Interrogatory Responses



PUC Distribution Inc • EB-2022-0059 • Filed: Novmber 28, 2022

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Ontario Energy Board (OEB) Staff Interrogatories

Exhibit 1 - Administrative

Staff 1

Reference: Updated Revenue Requirement Workform (RRWF) and Models

Question:

Upon completing all interrogatories from Ontario Energy Board (OEB) staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that the Applicant wishes to make to the amounts in the populated version of the RRWF filed in the initial applications. Entries for changes and adjustments should be included in the middle column on Sheet 3 (Data_Input_Sheet). Sheets 10 (Load Forecast), 11 (Cost Allocation), and 13 (Rate Design) should be updated, as necessary. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note. Such notes should be documented on Sheet 14 (Tracking Sheet) and may also be included on other sheets in the RRWF to assist in understanding the changes.

In addition, please file an updated set of models, as applicable, that reflects the interrogatory responses, including an updated Tariff Schedule and Bill Impact model for all classes at the typical consumption/demand levels (e.g., 750 kWh for residential, 2,000 kWh for GS<50, etc.).

Response:

The following models have been updated and are filed with interrogatory responses:

- PUC_2023_Rev_Reqt_Workform_1.0_20221128
- PUC_2023_Filing_Requirements_Chapter2_Appendices_20221128
- PUC_2023_Cost_Allocation_Model_20221128
- PUC_2023_DVA_Continuity_Schedule_20221128
- PUC_2023_GA_Analysis_Workform_20221128
- PUC_2023_LRAMVA_Workform_20221128
- PUC_2023_Tariff_Schedule_and_Bill_Impact_Model_20221128
- PUC_2023_Test_year_Income_Tax_PILs_20221128
- PUC_2023_RTSR_Workform_1.0_20221128
- PUC_2023_Load Forecast – With Regression Analysis_20221128

The following table outlines the list of major updates that were completed to the models as a result of the responses to these IR's.

Table 1: Summary of Cost of Service Model Updates

IR Response	Description of Update	Change in Revenue Requirement	Change in Final Rates	Models Updated
OEB Staff 21d	October 21, 2022 RPP Price Update	yes	yes	Chapter 2 Appendices 2-ZB, Cost Allocation, RRWF, Tariff and Bill Impact Model
OEB 22 VECC-17	Year to Date 2022 Actual Capital Expenditures to be updated in 2-AA and 2-AB and references added to reconcile to DSP Material Narratives	no	no	Chapter 2 Appendices 2-AA and 2-AB
OEB 54b VECC-22d	removing customer count variable from regression model due to insignificance	yes	yes	All Models
OEB 58b VECC-24	CDM adjustment update within the load forecase	yes	yes	All Models
OEB-60	Provide a version of Tab 2-JC of the Chapter 2 Appendices that includes an additional column which shows actual amounts for 2022 for as many months as possible, and another additional column that shows year-to-date actuals at the same point in 2021.	no	no	Chapter 2 Appendices , Tab 2-JC
OEB 64, VECC 10, SEC 24	Green Button Capital Costs now included in 2023 Test year Capital. No longer need use of account 1508 for Green Button Initiative	yes	yes	Chapter 2 Appendices, RRWF, Cost Allocation, Tariff and Bill Impact Model
OEB-72	Revised table 4-16 and 4-17	no	no	Chapter 2 Appendices , Tab 2-K
OEB-73	Revised table 4-17 OM&A and Capital	no	no	Chapter 2 Appendices , Tab 2-K
OEB 76	Sahred Services and Corporate Cost Allocation update. Clarified direction of costs, added property taxes and revised 2023 test year building charge based on updated COC parameters	yes	yes	Chapter 2 Appendices 2-N and 2-H
OEB-81b	Updated LRAMVA Workform to tie to DVA Continuity	no	yes	LRAMVA Workfrom
OEB-84, VECC 34, CCC 7, SEC 31	Update Cost of Capital Parameters	yes	yes	All Models
OEB 85	Update of Debt Rate used on PUC's intercompany loan to 4.88%	yes	yes	All Models
OEB-90a	revisison to CCA smoothing calculation for adjustment to accounting income in revenue requirement	yes	yes	RRWF, PILS Model, Cost Allocation, Tariff and Bill Impact Model
OEB-98a	SME charge update	yes	yes	All Models
OEB-100	RTSR workform	yes	yes	RTSR Workform, Chapter 2 Appendices 2-ZB, RRWF, Cost Allocation, and Tariff and Bill Impact Model
OEB-101	Update Retailer service charges and pole attachment rates	yes	yes	Chapter 2 Appendices 2-h, Cost Allocation, RRWF, Tariff and Bill Impacts Model
OEB-102	Update 1595 and 1588 account numbers	no	yes	DVA Continuity Schedule Tariff and Bill Impact Model
OEB-104b	Updated DVA 1508 Pole Attachment to include 2022 forecast amount	no	yes	DVA Continuity Schedule Tariff and Bill Impact Model
OEB-105	Update amounts forecasted	no	yes	DVA Continuity Schedule Tariff and Bill Impact Model
OEB-107	Update 1595 (2018) amount withdrawn	no	yes	DVA Continuity Schedule Tariff and Bill Impact Model
OEB-108	Updated GA Workform	no	yes	GA Workform DVA Continuity Schedule Tariff and Bill Impact Model
OEB-109	Updated GA Workform	no	yes	GA Workform DVA Continuity Schedule Tariff and Bill Impact Model
VECC-5	2023 SSG ICM amount added to 2023 ICM column on Chapter 2 Appendices 2-BA	no	no	Chapter 2 Appendices 2-BA
VECC-41c	update to meter reading weighting factors	no	yes	Cost allocation, RRWF, Tariff and Bill impact Model
VECC-54	revised claim for reconciliation of Substation 16 rate rider	no	yes	DVA Continuity Schedule Tariff and Bill Impact Model

Staff 2

Reference: Responses to Letters of Comment

Question:

Following publication of the Notice of Application, the OEB received 1 letter of comment. Section 2.1.5 of the Filing Requirements states that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters, they may be accessed from the public record for this proceeding.

Please file a response to the matters raised in the letter of comment referenced above. Going forward, please ensure that responses to any matters raised in subsequent comments or letter are filed in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

Response:

A Response has been provided to the letter of comment received from PUC's customer and is attached as Appendix IR 17 – Letter of Comment Reply.

The response has been delivered to OEB Staff since the contact information of the customer is redacted.

Staff 3

Customer Engagement
Reference 1: Exhibit 1, pg. 50-51
Reference 2: Exhibit 1, pg. 64

Question:

PUC Distribution states that the MyPUC App launched in July 2021, and as of August 2022, 3,360 customers are using the App. Further, when customers download and activate the MyPUC App, they are also enrolled in e-billing.

a) Are there ongoing incremental OM&A costs associated with the mobile app? If yes, what are the costs and in which OM&A program are these costs recorded?
b) Has PUC Distribution estimated the user uptake of the MyPUC App for the 2023 test year and beyond? If yes, please provide those estimates and explain how PUC Distribution developed its estimates.
c) Has PUC Distribution incorporated any anticipated OM&A savings related to fewer customers on paper billing as a result of downloading the MyPUC App? If yes, please provide the quantum and explain how the savings were calculated.

Reference 2 states that PUC Distribution's goal is to become a paperless operation by 2024.

d) Please confirm if PUC Distribution has built this target into its proposed OM&A costs. If not, please explain why.

Response:

a) Yes, there are ongoing incremental OM&A costs associated with the mobile App. The annual ongoing costs are estimated as $48k in Acct 5630.

b) PUC's target for 2022 is to increase MyPUC App downloads by 25%. This was a corporate target set by the Executive. PUC anticipates that it will meet this target by December 31st, 2022. Going forward, PUC estimates the user uptake will grow by approximately 5% of current enrollment on an annual basis. For 2023, PUC anticipates 970 new users, 4,664 total. This estimate is based on continued interest of customer to receive information on power outages, energy and consumption and billing information on a mobile solution.

c) Some users who sign up for the MyPUC App are already signed up for e-billing. Net new users who signed up for e-billing in 2022 is 170 to date. Yes, reductions were included in calculating the cost of mail outs (e.g., stamps, envelopes, printing costs), approximately $4k in savings.

d) Yes, PUC has built these targets into its proposed OM&A costs.

Staff 4

Facilitating Innovation
Reference 1: Exhibit 1, page 119
Reference 2: https://northernontario.ctvnews.ca/battery-storage-facility-in-the-sault-worth-300m-could-open-in-2025-1.6074708
Reference 3: https://www.timminspress.com/news/battery-energy-storage-project-sizzles-with-unanswered-questions

Question:

At reference 1, PUC Distribution states that it has:

> …partnered with Demand Power Group Inc. to help the Sault Area Hospital with a new innovative program that will save millions on energy costs. The Customer Energy Management (CEMa) program will help larger customers reduce their electricity bill by providing improved power reliability and quality while reducing energy through the use of a battery energy storage system. This will allow the customer to store electricity during off peak hours and use it during peak rate times.

a) Please confirm if the quote from the evidence above discusses the same project noted in the links in references 2 and 3.
b) If the battery energy storage system moves forward, please explain how PUC Distribution anticipates it would affect PUC Distribution's operations. For example, will there be any implications on PUC Distribution's load or revenues?
c) If applicable, has PUC Distribution determined how it intends to mitigate any risks to its operations?

Response:

a) The quote from the evidence above is not the same project as in references 2 and 3. For clarity, PUC Services has partnered with Demand Power Group, not PUC Distribution.

b) The Battery Energy Storage System (BESS) with Demand Power at the Sault Area Hospital will not impact PUC operations. When operational it will shift load from peak to off-peak 15-20 times a year but will not reduce consumption. There will be minimal impact to PUC's revenues with the BESS.

c) As part of initial consultations, the customer provided PUC with adequate technical information to determine that the steady state and transient behavior of their behind-the-meter energy storage facility will have no adverse impact or add to risks for PUC's operations or its distribution network.

Staff 5

Productivity
Reference: Exhibit 1, page 97

Question:

a) Please discuss if PUC Distribution has implemented any productivity initiatives over the 2018-2022 period to improve cost efficiency. If so, please provide details of these initiatives and quantified cost savings (for both capital and OM&A).
b) Please discuss PUC Distribution's plans for any new productivity initiatives for the period of 2023-2027.

Response:

a) **Productivity Initiatives 2018-2022:**

Smart Grid Project

The main productivity initiative worked on during the 2018-22 period was the Sault Ste. Marie Smart Grid ("SSG") Project. A significant level of effort was required at all levels of the organization to evaluate solutions and submit a satisfactory Incremental Capital Model ("ICM") to the OEB for approval. Following the approval of the ICM, planning, change management and design support efforts were required across the organization. The project includes two main components: Volt-Var Optimization ("VVO") and Distribution Automation ("DA").

The VVO effectively optimizes voltage levels to reduce customer energy consumption. The DA will improve the reliability of the Distribution System by implementing automatic switching.

VVO's scope is extensive. It will impact our entire Distribution system, and as such, activities and outages at all substations will be required to accommodate construction activities. It will be the first community-wide Smart Grid project in Canada. The Engineering and Operations teams have been actively engaged in supporting this transformational project.

Quantified planned efficiencies can be seen in EB-2018-0219/EB-2020-0249.

COVID pandemic impacts

Based on the impacts to PUC's activities, it is important to mention that many initiatives had to be paused for about two years due to the COVID pandemic. During that period, efforts were required to implement remote working alternatives and adjust practices to reduce propagation risks while maintaining safe and reliable essential electrical services to PUC's customers. A number of challenges had to be managed, including material supply chain issues and labour, as well as bringing in contractors from higher risk areas. The focus in that period was on keeping our employees and community safe while continuing to provide reliable services to customers.

Electronic communication for frontline staff and digital forms

This initiative provided means for electronic communication for our frontline staff, such as tablets or laptop as well as the development of electronic forms. PUC front-line staff are transitioning from paper forms, maps, and drawings to electronic access. These improvements are not in themselves expected to generate cost efficiencies but will facilitate data analytics expected to enable future improvements. Some of the processes that went from paper to digital in the period include the following.

Safety:

H&S Incident reporting, Environmental incident (spill) reporting, confined Space Entry (permit and coordination document if more than one employer is involved).

Purchasing and Stores:

Stores material requisition form, PUC provided PPE purchasing form for safety eyewear and fire-retardant clothing as well as driver's license medical and other expenses reimbursement forms.

Line Operations:

Electrical Standards and Drawing app that allows field employees to consult USF and PUC standards electronically in the field. Utility Work Protection Code Forms that are used to isolate and de-energize or re-energize hazardous energy sources. Excavation and Restoration reports to enable data entry directly to the GIS system. Also, as mentioned in Staff-9 response below, the use of Clearion for Vegetation management has been established to gather better vegetation management data.

North Eastern Distributors Buying Consortium (NEDBC)

For over nineteen years, PUC has been a member of the Northern Ontario purchasing consortium. In addition to PUC, the group of LDCs includes North Bay Hydro, Greater Sudbury Hydro, Chapleau Public Utilities Corporation, Northern Ontario Wires, Espanola Regional Hydro Distribution Corporation and Algoma Power. Benefits of the group

include bulk purchasing discounts as a result of the consortium representing a customer base in the top ten in the province. Saved time due to the shared preparation of major tenders for electrical equipment is also a benefit. Shared purchases include transformers, poles, wire, hardware, switches, insulators, PCB piping and rubber goods.

b) **Productivity Initiatives 2023-2027:**

Completion of the Voltage Conversion program

PUC will be completing its voltage conversion program from 4.16 kV to 12.5kV which will result in the removal from service of two substations. The program completion will also result in the optimization of the inventory levels, eliminating all 4.16kV Distribution transformers and other related devices.

Expected addition of an additional utility: PUC Transmission

PUC is expecting to add an additional affiliated utility company by 2026 to provide Transmission services to local industrial and potentially system customers. With the creation of this additional line of business, the shared services model will be further leveraged. It is still too early to quantify the anticipated efficiencies to be gained, but it is expected to be an important focus area that will bring benefits to PUC's customers.

Website automation and chatbot

PUC intends to revamp its website to provide a better interface for customers and allow them to access data and communicate with PUC via improved website automation and functionality such as chatbot at any hour of the day.

Staff 6

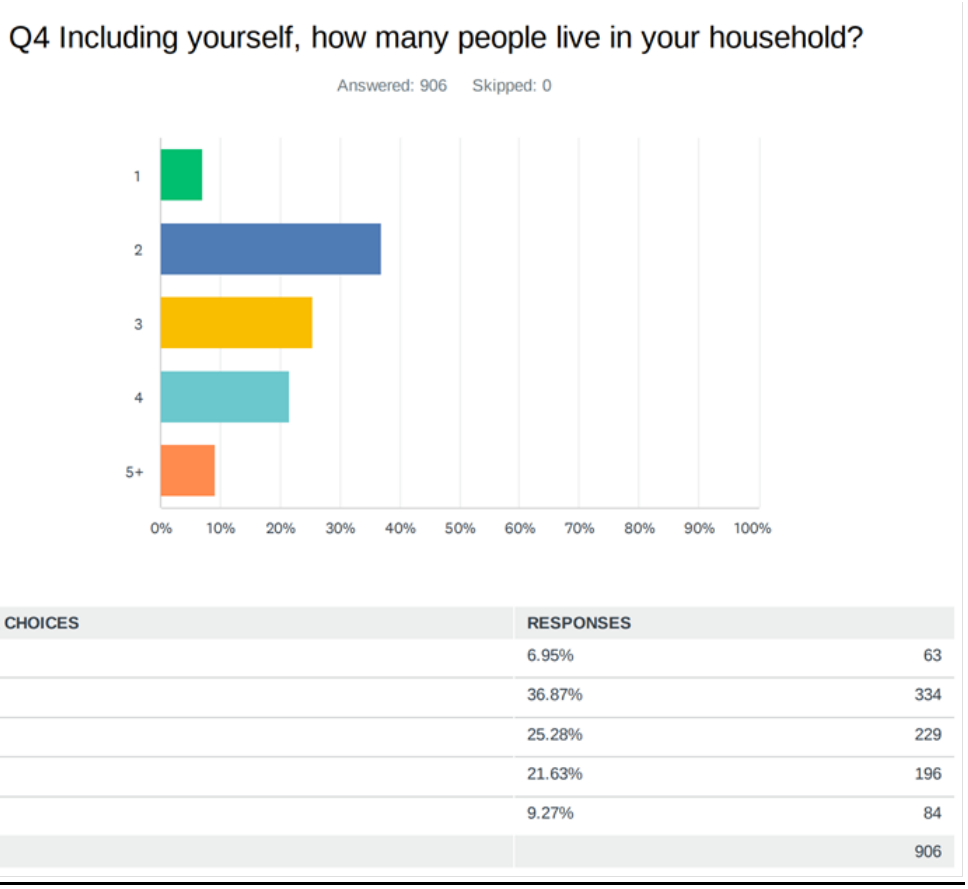
Customer Engagement
Reference: Exhibit 1, Appendix L – Customer Engagement Survey Phase 1

Question:

The response choices to questions 4 and 6 have not been provided. Please provide the responses to questions 4 and 6.

Response:

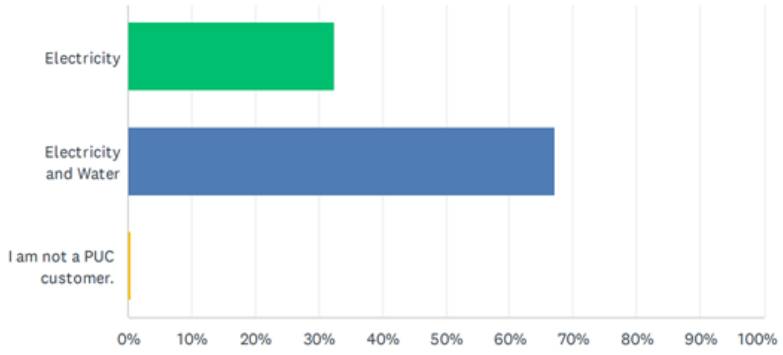
PUC has provided the responses to Questions 4 and 6 below:



ANSWER CHOICES	RESPONSES	
1	6.95%	63
2	36.87%	334
3	25.28%	229
4	21.63%	196
5+	9.27%	84
TOTAL		906

Q6 What services do you currently receive from PUC?

Answered: 906 Skipped: 0



ANSWER CHOICES	RESPONSES	
Electricity	32.45%	294
Electricity and Water	67.22%	609
I am not a PUC customer.	0.33%	3
TOTAL		906

1

Staff 7

Customer Engagement
Reference 1: Exhibit 1, page 60-61
Reference 2: Exhibit 1, page 50

Question:

PUC Distribution states that proposals in the current application were communicated with customers via an online customer engagement survey conducted during a three-week period between May 20 and June 10, 2022. The purpose was to ultimately inform PUC Distribution's 2023 application.

On page 61 of Exhibit 1, PUC Distribution states that the feedback collected from this survey has informed the application in a number of ways. The evidence goes on to discuss how PUC Distribution is making significant investments in the Sault Smart Grid (SSG) and investments in customer service tools such as the MyPUC App.

OEB staff notes that on page 50 of Exhibit 1, PUC Distribution states that the MyPUC App was developed in 2021. Further, the SSG project was approved by the OEB in April 2021. Both the SSG and MyPUC App seem to have been underway prior to these surveys.

a) Please clarify how feedback collected from the cost-of-service application surveys specifically have informed the application.
b) Please describe any changes made to the proposed capital and operating plans as a result of any feedback received.

Response:

a) PUC has discussed how feedback collected through customer engagement has informed the application in section 5.2.2.1 of the DSP, starting on page 9.

b) PUC has described changes to the proposed capital and operating plans as a result of feedback received through customer engagement in section 5.2.2.1 of the DSP, starting on page 9.

Staff 8

Electric Vehicles
Reference 1: Exhibit 1, pg. 62
Reference 2: Exhibit 1, Appendix M – Customer Engagement Survey, Question 8
Reference 3: Exhibit 4, Appendix B - Full Absorption Cost Allocation Review, pg. 17

Question:

Reference 1 states that PUC has purchased electric vehicles and developed a plan to further electrify their fleet to lower maintenance and fuel costs and lower their carbon footprint.

The question in reference 2 asked customers to rank a list of factors other people have identified as important when considering whether to buy an electric vehicle in terms of importance. OEB staff interprets the results to mean that initial purchase price was ranked first.

Based on the evidence, OEB staff understands that PUC Distribution's OM&A expenses include a charge from PUC Services that is based on depreciating and financing of vehicles that are utilized to provide services to PUC Distribution. Reference 3 notes:

> Rates are set to recover actual costs when applied to all vehicle hours, where actual cost includes fuel, maintenance, and amortization, and cost of capital based on the OEB-approved rate of return applied to the net book value of the assets. Different rates are set for each of several vehicle classes, based on review by Finance staff as to the relative cost of each vehicle class.

a) What percentage of vehicles are electric?
b) What were the top criteria for determining which electric vehicles to purchase?
c) Have lower maintenance, fuel, or other costs been incorporated into the proposed test year OM&A as a result of the electrification of some vehicles? If so, how? If not, why not?
    i. How were the savings determined?
d) What facilities are used to charge these electric vehicles and how have any incremental costs been incorporated in this application? Please detail the costs.

Response:

a) Currently, PUC Services has 3.8% of its purchased passenger fleet as electric.

b) Features that PUC Services considers when purchasing electric vehicles are as follows:
   i. AWD and ground clearance for winter driving
   ii. Sizing to meet needs
   iii. Range of the charge
   iv. Cost

c) PUC Services is in the early stages of executing its electric fleet plan, therefore, lower costs have not been incorporated into the proposed test year OM&A since it is immaterial.

d) PUC is currently installing electric vehicle charging stations at some of its facilities. Capital costs have been included in PUC's 2022 capital budget. NRCan funding is offsetting 50% of the costs of the chargers. Due to the low percentage of electric vehicles, OM&A costs are expected to be immaterial and have not been included in this application.

Staff 9

Scorecard - SAIDI
Reference: Exhibit 1, pg. 88-89

Question:

PUC Distribution's SAIDI result in 2021 of 1.81 was above the distributor target of 1.38. PUC Distribution states that there are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

Please describe any changes made to PUC Distribution's vegetation management program compared to its historical practice.

Response:

PUC continued using a similar cycle management process, which consists of the service territory being divided into four similarly sized sections completed over a four-year cycle. To improve vegetation management related decision-making, PUC requested that its selected forestry contractor utilize a digital utility vegetation management ("UVM") software application (Clearion). Clearion provides a UVM inventory that, for example, allows identification of certain fast-growing species of trees that can then be addressed more frequently. It also provides improved data analytic opportunities to assist in adjusting the annual program, as necessary.

Staff 10

Debt to Equity
Reference 1: Exhibit 1, page 104
Reference 2: Exhibit 1, Appendix E – OEB 2021 Scorecard
Reference 3: Chapter 2 Appendices, Tab 2-OB – Debt Instruments

Question:

Reference 1 states the following:

> Historically, PUC's debt to equity has remained at a level close to 2:1. PUC will be undergoing additional financing for the completion of the SSG project in 2022. This will increase debt to equity in 2023 to approximately 2.36:1. PUC's long-range plan is to push the debt to equity back towards the deemed 60/40 level.
>
> PUC's target for this metric in 2023 is to reduce the debt to equity to 60%/40%.

a) Please reconcile the statements which indicate that: (1) PUC Distribution is expecting its debt-to-equity ratio for 2023 to be approximately 2.36:1; (2) PUC Distribution's target is to reduce the debt to equity to the OEB's deemed 60/40 split in 2023; and (3) PUC's long-range plan is to push the debt to equity back towards the deemed 60/40 level.
b) Please outline the expected timing and plan for bringing PUC Distribution's total debt to equity ratio closer to the OEB's deemed 60/40 split.
c) Tab 2-OB from PUC Distribution's Chapter 2 Appendices shows Infrastructure Ontario as the lender for loans 2-7. Has PUC Distribution considered both the implications on the availability of and the expected rates for debt that could not be obtained through Infrastructure Ontario? Please describe the risks, and how PUC Distribution intends to mitigate those risks should that become a circumstance faced by the utility.

Response:

a) PUC can confirm that it anticipates its 2023 debt-to-equity to be approximately 2.36:1. PUC acknowledges that it will not achieve a 60/40 debt-to-equity ratio in 2023 but its target remains to work towards this 60/40 split.

b) After the SSG financing, PUC will continually monitor its debt levels, cash flow forecasts, capital, and OM&A spending so that it can continue to work towards achieving a 60/40 debt-to-equity ratio. PUC is planning to obtain a 60/40 split by 2026.

c) PUC closely monitors its financing situation and can confirm that loans 2-7 have already been committed as a preapproval from IO as a revolving credit facility. PUC has also closely monitored the fluctuating rate situation by keeping in frequent contact with its IO financing representative

Exhibit 2 – Rate Base

Staff 11

Allowance for Working Capital
Reference 1: Revenue Requirement Workform, Tab 3 – Data Input Sheet
Reference 2: Exhibit 2, pg. 53

Question:

There may be a minor typographical error on tab 3 of the RRWF. The controllable expenses on tab 3 shows an input of $13,949,291. Reference 2 shows a figure of $13,949,277.

Please make the necessary correction to the RRWF as applicable

Response:

Reference 2 is incorrect. Table 2-21 on page 53 has donations – LEAP of $31,130. The correct amount for donations – LEAP is $31,144 making the controllable expenses $13,949,291 as shown in the RRWF.

Staff 12

Reference 1: Chapter 2 Appendices, Tab 2-BA – Fixed Asset Cont
Reference 2: Chapter 2 Appendices, Tab 2-H – Other Revenue
Reference 3: Excel PILs model

Question:

There are no disposals in Appendix 2-BA for 2020-2023. There are no proceeds of dispositions in the UCC schedules of the Excel PILs model. There are no gains/losses on asset disposition/retirement in Appendix 2-H for 2020-2023. Please confirm that this is appropriate. If not confirmed, please revise the evidence as necessary.

Response:

PUC only owns electrical distribution infrastructure which would not be sold for a gain/loss on disposition/retirement.

Staff 13

Reference 1: Exhibit 2, pg. 44, 58
Reference 2: Chapter 2 Appendices, Tab 2-BA - Fixed Asset Cont

Question:

PUC Distribution states that the Substation-16 project was substantially completed in 2021 at a revised total cost of $6,020,119.

PUC Distribution states that it has:

> brought both ICM's (Sub 16 and SSG) into rate base in 2022. Sub-16 had a half year of depreciation in 2021 and full year in 2022. Chapter 2 Appendices 2-C is showing a variance of $150,503 in 2022 Bridge Year. This is because the formula doesn't account for the fact that Sub 16 had a half year worth of depreciation when it was part of 1508 regulatory assets.

Please confirm that the net book value as at January 1, 2023 represents Substation-16 being placed into service in 2021 with half-year depreciation in 2021 and a full year depreciation in 2022.

Response:

PUC confirms that the net book value as at January 1, 2023 represents Substation 16 being placed into service in 2021 with a half-year of depreciation in 2021 and a full year of depreciation in 2022.

Staff 14

PP&E
Reference 1: Chapter 2 Appendix 2-BA
Reference 2: Exhibit 1, Appendix G, 2021 Audited Financial Statements (AFSs)

Question:

In Appendix 2-BA, the 2021 net book value of $102,514,079, excluding Account 2440 – Deferred Revenues agree to the net book value excluding Construction-in-Process as shown in note 6 of PUC Distribution's 2021 AFSs.

In Appendix 2-BA, the 2021 net book value in Account 2440 – Deferred Revenues is $5,330,111. In PUC Distribution's 2021 AFSs, note 9 shows that the 2021 carrying amount of deferred revenues is $7,034,528.

Please reconcile the difference in 2021 deferred revenues between Appendix 2-BA and the amount in the 2021 AFSs.

Response:

The 2021 AFS include $1,704,417 in deferred revenue that is part of the SSG Project and is still considered in CWIP.

Staff 15

Depreciation
Reference 1: Exhibit 2, pg. 43
Reference 2: Accounting Procedures Handbook, effective January 1, 2012

Question:

Regarding depreciation, per page 16 of Article 410 of the Accounting Procedures Handbook (APH), any property, plant and equipment asset that is readily identifiable in the plant records should be separately accounted for and depreciated over its estimated useful life. In addition, page 14 indicates that for regulatory purposes, distributors have the option of categorizing "like assets" together due to certain circumstances. Regarding depreciation, PUC Distribution uses the pooling of assets for all fixed assets.

Please clarify this statement and comment on whether the depreciation of pooled of assets meet the circumstances noted in the APH for all fixed assets.

Response:

Depreciation is recognized on a straight-line basis over the estimated useful life of each significant identifiable component of an item of property, plant, and equipment ("PP&E"). PUC uses the pooling of assets for "like assets" e.g., poles.

PUC confirms that significant parts or components of each item of PP&E are being depreciated separately. PUC is following the APH treatment for fixed assets.

Staff 16

Useful Lives
Reference 1: Chapter 2 Appendix 2-BB
Reference 2: Exhibit 2, pg. 43

Question:

In Appendix 2-BB, it indicates that Account 1808 Buildings and Fixtures – HVAC/Mechanical currently has a service life of 50 years and is being proposed to have a service life of 25 years. Exhibit 2 shows a 50-year service life.

a) Please clarify what is the service life being proposed for the assets in Account 1808.
b) If there is a proposed change in service life, please explain why.

