for System Modernization and Reliability Project”.
- Expert Witness presentation to Connecticut Governors “Two Storm Panel”, 2012.
- Docket No. EB-2012-0064, Toronto Hydro’s Incremental Capital Module (ICM) request for added capital funding.
- Docket No. 09-0306, Central Illinois Light rate case filing.
- Docket No. 09-0307, Central Illinois Public Service Company rate case filing.
- Docket No. 09-0308, Illinois Power rate case filing.

Recent Conference Presentations

- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2019.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2018.
- Panel Moderator at WPUI conference on cost allocation and innovative rate designs at Madison WI. June 2018.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2017.
- Wisconsin Manager’s Meeting, “Reliability Target Setting Using Econometric Benchmarking”. November 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2016.

- Wisconsin Electric Cooperative Association (WECA) Conference, "An Introduction to Peak Time Rebates". September 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2015.
- EUCI conference chair, 2015. "Evaluating the Performance of Gas and Electric Distribution Utilities."
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2014.
- Cooperative Exchange Conference, Williamsburg VA. "Smart Thermostat versus AC Direct Load Control Impacts". August 2014.
- EUCI conference chair in Chicago. "The Economics of Demand Response". February 2014.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, "Performance Benchmarking". October 2013.
- EUCI conference chair in Chicago. "Evaluating the Performance of Gas and Electric Distribution Utilities." August 2013.
- Presentation to the Ontario Energy Board, "Research and Recommendations on 4th Generation Incentive Regulation".
- Presentation to the Canadian Electricity Association's best practice working group. 2013
- Conference chair for EUCI conference in March 2013 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- Presentation to the board of directors of Great Lakes Energy on benchmarking results, December 2012.
- Presentation on making optimal infrastructure investments and the impact on rates, Electricity Distribution Association, Toronto, Ontario. November 2012.
- Conference chair for EUCI conference in August 2012 titled, "Performance Benchmarking for Electric and Gas Distribution Utilities."
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Reliability Target Setting and Performance Evaluation".
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, "Making the Business Case for Reliability-Driven Investments".
- Conference chair for EUCI conference in 2012 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". St. Louis.
- Conference chair for EUCI conference in 2012 titled, "Demand Response: The Economic and Technology Considerations from Pilot to Deployment". St. Louis.
- 2012 Presentation in the Missouri PSC Smart Grid conference entitled, "Maximizing the Value of DSM Deployments". Jefferson City.
- 2011 conference chair on a nationwide benchmarking conference for rural electrical cooperatives. Madison.
- 2011 presentation on optimizing demand response program at the CRN Summit. Cleveland.
- Conference chair for EUCI conference in 2011 titled, "Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities". Denver.
- 2010 presentation on cost benchmarking techniques for REMC. Wisconsin Dells.

HUMAN RESOURCES, ENVIRONMENT AND SAFETY

1. OVERVIEW

Table 1: Human Resources, Environment and Safety Program Summary

Fleet and Equipment Program Summary									
Outcomes: Public Policy Responsiveness, Environment, Operational Effectiveness - Safety, Financial Performance									
Segments: • Environment, Health & Safety • Human Resources Services & Systems, Organizational Effectiveness & Employee Labour Relations • Talent Management, Change Leadership & Sustainability									
Program Costs ($ Millions)									
2020A	**2021A**	**2022A**	**2023B**	**2024B**	**2025F**	**2026F**	**2027F**	**2028F**	**2029F**
15.5	17.6	16.7	18.9	21.3	22.6	23.2	24.2	25.3	26.3

The Human Resources (“HR”), Environment and Safety program (the “Program”) provides broad human resource management services to Toronto Hydro. The Program’s activities manage the employee lifecycle through the processes of employee recruitment, compensation and benefits, onboarding, performance management, training and leadership development, labour relations, employee communications and engagement, and human resources technology management. All of these activities are carried out within a culture of ensuring employees’ health and safety and environmental sustainability. The delivery of these activities is tailored to the utility’s complex capital program and operating environment, labour dynamics and workforce demographics.

To achieve these outcomes, adequate funding and staffing for the Program will be crucial to the utility’s success.

2. OUTCOMES AND MEASURES

Table 2: Human Resources, Environment and Safety Program Outcomes and Measures

Summary

Public Policy Responsiveness	• Contributes to Toronto Hydro's public policy responsiveness objectives by ensuring regulatory and legislative requirements are met in relation to employee training, collective bargaining and the development of utility-wide policies.
Environment	• Contributes to Toronto Hydro's environmental objectives and Net Zero 2040 commitment by: ○ Integrating environmental, social and economic issues into planning; ○ Measuring greenhouse gas ("GHG") emissions, waste reduction, and promoting recycling and a culture of conservation; ○ Ensuring compliance with legislative and regulatory requirements such as the *Environmental Protection Act, 1990*[1].
Operational Effectiveness – Safety	• Contributes to Toronto Hydro's health and safety objectives, measured through metrics like Total Recordable Injury Frequency ("TRIF") by: ○ Implementing controls to reduce the risks associated with exposure to hazards and ensure employees are working safely; ○ Providing training on workplace safety to employees; ○ Closing gaps associated with audit and inspection findings; and • Ensuring compliance with legislative requirements.

[1] RSO 1990, c E.19. ["*Environmental Protection Act*"].

Financial Performance	• Contributes to Toronto Hydro's total cost and efficiency measures through the development and delivery of virtual training and internal training facilitation to reduce reliance on external services. • Focuses Toronto Hydro's workforce on work aligned with organizational objectives by utilizing a rigorous performance management system, thereby decreasing costly wasted productive time. • Promotes processes that decrease Workplace Safety & Insurance Board premiums and other costs.

3. PROGRAM DESCRIPTION

The Program provides broad human resource management services to Toronto Hydro. The Program's activities enable the utility to maintain a robust and effective work environment, the health and wellness of its employees, and its safety management system. The Program also supports the utility's sustainability activities and the promotion of good working conditions to increase employees' job satisfaction, facilitate productivity and promote innovation.

The Program's activities support key operational goals by deploying technology solutions, applying risk-based management system standards, and supporting effective training, diligent inspections, and appropriate investigations into incidents and near misses. Toronto Hydro's business operations and dense urban environment create a number of distinct challenges for the Program, including:

- A complex and rapidly evolving distribution system that includes an asset-intensive downtown distribution network;
- Mature and diverse grid infrastructure featuring legacy assets that require specialized asset management skills (e.g. box construction and paper insulated lead covered cable);

- An increasingly complex mix of load consumers and distributed energy resources of varying sizes, driving the need for a broad range of advanced customer service, data analysis, strategic planning, and technological know-how skills; and
- Unique safety challenges for executing work.

These challenges drive Toronto Hydro to maintain a high standard of health and safety requirements and provide comprehensive training and apprenticeship programs for employees. These challenges also make it important for Toronto Hydro to prepare talent to fill future key roles so that leaders can continue to be responsive to the utility's operating conditions.

The Program includes three segments, each described in detail below:

- Environment, Health & Safety;
- Human Resource Services & Systems, Organizational Effectiveness & Employee Labour Relations; and
- Talent Management, Change Leadership & Sustainability.

The objective of the Environment, Health & Safety ("EHS") segment is to ensure that Toronto Hydro operates in a safe, environmentally responsible, and sustainable manner. Toronto Hydro achieves these operational objectives by implementing programs, procedures, safe work practices, and engineering and administrative controls as required. This segment also ensures that Toronto Hydro complies with applicable legislative requirements pertaining to health and safety, environmental protection and sustainability.

The objective of the Human Resource Services & Systems, Organizational Effectiveness & Employee Labour Relations segment is to effectively manage labour relations with the utility's employees, compensate employees appropriately and provide benefits to support employee health and well-being. Activities within this segment include interpreting, administering and negotiating collective agreement provisions, case management, performance management, productivity measurement, designing and administering the utility's compensation and benefits program, and administering technology systems to support human resources, environment and safety data.

This segment also includes a program to foster innovation and another program to track the benefits of initiatives undertaken by the utility. In addition, this segment supports the organization to ensure workplace issues are addressed promptly and in compliance with applicable legislation, policies, and collective agreements. This segment oversees all employee engagement events, including Toronto Hydro's annual United Way campaign. It also manages all internal communications to employees, including the semi-annual publication of the utility's company magazine, Spectrum.

The objective of the Talent Management, Change Leadership & Sustainability segment is to develop and execute the utility's workforce staffing and development plans and conduct organization design and job design activities, to support the organization's talent development and succession planning processes and programs. Teams in this segment are responsible for internal and external staffing selection. They also create and implement a variety of training, development, and change management initiatives to ensure Toronto Hydro employees are qualified and have the necessary skills, resources, and tools to successfully execute their role.

4. PROGRAM COSTS

In 2025 Toronto Hydro requires $22.6 million in rate funding for Human Resources and Safety program, which represents an increase of $7.1 million over the last Custom Incentive Risk application in 2020. When normalized for shared services recoveries outlined in Exhibit 4, Tab 5, Schedule 1, the expected increase in this program is $6.1 million.

Over the 2025-2029 rate period, the utility expects the cost of this program to increase by annual growth rate of 3.9 percent which is necessary to address the program needs and deliver the customers outcomes enabled by this program. The Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for each segment are summarized in Table 3 below.

Table 3: Human Resource and Safety Program Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
Environment, Health & Safety	2.4	2.3	2.4	3.0	3.1	3.3	3.4	3.6	3.8	3.9
Human Resource Services & Systems, Organizational Effectiveness & Employee Labour Relations	5.9	6.3	5.9	8.0	9.4	10.0	10.4	10.8	11.3	11.8
Talent Management, Change Leadership & Sustainability	7.2	9.0	8.4	7.9	8.8	9.3	9.4	9.8	10.2	10.6
Total	**15.5**	**17.6**	**16.7**	**18.9**	**21.3**	**22.6**	**23.2**	**24.2**	**25.3**	**26.3**

4.1 Cost Drivers

The cost increases are primarily a result of:

- **Increasing Capacity to Support Investment Plan*:*** Staffing changes to support projects and to fill vacancies have created yearly variances in actual and budgeted segment costs. These are outlined in the sections below. Payroll costs are expected to increase by approximately $2.1 million in 2024 and $1.3 million in 2025. These variances are driven by headcount increases to attract, recruit and train talent, to support grid and technology modernization efforts, capital and operating programs and environment, social and governance and compliance activities; and

- **Legal and arbitration related expenses:** Legal expenses associated with grievance arbitrations, and other employment related legal matters have trended upwards in the Program. These expenses vary based on the matter's complexity, the number of internal and external witnesses, and the degree of preparation and legal research required. An increase in headcount in bargaining unit positions is expected to increase the volume of arbitration and grievance matters. Both PWU and Society IT collective agreements will be renegotiated during the next rate application which will drive additional legal costs.

4.2 Cost Control and Productivity Measures

4.2.1 Cost Management

Toronto Hydro has implemented or is in the process of executing the following initiatives to realize cost savings:

- Using services, including specialized software, to collect and report data on incidents, inspections, audits, and facilitate contractor prequalification screening;
- Optimizing training by leveraging digital tools to facilitate sessions, clustering training in concentrated blocks of one to two weeks to minimize operational disruption; engaging internal resources, familiar with Toronto Hydro systems, processes and equipment, to complete program development, testing, audits and completion of applications;

- Toronto Hydro has completed a proof of concept for virtual reality training. This training would offer employees a safe environment to learn and develop skills prior to executing them in a physical environment. A request for proposal is currently underway to select a vendor for this solution. This technology will decrease the time required for employees to travel to training, and the time required to deliver training; and
- Using existing internal resources instead of hiring specialized external service providers to develop and distribute EHS related communications materials including posters, Toronto Hydro TV and safety meeting materials; This results in a cost savings associated with not having to hire external service providers to complete this work.

The utility has negotiated a five-year collective agreement with the Power Workers' Union ("PWU") (2022-2027) and a four-year agreement with the Society of United Professionals ("Society") (IT) (2021-2025). These agreements will provide labour stability and predictability around compensation and benefits costs.

4.2.2 Productivity

The Program has enabled the utility to achieve significant and sustained productivity outcomes. For example, from 2018 to 2022, the utility achieved improvements relating to:

- Occupational safety, including a 43 percent improvement in total recordable injury frequency;
- A 94 percent improvement in lost time severity; and
- The corporate attendance number remained stable, with an improvement of 1.9 percent.

The above was achieved despite the effects of the COVID-19 pandemic. Toronto Hydro's absenteeism rate remains much lower than historic rates, both within the organization and broader industry. Toronto Hydro has been able to effectively manage employee absenteeism and ensure the workforce is productive and engaged.

Toronto Hydro's implementation of the cloud-based Success Factors program has supported the business processes and innovation. The foundational design integrates between modules and facilitates automation of workflows. The integrated solution supports the employee life cycle starting with the foundation of 'Employee Central', which houses core employee information from job to organizational data. The core employee data is integrated with other modules within Success Factors such as recruitment, on-boarding, performance management, learning, benefits and compensation. The integration has expanded the capture of master data, increased data accurancy and operational efficiences. The system has enabled employees to self-serve, allowing employees access to manage their own personal data such as home address, phone number and emergency contact, increasing overall data accurancy. The technology also supports other systems in the organization through integration, feeding real-time employee master information such as job and organizational data. The cloud solution has annual releases of new features to expand system functionalities and optimize business processes.

- Toronto Hydro has upgraded the video and audio-conferencing applications of its work centres, making remote and hybrid work more effective and reducing the facilitation costs of virtual learning and training programs.
- Electronic tailboards are used by crews to complete a risk assessment digitally prior to their work as part of developing a safe job plan have increased productivity. This electronic tool allows leaders to access job planning details

without having to be on site. Moving from what was previously a paper process to an electronic process has resulted in improved data analytics and auditing capabilities and increased job planning quality, which has contributed to a decrease in injuries. Recordable injury performance has improved by 16 percent in the year following the introduction of the electronic tailboard and the utility has not had any critical or fatal injury since the electronic tailboard was launched.

- A new Employee and Labour Relations solution was implemented in 2022 to streamline the administration and tracking of grievances, arbitrations and to facilitate contract negotiations through system integration and automation. Leveraging the SuccessFactors foundation, an integration was built to pull real-time employee data such as job and organizational data to effectively manage a centralized employee labour relations system. Some of the features included automation of the Collective Agreement, ease of updating clauses and consistent policy interpretation.

5. ENVIRONMENT, HEALTH & SAFETY SEGMENT

5.1 Segment Description

The Environment, Health & Safety ("EHS") segment ensures that Toronto Hydro operates in an environmentally conscious manner and implements programs, procedures, safe work practices, and engineering and administrative controls to provide a healthy and safe working environment for employees.

The activities performed as part of this segment are instrumental to ensuring that the utility complies with legislative and regulatory requirements. The EHS segment executes operational activities, prepares the planning and delivery of targeted initiatives and executes applicable internal and external reporting requirements. The work performed within this segment is carried out 24 hours a day, 7 days a week in line with Toronto Hydro's service obligations. Functions within this segment include Health Services and Environment, Health and Safety.

5.1.1 Health Services

Toronto Hydro's health services function effectively processes and monitors occupational and non-occupational health and injury claims. Health services supports injured employees receiving appropriate treatment and recovery measures, and encourages their participation in the workplace within their prescribed restrictions until they can safely return to their pre-injury role. Health services also manages short and long-term disability cases. As a result of these efforts, Toronto Hydro achieved a 94 percent improvement in its lost time severity from 2018 to 2022.

During the pandemic Health Services played a significant role in supporting the utility's successful response to COVID-19 through the implementation of the infectious disease plan. This included the development and implementation of protocols for reporting illness, returning to work, contact tracing, health screening as well as organizing vaccination clinics for employees. This contributed to the company maintaining a healthy and safe environment for employees, including no substantiated cases of workplace transmission since the onset of the pandemic.

5.1.2 Environment, Health and Safety

Environment, Health and Safety ("EHS") activities include the following:

- **Environment, Health & Safety Management Systems ("EHSMS"):** The EHSMS improves the efficiency of activities within this segment. The EHSMS system also facilitates Toronto Hydro's compliance with applicable legislative and regulatory requirements such as the *Utility Work Protection Code*[2], *Electrical Utility Safety Rules*[3], *and Occupational Health & Safety Act, 1990* and Regulations.[4] In addition, the EHSMS provides a mechanism for mitigating risk and achieving corporate objectives relating to health, safety, and environmental performance. The EHSMS established the frameworks (such as contact tracing) to successfully manage the COVID-19 Pandemic;

- **EHS Framework:** Toronto Hydro coordinates all EHS activities in accordance with internationally recognized ISO standards. Toronto Hydro is certified in conformance with ISO 14001:2015 and ISO 45001:2018, both of which are internationally recognized EHS standards requiring third-party audits. In line with these certifications, Toronto Hydro has implemented a framework that incorporates effective risk management and continual improvement to support occupational health and safety performance and prevent employee illness and injuries;
- **Occupational Health and Safety Activities:** Toronto Hydro implements robust occupational health and safety training programs. These programs maintain the long-term health, safety and wellness of the utility's workforce. The utility continually improves these programs by developing action plans to address identified gaps from investigation and audit activities. Our recordable injury performance has improved by 19% since 2020 and we have not had any critical or fatal incidents since that time; and /C
- **Environmental, Social and Governance ("ESG"):** The internationally recognized guidance document ISO 26000:2010 informs Toronto Hydro's approach to social responsibility. In line with this document, Toronto Hydro has integrated the

[2] Ontario Infrastructure Health and Safety Association, Utility Work Protection Code.
[3] Ontario Infrastructure Health and Safety Association, Electrical Utility Safety Rules.
[4] R.S.O. 1990, c. O.1. [*"Occupational Health and Safety Act"]*

promotion of social responsibility into its core values, processes, and operations.[5] Toronto Hydro has leveraged this guidance document together with elements of the EHS management system to develop and implement a consolidated ESG strategy. The utility's ESG activities and performance have been recognized with 10 ESG-related awards since 2018.[6]

EHS complies with applicable environmental legislation and regulations such as the *Environmental Protection Act, 1990*[7] and the utility's environmental policy by delivering a number of environmental protection and compliance programs, such as:

- Environmental spill response, cleanup, investigation and reporting;
- Delivery of prescribed environmental training (e.g. Transportation of Dangerous Goods);
- Maintenance of environmental permits for equipment that discharges contaminants into the atmosphere;
- Registering Hazardous waste streams and reporting waste management activities with the Ontario Ministry of the Environment, Conservation and Parks; and
- Internal and External Reporting, including internal and external reporting on EHS performance; external reporting including mandatory reports and notifications to the City of Toronto, the Ministry of Labour, Immigration, Training and Skills Development, the Work Safety and Insurance Board, the Ontario Ministry of the Environment, Conservation and Parks, and Environment and Climate Change Canada and Electricity Canada.

[5] Adherence to this ISO 26000 standard is required for the utility's continued maintenance of its Sustainable Electricity Company designation from Electricity Canada.
[6] Toronto Hydro has been recognized by Corporate Knights, Electricity Canada, Centre of Excellence and Canadian Occupational Safety Magazine.
[7] *Supra* note 2.

5.2 Environment, Health & Safety Segment Costs

Table 4, below, provides the Historical (2020-2022), Bridge (2023-2024), and Forecast (2025-2029) expenditures for the EHS segment.

Table 4: Environment, Health & Safety Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Environment, Health & Safety	2.4	2.3	2.4	3.0	3.1	3.3	3.4	3.6	3.8	3.9

The cost increases are primarily attributable to filling employee positions in order to support the safe execution of the utility's capital work program and inflationary pressures.

5.3 Environment, Health & Safety Segment Year-over-Year Variance Analysis

2020-2021 Variance Explanation

From 2020 to 2021, costs decreased by $0.1 million due to delays in hiring as a result the COVID-19 pandemic.

2021-2022 Variance Explanation

From 2021 to 2022, costs increased by $0.1 million, due to an increase in hiring that had been previously postponed due to the COVID-19 pandemic.

2022-2025 Variance Explanation

From the 2022 actual to 2025, costs are expected to increase by $0.9 million. This increase is required to increase capacity and capabilities to perform the hiring necessary to facilitate the safe execution of the utility's 2025-2029 investment plan.

2025-2029 Variance Explanation

Between 2025 and 2029 costs in this segment are expected to increase by $0.6 million, or an average of $0.2 million per year. If the utility does not receive the funding it requires to execute this segment as described, Toronto Hydro could be exposed to a number of risks, including:

- Injuries, illnesses or fatalities to employees due to occupational health and safety hazards;
- Stop work orders, which would halt the execution of the utility's capital work program.
- An increased likelihood of safety-related incidents, including critical injuries or fatalities to Toronto Hydro employees;
- An increased likelihood of incidents with a negative environmental impact or worsening environmental performance;
- Legislative or regulatory non-compliance because of inadequate training and resources to provide advice, consultation, and research on matters relating to employment and labour relations, safety, and the environment.

6. HUMAN RESOURCES SERVICES & SYSTEMS, ORGANIZATIONAL EFFECTIVENESS & EMPLOYEE LABOUR RELATIONS SEGMENT

6.1 Segment Description

This segment delivers Human Resources services and leverages technology solutions to support the utility's employment life cycle. Its activities also drive effective performance management through ensuring market competitive compensation and benefits and overseeing employee and union relations.

Functions within this segment include:

- Employee and Labour Relations;

- Employee Engagement and Communications;
- Compensation and Benefits;
- Performance Management and Productivity;
- Innovation, and
- HR Systems and Data Governance.

6.1.1 Employee and Labour Relations

The Employee Labour Relations ("ELR") function manages issues relating to employee and labour relations and employee compliance with legislative and regulatory requirements, corporate policies and collective agreement provisions. ELR also supports Toronto Hydro's unionized and non-unionized work groups by ensuring that the utility follows all applicable labour and employment related legislation, policies, and collective agreement requirements.

This work requires labour relations and legal professionals to provide advice, guidance, and support on how to address challenges, and where necessary, assist in preparing for dispute resolution. This dispute resolution can include grievance arbitration, civil employment claims, Ontario Labour Relations Board matters, and human rights claims.
Toronto Hydro has a diverse workforce that includes both unionized and non-unionized employees. Over half of Toronto Hydro's employees belong to a union. There are two unions at Toronto Hydro – the Power Workers' Union (PWU) and the Society of United Professionals. Unionized employees are organized into four bargaining units. Inside workers and outside workers are represented by the PWU, and information and technology employees and professional engineers are represented by the Society of United Professionals.

6.1.2 Employee Engagement and Communications

The Employee Engagement and Communications function provides employees with awareness of important and key messages through multiple channels such as, company intranet, mass communications, pulse surveys, posters, employee magazine, and in-person gatherings. This function also oversees all employee events including the annual United Way campaign.

6.1.3 Compensation and Benefits

This function oversees and administers Toronto Hydro's workforce compensation strategy and practices. This function is critical to maintaining a workforce that is skilled, adaptable, committed, and performance-driven within a tight labour market. Toronto Hydro strives to achieve these key outcomes in a financially responsible manner by providing employees with a competitive total reward offering. This function compensates employees for contribution to individual, divisional, and corporate performance goals. For more information on Toronto Hydro's compensation and benefits program.[8]

6.1.4 Performance Management and Productivity

Toronto Hydro utilizes a Management Control and Reporting System ("MCRS") which sets forth a disciplined methodology to forecast, plan, control and report on its processes in order to keep focused on organizational objectives and continually improve.
Every year, Toronto Hydro reviews its corporate objectives in light of organizational priorities and updates its balanced scorecard to ensure appropriate targets are set. The same is done at the divisional and department level to result on a fresh slate of objectives at the beginning of each year, where progress is then reported out on a monthly basis.

[8] Exhibit 4, Tab 4, Schedule 4.

The performance management process also provides employees and managers with multiple opportunities to set individual goals throughout the year that are aligned with corporate objectives and outcomes. This ensures that employees understand their job expectations and how their roles support the utility's strategic objectives.[9] There is ongoing feedback to ensure project deadlines and goals are achieved. All employees are coached on aligning individual and organizational outcomes.

This rigourous performance system has become instrumental to Toronto Hydro's success in the face of challenges to the utility such as COVID-19 and extreme weather. Looking forward, this performance system will help the organization adopt new technologies and support new ways of operating (e.g. distributed energy resources) through setting evidence based goals, tracking progress and having past results inform future goals.
This function also includes various productivity initiatives such as LEAN and 5S (a subset of LEAN pertaining to workspace organization) which have allowed for the elimination of waste from printing rooms to warehouse environments.

6.1.5 Innovation

Further to the performance systems, Toronto Hydro also has an "Innovation @ Toronto Hydro" program which sets aside an annual budget to incubate and bring employee innovation to life. Projects with a completed proof of concept to-date include virtual reality training and implementation of project management software.

6.1.6 HR Systems and Data Governance

The HR Systems and Data Governance function supports the organization's technology needs with respect to employee data. The team oversees all HR related technology

[9] Exhibit 1B, Tab 2, Schedule 1.

solutions and develops the utility's long term system plan. This function conducts a regular review of systems to identify opportunities to optimize functionality and maximize benefits. SuccessFactors has enabled the utility to integrate and automate management of the employee life cycle from hire to retire.

6.2 Human Resources Services & Systems, Organizational Effectiveness & Employee Labour Relations Segment Costs

Table 5, below, provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Year (2025-2029) expenditures for the Human Resource Services and Employee Relations segment.

Table 5: Human Resources Services & Systems, Organizational Effectiveness & Employee Labour Relations Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Human Resource Services & Systems, Organizational Effectiveness & Employee Labour Relations	5.9	6.3	5.9	8.0	9.4	10.0	10.4	10.8	11.3	11.8

6.3 Human Resources Services & Systems, Organizational Effectiveness & Employee Labour Relations Segment Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

Costs increased by $0.4 million from 2020 to 2021 due to inflationary pressures.

2021 – 2022 Variance Explanation

Costs decreased by $0.4 million from 2021 to 2022 due to hiring plan adjustments.

<u>2022 – 2025 Variance Explanation</u>

From 2022 to 2025, costs are expected to increase by approximately $4.1 million due to reorganization within the HR, Environmental & Safety division to align leadership and support delivery on current and upcoming organizational operational strategies and strategic projects. This reorganization will support the following outcomes:

- Support for the SAP S4 HANA upgrade as outlined in Exhibit 2B, section E8.4, specifically for the component associated with human resources data, including timekeeping and employee master data systems;
- Increased headcount due to the delay in hiring from the pandemic;
- Support succession planning and development within the division; and
- Support the Human Resources, Environment and Safety division in the rate application.

<u>2025 – 2029 Variance Explanation</u>

Between 2025 and 2029 costs in this segment are expected to increase by $1.8 million, or an average of $0.5 million per year. If the utility does not receive the funding it requires to execute this segment as described, Toronto Hydro could be exposed to a number of risks, including:

- Insufficient resources to monitor, advise, and enforce compliance with the utility's legislative and regulatory obligations;
- Insufficient resources to investigate and remedy employment issues such as attendance management, lowering workforce productivity;
- A lack of competitive and informed total rewards compensation offerings contributing to an inability to attract talent in a tight labour market in a large urban city, as well as losing talent to other utilities, resulting in an insufficient

workforce to execute the utility's capital program and growth and modernization programs;

- An inability for the utility to defend itself against civil employment claims, Ontario Labour Relations Board matters, and human rights claims;
- A lack of resources to improve the utility's innovation capabilities and a lack of productivity support to run lean programs that decrease organizational waste (e.g. time, materials, etc); and
- A lack of modern technology solutions requiring employees to focus more on manual and tedious data work rather than focusing on higher-level value-added work;

7. TALENT MANAGEMENT, CHANGE LEADERSHIP & SUSTAINABILITY SEGMENT

7.1 Segment Description

The Talent Management, Change Leadership & Sustainability segment governs the development and execution of the utility's workforce staffing plan, career succession, and employee development strategies and programs. The primary objective of this segment is to align workforce and culture change strategies to organizational strategies and key competencies for current and future workforce requirements. This enables the advancement of the organization as an employer of choice, builds workforce competence to drive technology, process change and innovation, and enhances leadership skills and competence. Functions within this segment include:

- Short and long-term workforce staffing and planning;
- Talent attraction and retention;
- Succession planning and career development;
- Organization and job and design;
- Diversity, equity and inclusion; and

- Change management systems; training and development.

7.1.1 Talent Management

The Talent Management function plans and executes the utility's short and long-term workforce strategy,[10] which includes: (i) mapping the resources that the utility needs to execute its capital plans and operational programs; (ii) analyzing the availability of talent within the utility and in the external labour market; and (iii) understanding the utility's actual and projected turnover rates. This information forms the basis of the utility's workforce strategy. This segment is also responsible for administering collaborations with colleges and universities and its talent attraction strategies.

The utility has evolved its talent management processes to build a more diverse workforce. Specific plans to support these objectives include creating engagement, communication and educational opportunities to build employees' understanding of unconscious bias and the importance of inclusive leadership. For example, as of June 1, 2023, 241 leaders (91 percent) have completed unconscious bias training.

The utility's Talent Management processes supports a bias and barrier-free recruiting experience. Toronto Hydro is committed to attracting, retaining and promoting qualified individuals to meet its resourcing requirements. Toronto Hydro uses a competency-based selection approach to align candidates to behavioural corporate competencies and technical job specific requirements. This process mitigates operational and safety risks for the organization due to poor hiring decisions.

[10] Exhibit 4, Tab 4, Schedule 3.

Toronto Hydro collaborated with George Brown College to develop curriculum for the Electromechanical Engineering Technology – Power and Control Program. Graduates of this program will meet minimum entry qualifications to Power Line Technician, Engineering Technologist, Distribution System Technology, Power System Controller and Certified Meter Mechanic Tester roles. All of these are key certified and skilled trades and designated technical professional roles that support the safe, productive, design and operation of the distribution system. This program was launched in 2021 and demonstrates the utility's commitment to investing in future talent by giving back to the diverse community it serves. The first graduates of this program will reach the labour market in the spring of 2024.

Team members from this segment work directly with educational institutions, including George Brown College, to lead the establishment of collaboration outcomes. These include annual goal setting in the areas of curriculum development, training support, recruitment and marketing for current and prospective students, scholarships and awards and work integrated learning program support, and lab equipment upgrades. Expected outcomes for the utility include a ready talent pool versed in relevant knowledge to fill short and long-term workforce needs over the 2025-2029 period.

7.1.2 Organization Design

Toronto Hydro's organization design function collects information on business departments' functional responsibilities and processes for the purpose of optimizing business functionalities, identifying strategies that enhance existing processes, seeking options to increase workforce flexibility, achieving operational efficiencies and cost savings, and improving overall organizational performance. This function ensures that job roles are clearly defined. This function also assesses the utility's management systems and operational processes to identify short and long-term talent needs and opportunities and support succession plans at all levels. This organizational design process flows into creating tailored short-term and long-term workforce and leadership requirements to meet the utility's objectives.