Response:

a) There was an administrative error in Chapter 2 Appendix 2-BB. HVAC/Mechanical currently has a service life of 25 years. No change is being proposed. All other assets in Chapter 2 Appendix 2-BB are accurate.

b) PUC confirms there is no proposed change in service life.

Staff 17

SSG – 2023 Costs
Reference 1: Exhibit 2, pg. 42
Reference 2: Exhibit 2, pg. 37-40

Question:

PUC Distribution states that $3,190,371 of the total project costs related to the SSG are being completed in Q1 2023 and that this amount has been removed from the ICM project and included as part of 2023 capital additions.

On pages 37-40 of Exhibit 2, PUC Distribution lists the major components of the $10,113,3717 variance between 2022 bridge and 2023 test year gross assets.

OEB staff calculates that the sum of the items in the various accounts related to the SSG amount to a total of $3,315,493.

a) Please confirm if OEB staff's calculation is correct.
b) If yes, please reconcile with the amount of $3,190,371.
c) Please confirm the depreciation amounts included are appropriate.
d) If any changes are required, please make them, as appropriate.

Response:

Responses for (a) to (d) are as follows:

PUC reviewed exhibit 2 page 42 and page 37 – 40 and has provided the following table to correct the discrepancies:

OEB Account	As Submitted, August 31, 2022	Revised November 11, 2022	Change
1820 DS Equipment	$2,291,402	$2,291,402	$0
1830 Poles & Fixtures	$220,864	$121,413	$99,451
1835 OH Conductors & Devices	$261,226	$235,375	$25,851
1845 UG conductors & Devices	$113,678	$113,678	$0
1850 Line Transformers	$40,819	$40,819	$0
1980 System Supervisory Equipment	$387,684	$387,684	$0
Total	$3,315,673	$3,190,371	$125,302

PUC's calculations indicate the as submitted amount on Exhibit 2 pages 37-40 total $3,315,673. This does not total the amount the OEB calculated of $3,315,493. However, PUC can confirm that those amounts are not correct. The second column in the table above shows the revised amounts that reconcile to $3,190,371. The 2023 depreciation has been calculated accurately based on the $3,190,371 in 2023 additions for SSG.

Staff 18

SSG – 2023 Costs
Reference: Exhibit 2, pg. 65-66

Question:

PUC Distribution states a small portion of testing is to occur in Q1 2023 related to the SSG, and that it has excluded that portion of asset additions from 2022 rate base and included it as part of 2023 rate base. As noted in the interrogatory above, there is about $3.19M in costs related to the SSG for 2023.

Please detail the testing required for the SSG which amounts to a total of over $3.19M.

Response:

The SSG EPC contract is structured with "milestones" for the project execution progress payment. In 2023 the testing and optimization phase of the work at a high level will involve taking each of the station VVO and DA areas from the "Functionally Complete" milestone stage through to the "Substantially Complete" milestone stage.

In VVO each station, voltage control equipment in operation being monitored and controlled in the new ADMS/SCADA system (Functional Complete), will undergo optimization and testing to finalize voltage reduction settings and control systems. Once each station is complete full system wide testing and confirmation of performance including integrated measurement, verification, and reporting ("Substantially Complete").

Similarly for DA, the equipment in operation for each FLISR area or zone will be tested and exercised for fault/automated outage restoration scenarios to confirm correct operation and SCADA/FLISR control. The integration of these systems to the OMS will also be tested to confirm outage data collection, calculations, notification, and statistical reporting. As with the VVO, a final full system level test and confirmation is required to achieve the "Substantially Completion" phase.

The last major element of work under the contract for the "Close Out & Acceptance" milestone will encompass close out activities for as-bult drawings, records, reports, procedures and final turnover and acceptance.

Staff 19

SSG ICM
Reference 1: Chapter 2 Appendix 2-BA
Reference 2: DVA Continuity Schedule
Reference 3: Exhibit 9, Appendix A – SSG ICM Accounting Order

Question:

Tab 2b of the DVA Continuity Schedule shows the forecasted 2022 year-end balances for Account 1508, Sub-account ICM Sault Smart Grid Capital to be $21,357,909, and Account 1508, Sub-account ICM Sault Smart Grid Depreciation and Accumulated Depreciation to be $500,407 and ($500,407) respectively. Per Appendix A of the DVA Continuity Schedule, $300,080 has been forecasted for depreciation for 2022. In Chapter 2 Appendix 2-BA, depreciation for the SSG ICM is $300,244 for 2022 and $600,488 for 2023.

a) Please reconcile the depreciation in the applicable 1508 ICM SSG sub-accounts to the depreciation in Appendix 2-BA.
b) In the SSG ICM accounting orders, accounts #7 to 10 relate to capital contributions for the NRCan Grant. These sub-accounts are not shown in the DVA Continuity Schedule. Please confirm that the SSG ICM sub-accounts shown in the DVA Continuity Schedule are net of the applicable capital contribution sub-accounts. If not confirmed, please explain how the capital contribution sub-accounts are used.

Response:

a) On Tab 2b of the "PUC_2023_DVA Continuity Schedule_20221128", the amount of $500,407 in account 1508 ICM SSG sub-accounts depreciation, includes 4 months of depreciation on the ICM SSG asset additions. The Chapter 2 Appendix 2-BA includes the same amount of depreciation, $300,244, for 2022. The Chapter 2 Appendix 2-BA does not delineate the amount of depreciation in account 1508 ICM SSG sub-accounts depreciation. Instead, it just shows the full amount of depreciation for the year in column P.

   The question above indicates Appendix A of the DVA Continuity Schedule forecasts depreciation of $300,080. PUC does not know where this reference is located. However, PUC can confirm that the correct amount of 2022 depreciation is $300,244.

b) In the DVA Continuity Schedule, the following 1508 sub-accounts in relation to the ICM SSG are net of contributed capital received from the NRCan grant:

i. 1508 Other Regulatory Assets – Sub-Account – ICM SSG Capital
ii. 1508 Other Regulatory Assets – Sub-account – ICM SSG Depreciation
iii. 1508 Other Regulatory Assets – Sub-account – ICM SSG Accumulated Depreciation

When the assets are put into service, PUC will account for them as per the Accounting Order with the NRCan capital contribution tracked in identifiable sub-accounts.

Staff 20

Substation-16 ICM True-up
Reference 1: Exhibit 2, pg. 59-64
Reference 2: Chapter 2 Filing Requirements, 2022 Edition for 2023 Rate Applications, April 18, 2022
Reference 3: Exhibit 9, pg. 10
Reference 4: DVA Continuity Schedule

Question:

The Filing Requirements indicate that the ICM true-up calculation compares the recalculated revenue requirement based on actual capital spending relating to the OEB-approved ICM project(s) to the rate rider revenues collected in the same period.

Table 2-27 recalculates the ICM revenue requirement for Substation-16 based on the actual cost of $6,020,000 and the in-service year of 2021. In the calculation, the "eligible for ICM amount" is $3,894,622, which is an increase from the $2,602,851 that was in the approved ICM in Table 2-26.

a) Please indicate the updates made which revised the "eligible for ICM amount" (e.g., CAPEX and materiality threshold used).

b) PUC Distribution provided a recalculated approved ICM revenue requirement in Table 2-28, with the half-year rule applied to depreciation and CCA only. Please provide a recalculated revenue requirement based on actual costs, applying the half-year rule to the capital cost, depreciation and CCA, consistent with the OEB's ICM model.

c) In Exhibit 9, it was stated that the reconciliation for Substation 16 includes Account 1509 – ICM Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation, effective from November 1, 2020, to October 1, 2022. Please clarify what the statement means.
    i. Table 2-25A in Exhibit 2 shows the projected rate rider revenues from 2020 to 2023 to be $713,107. This appears to equal the sum of the ending balances in Account 1508 – ICM Substation 16 Rate Riders and Account 1509 ICM Substation 16 Rate Riders in the DVA Continuity Schedule. Please confirm that the balances in these two sub-accounts represent the actual rate riders collected by PUC Distribution. If not confirmed, please explain.

ii. In tab 2b of the DVA Continuity Schedule, there are ending balances for Account 1508 - COVID-19 Foregone Revenue - ICM Substation Delayed Rate Implementation and Account 1509, COVID-19 Foregone Revenue - ICM Substation Delayed Rate Implementation of ($115,142) and $115,142, respectively. Please confirm that these balances represent the actual foregone revenue. If not confirmed, please explain.

Response:

a) The following chart outlines the updates that were made on Tab 9b of the "PUC_2020_ACM_ICM_Model_OEB Updated_No Accelerated CCA" from EB-2019-0170:

	Approved ICM Submission	ICM Submission Revised for Actual Spend
ICM Capital Spend	$4,728,229	$6,020,000
Depreciation	$117,206	$150,500
CCA	$189,129	$240,800

b) PUC applied a half year to cell G25 of the ICM Revenue requirement model which resulted in the following output on tab 10. Incremental Capital Adj. PUC has also filed this updated model as "PUC 2020 ACM ICM Model_OEB Updated_No Accelerated CCA_half year depreciation" to prevent any further confusion.

c) PUC was approved to collect the ICM Substation 16 Rate Rider starting May 1, 2020. On April 16, 2020, the OEB issued a letter giving LDC's the option to postpone the implementation of the May 1, 2020 distribution rate increase. PUC elected this option, for both its distribution rates and the ICM rate rider, to give financial relief to its customers. The collection of this foregone revenue from the delayed implementation of the sub 16 rate rider was tracked and recorded in a 1509 foregone revenue sub account specific to the delayed implementation of the Substation 16 rate rider. When reconciling the rate rider collected for Substation 16 to the amount that should have been collected, PUC has included all amounts recorded in 1509 – ICM Rate Rider for Recovery of COVID-19 Forgone Revenue – Substation 16 Rate Rider.

i. PUC confirms that the balances in the two sub accounts represent the actual rate riders collected for Sub 16. Tab2b of the "PUC_2023_DVA Continuity Schedule_20221128", the rate riders collected for sub16 are reconciled on rows

57-60. These amounts represent the amounts projected to be collected up to October 31, 2022. PUC was trying to show the total ending balances that would be contained within the 1508 Sub Accounts as of April 30, 2022. Tab 2b doesn't have columns for 2022 projections which would be very helpful to the understanding of this model. Thus, PUC included all 2022 projections and the first 4 months of 2023 as a principal adjustment in 2021.

ii. Yes, these numbers represent the actual foregone revenue from the delayed implementation of the ICM Substation 16 rate rider.

Staff 21

Cost of Power
Reference 1: Chapter 2 Appendices, Tab 2-ZB – Cost of Power
Reference 2: Regulated Price Plan Price Report, November 1, 2022, to October 31, 2023, issued October 21, 2022

Question:

Regarding Tab 2-ZB of the Chapter 2 Appendices:

a) Please confirm that for the demand-based classes, it is accurate that no loss factor has been applied to the volumes entered.
b) If the answer to (a) is yes, please provide an explanation why.
c) If any changes are required, please make them to the required tab(s).
d) On October 21, 2022, the OEB announced electricity prices under the Regulated Price Plan (RPP) effective November 1, 2022. Also, effective November 1, 2022, the Ontario government's Ontario Electricity Rebate (OER) will be 11.7%. Please update the cost of power calculation.

Response:

a) Loss factors have been applied to any calculation that uses kWh within the calculation. A calculation that uses demand (kW), no loss factor has been applied. Chapter 2 Appendices 2-ZB have been reproduced below and any calculation that includes loss factor has been highlighted.

		2023 Test Year	RPP		2023 Test Year	non-RPP		Total
Electricity Commodity	**Units**	Volume	Rate	$	Volume	Rate	$	$
Class per Load Forecast								
Residential	kWh	283,912,095		26,517,390	3,519,514		205,293	
GS < 50	kWh	70,079,044		6,545,383	12,624,665		736,397	
GS > 50	kW	42,755,086		3,993,325	188,926,311		11,020,072	
Embedded Distributor		0		-	0		-	
Street Light	kW	135,706		12,675	2,437,941		142,205	
Sentinel Light	kW	202,796		18,941	0		-	
USL	kWh	919,116		85,845	0		-	
SUB-TOTAL				37,173,559			12,103,967	$ 49,277,526

Global Adjustment non-RPP	**Units**	Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential - Class B	kWh			0			137,402	
GS < 50 - Class B	kWh			0			492,867	
GS > 50 - Class B	kW			0			5,831,121	
Embedded Distributor - Class B				0			-	
Street Light - Class B	kW			0			95,177	
Customer A - Class A				0			392,992	
Customer B - Class A				0			1,097,367	
Customer C - Class A				0			72,685	
Customer D - Class A				0			299,321	
Customer E - Class A				0			337,190	
SUB-TOTAL				0			8,756,122	$ 8,756,122

Transmission - Network		Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential	kWh	283,912,095	0.0090	2,555,209	3,519,514	0.0090	31,676	
GS < 50	kWh	70,079,044	0.0083	581,656	12,624,665	0.0083	104,785	
GS > 50	kW	101,072	3.3697	340,581	111,654	3.3697	376,240	
GS>50 Interval Metered	kW				334,962	4.2388	1,419,836	
Embedded Distributor						-	-	
Street Light	kW	380	2.5422	965	6,820	2.5422	17,339	
Sentinel Light	kW	566	2.5547	1,447	-	2.5547	-	
USL	kWh	919,116	0.0083	7,629	-	0.0083	-	
SUB-TOTAL				3,487,486			1,949,876	5,437,362

Wholesale Market Service								
Class per Load Forecast							$	Total
Residential	kWh	283,912,095	0.0030	851,736	3,519,514	0.0030	10,559	
GS < 50	kWh	70,079,044	0.0030	210,237	12,624,665	0.0030	37,874	
GS > 50	kWh	42,755,086	0.0030	128,265	188,926,311	0.0030	566,779	
Embedded Distributor		-	0.0030	-	-	0.0030	-	
Street Light	kWh	135,706	0.0030	407	2,437,941	0.0030	7,314	
Sentinel Light	kWh	202,796	0.0030	608	-	0.0030	-	
USL	kWh	919,116	0.0030	2,757	-	0.0030	-	
SUB-TOTAL				1,194,012			622,525	1,816,537

Class A CBR								
Class per Load Forecast							$	Total
Residential	kWh		0.0004			0	-	
GS < 50	kWh		0.0004			0	-	
GS > 50	kWh		0.0004		39,583,764	0.0004	15,834	
Embedded Distributor			0.0004			0	-	
Street Light	kW		0.0004			0	-	
Sentinel Light	kW		0.0004			0	-	
USL	kWh		0.0004			0	-	
SUB-TOTAL							15,834	15,834
Class B CBR								
Class per Load Forecast							$	Total
Residential	kWh	283,912,095	0.0004	113,565	3,519,514	0.0004	1,408	
GS < 50	kWh	70,079,044	0.0004	28,032	12,624,665	0.0004	5,050	
GS > 50	kWh	42,755,086	0.0004	17,102	149,342,547	0.0004	59,737	
Embedded Distributor	kWh	-	0.0004	-	-	0.0004	-	
Street Light	kWh	135,706	0.0004	54	2,437,941	0.0004	975	
Sentinel Light	kWh	202,796	0.0004	81	-	0.0004	-	
USL	kWh	919,116	0.0004	368	-	0.0004	-	
SUB-TOTAL				159,202			67,170	226,371
RRRP								
Class per Load Forecast							$	Total
Residential	kWh	283,912,095	0.0005	141,956	3,519,514	0.0005	1,760	
GS < 50	kWh	70,079,044	0.0005	35,040	12,624,665	0.0005	6,312	
GS > 50	kWh	42,755,086	0.0005	21,378	188,926,311	0.0005	94,463	
Embedded Distributor		-	0.0005	-	-	0.0005	-	
Street Light	kWh	135,706	0.0005	68	2,437,941	0.0005	1,219	
Sentinel Light	kWh	202,796	0.0005	101	-	0.0005	-	
USL	kWh	919,116	0.0005	460	-	0.0005	-	
SUB-TOTAL				199,002			103,754	302,756

Rate Rider for Embedded Generation Adjustment								
Class per Load Forecast							$	Total
Residential	kWh	271,374,589	(0.0005)	(135,687)	3,364,092	(0.0005)	(1,682)	
GS < 50	kWh	66,984,366	(0.0005)	(33,492)	12,067,162	(0.0005)	(6,034)	
GS > 50	kWh	40,867,029	(0.0005)	(20,434)	180,583,360	(0.0005)	(90,292)	
Embedded Distributor		-	(0.0005)	-	-	(0.0005)	-	
Street Light	kWh	129,713	(0.0005)	(65)	2,330,282	(0.0005)	(1,165)	
Sentinel Light	kWh	193,841	(0.0005)	(97)	-	(0.0005)	-	
USL	kWh	878,528	(0.0005)	(439)	-	(0.0005)	-	
SUB-TOTAL				(190,214)			(99,172)	(289,386)

Smart Meter Entity Charge								
Class per Load Forecast							$	Total
Residential		30,340	0.42	152,914			-	
GS < 50		3,400	0.42	17,136			-	
SUB-TOTAL				170,050			-	170,050
SUB- TOTAL				42,193,096			23,520,074	65,713,170
OER CREDIT	17%			(7,172,826)			0	(7,172,826)
TOTAL				**35,020,270**			**23,520,074**	**58,540,344**

b) The Loss factor has been applied to the electricity commodity and Global Adjustment categories, as PUC pays cost of power based on consumption that includes losses. The Loss factor has been applied to the transmission network, wholesale market service charge, CBR, and RRRP anywhere that kWh is the billing determinant used. This is how the calculation is presented in the bill impacts model and how PUC customers are billed. The Loss factor is not applied to any calculation that uses kW as the billing determinant.

c) PUC confirms that no changes are required.

d) The cost of power calculation has been updated to match the October 21, 2022 Regulated Price Plan (RPP) effective November 1, 2022, and the Ontario government's Ontario Electricity Rebate (OER) of 11.7%.

Staff 22

Historical Capital Expenditures
Reference: Distribution System Plan – 5.2.1.3 Capital Investment Highlights

Question:

In Table 5.2-2 in reference 1, PUC Distribution states that 0 months of actual expenditures are included in 2022.

Please provide an updated Appendix 2-AA and Appendix 2-AB with forecasted 2022 spending that includes as many months as possible of actual spending.

Response:

Please refer to the revised PUC_2023_Filing_Requirements_Chapter2_Appendices_20221128 filed in excel format with these IR Responses.

Staff 23

Asset Condition Assessment
Reference: Distribution System Plan – Appendix H – Asset Condition Assessment

Question:

METSCO has outlined a number of ways PUC Distribution can improve its asset condition assessment going forward.

How does PUC Distribution intend to improve its data availability index (DAI) for its assets going forward?

Response:

In the Asset Condition Assessment plan prepared by METSCO, a number of assets were identified as having data availability below the DAI threshold. These are listed in the table below, along with either solutions currently in progress, or solutions proposed in the 2023-2027 COS rate application to improve the DAI going forward.

Asset Type	Plans to Improve DAI
Steel poles	Steel pole population is only 57 or 0.45% of the entire pole population. Although a small percentage of the overall pole population, visual inspection, and data collection for these are to be added as part of routine annual one third plant inspection process completed by in-house staff.
Overhead transformers, Submersible transformers, Station Service transformers	During the 2018-2022 COS period, testing for PCBs was conducted on these transformers to ensure they meet environmental regulatory requirements beyond the 2025 regulatory deadline. PUC also seized the opportunity while oil PCB samples were being taken to conduct a comprehensive visual inspection of the transformers and to record the results in a database to serve as an input to justify the needs identified in the 2023-2027 COS rate application.
Fused and load break switches	The 2023-2027 DSP proposes capital investment in an upgrade of the current GIS system from a geometric to a utility network-based platform. This will provide a solid platform on which to record asset condition information as it is collected in the field. Although there is not an immediate plan for cataloging the Health Index for these

	specific lower value and lower risk assets immediately, it is anticipated they will be added as the new GIS comes into use.
Medium voltage switchgear and station breakers	As referenced in the 2023-2027 DSP Appendix A, Material Investment Narrative – Tools and Equipment, investments are proposed for a number of pieces of test equipment to allow for improved knowledge of the HI of station equipment, including relays, transformers, and switchgear. The Omicron injection tester, infrared Camera and ARCO reclose tester will all serve to provide more intelligence for the medium voltage switchgear and station breakers.
Station riser cables	The 2023-2027 COS operational budget has earmarked some limited expense dollars to secure a contractor to conduct testing on the most critical cables. PUC prioritizes cables based on a number of factors to ensure whether testing is the most prudent way to assess/prioritize renewal for this asset. Some questions considered are: • Number of customers or size of load • Is there an alternate backup/looped feed • Are cables in duct and easy to quickly replace upon failure or direct buried • Are failures with cables themselves or with terminations, junctions, and switches • Are cables in areas where all the associated infrastructure is at end of life (e.g.: failing duct structures, manholes, switching points)
115kV switches	The condition of these assets had been assessed prior to 2018-2023, and they were determined to be approaching poor condition and end of life, however a “like for like” replacement did not appear to be the approach as many of the assets in the two PUC transformer stations where these are installed (TS1 and TS2) are also approaching end of life. Funds have been included in the 2023-2027 DSP for preliminary Engineering to evaluate and develop a full renewal plan for these two stations, likely to be proposed for full renewal during the 2027-2031 COS cycle.

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Substation-16
Reference 1: Exhibit 2 – 2.8.1 Substation 16
Reference 2: EB-2019-0170, Application – Appendix 7, p. 6
Reference 3: EB-2019-0170, Application – Appendix 7 – Appendix B – Table 1
Reference 4: EB-2019-0170, Application – Appendix 7 – Appendix C
Reference 5: Report of the OEB – Regulatory Treatment of Impacts Arising from the COVID-19 Emergency

Question:

PUC Distribution originally estimated that Substation-16 would be complete in 2020 and cost $4.7 million. The project was completed in 2021 with actual costs of $6.0 million. As a result of the COVID-19 pandemic, PUC Distribution decided to delay construction. The higher costs were mostly due to higher bidding prices, environmental clean-up, road restoration, and COVID-related expenses.

a) PUC Distribution stated that the tender for the project was $608k higher than originally estimated. Please provide a table showing a cost breakdown for the original cost estimate and a cost breakdown of the awarded bid estimate.
b) Please confirm if there was any change in the original scope for the estimates provided in part (a).
c) PUC Distribution stated that during the demolition of the original substation transformer oil was found. In reference 3, it shows that oil was found in the soil and was known at the time of the ICM. Please explain why remediation was not part of the original scope in EB-2019-0170.
d) PUC Distribution stated that the duct bank and road restoration costs are $327k higher due to design changes. Please provide the changes in scope, explanation of the change, and breakdown of the cost of each change.
e) PUC Distribution stated that one of the reasons for the delay was consideration of logistics or project completion. Please explain the logistics considered due the COVID-19 pandemic.
f) PUC Distribution provided COVID related expenses of $176k, which were driven by equipment storage and handling and cost increases to labour and materials. Please provide a breakdown between the two areas, details related to the cost increases, and how PUC Distribution attempted to mitigate these costs.

g) In reference 5, the OEB established a sub-account to track COVID-19 impacts for capital-related revenue requirement. Please explain why PUC Distribution has proposed to include the $176k in the Substation-16 total cost rather than the COVID-19 Account 1509 sub-account.
   i. Please discuss the $176k in the context of the 1509 sub-account, including, but not limited to the amount of revenue requirement that would be recorded in the account, the means test, causation, materiality, and prudence.

h) Does PUC Distribution believe that, as long as additional project costs are prudently incurred, even if they are driven by the impacts of COVID-19, the applicant should be permitted to recover these amounts through the Substation-16 rather than the Account 1509 mechanism? Please explain and discuss PUC Distribution's views on how the rules for Account 1509 apply to these cost overruns.

Response:

a) The Substation 16 construction tender was a lump sum tender and therefore a detailed breakdown of the bidders' price was not provided.

b) PUC confirms that there was no change in the scope from 2019 when the Substation 16 ICM was submitted to when the Tender was issued.

c) Although boreholes and samples had been taken to assess the general site conditions prior to the project and reduce risks, the full extent of the remediation could not be known with certainty until completing the actual excavation for the foundations. At that time, it was determined that a larger and deeper excavation than anticipated was required.

d) When the estimate was prepared for the Substation 16 re-build, the detailed line design portion was not yet complete. To come up with an appropriate estimate, the costs from similar projects were used. The original estimate used the Substation 10 rebuild (2012) duct bank and road restoration actual costs as the base amount with inflation added per year and a contingency added. PUC used unit price costs from its Miscellaneous Underground and Restoration Contract, which is tendered annually, to complete the Sub 16 duct bank and restoration works that were outside the Substation 16 property. The actual costs were $327k higher than the original project estimate.

e) Arrival of major equipment was identified as a potential risk as the world was dealing with the evolving COVID pandemic situation and associated supply chain uncertainties. For this project, switchgear was supplied from Germany and transformers from the USA. It was unknown whether the manufacturing facilities, shipping companies, or international borders would close or remain closed. Also, bringing out of town people to Sault Ste. Marie and PUC, both consultants and contractors, was deemed a safety risk for PUC and the community. Once the project would have started, there would be no way to efficiently pivot if supply chain disruptions caused critical components to be delayed, or if labour resources were not available as planned. As a winter peaking utility, our goal was to have Substation 16 energized for the winter, and significant delays would jeopardize that. It was decided to postpone the project for a year to ensure critical components were delivered, labour resources were available, and the safety situation locally was acceptable.

f) The transformers had to be offloaded at a storage facility and have temporary power connected to them for the control unit heaters to eliminate condensation in the units. Weekly inspections were completed as per the manufacturer's recommendations. This cost was $47.5k, which was less than the alternative of storing the units at the manufacturer's facility. The switchgear was stored indoors at the manufacturer's facility for $37.6k, which was determined to be less than handling the units twice and renting storage at an indoor facility in Sault Ste. Marie. In regard to labour and materials increases, the unionized contractor labour rate increases for the 1-year delay and inflation on miscellaneous materials added an additional $91k. This amount was negotiated and agreed upon with the contractor prior to finalizing the decision to delay the construction by one year due to COVID. PUC reviewed the labour rates proposed and determined they were consistent with the union contract.

g) In the *Report of the OEB – Regulatory Treatment of Impacts Arising from the COVID-19 Emergency* (the "Report"), the OEB agreed that utilities should be required to demonstrate that they require use of the Account 1509, COVID-19 Deferral/Variance Account ("COVID DVA"), by way of the means test provided therein. At section 9.5.2.6 of Exhibit 9, starting at page 23, PUC described how the guidance in the Report was applied to its COVID DVA balances. Specifically, based on the outcome of the means testing and associated guidance in the Report, the $176k of costs included in the Substation 16 project are ineligible for recovery through the COVID DVA, therefore these costs are recorded using the traditional accounting methods as prescribed in the

Accounting Procedures Handbook.

h) PUC believes that the additional project costs were prudently incurred and should be recoverable through the Substation 16 ICM reconciliation process. PUC's views on the rules for Account 1509 are explained at section 9.5.2.6 of Exhibit 9, starting at page 23.

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Sault Smart Grid – Reprioritization
Reference 1: Exhibit 2 – 2.8.2 Sault Smart Grid
Reference 2: Exhibit 2 – Distribution System Plan – 5.3.6.2.1
Reference 3: Chapter 2 Appendices – 2-AA

Question:

In reference 1, it shows that the gross capital additions for the SSG is $28.7 million, which is the same amount shown in reference 3. PUC Distribution also states that it reallocated funds for Substation 22 renewal to the renewal of transformers, switchgears, and on-load tap changers, which will benefit the SSG. PUC Distribution also proposes to defer the GIS UN Migration project.

a) Please confirm the renewal of transformers, switchgears, and on-load tap changers referenced above were in the original SSG scope. If so, please confirm that those costs are not in other line items in 2-AA. If not, please explain how this was a reprioritization of capital projects to accommodate the SSG and not an increase in scope.
b) The costs for the switchgear and distribution station program increased significantly in 2023. Please explain the driver for the increase.
c) Based on PUC Distribution's prioritization criteria, please rank all the capital projects and programs in reference 3.
d) Please provide a cost variance breakdown for the SSG project comparing the actual cost of the project components compared to what was planned.
e) Based on PUC Distribution's prioritization criteria please provide the priority rankings and the prioritization score breakdown comparing all projects within the DSP period.

Response:

a) The original SSG scope did not specifically include the renewal of transformers, switchgear, and on-load tap changers. It did include a commitment from PUC to evaluate potential efficiencies in execution of the SSG project with asset management programs including the long-term station renewal plan (JTC2_13: 0201.12 - 2016 Projection for Distribution Capital Engineering). In the 5.3.6.2.1 reference for re-prioritized Stations Renewal assets, synergies are being captured by having the scope of work with the EPC contract in terms of execution expanded to renew selected station assets. The equivalent cost of the project scope of work for new voltage control equipment is still part of the SSG

scope and an incremental portion related to replacement of the aged station equipment is part of the Table 2-AA costs.

b) The question states "The costs for the switchgear and distribution station program increased significantly in 2023". PUC is unclear in reference to what the increase is being interpreted. As indicated in Figure 5.4-3, p110 of the 2023-2027 DSP, the distribution station renewal for the 5-year period is $2.140M or 12% of the System Renewal category. Although stations are not broken out identically in the 2018-2022 DSP of the $25.538M of System Renewal proposed in Table 21, p87 of that document, only approximately $10.72M was budgeted for station renewal. If the question is related to 2022 rather than 2023, please see answer on VECC-8.

c) The information requested requires a level of effort that greatly outweighs the probative value of the information. It took PUC months to complete the DSP, including the ranking of test year projects found in Table 5.4.15. It would be a significant undertaking to rank all projects in Reference 3. It is not feasible to complete this request in the allotted time.

d) As the project is still in progress and actual costs have not been fully incurred, it is still too early to provide a detailed breakdown of actual costs. These costs will also be trued-up and subject to OEB approval at a later date. To be of assistance, PUC can state that the project is currently trending on budget.

e) Please refer to "c" above.