7.1.3 Change Leadership

The change leadership function enables Toronto Hydro's journey to transform the workforce through key business processes alignment, continual improvement and innovation. In addition, this team supports the people side of change with upskilling, development and engagement and communication as applicable.

This function also supports the utility's culture change goals with its hybrid work arrangement and its focus on ESG and diversity, equity and inclusion goals. This function further executes strategies to maintain employee engagement and productivity throughout the planning, delivery and sustainment of these projects.

One example of organizational change at Toronto Hydro has been the development of the "Enterpriser" community across the organization. Enterprisers are a network of approximately 80 employees who are involved as change agents in the business. This cross divisional network has been maintained for five years following the implementation of SAP, and has supported system enhancements, adherence to standards and processes and the learning of employees who are onboarded or transition to new roles.

7.1.4 Training and Development

Toronto Hydro provides training and development programs to sustain a qualified and competent workforce. These include an onboarding program to support employees' transitions to new roles, apprenticeship training, leadership, technical, legislative, and Toronto Hydro-specific compliance programs. For example, in 2022, the Sustainability and Training team organized and delivered 655 scheduled classes across 86 distinct training programs. Toronto Hydro primarily develops these programs in-house. This in-house development has accelerated training program development time, increased the quality of training materials, and improved training material maintenance for a lower overall cost. External designers are only used for complex legislative compliance matters or complex technologies such as virtual reality.

Effective leadership and succession planning are essential to the utility's success. They provide value to Toronto Hydro's customers by driving productivity and efficiency and by protecting the continuity of the utility's operations. Leadership responsibilities include: championing environmental, social and governance programs, training, performance management, employee engagement, coaching and mentoring, and employee development.

The Sustainability and Training team facilitates these objectives, in conjunction with the performance management program, which allows employees to identify career development goals, specific interests, and any skill or knowledge gaps that they would like to fill. This information is critical to recognizing and developing potential leaders and successors from within the utility and to delivering Toronto Hydro's staffing strategy.[11] Through well-developed processes for identifying and developing leadership potential, Toronto Hydro has successfully improved leadership bench strength, creating a pool to fill this critical function. Leadership training is provided to employees at all levels of the organization.

[11] *Ibid.*

Toronto Hydro's technical training and development programs are an essential resource for meeting all legislative, compliance and utility specific training requirements. Comprehensive training is not only a legislative requirement under the *Occupational Health Safety Act, 1990*[12] and other key statutes and codes that govern Toronto Hydro, but it also contributes to higher employee productivity, efficiency and safer operations.

Toronto Hydro administers four certified apprenticeship training programs :

- Power Line Technician ("PLT");
- Distribution System Technologists ("DST");
- Power System Controllers ("PSC"); and
- Certified Meter Mechanics ("CMM").

Toronto Hydro also administers two technical training programs: (i) Engineering Technologists; and (ii) Engineers.

Together, these programs play a key role in facilitating the development and transfer of core knowledge about the complexities of Toronto Hydro's distribution system and in maintaining the specialized work skills which are critical to the utility's capital program and operations (e.g. network switching, positive identification of underground cable and lead cable splicing in the underground system). Informal mentorship also occurs, providing experienced employees with an opportunity to share best practices along with greater understanding of the complexities of the utility's assets.

Toronto Hydro was granted Training Delivery Agent status by the Provincial training authority to provide training to the utility's Powerline Technicians. Its other three

[12] *Supra* note 4.

apprenticeship programs are structured and designed in a similar fashion with the objective of developing and maintaining the specialized skills and knowledge that certified and skilled trades and designated and technical professionals require to work on Toronto Hydro's distribution system safely and efficiently.

7.2 Talent Management, Change Leadership & Sustainability Segment Costs

Table 6, below, provides the Historical (2020-2022), Bridge (2023-2024), and Forecast Years (2025-2029) expenditures associated with the Talent Management, Change Leadership & Sustainability segment.

Table 6: Talent Management, Change Leadership & Sustainability Segment Expenditures ($ Millions)

Segment	Actual			Bridge		Forecast				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Talent Management, Change Leadership & Sustainability	7.2	9.0	8.4	7.9	8.8	9.3	9.4	9.8	10.2	10.6

7.3 Talent Management, Change Leadership & Sustainability Year-over-Year Variance Analysis

2020 – 2021 Variance Explanation

From 2020 to 2021, costs increased by $1.8 million due to:

- The introduction of additional headcount as additional trainers for the apprenticeship program in Sustainability & Training;
- The re-initiation of training programs that were paused in 2020 due to the COVID-19 pandemic; and
- Headcount to support programs such as leadership development and corporate engagement and communication.

<u>2021 – 2022 Variance Explanation</u>

From 2021 to 2022, costs decreased by $0.6 million due to hiring plan adjustments.

<u>2022-2025 Variance Explanation</u>

From 2022-2025, costs are expected to increase by $0.9 million due to:

- Investments in headcount to support leadership development, diversity equity and inclusion programs and resources to attract and train the talent required to support capital and operational work programs

<u>2025-2029 Variance Explanation</u>

Between 2025 and 2029 costs in this segment are expected to increase by $1.3 million, or an average of $0.3 million per year. If Toronto Hydro does not receive the requested level of funding to perform the functions and satisfy the responsibilities identified in this segment, the utility could be exposed to a number of risks, including, a reduced ability to successfully recruit, advance the inclusive culture and develop the skilled and specialized resources that Toronto Hydro requires in the next five years.

WORKFORCE STAFFING PLAN AND STRATEGY

The 2025-2029 investment plan includes necessary investments in 38 distinct work programs to address existing and emerging challenges that the utility faces in serving its customers safely, reliably and efficiently in this decade and beyond as the city of Toronto continues to grow amidst an energy transition that is creating an expanded role for electricity across key sectors of the economy.

Toronto Hydro needs a robust, engaged and highly-skilled workforce to support execution of planned capital and operations work programs outlined in Exhibits 2B and 4, Tab 2, respectively. This schedule outlines Toronto Hydro's workforce philosophy and plans to secure the resources and skill sets that the utility needs to: (i) deliver its work programs safely, reliably and efficiently, and (ii) achieve the performance outcomes that customers need and stakeholders value as outlined in Exhibit 1B, Tab 3, Schedules 1 and 2.

The evidence is organized as follows:

- Workforce Philosophy
- Workforce Drivers and Needs
- Workforce Breakdown by Segment
- Talent Development Strategy

1. WORKFORCE PHILOSOPHY

Demographic and post-pandemic societal shifts are reshaping the labour market in Canada, at the same time that technology and digital innovation are redefining the skill sets and strategies needed to ensure an agile, engaged and productive workforce. Toronto Hydro's workforce philosophy is mindful and responsive to key changes in the labour market and employee preferences. To maintain its competitive advantage in the evolving labour market and remain an employer of choice, Toronto Hydro must invest in its greatest asset – its people. These investments entail increases in the capacity of the workforce to maintain employee wellness and avoid employee burnout through work-life balance (the right to disconnect from work). Similarly, Toronto Hydro must invest in advanced skills and capabilities to empower its workforce to excel in the face of rapid technological advancement, and changing policy requirements and evolving customer expectations.

To build and maintain a robust, diverse, engaged and productive workforce, Toronto Hydro relies on the following key tenets of its workforce philosophy:

a) **Talent Acquisition & Development**: Attract and recruit talent for the organization to fill critical roles and achieve business objectives. Provide training and development opportunities to help employees grow and acquire new skills, create career paths and implement succession plans.

a) **Workforce Culture, Diversity and Inclusion**: Create a diverse and inclusive workplace where everyone feels valued, supported and respected. Foster a growth mindset and positive culture that promotes employee engagement, wellness and work-life balance to maintain an engaged, innovative and high-performing workforce.

b) **Performance and Productivity**: Achieve objectives by setting clear expectations, providing regular feedback, and recognizing and rewarding employees who meet or exceed expectations. Embrace new technology and invest in tools and systems that can improve efficiency, automate repetitive tasks, enhance the quality of work, and promote collaboration across teams.

c) **Agility & Innovation**: Adapt to evolving business needs, emerging technologies, and changing market conditions by leveraging data and analytics to monitor market trends, measure performance, and make data-driven decisions.

2. WORKFORCE DRIVERS AND NEEDS

2.1. Challenges

Over the last decade and throughout the current rate period, Toronto Hydro focused on rebuilding and replenishing its workforce in the face of both familiar and emerging challenges. Familiar challenges for Toronto Hydro include renewing its workforce due to retirements, attracting and retaining talent, and developing new entrants to its workforce through partnerships with colleges and universities. For the last ten years, Toronto Hydro has managed the workforce renewal challenge brought by the wave of baby-boomer retirements.[1] After each retirement, the organization must deal with not only a loss of knowledge and experience, but also a need to train and develop the individuals promoted or newly hired. In addition to demographic-related challenges, Toronto Hydro employees are often sought after by other organizations that may offer similar roles in neighbouring geographic regions. A competitive labour market challenges the utility to maintain market competitiveness of its compensation and benefits programs to attract and retain employees to work in Toronto.

Although employment in the utilities sector has remained relatively stable, labour market changes, including demographic shifts, increasing competition and strong demand for workers with digital skills have led to shortages of workers trained in science, technology, engineering and mathematics (STEM), as well as in digital skills.[2] Toronto is the largest city in Canada and one of the fastest growing urban centers in North America and the demand for qualified and knowledgeable STEM resources is strong, not only with the utilities sector but among multiple sectors outside of the industry.

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[1] The term “baby boomers” refers to those individuals that were born between 1947 and 1965.
[2] Mahboubi, Parisa. 2022. The Knowledge Gap: Canada Faces a Shortage in Digital and STEM Skills. Commentary 626. Toronto: C.D. Howe Institute: https://www.cdhowe.org/sites/default/files/2022-08/Commentary_626_0.pdf

Toronto Hydro also faced unprecedented challenges posed by the COVID-19 pandemic and consequent impacts. During the pandemic, Toronto Hydro's workforce numbers reached a historic low in 2021. Retirements that were expected to be paced fairly evenly over the 2020-2025 rate period were instead concentrated in years 2020 and 2021. At the same time, the pandemic temporarily suspended talent acquisition, training, and development for critical areas and skill sets established during the previous rate period. As a result, Toronto Hydro's plans to increase its staffing levels over the 2020-2024 period were delayed, particularly as it relates to the Power Line Technician trade hiring plan. The rapidly changing business environment and social distancing requirements impacting hiring for positions requiring in-person training contributed to this unavoidable hiring delay.

Toronto Hydro successfully weathered the challenges of remote work and of addressing increased safety risks, with a comprehensive infectious disease response plan. At the outset of the COVID-19 pandemic, Toronto Hydro mobilized immediately to protect its workforce and the public while continuing to provide safe and reliable delivery of power throughout the city of Toronto. The plan established protocols required to manage an infectious communicable disease outbreak to maintain the health and safety of employees and mitigate the spread of infectious disease through the workforce. Toronto Hydro did not experience any workplace transmission of COVID-19 through 2022. In recognition of its response to COVID-19, Toronto Hydro received the Most Effective Recovery Award from the Business Continuity Institute (BCI) Americas. The BCI, a global organization of business continuity and resilience professionals representing more than 100 countries worldwide, gives this award to an organization that was significantly impacted by an incident or crisis, but managed to recover and demonstrate resilience.

The COVID-19 pandemic significantly impacted traditional talent management approaches and introduced a new level of complexity in recruiting talent. Changing attitudes towards commuting to the workplace and the overall concern of extended commute times in the City of Toronto added a new layer of challenge and complexity to the utility's attraction and retention efforts.[3] The utility addressed this through flexible work policies that are responsive to changing preferences. Specifically, in 2022, Toronto Hydro transitioned to a hybrid work arrangement that enables employees who can perform their work from home with the flexibility to attend their assigned work center a minimum number of days a week and work remotely the other days. Reintegrating the workforce into the office and building a hybrid work culture where employees feel engaged was a notable challenge that Toronto Hydro worked hard to overcome over the last two years. It succeeded by adopting work policies and practices that were informed by employee feedback, and implemented incrementally with a focus on the unique needs of each operational area. This was complemented by a gradual increase in in-person employee engagement, which helped ensure the successful adoption of the new hybrid work model throughout the organization.

Once the acute challenges of the pandemic began to subside, customers, governments, and markets started coalescing around a need to accelerate the energy transition to mitigate the existential and economic impacts of climate change. As customers electrify previously non-electric energy uses (e.g. transportation, heating) and increase participation in clean energy production and management, these actions will have fundamental long-term implications

[3] In 2022, Mercer conducted the Flexible Working Policies and Practices Survey across Canada, polling employers and employees on offerings and preferences for onsite, hybrid and fully remote working arrangements. The survey indicated that 53% of employers offered and 53% of employees wanted hybrid working arrangements. https://www.imercer.com/ca/products/flexible-working policies-practices-survey-ca

for Toronto Hydro and its system, including—but not limited to—being ready to serve a future demand for electricity that is expected to roughly double over the next two decades.[4]

Given its fundamental obligation to connect customers who want to access the distribution grid, Toronto Hydro cannot enter this period of significant change unprepared to handle increased demand and consumption, bi-directional power flows, increased societal reliance on electricity, and enhanced customer expectations that naturally flow from these evolutions. As with investments in Toronto Hydro's grid, human capital investments require a long lead-time to develop and safely train. Depending on the trade, for example, it takes anywhere from four and half to six and a half years to train a new certified and skilled trades person, plus a minimum additional one to two years to develop a new front-line leader post apprenticeship. Due to the long lead time required for investment in both grid and human capital, to meet these needs Toronto Hydro must begin work today to be prepared for an accelerated energy transition in the next decade.

2.2. Capacity

As the operating conditions affected by COVID-19 pandemic stabilized in 2022, Toronto Hydro started increasing the pace of its recruitment to 'catch-up' to its projected staffing levels by the end of 2023. Yet, because the external environment has changed, these catch-up efforts are also a foundational step towards a future-ready plan that includes investments in resourcing capacity (headcount) and capabilities (enhanced skills) that are necessary to meet the challenge ahead.

Toronto Hydro needs to expand its workforce by approximately 214 resources starting in 2024 through 2029 to meet the imperatives and objectives of its 2025-2029 investment

[4] As shown in Future Energy Scenarios report filed as Exhibit 2B, Section D4, Appendices A and B.

plan.[5] These investments are necessary to: (i) ensure adequate resourcing to support the safe and efficient execution of planned work programs outlined in Exhibits 2B, Section E and Exhibit 4, Tab 2, and (ii) develop advanced capabilities to advance outcomes that matter to customers and stakeholders, including a building a more resilient and efficient grid for the future and enabling the city's economic growth and electrification.

Toronto Hydro's workforce requirements have been optimized by a decade and half journey of productivity. This includes harmonizing jobs to create a more efficient and agile workforce, outsourcing certain functions and aspect of work to focus on critical competencies and skills, and automating repetitive manual processes to provide more efficient service. These efforts produced a demonstrably lean workforce, enabling Toronto Hydro to tackle the staffing needs and challenges ahead from a position of strength.[6]

After more than a decade of realizing sustained efficiencies while managing complex operations with a flat headcount, it is no longer possible nor prudent for Toronto Hydro to meet its obligations without additional resources. As the utility takes "least regrets" actions to expand and modernize the grid to be ready and equipped for a once-in-a century transformation of the energy system, it similarly needs to invest in an expanded resource pool with new and enhanced skill sets to get the work done safely and cost-effectively.

Section 3 below provides an overview of the different segments of Toronto Hydro workforce and explains the capacity investments that Toronto Hydro intends to make over the coming years to meet the challenges ahead. The Designated and Technical Professionals segment will see the largest number of resources added with the addition of approximately 250

[5] The staffing plan is based on headcount needs and requirements over the filed period. Appendix 2-K presents the translation of the staffing plan to budgeted full time equivalents (FTEs).
[6] Please see Exhibit 4, Tab 1, Schedule 1 at section 2.

resources over the 2023-2029 period. Workers in this segment will support not only a growing capital program, but will also provide new needed capabilities related to technology, advanced data analytics and other digital skills.

2.3. Capabilities

Technological advancements and evolving customer expectations require Toronto Hydro to accelerate digital transformation to keep up with the pace of change. With increasing technology on the grid (e.g. Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI), sensors and other field monitoring technologies) comes a significant increase in the volume of data generated in the field. To effectively leverage this data and gain valuable insights that can be used for improved planning and optimized decision-making, Toronto Hydro needs to hire and develop resources with expertise in advanced data analytics, statistical modelling, data science and machine learning techniques.

Toronto Hydro must prepare to respond by attracting and developing employees with the skills and competencies to meet the technical challenges and achieve the objectives of modernizing and expanding the grid. For example, the Control Centre requires the support of a team of technical staff whose duties include work scheduling, design review, system analysis, energy management, reporting, and maintenance/development of core operating technology platforms and tools (e.g. SCADA, Energy Centre, Network Management System, etc.) Over the next several years, Toronto Hydro expects a significant increase in workload associated with these functions to support increased distribution system automation, the development and sustainment of energy management functions, distribution system growth (load and connection volumes), and the expansion of the SCADA system to enable more remote and autonomous operational capabilities. See Exhibit 4, Tab 2, Schedule 7 – Control Centre Operations.

By employing and cultivating resources with advanced digital skills and capabilities, the utility can gain a much more comprehensive understanding of grid performance, identify anomalies, and optimize various aspects of grid operations. Data analysts empowered with the right technology tools can develop models and algorithms that enable predictive maintenance, load forecasting and demand response optimization. They can also uncover hidden relationships between variables to improve grid stability, enhance asset management strategies, and enhance outage management processes. The ability to extract actionable insights from vast amounts of grid data can enable Toronto Hydro to make better decisions and deliver enhanced value to customers. For example, with the implementation of AMI2.0 Toronto Hydro can perform advanced analytics on meter-level outage data to better understand reliability performance at the customer level, and optimize investments to enable a more resilient and efficient grid for the future.

Building advanced capabilities to leverage technology and advanced data analytics to improve existing systems and processes is a critical component of the utility's workforce strategy. To upskill its existing workforce, Toronto Hydro is taking the following actions:

- **Providing Opportunities for Skills Development:** The utility proactively identifies resourcing requirements and provides internal resources with opportunities for skills development. Multiple methods have been used to achieve successful outcomes including: (1) continuing education at post secondary institutions and certification programs, (2) experiential learning opportunities through secondments, stretch assignments and involvement on project teams, and (3) formal job-specific training on technical and soft skills. The organization's performance management system encourages leaders to have regular meetings with employees to understand individual learning goals and structured development plans with milestones and objectives.

- **Developing and Delivering Training Programs:** As new and future skill requirements are identified, the utility develops and aligns training programs with specific learning goals and outcomes and delivers them to its workforce. Training develops transferable skills and increases the employee's capacity to learn. Training is supported with confirmation of learning and skills transfer in the field and inspections conducted by front line leaders. This ensures that the workforce knowledge has increased sufficiently to safely and efficiently apply the new skill in practice. Upskilling equips employees with the skills needed now and for the future, supports career progression and is a strategy that supports retention.
- **Maintaining Safe Ratios of Supervision and Mentorship:** Toronto Hydro conducts sophisticated long-term workforce staffing planning within its Certified and Skilled Trades and Designated and Technical Professional positions to maintain the workforce's competencies. This ensures that the learning and development opportunities afforded to apprentices remain safe as a result of Toronto Hydro established ratios of supervision and mentorship.

Toronto Hydro must invest in building a workforce with expanded skills in data analytics, data science and big data who can leverage technology solutions such as artificial intelligence (AI) software and other tools to manage and analyze large datasets towards the following types of objectives.

1. Respond to risks posed by potentially disrupting technologies to the distribution system. Grid modernization involves the integration of numerous digital technologies. Ensuring robust cybersecurity measures is of paramount importance.

To address this evolving threat landscape, there is a need to prioritize and augment capabilities and implement comprehensive strategies, such as conducting regular security audits, and deploying advanced monitoring systems. The utility must assess the security posture of grid components, such as smart meters, ADMS systems, and communication networks. Specialized knowledge is required to recommend appropriate security controls and measures. The addition of resources to support cybersecurity risk and threat management ensures the resilience and reliability of the grid system as it undergoes modernization efforts.

2. Design, operate and manage an automated and bi-directional grid that is capable of connecting and integrating higher volume of distributed energy resources (DERs). DER integration professionals collaborate with stakeholders including regulators, DER providers, and customers to develop standardized interconnection processes, address technical challenges, and streamline grid operations. With employees knowledgeable in DER integration, it is easier to unlock the full potential of DERs, maximize grid efficiency, and accelerate the transition to a clean and decentralized energy future. The utility must also invest in training activities to enhance the knowledge and capabilities of its Certified and Skilled Trades segment to safely plan and operate within an automated and bi-directional grid. This will enable Toronto Hydro to effectively manage grid variability, enhance resiliency, and optimize asset utilization.
3. Building the utility’s capacity and capability to provide proactive information and service to drive improvements to customer experience, outcomes and interaction with the grid. Toronto Hydro is working to meet customers’ evolving expectations of the utility. For example, as EV ownership increases and as more customers adopt DERs, Toronto Hydro anticipates an increase in customer inquiries related to these technologies, including topics such as service upgrades, connections, pricing plans

for EV charging and net metering and associated billing for DERs. The utility is looking to enhance the capabilities of its customer service representatives to ensure that Toronto Hydro is prepared to respond to customer needs in time for the energy transition.[7]

4. Building the utility's capacity and capability to respond effectively to fast-evolving regulatory policy developments, challenges and opportunities in the current business environment. The utility has extensive legal, regulatory and communication needs served by highly-trained legal, regulatory and communications professionals. This team's capacity and capabilities need to be enhanced in order to keep up with the volume and complexity of work necessary to support the utility's work program which is shaped by electrification, the energy transition, new technologies and evolving customer choice. Drivers of this increase include an increase in contract volumes, claims volumes, agreements associated with large transit projects, and legal, compliance and policy work responsive to changes in the energy sector.

Table 1 below provides a summary of the skills sets and sample jobs where the utility is investing to build the workforce of the future.

Table 1: Skill Sets and Job Types for the Future Workforce

Skill Sets	**Job Types**	**Approximate Proportion of Staffing Plan**
"Big Data" Analytics – Consolidation & Presentation of data to support Decision Making	Analysts – cross functional	23%

[7] Cross-references to 4A Customer Care program

Skill Sets	Job Types	Approximate Proportion of Staffing Plan	
Design, operational and management of distribution grid	Power Line Technician, Engineering Technologist, Power System Controller, Meter Mechanic, Meter Data Technologist, Distribution System Technologist, Dispatcher	18%	/C
Front-line Leadership	Day-to-day operations and people management	20%	/C
Financial management, regulatory affairs management, legal management, supply chain management, operations support, human resources management	Professional & supporting skills – cross functional	12%	/C
Distribution system design and engineering to support existing and new technologies (e.g. bi-directional grid, distributed energy resources)	Engineers	11%	
Customer Experience, Key Account Management, Customer Relations Management	Large Customer & Key Account Consultant Customer Relations Representative	10%	
New technical and cyber security skills to support technology advancements and innovation	IT Technical Consultant Cyber Security Specialist	7%	
TOTAL		**100%**	

3. WORKFORCE BREAKDOWN BY SEGMENT

Toronto Hydro has a robust workforce of highly-skilled employees across diverse areas of expertise. Figure 1 shows the current and future composition of the projected workforce, by segment, out the end of the decade. The skills of employees and type of work executed within each segment is discussed in detail below.

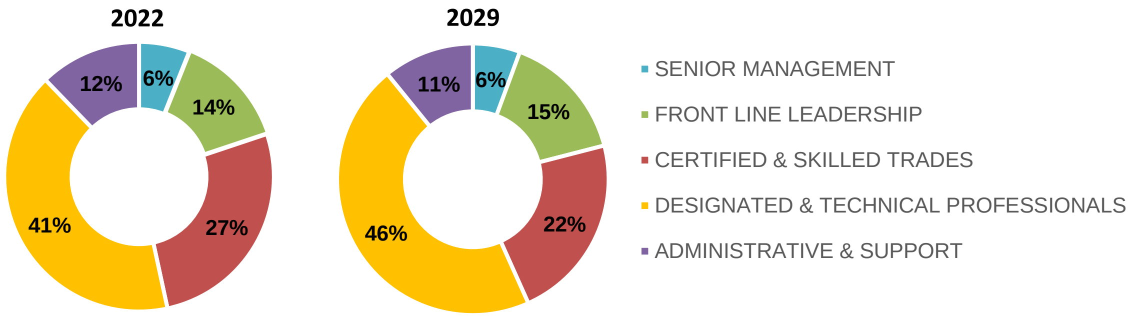


Figure 1: Projected Toronto Hydro Workforce Segments (2022 & 2029)

3.1. Certified and Skilled Trades Segment

Certified and Skilled Trades are responsible for executing the work required to construct and maintain the distribution system infrastructure, and for responding to trouble calls and emergency situations to restore power or address asset deficiencies or other circumstances that pose safety, environmental or reliability risks. Certified and Skilled Trades comprised approximately 27 percent of Toronto Hydro's workforce as of the end of 2022. Although this segment is anticipated to decrease slightly as a percent of the total population of employees because of practical limitations of safely absorbing new certified and skilled trades into the organization (i.e. maintaining the appropriate apprentice to qualified journeyperson ratios), Certified and Skilled Trades are expected to grow by approximately 40 resources by 2029 to replenish the workforce in this segment.

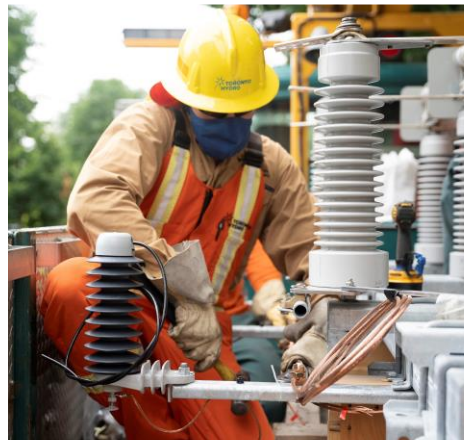
Below is a detailed list of the positions and associated responsibilities within this segment.

- **Certified Meter Mechanic/Tester ("CMMT"):** Installs, changes, removes, repairs, inspects, tests and calibrates of all types of meters and metering equipment for correct wiring and accuracy of metering, operation of meter test equipment according to documented procedures and to troubleshoot faults in meters.

- **Distribution System Technologist ("DST"):** In 2009, job harmonization merged six classifications into the new classification of Distribution System Technologist (DST). The DST operates, installs, commissions, constructs, repairs, maintains, and decommissions all types of substation equipment, protective relay and control systems, station metering, distribution automation equipment, and SCADA systems, including completion of all associated work orders, specifications, engineering drawings, reports, and work procedures**.**
- **Power Line Technician ("PLT")**: Constructs, operates, maintains and repairs overhead and underground electrical and distribution systems. Erects and maintains steel, wood, fiberglass, laminate and concrete poles, structures, and other related hardware. The PLT installs, maintains and repairs overhead and underground apparatus, and other associated equipment, such as insulators, cable, conductors, lightening arrestors, switches, metering systems, transformers and lighting and control systems. Splices and terminates cable and conductors to connect power distribution and transmission networks. Previously, this work had been performed by two distinct trades groups, the Certified Power Cable Person ("CPCP") and Certified Power Line Person ("CPLP"). Similar to the approach used in prior years as part of the collective bargaining process, in 2022, these two roles were harmonized into the Toronto Hydro Power Line Technician role. Graduates of the PLT Apprenticeship program will be competent to work safely on any aspect of the overhead or underground distribution system for both capital construction as well as reactive or emergency scenarios. This will provide Toronto Hydro with significantly greater flexibility in crew assignments and execution of work.
- **Power System Controller ("PSC")**: Operates the electrical distribution system to provide safe, reliable, and cost-effective delivery of electrical power on a rotating

24/7, 365 days/year shift schedule. Develops, directs, and dispatches system switching, work protection, and trouble response for planned and emergency events.

PLT - Underground Plant



PLT - Overhead Plant

Figure 2: PLT Employees at Work

3.2. Designated and Technical Professionals

Designated and Technical Professionals are responsible for planning, designing and executing work programs and for ensuring the utility's compliance with legal, regulatory, financial, and environmental requirements, applicable standards and best practices.[8] This segment comprised approximately 41 percent of Toronto Hydro's workforce as of the end of 2022, and is anticipated to grow to 46 percent with the addition of approximately 250 resources over the 2023-2029 period. The increase is driven by a multitude of factors including: (i) responding to more complex legal and regulatory requirements such as related to integration of Distribute Energy Resources ("DER"), (ii) operating in a more data-intensive

[8] For example, Toronto Hydro must ensure compliance with environment, health and safety requirements including the Utility Work Protection Code, Electrical Utility Safety Rules, *Occupational Health & Safety Act* and Regulations, ISO 14001:2015 and ISO 45001:2018 standards, and the *Environmental Protection Act*. See Exhibit 4, Tab 2, Schedule 17 – Human Resources, Environment and Safety for further details.

environment driven by technology and modernization, and (iii) supporting an increase volume of capital and operating programs over the period. All of these factors, and many others that are detailed throughout the programmatic evidence in Exhibit 4, Tab 2 translate to a corresponding increase in talent for the following positions and associated responsibilities within this segment:

- **Engineers**: Participates in short- and long-range strategic asset planning to ensure technical soundness, reliability, cost effectiveness, and safety for the utility; prepares engineering reports and studies; performs engineering analysis and evaluations; provides timely technical support/consultation, project management, and testing; develops proposals and plans; and prepares and/or reviews methods, procedures (process re-engineering), and designs. Engineers are accountable, and legally responsible, for personal engineering work product (e.g. drawings, calculations, documents, and the work of others which the engineer has signed).
- **Engineering Technologists:** Supports the formulation of electric system plans and co-ordinates system operation services with the control centre; develops distribution plans by calculating load forecasts; prepares conceptual and detailed designs and cost estimates for projects related to system expansion, rehabilitation, and maintenance of the electrical and civil infrastructure; conducts studies, prepares reports, makes recommendations relating to station and system distribution load forecasts, engineering studies, technical standards, utility materials, tools, and construction practices; and prepares, reviews, and maintains project schedules.
- **Analysts**: Enable the utility to make data driven decisions, provide valuable insights and satisfy a variety of external obligations and internal responsibilities. As systems evolve and are added and more data is produced, roles are required to analyze and integrate various data sets. Analysts in both corporate and operational areas require critical thinking, creativity, and problem-solving techniques to define needs and

recommend solutions that deliver value to stakeholders. Analysts employ a variety of tools, including: predictive analysis to elevate the customer experience; numerical skills to measure and statistically analyze large data sets; technical skills to understand business problems, organize and present data.

Without the required staffing levels of Designated and Technical professionals, Toronto Hydro would not have the necessary resources to plan and design a safe, secure and reliable distribution system in compliance with legislative and regulatory requirements, applicable standards and best practices. As shown in Figure 3 below, the capacity of this segment tracks closely with the overall size of the capital investment plan as measured by expenditures.