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Sault Smart Grid - Benefits
Reference 1: Exhibit 2 – 2.8.2 Sault Smart Grid
Reference 2: Exhibit 2 – Distribution System Plan – 5.3.6.2.2
Reference 3: EB-2020-0249 - PUC Amended Application, p. 17
Reference 4: Regulated Price Plan Price Report, November 1, 2022, to October 31, 2023, issued October 21, 2022
Reference 5: Exhibit 2 – Distribution System Plan – pg.93, Table 5.3-27

Question:

Reference 3 states that the scope of work could be reduced by PUC Distribution to maintain project capital limit set for the project. In reference 2, PUC Distribution confirmed that it has adjusted the scope of the distribution automation.

a) Please confirm the scope of the reduction in distribution automation and a cost estimate to complete the reduced scope items.
b) The forecasted annual reliability benefit to customers is $2.0 million. Please provide the basis of how the $2.0 million is forecasted.
c) Please confirm if the reduction in scope for distribution automation could affect the reliability benefits to customers. If so, quantify the benefit loss provided in part (b). If not, please explain why not.
d) The RPP Report was issued October 21, 2022. Please update the cost of power.
e) Please reconcile the 2023 Update in Table 5.3-27 in reference 5. The total projected benefit to customers does not sum up to the annual net benefit to customers and the annual reliability benefit to customers.

Response:

a) The Distribution Automation ("DA") scope reduction to achieve budget available was expected to be applied to maintain overall ICM budget. As part of the preliminary design stage criteria to rank DA priority was developed to be applied to feeder selection with factors such as evaluation of historical outage performance, circuit exposure, strength, or capacity of existing or new circuit tie points, and capacity at normal and alternate supply. The 34.5kV sub transmission FLISR automation remains as the top priority as it will support reliability improvement to all customers. Feeder FLISR automation will be applied

to 16 circuits. The balance of 32 circuits will not include FLISR automation although some selected fault locating instrumentation will be applied. Overall, the preliminary cost estimate (without detail design) of reduced DA scope is ~$3.2M +/-20%. Note that the reliability benefit was not part of the economic evaluation of the project. Scope reductions/additions to the DA will not impact the net economic benefit to the customer.

b) On October 28, 2020, PUC filed a revised ICM Application for its SSG Application (EB-2020-0249). Appendix AA10 (Navigant Report did long term NPV estimate) that was used to calculate the NPV of the annual reliability benefits over 20 years.

c) The reliability benefit estimate was not part of the economic net benefit calculations but was provided as part of the ICM application in support of the benefits in the Distribution Automation systems. The reduced scope of DA will affect the reliability benefit to customers. As described in (a) above, analysis using several criteria was used to identify priority to apply the DA reliability improvements to the worst performing circuits and areas.

d) PUC has updated the Cost of Power to reflect the OEB's RPP Report from October 21, 2022 in all of the OEB Models.

e) Table 5.3-27 has been updated below to reflect the error identified by OEB Staff.

Table 5.3-27 Customer Annual Net Benefit Summary Comparison (Revised)

	28-Oct-2020 Submission	2023 Update	Variance
Cost of Power - updated to current estimate (not including GS>50 on 34.5kV)	$82,512,685	$69,302,488	($13,210,197)
Projected energy savings with SSG implementation	2.70%	2.70%	$0
Projected customer energy savings through SSG	$2,227,842	$1,871,167	($356,675)
Projected system loss energy savings through SSG	$105,111	$79,664	($25,447)
Total purchased power savings	$2,332,953	$1,950,831	($382,122)
Additional revenue from increased SSG asset base	$1,754,862	$1,755,460	$598
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	$0
Additional O & M expenses due to SSG implementation	$296,400	$296,400	$0
Operating efficiency benefits due to SSG implementation	($30,816)	($30,816)	$0
Change In Revenue Requirement	$1,716,056	$1,716,654	$598
Annual net benefit to customers	**$616,897**	**$234,177**	**($382,720)**
Annual projected reliability benefit to customers	$2,017,000	$2,017,000	$0
Total projected benefit to customers	$2,633,897	$2,251,177	($382,720)

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Sault Smart Grid - Performance
Reference 1: Exhibit 2 – Distribution System Plan – 5.3.6.2.3
Reference 2: 2023 Cost of Capital, October 20, 2022

Question:

PUC Distribution proposes a method to symmetrically link VVO savings to ROE through a deferral and variance account. PUC Distribution intends to measure the VVO consumption savings.

a) Please explain from a technical perspective how PUC Distribution will measure the VVO consumption savings.
b) Please provide the formulas used for the calculations in Table 5.3-29 Customer Net Benefit summary (preferably in excel format).
c) Please provide the loss factor calculation PUC Distribution referenced from EB-2018-0219/2020-0249 Appendix AA-14.
d) Please update the calculations with the 2023 cost of capital parameters.
e) Please explain the benefits of a symmetrical maximum upside/downside cap in the DVA.
f) Please comment on the probability that scenario 3 will happen as compared to scenario 4. If one scenario is more likely to happen than the other how is the symmetrical cap truly symmetrical?

Response:

a) Please refer to supplementary filing of Appendix H to the previously filed Exhibit 2 of the 2023 Cost of Service Application (EB-2022-0059).

b) PUC has added a column to help explain the formulas used in table 5.3-29. Table 5.3-29 is reproduced below with a formulas column to help explain the calculations. A, B, C, I, K, L, M, and N are inputs described as follows:

A – The measured VVO consumption savings as per the methodology outlined in Appendix H_Sault Smart Grid_Performance Metrics_OEB Order No. 6_20221026
B – The annual reported consumption as determined by PUC's meters
C – The total Cost of power of $69,302,488

I – The annual consumption information is plugged into Appendix AA14 from PUC's Sault Smart Grid Application (EB-20180219/2020-0249) to produce the dollar savings from loss factor consumption reduction.

K – The additional revenue from increase SSG asset base comes from the calculation of the average NBV of SSG assets included in rate base. Appendix IR1 – Additional revenue from increased SSG Asset base has been provided to support the calculation of $1,755,460. Please note that this calculation includes the update requested in Staff 27d

L – The benefit of reduced capital expenditures obtained from the customer net benefit table produced in PUC's ICM Smart Grid Application (EB-2018-0219/2020-0249)

M – The additional O&M expenses due to SSG implementation obtained from the customer net benefit table produced in PUC's ICM Smart Grid Application (EB-2018-0219/2020-0249)

N – The operating efficiency benefits due to SSG implementation obtained from the customer net benefit table produced in PUC's ICM Smart Grid Application (EB-2018-0219/2020-0249)

	Formulas	Top of Dead Band	Bottom of Dead Band	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Measured (estimate) VVO Consumption Savings	**A**	16,324,838	14,327,652	13,350,394	16,822,310	782,551	29,750,110
PUC Annual Consumption	**B**	604,623,538	606,565,655	607,598,147	603,161,981	603,161,981	603,161,981
PUC Consumption without SSG (projection from LF)	**D = A+B**	620,948,376	620,893,307	620,948,541	619,984,291	603,944,531	632,912,091
% Savings	**E = A/B**	2.70%	2.36%	2.20%	2.79%	0.13%	4.93%
PUC Cost of Power Paid	**C**	$ 69,302,488	$ 69,302,488	$ 69,302,488	$ 69,302,488	$ 69,302,488	$ 69,302,488
Avg $/kWh	**F = C/B**	0.1146	0.1143	0.1141	0.1149	0.1149	0.1149
PUC Cost of Power Paid without SSG consumption savings	**G = D*F**	$ 71,173,655	$ 70,939,478	$ 70,825,230	$ 71,235,348	$ 69,392,402	$ 72,720,735
Customer Energy Savings ($)	**H = G-C**	$ 1,871,167	$ 1,636,990	$ 1,522,742	$ 1,932,860	$ 89,914	$ 3,418,247
Dollar Savings from Loss Factor consumption reduction (Appendix AA14)	**(I)**	$ 79,664	$ 79,664	$ 79,664	$ 79,664	$ 79,664	$ 79,664
Total purchased power savings	**J = H+I**	**$ 1,950,831**	**$ 1,716,654**	**$ 1,602,406**	**$ 2,012,524**	**$ 169,578**	**$ 3,497,911**
Additional revenue from increased SSG asset base	**K**	$ 1,755,460	$ 1,755,460	$ 1,755,460	$ 1,755,460	$ 1,755,460	$ 1,755,460
Benefit of reduced capital expenditures witth SSG	**L**	($304,390)	($304,390)	($304,389)	($304,388)	($304,388)	($304,388)
Additional O & M expenses due to SSG implementation	**M**	$ 296,400	$ 296,400	$ 296,400	$ 296,400	$ 296,400	$ 296,400
Operating efficiency benefits due to SSG implementation	**N**	($30,816)	($30,816)	($30,816)	($30,816)	($30,816)	($30,816)
Change In Revenue Requirement	**O = K+L+M+N**	$ 1,716,654	$ 1,716,654	$ 1,716,655	$ 1,716,656	$ 1,716,656	$ 1,716,656
Annual net benefit to customers	**P = J-O**	$ 234,177	-$ 0	-$ 114,249	$ 295,868	-$ 1,547,078	$ 1,781,255

c) PUC has provided the file in Appendix IR2 – PUC_App_AA14 Copy_VVM Energy Savings Est for ICM 20200120_20220811, which supports the Dollar Savings from Loss Factor Consumption of $79.7k.

d) The Cost of Capital Parameters has been updated in Appendix IR1 – Additional Revenue from increased SSG Asset Base which results in the following revised table 5.3-29:

Table 5.3-29 Customer Net Benefit Summary

	Formulas	Top of Dead Band	Bottom of Dead Band	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Measured (estimate) VVO Consumption Savings	A	16,324,838	14,327,652	13,350,394	16,822,310	782,551	30,838,482
PUC Annual Consumption	B	604,623,538	606,565,655	607,598,147	603,161,981	603,161,981	603,161,981
PUC Consumption without SSG (projection from LF)	D = A+B	620,948,376	620,893,307	620,948,541	619,984,291	603,944,531	634,000,463
% Savings	E = A/B	2.70%	2.36%	2.20%	2.79%	0.13%	5.11%
PUC Cost of Power Paid	C	$ 69,302,488	$ 69,302,488	$ 69,302,488	$ 69,302,488	$ 69,302,488	$ 69,302,488
Avg $/kWh	F = C/B	0.1146	0.1143	0.1141	0.1149	0.1149	0.1149
PUC Cost of Power Paid without SSG consumption savings	G = D*F	$ 71,173,655	$ 70,939,478	$ 70,825,230	$ 71,235,348	$ 69,392,402	$ 72,845,787
Customer Energy Savings ($)	H = G-C	$ 1,871,167	$ 1,636,990	$ 1,522,742	$ 1,932,860	$ 89,914	$ 3,543,299
Dollar Savings from Loss Factor consumption reduction (Appendix AA14)	(I)	$ 79,664	$ 79,664	$ 79,664	$ 79,664	$ 79,664	$ 79,664
Total purchased power savings	J = H+I	**$ 1,950,831**	**$ 1,716,654**	**$ 1,602,406**	**$ 2,012,524**	**$ 169,578**	**$ 3,622,963**
Additional revenue from increased SSG asset base	K	$ 1,986,663	$ 1,986,663	$ 1,986,663	$ 1,986,663	$ 1,986,663	$ 1,986,663
Benefit of reduced capital expenditures witth SSG	L	($304,390)	($304,390)	($304,389)	($304,388)	($304,388)	($304,388)
Additional O & M expenses due to SSG implementation	M	$ 296,400	$ 296,400	$ 296,400	$ 296,400	$ 296,400	$ 296,400
Operating efficiency benefits due to SSG implementation	N	($30,816)	($30,816)	($30,816)	($30,816)	($30,816)	($30,816)
Change In Revenue Requirement	O = K+L+M+N	$ 1,947,857	$ 1,947,857	$ 1,947,858	$ 1,947,859	$ 1,947,859	$ 1,947,859
Annual net benefit to customers	P = J-O	$ 2,974	-$ 231,203	-$ 345,452	$ 64,665	-$ 1,778,281	$ 1,675,104

e) The purpose of the maximum upside/downside cap for the DVA account is to refund customers the portion of revenue requirement directly related to the return on SSG Assets. In order to keep the benefits symmetrical, an equal maximum cap must be for VVO savings.

f) The different scenarios are presented to help explain the results that may occur and how the symmetrical calculation is being achieved. The likelihood of one scenario over another doesn't have an impact on effect on the symmetrical nature of the calculation. The symmetrical nature of the calculation is to provide an equal upside/downside benefit depending on the amount of VVO consumption savings. For example, for every 0.10% increase or decrease to VVO consumption savings beyond the dead band of 2.36% to 2.70%, represented a $34,650 refund or collection from customers.

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Sault Smart Grid - Performance Metrics

Reference 1: Distribution System Plan – 5.3.6.2.3 PUC's Response to OEB Order #6

Question:

PUC Distribution has provided an example of 2.7% electricity savings from the SSG project, which results in annual electricity savings of 17,456,712 kWh.

a) Please reconcile the 17,456,712-kWh savings with the 16,324,838-kWh savings estimated in Section 5.3.6.3.2.3 within the Distribution System Plan.

In reference 1, PUC Distribution intends to track the reduction in demand reduction by trending the kW on station assets.

b) Please explain how PUC Distribution will normalize across the years to take into consideration changes in load growth such that it is a fair comparison on the reduction as a result of VVO performance.
c) How does PUC Distribution expect the forecasted annual electricity savings (kWh) from the SSG project to change when considering DERs, EVs, and other future technologies?
d) Please explain if PUC Distribution considered establishing a % target for demand reduction. If not, why not?

One of the metrics was avoided revenue loss, which is calculated based on minutes of customer reliability improvement and average customer revenue.

e) Please confirm this is calculated by rate class and uses average customer revenue by rate class.

The calculation for customer reliability improvement is based on customers that experience a momentary outage divided by total customer outages in one event.

f) Please explain how PUC Distribution differentiates momentary outages benefited from equipment installed prior to SSG (e.g., reclosers) to equipment installed as part of the SSG.

PUC Distribution provided in table 2 a table of projected green house gas emissions savings.

g) Please provide the equivalent PUC Distribution energy savings each for the ten years and confirm whether PUC Distribution intends to update the electricity sector GHG emissions, IESO annual energy demand, and emission factor yearly.
h) Please provide the document that supports the 4.32 emission factor.
i) How does PUC Distribution expect the forecasted annual emission factor to change and what impact will it have on the forecasted emission savings? Has PUC Distribution considered external studies that have forecasted Ontario's electrical emission factors?

Response:

a) The 17,456,712 calculation includes losses and the 16,324,818 excludes losses. Please see table below for reconciliation:

	Appendix H: SSG Perforamnce Metrics	**DSP 5.3.6.2.3 Table 5.3-29**
Consumption Savings	16,670,199	16,324,838
System Energy Loss Savings Estimate (kW)	786,513	
Total kWh saved with losses included.	17,456,712	
Purchased Energy	617,414,778	604,623,538
Purchased Energy Including Savings	634,087,977	620,948,376
VVO Savings	2.70%	2.70%

b) The method to be used for measurement of energy savings will be ongoing and should be inherently normalized as it is being re-calculated based on the characteristics of the load and potential embedded supply mix at that point in time. Over the years the energy savings measured each year will accumulate and are real savings from the supply system. The VVO M&V methodology summary is provided in Appendix A of "AppendixH_Sault Smart Grid_Performance Metrics_OEB Order No. 6_20221026". This method considers the energy and voltage during the on/off periods and will account for changes in load growth as the ratio of savings between VVO on/off is expected to stay consistent.

c) PUC has not undertaken any research in this area.

d) PUC did not consider establishing a % target for demand reduction.

The distribution system supply is currently not experiencing demand constraints in operation nor expecting them to arise in this DSP planning horizon. As such, prioritization towards research for system benefits or a business case for a demand reduction program has not been undertaken. If future distribution demand supply constraints are emerging this would be explored in more detail.

e) Yes, PUC is proposing to calculate the avoided revenue loss from reliability improvement by rate class utilizing average customer revenue by rate class.

f) The SSG metric proposed looks at the new distribution automation zones being installed primarily as the benefit being measured from the automated restoration aspect of the system (customers restored from automated alternate supply). The three existing reclosures are on radial circuits and will not impact the PUC metric proposed.

g) The PUC energy savings input to the GHG calculation used the base year estimate of the ICM application (17,456,712 kWh) as a constant. No long-term energy forecast was developed for the 10-year period. The only variable input value was the delta or variation in IESO GHG Emissions forecast from the referenced IESO Annual Planning Outlook report (Dec 2020).

PUC does intend to update the GHG calculations annually using most recent available reporting data from the IESO and The Atmospheric Fund (TAF) Ontario Emissions data reporting.

h) PUC described the basis of the 4.32 emission factor in its previous reply to an interrogatory question posed by Environmental Defence in the SSG ICM application. It relates to the ratio of Annual Marginal Emission Factor (MEF) to Annual Average Emission Factor (AEF). Please refer to ED-1 of Interrogatory Responses of EB-2020-0249/EB-2018-0219.PUC has included this document as Appendix IR4 to these IR responses.

i) PUC has no direct research on the trending of the forecasted annual emission factor but can offer the following references as consideration. In the IESO Annual Planning Outlook Report (2020) the IESO noted they expected GHG emissions to be rising over time in the electricity sector in Ontario (4 Mt CO2e in 2022 to 15 Mt CO2e in 2040). The IESO report for 2021 still maintained a similar trend line in forecasts. In the most recent TAF report (2021) on Ontario electricity emissions factors the ratio of Marginal Emission Factor to Annual Emission Factor has decreased to 123/31=3.97.

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Sault Smart Grid – Liquidated Damages
Reference 1: Exhibit 2 – 2.8.2 Sault Smart Grid
Reference 2: Exhibit 2 – Distribution System Plan – 5.3.6.2.4

Question:

PUC Distribution states that it does not expect any EPC Contract Liquidated Damages. The EPC Contract Liquidated Damages was filed confidentially in EB-2018-0217/2020-0249 and the decision notes that it covers damages resulting from "performance" or "delay". The SSG was originally planned to be in-service end of 2022 but now there is still testing and optimization in 2023.

a) Please confirm if the testing and optimization was originally planned for end of 2022.
b) Please explain whether the work in 2023 would constitute as a delay from the EPC contract.
c) Please explain how "performance" was assessed if testing and optimization has not been completed.

Response:

a) The testing and optimization phase of the project was expected to extend into 2023 based on the project notice to proceed following the final project approvals.

b) The work in 2023 does not constitute as delay under the terms of the EPC contract.

c) Performance assessment will be completed in the testing and optimization period.

Staff 30

Reliability
Reference: Distribution System Plan – 5.2.3.2.3 Outage Details for Years 2017-2021

Question:

PUC Distribution showed that the highest outage cause is due to defective equipment.

Please provide a further breakdown of defective equipment outages identifying the equipment that caused the outage.

Response:

Please see the table below for the breakdown of the number of Defective Equipment outages for the years 2018-2021 by asset type sub cause codes. The Defective Equipment value in Table 5.2-12 of the DSP included major event days in the value for 2020. The actual value should be 173.

Number of Outages					
Defective Equipment	**2018**	**2019**	**2020**	**2021**	**Grand Total**
Arrestor	6	1		1	8
Conductor - Primary	19	25	38	22	104
Conductor - Secondary	17	29	35	10	91
Conductor - Termination	6	25	16	11	58
Insulator	3	2	3		8
Pole or Guy Wire			4	2	6
Recloser	1	1			2
Switch - Breaker	2	1		2	5
Switch - Cable Riser		1			1
Switch - Fused	13	3	6	2	24
Switch - Kabar			2	3	5
Switch - Solid Blade		4	1		5
Transformer - Distribution	4	19	61	23	107
Transformer - Padmount		1	3	3	7
Transformer - Submersible	3	10	4	10	27
Grand Total	**74**	**122**	**173**	**89**	**458**

Staff 31

Cause Code – Foreign Interference
Reference: Distribution System Plan – 5.2.3.2.3 Outage Details for Years 2017-2021

Question:

According to PUC Distribution, 14% of customer hours of interruption are due to foreign interferences, excluding major event days.

What plans does PUC Distribution have to reduce foreign interference outages during the DSP period?

Response:

Some examples of how PUC attempts to mitigate foreign interference impacts are as follows:

1. Designs consider pole setbacks from roadways and high traffic areas to mitigate motor vehicle accidents.
2. Designs maximize separations and clearances to vegetation and structures to mitigate impacts of line to ground faults from animals, trees, etc.
3. Install wildlife protection covers onto insulators in high concern areas (e.g: squirrel guards).
4. Continue to perform advanced vegetation management techniques to mitigate tree contacts.
5. Installation of resin poles in areas with higher-than-normal wood pecker populations (swamps, marshes, and meadows).
6. Installation of mechanical barriers and bollards around pad mounted equipment in high traffic areas.
7. Installation of warning signage for underground equipment above and beyond CSA requirements to mitigate impacts of snow removal and snow-plow collisions.

Staff 32

System Renewal
Reference: Distribution System Plan – 5.4.1.2.2 System Renewal

Question:

The forecasted system renewal spending varies from $4.561 million to $2.525 million between 2023 to 2027.

Can system renewal projects be deferred from 2023 to later years to better pace system renewal spending?

Response:

There may be some flexibility to defer some small amounts from 2023 to better pace overall renewal spending however there is some strong rationale to how projects were placed across the 5-year application period as follows:

- An integrated resources plan is used to ensure the time spend by internal resources (engineering, line crews) is optimized at all times across the 5-year period eliminating the need for temporary layoffs or conversely undue overtime.

- Due to the relatively small size of the LDC and associated projects and programs, overall economies of scale are achieved on some of the projects by not breaking them into small equalized annual parts that would incur additional administration or mobilization and demobilization costs.

- Some investments are placed earlier due to higher risk levels where assets are already at end of life so risk levels would go up if deferred (voltage conversion is an example where pushing out the remaining conversion linework scheduled in 2023 would necessitate that the two remaining end of life 4160V stations would have their retirement deferred).

- The entire net capital budget across the 5-year period (with the exception of the one major station build in year 5 which is primarily built by external resources) is paced so that the total of all categories (System Access, System Renewal, System Service and

General Plant) will result in a fairly level expenditure rate. The station build project is in the final year of the application of necessity as a significant degree of lead-up planning work needs to be done before this project can be implemented.

Staff 33

DSP Performance Measures – Telephone Calls Answered on Time
Reference: Distribution System Plan – 5.2.3.1 Distribution System Plan

Question:

According to PUC Distribution, the percentage of telephone calls answered on time has decreased from 80% in 2018 to 71% in 2021. PUC Distribution's target is to answer at least 65% of phone calls on time.

a) Why has the number of phone calls answered on time been trending down?
b) Does PUC Distribution intend to improve the number of phone calls answered on time during the DSP period? If so, how does PUC Distribution intend to improve this measure?

Response:

The following is the response for parts "a" and "b".

PUC continues to exceed the OEB set requirement of 65%, however has seen the percentage of telephone calls answered on time decrease from 80% to 71% over the last 4 years. This has trended down due to a couple factors. First, and more recently there has been increased OEB Program changes such as the introduction of Customer Choice, CEAP as well as multiple electricity pricing and rebate changes which has increased customer call times resulting in more call queues.

PUC has also experienced a significant turnover in staffing within the Customer Experience department. Employees took roles in other departments covering long term vacancies which left Customer Experience with new employees with significantly less experience. This also increased call times.

When the COVID pandemic hit, PUC Customer Experience employees were forced to work from home. This necessitated changes to systems including remote access to the CIS database which is not as quick as access within the office environment. Coupled with increased sick time, this caused downward pressure to the call metrics.

As COVID restrictions have eased and turnover has levelled off, PUC has been trending above 74% and working to get back to 2018 levels. PUC continues to strive to offer customers

exceptional customer experiences. PUC will also continue to work to offer customers convenient access to Customer Experience through email and online access service requests.

Recent investments in the mobile app, and future investments planned for self serve web functions, should help lower the customer calls received in the queue and should help promote an upward trend on call metrics.

Staff 34

City Projects
Reference 1: Chapter 2 Appendices – 2-AA
Reference 2: Distribution System Plan – Appendix A – City Projects

Question:

PUC Distribution states that in 2023 it anticipates the relocation of an underground vault and an overhead to underground relocation.

a) Please provide the cost estimate for these projects and any other known city projects currently.
b) The capital contributions provided in table 1 of reference 2 show that on a percentage basis, the capital contributions for 2022 and 2023 are lower than historical years. Please explain why.

Response:

a) City projects are dynamic in nature with scope of work and target completion dates dependent upon City budget approvals, availability of grants or funding and other potential concurrent City needs or influence. The updated list of 2023 City projects with associated PUC costs are noted below:

Project	Estimated Costs
Queen Street East (Design Only)	$20,000
Biggins Ave.	$150,000
Stanley Street	$15,000
Wemyss Street	$25,000
Blake Ave.	$16,000
Misc. Road Resurfacing	$25,000

b) Capital contributions within this program generally follow the cost recovery regulation for improvements noted in the Municipal Act. The degree to which PUC can recover costs through capital contributions may therefore vary based on the nature of the project (e.g., road project, sewer or aqueduct project, non-municipal right of way, etc.).

Staff 35

Joint Use
Reference 1: Distribution System Plan – 5.2.2.4 Telecommunication Entities
Reference 2: Distribution System Plan – Appendix A – City Projects

Question:

PUC Distribution provides a summary of consultations in reference 1. The last consultation with telecommunication entities was in 2020.

a) Please provide any updated consultations with telecommunication entities since 2020.
b) Are there any planned consultations with telecommunication entities? If not, why?

Response:

a) The most recent formal exchange of information from PUC to telecommunications companies occurred February 12, 2020. Ad-hoc communications with telecommunications companies occur on a regular basis.

b) With regards to planned consultations, PUC circulates information on planned projects on an annual basis. Continuation of ad-hoc conversations between those annual consultations is critical as projects arise frequently impacting telecommunication infrastructure.

Staff 36

Services
Reference 1: Distribution System Plan – Appendix A – Services
Reference 2: Load Forecast Model

Question:

PUC Distribution states that some new/upgraded services in existing areas require distribution system upgrades to service the customer. In reference 2, it shows that the overall trend for system load is declining.

a) Please explain what system upgrades are required to accommodate new services since the overall system load is declining.
b) Please divide the services budget by expansion projects and system upgrade projects.

Response:

a) Many system service upgrades requested are a result of requirements of the Ontario Electrical Safety Code (OESC) in which the customer is required to move for example from a 60A or 100A service to a 200A service due to work they are doing in the home or business. The current OESC rules applying to the service on the customer side require dedicated breakers for things such as kitchen receptacles, outdoor plugs, hot tubs, etc., and that the service be sized according to prescribed loading calculations outlined in the code. In the past OESC, the requirements were less stringent, and a service upgrade may not have been required. So, a customer may do a renovation or add square footage to the building, but the actual load does not necessarily increase. However, the service is now to current code, and ready in the future for the worst case should it be loaded to its limits. On the utility side, PUC may need to upsize the service wires to the connection point on the distribution network either at a pole or in an underground handbox accordingly. When the utility connection point is built to a historical standard, it too may need to be upgraded to a current standard.

b) The requested division of costs has not historically tracked so cannot be readily determined. From experiential knowledge, it can be reasonably stated that the vast majority of the costs within the Customer Demand - Services category are for system upgrades. And the majority of recent expansions are related to residential subdivisions

and have therefore been captured in the separate 'Customer Demand - Subdivisions' budget line item.

Staff 37

New Subdivisions
Reference 1: Distribution System Plan – Appendix A – Services
Reference 2: Load Forecast Model

Question:

PUC Distribution states that it anticipates 150 new lots throughout PUC Distribution's service territory in 2023. However, in reference 2, the change in the number of customers for the residential rate class between 2022 and 2023 is only 103.

Please explain whether PUC Distribution would agree that a manual adjustment is required considering it has actual forecasted information on new lots connecting to the system. If not, please explain why not.

Response:

PUC does not believe that a manual adjustment would be applicable due to two contributing factors that account for a difference between the number of builds and the number of new customers in the load forecast. Firstly, of the 150 anticipated new service builds, some portion of the lots will have houses that are not constructed immediately. The distribution network infrastructure will be installed, but it may be several years before all the actual homes are built and connected to the network. This slow pace of subdivision infill is typical in Sault Ste. Marie and differs generally from the pace of build in southern Ontario where the homes are all typically built immediately. Secondly, the Sault Ste. Marie population growth has been relatively stagnant or slightly declining level. The bulk of the development is primarily for larger or higher end homes. As these homes are occupied, it is often accompanied by some retirement of older homes in the community, or by residents cascading from rental units to starter homes, from starter homes to higher end homes, or from larger older homes to new smaller homes in retirement. There therefore is not a strong correlation between the count of services and system loading.

Staff 38

Distribution Station
Reference 1: Chapter 2 appendices – 2-AA
Reference 2: Distribution System Plan – Appendix A

Question:

In reference 1, the distribution station budget in forced renewal and improvements and enhancements totals $301k. In reference 2, there is a material investment narrative called stations renewal – buildings & fence repair, which includes $144k for the test year.

The material investment narratives for station renewal appear to be missing $157k. Please provide the narrative for the remaining balance or please explain which narrative in reference 2 should explain the remaining balance.

Response:

The discrepancy in the amounts between the two referenced documents is attributable to the sum of the three planned capital items highlighted in yellow in the table below that need to be added to the $144k referenced in the question and highlighted in green. Material investment narratives are not available for these items as they are items below the materiality threshold and narratives have not been written. A brief description has been provided as to what these items are and to explain the rationale for the proposed expenditure:

- Unplanned renewal of Distribution Station Assets – this is an annual allowance for the replacement of unforeseen failed equipment such as relays, breakers, switches, bushings, or other large items that qualify as capital investments upon failure. An amount reflective of longer-term historical needs each year is budgeted.

- Planned Distribution Station Transformation – this is for the replacement of one of the 18 station service transformers identified in the ACA, page 77. Although no health information is available for these critical assets, as can be seen in Figure 4-38, 13 are between 31-60 years of age and are in need of attention.

- Planned Distribution Station Battery and Charger replacement – PUC has an annual program for the routine replacement of these critical assets that generally have a short life A detailed account of the health is described in the ACA, p78 (Exhibit 2,

p643). Generally one station bank and/or charger is scheduled to be replaced per year to keep pace with maintaining these assets at an acceptable reliability level.

DSP Renewal

Year of Proposed Investment		2023
Distribution Stations	Unplanned renewal of Distribution Station assets - emergency repairs upon failure	$ 75,265
	Planned - Distribution Station building and fence repairs	$ 144,259
	Planned - Distribution Station Transformation	$ 37,633
	Planned - Distribution Station Switchgear, protection, and control renewal (Sub 1, 11 and 20)	$ 175,619
	Planned - Distribution Station SCADA and Communications asset renewal	$ 12,544
	Planned - Distribution Station Battery and Charger replacement	$ 43,905
	Planned - DS HV Interconnections	$ -
	Planned - DS rebuilds (excludes reserves set aside)	$ -
	Planned - DS Additional	$ -
	Subtotal - Distribution Station renewal work	**$ 489,225**

Staff 39

Station Renewal – Building and Fence Repair
Reference 1: Distribution System Plan – Appendix A – Station Renewal – Building and Fence Repairs
Reference 2: Asset Condition Assessment

Question:

PUC Distribution states in reference 1 that the Building and Fence Repair program is to ensure the upkeep of buildings and associated fences. From 2018 to 2022, PUC Distribution spent $30k on average in this program but in 2023 to 2027, PUC Distribution forecasts an average spend of $110k. In reference 2, it shows that the building and fence condition is either very good or good.

Please explain why the average spend of this program would need to increase when the condition of the assets is still very good and good.

Response:

As summarized in Table 1 of the material investment narrative, the total 2018-2022 historical 5-year spend for this item was $206k whereas the proposed 5-year budget for 2023-2027 is $554k. The increased needs identified for the proposed plan were primarily associated with two factors:

- A significant increase in copper theft from fences and in stations over the past 2-3 years. Although recently installed cameras are expected to help with this going forward, replacement will require review and testing to determine what is missing, possibly engineering design, and ultimately replacement.

- Of the station buildings identified in Figure 4-45 of the ACA, p83, (Exhibit 2, p648) six have a health index below the DAI threshold and proposed capital associated with sandblasting and painting units amongst these is included in the plan. Paint in these 40–50-year-old metalclad enclosure type buildings is known to have lead paint content and costs are reflective of the associated environmental controls and work methods required to complete the work.

Staff 40

OH Renewal - Pole Replacement
Reference: Distribution System Plan – Appendix A – OH Renewal - Poles

Question:

PUC Distribution states that it plans to replace approximately 60 poles per year during the forecasted period (not including forced replacements). On average, PUC Distribution plans to spend on average $620k per year on poles within this program. Historically, PUC Distribution spent on average $514k per year on poles through the same program (2018-2022).

a) Please state how many poles were replaced within this program for each year between 2018 to 2022 (unforced pole replacements).
b) Approximately how many poles does PUC Distribution expect to be in poor or very poor condition by the end of the DSP period (including those currently in fair condition)?

Response:

a) For the years 2018 through 2022, deteriorated poles replaced as part of the OH Renewal – Pole replacement program are as follows. Please note for the year 2022, the count includes a combination of actual poles prior to November 15 and projected until year end.

Year	Number of Poles
2018	33
2019	41
2020	48
2021	26
2022	60 (45 to date)
Total	193

b) As described in the Asset Condition Assessment (ACA), Table 0-1, (Appendix H to the DSP, p574 of Exhibit 2), for poles in Poor condition the recommendation is to "Start the planning process to replace or rehabilitate, considering the risk and consequence of failure". For poles in Very Poor condition "The asset has reached its end of life"; so immediately assess risk and replace or refurbish based on assessment. In its capital plan for 2023-2027 PUC has planned to replace 1,050 poles, 300 of them directly through the OH Renewal – Pole Replacement program and 750 incidentally through other overhead

lines programs such as restricted wire, voltage conversion or unplanned renewal. In Figure 4-3 on page 38 of the ACA (Appendix H to the DSP, p603 of Exhibit 2), 590 were identified as in Poor condition and 574 were in Very Poor condition. So, it is anticipated that at the end of the COS cycle, the vast majority of the Very Poor poles will have been fully replaced and that an almost equivalent number of those in Poor or perhaps better condition will have fallen to a health level of Very Poor. Ongoing annual pole testing however will validate this in time to adjust, if necessary, the proposed investment in subsequent Distribution System Plans.

Staff 41

Unplanned Line Renewal
Reference 1: Distribution System Plan – Appendix A – Unplanned OH Renewal
Reference 2: Distribution System Plan – Appendix A – Unplanned UG Renewal

Question:

In reference 1 and 2, PUC Distribution provides table 1, which shows the estimated number of replacements per year.

Please provide the number of historical (2018 to 2022) replacements for all assets shown in table 1.

Response:

The below tables illustrate the quantity of assets installed between 2018 and 2022 (up to November 17, 2022).

OH Renewal (1C200-1-1)

Asset	# Replaced/Installed
Poles	94
Pole Mount Transformers	63
Fused Disconnects	27
Disconnect Switches	12

UG Renewal (1C200-1-2)

Asset	# Replaced/Installed
Pad Mount Transformers	32
Submersible Transformers	23

Staff 42

Overhead Renewal Transformers (PCBs)
Reference 1: Distribution System Plan – Appendix A – Overhead Renewal Transformers (PCBs)
Reference 2: Chapter 2 Appendices – 2-AA

Question:

Reference 1 shows that PUC Distribution intends to spend $711k on a program to replace PCB transformers. In reference 2, there is capital expenditure of $1.48M for OH Renewal.

a) Please confirm if the budget to replace PCB transformers is included in the $1.48M.
b) The requirement to remove PCB transformers has been known since 2008 however PUC Distribution has not spent any capital budget on PCBs in the past five years. Please explain why PUC Distribution has not done so, and how this decision was prudent.
c) This program is stated as high priority but is only starting in 2023. Please show this program's priority in comparison to capital projects/programs in the past five years.
d) Please provide an approximate number of poles which will be replaced through this program.
e) Is PUC Distribution expecting overlap with other pole replacement programs? Do the estimated costs in each program account for overlap?

Response:

a) PUC confirms that the budget to replace PCB transformers is included in the $1.48M.

b) PUC was aware of the regulations regarding PCB elimination since their inception and believes its prioritization was prudent. PUC opted to complete testing then replace of all padmount and submersible transformers first, which has been fully completed. These were considered the highest environmental risk assets due to the possibility for oil leaks to disperse through ground water or underground conduits. They are also more susceptible to failure due to rust from ground water and road salt. Overhead transformers were considered a much lower relative risk from an environmental perspective being highly visible, not as prone to deterioration and subject to one third annual visual inspections. Testing to determine the scope of replacements was budgeted for and completed during the 2018-2022 COS period. Other projects and programs during that period were enumerated to be of a higher immediate concern (i.e., deteriorated poles, restricted wire and voltage conversion) to allow the retirement of end-of-life

Substations 4 and 5. Prudence is demonstrated in that existing overhead transformer assets were leveraged to their full potential with limited risk while eliminating other assets where the consequences of failure could potentially be high sooner (i.e., structural failure of a deteriorated pole or restricted conductor creating a public hazard, loss of either of the last two remaining 4.16kV substations for which compatible parts are no longer available).

c) As set out on page 130 of the DSP and in the Material Investment Narrative at PDF page 283 of Exhibit 2, the priority has increased from a low to high priority primarily due to the consequences of regulatory non-compliance if not completed by the 2025 deadline. Environmental risks have only increased minimally and the risk of failure due to asset age has increased moderately. However, most would be expected to continue to have a significant service life if allowed to continue operating. Although PUC does not have a formal ranking of every project and program over the past 5-year period, it can confirm that this was considered low priority strictly from a risk perspective relative to the majority of renewal work planned and executed over that period. Furthermore, from a prudence perspective, PUC reviewed options to execute the project paced across a long period versus doing over a shorter period as a one-time project and found that the one-time project would lead to economies of scale through reduction of mobilization/demobilization and less administrative efforts.

d) It is estimated the 2/3 of the transformer replacements will require a pole replacement, primarily due to inadequate clearances to meet current standards, or due to pole strength and life. Of those requiring pole replacements, a portion of those will require adjacent poles to be replaced to accommodate for conductor uplift and maximizing infrastructure renewal efficiencies. It is estimated that approximately 200 poles will be replaced within the PCB transformer replacement program.

e) A detailed review or the transformer locations that require replacement is required. During such review, coordination of infrastructure renewal programs will be considered to maximize the efficient replacement of assets. With the currently available information, it is assumed that approximately 10% of transformer replacements will be captured within overlapping programs (restricted wire, deteriorated poles, etc.). Additionally, no overhead transformers within PUC's 4.16kV system have been tested, as PUC's plan is to convert all of the 4.16kV system prior to 2025 under its voltage conversion program. This

will include the removal of all 4.16kV transformers of potential concern. Cost savings have been considered when estimating all programs.

Staff 43

Voltage Conversion
Reference: Distribution System Plan – Appendix A – Overhead Renewal Voltage Conversion

Question:

PUC Distribution states that it intends to voltage convert the 4.16kV system in this period of the DSP and to disconnect Substation-4 and 5 but will not decommission them until the next cost of service period. Table 1 in reference 1 also only shows expenditures in 2023.

a) Please confirm if all the 4.16kV systems will be converted at the end of 2023. If not, please explain why there are no other planned capital amounts in future years. If so, please explain why PUC Distribution has not paced the voltage conversion over five years since the substations will not be decommissioned until the next cost of service.
b) Please provide the number of km of line that will be converted by the end of 2023.
c) Please explain if there are any safety risks in leaving two substations disconnected but not decommissioned for five years and whether this decision will incur current or future incremental OM&A costs as compared to decommissioning the stations now.
d) Please confirm if Substations-4 and 5 still have net book value in rate base.

Response:

a) PUC confirms all of the 4.16kV systems will be converted at the end of 2023. PUC's reasoning to not spread the costs out and pace across the 5-year period is due to a number of factors. First, Substations 4 and 5 were evaluated as being beyond their service life and as in very poor in condition assessments predating the first OEB submitted COS application in 2018-2022. They were not reconsidered in the 2018 ACA as it was already planned at that time for them to come out of service with the retirement of the 4.16kV distribution lines. Also, Substation 5 has electromechanical protection relays with rusted moving parts and Substation 4 has switchgear with leaking insulators that are no longer available and would need custom manufacturing in the event of a failure. Consequently, the urgency of taking these out of service without delay continues to grow.

b) For the same reasons described at further length in four bullet items provided in response to OEB Staff-32 (e.g., resource planning, economies of scale, risk/benefit prioritizations, pacing across application periods).

c) There will be no material safety risks with leaving the stations disconnected, out of service for the period. The additional time was intended to allow planners time to determine if there are any future uses for the property and to schedule the work at a time that fits best with other risks and costs. Following internal review and discussions since the DSP was written, PUC now expects to revisit this approach to evaluate completing the decommissioning of the stations earlier.

d) Substations 4 and 5 do not have a net book value in rate base.

Staff 44

Underground Renewal – Padmount Transformers
Reference 1: Distribution System Plan – Appendix A – Unplanned UG Renewal (Forced)
Reference 2: Exhibit 2, PUC Distribution Inc. Asset Condition Assessment, pg.50

Question:

As per reference 1, PUC Distribution estimates that six padmount transformers and seven submersible transformers will be replaced each year of the DSP period (2023-2027). According to the asset condition assessment performed by METSCO, approximately 47 padmount transformers are in poor or very poor condition and 128 submersible transformers are in poor or very poor condition.

The average cost per year between 2023 and 2027 for the program is $387.4k. The average cost per year between 2019 and 2021 was approximately $338k, a 15% increase. In that period, five mini padmount transformers, 13 padmount transformers, and 21 submersible transformers were replaced.

a) Please explain the increase to the average cost of the program between 2019-2021 and 2023-2027.
b) Please explain the reasoning for replacing approximately 30 padmount transformers, given that only 47 are currently in poor or very poor condition (64%). Is PUC Distribution aiming to replace all its padmount transformers in poor condition at some point?

Response:

a) When budgeting for the 2023-2027 COS period for this program on 2022, PUC used historical values for the 2018-2022 period (actuals for 2018-2021 and projected for 2022) and applied a 2.5% annual inflation factor for the 5 years (e.g., 13.1%). This equates approximately to the 15.0% increase noted above.

b) The 30 padmount transformers estimated in the Material Investment Narrative referenced are transformers that could be of any age from newly installed to end of life that have either failed due to a storm, vehicle accident, premature failure, fault damage or other uncontrollable event. The program is referred to as 'Forced' renewal because these are assets that need to be replaced due to unforeseen failure. So, these may only

be by chance, assets that require renewal due to age or health. In the ACA please refer to both Table 3-1, p33 (Exhibit 2, p598) and Figure 4-17, p50 (Exhibit 2, p615). Based on the 'Implications' column in Table 3-1, only the 14 transformers identified as Very Poor in Figure 4-17 are currently candidates for planned replacement. During the 2023-2027 period, the actual budget proposed for renewal of these transformers is $0 and associated dollars have been allocated to other assets and programs where the risks were determined to be of higher priority. Part of the rationale includes that these are lower risk assets that can generally be run to fail and be quickly changed out if they fail with minimal customer impact. They are also part of a one third plant inspection program so can be visually monitored to ensure that overloading, poor connections, or oil leaks does not go unchecked. The likelihood of failure should therefore be low.

Staff 45

Restricted Wire
Reference: Distribution System Plan – Appendix A – Restricted Conductor

Question:

PUC Distribution is removing #6 copper conductor and replacing it with #2ACSR conductor. On average, PUC Distribution plans to spend $600k per year on restricted conductors. Historically, PUC Distribution spent $598k per year on restricted conductors (2018-2022).

a) Please explain if PUC Distribution has considered the benefits of a larger conductor size in comparison to the incremental costs. If not, please explain how PUC Distribution assessed that #2ACSR is a suitable size for future capacity needs and storm hardening its distribution system.
b) Please state the historical restricted conductor projects completed in each year from 2018 to 2022.
c) Please provide a table outlining how many meters of conductor was replaced with each historical project (2018 to 2022) and each forecasted project (2022).

Response:

a) PUC does consider conductor size when executing voltage conversion projects. In general, it has standardized on three conductor sizes: #2ACSR (184A), 3/0 (315A) and 336ACSR (535A). The conductors are selected and matched with standardized feeder ampacities which have breakers, switch ratings and protections which have nominal ratings of 150A, 300A and 600A to correspond. Although #2ACSR works in most of the areas where voltage conversion is being executed, 3/0 or 336ACSR may be applied in some applications on main feeder trunks closer to stations where additional capacity provides the most value. The incremental cost of conductor size is minimal on overall project costs so the largest conductor size to suit the application is always used. From a storm hardening perspective, voltage conversion projects are always executed with designs based on USF standards, which are derived using current CSA and industry standards that account for the latest applicable, wind, ice and storm loading and climate change conditions.

b) The below identifies the main, restricted wire removal projects for 2018 to 2022.

2018
- Red Pine Drive
- Wallace Terrace, 5th Ave, 6th Ave
- Devon Road
- Carpin Beach Road

2019
- 2nd Ave
- Welcome Ave.
- Cumberland/Woodcroft

2020
- Case Road, Old Garden River Rd.
- Chippewa Street
- Moss Road North

2021
- Grandview/Spruce/Birch

2022
- Lennox/Bainbridge
- Moss Road South
- 4th Line East
- River Road
- Leigh's Bay Road

c) The table below identifies the total quantity of restricted conductor replaced between 2018 and 2022 that corresponds to the projects listed in "b" above.

Year	Single-Phase (m)	Three-Phase (m)
2018	3352	0
2019	2640	0
2020	6274	2772
2021	1295	0
2022	3510	0

Staff 46

Customer Demand – Revenue Meters
Reference: Distribution System Plan – Appendix A – Revenue Meters

Question:

PUC Distribution states that as part of its revenue meters replacement program, it will replace on average 400 meters per year during the DSP period. The average cost estimated by PUC Distribution equates to $348k per year or $870 per meter during the DSP period. From 2018 to 2022, the average cost per meter was $742 per meter. The average replacement cost per meter has increased by 17% from the historic to the test period.

Please explain the increase in the gross cost to install the revenue meters.

Response:

A number of factors contribute to influence the amount of the line-item Revenue Meters as bulleted below. The 17% increase observed will be a composite result of these factors:

a) In each year, quantities, and ratio of single-phase meters and three phase meters purchased vary depending upon stock in inventory and customer demand. Prices for three phase meters are higher than single phase;

b) Meter purchases are committed in US dollars and subject to currency exchange fluctuations;

c) Meter pricing is subject to inflation;

d) Increases in negotiated staff wages increase installation costs over time; and

e) Increases in trucking tools generally increase installation costs over time.

Staff 47

Underground Renewal – Vaults
Reference: Distribution System Plan – Appendix A – UG Renewal Vaults

Question:

PUC Distribution intends to rejuvenate major/minor vaults identified as deficient and Manhole 123. The budget for underground renewals in 2023 is also $401k.

a) Please provide the work planned for 2023 and explain why the budget is higher for 2023 than in other years.
b) Please provide a cost assessment for the worst-case scenario and the best-case scenario to address Manhole 123.
c) Please explain how PUC Distribution has tried to pace the underground renewal work over the DSP period.

Response:

a) The work planned in 2023 is to replace a large manhole vault that has deteriorated to the point of a safety concern. Manhole 123 is located in a public parking lot. The relatively higher costs are associated with the large size of the vault and complexities with site access and traffic control due to the high traffic public location.

b) The estimate for Manhole 123 in 2023 is approximately $315k. A detailed engineering assessment is required to determine options for replacement/rejuvenation and is planned for during implementation. Preliminary estimates for each option are noted below. Estimates are dependent on the final requirements and contractor availability and pricing. Multiple options will be reviewed in further detail, including, but not limited to:

- Vault removal – Replace and reroute cables to not require vault in the public parking lot. Break down vault, fill in and restore parking lot. Higher capital cost with decreased future maintenance costs - $300k.

- Vault rejuvenation – Remove a portion of the vault, rejuvenate using mechanical reinforced structure and restore parking lot. Lower capital cost with

ongoing O&M costs - $150k.

- Vault replacement – Replace vault with a new vault. Assessment to be made if new vault could be formed and poured inside of existing vault or if complete removal and replacement is required. Higher capital cost with minimal O&M costs for 25-40 years – between $200k and $315k.

c) PUC has paced the underground renewal work, along with all of its renewal activities in accordance with the objectives described in detail per the response to OEB Staff-32.

Staff 48

Substation-22
Reference: Distribution System Plan – 5.3.6.2.1 PUC's Response to OEB Order #4

Question:

PUC Distribution deferred its Substation-22 rebuild project to 2027.

a) Please provide a high-level scope of work for the rebuild.
b) What risks are associated with moving the Substation 22 rebuild project to 2027?
c) How did PUC Distribution determine the sizing requirements for Substation 22?
d) Could load be shifted across other substations to avoid the Substation 22 rebuild?
e) Were DERs and electric vehicles considered when sizing Substation 22?

Response:

a) For context, at the time of preparing the 2018-2022 COS it was determined through the associated ACA, that the renewal of two distribution stations was warranted. Replacement of Substation 16 was established with certainty and proceeded as planned. The location of the second station (e.g., Substation 22) had not yet been selected or finalized however a need was established. Some of the options being evaluated at the time but not finalized were:

    - The new 12kV station 22 would replace 4.16kV stations 4, 5, 14 & 17 which were recently retired or to be retired due to voltage conversion.
    - Replace end of life Substation 2 or Substation 20 which both has transformers and switchgear assessed to be in poor and very poor condition.

    In response to the specific question, although a final site for replacement had not been determined, the scope envisioned was to replace retired station assets with our standard design station:

    - 34.5kV switchgear with two 600A supply feeds
    - Two new 10MVA transformers with 13.33MVA future provisions
    - 12.47kV switchgear with four 600A outgoing feeders
    - Control building, SCADA, and cabling for all distribution system interconnections

b) Risks associated with deferring the substation work were established to be manageable, being primarily the risk of losing a switchgear or transformer element to failure at one of the end-of-life candidate stations. The risk was determined to be manageable as the stations involved are all interconnected by looped feeds on both 34.5kV and 12.47kV systems, and the circuits generally have sufficient capacity to transfer load to adjacent stations. The system can operate in this 'N-1' mode with one station out of service for extended long enough periods to address the situation.

c) Being a smaller municipality, and given its relatively low load density, PUC has taken a strategy of using a standard design and 20MVA size for all stations equally across its service territory. Capacity is then matched to demand by adjusting the location of the stations to match past, current, and anticipated future load.

d) Evaluating shifting of load rather than reconstruction is always a consideration of PUC in planning a new station. In the consideration of this particular station, load shifting was used with the retirements of Substations 4, 5, 14 & 17, and were part of the decision process to instead focus investments to Substations 2 or 20. Loads at Substations 2 and 20 are more significant, and this strategy could not be employed while still maintaining current reliability and service levels.

e) Yes, DER and EVs were given consideration. Much of the PUC distribution system was built out with capacity based on electric heating promoted in the 1960s and 1970s when the city population peaked around 81,000. From the 1980s through present where the population is closer to 75,000, there has been a decline in load of approximately 0.5% per year over the 40 years due to promotion of natural gas heating, accompanied by CDM initiatives. To support DER and EVs, for the next 5-year period, PUC's strategy is to leverage the freed-up capacity from the aforementioned load decline. Depending upon the acceleration of adoption of these new technologies, a different strategy may be required in the longer term.

Staff 49

GIS UN Migration
Reference: Distribution System Plan – 5.4.2.1.1 GIS UN Migration Project

Question:

According to PUC Distribution, ESRI Canada was consulted to provide a gap analysis and assist in developing a technology roadmap for the migration to the Utility Network (UN). PUC Distribution states that its existing GIS is based on Geometric Network technology, which is approximately twenty-five years old, approaching end of useful life, and will no longer be supported by the vendor in the next three years as they move exclusively to a UN platform.

Please explain how PUC Distribution determined to use the UN software. Please describe what other options were considered.

Response:

ESRI, the GIS industry leader, notified users of ArcGIS they would be moving their platform to Utility Networks from Geometric Networks and would cease supporting the current platform in 2023 (later extended). This is a significant change that requires some upfront work to transition the data and connectivity. However, it also provides utilities with significant benefits with respect to increased data sharing across the platform, and numerous tools including mobile tools. To learn more about this visit: https://www.esri.ca/en-ca/home.

PUC addressed the situation by conducting an assessment which looked at how other utilities were addressing the challenge and what other options existed. It was determined that continuing to use the ESRI platform with the required upgrade was the right decision. Based on the financial investment required with the current vendor it would be beneficial to bring the service in house versus the status quo.

PUC then engaged with ESRI Canada to determine the most cost-effective way to facilitate the transition to Utility Networks.

Staff 50

Buildings
Reference: Distribution System Plan – Appendix A – Buildings

Question:

PUC Distribution provides a list of proposed building work for 2023. In table 1 in the above reference, the budgeted building costs also increase over the five years.

Please provide the list of proposed building work for 2024 to 2027 along with estimated costs to build out table 1.

Response:

See below for the list of proposed building work and estimated costs:

Year	Proposed Building Work and Costs
2024	3 gate and controllers replacements – $95-441 Man door and frames replacement – $152,706 Misc. items – $44,539
2025	2 boilers – $207,116 Misc. items – $58,251
2026	Rooftop HVAC units – $204,571 Ops air compressor – $81,829 Misc. items – $75,009
2027	Rooftop HVAC units – $191,055 Chillers – admin rooftop – $318,425 Misc. items – $82,790

Staff 51

Tools and Equipment
Reference: Distribution System Plan – Appendix A – Tools and Equipment

Question:

PUC Distribution intends to replace an Omicron Injection Tester and Transformer Oil Drying Equipment in 2023.

a) Please provide a cost breakdown of both pieces of equipment.
b) Please explain why purchasing either piece of equipment cannot be deferred to 2024.

Response:

a) Including consideration for inflation and internal overheads, $106.6k was allocated for the Omicron Injection Tester, and $188.2k for the Transformer Oil Drying Unit

b) As described in section 6 of the Material Investment Narrative, these are a relatively lower priority investment items that will only have material consequences if deferred for longer periods of time. There is an opportunity to defer within the DSP period, however beyond that timeframe, the risks would increase with respect to:
    - The likelihood of not being able to detect a preventable and predictable failure of critical assets;
    - The inability to cost effectively conduct O&M activities; and
    - Lack of information to inform an ACA.

Staff 52

Transmission Station Improvement
Reference: Chapter 2 Appendices – 2-AA

Question:

In the reference, there is a transmission station improvements and enhancements investment with no material investment summary.

Please provide the material investment summary to support the $175k.

Response:

The amount of $175k is representative of a group of four non-material initiatives for which material investment summaries have not been prepared. They are summarized below to provide some clarification and background in the descriptions:

Year of Proposed Investment		2023
Transformer Station & Distribution Stations	Unplanned renewal of Transformer Station assets - emergency repairs upon failure	$ 75,265
	Unplanned renewal of Transformer Station building and fence repairs	$ 12,544
	Planned - Transformer Station Transformation – 2023 replacement of damaged oil temperature and pressure gauges at TS1, TS2	$ 62,721
	Planned - Transformer Station SCADA and Communications asset renewal – installation of GPS clock equipment for synchronizing of protective relaying systems	$ 25,088

Exhibit 3 – Operating Revenue

Staff 53

Customer/Connection Forecast
Reference 1: Exhibit 3, pg. 12
Reference 2: Load Forecast Model, Rate Class Customer Model

Question:

PUC Distribution has proposed an adjusted customer connection count for the GS < 50 and GS > 50 customer classes.

a) Please explain why the adjusted 2021 customer connection counts are used as the starting point for growth instead of the 2021 historic actual connections.
b) Please provide the monthly customer connection counts for all rate classes for the most recent month available, and for the 11 prior months (12 months total).
c) The GS > 50 customer counts have been declining and are forecast to decline in the test year. Does PUC Distribution have insights into the cause of the reduction in customer connections in the GS > 50 customer class?

Response:

a) The 2021 historical connection count for GS<50 and GS>50 is 3423 and 308 customers respectively. The way PUC's regression model works is it applies the geomean to the last historical year when determining growth. This would have resulted in the following customer counter for 2022 and 2023 for the GS<50 and GS>50 rate classes.

	GS<50	GS>50
2021 (actual)	3423	308
10 Year Geo Mean	1.017	0.9911
2022 (Projected)	3481	305
2023 (Projected)	3540	303

If PUC had used the historical actual connections as the starting point for customer count, it would be using an outlier year (due to COVID-19) as the starting point for growth. PUC identified that since 2021 was an abnormal year, it should normalize the customer count and then apply the 10-year geomean to that normalized 2021 customer count.

b) The monthly customer counts for November 2021 to October 2022 are presented in the table below.

	2021		2022									
	Nov	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**
Residential	30106	30140	30169	30190	30167	30182	30170	30174	30148	30163	30168	30168
GS<50	3416	3421	3426	3427	3428	3430	3427	3422	3415	3414	3408	3408
GS>50	307	307	307	307	307	307	307	307	308	308	308	308
Sentinel	348	348	348	348	348	348	348	348	348	348	348	348
Street	8037	8037	8037	8037	8037	8037	8037	8037	8037	8037	8037	8037
USL	25	25	28	28	27	27	27	27	27	27	27	27

c) PUC believes that the COVID-19 pandemic has had the largest impact on the decline in GS>50 customers, primarily due to the timing of when the reduction in the GS>50 customer counts occurs. PUC saw many of the GS>50 customers move into the GS<50 class. However, there may be other economic or social factors that have contributed to the drop that PUC is unaware of at this time. For example, there have been CDM activities within PUC's service territory that could reduce overall consumption and load. As for the overall declining trend in GS>50 customers prior to 2021, PUC does not have specifics of what might be causing the overall decline in the GS>50 class and it may be the result of a multitude of factors.