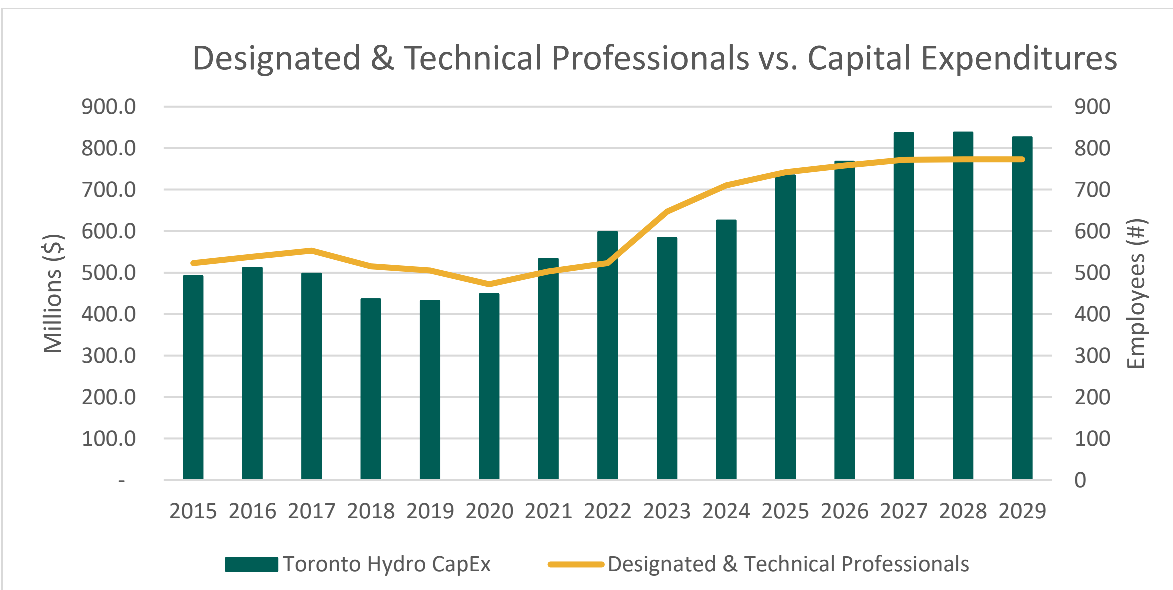


Figure 3: Designated & Technical Professionals Compared to Capital Expenditures

In addition to keeping up with increasing work volumes, the employees in this segment are tasked with designing and planning for changes to how customers use electricity and how the utility operates the grid brought by technological advancements and necessitated by customer demands in an electrified future. This includes grid automation technologies to enhance system observability and controllability and to enable the gradual transition to a two-way power flow grid that provides customer greater choice over their electricity consumption, and the opportunity to participate in the system by selling electricity back to the grid.

Last but not least, the resources in this segment are an important source of internal talent for front line and senior management leadership roles. Investments in this segment produce proprietary industry knowledge and expertise that Toronto Hydro relies on to fulfill leadership roles efficiently and effectively through internal recruitments. In 2022, 46 percent of internally filled leadership roles (front line and senior management) were from the Designated and Technical professionals’ segment.

3.3. Front Line Leadership

Front Line Leadership positions are responsible for managing and overseeing the complex design and execution of the utility’s capital and operations work plans. The responsibilities associated with these positions include safety training, inspections, audits, investigations, risk management, problem-solving, staff training and development, performance management, employee engagement, coaching and mentoring.

Front Line Leadership employees are primarily trained, developed and promoted from within the organization to leverage their in-depth experience and track-record of high-performance at the utility. At the end of 2022, this segment comprised approximately 14 percent of Toronto Hydro’s workforce. Over the 2025-2029 rate period, this segment must remain stable in order to oversee the delivery of the utility’s work programs and ensure that internal and external resources work in a safe, productive and environmentally responsible manner. To maintain its proportion to the overall compliment, the segment is expected to grow by approximately 80 resources from 2023-2029. Without sufficient resources in Front-Line Leadership positions, Toronto Hydro's track-record of productivity and performance would be compromised.[9]

3.4. Operational Support & Administration

Operational Support & Administration staff enable the efficient execution of work within operations, customer care and corporate functions. This segment provides administrative support to function specific management and technology systems, creates and maintains professionally formatted business documentation and makes recommendations to streamline and improve the administration, coordination and delivery of processes within the assigned business unit. Employees within this work segment are continuously reskilling and upskilling to take on higher-value work such as reporting, research and analysis tasks.

At the end of 2022, this segment comprised approximately 12 percent of Toronto Hydro's workforce. Efforts throughout the 2017 to 2022 period to streamline processes resulted in an 18 percent decrease in the number of employees in this segment. Furthermore, as a result of investments in upskilling these employees, operational support and administration staff have become a valuable pipeline for development and career progression in the organization. From 2020 to 2022, 25 percent of internal professional and certified and skilled trades recruitment was filled by employees from this segment.

This segment needs to remain stable through 2029 to support the efficient execution of work, to attract new labour market entrants to the organization, and provide a pipeline for

[9] See Exhibit 1B, Tab 3, Schedules 2 and 3 for more information about the utility's performance and productivity track-record.

other workforce segments. Without appropriate staffing levels in these positions, Toronto Hydro would not only risk a reduction in productivity as a result of higher cost resources having to perform process-focused administrative work, but would also lose the opportunity to develop a critical source of internal talent. The number of resources is expected to increase by approximately 30 over the 2023-2029 period.

3.5. Senior Management

Senior Management positions provide the leadership and strategic guidance necessary to achieve Toronto Hydro's objectives in a complex, highly-specialized and regulated environment. Senior Management leaders hold extensive portfolios of accountabilities that are responsive to dynamic systems, processes and technologies. These accountabilities are evolving as result of changes in the external environment including changing customer expectations with respect to reliability and resilience, technological advancement and emerging public policy imperatives to modernize and prepare Toronto Hydro's grid and operations for electrification.

Through well-developed processes for identifying and developing leadership potential, Toronto Hydro has successfully improved leadership bench strength and created a pool of qualified and talented employees to fill critical Senior Management positions. From 2020-2022, 93 percent of senior management roles were filled internally, with limited reliance on the external market to fill increasingly senior leadership roles. On average over the period, these roles filled approximately 60 percent faster than externally filled positions, positively impacting operational efficiency and productivity.

As of the end of 2022, this segment comprised approximately 6 percent of the workforce. Over the next rate period, Toronto Hydro needs to maintain the proportion of resources in this segment stable in order to manage and lead the organization to achieve its core objective and rise up to the challenge of serving higher customer demand and expectations for safe, reliable and cost-effective power in an electrified future. The segment is expected to increase by approximately 20 resource over 2023-2029.

4. TALENT DEVELOPMENT STRATEGY

A strong talent attraction and engagement strategy is critical to: (i) continue to position Toronto Hydro as an employer of choice; (ii) build staff competence to address requirements, deliver plans, and integrate more technology and innovation into their work; and (iii) advance leadership skills and competence to support diversity, equity and inclusion, lead in a hybrid work environment and role model culture change. This section will outline how the utility will develop existing resources and execute an effective internal and external hiring strategy.

4.1. Existing Resources

Toronto Hydro takes a comprehensive, forward-looking approach to maximizing the value of its existing employee resources by providing timely upskilling and training opportunities, applying productivity strategies, supporting innovation, promoting from within the organization, and using management tools to maximize employee performance. Each of these approaches is discussed in detail below. Toronto Hydro relies on a combination of all these approaches to achieve organizational success and meet its human resource requirements.

4.1.1. Upskilling and Training Opportunities

Toronto Hydro provides employees with extensive training and upskilling opportunities. These opportunities serve several purposes. They ensure that employees within each workforce segment have the requisite knowledge and skills required to perform their jobs competently, safely and in compliance with the relevant rules, codes and authorities. They also serve to enhance awareness of equity, diversity and inclusion issues in the organization, equip employees with the capabilities to meet emerging technology challenges, and prepare the right talent for promotion from within.

Toronto Hydro delivered nearly 550 training and development programs from 2020 to 2022. These programs are tailored to the work requirements of different positions across the organization. For example, within the Certified and Skilled Trades segment, Toronto Hydro is focused on providing training through a trade school that maintains safe apprentice-journeyperson ratios and equips workers with the competence to execute work efficiently and safely on electrified assets within Toronto Hydro's dense urban service territory. Toronto Hydro periodically updates the content and form of this training to reflect current best practices and deliver it in an effective manner.

Over the current rate period, Toronto Hydro transitioned 29 of its training programs from being led by instructors in-person to being delivered virtually. This conversion will eliminate the need for employees to travel to a training location, reducing vehicle emissions and increasing the number of trainees who can attend a given class session.

Toronto Hydro also delivers upskilling opportunities to its employees across all segments to enhance their technical and professional abilities and improve operational capabilities to address emerging business needs and challenges posed by technological advancement. For example, after the implementation of the new SAP system in 2018, Toronto Hydro created a group of highly-trained and skilled employees, called Enterprisers, to enable and assist SAP users through the company to unlock the full functionality of the new system.

Over the 2025-2029 rate period, Toronto Hydro intends to develop and enhance data analytics capabilities as a critical skill given increased data generated from new technologies (e.g. AMI 2.0). Toronto Hydro is continuing to develop in-house training that focuses on building employees' future-ready skills including fluency with data analysis programs such as Tableau to perform sophisticated research using modern software tools. These investments in upskilling the workforce are critical to developing advanced operational capabilities to intelligently manage a more complex and highly-utilized energy system.

Toronto Hydro is also incorporating emerging technologies in its upskilling. A Virtual Reality (VR) training module was introduced in 2022 for crew members that focuses on Pad-Mounted Switchgear operations and repair. The VR training is designed to provide crews with a realistic, interactive simulation that covers everything from inspecting the job site for hazards to safely repairing and operating the switchgear being exposed to the many hazards associated with performing this task in the field. VR training also facilitates real-time assessments and data collection.

Finally, Toronto Hydro provides education opportunities focused on building the competence of all employees on the value of diversity, equity and inclusion, the identification and understanding of unconscious bias, and the importance of inclusive leadership. 91 percent of leaders in the organization completed unconscious bias training in 2022.

Table 2: Training and Development Programs (2020-2022)

Area	2020 Courses	2021 Courses	2022 Courses
Compliance (e.g. Environmental and Safety legislative training, EUSA and ESA Rules, Confined Space, Work Protection Code, Network Switching)	52	49	51
Legislative (e.g. WHMIS, Defensive Driving, Forklift Training)	48	48	51
Apprentice (e.g. Distribution Systems Technologist, Power Systems Controllers, Certified Power Cable Persons, Certified Power Line Persons, Meter Mechanics)	20	20	27
Leadership (e.g. Safety Leadership, Performance Management, Management Control & Reporting System, Project Management, Policy Administration)	5	4	15
Technical & Customer Service (e.g. Engineering Technicians, Electrical Awareness, Project Execution, Customer Education Training)	54	51	53
Total	**179**	**172**	**197**

Investments in the development and upskilling of talent offers many benefits for the utility, including creating a valuable pipeline for fulfilling vacancies internally and leveraging career progression as a retention strategy. Front line operational support and administrative staff are a prime example of this strategy at work. From 2020 to 2022, approximately 25 percent of internal professional and certified and skilled trades recruitment was filled by employees from this segment.

4.1.2. Promotion from Within

Promotion from within the organization is a key tenet of Toronto Hydro's talent management strategy. The utility has built an internal pipeline to develop employees' skills, experience and abilities. Developing new leaders and upskilling current employees with the potential to grow is crucial to future success. Establishing a pipeline allows Toronto Hydro to identify, develop and place the right talent in critical roles throughout the organization. Internal candidates have a strong knowledge of Toronto Hydro's culture and management systems. This knowledge is a strategic asset that the utility capitalizes on through its succession planning. Effective succession planning is an important tool for engaging, developing, and retaining employees.

Toronto Hydro successfully executes this strategy to fill positions in its Designated and Technical Professional, Certified and Skilled Trades, Front Line Leadership and Senior Management segments. Between 2020 and 2022, approximately 40 percent of vacancies were filled internally, 28 percent of which were internal promotions to more senior roles. Leadership roles are predominately developed and promoted from within the organization to realize the full benefits of investments made in employee upskilling and development, and retain their in-depth experience and track-record of high-performance at the utility. From 2020-2022, approximately 93 percent of senior management roles were filled internally.

4.1.3. Employee Performance

Toronto Hydro uses a performance-based management and compensation system to set expectations for employees, provide feedback, and recognize employees who meet and exceed expectations. The individual component of the performance management system is administered through annual performance contracts and biannual performance reviews. The utility often sees over 90 percent compliance with its performance management system, showcasing the timely utilization of setting goals and evaluating employees based on their achievements. For management employees, performance pay is directly related to the achievement of both individual and organizational objectives.

4.2. External Hiring

While Toronto Hydro maximizes the value of its existing workforce, the utility is unable to meet the needs and drivers of its staffing plan exclusively from hiring internally. To meet its staffing needs through external recruits, Toronto Hydro employs a combination approach that includes acquiring additional talent from the market, hiring new graduates, leveraging its relationships with colleges and universities, and outsourcing work to third-party service providers where appropriate. Each of these strategies is discussed in detail below.

4.2.1. Acquiring Additional Talent from the Market

Toronto Hydro strategically recruits talent from the external market in the Greater Toronto Area from both the general and energy industries and monitors market trends such as cost of living pressures on an ongoing basis to adapt to changing conditions. The utility's external recruitment process allows it to draw from a larger supply of diverse candidates and hire specific skills that are not readily available within the organization. In addition, external recruitment is key to expanding the workforce's capacity to execute Toronto Hydro's 2025-2029 investment plan.

4.2.2. Hiring New Graduates

The complexity of Toronto Hydro's distribution system and dynamic operating conditions mean that it is optimal for the utility to supplement its hiring of skilled external resources in the market with hiring new graduates, particularly for its Certified and Skilled Trades positions where skills are not readily available in the marketplace. This hiring pipeline relies on the utility's training and apprenticeship programs to instill the specialized skills and knowledge that are required to operate the distribution system reliably and safely. In addition, this hiring strategy allows Toronto Hydro to develop and maintain a dependable workforce that is capable of servicing the utility's operational needs well into the future. The volume of hiring through this hiring pipeline is driven by safety requirements for training on electrical apparatus that limit the number of apprentices who can be trained by a given volume of field crews.

Depending on the trade, it takes anywhere from four and half to six and a half years to train a new certified and skilled trades person, plus a minimum additional one to two years to develop a new front-line leader post apprenticeship. The development period for certified and skilled trades considers both operational and legislative requirements. Operational requirements include relevant rules, policies, procedures, construction standards and equipment to build knowledge, skills and expertise to safely operate the distribution system. Legislative requirements incorporate standard knowledge and skills set out by governing bodies such as the Ministry of Labour, Immigration, Training and Skills, the Ministries of Environment and Transportation, the Technical Safety Standards Authority and the Electrical Safety Authority. Toronto Hydro's apprenticeship program is comprehensive in that incorporates technical trades training, best practices for the design and delivery of hands-on operational and compliance training and rigorous testing at each phase of the apprenticeship to confirm milestones are met.

Over a decade ago, Toronto Hydro adopted minimum qualifications for post-secondary education in an electrical field of study for all entry level certified and skilled trades and designated technical professional roles. The organization continues to evolve minimum entry level qualifications across operational and corporate business areas and requires that new hires have a university or college diploma in a related field of study. Toronto Hydro has elected to prescribe this requirement as post secondary students enrolled in formal learning programs are well-prepared for the workforce with future ready knowledge, skills and abilities - namely, enhanced problem-solving skills, increased ability to analyze and think critically, communication and comprehension aptitudes, and heightened initiative and resourcefulness. This strategy has proven successful for Toronto Hydro and the quality of instruction and work integrated learning programs provided through post secondary education allows for both a ready talent pool for the organization and an accelerated transition to the organization.

4.2.3. Colleges and Universities

Toronto Hydro continues to collaborate with colleges and universities to develop new curricula and explore interdisciplinary learning opportunities that enable the availability of short- and long-term workforce requirements. The utility offers valuable work experience to post secondary students across Canada through well established work integrated learning (WIL) opportunities that enable postsecondary students to apply the academic knowledge gained through studies to a practical work environment.

Investments in experiential learning have resulted in 20 percent of former co-op students finding employment at Toronto Hydro after graduation. To develop a pipeline of talent situated within the utility’s geographic service territory and to mitigate risks of talent loss to neighbouring comparators, in 2020, Toronto Hydro partnered with George Brown College to influence curriculum on a new three-year Electromechanical Engineering Technology – Power and Control Diploma Program. Collaborations with institutions such as George Brown College, Georgian College and Toronto Metropolitan University support academic programs aligned to entry level qualifications for Certified and Skilled Trades and Designated and

Technical professionals and advance skill sets prior to entry for incoming talent. Such collaborations are valuable because they allow Toronto Hydro to:

- influence and shape the programs and curricula, including diversity, equity and inclusion to better match the utility's strategic goals and long-term needs;
- spread awareness about the utility's career prospects and human resource requirements;
- build recruitment relationships with future graduates; and
- help bridge the gap and remove barriers to the labour market for newcomers to the labour market.

Toronto Hydro's commitment to hiring apprentices requires careful planning and coordination to enable efficient and effective execution. Apprenticeships can be as long as six and a half years where apprentices spend time in class as well as embedded with crews to practice and refine skills in real world conditions. Hiring and training needs to be done proactively so that apprentices have sufficient time to complete their programs, with journeyperson oversight and mentoring, before becoming fully qualified to augment resourcing levels and productively contribute to program outcomes. To minimize the total cost of the apprenticeship process, recruits are typically hired in cohorts of between four and eight resources at a time. From a talent attraction perspective, aligning recruitment activities with post-secondary graduation cycles ensures the utility access to the broadest range of qualified applicants to fill available opportunities.

4.2.4. Outsourcing

Toronto Hydro relies on third-party service providers to enable the utility to resource in times of peak demand, maintain flexibility in operations, and gain access to specialized expertise and knowledge. Outsourcing decisions are continually reviewed to determine if operational requirements and other business drivers have changed the demand for outsourced services. Outsourced services may be reintegrated to internal utility operations to improve outcomes and retain critical and complex knowledge. This is evidenced during the current rate period in that a complement of additional resources in the areas of customer care, supply chain, and fleet operations were brought in house to augment internal capabilities and maintain effective business operations. [10,11,12]

[10] Exhibit 4, Tab 2, Section 16.
[11] Exhibit 4, Tab 2, Section 15.
[12] Exhibit 4, Tab 2, Section 13.

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

Third Party Evaluation Reports

This document includes the following third party evaluation reports:

Process and Systems Upgrades Program:

- #601601
- #601602
- #601814
- #601869
- #601883
- #601885
- #601910
- #601911

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-[redacted]-601601

July 14, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	July 14, 2023	July 14th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
July 14, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of August 27, 2021 to August 26, 2022, are 1,118 MWh, which represents 99% of the Anticipated Electricity Savings.

The In-Service Date was originally set to January 1, 2020. However, the Participant requested the Reporting Period begin August 27, 2021, due to necessary equipment repairs as well as a result of the COVID-19 pandemic affecting normal operations.

The Incentive payable to the Participant for this Reporting Period is $112,600. Refer to the Appendix for details.

The Electricity Savings meet the 80% performance threshold required by the Program Rules.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Aug 27 to Nov 26, 2021	285	100%	$40,185
1st Annual	Aug 27, 2021 to Aug 26, 2022	1,118	99%	$157,638

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of January 1, 2020, was established on November 17, 2020.

1st Quarterly Report was issued on January 27, 2022 with an updated in-service date of August 27, 2021.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $141/MWh obtained from the Project Application Review.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on January 25, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	August 27, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	August 26, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date
Available Data	8,760	hours	
Missing Data	0	hours	0% of the Reporting Period Duration
Hours of Operation	8,529	hours	97.4% of the Reporting Period Duration

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,176	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	58	MWh	Equal to 4.9% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,118	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	128	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	121	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The ICE supplier confirmed via email on January 18, 2022, that the metered power output from the ICE is gross power (i.e., does not exclude any internal or external auxiliary loads). As a conservative approach, auxiliary loads were assumed to be 3% of the 125 kW ICE gross capacity. The auxiliary loads were applied for each unit individually (ie. if one unit was operating the loads were 3.75 kWh and 7.5 kWh if both units were operating simultaneously). Because the System performed well above the 80% performance requirement, the Technical Reviewer deemed this approach sufficient.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,118	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,118	MWh	Equal to the Reporting Period Energy.
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,126	MWh	Obtained from the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	99%	-	
Average Demand Savings	128	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	121	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,118 MWh and represent 99% of the Anticipated Electricity Savings.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,176	MWh	See the comment below.
CHP Thermal Output Utilized	1,384	MWh	
CHP Energy Input	3,582	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 37.3 MJ/m^3 (10.36 kWh/m^3), obtained from the Canada Energy Regulator's Energy conversion tables.
Metered Total System Efficiency	71.5%	-	

The system achieved a TSE of 71.5%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

The is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

The Incentive payable for the 1st Annual M&V Reporting Period is $112,600. Table 6 outlines the payment schedule as defined in the contract and Program Rules, for reference.

Table 6. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

Disclaimer and Limitations

This document was prepared by Aladaco Consulting Inc. for the Independent Electricity System Operator (IESO) and exclusively for the purposes set out in the Program Management Agreement between the IESO and Aladaco Consulting Inc., as may be amended and restated from time to time.

This document was prepared based on information available to Aladaco Consulting Inc. at the time of preparation, and is subject to all limitations, assumptions and qualifications contained herein. In addition, financial or other projections contained herein are based upon assumptions concerning future events and circumstances over which Aladaco Consulting Inc. has no control. Such projections are by their nature uncertain and should be treated accordingly and read in the full context of this document, including such projects.

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Please note:

Capitalized terms used in this document have the meaning given to them either in the Save on Energy Process and Systems Upgrade Program Rules, or the IPMVP Core Concepts dated October 2016 and Uncertainty Assessment for IPMVP, dated April 2018, as applicable.

IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-[redacted]601602

July 20, 2023

Revision 1

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	July 14, 2023	July 14th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
July 14, 2023	M&V Report first issuance.	0	[redacted]
July 20, 2023	Tables 6 and 7 added to Appendix	1	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of September 8, 2021 to September 7, 2022, are 1,431 MWh, which represents 110% of the Anticipated Electricity Savings.

The In-Service Date was originally set to January 28, 2020. However, the Participant requested the Reporting Period begin Septpember 8, 2021, due to necessary equipment repairs as well as a result of the COVID-19 pandemic affecting normal operation.

The Incentive payable to the Participant for this Reporting Period is $130,200. Refer to the Appendix for details.

The Electricity Savings meet the 80% performance threshold required by the Program Rules.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Sept 8 to Dec 12, 2021[3]	394	122%	$56,400
1st Annual	Sept 8, 2021 to Sept 7, 2022	1,431	110%	$204,633

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of January 28, 2020, was established on November 17, 2020.

1st Quarterly Report was issued on January 28, 2022 with an updated in-service date of September 8, 2021.

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[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $143/MWh obtained from the Project Application Review.
[3] There were 115 hours of missing data points in the raw data. Therefore, the 1st Quarterly Reporting Period was extended by 115 hours.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on January 25, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	September 8, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	September 7, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date
Available Data	8,645	hours	
Missing Data	115	hours	1.3% of the Reporting Period Duration.
Hours of Operation	8,557	hours	97.7% of the Reporting Period Duration

115 hours of data, or 1.3% of the Reporting Period, is missing. Since this represents less than 10% of the total data for the Reporting Period, the available data was used for the analysis and the missing hours assumed to represent 0 MWh savings, per Section B.6.2. of the M&V Plan.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,493	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	63	MWh	Equal to 4.2% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,431	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	165	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	100	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The ICE supplier confirmed via email on January 18, 2022, that the metered power output from the ICE is gross power (i.e., does not exclude any internal or external auxiliary loads). As a conservative approach, auxiliary loads were assumed to be 3% of the 125 kW ICE gross capacity. The auxiliary loads were applied for each unit individually (ie. if one unit was operating the loads were 3.75 kWh and 7.5 kWh if both units were operating simultaneously). Because the System performed well above the 80% performance requirement, the Technical Reviewer deemed this approach sufficient.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,431	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,431	MWh	Equal to the Reporting Period Energy.
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,302	MWh	Obtained from the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	110%	-	
Average Demand Savings	165	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	100	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,431 MWh and represent 110% of the Anticipated Electricity Savings.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,493	MWh	
CHP Thermal Output Utilized	1,843	MWh	
CHP Energy Input	4,450	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 37.3 MJ/m^3 (10.36 kWh/m^3), obtained from the Canada Energy Regulator’s Energy Conversion tables.
Metered Total System Efficiency	75.0%	-	

The system achieved a TSE of 75.0%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

The is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $130,200, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Anticipated Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,431	From Table 4
Estimated Eligible Costs	**$1,541,326**	From the SCP Agreement, Schedule "B".
Actual Eligible Costs	$9,622,565	From the 1st Master Payment Requisition.
Electricity Billed Savings	$204,633	Based on the Project Review Electricity Billing Rate of $143/MWh
Other Costs	$120,764	From the SCP Agreement, Schedule "B".
Net Project Benefits	$83,869	Electricity Billed Savings - Other Costs
Approved Incentive Amount	**$260,400**	From the SCP Agreement, Schedule "B".
Limiter 1 - Electricity Savings	$260, 400	100% of the Approved Incentive Amount, if Performance is >80%..
Limiter 2 - Eligible Costs	$616,530	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$1,457,457	Eligible costs minus Net Project Benefits
Project Incentive	$260,400	Minimum of the three limiters.
Incentives paid to date	**$ 130,200**	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$130,200**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

Disclaimer and Limitations

This document was prepared by Aladaco Consulting Inc. for the Independent Electricity System Operator (IESO) and exclusively for the purposes set out in the Program Management Agreement between the IESO and Aladaco Consulting Inc., as may be amended and restated from time to time.

This document was prepared based on information available to Aladaco Consulting Inc. at the time of preparation, and is subject to all limitations, assumptions and qualifications contained herein. In addition, financial or other projections contained herein are based upon assumptions concerning future events and circumstances over which Aladaco Consulting Inc. has no control. Such projections are by their nature uncertain and should be treated accordingly and read in the full context of this document, including such projects.

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Please note:

Capitalized terms used in this document have the meaning given to them either in the Save on Energy Process and Systems Upgrade Program Rules, or the IPMVP Core Concepts dated October 2016 and Uncertainty Assessment for IPMVP, dated April 2018, as applicable.

IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK : PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted] Cogeneration System

April 26, 2023

Revision 0

Project ID:

TorontoHydro-SCP-601814-[redacted]-Cogeneration System-Y1-MVR

Prepared for:

Toronto Hydro-Electric System Limited

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements (FINAL v2.0 April 6, 2018)

Approvals

	Written by	Reviewed by
Name:	[redacted]	[redacted]
Date:	April 26, 2023	April 27th, 2023
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
April 26, 2023	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of November 1, 2021 to November 14, 2022 are 311 MWh, which represents 125% of the Anticipated Electricity Savings. The Incentive payable to the Participant for this Reporting Period is $30,394, calculated in accordance to Program Rules. Refer to the Appendix for details.

Note that the Participant submitted an Application[1] for this Project on September 1, 2020, which was after the Application submission deadline however, in an email dated July 19, 2021, the IESO confirmed their acceptance of the Application and Anticipated Electricity Savings.

The original Reporting Period of November 1, 2021, to November 1, 2022, was extended by 14 days to November 14, 2022. The 14-day extension was a result of 14 days of erroneous data provided during the Q1 Reporting Period, for the period from January 22 to February 5, 2022. The combined heat and power (CHP) System operated during this period, however, the metered data recorded erroneous values due to an unexpected defect in the PLC system.

During the course of construction of the Cogeneration System, the Applicant installed and commissioned an Absorption Chiller which now forms part of the combined Cogeneration System originally shown in Figure 1 of the M&V Plan. The Absorption Chiller was not previously considered in the M&V Plan nor in the previously issued Q1 M&V Report. As the Absorption Chiller is receiving waste heat energy from the turbines exhaust gases and providing cooling to the facility the decision was made to include the equipment within this report. Aladaco Consulting received confirmation from Toronto Hydro to include the Absorption Chiller in an email dated April 20, 2023. This item is covered in more detail in the Non-Routine Adjustments section.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[2]	Electricity Cost Savings[3]
1st Quarterly	November 1,2021 to February 14, 2022	101	118%	$15,600
1st Annual	November 1,2021 to November 14, 2022	311	125%	$48,240

[1] The Application was submitted under the Conservation First Framework (CFF), Final V2.0.

[2] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[3] Based on $155/MWh obtained from the Project Approval Letter.

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan rev.0, dated February 15, 2019, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of November 1, 2021, was established on February 7, 2022.

Metered Data Analysis

[redacted], a representative of Toronto Hydro, provided the M&V data on February 15, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Nov. 1, 2021, 0:00		Start date of the Reporting Period.
Reporting Period End	Nov. 14, 2022, 23:00		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date less data removed
Available Data	8,760	hours	
Missing Data	336	hours	4% of the Reporting Period Duration
Hours of Operation	8,741	hours	99.8% of the Reporting Period Duration

The original Q1 data included 237 hours of erroneous data for the period from January 22, 3:00 to January 31, 23.00, 2022. The CHP system operated during this period, however, the metered data recorded erroneous values for all the parameters, due to an unexpected defect in the PLC system. The erroneous data represented 10.7% of the Q1 dataset. This data was replaced by 237 hours of valid data during the period February 1 to February 14, 2022 (336 hours). Thus the remaining 3 Quarters of data required to complete the Year 1 Reporting Period begins February 14, 2022 through November 14, 2022.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Reporting Period Energy – Baseline Energy ± Non-Routine Adjustments

Reporting Period Energy

The electrical consumption of the System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	505	MWh	Calculated using hourly Net Electrical Energy and Auxiliary Load Energy of 5.5 kW per CHP system operating hour.
Gas Turbine Auxiliary Loads Energy	48	MWh	9.5% of the Gross Electrical Energy.
Absorption Chiller Electrical Load	14	MWh	*Absorption Chiller Electrical Load = 3.8 kW of Chiller Electrical Power x (Chiller Operating Hours)* As per Absorption Chiller Specification Sheet. See note below.
Reporting Period Energy	443	MWh	CHP Net Electrical Output.
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Average Demand	50.6	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Demand	44	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm,

Additional loads for chilled water and cooling tower pumps were not considered as they form part of the larger facility's chilled water loop. The Participant reported that the operation of these pumps did not increase as a result of the addition of the Absorption Chiller. Additionally, Chiller Data was not provided for the period of November 1, 2021 to January 1, 2022. It was assumed that the chiller was not operational over this period as there is no cooling demand at the facility during the winter months.

Non-Routine Adjustments

The Facility currently operates two CHP systems, each consisting of a micro-turbine generator and a heat recovery system. The two CHP systems are identical in capacity, i.e., 65 kW each. One of the CHP systems (Unit #1) was implemented under a previous PSU Project (Toronto-SCP-601491) and has confirmed In-

Service Date of June 2, 2018. The review of this M&V Report is for the second CHP system (Unit #2), implemented under the second PSU Project (Toronto-SCP-601814).

As per the M&V Plan Rev.0 dated February 15, 2019, Unit #1 has priority over Unit #2 for the purposes of determining the Reporting Period Energy, whereby if the combined electricity generated by the two CHP systems exceeds the full load output of a single CHP system, then the apportionment of electricity generation between the two generators will be such that Unit #1 will be allocated the full load output, while Unit #2 will be allocated the remainder of the electricity generation. For each hour in the dataset, the full load output of the Unit#1 was determined based on the outside air temperature (OAT). The relationship between OAT and electrical output was established in the Project Review.

The Baseline Energy for Unit #2 is considered 0 kWh as Unit #2 has no prior generation. However, the adjustment of electricity generation for the two CHP systems, based on priority, was treated as a Non-Routine Adjustment. The Non-Routine Adjustment is calculated to be -132 MWh for the 1st Annual Reporting Period.

The inclusion of the Absorption Chiller, which was not previously considered in previous reports relating to this project, primarily affected the Total System Efficiency calculations. There was a slight adjustment to the Reporting Period Energy to account for additional system loads, however after accounting for the previously discussed Non-Routine Adjustment the final Adjusted Reporting Period Energy did not change as a result of the Abosrtion Chiller addition.

The Total System Efficiency (TSE) calculation required adjustment to account for the inclusion of Absorption Chiller. The Recovered Thermal Output is the cooling energy generated in the Absorption Chiller through the use of waste heat from the Micro-Turbine exhaust. The Participant was only able to provide data for the combined energy contribution from both Micro-Turbines to the Chilled Water supply, so to account for Unit #2’s contribution for TSE purposes the total Chilled Water Energy was proportionally attributed based on the amount of generation produced per hour. The following data was provided by the Participant for the Absorption Chiller:

Table 4. Absorption Chiller Data

Description	Quantity	Unit	Comment
Chilled Water Flow Rate	6 minutes of 1-second interval readings on Sept. 28, 2021 from 16:63:58 to 16:56:57	Gal/min	
Chilled Water Out	15-minute intervals (January 1, 2022 to November 14, 2022)	Deg F	Chilled water temperature from the absorption chiller
Chilled Water In	15-minute intervals (January 1, 2022 to November 14, 2022)	Deg F	Chilled water temperature to the absorption chiller

The Flow Rate data provided by the Participant was from the commissioning of the Absorption Chiller and a non-permanent meter for which no specifications were provided. As the pumps associated with the Absorption Chiller are not VFD equipped it is assumed that the Flow Rate is constant when the Chiller is in operation. This is further supported by the metered flow rate closely matching the specified flow rate from the Absorption Chiller specification sheet.

Chilled water temperatures are metered by the Absorption Chiller using Resistance Temperature Detectors for which no specifications or accuracy information was provided.

To determine the TSE contribution from the Absorption Chiller the following formula was used:

Eq. 1 *Unit#2 Absorption Chiller Recovered Thermal Output (MWh) = (Total Chilled Water Heat Recovery) × (Unit #2 Proportional Energy Contribution) (over the Reporting Period)*

Eq. 1a *Total Chilled Water Heat Recovery (MWh) = Sum of (Chiller Hours of Operation) × Chilled Water Delta T × Chilled Water Flow Rate × (Chilled Water Density) × Chilled Water Specific Heat)*

Eq. 1b *Chilled Water Density = The density of water taken at the average temperature of the chilled water during all (Chiller Operating Hours)*

Eq. 1c *Chiller Operating Hours = Chiller was assumed to be operating whenever the Chilled Water Out was a lower temperature than the Chilled Water In*

Eq. 1d *Unit #2 Proportional Energy Contribution = Unit #2 Gross Electrical Energy ÷ (Unit #1 Gross Electrical Energy + Unit #2 Gross Electrical Energy)*

The Adjusted Total System Efficiency was calculated as:

Eq. 2 *Adjusted TSE (%) = [Gross Electrical Energy + Total Recovered Thermal Output + Unit #2 Absorption Chiller Recovered Thermal Output] ÷ Total Natural Gas Energy Input*

Electricity Savings

The Reporting Period Energy, the Non-Routine Adjustment, and the Electricity Savings are presented in Table 5. The original M&V Plan prescribed IPMVP Option B methodology of calculating the Electricity Savings, however after the Non-Routine Adjustmeents and the inclusion of the Absorption Chiller this report uses an IPMVP Option A methodology, with Net Electrical Generation, Natural Gas Consumption, Heating Water Temperature, and Chilled Water Temperatures being the measured variables. Chiller Operating Hours, Water flow rates and parasitic loads were unmetered and based on spot measurements, equipment specifications, or inferred from other metered data.

Table 5. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	443	MWh	Obtained from Table 3.
Non-Routine Adjustment	-132	MWh	Calculated as per the M&V Plan and as described in the Non-Routine Adjustments section.
Electricity Savings	311	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.

Anticipated Electricity Savings	249	MWh	Obtained from the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	125%		
Average Demand Savings	36	kW	Electricity Savings divided by Reporting Period Duration.
Summer Peak Demand Savings	22	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm,

The 1st Annual Electricity Savings are 311 MWh and represent 125% of the Anticipated Electricity Savings.

The main reason for the overperformance is the increased operating hours of Unit #2 Micro-Turbine during the facility cooling season. This operation was facilitated by the use of the Absorption Chiller which allowed for greater generation with only a minor impact to TSE. Unit #2 had a 99.8% uptime as compared to a 50.7% uptime estimated at Application Review.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 3 *TSE (%) = [CHP System Gross Electrical Energy + CHP System Usable Thermal Output] / CHP System Natural Gas Consumption*

The Adjusted TSE including Non-Routine Adjustments is calculated according to the following equation:

Eq. 2 *Adjusted TSE (%) = [Gross Electrical Energy + Total Recovered Thermal Output + Unit #2 Absorption Chiller Recovered Thermal Output] ÷ Total Natural Gas Energy Input*

Table 6. Total System Efficiency

Description	Value	Unit	Comment
Unit #2 Gross Electrical Energy	505	MWh	
Total Recovered Thermal Output	814	MWh	
Unit #2 Natural Gas Consumption	230,867	m^3	
Natural Gas HHV	10.75	kWh/m^3	From the M&V Plan
Total Natural Gas Energy Input (HHV)	2,481	MWh	
Total System Efficiency	53.2%		
Absorption Chiller Recovered Thermal Output	317	MWh	Unit#2 absorption chiller recovered thermal output
Adjusted Total System Efficiency	66.0%		

Inclusion of the Absorption Chiller increased the Adjusted TSE value above the required minimum 57.5% required by Program Rules. The main reason for the underperformance of the TSE is due to the increased operation of the Cogeneration System, particularly during the summer months. During Application Review it was assumed that the Cogeneration System would only operate during the winter and shoulder seasons when the facility had heating demand.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, the recommended Incentive Amount of $30,394 was calculated in accordance with the Program Rules and is limited by the "$200/MWh of Electricity Savings", up to a maximum of 120% of Approved Incentive amount. The Final Incentive Payment is the Gross Project Incentive of $59,760, less the Q1 Incentive Payment. The Final Incentive Payment is pending the issuance of the Master Payment Requisition.

Description	Value	Comment
Electricity Savings (MWh)	311	Annual Electricity Savings, as defined in this Report
Limiter 1 - Electricity Savings	$62,245	$200 per MWh of Electricity Savings
Actual Project Costs	$405,911	From the Invoice Reconciliation Form
Limiter 2 - Project Costs	$162,364	40% of Eligible costs
Net benefits	$21,240	Includes electricity savings at $155/MWh and Other Costs from Project Letter of Approval
Limiter 3 - Project Payback	$384,671	Eligible costs minus net benefits
Limiter 4 – 120% of Pre-Approved Incentive	$59,760	From Project Letter of Approval
Gross Project Incentive	$59,760	Minimum of the four limiters
Total Payments to Date	$29,367	From Q1 Master Payment Requisition
Incentive Payable	**$30,394**	*Gross Project Incentive – Total Payments to Date*

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted]

Project ID: Toronto-SCP-601869

June 20, 2023
Revision 0

Prepared for:
Toronto Hydro-Electric System Ltd. (the LDC)

Prepared by:
Aladaco Consulting Inc (The Technical Reviewer)

Revision History

Date	Description	Revision	Author
June 20, 2023	M&V Report first issuance.	0	[redacted]

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name	[redacted]	
Date	June 20, 2023	June 20th, 2023
Signature	[redacted]	[redacted]

Summary

The Electricity Savings for the Year 1 Reporting Period of March 29, 2022 to March 28, 2023, are 207.78 MWh, which represent 73.7% of the Anticipated Electricity Savings.

Note that the Project's In-Service Date was November 23, 2021. However, the start of the Year 1 Period was delayed to March 29, 2022 due to a significant underperformance resulting from the following:

- A 7-hour shutdown every night during the period November 23 to December 29, 2021 as the sound enclosure on the combined heat and power (CHP) system was not fully constructed and the shutdown was required to abide by the noise bylaws.
- A complete shutdown of the CHP system during the period December 30, 2021 to February 15, 2022, to modify the CHP system's enclosure in order to discharge the exhaust gas further away from the building.
- On March 10, 2022, Enbridge gas had shut off the main gas supply, which resulted in tripping of the CHP system. A mechanical contractor who was at the Facility to restart the boilers after the gas supply was restored tempered with the CHP system's controller, in an attempt to bring the system back into operation. As a result, the CHP system was started but was operating under its old scheduled hours (overnight shutdown) until March 28, 2022, when the problem was identified and corrected.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings
1st Quarterly	Mar 29, 2022 to Jun 28, 2022	51	75%	$7,196[2]
1st Annual	Mar 29, 2022 to Mar 28, 2023	207.78	73.7%	$29,089[2]

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data for the Reporting Period.
- The Reporting Period Energy.

[1] Percentage of the Anticipated Electricity Savings shown in the M&V Plan.

[2] Based on the Electricity Billing Rate of $140/MWh from the Project Review.

- The electrical and thermal performance of the Measure.
- The Incentive based on the performance of the Measure.

In-Service Date Confirmation

The In-Service Date of November 23, 2021 was established on January 28, 2022.

Metered Data Analysis

[redacted], the LDC representative, provided the raw data to the Technical Reviewer for analysis. The raw data includes the following hourly interval data for the combined heat and power (CHP) system:

- Gross electricity generation
- Natural gas consumption
- Heat utilized

The data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Mar 29, 2022, 00:00		
Reporting Period End	Mar 28, 2023, 23:00		
Reporting Period Duration	8,760.0	hours	
Available Data	8,760.0	hours	
Downtime	258.0	hours	Data reported as “0”, assumed unit not running, equivalent to 2.9% of the time.
Hours of Operation	8,502.0	hours	Unit running 97.1% of the Reporting Period duration.

Performance of the Measure

The electrical performance of this generation project is based on the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Reporting Period Energy

The Reporting Period Energy for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	216.91	MWh	
Auxiliary Loads Energy	9.13	MWh	Represents 4.2% of the Gross Electrical Energy. See comment below.
Reporting Period Energy	207.78	MWh	Gross Electrical Energy - Auxiliary Loads Energy
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	24.8	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	30.8	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm.

The M&V data did not include metered data for the CHP system auxiliary loads. However, the Participant's representative provided the following information regarding the auxiliary loads:

- The metered electrical output readings are net of the dry cooler load.
- The auxiliary loads, which need to be accounted for to calculate the net electricity generation consists of two hot water circulation pumps, with a total nameplate rating of 1.44 hp.

The Technical Reviewer calculated that total auxiliary loads electricity consumption of 9.13MWh by multiplying the nameplate rating of the pumps with the Reporting Period operating hours.

Electricity Savings

The Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings. Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.1, Non-Routine Adjustments are not required for this Reporting Period.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Reporting Period Energy	207.78	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	207.78	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Anticipated Electricity Savings	282.00	MWh	Per the M&V Plan.
Electricity Savings as Percentage of Anticipated Electricity Savings	73.7%		
Average Demand Savings	24.8	kW	Equal to Average Generation, obtained from Table 3.
Summer Peak Demand Savings	30.8	kW	Equal to Summer Peak Demand Generation, obtained from Table 3.

The Electricity Savings of the Year 1 Reporting Period are 207.78 MWh, which represent 73.7% of the Anticipated Electricity Savings.

The underperformance resulted from a lower than anticipated net operating electrical output of the CHP system. The CHP system was anticipated to have an average net operating electrical output of 32 kW. However, the Reporting Period average net operating electrical output was 24.8 kW.

Total System Efficiency

The CHP System's Total System Efficiency (TSE) is calculated according to the following equation.

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / [Fuel Energy Input]

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	216.91	MWh	Obtained from Table 3.
Recovered Heat Utilized	336.44	MWh	
Fuel Energy Input	780.42	MWh	Calculated using the total volumetric natural gas consumption and a natural gas higher heating value (HHV) of 10.75 kWh/m^3 shown in the M&V Plan.
Total System Efficiency	70.9%		This value is higher than the minimum 65% required by the Program.

The Technical Reviewer obtained a TSE of 70.9%, which is higher than the minimum 65% required by the Program.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix - Incentive Payment

The Participant is eligible for an Incentive Payment of $41,555 for this Reporting Period, calculated in accordance with the terms of the Project Agreement.

Table 6. Incentive Calculation

Y1 Electricity Savings (MWh)	207.78
Electricity Billing Rate ($/MWh)	$140
Electricity Billed Savings	$29,089
Net Other Benefits and Costs – Per Contract[3]	$5,762
Net Project Benefits	$34,851
Estimated Eligible Costs – Per Contract	$231,938
Actual Eligible Costs – Per Invoice Reconciliation Form	$327,035
Approved Incentive Amount – Per Letter of Approval	$56,400
Incentive Limiter 1 - $200/MWh	$41,555
Incentive Limiter 2 - 40% of Eligible Costs (lower of Estimated or Actual)	$92,775
Incentive Limiter 3 - 1-year Payback	$197,087
Project Incentive (Minimum of 3 limiters)	$41,555
5% Penalty for TSE < 65%	$0
Adjusted Incentive	$41,555
Q1 Incentive Paid[4]	$0
Payable Incentive - Balance Year 1	$41,555

[3] Note that there are discrepancies in the project benefits and costs values within the Project Contract, Application Review, and Application Letter of Approval. The Technical Reviewer used the values from the Project Contract to assess Incentive Limiter 3, however has confirmed that there is no impact on the incentive payable in any case (i.e. using any of the values specified within these documents).

[4] Note that no Q1 incentive was paid as the Q1 Performance Ratio was below 80%.

Table 7 provides the Incentive payment schedule.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Calculated Amount
Payment 1 **(Not Paid)**	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. Not paid due to project not achieving 80% performance.
Final Payment (Payable)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601883

July 4, 2022
Revision 0

Prepared for:
Toronto Hydro-Electrical System Ltd. (the LDC)

Prepared by:
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Revision History

Date	Description	Revision	Author
July 4, 2022	M&V Report first issuance.	0	[redacted]

Approvals

	Written by Technical Reviewer	Reviewed by Engineering Manager
Name	[redacted]	
Date	June 28, 2022	June 30, 2022
Signature	[redacted]	

Summary

The Electricity Savings for the 1st Annual Reporting Period of April 7, 2021, to April 6, 2022, are 497 MWh, which represent 95% of the Anticipated Electricity Savings. The Total System Efficiency achieved for the 1st Annual Reporting Period is 58%, which does not meet the Program Rules requirement of 65%.

The Participant is eligible for an Incentive Payment of $38,243 for this Reporting Period, calculated in accordance with the terms of the Project Agreement. See the Appendix for the Incentive calculation, which includes the penalty for not achieving the minimum 65% Total System Efficiency (TSE) requirement.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings
1st Quarterly	Apr 7 to Jun 6, 2021	116	87	$15,045[2]
1st Annual	Apr 7, 2021 to Apr 6, 2022	497	95	$64,408[2]

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data for the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the Measure.
- The Incentive based on the performance of the Measure.

In-Service Date Confirmation

The In-Service Date of April 7, 2021, was established on November 2, 2021, conditional upon the submission of the Environmental Compliance Approval (ECA). The ECA was submitted by the Participant on December 16, 2021.

[1] Percentage of the Anticipated Electricity Savings shown in the M&V Plan.

[2] Based on the Electricity Billing Rate of $129.7/MWh shown in the Approval Letter.

Metered Data Analysis

[redacted] the LDC representative, provided the raw data to the Technical Reviewer for analysis. The raw data includes the following hourly data for the CHP system:

- Net electricity generation
- Natural gas consumption
- Heat utilized

The data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Apr 7, 2021, 00:00		
Reporting Period End	Apr 6, 2022, 23:59		
Reporting Period Duration	8,760	hours	
Available Data	8,760	hours	
Missing Data	0	hours	
Hours of Operation	8,738	hours	99.7% of the Reporting Period duration.

Performance of the Measure

The electrical performance of this generation project is based on the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Reporting Period Energy

The Reporting Period Energy for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Net Electrical Energy	497	MWh	The electrical metering data provided represents the electricity generation, net of auxiliary loads
Auxiliary Loads Energy	48	MWh	Equal to 5.5 kW per operating hour (see comment below table)
CHP Gross Electrical Energy	545	MWh	Net Electrical Energy + Auxiliary Loads Energy
Reporting Period Energy	497	MWh	Equal to the Net Electrical Energy
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	57	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	46	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm.

The Participant provided an auxiliary load estimate of 5 to 6 kW and confirmed that the metered electrical output is net of the auxiliary loads, which is a typical arrangement for the Capstone C65 micro-turbine system. The Technical Reviewer applied an auxiliary load of 5.5 kW per operating hour to calculate the Auxiliary Load Energy.

Electricity Savings

The Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings. Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.1, Non-Routine Adjustments are not required for this Reporting Period.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Reporting Period Energy	497	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	497	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Anticipated Electricity Savings	524	MWh	Prorated Anticipated Electricity Savings per the M&V Plan.
Electricity Savings as Percentage of Anticipated Electricity Savings	95%		
Average Demand Savings	57	kW	Equal to Average Generation, obtained from Table 3.
Summer Peak Demand Savings	46	kW	Equal to Summer Peak Demand Generation, obtained from Table 3.

The Electricity Savings of the 1st Annual Reporting Period are 497 MWh, which represent 95% of the Anticipated Electricity Savings.

The underperformance resulted from lower than anticipated average operating net electrical output. The CHP system was anticipated to produce an average operating net electrical output of 60 kW whereas the Reporting Period average operating net electrical output was 57 kW.

Total System Efficiency

The CHP System's Total System Efficiency (TSE) is calculated according to the following equation.

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / [Fuel Energy Input]

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	545	MWh	Obtained from Table 3.
Recovered Heat Utilized	805	MWh	
Fuel Energy Input	2,314	MWh	Calculated from total volumetric natural gas consumption and a natural gas higher heating value (HHV) of 10.75 kWh/m^3 specified in the M&V Plan.
Total System Efficiency	58.3%		This value is lower than the 65% threshold required by the Program.

The Technical Reviewer obtained a TSE of 58.3%, which is lower than the minimum 65% required by the Program. However, the Participant is eligible for an Incentive, subject to a 15%[3] penalty. See the Appendix for the Incentive calculation.

Next Reporting Period

The 1st Annual Reporting Period is the final Reporting Period and there is no further M&V reporting, unless requested by the IESO.

[3] Based on Program Rules, a TSE that is greater than equal to 57.5% but less than 60%, results in a 15% penalty on the Incentive.

Appendix - Incentive Payment

The Participant is eligible for an Incentive Payment of $38,243 for this Reporting Period, calculated in accordance with the terms of the Project Agreement. The Incentive calculation is shown in Table A1.

Table A1. Incentive Calculation

Reporting Period Electricity Savings (MWh)	497
Electricity Billing Rate ($/MWh)	129.7
Electricity Billed Savings	$64,408
Net Other Benefits and Costs	-$37,347[4]
Project Benefits	$27,061
Estimated Eligible Costs	$480,000[4]
Actual Eligible Costs	$865,654.69
Approved Incentive Amount	$104,800[4]
Incentive 1 - $200/MWh (Capped at 120% of the contracted Incentive amount)	$99,318
Incentive 2 - 40% of Minimum of Actual and Estimated Eligible Costs	$192,000
Incentive 3 - 1-year Payback	$452,939
Project Incentive (Minimum of 3 limiters)	$99,318
Incentive Penalty for TSE (15%))	$14,898
Adjusted Project Incentive	$84,420
First Payment (Recommended for First Quarterly Reporting Period)	$46,177
Balance Payment	$38,243

[4] From the Approval Letter

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report Year 1 Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601885

April 27, 2023
Revision 0

Prepared for:
Toronto Hydro-Electrical System Ltd. (the LDC)

Prepared by:
Aladaco Consulting Inc. (the Technical Reviewer)

Revision History

Date	Description	Revision	Author
April 27, 2023	Y1 M&V Report first issuance.	0	[redacted]

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name	[redacted]	[redacted]
Date	April 27, 2023	April 28, 2023
Signature	[redacted]	[redacted]

Summary

The Electricity Savings for Year 1 Reporting Period of February 1, 2022 to January 31, 2023, are 942.24 MWh, which represent 91.0%% of the Anticipated Electricity Savings.

The Participant is eligible for an Incentive Payment of $72,998 for this Reporting Period, calculated in accordance with the terms of the Project Agreement. Note that the Incentive Payment was impacted by a 5% Total System Efficiency Penalty (TSE) for a TSE of 64.8%. See the Appendix for the Incentive calculation.

Note that the Project's In-Service Date was September 16, 2021. However, the start of the Reporting Period was delayed to February 1, 2022, to allow the Participant to rectify issues with the heat recovery system and natural gas readings, which were identified as the In-service Date confirmation.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings
1st Quarterly	Feb 1 to Apr 30, 2022	259	102	$31,024[2]
1st Annual	Feb 1, 2022 to Jan 31, 2023	942	91	$113,069[2]

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data for the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the Measure.
- The Incentive based on the performance of the Measure.

In-Service Date Confirmation

The In-Service Date of September 16, 2021 was established on January 25, 2022. However, the start of the Year 1 Reporting Period was delayed to February 1, 2022.

[1] Percentage of the Anticipated Electricity Savings shown in the M&V Plan.

[2] Based on the Electricity Billing Rate of $120/MWh shown in the Approval Letter.

Metered Data Analysis

[redacted], the LDC representative, provided the raw data to the Technical Reviewer for analysis. The raw data includes the following hourly data for the CHP system:

- Net electricity generation
- Natural gas consumption
- Heat Recovered

The data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Feb 1, 2022, 01:00		One hour after actual Reporting Period
Reporting Period End	Feb 1, 2023, 00:00		One hour after actual Reporting Period
Reporting Period Duration	8,760	hours	
Available Data	8,757	hours	
Missing Data	3	hours	Assumed Missing Data = Units Not Running
Hours of Operation	8,757	hours	99.97% of the Reporting Period duration.

Performance of the Measure

The electrical performance of this generation project is based on the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Reporting Period Energy

The Reporting Period Energy for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
CHP Net Electrical Energy	942.24	MWh	The electrical metering data provided represents the electricity generation, net of auxiliary loads
Auxiliary Loads Energy	93.63	MWh	Equal to 5.5 kW per micro-turbine per operating hour (see comment below table)
CHP Gross Electrical Energy	1,035.87	MWh	Net Electrical Energy + Auxiliary Loads Energy
Reporting Period Energy	942.24	MWh	Equal to the Net Electrical Energy
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	107.6	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	84.7	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm.

The Participant provided an auxiliary load estimate of 5 to 6 kW and confirmed that the metered electrical output is net of the auxiliary loads, which is a typical arrangement for the Capstone C65 micro-turbine system. The Technical Reviewer applied an auxiliary load of 5.5 kW per micro-turbine per operating hour to calculate the Auxiliary Load Energy. Data shows that during Year 1 only 1 Unit was in operation during 490 hours. This was taken into account to calculate the total Auxiliary Load consumption.

Electricity Savings

The Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings. Since there has been no change in the Static Factors as defined in the M&V Plan Section B.5.1, Non-Routine Adjustments are not required for this Reporting Period.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Reporting Period Energy	942.24	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	942.24	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Anticipated Electricity Savings	1,035	MWh	Annual Anticipated Electricity Savings per Letter of Approval
Electricity Savings as Percentage of Anticipated Electricity Savings	91.0%		

Average Demand Savings	107.6	kW	Equal to Average Generation, obtained from Table 3.
Summer Peak Demand Savings	84.7	kW	Equal to Summer Peak Demand Generation, obtained from Table 3.

The Electricity Savings of Year 1 Period are 942.24 MWh, which represent 91.0% of the Anticipated Electricity Savings.

The underperformance resulted from lower than anticipated average operating net electrical output. The CHP system was anticipated to produce an average operating net electrical output of 118 kW (per Application Review document) whereas the Reporting Period average operating net electrical output was 107.6 kW. An important factor was that only 1 Unit was in operation during 490 hours, which was not anticipated.

Total System Efficiency

The CHP System's Total System Efficiency (TSE) is calculated according to the following equation.

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / [Fuel Energy Input]

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
Gross Electrical Energy	1,035.87	MWh	Obtained from Table 3.
Recovered Heat Utilized	1,753.24	MWh	
Fuel Energy Input	4,306.55	MWh	Calculated from total volumetric natural gas consumption and a natural gas higher heating value (HHV) of 10.75 kWh/m specified in the M&V Plan.
Total System Efficiency	64.8%		This value is lower than the minimum 65% required by the Program.

The Total System Efficiency (TSE) was determined to be 64.8%, which falls short of the anticipated TSE of 73.1% (per Application Review document). In an effort to understand the reason for the difference, we compared the Y1 values with the anticipated values and found:

- Total Gross Generation is 7% lower than anticipated.
- Total Heat Recovered is 10% lower than anticipated.
- Natural Gas consumption is 3% higher than anticipated.

While it is difficult to draw a conclusion without a detailed analysis, it seems that both the electrical efficiency and the thermal efficiency of the units are responsible as they don't correlate with higher gas consumption as could be expected.

Note that there were some issues[3] with the natural gas readings and heat recovery system which were identified as the In-service Date confirmation stage, which resulted in an invalid Total System Efficiency value. However, these issues appear to have been rectified by the Participant before the start date of the Year 1 Reporting Period.

Per the PSU Project Terms and Conditions Section 3.3 c) a 5% discount is applied to the Participant Incentive where the M&V Report demonstrates the CHP project achieves a TSE between 62.5 and 65% (rounded to the second decimal). More information on the incentive calculation can be found in the Appendix.

Next Reporting Period

This is the final Reporting Period. No additional data is required.

[3] Refer to email with subject heading "[redacted]

Appendix - Incentive Payment

The Participant is eligible for an Incentive Payment of $72,998 for this Reporting Period, calculated in accordance with the terms of the Project Agreement.

Table 6. Incentive Calculation

Y1 Electricity Savings (MWh)	942
Electricity Billing Rate ($/MWh)	120
Electricity Billed Savings	$113,069
Net Other Benefits and Costs – Per Letter of Approval	-$71,647
Net Project Benefits	$41,422
Actual Eligible Costs – Per Cost Reconciliation Form	$1,336,461
Approved Incentive Amount – Per Letter of Approval	$207,000
Incentive Limiter 1 - $200/MWh (Capped at 120% of the contracted Incentive amount)	$188,448
Incentive Limiter 2 - 40% of Actual Eligible Costs	$534,585
Incentive Limiter 3 - 1-year Payback	$1,295,040
Project Incentive (Minimum of 3 limiters)	$188,448
5% Penalty for TSE < 65%	$9,422
Adjusted Incentive	$179,026
Q1 Incentive Paid	$106,028
Payable Incentive - Balance Year 1	$72,998

Table 7 provides the Incentive payment schedule.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Calculated Amount
Payment 1 (Paid)	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive was calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Payable)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601910

June 05, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	June 5, 2023	June 1, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
June 1, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 26, 2021, to December 25, 2022, are 798 MWh, which represents 90% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $84,727, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 26, 2021 to Mar 25, 2022	205	84%	$25,056
1st Annual	Dec 26, 2021 to Dec 25, 2022	798	90%	$97,763

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of December 26, 2021, was established on February 8, 2022.

The 1st Quarterly Report was issued on July 8, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $122.51/MWh obtained from the Project Application Review.

Metered Data Analysis

[redacted], a representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 26, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 25, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	Hours	End date minus start date.
Available Data	8,668	Hours	
Missing Data	92	Hours	1.1% of the Reporting Period Duration.
Hours of Operation	8,667	Hours	99.99% of the Reporting Period Duration

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	821	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	23	MWh	Equal to 2.0% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	798	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	91	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	95	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. The Gross Electrical Energy of 821 MWh is net of the internal auxiliary loads. The 23 MWh Auxiliary Loads Energy was calculated based on the 2.62 kW external auxiliary load and 8,667 operating hours.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] where a similar type of CHP system, involving Yanmar CP35D1 engines, and a similar hot water heat recovery system were present.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	798	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	798	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	891	MWh	Obtained from the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	90%	-	
Average Demand Savings	91	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	95	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 798 MWh and represent 90% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 125 kW, consisting of two 125 kW internal combustion engines, one of which to be used for emergency backup only. In the completed Project, three 35 kW ICEs were installed with a nominal capacity of 105 kW. The under-performance resulted from lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (91 kW) is approximately 12% lower than the anticipated average output in the Application Review (104 kW).

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	821	MWh	See comment below table.
CHP Thermal Output Utilized	1,064	MWh	
CHP Energy Input	2,850	MWh	See comment below table.
Total System Efficiency	66.1%	-	

The CHP Energy Input was determined using the Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m3, obtained from the M&V Plan. The TSE of 66.1% exceeds the minimum 65% Program Requirement.

Next Reporting Period

The is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, the Incentive payable to the Participant is $84,727.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Annual Electricity Savings (MWh)	798	From Table 4
Actual Eligible Costs	**$585,669**	Per the vendor invoices.
Electricity Billed Savings	$97,763	Based on the Project Approval Letter Electricity Billing Rate of $122.51/MWh
Other Benefits	$37,354	From the Project Approval Letter
Other Costs	$116,586	From the Project Approval Letter
Net Project Benefits	$18,531	Electricity Billed Savings +Other Benefits – Other Costs
Approved Incentive Amount	**$178,200**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$159,600	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$234,268	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$567,138	Eligible costs minus Net Project Benefits
Project Incentive	$159,600	Minimum of the three limiters.
Project Incentive paid to Date	$74,873	Paid for 1st Quarterly Reporting Period.
Final Incentive payable	**$84,727**	Project Incentive minus Incentive paid to date.