PUC would like to clarify that the actual number of customers in 2021 is 308 and PUC projected an increase to 348 in the 2022 bridge year. Then the forecast for the 2023 projects a decline from that 348 in 2022 to 344 in 2023.

Staff 54

Wholesale Purchases Forecast
Reference: Load Forecast Model, sheets Purchased Power Model, Regressions

Question:

The worksheet Purchased Power Model includes three sets of regression output prefaced by three different dates, March 3, 2022, May 17, 2022, and August 5, 2022. All sets of output use the same explanatory variables but have different output values. The equations used to predict purchases reference the last output, labelled August 5, 2022.

a) Please explain what caused the difference in results between the three runs, and why the last run was ultimately selected.
b) Please explain why the Number of Customers was ultimately retained despite having an insignificant t-stat of -0.017, and a counter-intuitive negative sign implying that as customers are added, load decreases.
c) Has PUC distribution attempted to identify a cause for the decreasing load and attempted identify an explanatory variable that could be used to estimate this decrease?
d) As a scenario, please provide a model which excludes the customer count variable.

The worksheet Regressions includes several regression output statistics.

e) Please explain the purpose of these runs, and on what basis they can be compared to the proposed model, or any of the output in the Power Purchase Model worksheet.

Response:

a) The March 3, 2022 regression was the original regression chosen after all the scenarios were run as seen on the regressions tab. On May 17, 2022, it was discovered that historical data was missing for heating and cooling degree days. PUC inputs those missing values by averaging the heating and cooling degree stats directly before and after the missing date. The regression model was rerun to produce the May 17, 2022 version. As PUC was progressing through the application, it determined that an adjustment was required to account for the two historical years of outlier data for 2020 and 2021 actuals. It was determined that this was the result of COVID-19, and therefore PUC thought it would be prudent to make some kind of normalized COVID-19 adjustment. After PUC

normalized 2020 and 2021 data the regression was rerun to produce the August 5, 2022 version which was the final version for this application.

b) Retaining the number of customers as a variable was an oversight by PUC.

c) PUC has been unable to identify a cause for the decreasing load and thus believes the declining load is in relation to a multitude of factors of which no one variable has been the main cause of the decrease. The trend variable is an all-encompassing variable to capture the overall declining trend in consumption that PUC has been experiencing.

d) PUC has provided a model which excludes customer count as a variable. The excel file is titled “PUC_2023_Load Forecast – with Regression Analysis_20220831_Staff 54d”.

e) The purpose of the regressions tab is to show the different regressions tested to produce the possible output. The output chosen was the one that yielded the best adjusted R squared value. A different combination of variables and amount of historical data was used in each regression. Ultimately using the combination of variables shown in the May 17, 2022, that regression was chosen as it yielded the best adjusted R square value of 95.61%. However, when PUC normalized the 2020 and 2021 actual data it dropped the adjusted R square value to 94.8%. PUC believes that this is still a good regression output.

Staff 55

COVID-19
Reference: Exhibit 3, pg. 11, 19

Question:

PUC Distribution states that 2020 and 2021 actual purchases and customer count were normalized to adjust for those years being affected by COVID-19.

a) Please provide the unadjusted, adjustment, and adjusted values for the purchases on a monthly basis.
b) Has PUC distribution observed changes in Residential consumption due to the COVID-19 pandemic, and if so, how has it been considered in adjusting wholesale purchases?
c) Please indicate how COVID-19 impacted the rate classes differently, and how this influenced the proposed rate class energy forecasts.
d) As a scenario, please provide a load forecast and all output statistics where the wholesale purchases are un-adjusted, but the adjustment is included as an explanatory variable instead.

Response:

a) The table below provides the unadjusted, adjustment and adjusted values used for the monthly purchases for 2020 and 2021:

2020					2021			
Month	**Unadjusted**	**Adjustment**	**Adjusted**		**Month**	**Unadjusted**	**Adjustment**	**Adjusted**
Jan	65,083,752	1,526,904	66,610,656		Jan	63,498,704	1,579,660	65,078,364
Feb	61,713,926	1,526,904	63,240,830		Feb	60,964,337	1,579,660	62,543,997
Mar	59,720,310	1,526,904	61,247,214		Mar	59,724,292	1,579,660	61,303,952
Apr	51,777,990	1,526,904	53,304,894		Apr	49,030,461	1,579,660	50,610,121
May	47,575,790	1,526,904	49,102,694		May	45,410,415	1,579,660	46,990,075
Jun	44,657,123	1,526,904	46,184,027		Jun	45,297,226	1,579,660	46,876,886
Jul	51,307,535	1,526,904	52,834,439		Jul	47,899,490	1,579,660	49,479,150
Aug	47,940,782	1,526,904	49,467,686		Aug	50,869,102	1,579,660	52,448,762
Sep	43,174,730	1,526,904	44,701,634		Sep	42,853,918	1,579,660	44,433,578
Oct	51,030,331	1,526,904	52,557,235		Oct	46,624,358	1,579,660	48,204,018
Nov	53,648,614	1,526,904	55,175,518		Nov	53,605,643	1,579,660	55,185,303
Dec	63,114,865	1,526,904	64,641,769		Dec	63,007,071	1,579,660	64,586,731
Total	640,745,748	18,322,848	659,068,596		Total	628,785,017	18,955,920	647,740,937

b) PUC has seen minor changes in Residential consumption, since 2020, however, the observed changes in consumption cannot conclusively be attributed to the COVID-19 pandemic. The overall trend has remained consistent with years prior to 2020 and 2021.

c) PUC noticed the impacts of COVID-19 from the review of the actual data for 2020 and 2021. PUC first noticed the drop in GS>50 customers which prompted further analysis. It was discovered that those lost customers from the GS>50 class shifted to the GS<50 rate classes. A main contributing factor to this shift is from COVID-19 pandemic which required multiple government shutdowns which decreased productivity for various local business. Pending no further government ordered shutdowns, the COVID normalization adjustment can account for this general service customer change in 2020 and 2021. It is anticipated that the General Service customer classes will return in some capacity to pre pandemic levels of consumption and customer count, but the full details might not be known for a few years.

d) PUC has provided the requested load forecast in excel format titled as “PUC_2023_Load Forecast – with Regression Analysis_20220831_Staff55d”.

Staff 56

Wholesale Purchases Forecast
Reference: Load Forecast Model, sheet Summary

Question:

The Summary sheet indicates that predicted purchases were lower than actual in 2011-2014, then higher than actual from 2015 to 2019, and then was below actual again in 2020 to 2021. The 2011 actual load was 745.0 GWh and 2017 actual load was 653.0 GWh reflecting an average decrease of 2.2% per year. The 2018 actual load was 666.7 GWh and 2021 actual load was 647.7 GWh reflecting an average decrease of 1.0% per year.

a) Does PUC distribution have any insights into the slowing of the load reductions?
b) As a scenario, please provide a model where two Trend variables are used instead of the existing trend variable. The first trend variable takes a value of 1 in January 2011 and increases by 1 each month reaching 84 in December 2017 and remains at 84 for all remaining months to December 2023. The second trend variable takes a value of 0 each month from January 2011 to December 2017, then takes a value of 1 in January 2018, increasing by 1 each month, and reaches a value of 60 in December 2023.

Response:

a) PUC doesn't have definitive insights into what has occurred to create this drop in load reduction.

b) PUC has provided the requested model in excel format titled as "PUC_2023_Load Forecast – with Regression Analysis_20220831_Staff56b". PUC has excluded the number of customers as an explanatory variable in this scenario, as it was identified in Staff - 54b that number of customers had an insignificant t-stat.

Staff 57

CDM Adjustment
Reference: Exhibit 3, pages 28-29

Question:

PUC Distribution notes that a CDM adjustment has been made to its load forecast to reflect the impact of CDM activities that are expected to be implemented from 2023 to 2027 within PUC Distribution's service territory based on its share of electricity use within the province, the IESO's 2021-2024 CDM Framework, and the IESO's Planning Outlook.

PUC Distribution further notes that no CDM adjustment is required for PUC's CDM programs offered under the Conservation First Framework, as there were no projects completed in 2021, and the use of actual load data for 2021 in the forecast means that the impact of CFF programs is already fully captured in the load forecast.
Please provide PUC's Distribution's rationale for using a single year for historical impacts of CDM (i.e., not accounting for declining persistence of historical CDM over the rebasing period) while proposing to include the average impact of new CDM over the full rebasing period.

Response:

PUC forecasted using regression analysis on actual loads through 2021. This captures CDM activities captured in all those years, not just one year. If there would have been CDM projects in 2021, because they would not have been rolled out on January 1 and been available for the entire year, then the persistence in 2023 and later would have been larger than what was captured in the regression analysis. Nominally, 2023 persistence would have been double the 2021 savings captured in the regression analysis. 2021 is discussed only to point out that no manual adjustment for CFF CDM activities is required, since the impact of CFF in future years is fully captured in the regression analysis.

Staff 58

CDM Adjustment
Reference: Exhibit 3, pg. 32

Question:

PUC Distribution notes that an adjustment is applied to the forecast CDM results as the estimated value captured in the load forecast is based on an earlier estimate. The adjustment will be removed at the time other changes are made to the load forecast.

a) Please explain what is meant by the above-noted statement.
b) In Table 3-28, please explain the "adjustment to match load forecast" row and how it relates to the above-noted statement.

Response:

The following is a response to "a" and "b":

In Table 3-28 on page 32 of Exhibit 3, the total CDM results forecast line is different from what's contained in the "PUC_2023_Load Forecast – with Regression Analysis_20220831". PUC noticed that this line didn't match late in the application process and added the line "adjustment to match load forecast." PUC is now adjusting the load forecast so that it matches the Total CDM results forecast. PUC has updated the Load forecast for this change and provided in excel format titled as "PUC_2023_Load Forecast – with Regression Analysis_20221128". A comparison of the two load forecast results is presented in the table below:

Date of Load Forecast		Residential	GS<50	GS>50
2022-08-31	Consumption	276,382,466	85,136,275	228,476,460
	Cdm Adjustment	1,643,785	6,084,747	7,026,072
	Total	274,738,681	79,051,528	221,450,388
2022-11-28	Consumption	276,382,466	85,136,275	228,476,460
	Cdm Adjustment	2,752,600	6,299,251	9,308,501
	Total	273,629,866	78,837,024	219,167,959

Staff 59

Load Growth
Reference: Load Forecast

Question:

a) How has EV penetration been factored into load growth expectation over the forecast period?
b) Has PUC Distribution developed a load forecast specifically for EV growth?
c) Has PUC Distribution considered the impact of Distributed Energy Resources or other emerging technologies on its load forecast? Please explain your response.

Response:

a) Although EV penetration has been given consideration, no community uptake information is presently available and, to our awareness, no standard methodologies for calculating impact have been established. Given the very low anecdotally observed electric vehicles in the PUC service territory (perhaps 10 to 20 vehicles at present), no significant load growth that would impact our system has been assumed over the forecast period.

b) PUC has not developed a load forecast specifically for EV growth. PUC technical staff continue to keep abreast of industry developments in this area and anticipate a need to establish a methodology and project growth when local market data becomes readily available and as uptake accelerates.

c) Although PUC has considered the impact of Distributed Energy Resources or other emerging technologies from several technical perspectives, as outlined in the REG Plan attached in Appendix F of the DSP, it has projected a 0kW impact on its load over the next 5-year period.

Exhibit 4 – Operating Costs

Staff 60

OM&A Programs
Reference: Chapter 2 Appendices, Tab 2-JC_OM&A Programs

Question:

Please provide a version of Tab 2-JC of the Chapter 2 Appendices that includes an additional column which shows actual amounts for 2022 for as many months as possible, and another additional column that shows year-to-date actuals at the same point in 2021.

Response:

Please refer to the Chapter 2 Appendices, Tab 2-JC.

Staff 61

OM&A - Inflation
Reference: Exhibit 4, pg. 9

Question:

PUC Distribution states that:

> For 2022 and 2023 budgeted OM&A expenses, PUC incorporated inflationary increases for unionized labour per collective agreements of 2%, Executive and Management labour increases per PUC's management compensation policy and other non labour items at a general inflation rate of 3%.

Further on page 9, PUC Distribution provides Table 4-3 and states that the total increase from 2022 to the 2023 test year due to inflation is $447,630. Also on page 9, PUC Distribution states that it expects the IPI to increase in 2023 to above 7.7% (CPI May 2021 to May 2022).

It is unclear to OEB staff what inflation rate has been factored into the proposed 2023 OM&A costs given that PUC Distribution states it has budgeted non-labour items at a general inflation rate of 3%, while the table shows a rate of 7.4% (i.e., inflation of 7.7% - 0.30% stretch factor).

a) Please confirm the inflation rate(s) used in the OM&A inflation trends in table 4-3 for 2022 and 2023, and the inflation rate(s) incorporated into the 2022 and 2023 budgeted OM&A expenses.
b) Please reconcile the rates with the statements above table 4-3 on page 9.
c) Please explain why PUC Distribution has utilized the Canadian (national) CPI, not seasonally adjusted, for May 2022 versus May 2021 as an estimate for 2023 inflation given that: 1) Comparing inflation on a monthly basis is not always indicative of the annual rate, and 2) the OEB does not use CPI as a measure of inflation for capital-intensive utilities.

Response:

a) PUC confirms that the inflation rates used in table 4-3 for inflation trends were 3.0% and 7.4% for 2022 and 2023 respectively. PUC also confirms inflation factors for budgeting OM&A for 2022 and 2023 includes a 2.0% increase to unionized labour and a 3.0% increase to management labour. In addition, a general inflationary increase of 3.0% was

applied to other non-labour related items where detailed estimating was otherwise undeterminable. PUC also notes that specific elements with known increases are incorporated into the budgeted OM&A for 2022 and 2023, some of which are significantly above 3.0% (e.g., insurance premiums increased by 4.5% in 2022 and 13.1% in 2023 reflecting estimates provided by PUC's insurance provider).

b) The inflationary rates referenced in this question and response to part (a) are not reconcilable. Inflation factors are incorporated into the budgeting process where necessary to help determine the estimated OM&A costs for a given year. The inflation trending represents a benchmark by which PUC can measure the outcomes of its budgeting process. To clarify, as a final step in preparing its annual budgets, including the 2022 bridge and 2023 test years, PUC compares its total OM&A against the trending of the OEB's approved inflationary increases, per the IRM framework (e.g., IPI), less PUC's specific productivity factor. This exercise assists PUC in ensuring the upward pressures on OM&A costs over the horizon of the 5-year rate cycle align with the expectations of the OEB. Specifically, for the 2023 test year OM&A, despite significant cost pressures including hyperinflation, supply chain constraints, etc., PUC held certain increases to below inflation in order that its total OM&A would align with the inflation trend.

c) Given the inflation trending variable is used as a benchmarking exercise only, PUC selected the Canadian (national) CPI on a monthly basis to compare the most recent rolling 12 months with the expectation that inflation would continue to trend upwards and likely be higher by the outset of this proceeding. PUC expects further assessment would be performed during the proceeding but feels strongly that it must be able to adapt to the rapidly increasing inflationary environment to continue the safe and reliable operation of its distribution system.

Staff 62

COVID Costs
Reference 1: Exhibit 4, pg. 11
Reference 2: Chapter 2 Appendices, Tab 2-JB – OM&A Cost Drivers

Question:

PUC Distribution states that the slight increase in OM&A in 2020 is due to COVID related costs that PUC Distribution is not seeking recovery for as it was reversed in 2021.

Tab 2-JB shows a debit entry of $805,463 in 2021. PUC Distribution states costs in the COVID DVA account were deemed ineligible for recovery and $805,463 was recognized as an expense in 2021.

a) Please provide a breakdown of the $805,463 amount of COVID-related costs in 2021.
b) Please clarify if PUC Distribution has included any costs resulting from COVID in its 2022 and 2023 capital and OM&A budgets. As part of the response, please clarify if the $805k amount is included in PUC Distribution's base OM&A as seen in Table 4-5.

Response:

a) The COVID-related costs determined to be ineligible were salaries and wages provided by PUC Services to PUC. These were costs charged to a COVID work order to track time attributable to COVID activities during the pandemic. No further charges were made after the reversal was recorded in 2021.

b) PUC has not included any costs resulting from COVID-related costs in its 2022 and 2023 capital and OM&A budgets. The $805k amount is not included in PUC's base OM&A.

Staff 63

APB Benchmarking
Reference: Exhibit 4, pg. 8

Question:

PUC Distribution states that other than inflation, one of the reasons for the increase in test year OM&A, among others, is due to increased Cyber Security, Regulatory and IT resources (i.e., Green Button and APB Benchmarking) ($123k).

Please describe what incremental initiatives PUC Distribution is undertaking associated with APB benchmarking and the expected outcomes. As part of the response, please describe the responsibilities of the additional Regulatory Analyst related to these initiatives.

Response:

PUC is experiencing increased costs in Cyber Security, Regulatory and IT resources as outlined in the application. With respect to Cyber Security, PUC has increased efforts in response to Cyber Security requirements. With respect to IT resources, PUC has increased costs from added resources as PUC shifts to becoming more digital in its processes.

The addition of the Regulatory Analyst will allow a deep dive into its results of the APB Benchmarking metrics. Each year there are additional reporting required to formulate these metrics. PUC will be creating a process to define exactly what it needs to report for each metric and to ensure the information reported is consistent from year to year. This will be a collective effort of the regulatory analyst and use of IT resources, as well as all departments, to put the proper systems in place to ensure accurate reporting from year to year. The Regulatory Analyst will also be responsible for providing analysis to the executive team and each operational department to help formulate a strategy on how PUC can improve in such APB metrics or document what it is doing well in each metric. It is through the use of the Regulatory Analyst that PUC hopes to develop the process and improve on its results in the APB reporting.

Staff 64

Green Button
Reference: Exhibit 4, pg. 12

Question:

OEB staff notes that the Green Button Regulation came into effect on November 1, 2021, and requires distributors to implement Green Button by November 1, 2023, for the purposes of complying with section 25.35.8 of the *Electricity Act*, 1998.

The OEB approved the establishment of a generic deferral account for rate regulated distributors to record the incremental costs directly attributable to the implementation of the Green Button initiative, in a manner that accords with the requirements set out in the Green Button Regulation.

The evidence in this application states that:

> Green Button incremental initiative costs for 2022 have been recorded in the generic Account 1508 Deferral Account, however, PUC has included costs in OM&A for the 2023 Test year.

a) Please detail the costs that have been included in PUC Distribution's proposed operating and/or capital budgets for Green Button implementation. As part of the response, please identify where the costs have been included (e.g., which program).
b) Please confirm if PUC Distribution is managing or planning to manage Green Button implementation internally or through an external vendor (i.e., outside of PUC Services).
    i. If PUC Distribution is planning to manage Green Button implementation through an external vendor, please describe the responsibilities of the additional Regulatory Analyst related to the Green Button initiative.
c) Please provide the balance in the generic Account 1508 Deferral Account related to the Green Button initiative incurred to date.
d) Please confirm that PUC Distribution is not seeking disposition of the generic account for incremental costs for 2022 in the current application, as the current proceeding is proposing to dispose 2021 audited balances. If not confirmed, please explain.

Response:

a) PUC has recently finalized the contract with its Vendor to facilitate the Green Button Initiative. PUC has included the annual operating costs of $21,000 in its OM&A. The estimate capital cost is $80,000 which has been included in 2023 test year capital expenditures. PUC is confident that the final capital cost in 2023 for its Green Button Initiative will be approximately $80,000 as it has finalized its contract with the third party vendor and the remaining capital costs can be reasonably estimated for 2023.

b) PUC is managing the Green Button Initiative with the use of an external vendor
    i. The additional Regulatory Analyst will be responsible for working with the External provider to assist with the implementation and then ongoing activities to ensure the program is running effectively.

c) The balance in the Account 1508 related to Green Button as of October 31, 2022, is $16,163. PUC is proposing to shift the amount in 1508 to WIP as it will form part of the capital cost for the implementation of its Green Button Initiative to be finalized in 2023.

d) PUC confirms it did not have any balances in 1508 related to Green Button in 2021.

Staff 65

OM&A Variances
Reference 1: Exhibit 4, section 4.3 OM&A variance analysis
Reference 2: Chapter 2 Filing Requirements, April 18, 2022, pg. 28
Reference 3: Chapter 2 Appendices, Tab 2-JC

Question:

The Filing Requirements state a variance analysis in required for the test year vs the bridge year in relation to 2-JC, and that the materiality threshold applies to details of the OM&A programs if using Appendix 2-JC.

OEB staff notes that there are line items above the materiality threshold when comparing the 2023 test year to the 2022 bridge year which an accompanying variance analysis has not been provided. These programs include load dispatching, regulatory affairs, and administrative.

Please provide a discussion on the variances for these items between the 2023 test year and the 2022 bridge year.

Response:

Please refer to Exhibit 4, page 22 for the variance analysis. This analysis was provided in relation to 2-JB.

Staff 66

Community Relations Costs
Reference: Chapter 2 Appendices, Tab 2-JC – OM&A Programs

Question:

Please explain the driver(s) for the increase in community relations expenses between 2018 actuals and the 2023 test year (i.e., approximately $133k).

Response:

The primary driver for the increase in community relation expenses since 2018 is due to inflationary increases in labour and IT software maintenance fees, as well as additional training programs related to public safety.

Staff 67

Operations Expenses
Reference 1: Chapter 2 Appendices, Tab 2-JC – OM&A Programs
Reference 2: Exhibit 4, pg. 8
Reference 3: Exhibit 4, pg. 26

Question:

The Operations – Load Dispatching line item is proposed to increase by approximately $153k when comparing the 2023 test year to the 2018 OEB-approved amount (or $171k when comparing the 2022 bridge year to the 2023 test year). PUC Distribution notes that it has added an additional System Operator position in support of SSG.

The Operations - Miscellaneous Operating line item is proposed to increase by approximately $149k when comparing the 2023 test year to the 2018 OEB-approved amount. Part of the increase is attributed to an increase in labour costs as a result of an additional Electrical Engineer in support of the SSG.

a) Please confirm that these are the 2 FTEs associated with the SSG project noted on page 8 of exhibit 4.
b) Please confirm if the costs associated with these 2 FTEs are 100% directly allocated to PUC Distribution. If not, please describe how costs have been allocated between PUC Distribution and its affiliate.
c) Please describe the roles and responsibilities of each of the System Operator and the Electrical Engineer.
d) What is the expected timeframe for the hiring of these two positions?

Response:

a) PUC confirms that these are the 2 FTEs associated with the SSG project.

b) PUC confirms that they are 100% directly allocated to PUC.

c) Electric System Operator:

- In conjunction with the Lead Hand Stations and Substation Operation Technician, promotes the overall efficient, effective, and safe deployment of electrical system staff

and equipment to maintain a stable and reliable supply of power to the company's customers.

- Coordinates power restoration activities and provides guidance to field staff to minimize outage scope and duration.
- Coordinates with field staff to Administer Work Protection to allow for a safe working environment, often under emergency conditions.
- Supports the Line Department in power restoration and the preparation of the next day's activities (creating switch orders, work protection, regulators setting changes, etc.).
- Administrate, maintain, and configure the SCADA system as well as providing design inputs and editing of electrical system schematics, related graphics, report generation, alarm points and control schemes within SCADA.

<u>System Operations Engineer (Electrical Engineer)</u>:

- Provides leadership and supervision in electrical system control operations with emphasis on Smart Grid, SCADA, and AMI systems.
- As the owner of the SCADA system, the System Operations Engineer is responsible for data integrity and the appropriate management of changes to the SCADA system, as well as reliability performance reporting.
- Leads the integration of Smart Grid systems into Operations, defining, and implementing needed changes to processes, procedures, and maintenance programs, as well as being the technical protection and control expert to support the Stations and Metering operational teams.
- When control settings need to be altered, this position has accountability for the review and authentication of changes per PEO requirements and the responsibility to ensure compliance with Regulation 22-04.

d) The System Operations Engineer started on October 3, 2022, and the Electric System Operator will start in December 2022.

Staff 68

Maintenance Expenses
Reference 1: Chapter 2 Appendices, Tab 2-JC – OM&A Programs
Reference 2: Exhibit 4, pg. 27

Question:

The costs proposed in 2023 for the Maintenance – Stations line item is about $705k. The variance between the test year and 2021 actuals represents an increase of approximately $264k. PUC Distribution states that one of the drivers for this increase is "the shift of labour from capital to maintenance. In 2021, extensive resources were directed to capital work for the Substation 16 re-build which decreased the allocation of labour charged to station operations and maintenance accounts."

OEB staff notes that between 2018 actuals and 2021, costs ranged between $295k and $471k. Increases are shown in 2022 ($606k) and 2023 ($705k).

Please explain the driver(s) for the lower costs for this line item between 2018 and 2020, followed by increases in 2022 and 2023.

Response:

The primary cost drivers for Maintenance are Stations labour costs. The shift in labour is directly related to changes in labour from capital to maintenance depending on the work plan for that year. In 2018 ($400k), 2019 ($295k), 2020 ($471k), 2021 ($442), 2022 ($606k budget) and 2023 Test ($705k). In 2019, there was a vacancy in Stations partly through the year. In 2019 and 2021, there were decreases in OM&A due to more capital projects whereas in 2018, 2021 and 2022 budget, OM&A costs increase due to higher maintenance work plans.

Aside from inflation, the increase in 2022 is due to the addition of a Systems Operations Engineer position in support of SSG. In 2023, additional amounts include costs for the retirement of substations for environmental remediation work.

Staff 69

Administrative Expenses
Reference 1: Chapter 2 Appendices, Tab 2-JC – OM&A Programs
Reference 2: Exhibit 4, pg. 29

Question:

The costs proposed in 2023 for the Administrative line item is about $2.8M. The variance between the test year and 2018 OEB-approved amounts represents an increase of approximately $943k. Part of the increase is associated with new software to support electronic process conversions including software for contractor management, accounts payable processing, and a new platform for electronic forms for PUC's operations group.

a) Please confirm if any capital costs have been included for the new software. If yes, please detail the quantum. If no capital costs have been included, please explain why.
b) Does PUC Distribution anticipate efficiencies related to the enhanced digitization of the above items? If yes, please describe.
c) Has PUC Distribution reflected any anticipated OM&A savings from the items above into its OM&A budget? If yes, please quantify the amounts and how they were calculated. If not, why not?
d) Please explain the decrease in costs in 2022 (relative to 2021), followed by an increase in 2023.

Response:

a) PUC confirms that there are no capital costs included as this software is owned by PUC Services and charged to PUC per the shared services cost allocation through a cost of capital and asset charge.

b) PUC does expect some efficiencies related to enhanced digitization due to the new software platforms in saving time and having data more readily available and electronically available for review.

c) PUC has not incorporated these efficiencies for anticipated savings since cost savings are not expected to be material.

d) The 2021 increase includes the reversal of COVID ineligible expenses from 2020 which were mainly administrative salaries. In 2023, new positions were added for additional resources including the Technical Accountant and IT Analyst position.

Staff 70

Administrative Expenses
Reference 1: Chapter 2 Appendices, Tab 2-JC – OM&A Programs
Reference 2: Exhibit 4, pg. 30

Question:

As noted in the interrogatory above, the costs proposed in 2023 for the Administrative line item is about $2.8M. The variance between the test year and 2018 OEB-approved amounts represents an increase of approximately $943k. Part of the variance can be attributed to the following additions by PUC Services:

- Vice President, Corporate Services
- Director of Innovation & Technology
- Information Security Analyst
- Senior People & Culture Business partner
- Assistant Controller

OEB staff notes that on page 22 of exhibit 4, there is also a statement regarding the addition of a Technical Accountant by PUC Services.

a) Please confirm if the Technical Accountant noted on page 22 also contributes to part of the $943k increase.
b) For each position identified above please describe the roles and responsibilities for each.
c) When were each of the roles added, or expected to be added? If applicable, please also indicate which of the roles are currently filled.
d) Please describe how the costs of these positions have been allocated between PUC Distribution and PUC Services.

Response:

a) PUC confirms that the Technical Accountant also contributes to the increase.

b) Each position identified:

Vice President, Corporate Services

- This is not an incremental role to the PUC Services Executive team but will result in an increase in the allocation to PUC. Additional OM&A expenses would be incurred as a reorganization of duties shifted some of the

accountabilities of special projects (e.g., Business Development) to another role and a title change resulted.

- Provides oversight, expertise, and innovation in leading the People & Culture, IT, Fleet, Facilities and Health & Safety departments in support of the attainment of the corporate strategic plan.

Director of Innovation & Technology

- Leads innovation and transformation by planning, designing, and executing the IT strategic plan to align with a future focused approach for PUC and its affiliates.

Information Security Analyst

- Monitors the organization's networks for security breaches and investigate when one occurs.
- Manage and maintain software, such as firewalls and data encryption programs, to protect sensitive information.
- Check for vulnerabilities in computer and network systems.

Senior People & Culture Business Partner

- A strategic business partner and internal advisor to employees and management, within assigned business areas, and helps to drive initiatives that impact employee engagement, talent management, talent acquisition, performance, and culture.

Assistant Controller

- Provides oversight for all regulatory and compliance matters and assists with management of accounting, auditing, and budgeting within the organization.

c)

- Vice President, Corporate Services – hired in Aug-2021
- Director of Innovation & Technology hired in Nov-2022
- Information Security Analyst hired in Aug-2022
- Senior People & Culture Business partner hired in Oct-2022
- Assistant Controller – hired in Jul-2019

d) As employed by PUC Services, these positions are included in the allocation methodology for Administration salaries charged to PUC.