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601911

June 05, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	[redacted]
Date:	June 5, 2023	June 1, 2023
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
June 1, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 24, 2021, to December 23, 2022, are 1,095 MWh, which represents 119% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $127,346, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 24, 2021 to Mar 23, 2022	257	100%	$32,933
1st Annual	Dec 24, 2021 to Dec 23, 2022	1,095	119%	$140,152

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of December 24, 2021, was established on February 16, 2022.

The 1st Quarterly Report was issued on July 8, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $128/MWh obtained from the Project Application Review.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 24, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 23, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data			
Electrical and Thermal Meters	*8,687*	*hours*	
Natural Gas Meter	*7,684*	*hours*	
Missing Data			
Electrical and Thermal Meters	*73*	*hours*	*0.8% of the Reporting Period Duration.*
Natural Gas Meter	*1,076*	*hours*	*12.3% (See comment below table)*
Hours of Operation	8,683	hours	99.95% of the Reporting Period Duration

When providing the raw data, [redacted]noted that natural gas data from May 12 to June 23, 2022 was missing. This was due to the existing gas meter failing and the delay to replace the meter. The missing data represents 1,076 hours or 12.3% of the Reporting Period. The Technical Reviewer has used the CHP electrical output and the part-load data for the Yanmar CP35D1 in order to calculate the natural gas consumption during this period.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,118	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	23	MWh	Equal to 2.0% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,095	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	125	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	124	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. The Gross Electrical Energy of 1,118 MWh is net of the internal auxiliary loads. The 23 MWh Auxiliary Loads Energy was calculated based on the 2.62 kW external auxiliary load and 8,683 operating hours.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] where a similar type of CHP system, involving Yanmar CP35D1 engines, and a similar hot water heat recovery system were present.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,095	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,095	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	920	MWh	Obtained from the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	119%	-	
Average Demand Savings	126	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	124	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,095 MWh and represent 119% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 130 kW, consisting of three 65 kW micro-turbines, one of which to be used for emergency backup only. In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The over-performance resulted from higher than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (125 kW) is approximately 19% higher than the anticipated average output in the Application Review (105 kW).

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,118	MWh	See comment below table.
CHP Thermal Output Utilized	1,499	MWh	
CHP Energy Input	3,694	MWh	See comment below table.
Total System Efficiency	70.8%	-	

The CHP Energy Input was calculated using two methods, based on the availability of natural gas flowrate data:

- When the metered volumetric flowrate data was available, the energy input was determined using the Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m3, obtained from the M&V Plan.

- When the meter flowrate data was not available, the energy input was calculated using the CHP units' electrical output and the part-load data for the Yanmar CP35D1.

The TSE of 70.8% exceeds the minimum 65% Program Requirement.

Next Reporting Period

The is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, the Incentive payable to the Participant is $127,346.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Annual Electricity Savings (MWh)	1,095	From Table 4
Actual Eligible Costs	**$753,479**	Per the vendor invoices.
Electricity Billed Savings	$140,160	Based on the Project Approval Letter Electricity Billing Rate of $128/MWh
Other Benefits	$50,888	From the Project Approval Letter
Other Costs	$139,908	From the Project Approval Letter
Net Project Benefits	$51,140	Electricity Billed Savings +Other Benefits – Other Costs
Approved Incentive Amount	**$184,000**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$219,000	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$301,392	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$720,339	Eligible costs minus Net Project Benefits
Project Incentive	$219,000	Minimum of the three limiters.
Project Incentive paid to Date	$91,654	Paid for 1st Quarterly Reporting Period.
Final Incentive payable	**$127,346**	Project Incentive minus Incentive paid to date.

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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Please note:

Capitalized terms used in this document have the meaning given to them either in the Save on Energy Process and Systems Upgrade Program Rules, or the IPMVP Core Concepts dated October 2016 and Uncertainty Assessment for IPMVP, dated April 2018, as applicable.

IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

Third Party Evaluation Reports

This document includes the following third party evaluation reports:

Process and Systems Upgrades Program:

- #601916
- #601917
- #601921
- #601922
- #601923
- #601924
- #601930
- #601932

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601916

July 28, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	[redacted]
Date:	July 28, 2023	July 28th, 2023
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
July 28, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of July 1, 2022, to June 30, 2023, are 814 MWh, which represents 90% of the Anticipated Electricity Savings.

The in-service date is December 22, 2022; however, THES approved a Reporting Period of July 1, 2022 to June 30, 2023 due to an error in the grid import settings identified by [redacted], the Participant's consultant.

The Incentive payable to the Participant for this Reporting Period is $87,700, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	July 1 to Sept 30, 2022	195	83%	$24,777
1st Annual	July 1, 2022 to Jun 30, 2023	814	90%	$103,427

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 22, 2021, which was established on January 31, 2022.

The 1st Quarterly Report was issued on September 9, 2022, for a Reporting Period of December 22, 2021 to March 21, 2022.

A revised 1st Quarterly Report was issued on March 13, 2023, for a Reporting Period of July 1 to September 30, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $127.06/MWh obtained from the Project Letter of Approval.

Metered Data Analysis

[redacted], a representative of THES, provided the M&V data on July 12, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Jul 1, 2022 00:00		Start date of the Reporting Period.
Reporting Period End	Jun 30, 2023 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date, excluding the shutdown periods noted below.
Available Data	8,693	hours	See comments below.
Shutdown Periods	945	hours	10.9% of the Available Data. See comments below.
Missing Data	67	hours	0.8% of the Reporting Period Duration.
Hours of Operation	8,691	hours	99.2% of the Reporting Period Duration.

[redacted] provided a summary of unscheduled shutdowns that occurred during the 1st Annual Reporting Period. All the dates the CHP was not operating normally or the system was shut off for repairs are provided below:

- November 1, 6:00 to November 7, 12:59, 2022 (151 hours) due failure of Unit #3,
- November 17, 15:00 to November 22, 12:59, 2022 (118 hours) due failure of Unit #3,
- January 4, 7:00 to January 12, 13:59, 2023 (199 hours) due failure of Unit #2, and
- February 24, 14:00 to March 16, 10:59, 2023 (477 hours) due failure of Unit #2.

The shutdown periods represent 945 hours total, which is divided between two separate data sets as follows:

- Unit #2 – 676 hours which represents 7.8% of the total data for the Reporting Period, and
- Unit #3 – 269 hours which represents 3.1% of the total data for the Reporting Period.

In addition to the dates noted above, there were 67 hours of missing data, or 0.8% of the Reporting Period, with no explanation provided by [redacted]. Since the total unavailable for each data sets represents less than 10% of the total data for the Reporting Period, the analysis was completed per Section B.6.2. of the M&V Plan, in the following way (agreed to by THES):

- The remaining 92.2% of the Unit #2 data and 96.9% of the Unit #3 data was used to predict the units' operation during the unscheduled shutdowns using a linear extrapolation, and
- The missing hours are assumed to represent 0 MWh savings.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	811	MWh	CHP System Gross Electrical Output is the sum of the following: • Unit #1 – 296 MWh • Unit #2 – 251 MWh • Unit #3 – 264 MWh
Annualized Gross Electricity Energy	837		Annualized CHP System Gross Electrical Output is the sum of the following: • Unit #1 – 296 MWh • Unit #2 – 270 MWh • Unit #3 – 271 MWh
Auxiliary Loads Energy	23	MWh	Equal to 2.7% of the Gross Electrical Energy. See comment below table.
Reporting Period Energy	814	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	93	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	93	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

[redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	814	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	814	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	904	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	90%	-	
Average Demand Savings	93	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	93	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 814 MWh and represent 90% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 130 kW, consisting of three 65 kW micro-turbines, one operating as emergyency backup only. In the completed Project, three 35 kW internal combustion engines were installed with a nominal capacity of 105 kW. The under-performance is due to this re-design which resulted in a lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (93 kW) is approximately 10% lower than the anticipated average output in the Application Review (103 kW) which reflects the 19% decrease in system capacity.

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[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	811	MWh	See comments below table.
CHP Thermal Output Utilized	1,028	MWh	See comments below table.
CHP Energy Input	2,749	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan. See comments below table.
Total System Efficiency	66.9%	-	

The CHP energy input and outputs are the sums of the available data, they have not been extrapolated to account for the shutdown periods. The system achieved a TSE of 66.9%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $87,700, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	814	From Table 4
Eligible Costs	**$588,652**	**From the 1st Master Payment Requisition.**
Electricity Billed Savings	$103,427	Based on the Project Approval Letter Electricity Billing Rate of $127.06/MWh
Other Benefits	$49,478	From the Project Approval Letter
Other Costs	$121,113	From the Project Approval Letter
Net Project Benefits	$31,792	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$180,800**	**From the Project Approval Letter**
Limiter 1 - Electricity Savings	$162,800	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$235,461	40% of the minimum of Actual and Estimated Eligible costs.
Limiter 3 - Project Payback	$556,860	Eligible costs minus Net Project Benefits
TSE Incentive Discount	$0	0% discount for TSE ≥ 65.0%
Project Incentive	**$162,800**	**Minimum of the three limiters – TSE Incentive Discount**
Incentives paid to date	$75,100	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$87,700**	**Project Incentive - Incentives paid to date**

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

Disclaimer and Limitations

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601917

July 06, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	July 6th, 2023	July 6th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
July 6th, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 23, 2021 to December 22, 2023, are 1,004 MWh, which represents 108% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $94,394, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 23, 2021, to Mar 22, 2022	262	114%	$32,488
1st Annual	Dec 23, 2021, to Dec 22, 2022	1,004	108%	$124,496

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 23, 2021, which was established on February 2, 2022.

1st Quarterly Report was issued on December 7, 2022.

Metered Data Analysis

[redacted]a representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $124/MWh obtained from the Project Letter of Approval.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 23, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 22, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,620	hours	
Missing Data	140	hours	1.6% of the Reporting Period Duration.
Hours of Operation	8,617	hours	98.37% of the Reporting Period Duration

There were 140 hours of missing data, or 1.6% of the Reporting Period, which represents less than 10% of the total data for the Reporting Period. The available data was used for the analysis and the missing hours assumed to represent 0 MWh savings, per Section B.6.2. of the M&V Plan.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,026	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	22	MWh	Equal to 2.2% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,004	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	115	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	119	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

[redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,004	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,004	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	932	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	108%	-	
Average Demand Savings	115	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	119	kW	Equal to Summer Peak Generation from Table 3.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

The 1st Annual Electricity Savings are 1,004 MWh and represent 108% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 125 kW, consisting of a single 125 kW internal combustion engine (ICE). In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The over-performance is due to this re-design which resulted in higher than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (115 kW) is approximately 8% higher than the anticipated average output in the Application Review (106 kW) which reflects the 12% increase in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,026	MWh	See the comment below.
CHP Thermal Output Utilized	1,443	MWh	
CHP Energy Input	3,419	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	72.2%	-	

The system achieved a TSE of 72.2%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $94,394, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,004	From Table 4
Eligible Costs	**$816,746**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$124,496	Based on the Project Approval Letter Electricity Billing Rate of $124/MWh
Other Benefits	$47,391	From the Project Approval Letter
Other Costs	$133,504	From the Project Approval Letter
Net Project Benefits	$38,383	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$186,400**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$200,800	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$326,698	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$778,363	Eligible costs minus Net Project Benefits
Project Incentive	$200,800	Minimum of the three limiters.
Incentives paid to date	**$106,406**	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$94,394**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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Please note:

Capitalized terms used in this document have the meaning given to them either in the Save on Energy Process and Systems Upgrade Program Rules, or the IPMVP Core Concepts dated October 2016 and Uncertainty Assessment for IPMVP, dated April 2018, as applicable.

IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601921

October 10, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	October 10, 2023	September 19, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
October 10, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of March 25, 2022 to March 24, 2023, are 1,035 MWh, which represents 108% of the Anticipated Electricity Savings.

The original in-service date was December 24, 2021. However, one of the four units was not working properly after commissioning and THES has approved a Reporting Period starting March 25, 2022. This change was approved after the 1st Quarterly Report was issued.

The Incentive payable to the Participant for this Reporting Period is $125,374, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 24, 2021 to Mar 23, 2022	221	85%	$26,741
1st Annual	Mar 25, 2022, to Mar 24, 2023	1,035	108%	$125,235

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 24, 2021, which was established on March 9, 2022.

The 1st Quarterly Report was issued on September 21, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $121/MWh obtained from the Project Letter of Approval.

Metered Data Analysis

[redacted], a representative of THES, provided the M&V data on June 1, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Mar 25, 2022 00:00		Start date of the Reporting Period.
Reporting Period End	Mar 24, 2023 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date, excluding the shutdown periods noted below.
Available Data	8,116	hours	
Shutdown Periods	556	hours	6.9% of the Available Data.
Missing Data	88	hours	1.1% of the Reporting Period Duration.
Hours of Operation	8,115	hours	98.92% of the Reporting Period Duration – Shutdown Periods

[redacted] the Participant's consultant, provided a summary of unscheduled shutdowns that occurred during the 1st Annual Reporting Period. All the dates the CHP was not operating normally or the system was shut off for repairs are provided below:

- May 5, 7:00 to May 10, 12:59, 2022 (126 hours) due damage to the telemetry controller, which needed to be sent for repairs.
- May 26, 7:00 to June 3, 11:59, 2022 (197 hours) due to a gas leak.
- December 17, 14:00 to December 22, 10:59, 2022 (117 hours) due to a short circuit failure.
- December 23, 14:00 to December 28, 9:59, 2022 (116 hours) due an air/fuel sensor failure.

The shutdown periods represent 556 hours total, which represents 6.9%, or less than 10%, of the total data for the Reporting Period. In addition to the dates noted above, there were 88 hours of missing data, or 1.1% of the Reporting Period, with no explanation provided by [redacted]

Since the total unavailable data represents less than 10% of the total data for the Reporting Period, the analysis was completed per Section B.6.2. of the M&V Plan, in the following way:

- The remaining 92.0% of data was used to predict the CHP system operation during the unscheduled shutdowns using a linear extrapolation, and
- The missing hours are assumed to represent 0 MWh savings.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,058	MWh	CHP System Annualized Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	23	MWh	Equal to 2.1% of the Annualized Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,035	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	118	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	130	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

[redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefore, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,035	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,035	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	956	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	108%	-	
Average Demand Savings	118	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	130	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,035 MWh and represent 108% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 130 kW, consisting of three 65 kW micro-turbines, one operating as emergency backup only. In the completed Project, four 35 kW internal combustion engines were installed with a nominal capacity of 140 kW. The over-performance is due to this re-design which resulted in a higher than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (118 kW) is approximately 8% higher than the anticipated average output in the Application Review (109 kW) which reflects the 8% increase in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	991	MWh	See the comment below.
CHP Thermal Output Utilized	1,186	MWh	
CHP Energy Input	3,281	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	66.4%	-	

The CHP energy input and outputs are the sums of the available data, they have not been extrapolated to account for the shutdown periods. The system achieved a TSE of 66.4%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $125,374, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,035	From Table 4
Eligible Costs	**$808,168**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$125,235	Based on the Project Approval Letter Electricity Billing Rate of $121/MWh
Other Benefits	$51,336	From the Project Approval Letter
Other Costs	$140,491	From the Project Approval Letter
Net Project Benefits	$36,080	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$191,200**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$207,000	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$323,267	40% of the minimum of Actual and Estimated Eligible Costs.
Limited 3 - Project Payback	$772,088	Eligible Costs minus Net Project Benefits
TSE Incentive Discount	$0	No discount for TSE ≥ 65.0%
Project Incentive	**$207,000**	**Minimum of the three limiters – TSE Incentive Discount**
Incentives paid to date	$81,626	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$125,374**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601922

June 22, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	June 22nd, 2023	June 22nd, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
June 21, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 24, 2021 to December 23, 2022, are 1,003 MWh, which represents 112% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $108,537, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 24, 2021, to Mar 23, 2022	263	102%	$32,612
1st Annual	Dec 24, 2021, to Dec 23, 2022	1,003	112%	$124,372

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 24, 2021, which was established on March 9, 2022.

1st Quarterly Report was issued on December 7, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $124/MWh obtained from the Project Application Review.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 24, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 23, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,475	hours	
Missing Data	285	hours	3.3% of the Reporting Period Duration.
Hours of Operation	8,474	hours	96.74% of the Reporting Period Duration

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,025	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	22	MWh	Equal to 2.2% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,003	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	114	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	118	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,003	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,003	MWh	Equal to the Reporting Period Energy
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	899	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	112%	-	
Average Demand Savings	114	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	118	kW	Equal to Summer Peak Generation from Table 3.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

The 1st Annual Electricity Savings are 1,003 MWh and represent 112% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 130 kW, consisting of three 65 kW micro-turbines, one of which to be standby only. In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The over-performance resulted from higher than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (114 kW) is approximately 12% higher than the anticipated average output in the Application Review (103 kW).

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,025	MWh	See the comment below.
CHP Thermal Output Utilized	1,474	MWh	
CHP Energy Input	3,347	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	74.7%	-	

The system achieved a TSE of 74.7%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $108,537, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,003	From Table 4
Eligible Costs	**$774,683**	From the 1st Master Payment Requisition (Actual Estimated Costs are lower than Estimated Eligible Costs)
Electricity Billed Savings	$124,372	Based on the Project Approval Letter Electricity Billing Rate of $124/MWh
Other Benefits	$47,873	From the Project Approval Letter
Other Costs	$133,319	From the Project Approval Letter
Net Project Benefits	$38,926	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$179,800**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$200,600	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$309,873	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$735,757	Eligible costs minus Net Project Benefits
Project Incentive	$200,600	Minimum of the three limiters.
Incentives paid to date	**$92,063**	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$108,537**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Quarterly Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601923
August 11, 2022
Revision 0

Prepared for:
Toronto Hydro-Electric System Limited
[redacted]

Prepared by:
CLEAResult (the Technical Reviewer)
393 University Avenue, Suite 1622, Toronto, ON M5G 1E6
(416) 504-3400

Prepared per Program Rules version “saveONenergy Process & Systems Upgrades Program, FINAL v2.0 April 6, 2018”

Approvals

	Written by Technical Reviewer	Reviewed by Technical Reviewer
Name:	[redacted]	[redacted]
Date:	August 3, 2022	August 10, 2022
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
August 11, 2022	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Quarterly Reporting Period of December 23, 2021, to March 22, 2022, are 275 MWh, which represents 94% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $110,155. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 23, 2021 to Mar 22, 2022	275	94%	$36,025
1st Annual	Dec 23, 2021 to Dec 22, 2022	N/A	N/A	N/A

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date was set to December 23, 2021, on February 2, 2022, by the Technical Reviewer.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $131/MWh obtained from the Project Approval Letter.

Metered Data Analysis

[redacted] the LDC representative, provided the M&V data on May 3, 2022, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	December 23, 2021, 0:00		Start date of the Reporting Period.
Reporting Period End	March 22, 2022, 23:59		End date of the Reporting Period.
Reporting Period Duration	2,160	hours	End date minus start date.
Available Data	2,160	hours	
Missing Data	0	hours	0% of the Reporting Period Duration.
Hours of Operation	2,156	hours	99.8% of the Reporting Period Duration.

Performance of the Measure

The electrical performance of the Project is based on the reporting period energy, as follows:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the generation Baseline Energy is 0 MWh/year.

Reporting Period Energy

The electricity generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	281	MWh	
Auxiliary Loads Energy	5.7	MWh	2% of the CHP Gross Electrical Output. See details below Table 3.
Reporting Period Energy	275	MWh	Gross Electrical Energy – Auxiliary Load Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	%	The Uncertainty is the accuracy of the electrical meter.
Average Generation	127	kW	Reporting Period Energy ÷ Reporting Period Duration
Summer Peak Demand Generation	N/A	kW	Summer peak demand period is defined as Monday to Friday, 1:00 pm - 7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset, are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. These loads draw their power directly from the internal combustion engines (ICEs). However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. The Gross Electrical Energy of 281 MWh is net of the internal auxiliary loads. The 5.7 MWh Auxiliary Loads Energy was calculated based on the 2.62 kW external auxiliary load and 2,156 operating hours.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	275	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	275	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	294	MWh	Based on the anticipated annual electricity savings, pro-rated for this Reporting Period according to Table 5 of the M&V Plan.

[3] The spot metering of the pumps was done at another Facility operated by Toronto Community Housing Corporation (TCHC) and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Electricity Savings as a Percentage of Anticipated Electricity Savings	94%		
Average Demand Savings	127	kW	Equal to Average Generation from Table 3
Summer Peak Demand Savings	N/A	kW	Equal to Summer Peak Demand Generation from Table 3.
Projected Annual Electricity Savings	1,102	MWh/year	For Incentive evaluation purposes only. Assumes the same performance (i.e., 94%) is applicable to the entire 1st Annual Reporting Period.

The 1st Quarterly Electricity Savings are 275 MWh, which represents 94% of the Anticipated Electricity Savings. The slight underperformance is likely due to a lower than anticipated uptime of one CHP system.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

Eq. 1 TSE (%) = [CHP Gross Energy (MWh) + CHP Utilized Thermal Output (MWh)] / CHP Fuel Energy Input (MWh)

Table 5. Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	281	MWh	From Table 3.
Utilized Thermal Output	434	MWh	
Natural Gas Higher Heating Value (HHV)	10.75	kWh/m^3	As per the M&V Plan.
CHP Fuel Energy Input (HHV)	940	MWh	Calculated using the Reporting Period metered total natural gas volumetric flowrate and the natural gas HHV.
Total System Efficiency	75.95	%	

The CHP Gross Electrical Energy of 281 MWh is net of internal auxiliary loads. Thus, the actual Gross Electrical Energy is expected to be slightly higher than 281 MWh. Due to lack of data on the internal auxiliary loads, the Technical Reviewer did not account for the internal auxiliary loads to calculate the Gross Electrical Energy. Additionally, the calculated value of TSE 76% is a conservative value given that the actual Gross Electricity is higher than 281 MWh.

The TSE of 76% exceeds the minimum 65% Program Requirement. Note that this TSE value is for information purposes only as the TSE value from the 1st Annual Reporting Period will be used to assess whether the Project has met the minimum 65% Program Requirement and whether an Incentive penalty needs to be applied.

Next Reporting Period

The Participant will need to provide the metered data for the next Reporting Period in the same format as previously provided. The review of the next M&V Report (1st Annual Report) will include the analysis of the Electricity Savings and calculation of the Incentive for the 1st Annual Reporting Period.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Quarterly M&V Reporting Period, the Incentive payable to the Participant is $110,155, subject to review of Eligible Costs.[4] The Master Payment Requisition will be issued once the Participant has provided the required supporting information, including information required to review the Eligible Costs.

Table 6 outlines the Incentive payment calculation using the latest available information. The Projected Annual Electricity Savings of 1,102 MWh results in an Incentive of $220,310, which is based on the $200/MWh of Electricity Savings limiter (capped at 120% of the Approved Amount in the Project Approval Letter), as per the Program Rules. The Incentive payable for the 1st Quarterly Reporting Period is $110,155, which is 50% of $220,310. Note that the Eligible Costs used in the Incentive calculation are from the Project Approval Letter. The actual Eligible Costs will be reviewed as part of the Payment Recommendation process.

Table 6. Incentive Calculation

Description	Value	Comment
Projected Electricity Savings (MWh)	1,102	Projected Annual Electricity Savings, based on applying the 1st Quarterly Reporting Period Performance Ratio of 94% to the Annual Anticipated Electricity Savings of 1,176 MWh.
Estimated Eligible Costs	$1,983,299	As per the Project Approval Letter
Electricity Billed Savings	$144,303	Based on the Project Approval Letter Electricity Billing Rate of $131/MWh
Other Benefits	$66,869	From the Project Approval Letter
Other Costs	$184,129	From the Project Approval Letter
Net Project Benefits	$27,043	Electricity Billed Savings +Other Benefits – Other Costs
Approved Incentive Amount	**$235,200**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$220,310	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$793,320	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 – Project Payback	$1,956,256	Eligible costs minus Net Project Benefits
Project Incentive	**$220,310**	Minimum of the three limiters.
Incentive payable for 1st Quarterly Reporting Period	**$110,155**	50% of the Project Incentive

Table 7 provides the Incentive payment schedule.

[4] Note the incentive could be impacted if the actual Eligible Costs are lower than the amount in the Project Approval Letter.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	% of Approved Amount
Payment 1	After issuance of the initial (Q1) M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the initial M&V Report.
Final Payment (Holdback)	After issuance of the final (Year 1) M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the final M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601924

June 22, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	June 22nd, 2023	June 22nd, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
June 22, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 23, 2021 to December 22, 2022, are 1,091 MWh, which represents 73% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $109,829.50, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 23, 2021, to Mar 22, 2022	281	73%	$37,092
1st Annual	Dec 23, 2021, to Dec 22, 2022	1,091	73%	$144,012

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 23, 2021, which was established on February 23, 2022.

1st Quarterly Report was issued on September 14, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on the Application Review Electricity Billing Rate of $132/MWh. Note, the Electricity Billing Rate in the Project Letter of Approval ($71.49/MWh) appears incorrect.

Metered Data Analysis

[redacted] representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 23, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 22, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,525	hours	
Missing Data	235	hours	2.7% of the Reporting Period Duration. See comments below table.
Hours of Operation	8,673	hours	99.01% of the Reporting Period Duration

There was a total of 235 hours missing from the data set; however, 149 of those hours show only natural gas consumption data missing. This missing data is discussed in more detail in the Total System Efficiency section found further in this report.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,113	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	23	MWh	Equal to 2.0% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,091	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	125	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	113	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,091	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,091	MWh	Equal to the Reporting Period Energy
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,490	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	73%	-	
Average Demand Savings	125	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	113	kW	Equal to Summer Peak Generation from Table 3.

[3] The spot metering of the pumps was done at another Facility operated by[redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

The 1st Annual Electricity Savings are 1,091 MWh and represent 73% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 195 kW, consisting of two 125 kW internal combustion engines (ICEs), one of which to be permanently derated to 70 kW. In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The under-performance resulted from this re-design which resulted in lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (125 kW) is approximately 27% lower than the anticipated average output in the Application Review (170 kW) which reflects the 28% decrease in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,113	MWh	See the comment below.
CHP Thermal Output Utilized	1,476	MWh	
CHP Energy Input	3,754	MWh	See comment below table.
Total System Efficiency	69.0%	-	

The system achieved a TSE of 69.0%, which exceeds the Program Rules minimum requirement of 65%.

The CHP energy input was calculated in two ways:

- From March 25, 2022 at 6:00 to March 31, 2022 at 10:59 the gross electrical output of each ICE along with part load data for the Yanmar CP31D1 model was used to calculate the natural gas consumption.
- The remainder of the Reporting Period was calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, which was obtained from the M&V Plan.

Figure 1 shows the CHP system operation for both methods detailed above and indicates that the calculated natural gas consumption aligns well with the metered consumption for a similar time period.

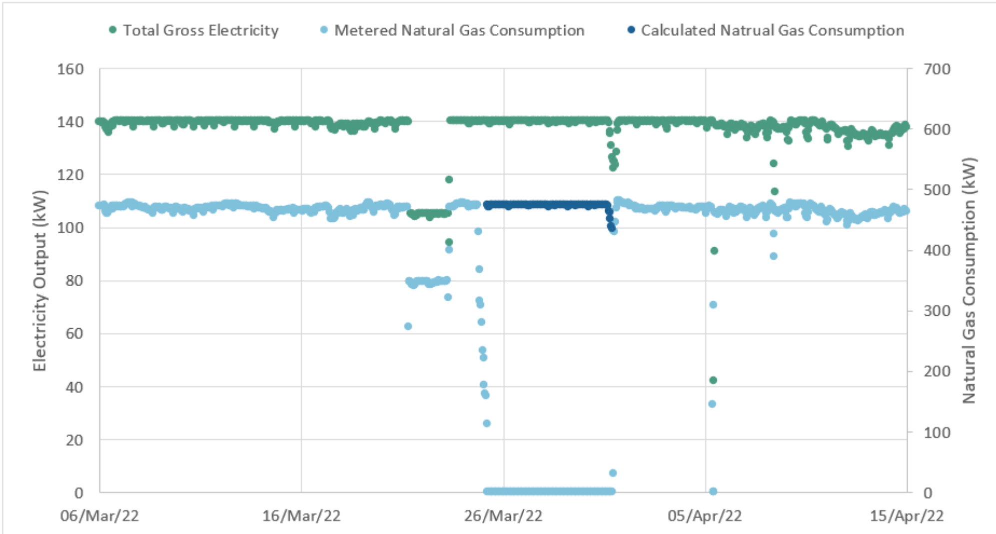

Figure 1. CHP System's gross electrical output and natural gas consumption

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $109,829.50, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,091	From Table 4
Eligible Costs	**$776,359.06**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$144,012.00	Based on the Application Review Electricity Billing Rate of $132/MWh
Other Benefits	$64,444.00	From the Project Approval Letter
Other Costs	$170,996.00	From the Project Approval Letter
Net Project Benefits	$37,460.00	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$298,000.00**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$218,200.00	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$310,543.62	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$738,899.06	Eligible costs minus Net Project Benefits
Project Incentive	$218,200.00	Minimum of the three limiters.
Incentives paid to date	$108,370.50	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$109,829.50**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601930

October 17, 2023

Revision 1

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	[redacted]
Date:	October 11th, 2023	October 11th, 2023
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
October 11, 2023	M&V Report first issuance.	0	[redacted]
October 17, 2023	M&V Report second issuance – the Reporting Period End Date was amended to September 27, 2023, 23:59	1	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of September 28, 2022, to September 27, 2023, are 743 MWh, which represents 92% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $72,500, calculated in accordance with Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Sept 28 to Dec 27, 2022	194	94%	$25,608
1st Annual	Sept 28, 2022, to Sept 27, 2023	743	92%	$98,076

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of July 15, 2022, was established on August 26, 2022. However, THES has approved a Reporting Period starting September 28, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $132/MWh obtained from the Project Application Review.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on October 10, 2023, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Sept 28, 2022, 00:00		Start date of the Reporting Period.
Reporting Period End	Sept 27, 2023, 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,760	hours	
Missing Data	0	hours	0% of the Reporting Period Duration.
Hours of Operation	8,495	hours	96.97% of the Reporting Period Duration and 98.89% of the Estimated Hours of Operation.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	765	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	22	MWh	Equal to 2.9% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	743	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	85	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	79	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.The Reporting Period does not include the Summer Peak period.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	743	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	743	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	807	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	92%	-	
Average Demand Savings	85	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	79	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 743 MWh and represent 92% of the Anticipated Electricity Savings.

The underperformance of the Project can be primarily attributed to the lower than expected average generation value of the combined CHP system. The Application Review estimated an Average Generation value of 92 kW. The Reporting Period Analysis resulted in an Average Generation of 85 kW (92%). Additionally, Summer Peak Demand Savings were expected to achieve a 91 kW average reduction, where only a 79 kW (87%) reduction was observed.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	765	MWh	
CHP Thermal Output Utilized	1,123	MWh	
CHP Energy Input	2,750	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	68.7%	-	

The system achieved a TSE of 68.7%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $72,500, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	743	From Table 4
Eligible Costs	**$642,962**	From the 1st Master Payment Requisition (Actual Eligible Costs are lower than Estimated Eligible Costs)
Electricity Billed Savings	$98,076	Based on the Project Approval Letter Electricity Billing Rate of $132/MWh
Other Benefits	$37,398	From the Project Approval Letter
Other Costs	$105,730	From the Project Approval Letter
Net Project Benefits	$29,744	Electricity Billed Savings + Other Benefits – Other Costs
Approved Incentive Amount	**$161,400**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$148,600	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$257,185	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$613,218	Eligible costs minus Net Project Benefits
Project Incentive	$148,600	Minimum of the three limiters.
Incentives paid to date	$76,100	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$72,500**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

Disclaimer and Limitations

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Please note:

Capitalized terms used in this document have the meaning given to them either in the Save on Energy Process and Systems Upgrade Program Rules, or the IPMVP Core Concepts dated October 2016 and Uncertainty Assessment for IPMVP, dated April 2018, as applicable.

IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601932

July 06, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	July 6th, 2023	July 5th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
July 6th, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 23, 2021 to January 28, 2023, are 841 MWh, which represents 89% of the Anticipated Electricity Savings.

The original Reporting Period has been extended by 885 hours (approximately 37 days). Please refer to Table 2 for details.

The Incentive payable to the Participant for this Reporting Period is $84,758, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 23, 2021, to Mar 27, 2022	208	88%	$28,080
1st Annual	Dec 23, 2021, to Jan 28, 2023	841	89%	$113,535

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 23, 2021, which was established on February 23, 2022.

The 1st Quarterly Report was issued on December 8, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $135/MWh obtained from the Project Letter of Approval.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 23, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Jan 28, 2023 20:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date, excluding the shutdown periods noted below.
Available Data	8,537	hours	
Missing Data	223	hours	2.5% of the Reporting Period Duration.
Hours of Operation	8,534	hours	97.42% of the Reporting Period Duration

[redacted], the Participant's consultant, provided a summary of unscheduled shutdowns that occurred during the 1st Annual Reporting Period. All the dates the CHP was not operating normally or the system was shut off for repairs are provided below:

- January 14, 20:00 to January 19, 16:59, 2022 (117 hours) due to an unexpected transformer failure.
- July 18, 11:00 to August 19, 2022, 10:59 (768 hours) due to leak that shorted out the CHP control system and a pump seal failure.

The 1st Annual Reporting period was extended by 885 hours to account for these shutdown periods.

In addition to the dates noted above, there were 223 hours of missing data, or 2.5% of the Reporting Period with no explanation provided by [redacted]. As this represents less than 10% of the total data for the Reporting Period, the available data was used for the analysis and the missing hours assumed to represent 0 MWh savings, per Section B.6.2. of the M&V Plan.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	863	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	22	MWh	Equal to 2.6% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	841	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	96	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	98	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

[redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	841	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	841	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	946	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	89%	-	
Average Demand Savings	96	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	98	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 841 MWh and represent 89% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 125 kW, consisting of a single 125 kW internal combustion engine (ICE). In the completed Project, three 35 kW ICEs were installed with a nominal capacity of 105 kW. The under-performance is due to this re-design which resulted in lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (96 kW) is approximately 11% lower than the anticipated average output in the Application Review (108 kW) which reflects the 16% decrease in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	863	MWh	See the comment below.
CHP Thermal Output Utilized	1,210	MWh	
CHP Energy Input	2,970	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	69.8%	-	

The system achieved a TSE of 69.8%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $84,758, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	841	From Table 4
Eligible Costs	**$702,516**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$113,535	Based on the Project Approval Letter Electricity Billing Rate of $135/MWh
Other Benefits	$42,824	From the Project Approval Letter
Other Costs	$133,514	From the Project Approval Letter
Net Project Benefits	$22,845	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$189,200**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$168,200	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$281,006	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$679,671	Eligible costs minus Net Project Benefits
Project Incentive	$168,200	Minimum of the three limiters.
Incentives paid to date	**$83,442**	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$84,758**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

Toronto Hydro-Electric System Limited
14 Carlton Street
Toronto, Ontario M5B 1K5

Third Party Evaluation Reports

This document includes the following third party evaluation reports:

Process and Systems Upgrades Program:

- #601936
- #601943
- #601950
- #601954
- #601973
- #601977

SAVE ON ENERGY | DELIVERY PARTNER™

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601936

June 22, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	June 22nd, 2023	June 22nd, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
June 22, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of April 13, 2022 to April 12, 2023, are 1,088 MWh, which represents 71% of the Anticipated Electricity Savings.

Note the In-Service Date of the Project is December 29, 2021. However, the start of the Reporting Period was delayed to April 13, 2022 to allow the Participant to rectify issues with the combined heat and power (CHP) system's heat recovery system, which could have impacted the Project's ability to meet the Total System Efficiency (TSE) requirement.

The Incentive payable to the Participant for this Reporting Period is $101,397.50, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Apr 13 to Jul 12, 2022	285	76%	$35,521
1st Annual	Apr 13, 2022, to Apr 12, 2023	1,088	71%	$131,681

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 29, 2021, which was established on February 23, 2022.

1st Quarterly Report was issued on August 15, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on the Projecy Letter of Approval Electricity Billing Rate of $121.03/MWh.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on May 10, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Apr 13, 2022 00:00		Start date of the Reporting Period.
Reporting Period End	Apr 12, 2023 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,483	hours	
Missing Data	277	hours	3.2% of the Reporting Period Duration.
Hours of Operation	8,483	hours	96.84% of the Reporting Period Duration

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,110	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	22	MWh	Equal to 2.0% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,088	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	124	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	130	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The Participant's consultant, [redacted], has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,088	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,088	MWh	Equal to the Reporting Period Energy.
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,524	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	71%	-	
Average Demand Savings	124	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	130	kW	Equal to Summer Peak Generation from Table 3.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

The 1st Annual Electricity Savings are 1,088 MWh and represent 71% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 195 kW, consisting of two 125 kW internal combustion engines (ICEs), one of which to be permanently derated to 70 kW. In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The under-performance resulted from this re-design which resulted in lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (124 kW) is approximately 29% lower than the anticipated average output in the Application Review (174 kW) which reflects the 28% decrease in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,110	MWh	See the comment below.
CHP Thermal Output Utilized	1,511	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m3, which was obtained from the M&V Plan.
CHP Energy Input	3,655	MWh	See comment below table.
Total System Efficiency	71.7%	-	

The system achieved a TSE of 71.7%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $101,397.50, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,088	From Table 4
Eligible Costs	**$786,635.01**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$131,680.64	Based on the Project Approval Letter Electricity Billing Rate of $121.03/MWh
Other Benefits	$78,570.00	From the Project Approval Letter
Other Costs	$198,346.00	From the Project Approval Letter
Net Project Benefits	$11,904.64	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$304,800.00**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$217,600.00	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$314,654.00	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$774,730.37	Eligible costs minus Net Project Benefits
Project Incentive	$217,600.00	Minimum of the three limiters.
Incentives paid to date	$116,202.50	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$101,397.50**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

Disclaimer and Limitations

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601943

August 30, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	August 30, 2023	August 29, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
August 30, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of April 20, 2022 to May 8, 2023, are 764 MWh, which represents 89% of the Anticipated Electricity Savings.

The In-Service Date of the Project is December 23, 2021. However, the start of the Reporting Period was delayed to April 20, 2022 due to [redacted] shutting off the CHP system while investigating an electrical issue at the facility.

The Incentive payable to the Participant for this Reporting Period is $63,600, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	April 20 to August 7, 2022	201	104%	$24,532
1st Annual	April 20, 2022 to May 8, 2023	764	89%	$93,246

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of December 23, 2021, was established on January 28, 2022.

The 1st Quarterly Report was issued on July 28, 2023.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $122.05/MWh obtained from the Project Application Review.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on June 2, 2023, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	April 20, 2022 00:00		Start date of the Reporting Period.
Reporting Period End	May 8, 2023 19:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date, excluding the shutdown periods noted below.
Available Data	8,723	hours	
Missing Data	37	hours	0.4% of the Reporting Period Duration.
Hours of Operation	8,717	hours	99.51% of the Reporting Period Duration.

[redacted] the Participant's consultant, provided a summary of unscheduled shutdowns that occurred during the 1st Annual Reporting Period. In June 2022, they discovered that the facility's domestic hot water thermostatic mixing valve (TMV) had failed, which negatively affected the CHP system's useful thermal output and, thus, its Total System Efficiency. Due to this failure, the CHP system was shut off for the following period:

- June 17, 13:00 to July 7, 8:59, 2022 (452 hours).

The 1st Annual Reporting period was extended by 452 hours to account for this unscheduled shutdown period.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	787	MWh	CHP System Gross Electrical Output.
Auxiliary Loads Energy	23	MWh	Equal to 2.8% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	764	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	87	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	79	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

The Participant's consultant,[redacted], has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	764	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	764	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	854	MWh	Obtained from Table 5 of the M&V Plan

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Electricity Savings as a Percentage of Anticipated Electricity Savings	89%	-	
Average Demand Savings	87	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	79	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 764 MWh and represent 89% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 125 kW, consisting of two 125 kW internal combustion engines (ICEs), one of which was stand-by. In the completed Project, three 35 kW ICEs were installed with a nominal capacity of 105 kW. The under-performance is due to this re-design which resulted in lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (87 kW) is approximately 11% lower than the anticipated average output in the Application Review (97 kW) which reflects the 16% decrease in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	787	MWh	See the comment below.
CHP Thermal Output Utilized	991	MWh	
CHP Energy Input	2,649	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	67.1%	-	

The system achieved a TSE of 67.1%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $63,600, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Annual Electricity Savings (MWh)	764	From Table 4
Eligible Costs	**$523,490**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$93,246	Based on the Project Approval Letter Electricity Billing Rate of $122.05/MWh
Other Benefits	$37,179	From the Project Approval Letter
Other Costs	$114,646	From the Project Approval Letter
Net Project Benefits	$15,779	Electricity Billed Savings + Other Benefits – Other Costs
Approved Incentive Amount	**$170,800**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$152,800	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$209,396	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$507,710	Eligible costs minus Net Project Benefits
Project Incentive	$152,800	Minimum of the three limiters.
Incentives paid to date	$89,200	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$63,600**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report 1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

July 7, 2023

Revision 0

Project ID: Toronto-PROJECT-601950

Prepared for:

Toronto Hydro-Electric System Limited (the LDC)

[redacted]

Prepared by:

Aladaco Consulting Inc. (the Technical Reviewer)

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	July 6, 2023	July 7th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
July 7, 2023	First M&V Report issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 24, 2021, to December 23, 2022, are 933 MWh, which represent 92% of the Anticipated Electricity Savings. The Incentive payable (balance payment) to the Participant for this Reporting Period is $80,740, calculated in accordance with Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 24, 2021, to Mar 23, 2022	267	104%	$35,713
1st Annual	Dec 24, 2021, to Dec 23, 2022	933	92%	$124,965

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan Rev.0, dated March 1, 2019, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data for the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the Measure.
- The Incentive based on the performance of the Measure.

In-Service Date Confirmation

The In-Service Date is December 24, 2021, which was established on January 28, 2022.

Metered Data Analysis

[redacted] the LDC representative, provided the M&V data on June 2, 2023, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

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[1] Percentage of the Anticipated Electricity Savings shown in the M&V Plan.

[2] Based on the Electricity Billing Rate of $134/MWh shown in the Approval Letter.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 24, 2021, 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 23, 2022, 23:59		End date of the Reporting Period.
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,541	hours	
Missing Data	219	hours	3% of the Reporting Period Duration. See note below.
Hours of Operation	8,538	hours	97% of the Reporting Period duration.

The raw data provided by the Participant included the following periods of missing generation data for the combined heat and power (CHP) System:

- 11 hours from May 17, 7:00 to May 17, 17:00, 2022.
- 166 hours from August 16, 13:00 to August 23, 10:00, 2022.
- 42 hours scattered during the period of October 6 to November 9, 2022.

The total missing data (219 hours) represents 3% of the Reporting Period duration. In an email dated June 2, 2023, Toronto Hydro explained the following reasons for the CHP System shutdown:

- May 17, 2022: Downtime on all CHP units due to electrical issue.
- August 16, to August 23, 2022: Downtime on all CHP units due to equipment issues.

For the periods of missing data, the CHP System was assumed to be not operational for conservativeness, i.e., no generation.

Performance of the Measure

The Electricity Savings of this cogeneration Project is calculated based on the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Reporting Period Energy

The electricity generation of the CHP System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comments
Gross Electrical Energy	955	MWh	Metered electrical output from the CHP System. see note below.
Auxiliary Loads Energy	22	MWh	Equal to 2.62 kW per operating hour. see note below.
Reporting Period Energy	933	MWh	CHP Net Electrical Output. *= Gross Electrical Energy – Auxiliary Loads Energy*
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	106	kW	*= Reporting Period Energy ÷ Reporting Period Duration*
Summer Peak Demand Generation	111	kW	Summer Peak Demand Period is defined as Monday to Friday, 1:00 pm - 7:00 pm, June 1 to August 31.

The Participant's consultant,[redacted], has indicated that the electrical output readings included in the M&V dataset, are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. These loads draw their power directly from the internal combustion engines (ICEs). However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. The Gross Electrical Energy of 955 MWh is net of the internal auxiliary loads. The 22 MWh Auxiliary Loads Energy was calculated based on the 2.62 kW external auxiliary load and 8,538 operating hours.

Non-Routine Adjustments

The Technical Reviewer did not identify any Non-Routine Event; therefore, a Non-Routine Adjustment is not required.

Electricity Savings

The Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comments
Reporting Period Energy	933	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	933	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,019	MWh	From the Project Letter of Approval.
Electricity Savings as Percentage of Anticipated Electricity Savings	92%		
Average Demand Savings	106	kW	Equal to Average Generation, obtained from Table 3.
Summer Peak Demand Savings	111	kW	Equal to Summer Peak Demand Generation, obtained from Table 3.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

The Electricity Savings of the 1st Annual Reporting Period are 933 MWh, which represent 92% of the Anticipated Electricity Savings. The underperformance is likely due to the lower than anticipated net electrical output and hours of operation of the CHP System.

The CHP System was anticipated to produce an average net electrical output of 116 kW, whereas the Reporting Period average net electrical output was 106 kW. This is likely due to a change in system configuration; the Project was originally planned for two 125 kW cogeneration systems (one operational standby). In the completed Project, four 35 kW ICEs were installed with a total capacity of 140 kW.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / Fuel Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comments
Gross Electrical Energy	955	MWh	Obtained from Table 3. See note below.
Recovered Heat Utilized	1,137	MWh	
Fuel Energy Input	3,080	MWh	Calculated from total volumetric natural gas consumption and a natural gas higher heating value (HHV) of 10.75 kWh/m^3 specified in the M&V Plan.
Total System Efficiency	68%		

The CHP Gross Electrical Energy of 955 MWh is net of internal auxiliary loads. Thus, the actual Gross Electrical Energy is expected to be slightly higher than 955 MWh. Due to lack of data on the internal auxiliary loads, the Technical Reviewer did not account for the internal auxiliary loads to calculate the Gross Electrical Energy. However, the internal auxiliary loads expected to be within the metering uncertainty shown in Table 4. Additionally, the calculated TSE of 68% is a conservative value given that the actual Gross Electrical Energy is higher than 955 MWh.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $80,740, pending issuance of the Master Payment Requisition. The Net Project Incentive Amount of $186,515 was calculated in accordance with the Program Rules and is limited by the “$200/MWh of Electricity Savings”, up to a maximum of 120% of the Approved Incentive Amount.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comments
Electricity Savings (MWh)	933	Annual Electricity Savings, from Table 4.
Limiter 1 - Electricity Savings ($)	186,515	$200 per MWh of Electricity Savings, limited to 120% of the Approved Incentive Amount.
Actual Eligible Costs ($)	800,944	Reviewed invoices provided by the Participant.
Estimated Eligible Costs ($)	971,573	From the Project Letter of Approval.
Limiter 2 - Eligible Costs ($)	320,378	40% of minimum Actual and Estimated Eligible Costs.
Project Net Benefits ($)	41,556	*= Electricity Billed Savings + Other Benefits (from Letter of Approval) – Other Costs (from Letter of Approval)*
Limiter 3 – 1-year Project Payback ($)	759,388	*= Actual Eligible Costs - Project Net Benefits*
Approved Incentive Amount ($)	203,800	From the Project Letter of Approval.
Net Project Incentive ($)	**186,515**	Minimum of the three limiters.
Incentives paid to date ($)	**105,775**	Paid for the 1st Quarterly Reporting Period.
Incentive payable (Balance Payment) ($)	**80,740**	*= Net Project Incentive – Incentives paid to date*

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601954

July 27, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	[redacted]
Date:	July 27, 2023	July 27th, 2023
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
July 27, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 22, 2021, to December 21, 2022, are 1,081 MWh, which represents 106% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $108,122.50, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 22, 2021, to Mar 21, 2022	272	106%	$35,904
1st Annual	Dec 22, 2021, to Dec 21, 2022	1,081	106%	$142,692

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 22, 2021, which was established on January 28, 2022.

The 1st Quarterly Report was issued on July 5, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $132/MWh obtained from the Project Letter of Approval.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on June 2, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 22, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 21, 2022 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date, excluding the shutdown periods noted below.
Available Data	8,020	hours	
Shutdown Periods	627	hours	7.8% of the Available Data.
Missing Data	113	hours	1.4% of the Reporting Period Duration.
Hours of Operation	8,020	hours	98.61% of the Reporting Period Duration – Shutdown Periods

[redacted] the Participant's consultant, provided a summary of unscheduled shutdowns that occurred during the 1st Annual Reporting Period. All the dates the CHP was not operating normally or the system was shut off for repairs are provided below:

- December 30, 4:00, 2021 to January 5, 10:59, 2022 (151 hours) due failure of Unit #4.
- February 19, 16:00 to March 7, 11:59, 2022 (380 hours) due failure of Unit #1.
- July 26, 6:00 to July 30, 5:59, 2022 (96 hours) due gas upgrades that resulted in Unit #1 being turned off.

The shutdown periods represent 627 hours total, which represents 7.8%, or less than 10%, of the total data for the Reporting Period. In addition to the dates noted above, there were 113 hours of missing data, or 1.4% of the Reporting Period, with no explanation provided by [redacted]

Since the total unavailable data represents less than 10% of the total data for the Reporting Period, the analysis was completed per Section B.6.2. of the M&V Plan, in the following way:

- The remaining 90.8% of data was used to predict the CHP system operation during the unscheduled shutdowns using a linear extrapolation, and
- The missing hours are assumed to represent 0 MWh savings.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,103	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	23	MWh	Equal to 2.1% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,081	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	123	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	110	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

[redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,081	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,081	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,020	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	106%	-	
Average Demand Savings	123	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	110	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,081 MWh and represent 106% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 125 kW, consisting of two 125 kW internal combustion engines (ICEs), one operating as emergyency backup only. In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The over-performance is due to this re-design which resulted in a higher than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (123 kW) is approximately 6% higher than the anticipated average output in the Application Review (116 kW) which reflects the 12% increase in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,024	MWh	See comments below table.
CHP Thermal Output Utilized	1,283	MWh	See comments below table.
CHP Energy Input	3,404	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan. See comments below table.
Total System Efficiency	67.8%	-	

The CHP energy input and outputs are the sums of the available data, they have not been extrapolated to account for the shutdown periods. The system achieved a TSE of 67.8%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $108,122.50, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,081	From Table 4
Eligible Costs	**$761,764**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$142,692	Based on the Project Approval Letter Electricity Billing Rate of $132/MWh
Other Benefits	$43,541	From the Project Approval Letter
Other Costs	$127,581	From the Project Approval Letter
Net Project Benefits	$58,652	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$204,000**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$216,200	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$304,706	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$703,112	Eligible costs minus Net Project Benefits
TSE Incentive Discount	$0	5% discount for TSE ≥ 62.5% and < 65.0%
Project Incentive	**$216,200**	**Minimum of the three limiters – TSE Incentive Discount**
Incentives paid to date	$108,077.50	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$108,122.50**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

Disclaimer and Limitations

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

Project ID: Toronto-PROJECT-601973

July 25, 2023

Revision 0

Prepared for:

Toronto Hydro-Electric System Limited (THES)

[redacted]

Prepared by:

Aladaco Consulting Inc.

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	[redacted]
Date:	July 25th, 2023	July 24th, 2023
Signature:	[redacted]	[redacted]

Revision History

Date	Description	Revision	Technical Reviewer
July 25th, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 22, 2021 to December 21, 2022, are 1,143 MWh, which represents 94% of the Anticipated Electricity Savings.

The Incentive payable to the Participant for this Reporting Period is $119,138, calculated in accordance to Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings and Incentive payments to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% of Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 22, 2021, to Mar 21, 2022	274	90%	$35,894
1st Annual	Dec 22, 2021, to Dec 21, 2022	1,143	94%	$149,733

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Adjusted Baseline Energy and the Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The In-Service Date of the Project is December 22, 2021, which was established on January 28, 2022.

The 1st Quarterly Report was issued on August 16, 2022.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.
[2] Based on $131/MWh obtained from the Project Letter of Approval.

Metered Data Analysis

[redacted] a representative of THES, provided the M&V data on June 1, 2023 to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	Dec 22, 2021 00:00		Start date of the Reporting Period.
Reporting Period End	Dec 21, 2022 20:59		End date of the Reporting Period
Reporting Period Duration	8,760	Hours	End date minus start date, excluding the shutdown periods noted below.
Available Data	8,729	Hours	
Missing Data	31	Hours	0.4% of the Reporting Period Duration.
Hours of Operation	8,727	Hours	99.62% of the Reporting Period Duration

31 hours, or 2.5% of the Reporting Period, were missing. As this represents less than 10% of the total data for the Reporting Period, the available data was used for the analysis and the missing hours assumed to represent 0 MWh savings, per Section B.6.2. of the M&V Plan.

Performance of the Measures

The electrical performance of the project is based on the adjusted baseline energy and the reporting period energy, as follows:

Electricity Savings = Adjusted Baseline Energy – Reporting Period Energy ± Non-Routine Adjustments

Baseline Energy

This is an electricity generation Project with no existing generation. Therefore, the Baseline Energy is 0 MWh/year.

Reporting Period Energy

The Reporting Period Energy is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comment
Gross Electrical Energy	1,166	MWh	CHP System Gross Electrical Output (See comment below table)
Auxiliary Loads Energy	23	MWh	Equal to 2.0% of the Gross Electrical Energy (See comment below table).
Reporting Period Energy	1,143	MWh	Gross Electrical Energy – Auxiliary Loads Energy.
Uncertainty of the Reporting Period Energy	± 2.5%	-	The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	130	kW	Reporting Period Energy divided by Reporting Period Duration.
Summer Peak Generation	130	kW	Summer peak demand period is defined as Monday to Fridays, 1:00 pm -7:00 pm, June 1 to August 31.

[redacted] has indicated that the electrical output readings included in the M&V dataset are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. Therefor, the Technical Reviewer used the hourly external auxiliary load of 2.62 kW per CHP operating hour to calculate the total auxiliary load energy.

Electricity Savings

The Baseline Energy, the Reporting Period Energy, and the Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Table 4. Electricity Savings

Description	Value	Unit	Comment
Baseline Energy	0	MWh	
Reporting Period Energy	1,143	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	1,143	MWh	
Uncertainty of the Electricity Savings	± 2.5%	-	The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	1,217	MWh	Obtained from Table 5 of the M&V Plan
Electricity Savings as a Percentage of Anticipated Electricity Savings	94%	-	
Average Demand Savings	130	kW	Equal to Average Generation from Table 3.
Summer Peak Demand Savings	130	kW	Equal to Summer Peak Generation from Table 3.

The 1st Annual Electricity Savings are 1,143 MWh and represent 94% of the Anticipated Electricity Savings.

The Project was originally planned for a total nominal capacity of 160 kW, consisting of a two 125 kW internal combustion engines (ICE), one permanently derated to 35 kW. In the completed Project, four 35 kW ICEs were installed with a nominal capacity of 140 kW. The under-performance is due to this re-design which resulted in lower than anticipated average electrical output of the CHP System. The average electrical power generated during the Reporting Period (130 kW) is approximately 6% lower than the anticipated average output in the Application Review (139 kW) which reflects the 13% decrease in system capacity.

Total System Efficiency

The Total System Efficiency (TSE) is calculated according to the following equation:

TSE (%) = [Gross Electrical Energy + CHP Thermal Output Utilized] / CHP Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comment
CHP Gross Electrical Energy	1,166	MWh	See the comment below.
CHP Thermal Output Utilized	1,438	MWh	
CHP Energy Input	3,950	MWh	Calculated using the metered volumetric flowrate of natural gas and Natural Gas Higher Heating Value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	65.9%	-	

The system achieved a TSE of 65.9%, which exceeds the Program Rules minimum requirement of 65%.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested by the IESO.

Appendix – Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $119,138, pending issuance of the Master Payment Requisition.

The Incentive is based on the $200/MWh of Electricity Savings limiter. Table 6 outlines the Incentive payment calculation.

Table 6. Incentive Calculation

Description	Value	Comment
Electricity Savings (MWh)	1,143	From Table 4
Eligible Costs	**$749,206**	From the 1st Master Payment Requisition.
Electricity Billed Savings	$149,733	Based on the Project Approval Letter Electricity Billing Rate of $131/MWh
Other Benefits	$64,394	From the Project Approval Letter
Other Costs	$163,417	From the Project Approval Letter
Net Project Benefits	$50,710	Electricity Billed Savings + Other Benefits - Other Costs
Approved Incentive Amount	**$243,400**	From the Project Approval Letter
Limiter 1 - Electricity Savings	$228,600	$200 per MWh of Electricity Savings, capped at 120% of Approved Incentive amount.
Limiter 2 - Eligible Costs	$299,682	40% of the minimum of Actual and Estimated Eligible costs.
Limited 3 - Project Payback	$698,496	Eligible costs minus Net Project Benefits
Project Incentive	$228,600	Minimum of the three limiters.
Incentives paid to date	**$109,462**	From the 1st Master Payment Requisition.
Incentive payable (Balance Payment) ($)	**$119,138**	Project Incentive - Incentives paid to date

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

CONSERVATION FIRST FRAMEWORK: PROCESS & SYSTEMS UPGRADES PROGRAM

Measurement & Verification Report

1st Annual Reporting Period

[redacted]

[redacted] Cogeneration System

June 14, 2023
Revision 0

Project ID: Toronto-PROJECT-601977

Prepared for:

Toronto Hydro-Electric System Limited (the LDC)

[redacted]

Prepared by:

Aladaco Consulting Inc. (the Technical Reviewer)

Prepared in accordance with:

Save On Energy Process & Systems Upgrades Program, Program Requirements, FINAL v2.0 April 6, 2018

Approvals

	Written by	Reviewed by
Name:	[redacted]	
Date:	June 14, 2023	June 14th, 2023
Signature:	[redacted]	

Revision History

Date	Description	Revision	Technical Reviewer
June 14, 2023	M&V Report first issuance.	0	[redacted]

Summary

The Electricity Savings for the 1st Annual Reporting Period of December 23, 2021, to December 22, 2022, are 737 MWh, which represents 85% of the Anticipated Electricity Savings. The Incentive payable (balance payment) to the Participant for this Reporting Period is $75,054, calculated in accordance with Program Rules. Refer to the Appendix for details.

The Electricity Savings for each Reporting Period to date are presented in Table 1.

Table 1. Electricity Savings to Date

Reporting Period	Start and End Dates	Electricity Savings (MWh)	% Anticipated Electricity Savings[1]	Electricity Cost Savings[2]
1st Quarterly	Dec 23, 2021, to Mar 29, 2022	216	84%	$28,711
1st Annual	Dec 23, 2021, to Dec 22, 2022	737	85%	$98,026

Content Overview

This M&V Report presents the Electricity Savings based on the metered data provided by the Participant for the Project and the methodology described in the M&V Plan Rev.0, dated March 27, 2019, which should be reviewed prior to reading this report. The report assesses the following items:

- The metered data of the Reporting Period.
- The Reporting Period Energy.
- The electrical and thermal performance of the measure.
- The Incentive based on the performance of the measure.

In-Service Date Confirmation

The Project's In-Service Date is December 23, 2021, which was established on February 23, 2022.

Metered Data Analysis

[redacted] a representative of Toronto Hydro, provided the M&V data, on May 10, 2023, to the Technical Reviewer for analysis. The provided data is compliant with the M&V Plan requirements.

[1] Percent of Anticipated Electricity Savings defined in the M&V Plan.

[2] Based on $133/MWh obtained from the Project Approval Letter.

Reporting Period Metrics and System Hours of Operation

Table 2 presents an overview of the values related to the Reporting Period, available data, and hours of operation.

Table 2. Reporting Period Metrics and System Hours of Operation

Description	Value	Unit	Comments
Reporting Period Start	December 23, 2021, 00:00		Start date of the Reporting Period.
Reporting Period End	December 22, 2022, 23:59		End date of the Reporting Period
Reporting Period Duration	8,760	hours	End date minus start date.
Available Data	8,716	hours	See note below.
Missing Data	44	hours	0.5% of the Reporting Period Duration.
Hours of Operation	8,445	hours	96.4% of the Reporting Period Duration.

The generation data was not collected during the following periods:

- August 9, 2022, from 03:00 am to 24:00 am (22 hours).
- September 4, 2022, from 03:00 am to 24:00 am (22 hours).

The total missing data (44 hours) represents 0.5% of the Reporting Period duration. In an email dated May 10th, 2023, the Participant confirmed that the combined heat and power (CHP) System was operational during these periods and the missing data was replaced with representative data from the previous day.

Performance of the Measure

The Electricity Savings of this cogeneration Project is calculated based on the following equation:

Electricity Savings = Reporting Period Energy ± Non-Routine Adjustments

Reporting Period Energy

The Reporting Period Energy of the System for this Reporting Period is presented in Table 3.

Table 3. Reporting Period Energy

Description	Value	Unit	Comments
Gross Electrical Energy	759	MWh	CHP System Gross Electrical Output (See note below).
Auxiliary Loads Energy	22	MWh	Equal to 2.9% of the Gross Electrical Energy (See note below).
Reporting Period Energy	737	MWh	CHP Net Electrical Output. = *Gross Electrical Energy - Auxiliary Loads Energy*
Uncertainty of the Reporting Period Energy	± 2.5%		The Uncertainty is mostly due to the accuracy of the meters.
Average Generation	84	kW	= *Reporting Period Energy ÷ Reporting Period Duration*
Summer Peak Generation	76	kW	Summer peak demand period is defined as June 1 to August 31, Monday to Friday, 1:00 pm -7:00 pm.