Staff 71

Executive and Management Employees
Reference: Exhibit 4, pg. 33-34, 37

Question:

PUC Distribution states that management staff compensation levels are reviewed on a regular basis and benchmarked against the MEARIE Group Management Salary Survey administered by Korn Ferry Hay Group.

Further, every three years a salary structure review is completed to compare the management salary bands against a utility peer group to ensure compensation remains within the 50th percentile. For the intervening years, adjustments are applied to the salary bands based on November CPI for Ontario in accordance with the Management Compensation policy.

a) When was the most recent review and benchmarking conducted against the MEARIE Group Management Salary Survey?
b) Table 4-13 shows management salary increases between 2018 and 2022. What percentage wage increase for management salary is embedded in the 2023 test year?
c) With respect to (b), please provide a discussion on the reasonability of the percentage embedded in the proposed test year amounts.
d) Page 37 states that adjustments for Management staff salaries are in accordance with PUC Services' Management Compensation Policy, in addition to adjustments for productivity, merit, and promotion. Please describe the methodology for determining adjustments for productivity and merit.

Response:

a) The most recent review was conducted in 2020. The next one to be scheduled will be for 2023.

b) The management salary increase embedded in the 2023 test year is 3.0%.

c) At the time budget was struck, inflation was assumed to decline. PUC is seeing increases in the range of 3.0% across the sector, so this should be a reasonable assumption.

d) PUC has not conducted a productivity increase to base salary in recent years. There is an adjustment for promotions if staff move job classes as a result. There are step increases within the band if there are steps remaining and if performance warrants it (merit based).

Staff 72

Employee Costs Table
Reference 1: Chapter 2 Appendices, Tab 2-K – Employee Costs
Reference 2: Exhibit 4, pg. 39-40

Question:

The Management and Non-Management line items under total compensation (salary, wages, & benefits) noted on Tab 2-K of the Chapter 2 Appendices does not reconcile to Exhibit 4, page 39.

a) Please confirm the correct figures.
b) Please file a revised version of Table 4-17 (page 40), if required.
c) Please explain the material increase in Management total benefits between 2021 and 2022 (i.e., increase of approximately 67%).

Response:

a) PUC can confirm input errors in Exhibit 4, Table 4-16. Table has been corrected and Tab 2-K of the Chapter 2 Appendices has been updated.

FTES and Employee Costs

Table 4-16: Employee Costs (Board Appendix 2-K)

	Last Rebasing Year (2018 OEB Approved)	Last Rebasing Year (2018 Actuals)	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Number of Employees (FTEs including Part-Time)							
Management (including executive)	19	19	18	18	21	21	23
Non-Management (union and non-union)	65	63	62	60	57	57	58
Total	84	82	80	78	78	78	81
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 2,219,285	$ 2,278,502	$ 2,147,051	$ 2,214,608	$ 2,180,535	$ 2,192,806	$ 2,412,944
Non-Management (union and non-union)	$ 5,475,807	$ 4,962,742	$ 5,087,619	$ 5,127,371	$ 4,984,153	$ 5,012,201	$ 5,515,381
Total	$ 7,695,092	$ 7,241,244	$ 7,234,670	$ 7,341,979	$ 7,164,688	$ 7,205,007	$ 7,928,325
Total Benefits (Current + Accrued)							
Management (including executive)	$ 562,869	$ 700,251	$ 679,384	$ 743,763	$ 697,294	$ 701,218	$ 771,614
Non-Management (union and non-union)	$ 1,445,296	$ 1,414,382	$ 1,333,848	$ 1,324,607	$ 1,503,636	$ 1,512,098	$ 1,663,899
Total	$ 2,008,164	$ 2,114,633	$ 2,013,232	$ 2,068,370	$ 2,200,930	$ 2,213,315	$ 2,435,513
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 2,782,154	$ 2,978,753	$ 2,826,435	$ 2,958,371	$ 2,877,829	$ 2,894,024	$ 3,184,558
Non-Management (union and non-union)	$ 6,921,103	$ 6,377,124	$ 6,421,467	$ 6,451,977	$ 6,487,789	$ 6,524,298	$ 7,179,280
Total	$ 9,703,257	$ 9,355,877	$ 9,247,902	$ 9,410,349	$ 9,365,618	$ 9,418,322	$ 10,363,838
Total Compensation Breakdown (Capital, OM&A)							
OM&A		$ 7,136,221	$ 6,726,296	$ 7,140,599	$ 6,879,233	$ 6,274,588	$ 7,947,124
Capital		$ 2,219,656	$ 2,521,605	$ 2,269,750	$ 2,486,385	$ 3,143,734	$ 2,416,714
Total	$ -	$ 9,355,878	$ 9,247,901	$ 9,410,348	$ 9,365,618	$ 9,418,322	$ 10,363,838

b) Table 4-17 FTE and Employee Cost Variances has been updated to correct the input errors in Table 4-16.

Table 4-17: FTE and Employee Cost Variances

	2018 OEB Approved to 2018 Actual	2018 Actuals to 2019 Actuals	2019 Actuals to 2020 Actuals	2020 Actuals to 2021 Actuals	2021 Actuals to 2022 Bridge	2022 Bridge to 2023 Test
Number of Employees (FTEs including Part-Time)						
Management (including executive)	0	(1)	(0)	3	0	2
Non-Management (union and non-union)	(2)	(1)	(1)	(3)	0	1
Total	(2)	(2)	(2)	(0)	0	3
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)	$ 59,217	$ (131,451)	$ 67,557	$ (34,073)	$ 12,271	$ 220,138
Non-Management (union and non-union)	$ (513,065)	$ 124,877	$ 39,752	$ (143,218)	$ 28,048	$ 503,180
Total	$ (453,848)	$ (6,574)	$ 107,309	$ (177,291)	$ 40,319	$ 723,318
Total Benefits (Current + Accrued)						
Management (including executive)	$ 137,382	$ (20,867)	$ 64,379	$ (46,469)	$ 3,924	$ 70,396
Non-Management (union and non-union)	$ (30,914)	$ (80,534)	$ (9,241)	$ 179,029	$ 8,462	$ 151,801
Total	$ 106,469	$ (101,401)	$ 55,138	$ 132,560	$ 12,385	$ 222,198
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 196,599	$ (152,318)	$ 131,936	$ (80,542)	$ 16,195	$ 290,534
Non-Management (union and non-union)	$ (543,979)	$ 44,343	$ 30,510	$ 35,812	$ 36,509	$ 654,982
Total	$ (347,379)	$ (107,975)	$ 162,447	$ (44,731)	$ 52,704	$ 945,516
Total Compensation Breakdown (Capital, OM&A)						
OM&A		$ (409,925)	$ 414,303	$ (261,366)	$ (604,645)	$ 1,672,536
Capital		$ 301,949	$ (251,855)	$ 216,636	$ 657,348	$ (727,020)
Total		$ (107,977)	$ 162,447	$ (44,730)	$ 52,704	$ 945,516

c) The variance has been corrected and is not material.

Staff 73

Pension and Other Post-Employment Benefits (OPEBs)
Reference 1: Exhibit 4, pg. 39, 41

Question:

Table 4-17 on page 41 provides the employee benefit costs charge to OM&A, which is reproduced below:

Table 4-17: Employee Benefit Costs

Benefit	2018 Last Rebasing	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge	2023 Test
CPP Employers' Portion	$ 188,142	$ 174,462	$ 187,643	$ 192,284	$ 237,683	$ 300,592	$ 331,238
EI Employers' Portion	$ 67,036	$ 77,083	$ 71,482	$ 71,818	$ 79,424	$ 100,446	$ 110,687
Employer Health Tax	$ 117,218	$ 116,266	$ 118,991	$ 120,618	$ 139,312	$ 176,184	$ 194,147
WSIB	$ 57,110	$ 67,224	$ 55,534	$ 63,614	$ 70,925	$ 89,697	$ 98,842
OMERS Employers' Portion	$ 591,221	$ 581,078	$ 618,817	$ 651,832	$ 692,231	$ 875,447	$ 964,701
OPEB	$ -	$ 42,183	$ 34,150	$ 48,978	$ 44,053	$ 55,713	$ 61,393
Corporate Benefits	$ 531,880	$ 751,427	$ 737,866	$ 646,635	$ 827,387	$ 1,046,375	$ 1,153,056
Total Benefits Charged to OM&A	**$ 1,552,607**	**$ 1,809,722**	**$ 1,824,483**	**$ 1,795,780**	**$ 2,091,015**	**$ 2,644,454**	**$ 2,914,064**

As per the Table 4-17 above, OEB staff calculated the growth of 2022 and 2023 amounts from the prior year amounts to be 26.5% (calculated as [($2,644,454 -$2,091,015)/$2,091,015] and 10.2% (calculated as [($2,914,064-$2,644,454)/$2,644,454]), respectively.

Page 41 states that: "For 2022 Bridge and 2023 Test years amounts have been forecasted using a 5% increase on prior year amounts."

a) Please reconcile the growth rates between PUC's statement and the calculated growth rates based on Table 4-17 on page 41.
b) Please explain what makes up the corporate benefit in Table 4-17.

Response:

a) PUC Services applied a 5% increase to its total 2021 Employee Benefit Costs and then allocated the shared portion to PUC at the applied capital and OM&A split. Due to corrections in Table 4.16 related to Employee Benefits Costs (Refer to OEB Staff-72), Table 4.17 has been updated to reflect corrected allocations.

Due to changes in the shared services allocation changes year to year, as well as the changes in capital versus OM&A allocation year to year, the growth will decrease or increase in OM&A. To show the total 2022 and 2023 growth, PUC has provided the total benefits charged to OM&A and Capital below.

Table 4-17: Employee Benefit Costs OM&A

Benefit	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge	2023 Test
CPP Employers' Portion	$ 155,492	$ 150,598	$ 168,053	$ 183,760	$ 184,794	$ 203,346
EI Employers' Portion	$ 68,701	$ 57,369	$ 62,768	$ 61,405	$ 61,751	$ 67,950
Employer Health Tax	$ 103,624	$ 95,499	$ 105,418	$ 107,706	$ 108,312	$ 119,186
WSIB	$ 59,914	$ 44,570	$ 55,598	$ 54,834	$ 55,143	$ 60,679
OMERS Employers' Portion	$ 517,894	$ 496,649	$ 569,692	$ 535,185	$ 538,196	$ 592,227
OPEB	$ 37,597	$ 27,408	$ 42,806	$ 34,059	$ 34,251	$ 37,689
Corporate Benefits	$ 669,721	$ 592,195	$ 565,150	$ 639,678	$ 643,277	$ 707,857
Total Benefits Charged to OM&A	**$ 1,612,942**	**$ 1,464,288**	**$ 1,569,485**	**$ 1,616,627**	**$ 1,625,724**	**$ 1,788,933**

Table 4-17: Employee Benefit Costs Capital

Benefit	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge	2023 Test
CPP Employers' Portion	$ 48,364	$ 56,457	$ 53,418	$ 66,417	$ 66,791	$ 73,496
EI Employers' Portion	$ 21,369	$ 21,507	$ 19,952	$ 22,194	$ 22,319	$ 24,559
Employer Health Tax	$ 32,231	$ 35,801	$ 33,509	$ 38,929	$ 39,148	$ 43,078
WSIB	$ 18,636	$ 16,709	$ 17,673	$ 19,819	$ 19,930	$ 21,931
OMERS Employers' Portion	$ 161,086	$ 186,187	$ 181,085	$ 193,434	$ 194,522	$ 214,050
OPEB	$ 11,694	$ 10,275	$ 13,607	$ 12,310	$ 12,379	$ 13,622
Corporate Benefits	$ 208,311	$ 222,006	$ 179,642	$ 231,201	$ 232,502	$ 255,843
Total Benefits Charged to Capital	**$ 501,691**	**$ 548,944**	**$ 498,885**	**$ 584,303**	**$ 587,591**	**$ 646,580**

Benefit	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge	2023 Test
Total Benefits Charged to OM&A	$ 1,612,942	$ 1,464,288	$ 1,569,485	$ 1,616,627	$ 1,625,724	$ 1,788,933
Total Benefits Charged to Capital	$ 501,691	$ 548,944	$ 498,885	$ 584,303	$ 587,591	$ 646,580
Total Benefits Charged to OM&A & Capital	**$ 2,114,633**	**$ 2,013,232**	**$ 2,068,370**	**$ 2,200,930**	**$ 2,213,315**	**$ 2,435,513**

b) Corporate benefits include Extended Health Care, Long-Term and Short-Term Disability, Dental, Life Insurance and Semi-Private insurance coverage.

Staff 74

Pension and Other Post-Employment Benefits
Reference 1: Exhibit 4, pg. 35, 39 and 41
Reference 2: Exhibit 2, pg. 72
Reference 3: Exhibit 4, Appendix A, PUCS Actuarial Report

Question:

Page 35 of Exhibit 4 states:

> PUCS recovers their Ontario Post Employment Benefits ("OPEB") costs based on the accrual method. This method recognizes the cost of OPEBs as an employee's service is rendered and the benefit is earned. PUC's shared portion of the accrued OPEBs is allocated as an overhead on direct labour on an annual basis. As such, PUC' Distributions obligation for OPEBs is treated similar to pension funding where there are no future obligations.

Page 41 further states PUC Distribution has determined the details of employee benefit programs breakdown above using the shared services allocation methodology described in the Shared Services section.

Reference 2 indicates that payroll costs in direct labour costs, which is capitalized in PP&E include benefits, pensions, CPP, EI etc. PUC filed 2021 Actuarial report of PUCS in Appendix A of Exhibit 4.

a) Please clarify and describe how the benefit amounts have been determined (e.g., direct assignment, or allocation factor based on summed FTE).
b) As PUC Distribution's OPEB obligation is treated similar to pension funding where there are no future obligations, please comment on PUC Distribution's recovery of OPEB amounts based on PUCS' accrued OPEB amounts.
    i. Please comment on whether PUC Distribution's recovery on a cash basis would be materiality different than recovery on the proposed accrual basis.
c) Please calculate the shared portion of PUC Distribution's shared portion of accrued OPEB liability for the years 2021 to 2024 by using the Defined benefit liability on the PUCS' actuarial report multiplied by the shared portion (%).
    i. Please explain if and where PUC Distribution's 2021 shared portion of accrued OPEB liability is included in the PUC's 2021 AFSs.

ii. Please explain where PUC Distribution's 2023 shared portion of accrued OPEB liability is included in 2023 rate application and models (including PILs model).

d) Please provide a table similar to Table 4-17, showing the benefits capitalized.

Response:

a) Benefit amounts have been determined using the shared services allocation methodology described in Exhibit 4 section 4.3.3.

b) PUC's share of PUC Services' OPEB expenses is on a cash basis. The current expenses are allocated to PUC based on the shared services allocation methodology described in Exhibit 4 section 4.3.3.
   i. PUC uses the cash basis for recording its share of PUC Services' OPEB costs.

c) PUC is not allocated a shared portion of PUC Service's accrued OPEB liability.
   i. PUC is not allocated a shared portion of PUC Service's accrued OPEB liability. Therefore, there is no amount included in the 2021 AFSs.
   ii. PUC is not allocated a shared portion of PUC Service's OPEB liability.

d) Please refer to OEB Staff-73.

Staff 75

Shared Services and Corporate Cost Allocation
Reference: Exhibit 4, pg. 42

Question:

PUC Distribution states that as a virtual utility, it shares certain resources with affiliates in order to create economies of scale and scope.

Please discuss how the shared services structure has provided value and benefits to customers.

Response:

With a shared services model, PUC allows its managed businesses to benefit from utilizing a well-defined infrastructure to enable higher value service delivery. PUC's group of companies share services, such as human resources, finance & accounting, information technology & security, supply chain and other front and back-office services. The benefits include cost-effectiveness, improved service levels, better controls and insights, improved communications, and improved productivity which provide value to PUC customers.

Staff 76

Shared Services and Corporate Cost Allocation
Reference 1: Exhibit 4, pg. 47
Reference 2: Exhibit 4, Appendix B - Full Absorption Cost Allocation Review, pg. 19
Reference 3: Chapter 2 Appendices, Tab 2-H – Other_Oper_Rev
Reference 4: Chapter 2 Appendices, Tab 2-N – Corp. Cost Allocation

Question:

Reference 1 states that all activities of the PUC group of companies are carried out in a shared building which is owned by PUC Distribution. The portion of the building used by affiliates is made available by PUC distribution under a lease arrangement. The lease is priced to affiliates at fully allocated cost. The rent is included in PUC's Other Revenue.

Reference 2 states that "building operating costs including property taxes, electricity, heating, water and sewer, insurance, janitorial, repairs and maintenance were determined on a square footage basis and charged in addition to the cost-based lease charge from PUCD."

a) Please explain the driver(s) behind the "Building Rental" charge from PUC Distribution to PUC Services declining in each year between 2018-2023.
b) Please explain how the "Building Rental" amount for 2023 was forecasted.
    i. Please confirm if the building operating costs which are charged in addition to the cost-based lease charge from PUC Distribution to PUC Services noted in reference 2 above are included in the Building Charge/Building Rental line items on Tabs 2-H – Other Revenue and 2-N – Corporate Cost Allocation, respectively. If not, where are they recorded?
c) Are there other entities that occupy the building? If yes, please confirm if PUC Distribution receives rent payments from other entities besides PUC Services.
d) Given that the building is owned by PUC Distribution, please explain the allocated cost from PUC Services to PUC Distribution for the "Building 5675" line item as seen in the Chapter 2 Appendices, Tab 2-N.

Response:

a) PUC's cost-based lease charge is a cost of capital charge based on the NBV of the building using the OEB approved Cost of Capital Parameters from its last COS rate application.

Since the NBV declines each year, the resulting lease charge has also declined from 2018 to 2023.

b) The 2023 forecast uses the estimated NBV of the building asset. The forecasted building lease for 2023 was determined by applying the Cost of Capital Parameters used in this application to the NBV.
    i. The building operating costs are charged from PUC Services to PUC based on the shared service corporate cost allocation model. PUC has identified an error in the Chapter 2 Appendices 2-N. It should have shown these costs being charged from PUC Services to PUC. This update has been made on the revised model filed in live excel format as "PUC_2020_Filing_Requirements_Chapter2_Appendices_20221128". Additionally, PUC has added property taxes to Appendix 2-N as PUC's portion of property taxes are allocated at cost based on the shared service corporate cost allocation model.

c) PUC confirms that PUC Services and the Public Utilities Commission are the only other entities to occupy the building. The portion of revenue that PUC receives is the aggregate from both of these companies.

d) Even though the building is owned by PUC, all O&M costs are paid for by PUC Services. PUC Services then allocates these costs based on the shared services corporate cost allocation model, including a portion back to PUC.

Staff 77

Shared Services and Corporate Cost Allocation
Reference 1: Exhibit 4, pg. 49
Reference 2: Exhibit 4, Appendix B - Full Absorption Cost Allocation Review, pg. 7

Question:

Tables 4-21 and 4-22 at reference 1 provide the shared service allocation between 2018 and 2021.

Reference 2 states that "For allocation of the building cost among affiliates, the allocator is Operations FTE hours, for all departments with operations out of the shared building."

Please explain the driver(s) behind the increase in the % of the building being allocated to PUC Distribution (based on the allocator "% of building utilized") between 2018 and 2021 (i.e., increase to 55.34% from 46.45%).

Response:

The driver used to determine the building allocation was direct FTE hours charged by Operation departments (e.g., Engineering, Lines, Metering, Locates, etc.) to the companies occupying the building. This update resulted in the increase from 2018 (46.45%) to 2021 (55.34%).

Staff 78

Shared Services and Corporate Cost Allocation
Reference 1: Exhibit 4, pg. 47
Reference 2: Chapter 2 Filing Requirements, April 18, 2022, pg. 31

Question:

The Filing Requirements indicate that respect to Tab 2-N of the Chapter 2 Appendices regarding corporate cost allocation, a variance analyses, with explanations, are required for the following:

- Test year vs. last OEB-approved
- Test year vs. most recent actuals

PUC Distribution provided a table at the bottom of page 47 showing the variances between the test year v. last OEB-approved, and test year vs. last actual, however an explanation of those variances does not seem to have been provided.

a) Please provide a discussion of the variances above materiality (i.e., test year v. last OEB-approved for "Customer Service Acct 5405 to 5420" and "Admin Acct 5605 to 5635, 5665").

Please explain the driver(s) behind the material increase in "Admin Acct 5605 to 5635, 5665" between 2020 and 2021.

Response:

a) Variances above materiality have been highlighted below:

Corporate Cost Allocation - Variance Analysis					
Service Offered	2018 Board Approved	2021 Actual	2023 Test	Test Year vs Last Actual	Test Year vs Board Approved
Billing Acct 5305 to 5315	$ 481,405	$ 524,770	$ 403,777	$ (120,994)	$ (77,628)
Collections Acct 5320 to 5335, excl. 532	$ 133,432	$ 67,606	$ 74,604	$ 6,998	$ (58,829)
Collections Acct 5321	$ 87,311	$ 88,508	$ 64,704	$ (23,805)	$ (22,607)
Customer Services Acct 5405 to 5420	$ 526,090	$ 584,897	$ 662,219	$ 77,322	$ 136,129
Admin Acct 5605 to 5635, 5665	$ 1,819,004	$ 2,614,914	$ 2,491,073	$ (123,841)	$ 672,068
Building 5675	$ 416,453	$ 333,356	$ 389,410	$ 56,055	$ (27,043)
	$ 3,463,696	**$ 4,214,051**	**$ 4,085,786**	**$ (128,265)**	**$ 622,090**

Test Year vs Last Actual

Billing Acct 5305 to 5315 – decrease of $120,944 is due to a reduction in Billing labour, billing materials (e.g., postage) and a decrease in management fees.

Admn Acct 5605 to 5635, 5665 - decrease of $123,841 is due to a reduction in Administration labour offset by increases in network and telephone charges.

Test Year vs Board Approved

Customer Services Acct 5405 to 5420 – increase of $136,129 is due to an increase in Customer Service labour.

Admn Acct 5605 to 5635, 5665 – increase of $672,068 is due to an increase in Administration labour and increases in network and telephone charges.

The 2021 increase includes the reversal of COVID ineligible expenses from 2020 which were mainly administrative salaries.

Staff 79

Reference 1: Exhibit 4, Appendix B - Full Absorption Cost Allocation Review, pg. 10
Reference 2: Exhibit 4, pg. 51

Question:

Reference 1 indicates that 17 Trees Inc. provides vegetation management services to its 3-way ownership partners, PUC Distribution, Greater Sudbury Utilities Inc., and North Bay Hydro Services Inc.

a) How did PUC Distribution help form this company?
b) OEB staff notes that work contracted to 17 Trees is sole sourced as seen in reference 2. How does PUC Distribution ensure that the prices from 17 Trees are competitive?

Response:

a) 17 Trees Inc. was a collaboration between affiliates of three LDCs in Northern Ontario. Although PUC did not have any direct involvement in forming 17 Trees, the two companies share the same parent company, PUC Inc.

b) Most importantly, PUC notes that one of the primary reasons for the formation of 17 Trees was to address the issue of the lack of a robust competitive market for tree clearing contractors in its service territory. PUC continually monitors the industry and compares the pricing of 17 Trees to the current available market, in addition to reviewing its vegetation management costs to ensure the sole sourced work remains economical.

Staff 80

Regulatory Costs
Reference 1: Chapter 2 Appendices, Tab 2-M – Regulatory Costs
Reference 2: Exhibit 4, pg. 51-52

Question:

Total application costs are forecasted to be $680k for the current application. The breakdown is provided in the table below.

Cost of Service Application Costs	Total $
Incremental operating expenses associated with staff resources allocated to this application	$126,366
Consultant Costs	$430,634
Intervenor Costs	$100,000
OEB Application Costs	$20,000
Settlement Conference Costs (virtual)	$3,000

a) How much has PUC Distribution spent to date for this application?
b) The 2018 OEB-approved consultant costs were $515k as seen on Tab 2-M. The actual 2018 consultant costs were about $267k. For the current application, consultant costs are about $431k.
    i. Please explain why the 2018 actual consultant costs were slightly less than half of what was forecasted.
    ii. For the current application, please provide details of the consulting costs by assignment.
c) Has PUC Distribution benchmarked its regulatory costs with other utilities? If not, please explain why.

Response:

a) To date, PUC has spent $427.9k on this application (of an estimated $680k).

External costs are outside party consultants. Incremental operating costs are PUC Services staff who are not directly allocated to PUC. These costs are considered incremental staff costs as their time is charged directly to the PUC's COS application compared to the Shared Service Corporate Cost Allocation Model. The COS application is considered a

special project outside of the yearly recurring tasks for shared staff and therefore time is charged directly to the project.

The 2018 COS OEB approved Application related one-time expenses to be amortized was $599k ($120k per year over 5 years). Actual spend was $578k.

Cost of Service Application Costs	Total COS	Amortized over 5 Years	YTD
Consultants' costs	$430,634	$86,127	$325,796
Incremental operating expenses	$126,366	$25,273	$102,120
Intervenor costs	$100,000	$20,000	$0
OEB Section 30 Costs (application-related)	$20,000	$4,000	$0
Settlement Conference Expenses	$3,000	$600	$0
	$680,000	**$136,000**	**$427,915**

b) In 2018, external consultant costs were $276k, however, incremental internal resources were $210k, compared to 2023 application's of $431k external and $126k internal, an increase of $79k (16% increase).

i. PUC's split between internal and external resources changed from 2018 to 2023.

ii. Cost by assignment is provided below.

Consultant	Amount
BLG (advisory)	$225,000
Metsco (DSP)	$180,000
Indeco (LRAM)	$12,000
BDR (Cost Allocation)	$14,000
	$431,000

c) PUC has compared its 2021 Regulatory costs to other comparable LDCs in Northern Ontario and it is one of the lowest:

LDC	Regulatory costs
PUC Distribution Inc.	**$ 274,354**
Greater Sudbury Hydro Inc.	$ 703,118
North Bay Hydro Distribution Limited	$ 323,961

Staff 81

LRAMVA Balance
Reference 1: LRAMVA Workform – Tab 1
Reference 2: DVA Continuity Schedule – Tab 2b and Tab 4
Reference 3: Exhibit 4, Table 4-28

Question:

The total LRAMVA balance in the LRAMVA balance does not match the balance in the DVA Continuity Schedule ($196,576 vs. $201,460). The difference appears to be that the total amount allocated to the GS < 50 class is a credit of 111,834 in tab 4 of the DVA Continuity Schedule and a credit of $106,950 in the LRAMVA Workform.

a) Please explain the discrepancy between the two balances and confirm the amount requested for disposition.
b) If required, please update the LRAMVA Workform and/or DVA Continuity Schedule to reflect the LRAMVA balance requested for disposition.

Response:

a) The difference is the remaining DVA balance in the LRAM 1589 account from the 2018 COS. The amount was added to the new DVA balance for the 2023 COS. The combined amount is $198,189, including carrying costs.

The LRAMVA Workform has been updated to tie to Tab 2b in the "PUC_2023_DVA Continuity Schedule_20221128". The DVA Continuity Schedule has been updated the forecasted interest rate using the Q4 OEB Interest rate for Q4 to April 30, 2023. Exhibit 9, Table 9-13 Account LRAM (2018 COS) and Table 9-14 Account 1598 (2023 COS) have been updated below.

Customer Class	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$42,005	$2,502	$44,507
GS<50 kW	kWh	($103,740)	($3,211)	($106,950)
GS 50-4,999 kW	kW	$256,254	$7,650	$263,903
Unmetered Scattered Load	kWh	$0	$0	$0
Sentinel Lighting	kW	$0	$0	$0
Street Lighting	kW	$0	$0	$0
Total		**$194,519**	**$6,941**	**$201,460**
Remaining 1568 DVA balance from 2018 COS, plus updated carrying costs per DVA Continuity				($3,271)
				$198,189

1

Table 9-13: Account 1568 LRAM (2018 COS)

Acct 1568	2017	2018	2019	2020	2021	Forecast 2022 -Apr 2023
Opening	$ (13,391)	$ (109,860)	$ 419,118	$ 288,959	$ 35,062	$ (6,064)
1568 Disposition		$ 528,978				
1568 Recovery	$ (96,469)		$ (130,159)	$ (253,897)	$ (41,126)	$ (22,841)
Closing	$ (109,860)	$ 419,118	$ 288,959	$ 35,062	$ (6,064)	$ (28,904)
Carrying costs					$ 20,326	$ 20,326
Balance					**$ 14,262**	**$ (8,578)**

Table 9-14: Account 1568 LRAM (2023 COS)

Acct 1568	2018	2019	2020	2021	2022	Forecast Jan-Apr 2023
1568 Disposition	47,519	45,919	34,779	35,197	31,105	**194,519**
Carrying costs					6,941	**12,249**
Balance	**47,519**	**45,919**	**34,779**	**35,197**	**38,047**	**206,768**

LRAM - (2018 COS)	**(8,578)**
LRAM - (2023 COS)	**$ 206,768**
	198,189

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4

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Staff 82

2019 Lost Revenues
Reference: LRAMVA Workform – Tab 5

Question:

In Table 5-e, please confirm that source of the adjustment to the 2019 savings for the Save on Energy Retrofit Program (row 883).

Response:

Row 882 has the values in PUC's April 2019 Participation and Cost report from the OEB. Row 883 shows the results for projects completed subsequent to the P&C report, from PUC's CDM databases. The details of those projects are provided on Tab 3a of the workform. Originally reported as gross savings, the net values are calculated using the NTG and RR values for PUC's retrofit program in 2017, consistent with the recommended methodology in the CDM Guidelines.