The Participant's consultant, [redacted]., has indicated that the electrical output readings included in the M&V dataset, are net of internal auxiliary loads, which includes the coolant pumps and heat rejection fans. These loads draw their power directly from the internal combustion engines (ICEs). However, there are system pumps that are powered externally and whose power draw was spot metered[3] to be 2.62 kW. The Gross Electrical Energy of 759 MWh is net of the internal auxiliary loads. The 22 MWh Auxiliary Loads Energy was calculated based on the 2.62 kW external auxiliary load and 8,445 operating hours.

Non-Routine Adjustments

The Technical Reviewer did not identify any Non-Routine Event; therefore, a Non-Routine Adjustment is not required.

Electricity Savings

The Electricity Savings are presented in Table 4. This is an IPMVP Option B methodology of calculating the Electricity Savings.

Table 4. Electricity Savings

Description	Value	Unit	Comments
Reporting Period Energy	737	MWh	Obtained from Table 3.
Non-Routine Adjustment	0	MWh	None.
Electricity Savings	737	MWh	
Uncertainty of the Electricity Savings	± 2.5%		The Uncertainty is the accuracy of the electrical meter.
Anticipated Electricity Savings	865	MWh	Obtained from the M&V Plan.
Electricity Savings as a Percentage of Anticipated Electricity Savings	85%		
Average Demand Savings	84	kW	Equal to Average Generation, obtained from Table 3.
Summer Peak Demand Savings	76	kW	Equal to Summer Peak Demand Generation, obtained from Table 3.

The Electricity Savings of the 1st Annual Reporting Period are 737 MWh, which represent 85% of the Anticipated Electricity Savings.

The Project scope was originally based on installation of three 65 kW micro-turbines with a total nominal capacity of 195 kW. However, the installed system comprises of three 35 kW ICEs with a total nominal capacity of 105 kW. The underperformance is a result of the lower capacity of the installed CHP System. The average anticipated net operating electrical output was 119 kW, but the actual average net operating electrical output was 87 kW.

[3] The spot metering of the pumps was done at another Facility operated by [redacted] and where a similar type of CHP system, involving Yanmar CP35D1 engines and a similar hot water heat recovery system.

Total System Efficiency

The CHP System's Total System Efficiency (TSE) is calculated according to the following equation.

TSE (%) = [Gross Electrical Energy + Recovered Heat Utilized] / Fuel Energy Input

Table 5. Calculations of Total System Efficiency

Description	Value	Unit	Comments
Gross Electrical Energy	759	MWh	Obtained from Table 3. (See comment below table).
Recovered Heat Utilized	1,198	MWh	
Fuel Energy Input	2,730	MWh	Calculated from total volumetric natural gas consumption and a natural gas higher heating value (HHV) of 10.75 kWh/m^3, obtained from the M&V Plan.
Total System Efficiency	71.7%		Exceeds the minimum 65% required by the Program.

The CHP Gross Electrical Energy of 759 MWh is net of internal auxiliary loads. Thus, the actual Gross Electrical Energy is expected to be slightly higher than 759 MWh. Due to lack of data on the internal auxiliary loads, the Technical Reviewer did not account for the internal auxiliary loads to calculate the Gross Electrical Energy. Therefore, the calculated TSE of 71.7% is a conservative value given that the actual Gross Electrical Energy is higher than 759 MWh.

Next Reporting Period

This is the final M&V Report, as the M&V Reporting Period is one year. No additional M&V data will be required, unless requested.

Appendix - Incentive Payment

Based on the Electricity Savings achieved in the 1st Annual Reporting Period, and review of the Eligible Costs, the Incentive payable (balance payment) to the Participant for this Reporting Period is $75,054, pending issuance of the Master Payment Requisition. The Net Project Incentive Amount of $147,407 was calculated in accordance with the Program Rules and is limited by the "$200/MWh of Electricity Savings", up to a maximum of 120% of the Approved Incentive Amount.

Table 6 outlines the Incentive payment calculation using the latest available information.

Table 6. Incentive Calculation

Description	Value	Comments
Electricity Savings (MWh)	737	Annual Electricity Savings, from Table 4.
Limiter 1 - Electricity Savings ($)	147,407	$200 per MWh of Electricity Savings, limited to 120% of the Approved Incentive Amount.
Actual Eligible Costs ($)	608,706	Reviewed invoices provided by the Participant.
Estimated Eligible Costs ($)	886,931	From the Project Letter of Approval.
Limiter 2 - Eligible Costs ($)	243,482	40% of minimum Actual and Estimated Eligible Costs.
Project Net Benefits ($)	29,532	*= Electricity Billed Savings + Other Benefits (from Letter of Approval) – Other Costs (from Letter of Approval)*
Limiter 3 – 1-year Project Payback ($)	579,174	*= Actual Eligible Costs - Project Net Benefits*
Approved Incentive Amount ($)	173,000	From the Project Letter of Approval.
Net Project Incentive ($)	**147,407**	Minimum of the three limiters.
Incentives paid to date ($)	**72,353**	Paid for the 1st Quarterly Reporting Period.
Incentive payable (Balance Payment) ($)	**75,054**	*= Net Project Incentive – Incentives paid to date*

The table below shows the payment schedule as defined in the contract and Program Rules, for reference.

Table 7. Incentive Payment Schedule

Deferred Payment Schedule	Projected Date	Incentive Amount
Initial Payment	After issuance of the 1st Quarterly M&V Report.	50% of Participant Incentive. The first payment towards the Participant Incentive is calculated based on Electricity Savings in the 1st Quarterly M&V Report.
Final Payment (Holdback)	After issuance of the 1st Annual M&V Report.	The balance payment is the difference between the actual Participant Incentive, calculated based on the 1st Annual M&V Report, and the total payments made to date.

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Please note:

Capitalized terms used in this document have the meaning given to them either in the Save on Energy Process and Systems Upgrade Program Rules, or the versions of IPMVP Core Concepts and Uncertainty Assessment for IPMVP, as applicable, available at the time of the M&V Plan Approval.

IPMVP defined terms:

Adjusted Baseline Energy, Avoided Energy Use, Baseline Energy, Baseline Period, Confidence Level, Interactive Effects, M&V, Measurement Boundary, Non-Routine Adjustments, Precision, Reporting Period, Reporting Period Energy, Savings, Static Factors, Uncertainty.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1B-STAFF-12

References: **Exhibit 1B / Tab 2 / Schedule 1, Figure 1**
Exhibit 1B / Tab 2 / Schedule 1
EB-2014-0219: Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 2014

Preamble:

Reference 1 is reproduced below:

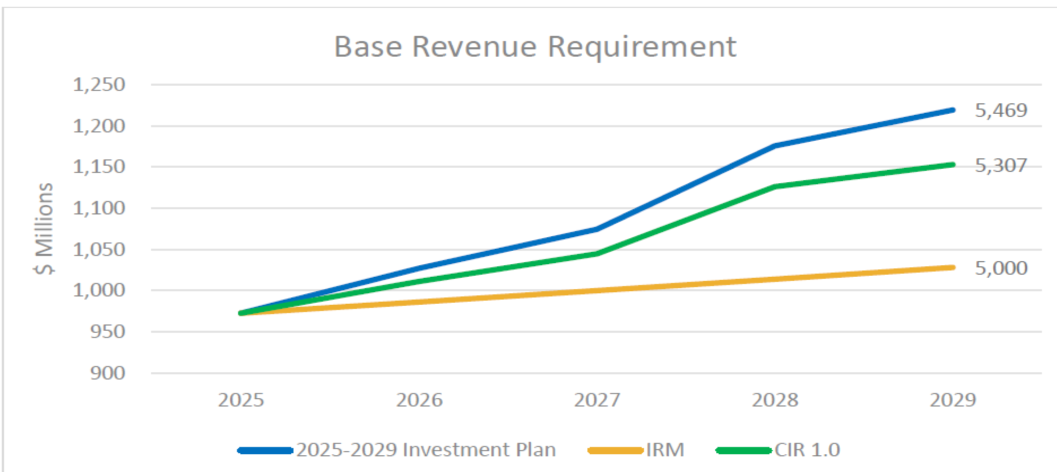

Figure 1: Cumulative 2025-2029 Base Revenue Requirement

QUESTION (A):

a) Please populate the following table, adding the proposed Custom Revenue Cap Index (CRCI):

Revenue Requirement ($ million, two decimal places)	2025	2026	2027	2028	2029
2025-2029 Investment Plan					
IRM					
Current Custom IR formula (Custom Price Cap Index (CPCI) / CIR 1.0)					
Proposed CRCI					

1 **RESPONSE (A): Table 1: 2025-2029 Revenue Projection Scenarios ($ Millions)**[1]

		2025	2026	2027	2028	2029	Total
A	2025-2029 Investment Plan	972	1,027	1,074	1,176	1,219	**5,469**
B	Revenue under IRM	972	986	1,000	1,014	1,028	**5,000**
C	Revenue under CIR1.0 with Custom Price Cap Index (CPCI)	972	1,011	1,044	1,126	1,153	**5,307**
D	Revenue under proposed Custom Revenue Cap Index (CRCI)	972	1,020	1,059	1,151	1,185	**5,387**
A-B	Revenue Deficiency under IRM	0	41	75	162	191	**469**
A-C	Revenue Deficiency under CIR1.0 with Custom Price Cap Index (CPCI)	0	16	30	50	66	**162**
A-D	Revenue Deficiency under the proposed CRCI	0	7	15	25	34	**81**

2

3 **QUESTION (B) :**

4 b) Please populate the following table with the values that correspond with developing
5 Reference 1:

CPCI Components	2026	2027	2028	2029
I				
X – productivity				
X – stretch				
Xcap				
Cn				
Scap				
g				
CPCI				

6

7 **RESPONSE (B):**

8 **Table 2: 2025-2029 Custom Price Cap Index (CPCI) Scenario**

CIR 1.0	2026	2027	2028	2029
I - Inflation	2.00%	2.00%	2.00%	2.00%
X - Productivity	0.00%	0.00%	0.00%	0.00%
X - Stretch	-0.60%	-0.60%	-0.60%	-0.60%

[2] https://www.oeb.ca/sites/default/files/uploads/Board_ACM_ICM_Report_20140918.pdf at pp. 13-14

CIR 1.0	**2026**	**2027**	**2028**	**2029**
Xcap* Scap	-0.21%	-0.21%	-0.21%	-0.21%
Cn - Cn factor	4.17%	3.53%	8.09%	2.59%
I x Scap	-1.40%	-1.40%	-1.43%	-1.43%
G - Growth	-0.20%	-0.20%	-0.20%	-0.20%
Custom Price Cap Index (CPCI)	**3.76%**	**3.12%**	**7.64%**	**2.15%**

CIR 1.0	**2026**	**2027**	**2028**	**2029**
I - Inflation	2.00%	2.00%	2.00%	2.00%
X - Productivity	0.00%	0.00%	0.00%	0.00%
X – Stretch (Non-CRRR)	-0.18%	-0.18%	-0.17%	-0.17%
Cn - Cn factor (including 0.9% Stretch)	3.54%	2.90%	7.45%	1.95%
I x Scap	-1.40%	-1.40%	-1.43%	-1.43%
G - Growth	-0.20%	-0.20%	-0.20%	-0.20%
Custom Price Cap Index (CPCI)	**3.76%**	**3.12%**	**7.64%**	**2.15%**

QUESTION (C) :

c) To what extent did Toronto Hydro consider other, non-Custom IR regulatory tools, such as, but not limited to, options discussed in Reference 3, to solve the funding gap identified throughout Reference 2. Please explain why Toronto Hydro rejected these other regulatory options.

RESPONSE (C):

Toronto Hydro considered all the non-custom regulatory mechanisms available under existing OEB policy. Toronto Hydro did not pursue the ICM or ACM options because the OEB policy is clear that: "*projects proposed for incremental capital funding during the IR term must be discrete projects, and not part of typical annual capital programs*."[2] The OEB Report goes on to say that "*[t] he use of an ACM is most appropriate for a distributor that: [a] does not have multiple discrete projects for each*

[2] https://www.oeb.ca/sites/default/files/uploads/Board_ACM_ICM_Report_20140918.pdf at pp. 13-14

of the four IR years for which it requires incremental capital funding; [b] is not seeking funding for a series of projects that are more related to recurring capital programs for replacements or refurbishments (i.e. "business as usual" type projects).

The vast majority of Toronto Hydro's capital expenditures as outlined in the Distribution System Plan at Sections E4-E8 consist of annual capital programs, rather than discrete projects. There are only a handful of discrete projects in Toronto Hydro's 2025-2029 Distribution System Plan that are not part of the utility's annual capital plan namely: Enterprise Data Center (Exhibit 2B, Section E8.1) , ADMS (Exhibit 2B, Section E8.4, page 22), AMI2.0 as part Metering (Exhibit 2B, Section E5.4), ERP (Exhibit 2B, Section E8.4, page 21), Stations Expansion (Exhibit 2B, Section E7.4). These projects total approximately $504.0 million out of the total $3,927.8 million capital expenditure plan. Applying for ACM treatment for these projects would not have been sufficient to carry out the necessary and prudent investments outlined in the 2025-2029 Distribution System Plan. In addition, it is key to note that there is no incremental funding available under ICM or ACM options for non-capital related expenditures. Approximately $66M of the revenue deficiency identified above is attributed to non-capital related revenue requirement expenses (i.e. OM&A and Other Revenue) that exceed revenue available to fund operations under a standard Price Cap IR framework.

QUESTION (D):

d) Please confirm that the IRM scenario in Reference 1 does not include consideration for the capital modules available to utilities on a Price-Cap IRM. Please add an "IRM with Capital Module(s)" scenario to both Figure 1 and the table in part a).

RESPONSE (D):

Confirmed. Please refer to the response in part (f) below.

QUESTION (E):

e) Based on the Capital Module regulatory mechanism, which projects or initiatives, would qualify? Please explain how they would apply.

RESPONSE (E):

Please refer to the response to part (c) above.

QUESTION (F) :

f) Please confirm that the revenue requirement projection presented in Reference 1 includes projects that would be subject to variance account treatment in the DRVA of the proposed plan. Please calculate the residual annual revenue requirement that would result if costs of generation protection monitoring and control, externally-initiated plant relocations and expansions, Hydro One contributions, metering, and non-wire alternatives were not funded by the index. Please then adjust this for Toronto Hydro's proposed X factor and place the results as a new row in the table of part a), or a new table, whichever suites Toronto Hydro.

RESPONSE (F):

Confirmed. Please see Table 3 below for the residual annual revenue requirement, adjusted for Toronto Hydro's proposed X-factor that would result of costs of the programs mentioned in the preamble were not funded by the index.

Table 3: Residual Revenue Requirement adjusted for X factor ($ Millions)[3] /C

		2025	2026	2027	2028	2029	Total
A	**Residual Revenue Requirement**	967	1,012	1,048	1,139	1,179	**5,346**
B	**Residual Revenue Requirement adjusted for the stretch factor**	967	1,005	1,033	1,115	1,146	**5,266**
A-B	**Variance**	-	**7**	**15**	**24**	**33**	**80**

[3] Based on updated evidence filed on April 2, 2024 where the total forecast 2025-2029 Revenue Requirement is $5,482.5 million. Please see Exhibit 1B, Tab 1, Schedule 3. /C

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 1B-CCC-37

Reference: Exhibit 1B, Tab 2, Schedule 1 p.35

Preamble:

Toronto Hydro is proposing a Demand-Related Variance Account (DRVA) to record the demand driven revenue requirement impacts arising from variances in actual versus forecast capital and operational expenditures for certain demand-based programs and the revenue impacts arising from variances in forecast versus actual billing determinants over the rate period. The Council is interested in understanding the scope of the DRVA;

QUESTION (A):

a) For each year 2020-2024 please provide the forecast and actual expenditures for the following capital and operating programs: Customer Connections, Customer Operations, Stations Expansion, Load Demand, Non-Wires Solutions, Generation Protection Monitoring and Control and Externally-initiated Plant Relocations and Expansions. Also, please provide the forecast and actual revenue requirement that would have been dealt with through the DRVA Expenditure sub-account had one been in place for that period;

RESPONSE (A):

Please see below Table 1 for Actuals/Bridge Capital Expenditures and Table 2 for Actuals/Bridge Operating Expenditures. In responding to this interrogatory Toronto Hydro has only included OM&A segments that would have been dealt with through the DRVA expenditure sub-account had one been in place for that period.

Table 1: Actuals/Bridge Capital Expenditures that would have been subject to the DRVA sub-account (in $ millions)

Programs	Actuals				Bridge
	2020	2021	2022	2023	2024
Customer Connections	35.6	92.4	76.1	86.8	78.2
Stations Expansion	18.2	50.3	47.5	10.4	16.1
Load Demand	24.0	29.7	30.8	26.7	23.2
Non-Wires Solutions[1]	1.0	0.5	0.1	0.0	0.6
Generation Protection Monitoring & Control[1]	0.8	0.8	0.1	0.2	7.8
Externally Initiated Plant Relocations & Expansions	8.7	9.3	12.9	16.0	13.0

Table 2: Actuals/Bridge Operating Expenditures that would have been subject to the DRVA sub-account (in $ millions)

OM&A Segments[2]	Actuals				Bridge
	2020	2021	2022	2023	2024
Customer Connections, Exhibit 4, Tab 2, Schedule 8, Section 5	3.7	1.6	1.6	3.1	3.6
Key Accounts, Exhibit 4, Tab 2, Schedule 8, Section 6	-	0.5	0.8	0.8	1.2
Flexibility Services, Exhibit 2B, Section E7.2	0.4	0.2	0.2	0.8	0.8

Please see Table 3 for approved Capital Expenditures and Table 4 for approved Operating Expenditures that would have been dealt with through the DRVA expenditure sub-account had one been in place for that period.

Table 3: Approved Capital Expenditures that would have been subject to DRVA sub-account (in $ millions)

Programs	Approved				
	2020	2021	2022	2023	2024
Customer Connections	40.1	40.9	41.7	42.6	43.4

[1] 94% of the Renewable Enabling portions of these investments will be provincially funded and not included in the DRVA
[2] Only includes segments associated with the DRVA

Programs	**Approved**				
	2020	**2021**	**2022**	**2023**	**2024**
Stations Expansion	19.5	40.0	49.3	12.5	15.2
Load Demand	11.3	11.4	18.5	22.6	23.6
Non-Wires Solutions[3]	1.0	3.7	3.8	1.0	1.0
Generation Protection Monitoring & Control[3]	3.7	2.3	2.4	2.5	2.7
Externally Initiated Plant Relocations & Expansions	11.4	20.8	4.6	4.7	4.5

As noted in Toronto Hydro's response to interrogatory 4-SEC-89(a), the total OM&A cost approved by the OEB for 2020 was $266.7 million, which was lower than the 2020 test year OM&A funding requested by Toronto Hydro.[4] The OEB approved OM&A on an envelope basis and therefore, Toronto Hydro cannot provide a breakdown by the specific programs or segments such as Customer connections. However, in order to provide a directional view of the segments that would have been dealt through the DRVA expenditure sub-account had one been in place for that period, Toronto Hydro has used its 2020 test[5] costs for Customer Connections, Key Accounts and Flexibility Services and have escalated it by the OEB approved Custom Price Cap Index ("CPCI") formula[6] for 2021-2024 using OEB's prescribed rates.

Table 4: Approved* Operating Expenditures that would have been subject to the DRVA sub-account (in $ millions)

OM&A Segments	**Approved***				
	2020	**2021**	**2022**	**2023**	**2024**
Customer Connections	3.2	3.3	3.3	3.4	3.6
Key Accounts	-	-	-	-	-
Flexibility Services	0.8	0.8	0.8	0.9	1.0

[3] 94% of the Renewable Enabling portions of these investments will be provincially funded and not included in the DRVA
[4] See also 1B-SEC-8 for a discussion of adjustments for Account 4380 with respect to the OEB-approved 2020 OM&A budget.
[5] EB-2018-0165, Exhibit 4A, Tab 2, Schedule 8
[6] EB-2018-0165, Ontario Energy Board, Decision and Order (December 19, 2019)

Please see Table 5 below for Approved and Actual/Bridge Revenue Requirement that would have been dealt with through the DRVA expenditure sub-account had one been in place for that period.

Table 5: Approved and Actual/Bridge Revenue Requirement that would have been subject to DRVA sub-account ($ Millions) /C

	2020	2021	2022	2023	2024	2020-2024
Approved Revenue Requirement	7.9	14.7	21.2	33.1	45.1	122.1
Actual/Bridge Revenue Requirement	7.1	17.4	51.4	69.4	68.1	213.4
Variance	**(0.8)**	**2.7**	**30.1**	**36.3**	**23.0**	**91.4**

QUESTION (B):

b) For each year 2025-2029 please provide the proposed revenue requirement for each of the programs listed in a). In effect, what is the proposed revenue requirement that will be the subject of the DRVA Expenditure Variance sub-account?

RESPONSE (B):

Please see below table 6 for proposed revenue requirement for each of the programs: /C

Table 6: 2025-2029 Revenue Requirement associated with DRVA Programs (in $ millions)[7] /C

	2025	2026	2027	2028	2029
Customer Connections	9.7	16.4	23.8	33.0	40.8
Stations Expansion	0.3	2.2	3.6	4.1	4.3
Load Demand	2.5	5.2	8.4	12.0	15.2
Non-Wires Solutions	0.2	0.9	1.1	1.6	1.9
Generation Protection Monitoring & Control	0.0	0.0	0.1	0.1	0.2
Externally Initiated Plant Relocations & Expansions	4.6	5.3	6.5	7.9	9.0
Customer Operations	4.7	4.8	5.2	5.4	5.7
Total Revenue Requirement	**22.0**	**34.8**	**48.5**	**64.1**	**77.1**

[7] Rounding variances may exist

QUESTION (C):

c) For the period 2020-2024 please provide the forecast and actual revenue that would have been dealt with through the DRVA Variance sub-account had one been in place for that period

RESPONSE (C):

Please refer to 1B-SEC-16 -Table 2.

QUESTION (D):

d) For each year 2025-2029 please provide the forecast revenue that will be the subject of the DRVA Revenue Variance sub-account.

RESPONSE (D):

Please refer to 1B-SEC-16-Table 1.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 1B-SEC-23

Reference: Exhibit 1B, Tab 3, Schedule 2

With respect to Toronto Hydro's scorecard:

QUESTION (A) AND (B):

a) [p.22] Please update Table 3 Custom Measure Performance to include 2023 results, as well as include the measure targets as set out in EB-2018-0165.

b) For each of the measures on Toronto Hydro's OEB scorecard, please provide the 2023 results.

RESPONSE (A):

Below is an updated table for Toronto Hydro's 2020-2024 Custom Measures which includes 2023 results as well as the targets set out in EB-2018-0165.[1]

2020-2023 Toronto Hydro Custom Measure Performance Results and Targets[2]

Toronto Hydro Outcome	OEB Reporting Category	Toronto Hydro's Custom Measures	2020 Results	2021 Results	2022 Results	2023 Results	Target
Customer Service	Customer Satisfaction	Customers on eBills	317,341	350,993	381,490	405,505	Improve
Safety	Safety	Total Recordable Injury Frequency	0.58	0.56	0.47	0.30	Maintain
		Network Units Modernization	61%	63%	65%	68%	Improve
Reliability	System Reliability	SAIDI - Defective Equipment	0.36	0.36	0.34	0.25	Maintain
		SAIFI - Defective Equipment	0.40	0.46	0.46	0.33	Maintain

/C

[1] EB-2018-0165, Decision and Order (December 1, 2019) at page 49.
[2] Updated Table 3 from Exhibit 1B, Tab 3, Schedule 2 at page 22.

Toronto Hydro Outcome	OEB Reporting Category	Toronto Hydro's Custom Measures	2020 Results	2021 Results	2022 Results	2023 Results	Target
		FESI-7 System (# of feeders)	9	10	27	27[3]	Improve
		FESI-6 Large Customers (# of feeders)	10	5	12	21	Maintain
		MAIFI	3.18	3.39	3.36	3.34	Monitor
	Asset Management	System Capacity (# of Stations)	11	11	12	12	Maintain
	Asset Management	System Health (Asset Condition) – Wood Poles[4]	11%	14%	9%	8%	Monitor
	Asset Management	Direct Buried Cable Replacement	729 km	697 km	679 km[5]	653 km	Improve
	Asset Management	In-Service Additions (Cumulative)	17%	35%	56%	78%	Monitor
Financial	Cost Control	Average Wood Pole Replacement Cost	$7,779	$7,847	$7,973	8,179	Improve
Financial	Cost Control	Vegetation Management Cost per Km	$2,158	$2,213	$2,175	2,355	Improve
Environment	Environment	Oil Spills Containing PCBs (# of spills)	0	0	1	1	Improve
Environment	Environment	Waste Diversion Rate	90.3%	91.5%	92.4%	91.4%	Monitor

/C

RESPONSE (B):

Below Toronto Hydro provides updated results including 2023 actuals for: (1) the OEB Scorecard and (2) the Electricity Service Quality Requirements (ESQR). Please note that for some measures the 2023 actuals are not available (n/a) until the end of Q2.

[3] As described in Exhibit 1B, Tab 3, Schedule 2, the increase in reported outages is attributed to the implementation of the OUA system, which tracks outages at a more granular level (i.e. previously not visible due to their size and location). The increased number of interruptions are outages with less than 100 Customers Interrupted, with the number of interruptions impacting more than 100 customers is consistent with prior years.

[4] As explained in Section 2.10 of this Schedule and Exhibit 2B, Section D3, Appendix A, Toronto Hydro refined its asset condition assessment methodology for wood poles. With this approach, the System Health (Asset Condition) for Wood Poles decreases to 6% in 2020 and decreases to 8% in 2021.

[5] In preparing this evidence, Toronto Hydro identified a data error in the number of km of direct buried cable remaining on the system reported for 2022 actuals. As of the end of 2022, Toronto Hydro has 666 kilometers of cable remaining rather than 679 kilometers. Please refer to Section 2.11 of this Schedule.

1 **Toronto Hydro Electricity Distributor Scorecard (EDS) 2023 Results and 2019-2023 Average**

Performance Measures		2023 Results	2019-2023 (5-yr avg)
New Residential/Small Business Services Connected on Time		99.91%	99.83%
Scheduled Appointments Met on Time		99.90%	99.73%
Telephone Calls Answered on Time		77.80%	75.68%
First Contact Resolution		92%	91.4%
Billing Accuracy		99.20%	99.14%
Customer Satisfaction Survey Results		94%	94%
Level of Public Awareness		64%	68%
Compliance with O. Reg 22/04		n/a	C
Serious Electrical Incidents	Number of General Public Incidents	n/a	n/a
	Rate per 10, 100, 1000 km of line	n/a	0.71
SAIDI		0.79	0.84
SAIFI		1.24	1.32
DSP Implementation		n/a	*n/a*
Efficiency Assessment		n/a	5
Total Cost per Customer		n/a	n/a
Total Cost per km of Line		n/a	n/a
New Micro-embedded Generation Facilities Connected on Time		98.40%	96.39%
Liquidity: Current Ratio		1.07	0.87
Leverage: Total Debt to Equity Ratio		1.19	1.17
Profitability: Regulatory ROE	Deemed	8.52%	8.68%
	Achieved	6.80%	7.13%

/C

1 **2018-2022 ESQR Performance Results (i.e. Updated Table 2 from Exhibit 1B, Tab 3, Schedule 2)**

ESQR	OEB Standard	2018	2019	2020	2021	2022	2023	2018-22 (5-yr avg)	2019-23 (5-yr avg)
Connection of New Services – Low Voltage ("LV") (EDS)	90	99.8	99.7	99.7	99.9	99.9	99.9	99.8	99.8
Connection of New Service – High Voltage ("HV")	90	100	99.3	99.7	99.3	99.2	100%	99.5	99.5
Connection of Micro-Embedded Generation Facilities (EDS)	90	100	100	100	92.3	91.3	98.4	96.7	96.4
Appointment Scheduling	90	81.6	91.8	94.1	90.7	81.2	95.3	87.9	91.4
Scheduled Appointments Met on Time (EDS)	90	99.7	99.0	99.9	99.9	99.9	99.9	99.7	99.7
Rescheduling a Missed Appointment	100	100	100	100	100	100	100	100	100
Telephone Accessibility (EDS)	65	80.2	74.8	69.9	76.9	79.1	77.8	76.2	75.7
Telephone Call Abandon Rate	10	1.4	3.5	2.7	1.1	1.1	0.7	1.96	1.8
Written Response to Enquires	80	98.4	99.4	96.3	98.3	99.7	99.8	98.4	98.5
Billing Accuracy (EDS)	98	99.3	99.2	99.2	99.0	99.1	99.2	99.2	99.1
Emergency Response (Urban)	80	86.6	92.4	88.3	88.5	86.5	88.5	88.5	88.8
Reconnection Performance Standard	85	97.7	99.9	99.5	NA	99.5	98	99.7	99.2

/C

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 2A-STAFF-107

Reference: Exhibit 2A, Tab 3, Schedule 1, Page.1

Question(s):

a) Please file the Lead-Lag study done by Guidehouse based on 2023 actuals. If the study is not yet completed, please advise when it will be.

RESPONSE:

Please see Appendix A to this response. /C

Guidehouse

Working Capital Requirements of Toronto Hydro-Electric System Limited

2025-2029

Prepared for:

TORONTO HYDRO

Toronto Hydro-Electric System Limited

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Executive Summary

Guidehouse was retained by Toronto Hydro-Electric System Limited ("THESL") to calculate the working capital requirements of THESL using a lead-lag study.

Working capital is the amount of funds that are required to finance the day-to-day operations, and which are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for the determination of working capital and was used by Guidehouse for this purpose. The results of this study are provided in this report.

This report is an update to Guidehouse's original report dated June 9, 2023. This study and accompanying report are based on THESL's more recent revenue and expense data from 2023. See section 5 of this report for analysis of how the results of this updated study compares to the original study.

The updated working capital requirement of THESL's distribution business is shown below.

Table 1: THESL Summary of Working Capital Requirement

	Test Year 2023
Percentage of OM&A and Cost of Power	7.08%
Working Capital Requirement ($M)	$200.97

The working capital requirements shown in Table 1 above are based upon the revenue lag and expense lead days shown in Table 2.

Table 2: THESL Working Capital Requirements (2023)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days
Cost of Power	53.24	32.63	20.61
OM&A Expenses	53.24	36.74	16.50
PILS	53.24	-14.00	67.24
Interest Expense	53.24	22.92	30.32

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1. Introduction and Methodology

Guidehouse Inc. was retained by Toronto Hydro-Electric System Limited ("THESL") to calculate its working capital requirements. This report provides the results of the assessment and the resulting working capital requirements.

Working capital is the amount of funds that are required to finance the day-to-day operations, and which are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for the determination of working capital and was used by Guidehouse for this purpose.

A lead-lag study analyzes the time between the date customers receive service and the date that customers' payments are available to THESL (or "lag") together with the time between the date THESL receives goods and services from its vendors and the date that THESL pays for them (or "lead").