Staff 83

Continued Use of the LRAMVA
Reference: Exhibit 4, pg. 55

Question:

The 2021 CDM Guidelines requires electricity distributors filing an application for 2023 rates to seek disposition of all outstanding LRAMVA balances related to previously established LRAMVA thresholds. PUC Distribution notes that it is not currently running any CDM programs.

a) Please confirm if PUC Distribution is seeking disposition of all outstanding LRAMVA balances and whether the LRAMVA would have a zero balance if disposition is approved.
b) Please explain whether PUC Distribution is requesting to use the LRAMVA for any CDM activities for 2023 or beyond at this time.

Response:

a) PUC is seeking disposition of all outstanding LRAMVA balances related to the Conservation First and earlier frameworks. The LRAMVA will have a zero balance if disposition is approved.

b) PUC does not have plans to offer new CDM activities in 2023 or later.

Exhibit 5 – Cost of Capital

Staff 84

Cost of Capital Parameters
Reference: 2023 Cost of Capital Parameters

Question:

On October 20, 2022, the OEB issued a letter announcing the cost of capital parameters applicable to 2023 cost-based applications.[1]

Please update the evidence, as required, to reflect the 2023 cost of capital parameters.

Response:

PUC has updated all OEB models filed with these IR responses to reflect the 2023 Cost of Capital Parameters.

[1] Ontario Energy Board, Letter re: 2023 Cost of Capital Parameters, October 20, 2022

Staff 85

Reference 1: Exhibit 5, pg. 4
Reference 2: Chapter 2 Appendices, Tab 2-OB – Debt Instruments
Reference 3: EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December 11, 2009, pg. 53

Question:

Reference 1 states that PUC Distribution has a promissory note payable to its parent company, PUC Inc., with interest payable quarterly, rates periodically negotiated (emphasis added), and principal payable one year after demand. In this application, as originally filed, the interest rate on this note will be based on the OEB's cost of capital parameter for deemed long term debt for 2023 cost of service rate applications issued October 28, 2021 which is 3.49%.

Tab 2-OB of the Chapter 2 Appendices indicates that this is a fixed rate note.

The *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* states that:

> The deemed long-term debt rate will act as a proxy or ceiling for what would be considered to be a market-based rate by the Board in certain circumstances. These circumstances include:
>
> - For affiliate debt (i.e., debt held by an affiliated party as defined by the Ontario Business Corporations Act, 1990) with a fixed rate, the deemed long-term debt rate at the time of issuance will be used as a ceiling on the rate allowed for that debt.
> - For debt that has a variable rate, the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. This applies whether the debt holder is an affiliate or a third-party.

a) Please confirm if this a fixed or variable rate note. If variable, please update Tab 2-OB as required.
b) Please confirm if PUC Distribution is proposing to update the rate with the OEB's cost of capital parameters applicable to 2023 applications, as issued by the OEB on October 20, 2022.

Response:

a) PUC confirms that this is a fixed rate note.

b) PUC confirms it is proposing an update to this fixed rate with the OEB's cost of capital parameters applicable to 2023 applications, as issued by the OEB on October 20, 2022.

Staff 86

Reference: Exhibit 5, pg. 6

Question:

The evidence indicates that Loan number 6 is to be finalized with Infrastructure Ontario. It is anticipated to be a 20-year debenture with an estimated fixed interest rate of 5.00% used for rate making purposes.

What is the status of the forecasted loan number 6 with a start date of January 1, 2023? If there is any update, please provide, and reflect in updated 2-OB schedules for the 2023 test year.

Response:

There is no update on loan number 6 at this time.

Exhibit 6 – Revenue Deficiency

Staff 87

PILs Workform
Reference 1: PILs Workform
Reference 2: Chapter 2 Appendix 2-BA

Question:

In the bridge year of the PILs Workform, tab B8 shows additions of $29,330,033, which agree to the sum of additions and ICM SSG additions in Appendix 2-BA for 2022.

a) Please confirm that the additions for the Substation-16 have already been included in PUC Distribution's 2021 tax return. If not confirmed, please explain PUC Distribution's CCA treatment for Substation 16.
b) Using the bridge year as an example, the additions in tab B8 of $29,330,033 include the reduction of $492,800 for capital contributions as shown in the breakdown of additions in Appendix 2-BA. Therefore, CCA has been reduced by the amortization related to capital contributions. On tab B1, there is a deduction of $246,348 for the amortization of contributed capital. The same circumstances apply to the test year. Please explain PUC Distribution's treatment of contributed capital (whether an election is made for contributed capital).
    i. Please explain whether there is any double counting of amortization for capital contributions. If so, please revise the evidence as needed.

Response:

a) PUC confirms that the additions for Substation-16 have already been included in PUC's 2021 tax return.
b) PUC can confirm that an election has been made for contributed capital.
    i. No, there is no double counting of amortization for capital contributions because PUC is only deducting the amortized capital for income tax purposes.

Staff 88

Loss Carry-forward
Reference: Exhibit 6, pg. 21-22

Question:

PUC Distribution is forecasting a tax loss carry-forward of $3,915,084 available for use in the test year, with $1,660,194 attributed to Account 1592, Sub-account CCA Changes. PUC Distribution is proposing to refund the tax loss carry-forward net of the 1592 sub-account amount of $2,254,890 to ratepayers through a two-year rate rider.

a) Please discuss the main drivers and the associated amounts that resulted in the tax loss carry-forward of $3,915,084.
b) Please explain PUC Distribution's rationale for proposing this approach relating to PILs.
c) Typically, the tax loss carry-forward available for use in the test year is amortized over the five years in the IRM term by applying one fifth of the tax loss carry-forward to the test year taxable income for regulatory purposes. Please explain whether PUC Distribution has considered this approach and explain why it was not proposed.

Response:

a) The main driver to the increase in tax loss carry-forwards is the treatment of CCA from Bill C-97. This created a significantly higher amount of loss carry-forwards for tax purposes as compared to regular CCA. Additionally, PUC had the addition of its SSG which is a net capital increase of $21,357,909 in the 2022 bridge year.

b) PUC's rationale for proposing the approach of splitting the $3,915,084 into $1,660,194 attributed to Account 1592, Sub-account CCA Changes and $2,254,890 to ratepayers through a two-year rate rider was to differentiate the amounts related to the 1592 accelerated CCA entry and the loss carry-forwards in excess of the 1592 balance.

c) PUC has considered this approach as this was the approach PUC recommended in its 2018 COS Rate Application (EB-2017-0071). However, it was recommended that PUC refund the tax loss carry-forward amount through the use of a rate rider over 19 months and that is what found its way into settlement. Therefore, PUC recommended the same approach that was settled on in its 2018 COS Rate Application.

Staff 89

Account 1592
Reference: Exhibit 6, pg. 17

Question:

The calculation for Account 1592, Sub-account CCA Changes is provided in Table 6-14. PUC Distribution indicated that the 2018 actual additions were used as the basis for its CCA calculation and journal entries for 2018 to 2022.

a) Please clarify what is meant by 2018 actual additions were used as the basis for the CCA calculation.
b) In Table 6-14, the 2018 amount for CCA – Old Rules and CCA – AIIP rules are both $205,202. Please explain whether this amount is CCA or actual additions for 2018.
c) In Table 6-14, please provide the formula for the line CCA – Old Rules and explain how it is calculated. Please clarify the correlation between the $205,202 in 2018 and how it relates to each subsequent year.
d) In Table 6-14, please provide the formula for the line CCA – AIIP Rules and explain how it is calculated. Please clarify the correlation between the $205,202 in 2018 how it relates to each subsequent year.
e) Please explain why 2018 actual additions are used as the basis for the CCA calculation and not actual additions in each year from 2019 to 2022.

Response:

PUC has provided its calculations of accelerated CCA for the years 2018-2022 and 2023-2027 in Appendix IR16 – PUCD Bill C97 Accelerated CCA, which has been filed in live excel format.

a) In Appendix IR16, the tab titled "2018-2022" shows capital additions of $5,134,274 for each year of 2018-2022 in the calculation of CCA (old rules) and accelerated CCA (AIIP).

b) PUC confirms that the amount of $205,202 is CCA as calculated in Appendix IR16.

c) The calculation for CCA-Old Rules in Table 6-14 is provided in Appendix IR16. The $205,202 is the result of the CCA calculation for the 2018 additions, for which the remaining UCC (undepreciated capital cost) balance related to these additions is carried forward to the calculation of total CCA for the years 2019-2022.

d) The calculation for CCA-AIIP Rules in Table 6-14 is provided in Appendix IR16. The $205,202 is the result of the CCA calculation for the 2018 additions, for which the remaining UCC (undepreciated capital cost) balance related to these additions is carried forward to the calculation of total CCA for the years 2019-2022.

e) The methodology used was discussed with and agreed to by PUC's auditor, KPMG. As an alternative, PUC could have used the actual capital additions for each year in the calculation of the difference in old CCA versus accelerated CCA. PUC notes that the difference of these options would be captured in PUC's loss carry-forwards which are proposed to be refunded to customers through a rate rider.

Staff 90

CCA Smoothing
Reference 1: Exhibit 6, pg. 23
Reference 2: PILs Workform

Question:

Table 6-22 provides the CCA smoothing calculation. For 2023, CCA is $1,178,982. It states that net capital additions of $10,113,371 were used to calculate accelerated CCA with no phase out row, and DSP projected additions are used to calculate accelerated CCA phase out row.

a) Please confirm that the 2023 CCA of $1,178,982 pertains only to the CCA of additions in 2023 and not CCA from prior year additions.
b) OEB staff calculated the 2023 CCA pertaining to 2023 additions to be $1,196,293 [($9,536,336 x 8% x 1.5) +($557,035 x 6% x 1.5)] based on tab T8 of the PILs Workform. Please explain how the $1,178,982 is calculated.
c) Please explain PUC Distribution's rationale for using the test year capital additions consistently for each year from 2022 to 2027 for the calculation of accelerated CCA with no phase out but using forecasted DSP additions for each year from 2022 to 2027 for the calculation of accelerated CCA with the phase out.
d) Please provide a CCA smoothing calculation using the test year capital additions for each year from 2022 to 2027 for both the calculations of accelerated CCA with and without phase out.
e) Please provide a CCA smoothing calculation using the DSP forecasted additions for each year from 2022 to 2027 for both the calculations of accelerated CCA with and without phase out.

Response:

PUC has provided its calculations of accelerated CCA for the years 2018-2022 and 2023-2027 in Appendix IR16 – PUCD Bill C97 Accelerated CCA, which has been filed in live excel format. This Appendix includes revised calculations for 2023-2027 resulting from reclassification of amounts for building, tools and equipment, and computer software for PUC's Green Button Implementation.

a) PUC confirms that the 2023 CCA of $1,178,982 pertains only to the CCA additions in 2023.

b) PUC identified an error in the classification of the $577,035, originally included in class 1 using a CCA rate of 4%. Upon further review, PUC identified that $294,789 of this $577,035 is for an Omicron Injection Tester which should have been classified in Account 1940 – Tools, Shop and Garage Equipment which carries a CCA rate of 8%. Also, the GIS UN Migration project in 2024 and 2025 has been reclassified from CCA class 1 to CCA class 47. Appendix IR16 – PUCD – Bill C97 Accelerated CCA contains a 2023-2027 tab which provides detailed calculations of the $452,766 adjustment to accounting income as submitted in the August 31, 2022, submission. The tab 2023-2027 Nov 28, 2022, shows the revised detailed calculations which includes the following changes

   a. Classifying the 1808 building additions from CCA class 1 to CCA class 1b
   b. Classifying specific items in account 1808 from 2023-2027 to the proper CCA class
      i. 2023 Omicron Injection tester is now classified as CCA class 8
      ii. 2024 and 2025 GIS UN Migration project amounts have been classified as CCA class 47

      These changes have resulted in a change to the adjustment to accounting income from $452,766 to $441,187.

c) PUC's CCA smoothing calculation covers 2023-2027. PUC's revenue requirement is based on 2023 test year capital additions. The actual taxes PUC will pay is based on the actual additions that occur from 2023-2027. PUC believes that the DSP is reflective of the actual capital additions that will occur from 2023-2027 and thus by using them as the basis of the CCA calculation with phase out, gives a more accurate calculation of the smoothing adjustment to accounting income.

d) PUC CCA has provided the CCA smoothing calculation as PUCD – Bill C97 Accelerate CCA_Staff90d for the years 2023-2027 using the test year additions or both accelerated CCA and phase out CCA.

e) PUC CCA has provided the CCA smoothing calculation as PUCD – Bill C97 Accelerate CCA_Staff90e for the years 2023-2027 using the DSP additions or both accelerated CCA and phase out CCA.

Staff 91

Other Revenues
Reference: Chapter 2 Appendices, Tab 2-H – Other Operating Revenue

Question:

a) Please explain the method PUC Distribution used to forecast its Other Revenues for 2023 for each applicable account noted in Tab 2-H.
b) Please provide a table (similar to the layout of Tab 2-H) with an added column showing year to date actuals for 2022.

Response:

a) The following chart explains the method used for forecasting each revenue account:

OEB Account	Method
4082	Inflationary increase of 2% was applied to 2022 bridge year budget.
4084	A 4-year average was used in determine the 2023 test year.
4210 Pole Rentals	PUC's 2022 pole count was used and the OEB's approved rate of $34.76. PUC has updated the rate to $36.05 in the revised OEB Models filed with these IR responses.
4210 Building Return	PUC used the projected NBV of the building as of December 31, 2022, and the OEB's Cost of Capital Parameters to determine the total return through rates that the building generates. Then PUC collects the shared portion from its affiliates according to the shared services model.
4210 Other Misc. Items	All other 4210 accounts are adjusted for inflation annually.
4225 Late Payment Charges	PUC used a 3-year average of 2018, 2019, and 2020 for the 2023 test year revenue.
4235	An inflationary adjustment was applied to the 2022 bridge year forecast.
4245	PUC used the deferred revenue from the contributed capital as per the FA continuity schedules.
4325	An inflationary adjustment was applied to the 2022 bridge year forecast
4390	PUC used a 3-year average of 2018,2019, and 2020 for the 2023 test year revenue.

b) Chapter 2 Appendix, Tab 2-H has been updated with an added column showing year to date actuals for 2022.

Staff 92

Other Revenue
Reference 1: Chapter 2 Appendices, Tab 2-H – Other_Oper_Rev
Reference 2: Chapter 2 Filing Requirements, April 18, 2022, pg. 41

Question:

Please confirm that any revenue related to microFIT charges are recorded as a revenue offset in Account 4235 and not included as part of the base distribution revenue requirement.

Response:

PUC confirms that any revenue related to microFIT charges are recorded as a revenue offset in Account 4235.

Staff 93

Other Revenues
Reference 1: Exhibit 6, pg. 30
Reference 2: Chapter 2 Appendices, Tab 2-H – Other_Oper_Rev
Reference 3: Chapter 2 Filing Requirements, April 18, 2022, pg. 40-41
Reference 4: Exhibit 4, pg. 44

Question:

PUC Distribution states that:

> Account 4210 includes the shared administrative building. A significant portion of the operating activities of the PUC group of companies are carried out in a shared building/facility at 500 Second Line East, which is owned by PUC. The portion of the building used by affiliates is made available by PUC under a lease arrangement. The lease is priced to affiliates at fully allocated cost.

The Filing Requirements indicate that revenues from affiliate transactions should be recorded in Account 4375, and expenses from affiliate transactions should be recorded in Account 4380.

Page 44 of Exhibit 4 shows the building rental for the 2023 test year from PUC Distribution to PUC Services in the Shared Services section.

a) Please explain why the "Building Charge" is being included in Account 4210 as opposed to Account 4375. If any changes are required, please make those changes to Tab 2-H.
b) Please confirm if the "Building Charge" in Tab 2-H represents the rent received by PUC Distribution from PUC Services for the shared office building.
c) Please explain why there are no expenses recorded in Account 4380 related to the portion of the shared building being used by PUC Distribution's affiliate.
d) Please confirm that there has been no changes to the regulatory treatment of the building leased to affiliates from PUC Distribution's last rebasing application to this application (e.g. resulting from the adoption of IFRS 16). If not confirmed, please explain.

Response:

a) PUC used account 4210 as the Accounting Procedures Handbook ("APH") states, "this account shall include rents received for the use by other of land, buildings, and other property devoted to electric operations by the utility". PUC interpreted that the shared

administrative building being used by the other companies constitutes rent received for the use of the building.

However, PUC agrees that account 4375 is also a good fit for the revenues received from affiliate transactions. PUC has continued to report the revenue as 4210 to keep comparable to its 2018 COS Rate Application.

b) The Building charge in Tab 2-H represents the rent received by PUC from PUC Services and the Public Utilities Commission.

c) All expenses related to the building are allocated according to the Shared Cost Allocation Model. PUC's portion of the shared expenses are recorded in the applicable OM&A accounts depending on the expense (e.g., PUC portion of insurance is recorded in 5635, utilities in 5675 and property taxes in 6105).

d) There have been no changes to the regulatory treatment of the building leased to affiliates from PUC's last rebasing application to this application. The lease continues to be priced at the fully allocated cost.

Exhibit 7 – Cost Allocation

Staff 94

Weighting Factors
Reference: Exhibit 7, pg. 4-5

Question:

PUC Distribution states that it "assigned a weighting factor of 1 to the Residential rate class and further calculated the associated weighting factors for the remaining rate classes."
Please provide the derivation of the weighting factors used.

Response:

PUC reviewed the weighting factors from its last COS Rate Application and discussed with staff experienced in the subject area to confirm that there have been no significant changes to the weighting factors.

Staff 95

Load Profiles
Reference: Exhibit 7, pg. 7-13

Question:

COVID Normalized Consumption Data was used to produce the load profiles.

a) Please indicate what was normalized.
    i. Does this refer to the hourly loads?
    ii. Does this refer to the annual forecast?
b) As a scenario, please provide the load profiles and the demand allocators that would result from using profiles that have not been normalized for COVID – i.e. normalized only for Weather.

The method of determining the proportion of system load that is HDD and CDD related energy use in each month is described leveraging the load forecast output. The Load forecast output includes coefficients for HDD and CDD. The average temperature for each ranked day in 2021 is compared to the historic average temperature for the ranked day, and a ratio is used in determining the adjustment.

c) How does the methodology address the potential for differences in weather sensitivity between the rate classes?
d) Has PUC Distribution looked for options to use HDD and CDD more directly to look at heating and cooling related load on a daily, rather than monthly basis? Please describe what was reviewed, and why the proposed methodology was ultimately chosen.

Response:

a) On tab 4. CP & NCP of the Demand profile, the following numbers are used:

Input: Test Year Load Forecast:					
274,738,681	79,051,528	221,450,388	2,459,994	193,841	878,528

These Load Forecast results incorporate the COVID normalization that was completed within the Load Forecast for 2020 and 2021.

b) The hourly load profiles have not been normalized. Only the input variables for the test year are from the Load Forecast that has been normalized for COVID. Table 7-5 from Exhibit 7 on Page 7-17 was meant to show the different results of scenarios run. Table 7-5 has been reproduced below. Additionally, the following chart represents the description of each scenario.

Scenario 1	Description
2020 and 2021 Actual Consumption Data to produce Load Forecast	The load forecast used had no adjustments for COVID.
2020 and 2021 COVID Normalized Consumption Data to produce Load Forecast	The load forecast used had 2020 and 2021 COVID normalized consumption data to produce the load forecast. However, 2021 actual hourly load data was used on tabs 3a. 3b. and 3c of the demand profile.
2018 COS Methodology Allocation Factor (2020 and 2021 Actual COVID Normalized)	PUC used the allocation factor in the same way as its last COS application. When creating the allocation factor, the 2020 and 2021 Consumption was normalized for COVID.

Table 7-5: 2023 Cost Allocation Model Results Using Different Demand Profile Updates

Method	Data Used	Residential	GS<50	GS>50	Street Light	Sentinel Light	USL
1	2020 and 2021 Actual Consumption Data to produce Load Forecast	$ 17,117,204	$ 3,616,755	$ 6,463,068	$ 363,504	$ 51,852	$ 53,105
2	2020 and 2021 COVID Normalized Consumption Data to produce load forecast	$ 17,128,169	$ 3,501,771	$ 6,667,329	$ 349,542	$ 52,120	$ 53,269
3	2018 COS Methodology Allocation Factor (2020 and 2021 Actual COVID Normalized)	$ 17,661,682	$ 3,510,521	$ 6,016,424	$ 372,677	$ 52,205	$ 51,979

c) The same HDD and CDD adjustment factor are used for the Residential, GS<50 and GS>50 rate classes when weather normalizing the consumption data. It does not apply a weather sensitivity between the rate classes. Instead, the Load Forecast numbers have a weather sensitivity component to the derivation of the yearly consumption. PUC believed that the weather sensitivity piece was being accounted for through the Load Forecast results.

d) PUC did not look at the option to use HDD and CDD more directly to look at heating and cooling related load on a daily basis. PUC has modelled its demand profile from other past profiles that have been submitted to the OEB for other COS rate applications. PUC compared different demand allocator results to test the difference in allocation of costs

between the rate classes to make sure that its profile ultimately chosen was similar to that used in previous COS Rate Applications.

Exhibit 8 – Rate Design

Staff 96

Fixed/Variable Charge
Reference 1: Revenue Requirement Work Form, sheet 13. Rate Design
Reference 2: Cost Allocation Model, sheet O2. Fixed Charge | Floor | Ceiling

Question:

The fixed charge is proposed to increase to $27.90 in the GS < 50 rate class, $154.07 in the GS > 50 rate class, and $17.09 for USL. All of these are above the minimum system with peak load carrying capability (PLCC) from the cost allocation model (commonly referred to as the ceiling).

Please provide the variable charge that would result if the fixed charge were maintained at the existing charge.

Response:

The following table displays what the variable charge that would result if the fixed charge were maintained at the existing charge:

	Fixed	Variable
GS<50	$22.32	$0.0363
GS>50	$123.27	$9.2685
USL	$13.67	$0.0528

Staff 97

Loss Adjustment Factors
Reference: Exhibit 8, pg. 14-15

Question:

The A (1) "Wholesale" kWh delivered to the distributor (higher value) and A (2) "Wholesale" kWh delivered to the distributor (lower value) are the same values. Therefore, the model has calculated a supply facility loss factor of 1.0000.

a) Please confirm that the values used reflect energy generated for use by PUC Distribution's customers inclusive of any transmission losses and any embedded generation.
b) If part (a) cannot be confirmed, please provide these values.

Response:

a) PUC confirms that the values used reflect energy generated for use by PUC's customers inclusive of any transmission losses and any embedded generation.

b) N/A

Staff 98

Smart Meter Entity Charge
Reference 1: OEB Letter, Smart Metering Charge to be Charged by Electricity Distributors from January 1, 2023 – December 31, 2027
Reference 2: Tariff and Bill Impact Model, Tab 3 – Regulatory Charges, Proposed Tariff of Rates and Charges (Excel)
Reference 3: Exhibit 8, pg. 14

Question:

On September 8, 2022, the OEB issued the letter in reference 1 with regards to the Smart Metering Entity Charge (SMC) to be charged by distributors from January 1, 2023, to December 31, 2027. Effective January 1, 2023, the retail SMC to be charged and collected by electricity distributors from applicable Residential and General Service <50kW customers will be $0.42 per smart meter per month.

a) Please incorporate the updated SMC in the Tariff and Bill Impact Model.
b) Please incorporate the updated SMC in the Chapter 2 Appendices, Tab 2-ZB – Cost of Power
c) Please file a stand-alone Excel version of the proposed Tariff of Rates and Charges.

Response:

a) PUC has incorporated the updated SMC charge in the Tariff and Bill Impact Model.

b) PUC has incorporated the updated SMC charge in the Chapter 2 Appendices, Tab 2-ZB – Cost of Power.

c) PUC has filed a stand-alone excel version of the proposed Tariff of Rates and Charges.

Staff 99

Bill Impacts
Reference 1: Exhibit 8, pg. 17, Table 8-16
Reference 2: Tariff and Bill Impact Model, Tab 6- Bill Impacts

Question:

PUC Distribution provided its proposed bill impacts which include the reduction of approximately 2.70% in VVO consumption savings from the SSG project.

Please provide a separate copy of the Tariff and Bill Impact Model which shows the proposed bill impacts (as may be updated through responses to interrogatories) excluding any savings from the SSG project.

Response:

PUC has provided a separate copy of the Tariff and Bill Impact Model which shows the proposed bill impacts excluding any savings from the SSG project and the corresponding ROE of $836,065 from the SSG project. The live excel model is entitled: "PUC_2023_Tariff_Schedule_and_Bill_Impact_Model_20221128_No SSG"

Staff 100

Retail Transmission Service Rates
Reference: RTSR Workform

Question:

An updated RTSR Workform has been posted on the OEB's 2023 electricity distribution rates webpage (https://www.oeb.ca/applications/applications-oeb/electricity-distribution-rates/2023-electricity-distribution-rate) to reflect certain corrections to the values on tab 4 and minor formula changes to tab 9.

a) Please re-file the RTSR Workform using the most recent version.
b) Please confirm the data entered on Tab 3 reflects the most recent RRR data for PUC Distribution.
c) Please ensure any resulting changes are made to other inputs/models as required (e.g., Cost of Power calculation Tab 2-ZB, Tariff of Rates and Charges etc.)

Response:

a) PUC has refiled the RTSR workform as PUC_2023_RTSR_Workform_1.0_20221128.

b) PUC confirms that the data entered on Tab 3 reflects the most recent RRR data.

c) The resulting changes have been incorporated into the other models as applicable.

Staff 101

Regulatory Charges
Reference 1: Tariff and Bill Impact Model, Tab 3 – Regulatory Charges
Reference 2: Exhibit 8, Appendix C - Proposed Tariff of Rates and Charges

Question:

On November 3, 2022, the OEB issued its Decision and Order in EB-2022-0220 with respect to energy retailer service charges for electricity distributors effective January 1, 2023. Similarly, the OEB issued its Decision and Order in EB-2022-0221 with respect to the Distribution Pole Attachment Charge effective January 1, 2023.

Please update the Tariff and Bill Impact Model and proposed Tariff of Rates and Charges to reflect the OEB's decisions for these matters.

Response:

PUC has made the requested updates which are reflected in "PUC_2023_Tariff_Schedule_and_Bill_Impact_Model_20221128".

Exhibit 9 – Deferral and Variance Accounts

Staff 102

Account 1588
Reference: DVA Continuity Schedule

Question:

In the DVA Continuity Schedule, cells D36 to D40 show Account 1588 as the account number for 1595 sub-accounts. Please revise the DVA Continuity Schedule to show the account number as Account 1595.

Response:

PUC has revised the "PUC_2023_DVA Continuity Schedule_20221128" cells D26 to D40.

Please note, PUC has made additional updates to "PUC_2023_DVA Continuity Schedule_20221128" as a result of IR responses. Appendix IR18 includes Exhibit 1 and Exhibit 9 Tables affected by these changes, including updates to the forecasted interest using the OEB Q4 rate.

Staff 103

Account 1522
Reference 1: DVA Continuity Schedule
Reference 2: Exhibit 4, pg. 35

Question:

In tab 2b of the DVA Continuity Schedule, there is $0 for Account 1522 – Pension & OPEB Forecast Accrual versus Actual Cash Payment Differential Carrying Charges as at the 2021 year-end.

a) Please explain whether PUC Distribution uses this account as PUC Distribution does not have future obligations for OPEBs.
b) If Account 1522 is used, please confirm that the $0 balance is appropriate.
c) If Account 1522 is not used, please explain why not.

Response:

a) PUC does not use this account as it does not have future obligations for OPEBs.

b) PUC confirms that it does not use Account 1592 and the $0 balance is appropriate.

c) Please refer to OEB Staff-74.

Staff 104

Pole Attachment variance
Reference: Exhibit 9, pg. 18

Question:

Reference 1 indicates that:

> In 2018, the pole attachment charge was initially updated from $22.35 to $28.09 for September 1, 2018, until December 31, 2018, and adjusted to the OEB rate of $43.63 effective January 1, 2019. The rate was again adjusted to $44.50 on January 1, 2020. PUC had its pole attachment rate updated with approval of its 2018 COS application and therefore has not calculated any further variance beyond 2018.

a) Please provide the pole attachment charge rates used to determine other revenues in the 2018 approved revenue requirement.
b) If the rate incorporated in the 2018 revenue requirement was $28.09, please explain why there is no variance calculated beyond 2018 as the $28.09 was a transitionary rate.

Response:

a) The OEB's rate of $43.63 was used in determining other revenues in the 2018 approved revenue requirement.

b) N/A

Due to the Accounting Order [2], the new 2022 rate of $34.76 will result in an additional $93,876 amount recorded in Acct 1508 -Pole Attachment variance. PUC has included this amount in the 2021 Principal Adjustments in Tab 2b, "PUC_2023_DVA Continuity Schedule_20221128". PUC has updated Table 9-8 Account 1508 (Poles) Disposal to include the 2022 amount below.