"Leads" and "Lags" are both measured in days and are dollar-weighted where appropriate. The dollar-weighted net lag (lag minus lead) days is then divided by 365 (or 366 for leap years) and then multiplied by the annual test year expenses to determine the amount of working capital required. The resulting amount of working capital is then included in THESL's rate base for the purpose of determining revenue requirement.

THESL provided revenue and expense data to support the lead-lag study for the 2021, 2022 and 2023 calendar years. Generally, for this updated report, Guidehouse utilized the revenue and expense data for the 2023 calendar year as it was the most recent source of data provided.

1.1 Key Concepts

The following section outlines the key concepts used throughout this report to assess the working capital requirements of THESL's business. This includes the mid-point method, statutory approach, revenue lag components, expense lead components and dollar weighting.

1.1.1 Mid-Point Method

When a service is provided to (or by) THESL over a period of time, the service is deemed to have been provided (or received) evenly over the period, unless specific information regarding the provision (or receipt) of that service indicates otherwise. If both the service end date ("Y") and the service start date ("X") are known, the mid-point of a service period can be calculated using Equation 1-1.

Equation 1-1

$$Mid - Point = \frac{(Y - X) + 1}{2}$$

When specific start and end dates are unknown, but it is known that a service is evenly distributed over the mid-point of a period, an alternative formula that is generally used is shown below. Equation 1-2 uses the number of days in a year ("A") and the number of periods in a year ("B"):

Equation 1-2

$$Mid - Point = \frac{A/B}{2}$$

1.1.2 Statutory Approach

In conjunction with the mid-point method, it is important to note that not all areas of this study may utilize dates on which actual payments were made to (or by) THESL. In some instances, the due dates for payments are established by statute or by regulation. In these instances, the due date established by statute has been used in lieu of when payments were made.

1.1.3 Revenue Lag Components

As used in this study, revenue lags are comprised of Retail Revenue, Independent Electricity System Operator ("IESO") Credits and Other Revenues. The lag associated with Retail Revenue consist of four components:

- Service Lag component (the average time from the provision of electricity to a customer until the meter is read)
- Billing Lag component (the average time from when the meter is read to when the bill is generated and provided to customers)
- Collections Lag component (the average time from when a bill is provided to the customer until the customer initiates payment to the utility
- Payment Processing Lag component (the average time from when the customer provides payment to the utility until when the payment is made liquid and available to the utility)

1.1.4 Expense Lead Components

As used in this study, expense leads are defined to consist of two components:

- Service Lead component (services are assumed to be provided to THESL evenly around the mid-point of the service period)
- Payment Lead component (the time period from the end of the service period to the time payment was made and when funds have left THESL's possession)

1.1.5 Dollar Weighting

Both leads and lags should be dollar-weighted where appropriate and where data is available to accurately reflect the flow of dollars. For example, suppose that a particular transaction has a lead time of 100 days and has a dollar value of $100. Further, suppose that another transaction has a lead time of 30 days with a dollar value of $1 million. A simple un-weighted average of the two transactions would give us a lead time of 65 days ([100+30]/2). However, when these two transactions are dollar weighted, the resulting lead time would be closer to 30 days which is more representative of how the dollars flow.

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1.2 Methodology

Performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated distribution business operates in terms of products and services sold to customers/purchased from vendors, and the policies and procedures that govern such transactions.
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of THESL's operations, interviews with personnel within THESL's Accounts Receivable, Customer Service, Wholesale Market Operations, Payroll, Treasury, and Tax Departments were conducted. Key questions that were addressed during the course of the interviews included:

1. What is being sold (or purchased)? If a service is being provided to (or by) THESL, over what time period was this service provided?
2. Who are the buyers (or sellers)?
3. What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment?
4. Are any changes to the terms for payment expected? Are these terms driven by industry or internally? What is the basis for any such changes?
5. Are there any new rules or regulations governing transactions relating to transmission operations that are expected to materialize over the time frame considered in this report?
6. How are payments made (or received)? Payment types have different payment lead times (i.e., internet payments have shorter deposit times than cheque deposit times).

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2. Revenue Lags

This section of the report provides the revenue lag days for THESL. A revenue lag represents the number of days from the date that is service is rendered by THESL until the date payments are received and funds are available to THESL.

THESL receives revenue from the following funding streams:

- **Retail Revenue:** a distribution utility providing service to its customers typically derives its revenues from bills paid for service by its customers.
- **IESO Credits:** THESL also receives revenue in the form of IESO reimbursement credits for Ontario Electricity Support Program ("OESP"), Ontario Electricity Rebate ("OER"), Renewable Energy Standard Offer Program ("RESOP"), Feed-in Tariff ("FIT"), and Micro Feed-in Tariff ("MFIT").
- **Other Revenue:** THESL staff indicated that it receives additional external revenue.

A summary of the revenue lags for THESL's distribution business is shown below.

Table 3: Summary of Retail Revenue Lag (2023)

Description	Amounts ($M)	Lag Days	Weighting (%)	Weighted Lag Days
Retail Revenue	$3,486.40	53.18	87.03%	46.28
IESO Credits	$354.07	63.22	8.84%	5.59
Other Revenue	$165.46	33.22	4.13%	1.37
Total	**$4,005.93**		**100.00%**	**53.24**

2.1 Retail Revenue Lag

Retail revenue lag consists of the following components:

- Service Lag
- Billing Lag
- Collections Lag
- Payment Processing Lag

Service Lag
The service lag is defined as the midpoint of the service period; the halfway point between the beginning of the service period and the end of the service period. The service period end is typically defined as the date the meter is read. All THESL customers are billed monthly. The Service Lag is calculated to be 15.21 days.

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Billing Lag
The billing lag is defined as the time period from period end (meter read) to the time that the customer's bill is generated in the customer information system. An analysis of THESL meter billing data indicated that THESL customers have an average billing lag of 12.35 days.

Collections Lag
The collections lag is defined as the time period from when the bill is generated in the customer information system to the time when the customer provides payment to THESL and when that payment is recorded in THESL's billing system. The collections lag is measured by analyzing the receivables aging data provided by THESL. THESL's collection lag was calculated to be 24.32 days, carried forward from the most recent study performed.[1]

Payment Processing Lag
The payment processing lag represents the average time from when the customer provides payment to the utility until when the payment is made liquid and available to the utility. THESL's payment processing lag was calculated to be 1.30 days.

2.2 IESO Credits

Table 4 below summarizes the amounts and revenue lag times associated with the components that make up IESO credits revenue.

Table 4: Summary of IESO Credits (2023)

Description	Amounts ($M)	Lag Days	Weighting (%)	Weighted Lag Days
OER	$272.28	63.19	76.90%	48.59
FIT	$55.93	63.38	15.80%	10.01
OESP	$21.62	63.18	6.11%	3.86
MFIT	$3.98	63.38	1.13%	0.71
RESOP	$0.26	62.94	0.07%	0.05
Total	**$354.07**		**100.00%**	**63.22**

2.3 Other External Revenue

THESL Distribution collects revenues from a variety of other sources, in addition to the retail revenue and IESO credits discussed above. THESL staff provided monthly data and payment

[1] Lead-lag studies use the most recent and accurate historical data available for calculating results. For this study revenue and expense data from 2023 was generally used. However, for purposes of calculation of collection lag days Guidehouse used the days calculated in the 2020 Addendum ("2020 Update") to the filed 2017 Lead Lag Study ("2017 Study"). Due to significant balances outstanding more than 120 days arising from the Covid-19 pandemic and resulting policy response by the Ontario Electric Board, calculating the collection lag days using receivables aging as of the end of 2023 would have inflated that calculation and the resulting Cash Working Capital percentage. It is Guidehouse' opinion that collection data from the 2020 Update is more reflective of normal business operations going forward over the period 2025 to 2029. This approach is unchanged from the original report dated June 9, 2023.

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information for the other external revenue. The table below summarizes revenue lag time associated this other external revenue.

Table 5: Summary of Other External Revenue (2023)

Description	Amounts ($M)	Lag Days	Weighting (%)	Weighted Lag Days
Other External Revenue	$165.46	33.22	100.00%	33.22
Total	**$165.46**		**100.00%**	**33.22**

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3. Expense Leads

The determination of working capital requires both a measurement of the lag in the collection of revenues for services provided by THESL, and the lead times associated with payments for services provided to THESL. Expense Leads are defined as the time period between when a service is provided to THESL and when payment is required for that service.

The following expense leads were calculated in this study:

- Cost of Power
- Operations, Maintenance and Administration (“OM&A”) expenses
- Payments in Lieu of Taxes (“PILs”)
- Interest on THESL’S debt
- Harmonized Sales Tax (“HST”)

3.1 Cost of Power

For the purpose of the lead-lag study, cost of power expenses were considered to consist of payments made by THESL to the following providers:

1. IESO cost of power expenses (includes the purchasing of power supply requirements on a monthly basis from the IESO on a schedule defined by the IESO’s billing and settlement procedures)
2. Hydro One Low Voltage Charges
3. Payments to Non-Utility Generators
4. Distributed Generation

Expense lead times were calculated individually for each of the items listed above and dollar-weighted to derive the expense lead time of 32.63 days, as seen in Table 6 below.

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Table 6: Cost of Power Expenses* (2023)

Delivery Month	Amounts ($M)	Lead Days	Weighting (%)	Weighted Lead Days
Jan-23	$199.10	31.50	8.32%	2.62
Feb-23	$200.81	30.00	8.39%	2.52
Mar-23	$220.82	35.50	9.23%	3.28
Apr-23	$167.40	31.00	7.00%	2.17
May-23	$192.38	31.50	8.04%	2.53
Jun-23	$206.35	34.00	8.62%	2.93
Jul-23	$223.52	32.50	9.34%	3.04
Aug-23	$230.28	34.50	9.62%	3.32
Sep-23	$158.25	34.00	6.61%	2.25
Oct-23	$215.68	32.50	9.01%	2.93
Nov-23	$175.81	33.00	7.35%	2.42
Dec-23	$202.37	32.50	8.46%	2.75
Total	**$2,392.76**		100.00%	**32.76**

This table does not include Distributed Generation charges of $60.18, Hydro One Low Voltage Charges of $.42 and payments to Non-Utility Generators of $.27. These lower the weighted-average cost of power slightly to 32.63.

3.2 Operations, Maintenance and Administration ("OM&A")

The following expenses are included in the calculation of lead days for OM&A expenses:

- **Payroll and Benefits**: this line item includes basic payroll, payroll withholdings, and benefit expenses related to the regulated utility. THESL staff provided the breakdown of payroll, payroll withholding and benefits expenses.

- **Consulting and Contracting Services:** this line item includes the provision of outside services to THESL.

- **Miscellaneous OM&A:** this line item includes miscellaneous OM&A expenses non-related to the procurement of Outside Services.

- **Property Tax:** this line item includes property tax payments to municipalities or taxing authorities in the Province of Ontario. These payments are typically made in installments.

- **Corporate Procurement Card**: this line item includes credit card expenses related to OM&A.

- **Lease Payments:** this line item includes payments made on the properties THESL uses for their operations.

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Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 36.74 days for OM&A expenses.

Table 7: Summary of OM&A Expenses (2023)

Description	Amounts ($M)	Lead Days	Weighting (%)	Weighted Lead Days
Payroll & Benefits	$223.40	32.55	58.15%	18.93
Consulting and Contract Staff	$111.68	43.88	29.07%	12.76
Miscellaneous OM&A	$43.28	47.70	11.26%	5.37
Property Tax	$5.13	-27.41	1.34%	-0.37
Corporate Procurement Card	$0.55	32.17	0.14%	0.05
Lease Payments	$0.15	2.39	0.04%	0.00
Total	**$384.19**		**100.00%**	**36.74**
Total Excluding Payroll & Benefits	$160.79			
Percent OM&A that attracts HST	**41.85%**			

3.2.1 Payroll and Benefits

In addition to basic and management payroll the following benefits were considered as expenses THESL's business:

1. Three types of payroll withholdings including the Canada Pension Plan, Employment Insurance, and Income Tax withholdings
2. Contributions made to the THESL Pension Plan
3. Payments made to the Worker Safety Improvement Board ("WSIB")
4. Payments made for the Employer Health Tax ("EHT")
5. Group Health, Dental, and Life Insurance related administrative fees and claims

When all payroll, withholdings and benefits were dollar-weighted using actual payment data, the weighted average expense lead time associated with payroll and benefits was determined to be 32.55 days as shown in the table below.

Table 8: Summary of Payroll & Benefits Expenses (2023)

Description	Amounts ($M)	Lead Days	Weighting (%)	Weighted Lead Days
Payroll	$108.84	23.67	48.72%	11.53
Payroll Withholdings	$53.75	45.65	24.06%	10.98
Pensions	$35.67	56.31	15.97%	8.99
Benefits	$20.81	7.78	9.31%	0.72
Other Benefits	$4.33	16.53	1.94%	0.32
Total	**$223.40**		**100.00%**	**32.55**

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3.2.2 Consulting and Contract Staff

THESL engages consulting and contract staff to provide assistance in the areas of engineering, environmental services, receivables management, accounting, and general consulting. A dollar-weighted expense lead time of 43.88 days was determined based on a review of invoices rendered and payments made by THESL in 2023.

3.2.3 Miscellaneous OM&A

This category of expense includes items such as product purchases, equipment rentals, and provision of general services to THESL. Based on transactions in THESL's accounts payable system under this category, a dollar-weighted expense lead time of 47.70 days was derived.

3.2.4 Property Taxes

THESL makes property tax payments to the City of Toronto in installments. Using actual payment dates and amounts associated with THESL's distribution business for calendar year 2023, a dollar-weighted expense lead (lag) time of (27.41) days was determined.

3.2.5 Corporate Procurement Card

Procurement (or charge) cards are used by THESL's employees primarily for purchases of vehicle fuel. Based on actual invoices from THESL's charge card provider and payments made by THESL, a dollar-weighted expense lead time of 32.17 days was determined.

3.2.6 Lease Payments

THESL leases office space to support its ongoing operations. Using actual invoices and payments for 2023, a dollar-weighted expense lead time of 2.39 days was determined.

3.3 Payments in Lieu of Taxes ("PILs")

THESL makes payments in lieu of taxes in installments to the relevant taxing authorities. Table 7 below summarizes the components of the PILS expense lead calculation.

Table 9: Summary of Payments in Lieu of Taxes Expenses (Average 2019-2023)[2]

Description	Amounts ($M)	Lead Days	Weighting (%)	Weighted Lead Days
PILS	$11.36	(14.00)	100.00%	(14.00)
Total	**$11.36**		**100.00%**	**(14.00)**

[2] Guidehouse used an average as 2023 did not represent normal PILs activity. The approach of using an average is unchanged from the original report dated June 9, 2023.

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3.4 Interest on Debt

THESL makes interest payments on its long and short-term debt. Such payments are generally made twice a year. Considering the various bonds and other long-term debt instruments, a dollar-weighted expense lead time of 22.92 days was determined for the 2023 calendar year.

Table 10: Interest Expense (2023)

Description	Amounts ($M)	Lead Days	Weighting (%)	Weighted Lead Days
Interest Expense	$128.00	22.92	100.00%	22.92
Total	**$128.00**		**100.00%**	**22.92**

3.5 Harmonized Sales Tax

The expense lead times associated with the following items that attract HST were considered in THESL's distribution lead-lag study.

1. Revenues
2. Cost of Power
3. OM&A

A summary of the expense lead times and working capital amounts associated with each of the above items is provided in the table below. Note that the statutory approach described at the outset was used to determine the expense lead times associated with THESL's remittances and disbursements of HST (*i.e.,* both remittances and collections are generally on the last day of the month following the date of the applicable invoice).

Table 11: Summary of HST Working Capital Amounts

Description	HST Lead Time	Working Capital Factor	Amounts Eligible	HST Amount	Test Year ($M)
Revenues	-6.96	-1.91%	$3,651.85	$474.74	-$9.05
Cost of Power	44.49	12.19%	$2,453.63	$318.97	$38.88
OM&A Expenses[3]	42.85	11.74%	$160.79	$20.90	$2.45
Total					**$32.28**

[3] Costs within OM&A that attract HST include Corporate Procurement Card, Lease Payments, Consulting and Contract Staff and Miscellaneous OM&A. These represent 41.57% of OM&A Expenses included in the study. See Table 7 for a breakdown.

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4. Working Capital Requirements

The table below summarizes THESL's working capital requirements for the test year.

Table 12: THESL Working Capital Requirements (Test Year 2023)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	53.24	32.63	20.61	5.65%	$2,453.63	$138.60
OM&A Expenses	53.24	36.74	16.50	4.52%	$384.19	$17.37
PILS	53.24	-14.00	67.24	18.42%	$11.36	$2.09
Interest Expense	53.24	22.92	30.32	8.31%	$128.00	$10.63
Total					**$2,977.18**	**$168.69**
HST						$32.28
Total - Including HST						**$200.97**
Working Capital as a Percentage of OM&A incl. Cost of Power						**7.08%**

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5. Findings and Conclusions

The purpose of this section is to compare the results from this study to THESL's original working capital study as completed by Guidehouse and dated June 9, 2023.

5.1 Comparison with Original Study

Table 13: THESL Working Capital Requirements (Test Year 2022)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	53.15	32.72	20.43	5.60%	$2,461.42	$137.80
OM&A Expenses	53.15	36.84	16.31	4.47%	$358.48	$16.02
PILS	53.15	7.88	45.27	12.40%	$13.39	$1.66
Interest Expense	53.15	12.45	40.70	11.15%	$91.13	$10.16
Total					**$2,924.42**	**$165.64**
HST						$32.23
Total - Including HST						**$197.87**
Working Capital as a Percentage of OM&A incl. Cost of Power						**7.02%**

Table 14: THESL Working Capital Requirements (Test Year 2023)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	53.24	32.63	20.61	5.65%	$2,453.63	$138.60
OM&A Expenses	53.24	36.74	16.50	4.52%	$384.19	$17.37
PILS	53.24	-14.00	67.24	18.42%	$11.36	$2.09
Interest Expense	53.24	22.92	30.32	8.31%	$128.00	$10.63
Total					**$2,977.18**	**$168.69**
HST						$32.28
Total - Including HST						**$200.97**
Working Capital as a Percentage of OM&A incl. Cost of Power						**7.08%**

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Table 15: THESL Working Capital Requirements (Updated versus Original)

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital ($M)
Cost of Power	.09	-.09	0.18	0.05%	- $7.79	$0.80
OM&A Expenses	.09	-.10	0.19	0.05%	$25.71	$1.35
PILS	.09	-21.88	21.97	6.02%	- $2.03	$0.43
Interest Expense	.09	10.47	-10.38	-2.84%	$36.87	$0.47
Total					**$52.76**	**$3.05**
HST						$0.05
Total - Including HST						**$3.10**
Working Capital as a Percentage of OM&A incl. Cost of Power						**0.06%**

Overall, the difference between the original study and the updated one using data through 2023 is an increase of 0.06%.

The principal driver of this minor increase is a slight increase in revenue lag days in the update (53.24 vs 53.15). Revenue lag has a large impact on the overall result of working capital studies, as it is considered in the working capital factor for all expense items. Minor variations in revenue lag can have large impacts on directional results. The other principal driver is a minor decrease in lead days associated with the cost of power (32.63 vs 32.72). COP payments were paid approximately 0.10 days earlier in 2023 vs 2022.

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RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES

INTERROGATORY 7-SEC-122

Reference: Exhibit 7, Tab 1, Schedule 1, Table 4

QUESTION:

For each of the scenarios presented in Table 4, B, C & D, please provide details of how Toronto Hydro would propose to rebalance revenues to return the Revenue to Cost ratios to the OEB's ranges and the resulting distribution bill impacts.

RESPONSE:

As stated at the same reference, Toronto Hydro "sees merit to a collaborative approach which takes into account the views, preferences, and expertise of all the parties whose interests are affected by cost allocation matters."

To the degree Toronto Hydro were to rebalance CSMUR Revenue to Cost (R/C) ratios to return to OEB range, Toronto Hydro would propose the same approach across each of the B, C and D scenarios shown; gradually phase in a reduction of CSMUR R/C ratios over a five-year period. As a result, the reduction of revenue from the CSMUR rate class would be recovered from other rate classes, with a nil net impact on overall revenues.

To complete this task, Toronto Hydro would implement the following:

1) Complete the 2025 Cost Allocation Model for both Status Quo cost allocation, as included in its pre-filed application, and Alternative cost allocation. The result would be two sets of allocated total costs to each rate class, which would allow for the calculation of a Cost

Allocation Difference (CAD) for each rate class,[1] which quantifies in dollars the difference between Status Quo and Alternative cost allocation, by rate class;

2) For 2025 rates, first complete rate design on the basis of Status Quo cost allocation to bring R/C ratios into balance with accepted ranges on a Status Quo basis. Second, add 1/5 of the CAD applicable to each rate class to the Status Quo costs assigned to each rate class;
3) For 2026 rates, first calculate the 2026 revenue requirement in accordance with the CRCI (no different than would be the case absent a phased-in change to cost allocation). Second, assign the 2026 revenue requirement to rate classes on the basis of Status Quo cost allocation proportions. Third, add 2/5 of the CAD applicable to each rate class to the assigned 2026 revenue requirement based on Status Quo cost allocation;
4) For 2027 through 2029 rates, repeat approach to 2026 rates, with the exception that CAD additions to assigned costs will be 3/5 in 2027, 4/5 in 2028, and 5/5 in 2029.

The bill impacts associated with implementation of the Alternative Cost Allocation will vary year over year by rate class based on a series of methodological decisions required, namely:

- Whether Alternative Cost Allocation is implemented in one year (i.e. 2025) as opposed to over a longer period of time (e.g. 2025 to 2029, as described above); and,
- Whether the targeted R/C Ratios for Residential and CSMUR rate classes remain at 100%, or transition towards an OEB range. Lacking an OEB-determined range, a range must be selected for the CSMUR rate class (e.g. aligned with Residential as 85-115% or the 80-120% range applied to most rate classes).

For the purpose of providing bill impacts while illustrating the results associated with the above-noted methodological options, Toronto Hydro has prepared distribution bill impacts in Appendix A to this response, based on the following scenarios: /C

[1] CAD applicable only to distribution rate portion of assigned costs, exclusive of Revenue Offsets

- **Original:** Continuation of Status-quo Cost Allocation methodology as provided in pre-filed evidence.[2] There are no adjustments made to align all rate classes to building-count as opposed to customer (i.e. meter) count, and no additional adjustments to line transformer and secondary system customer counts are made.

- **Scenario 1:** Toronto Hydro moves to the Alternative Cost Allocation methodology effective in 2025. The target R/C Ratios for the Residential and CSMUR rate classes remain at 100%.

- **Scenario 2:** Toronto Hydro moves to the Alternative Cost Allocation methodology over a 5-year period from 2025 to 2029, in the manner described in the interrogatory response above. The target R/C Ratios for the Residential and CSMUR rate classes remain at 100%. /C

- **Scenario 3:** Toronto Hydro moves to the Alternative Cost Allocation methodology effective in 2025. The target R/C Ratios for the Residential and CSMUR rate classes move to a range of 85-115%.

- **Scenario 4:** Toronto Hydro moves to the Alternative Cost Allocation methodology over a 5-year period from 2025 to 2029, in the manner described in the interrogatory response above. The target R/C Ratios for the Residential and CSMUR rate classes move to a range of 85-115%.

[2] Exhibit 8, Tab 1, Schedule 1, Table 5.

Scenario 1	CSMUR class is adjusted in 2025 with maintaining R/C ratio at 1
Scenario 2	CSMUR class is adjusted in 5 years phase-in with maintaining R/C ratio at 1
Scenario 3	CSMUR class is adjusted in 2025 without maintaining R/C ratio at 1 for Residential and CSMUR
Scenario 4	CSMUR class is adjusted in 5 years phase-in without keeping R/C ration at 1

Sub Total A		$/30 days						Year-over-Year change				
Rate Classes	**Change in Bill**	**2024**	**2025 Proposed**	**2026 Proposed**	**2027 Proposed**	**2028 Proposed**	**2029 Proposed**	**2025 Proposed**	**2026 Proposed**	**2027 Proposed**	**2028 Proposed**	**2029 Proposed**
Residential	**Original**	$42.69	$45.93	$49.33	$53.05	$57.02	$59.88	7.6%	7.4%	7.5%	7.5%	5.0%
	Scenario 1	$42.69	$49.34	$52.90	$56.76	$61.03	$64.02	15.6%	7.2%	7.3%	7.5%	4.9%
	Scenario 2	$42.69	$46.61	$50.69	$55.09	$59.73	$63.28	9.2%	8.8%	8.7%	8.4%	5.9%
	Scenario 3	$42.69	$48.32	$51.83	$55.65	$59.83	$62.78	13.2%	7.3%	7.4%	7.5%	4.9%
	Scenario 4	$42.69	$47.71	$51.84	$56.29	$61.03	$64.61	11.8%	8.7%	8.6%	8.4%	5.9%
Competitive Sector Multi-Unit Residential	**Original**	$35.49	$34.22	$36.06	$38.24	$40.51	$42.15	-3.6%	5.4%	6.0%	5.9%	4.0%
	Scenario 1	$35.49	$20.57	$22.03	$23.91	$25.22	$26.56	-42.0%	7.1%	8.5%	5.5%	5.3%
	Scenario 2	$35.49	$31.49	$30.71	$30.35	$30.18	$29.36	-11.3%	-2.5%	-1.2%	-0.6%	-2.7%
	Scenario 3	$35.49	$24.26	$25.82	$27.79	$29.35	$30.77	-31.6%	6.4%	7.6%	5.6%	4.8%
	Scenario 4	$35.49	$36.02	$35.37	$35.10	$35.25	$34.53	1.5%	-1.8%	-0.8%	0.4%	-2.0%
General Service <50 kW	**Original**	$118.49	$132.67	$141.91	$151.52	$162.19	$169.48	12.0%	7.0%	6.8%	7.0%	4.5%
	Scenario 1	$118.49	$130.00	$139.10	$148.62	$159.07	$166.27	9.7%	7.0%	6.8%	7.0%	4.5%
	Scenario 2	$118.49	$130.70	$137.99	$145.64	$154.42	$159.80	10.3%	5.6%	5.5%	6.0%	3.5%
	Scenario 3	$118.49	$130.00	$139.10	$148.62	$159.07	$166.27	9.7%	7.0%	6.8%	7.0%	4.5%
	Scenario 4	$118.49	$128.03	$135.19	$142.76	$151.33	$156.61	8.1%	5.6%	5.6%	6.0%	3.5%
General Service 50-999 kW	**Original**	$1,808.34	$2,043.69	$2,210.11	$2,385.12	$2,577.79	$2,728.24	13.0%	8.1%	7.9%	8.1%	5.8%
	Scenario 1	$1,808.34	$2,012.26	$2,176.96	$2,350.49	$2,540.13	$2,689.09	11.3%	8.2%	8.0%	8.1%	5.9%
	Scenario 2	$1,808.34	$2,043.40	$2,209.55	$2,384.30	$2,576.66	$2,726.84	13.0%	8.1%	7.9%	8.1%	5.8%
	Scenario 3	$1,808.34	$2,031.26	$2,197.00	$2,371.44	$2,562.89	$2,712.77	12.3%	8.2%	7.9%	8.1%	5.8%
	Scenario 4	$1,808.34	$1,986.44	$2,149.43	$2,321.49	$2,508.41	$2,655.83	9.8%	8.2%	8.0%	8.1%	5.9%
General Service 1,000-4,999 kW	**Original**	$14,918.74	$16,912.20	$18,378.81	$19,895.46	$21,495.11	$22,876.41	13.4%	8.7%	8.3%	8.0%	6.4%
	Scenario 1	$14,918.74	$16,448.67	$17,885.65	$19,376.55	$20,929.66	$22,283.19	10.3%	8.7%	8.3%	8.0%	6.5%
	Scenario 2	$14,918.74	$16,859.11	$18,271.10	$19,731.85	$21,276.33	$22,597.88	13.0%	8.4%	8.0%	7.8%	6.2%
	Scenario 3	$14,918.74	$16,621.63	$18,069.72	$19,570.28	$21,140.72	$22,504.64	11.4%	8.7%	8.3%	8.0%	6.5%
	Scenario 4	$14,918.74	$16,163.81	$17,531.15	$18,953.09	$20,428.06	$21,707.85	8.3%	8.5%	8.1%	7.8%	6.3%
Large Use	**Original**	$76,993.60	$87,118.04	$92,992.74	$101,557.00	$111,087.78	$118,648.49	13.1%	6.7%	9.2%	9.4%	6.8%
	Scenario 1	$76,993.60	$85,636.40	$91,442.62	$99,905.95	$109,264.07	$116,723.98	11.2%	6.8%	9.3%	9.4%	6.8%
	Scenario 2	$76,993.60	$86,780.65	$92,320.44	$100,522.52	$109,685.88	$116,851.47	12.7%	6.4%	8.9%	9.1%	6.5%
	Scenario 3	$76,993.60	$85,823.19	$91,637.51	$100,114.39	$109,493.99	$116,966.27	11.5%	6.8%	9.3%	9.4%	6.8%
	Scenario 4	$76,993.60	$85,053.52	$90,512.18	$98,597.76	$107,558.31	$114,607.81	10.5%	6.4%	8.9%	9.1%	6.6%
Street Lighting	**Original**	$145,013.30	$160,930.60	$173,207.70	$193,898.80	$206,034.40	$221,260.40	11.0%	7.6%	11.9%	6.3%	7.4%
	Scenario 1	$145,013.30	$160,930.60	$173,207.70	$193,898.80	$206,034.40	$221,260.40	11.0%	7.6%	11.9%	6.3%	7.4%
	Scenario 2	$145,013.30	$164,846.30	$180,972.30	$205,791.50	$222,134.70	$241,588.80	13.7%	9.8%	13.7%	7.9%	8.8%
	Scenario 3	$145,013.30	$160,930.60	$173,207.70	$193,898.80	$206,034.40	$221,260.40	11.0%	7.6%	11.9%	6.3%	7.4%
	Scenario 4	$145,013.30	$164,846.30	$180,972.30	$205,791.50	$222,134.70	$241,588.80	13.7%	9.8%	13.7%	7.9%	8.8%
Unmetered Scattered Load	**Original**	$31.21	$34.17	$36.58	$39.07	$42.18	$44.20	9.5%	7.1%	6.8%	8.0%	4.8%
	Scenario 1	$31.21	$35.92	$38.42	$40.97	$44.24	$46.33	15.1%	6.9%	6.6%	8.0%	4.7%
	Scenario 2	$31.21	$36.30	$39.81	$43.91	$48.62	$52.26	16.3%	9.7%	10.3%	10.7%	7.5%
	Scenario 3	$31.21	$36.81	$39.35	$41.94	$45.29	$47.40	17.9%	6.9%	6.6%	8.0%	4.7%
	Scenario 4	$31.21	$36.30	$39.81	$43.91	$48.62	$52.26	16.3%	9.7%	10.3%	10.7%	7.5%