Annual Joint Use Pole Billing Variance - 2022						
Company	# Joint Poles	New Rate/Pole Jan 2022	2018 Approved	2018 billing at Approved	Billed	Var
Total Joint Use Poles	19,375	$34.76	43.63	$845,331.25	**(751,454.96)**	**$93,876.29**

[2] OEB Decision and Order, EB-2021-0302, issued December 16, 2021 "Wireline Pole Attachment Charge"

1

Table 9-8 Account 1508 (Poles) Disposal					
Acct 1508- Pole	**2018**	**2019**	**2020**	**2021**	**01-Apr-23**
Opening	$ -	$ (25,567)	$ (25,567)	$ 68,309	$ 68,309
4210	$ (25,567)				
Closing	$ (25,567)	$ (25,567)	$ (25,567)	$ 68,309	$ 68,309
Carrying costs					$ 1,025
Balance				$ 68,309	**$ 69,334**
Joint Poles	17,817				
Rate Jan-Aug	$ 22.35				
Rate Sept-Dec	$ 28.09				
Annual change	$ 5.74				
/ 4 mths	**$ 25,567**			**$ 93,876**	

2

3

4

Staff 105

COVID-19 Delayed Implementation IRM Forgone Revenue Variance
Reference 1: Exhibit 9, pg. 22
Reference 2: Guidance for Electricity Distributors with Foregone Revenues Due to Postponed Rate Implementation from COVID-19, August 6, 2020

Question:

Table 9-10 in Reference 1 provides the calculation for the balance in Account 1509, Sub-account Foregone Revenues from Postponing Rate Implementation. The calculation includes a forecast of foregone revenue is up to October 2022.

a) Please provide any updates to the forecasted amount and rationale if the amount is significantly different from the actual rider collected.
b) Based on the accounting guidance in Reference 2, the audited balance is to be requested for disposition (Appendix A of the guidance notes that the audited 2021 balance is requested for disposition in the 2023 rate application). The balance requested for disposition has not been audited yet. Please confirm that PUC Distribution is still requesting the disposition of the balance in this proceeding.
    i. If confirmed, please confirm that PUC Distribution does not expect any further adjustments or activity in the sub-account after disposition. If not confirmed, please explain.
    ii. Please also confirm that this account be discontinued after the disposition of the amount. If not, please provide explanation.

Response:

a) PUC has provided an update to Exhibit 9 Table 9-10 below. PUC identified a minor error in the previous table in the actual amount collected. The total of rate riders collected and the forecast for part of September and October 2022 is estimated to be under $2,000 difference as compared to the actual foregone revenue.

Table 9-10: Acct 1509 COVID-19 Foregone Revenue – IRM Delayed Implementation

Table 9-10: Account 1509 COVID-19 Forgone Revenue – IRM Delayed Implementation						
Acct 1509	**Forecasted Foregone**	**Actual Foregone**	**Actual Collected**	**Forecast**	**Total Rider Collected**	**Variance**
RESIDENTIAL SERVICE CLASSIFICATION	$ 155,117	$ 135,019	$ (115,306)	$ (17,652)	$ (132,958)	$ 2,061
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	$ 22,253	$ 21,994	$ (23,633)	$ (3,924)	$ (27,557)	$ (5,563)
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	$ 32,876	$ 33,296	$ (28,179)	$ (4,420)	$ (32,599)	$ 698
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	$ 269	$ 301	$ (139)	$ (22)	$ (161)	$ 140
SENTINEL LIGHTING SERVICE CLASSIFICATION	$ 274	$ 281	$ (455)	$ (72)	$ (527)	$ (247)
STREET LIGHTING SERVICE CLASSIFICATION	$ 1,433	$ 1,468	$ (368)	$ (59)	$ (427)	$ 1,041
Balance	**$ 212,221**	**$ 192,359**	**$ (168,080)**	**$ (26,148)**	**$ (194,228)**	**$ (1,869)**
Carrying Costs					$ (42)	$ (60)
Balance		**192,359**			**(194,270)**	**$ (1,929)**

b) PUC can confirm that the final balance has not been audited, however, group 2 accounts can only be claimed during COS Applications. PUC is certain that the balance will not materially change from what is presented in the chart above and the updated DVA Continuity Schedule. Therefore, PUC is requesting disposition of this amount as final.

Staff 106

COVID-19 Incremental Expense Variance
Reference 1: Exhibit 9, pg. 27
Reference 2: Exhibit 9, pg. 24
Reference 3: Exhibit 1, pg. 103 ~105
Reference 4: Report of the OEB – Regulatory Treatment of Impacts Arising from the COVID-19 Emergency (EB-2020-0133), June 17, 0133 (COVID-19 Report)

Question:

PUC Distribution is requesting disposition of the balance in Account 1509, Sub-account Impacts from Complying with Government/OEB-initiated Customer Relief Programs.

a) Please confirm that the amounts in Table 9-12 were incurred in 2020 only. If not confirmed, please provide a breakdown of Table 9-12 by year. Please also discuss the means test, materiality, and methodology to determine incremental amounts for the annual balance in the sub-account.
b) Reference 1 indicates that the incremental costs were above the regular management and operation services provided by PUCS as they were to deal with additional services dealing with the extraordinary government and OEB emergency programs. Please confirm that the incremental costs are OM&A in nature and not capital.
    i. If not confirmed, please explain whether the revenue requirement impact has been reflected in the amounts proposed for disposition. If not, why not.
    ii. The OEB's COVID-19 Report provides a guide for a methodology to measure incremental costs. Please provide calculations of the incremental billing expenses and the incremental labour expenses in Table 9-12 in Reference 1 using a baseline comparison to the greater of
        1. The amount embedded in base rates (adjusted for inflationary increases less productivity)
        2. The highest actual amount over the past five years (2015 to 2019).
    iii. If the baseline methodology above was not used to determine incremental billing and labour expenses, please explain the methodology PUC Distribution used to determine incremental amounts.
    iv. Please explain how the amounts identified are clearly attributable to COVID-19.
c) In Reference 1, PUC Distribution stated that it believes it acted prudently to minimize the impacts and fully exploited all available cost reductions and savings. Please discuss the cost reductions and savings that were identified.

d) Reference 2 indicates that recovery of any balances recorded in the Account should be subject to evidence that the costs are not only reasonable, but also that recovery of the costs is necessary for the utility to maintain its opportunity to earn a fair return over the long run. Based on PUC's discussion of financial ratios in Reference 3, it appears that PUC Distribution already has a financing plan to improve its financial viability in the long run. Please comment on whether the recovery of the costs in the 1509 sub-account is necessary.

Response:

a) PUC confirms that the deferred amounts were incurred primarily in 2020, with some additional costs incurred early in 2021. The means test, materiality, and methodology to determine the incremental amounts were provided on pages 24-28 of Exhibit 9. A revised Table 9-12 with the annual breakdown is provided below:

Table 9-12 Account 1509 COVID-19 Incremental Expense Detail

Acct 1509	2020	2021	Total
Incremental billing expenses	$ 577	$ -	$ 577
Incremental labour	$ 199,927	$ 50,239	$ 250,166
Waived Interest	$ 119,153		$ 119,153
Additional LEAP funding	$ 13,133		$ 13,133
Principal	**$ 332,790**	**$ 50,239**	**$ 383,029**
Carrying Costs	$ 10,135	$ 8,603	$ 18,738
Balance	**$ 342,925**	**$ 58,842**	**$ 401,767**

b)

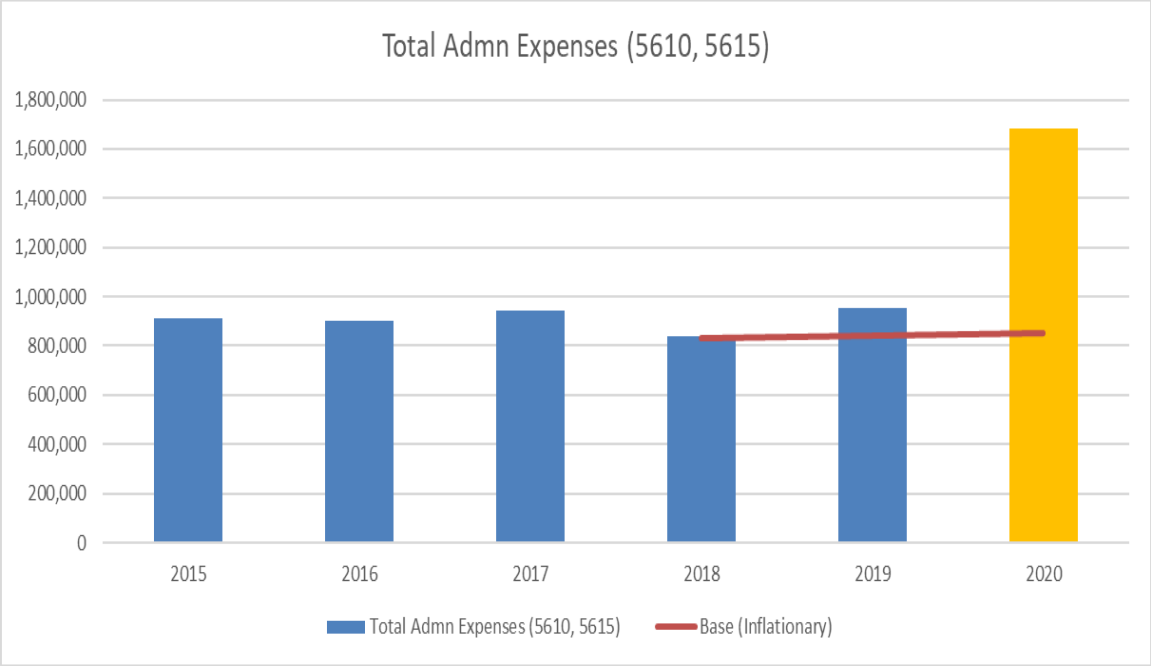
i. PUC can confirm that the incremental costs are OM&A and not capital.

ii. To clarify the point described in the question and reference 1, under the shared services model in which PUC operates, administrative costs are determined in one of two ways:

- Direct allocation of costs in support of PUC specific activities such as preparation of rate applications and other OEB required filings, electric billing system changes, etc.; or
- Indirect allocation of costs using the methodology described in the cost allocation report filed as Appendix B to Exhibit 4.

The costs related to compliance with government or OEB initiated actions to assist PUC's customers as a result of COVID-19 are examples of directly allocated costs which would not have otherwise been allocated to PUC. As a result of tracking these specific activities charged to administrative accounts 5610 and 5615, PUC is able to indisputably determine that these costs are incremental.

In relation to the OEB's methodology to measure incremental costs, the following chart illustrates PUC's historical costs for accounts 5610 and 5615 (normalized for amounts originally recorded to account 1509 in 2020), as well as the baseline amount embedded in rates from PUC's last rebasing application in 2018 (inflated for IPI less PUC's productivity factor):



iii. Please refer to the response to part (ii) above.

iv. The amounts are clearly attributable to COVID-19 as they are costs incurred to administer the government and OEB programs to assist customers. These were not services provided from PUC Services to PUC in the regular course of business under the management services agreement. In addition, outside costs are clearly identified as a direct costs of COVID mandates such as incremental LEAP funding and waived interest.

c) PUC carefully considered how to handle an increased workload to respond to the programs offered to assist its customers during this unprecedented time. To minimize the cost impacts, the additional work requirements were completed internally (not outsourced) under PUC's "at cost" management services agreement, reducing the cost to administer the extra programs.

d) PUC has recorded and submitted amounts in accordance with the OEB's guidelines for eligibility of recovery.

Staff 107

Account 1595
Reference 1: Exhibit 9, pg. 16
Reference 2: DVA Continuity Schedule
Reference 3: Chapter 2 Filing Requirements, 2022 Edition for 2023 Rate Applications, April 18, 2022

Question:

PUC Distribution is requesting final disposition of Account 1595 (2018). The associated rate rider ended April 30, 2020. PUC Distribution noted that it had no subsequent activity in this sub-account other than a reconciliation adjustment between Account 1595 (2019) to correct balances between disposal years. PUC expects no further activity to this account and requests final disposal of the residual balance.

Per page 61 of the Chapter 2 Filing Requirements, distributors become eligible to seek disposition of Account 1595 balances two years after the expiry of the rate rider and the balance in the sub-account is audited. For PUC Distribution's Account 1595 (2018), the sub-account would be eligible for disposition in its 2024 rate application and not the current proceeding.

Please provide PUC Distribution's thoughts on withdrawing the requested disposition of the sub-account. Please revise the relevant evidence.

Response:

PUC understands the filing requirements require the 1595 (2018) to be disposed of 2 years after the rate rider stops being collected. Although PUC does not expect any changes to this amount, and it would prefer to dispose of the amount, PUC has withdrawn this amount and updated the Tab 2a of the "PUC_2023_DVA Continuity Schedule_20221128".

Staff 108

Account 1589
Reference 1: GA Analysis Workform
Reference 2: EB-2021-0054 GA Analysis Workform, March 4, 2022

Question:

In the 2023 GA Analysis Workform, the principal adjustment tab shows no principal adjustments that were included in the last approved balance (Note 8). In PUC Distribution's 2022 GA Analysis Workform, there were principal adjustments of ($759,501) and $759,201 for Accounts 1589 and 1588, respectively, that were recorded in the 2021 general ledger.

a) Please explain why these principal adjustments are not shown in the 2023 GA Analysis Workform to be reversed in the 2021 Accounts 1588 and 1589 balances.
b) Please comment on whether there would be any double counting, where the principal adjustments are reflected in the 2020 balances approved for disposition already and are also included in the 2021 balances requested for disposition in this proceeding as the principal adjustments are recorded in the 2021 general ledger. Please revise the evidence as necessary and reassess the results of the GA Analysis Workform and Account 1588 tabs.

Response:

a) The activity shown in Net Change did not include the 2020 adjustment. The GA Workform has now been updated to show the amount in the activity and the reversal.

b) There is no double-counting. The balance in the account requested for disposition is only for 2021 activity.

Staff 109

GA Analysis Work Form
Reference 1: Exhibit 9, pg. 16
Reference 2: GA Analysis Workform
Reference 3: Accounting Guidance for IESO Charge Type 2148, May 15, 2019

Question:

Reference 1 indicates that "The total activity in 2021 for account 1588 RSVA Power is 1.4%, however, the amount includes a CT2148 prior year amounts. Excluding this amount, it would be 0.6%, less than 1.0% of the total power purchased in account 4705 – Power purchased net a 2020 prior year adjustment GA charge by IESO invoiced in 2021."

a) Please provide the amount for CT2148 and provide the calculation showing how to derive the 0.6% related to Account 1588 RSVA Power.
b) Per the Accounting Guidance in Reference 3, CT2148 is to be apportioned between RPP and non-RPP. Please explain why there is no reconciling item related to CT 2148 for Account 1589 RSVA Global Adjustment in the GA 2021 tab. Please provide the portion of CT 2148 for Account 1589 RSVA Global Adjustment and revise the evidence as needed, reassessing the GA Analysis Workform as applicable.

Response:

a) The CT2148 adjustment was $1,270,901 relating to unreported Embedded Generation amounts for October and November in 2020. The apportionment has now been corrected. The 1588 reasonability tab should explain that the RPP related adjustment ($1,002,372) results in a 0.19% variance.

4705 Power Purchased	63,431,384.98	
	-1.4%	>1%
1588 Variance	(884,854.64)	
Less: IESO Adj	1,002,372.32	
Revised variance	117,517.68	
	0.19%	< 1%

b) The GA Non-RPP 1589 portion of the CT 2148 prior period adjustment is $268,529. The GA WorkForm has been updated to reflect this and the amount will be recorded in 2022 to transfer the amount from Acct 1588 to Acct 1589.

Staff 110

1508 Sub-account Incremental VVO Savings or Costs
Reference 1: Exhibit 9, Appendix B
Reference 2: Exhibit 2, DSP, pg. 94-97

Question:

PUC Distribution is proposing two new sub-accounts for Incremental VVO Savings and Costs. On page 97 of the DSP, PUC Distribution notes that it is proposing a symmetrical maximum upside and downside equal to ROE of the SSG assets. Based on the revised project spend and the OEB's current cost of capital parameters, the current cap is ± $773,539.

a) Please discuss the causation, materiality, and prudence for the establishment of the sub-account.
b) Please clarify how the cap of $773,539 is calculated and how it is equal to the ROE of the SSG assets.
c) Please clarify if the cap amount will change. If yes, please explain what will cause a change to the cap.
d) The associated draft Accounting Order names two sub-accounts, one for Incremental SSG Costs and a second for Incremental VVO Savings. Table 2 shows both debit and credit journal entries being recorded in the Incremental SSG Costs sub-account. The example journal entries on the last page of the accounting order show journal entries being recorded in the sub-account Incremental SSG Costs or Savings. Please clarify, which sub-account(s) are proposed and revise the draft accounting order as needed.
e) The associated draft Accounting Order does not provide a reference to the cap noted in the DSP. Please update the Accounting Order to include this reference.

Response:

a) In Section 5, Conditions of Approval, of the decision and order for PUC's SSG ICM Application (EB-2018-0219/EB-2020-0249), PUC was ordered to do the following:

"PUC Distribution shall file all available information on the proposed Project performance metrics that it intends to track, along with proposed targets, in its next rebasing application. This shall include an appropriate metric and targets to symmetrically link the VVO performance of the Project to PUC's allowable ROE for this Project."

In order to satisfy the symmetrical link in VVO performance of the project to PUC's allowable ROE for the project, PUC is requesting the use of the proposed DVA accounts to satisfy this condition.

With respect to causation, the OEB has already determined in Decision EB-2020-0249/EB-2018-0219 that the "*SSG Project is therefore outside of the base upon which current rates were derived and the incremental capital being requested in this application is directly related to the cost of deploying the SSG Project.*" The proposed sub-accounts are (a) based on the SSG Project where causation has already been determined; and (b) are in response to a directive by the OEB when approving the SSG Project to symmetrically link the VVO performance of the Project to PUC's allowable ROE for this Project.

With respect to materiality, the forecasted amounts will exceed the OEB-defined materiality threshold and have a significant influence on the operations of PUC. The maximum upside/downside amount can reach the total value of the ROE on SSG assets included in the revenue requirement of PUC's 2023 Cost of Service Rate application. As submitted with its August 31, 2022, submission this amount is $773,539.

It is prudent to establish such an account to satisfy the OEB's condition of approval as the accounting order outlines the exact mechanistic nature of the calculation to occur depending on the results of VVO consumption savings and fluctuations in cost of power from one year to the next. It is also prudent that the mechanism used to calculate this benefit or refund to customers is fair and stable to all parties. PUC notes that the OEB found in Decision EB-2020-0249/EB-2018-0219 that "PUC Distribution has demonstrated that its plan to proceed with the SSG Project is prudent."

b) The ROE of SSG is calculated using the average net book value of SSG assets in 2023 and the OEB's cost of capital parameters as of October 28, 2021. The average net book value is $22,330,795*40%*8.66% = $773,539.

c) The cap amount can change based on the following variables:
   - The timing of capital work completed
   - The OEB's updated cost of capital parameters have cause a change to the cap already. The new cap is now $22,330,795*40%*9.36% = $836,065
   - The final classification of capital amounts spent

d) PUC is proposing to use one Sub-Account to record incremental VVO Savings or Costs to customers each year. This has been revised in the updated draft accounting order attached as Appendix IR5.

e) PUC has updated the draft accounting order with a description of the cap which is included in the updated accounting order attached as Appendix IR5.

Staff 111

1508 Sub-account SSG EPC Contract Liquidated Damages
Reference: Exhibit 9, Appendix C

Question:

PUC Distribution is proposing to establish a new sub-account to record the revenue requirement difference relating to the EPC contract liquidated damages. The draft accounting order states that the adjustment will occur on the earlier of December 31, 2023, or the date liquidated damages are actually received in accordance with applicable accounting standards. Depending on the timing of settling this liability, the amount may be estimated and further updated once a final amount is received.

a) Please discuss the causation, materiality, and prudence for the establishment of the sub-account.
b) Please clarify whether PUC Distribution is indicating that it will accrue an entry at December 31, 2023, if they are aware of liquidated damages even though it has not yet been received.
    i. If not confirmed, please explain the statement.
    ii. Please also explain the circumstances in which the amount of the entry may be estimated and the estimated quantum.

Response:

a) In Section 5, Conditions of Approval, of the decision and order for PUC's Sault Smart Grid ICM Application (EB-2018-0219/EB-2020-0249), PUC was ordered to do the following: "*Any EPC Contract liquidated damages resulting from "performance" or "delay" shall be used to reduce the Project capital cost and would be settled at the time of the next rebasing*".

   With respect to causation, the OEB has already determined in Decision EB-2020-0249/EB-2018-0219 that the "SSG Project is therefore outside of the base upon which current rates were derived and the incremental capital being requested in this application is directly related to the cost of deploying the SSG Project." The proposed sub-accounts are (a) based on the SSG Project where causation has already been determined; and (b) are in response to a directive by the OEB to track any liquidated damages resulting from "performance" or "delay" that will be settled at the time of the next rebasing.

With respect to materiality, it is not clear at this time whether the amounts will, in fact, exceed the OEB-defined materiality threshold and have a significant influence on the operations of PUC. However, if the liquidated damages provisions of the EPC Contract are triggered as a result of VVO savings not meeting target or if the project is delayed, the resulting amounts are likely to exceed the materiality threshold. It is not clear at this time whether the liquidated damages clause will be triggered, and PUC has taken a proactive position in drafting the 1508 Sub-account SSG EPC Contract Liquidated Damages in case it is needed.

With respect to prudence, it is prudent to establish such an account to satisfy the OEB's condition of approval. It is also prudent that the mechanism used to track any liquidated damages can easily be determined in a separate account to reduce the total cost of the SSG Project if specific targeted VVO savings are not achieved. PUC notes that the OEB found in Decision EB-2020-0249/EB-2018-0219 that "PUC Distribution has demonstrated that its plan to proceed with the SSG Project is prudent."

b) As provided in the draft accounting order as Appendix C in Exhibit 9, the adjustment will occur on the earlier of December 31, 2023, or the date liquidated damages are actually received in accordance with applicable accounting standards, i.e., material, and probable to occur. As this time, PUC is not aware of any liquidated damages.

Vulnerable Energy Consumers Coalition (VECC) Interrogatories

Exhibit 1 – Administrative

VECC – 1

Reference: Exhibit 1, pg. 58

Question:

"*To date, over 25% of PUC customers are now enrolled in e-billing*."

a) Please describe the enrollment process for a new customer specifically detailing whether paper billing is provided as an option or whether it is the default billing method.
b) Does PUC require a customer have an email address in order to enroll them in the billing system?
c) Does PUC accept credit card payments and if so does it apply any additional charge for this form of payment?

Response:

a) A customer can enroll in e-billing through PUC's Customer Connect on-line portal or through PUC's mobile APP called MyPUC. For new customers, the default is paper billing until the customer elects to enroll in e-billing either through Customer Connect or MyPUC APP.

b) PUC does not require a customer to have an email address to enroll in the billing system, but if a customer elects to enroll in e-billing a valid email address is required.

c) PUC does accept credit card payment through a provider called Paymentus. A charge is applied by Paymentus to the customer for use of this payment service.

Exhibit 2 – Rate Base

VECC – 2

Reference: Exhibit 2, pg. 19, Appendix 2-AB

Question:

a) What accounts for the shortfall in planned capital expenditure in 2019 of $9,454.00 and the actual amount expended of $5,835,000?
b) The net planned capital expenditures shown in Appendix 2-AB of this application are $8,996,00 whereas the net expenditures provided in Appendix 2-AB in EB-2017-0071 (and DSP page 109) are $8576,000. Please explain the difference.

Response:

a) The main shortfall in 2019 planned capital expenditures is due to the delay of the Substation 16 rebuild project which didn't commence until 2020. This was approximately a $4M change in 2019 planned v. actual capital expenditures.

b) As part of the Decision and Order issued by the OEB on September 27, 2018, for EB-2017-0071 (page 21 of 76), $420k was excluded from the 2018 capital expenditures as it was designated for the Substation 16 rebuild. Therefore, $420k was added to 2019 planned capital expenditures increasing the total from $8,576k to $8,996k. This update was missed when PUC filed the final update to the chapter 2 filing requirements. This is evident from original chapter 2 filing requirements, "PUC_2018 Filing_Requirements_Chapter2_Appendices_20180329", which contains the same $8,579k in total planned capital expenditures for 2019.

VECC – 3

Reference: Exhibit 2, pg. 58-

Question:

Table 1: Sub 16 Renewal Milestones

Date	Project Milestones
April 2020	Offload existing station, Equipment Removal and Site Remediation
April, May 2020	Complete Site Civil/Architectural work
June – August 2020	Equipment Installation
August, September 2020	Testing and Commissioning
October 2020	Acceptance, Training, and Turnover
October, November 2020	Document and Financial Closeout

a) The above table was provided in the ICM application (page 7) of EB-2019-0170. Please provide the actual dates of these events.
b) Please provide the detailed project budget that was provided in EB-2019-0170 and show the actual amounts against that budget.
c) Please provide the costs and proof of payment for any materials or services purchased in 2020 for this project.

Response:

a) A version of Table 1 can be seen below showing actual dates:

Date	Project Milestones
April – May 2021	Offload existing station, Equipment Removal and Site Remediation
June – August 2021	Complete Site Civil/Architectural work
September - October 2021	Equipment Installation
November - December 2021	Testing and Commissioning

December 2021	Acceptance, Training, and Turnover
January – March 2022	Document and Financial Closeout

b) Please see table below showing what was estimated in EB-2019-0170 and the actuals:

	Estimate to OEB	Actuals
Consultants/Engineering	$ 535,810.00	$ 535,810.00
Construction	$ 2,114,710.00	$ 3,348,658.56
Switchgear	$ 1,138,341.00	$ 1,228,283.44
Transformers	$ 939,368.00	$ 907,368.00
Total	**$ 4,728,229.00**	**$ 6,020,120.00**

c) Please see the table below for the 2020 Substation 16 costs. Proof of costs for the major equipment can been seen in the attachments provided in Appendix IR6-IR11.

	2020 Costs
Consultants/Engineering	$ 125,986.93
Construction	$ 75,086.73
Switchgear	$ 736,528.04
Transformers	$ 441,684.00
Total	$ 1,379,285.70

VECC – 4

Reference: Exhibit 2, pg. 58

Question:

"*After thoughtful consideration of the impacts related to the COVID-19 pandemic, including worker safety and logistics of project completion decided to delay construction*."

a) Did PUC seek to also delay implementation of the associated ICM rate rider? If not please explain why not and provide the correspondence to the OEB noting the delay in this project.
b) What is the rationale for recovery of monies from ratepayers in 2020 when the project was not under construction.

Response:

Please refer to Chapter 3 of the Filing Requirements, and in particular section 3.3.2.6. For incremental capital assets under construction, the normal construction work in progress accounting treatment applies until these assets go into service and are eligible to be recorded in the enumerated 1508 Sub-Accounts. All sub-accounts are subject to the OEB's approval as part of the true-up of any variances for the project. The recalculated revenue requirement relating to the actual ACM/ICM capital expenditures are compared to the rate rider revenues collected in the same period, plus the carrying charges in the respective sub-accounts. These variances would then be refunded to, or collected from, customers through rate riders.

Please also refer to the responses in OEB Staff 19 and 20(b).

VECC – 5

Reference 1: Exhibit 2, pg. 65-
Reference 2: Exhibit 2, DSP pg. 91-

Question:

The SSG Project is expected to be used and useful by the end of 2022, with a small portion of testing and optimization set to occur in the first quarter of 2023 to maximize project benefits.

a) If the SSG project is not projected to come into service until Q1 2023 why has PUC included the amount of $20,622,622 to be in service in 2022 as shown in Appendix 2 BA?
b) Table 5.3-26 shows an amount of $3,1990,371 of 2023 capital additions. Appendix 2-BA 2023 shows no additions for the ICM SSG. Please clarify the apparent discrepancy.
c) Please provide the current in-service date estimated for the project and specifically when the project is expected to be energized and fully connected to the distribution system.
d) Please explain what activity and how much money is captured by the phrase "*a small portion of testing and optimization set to occur in the first quarter of 2023"*

Response:

a) The end of 2022 in-service estimate reflects equipment expected to be energized and operating in the distribution system at year end. The SSG Project involves installation of new equipment in substations and on distribution circuits across the system. As stations are brought on-line the new regulation equipment is under System Control SCADA operation and control. Once equipment is live the testing and optimization of VVO station areas can commence and control settings be refined. A similar process will be applied to the DA equipment. As zones or areas are installed and energized the new equipment will also be brought under System Control operation and control. Zone testing of FLISR automation and control will be confirmed. Once all stations and zones are completed full system level acceptance can be completed.

b) PUC has revised the chapter 2 Appendices Appendix 2-BA to show the $3,190,371 as additions for the ICM SSG. The version has been filed with these IR responses as "PUC_2023_Filing_Requirements_Chapter2_Appendices_20221128".

c) The project is being connected and energized by individual station and DA zones as described above. All elements of the project, including testing and commissioning are still

on plan and scheduled to be completed by March 31, 2023. Construction in various stages is in progress or complete across 6 of 12 stations and latest schedule from October 23rd has last 3 stations at risk of extending being energized into early January 2023. Contractor schedule for DA indicated finish on Jan 4, 2023, so target remains end of 2022.

d) Please refer to OEB Staff-18.

VECC – 6

Reference: Exhibit 2, pg. 65- 91

Table 2-29: SSG ICM Reconciliation

	Original Submission	2022 Capital Additions (ICM)	2023 Capital Additions (COS)	Revised Total Project Spend	Variance
Gross Asset Additions	$ 32,938,213	$ 28,713,347	$ 3,190,371	$ 31,903,718	$(1,034,495)
NRCan	$ 8,109,553	$ 7,355,438	$ -	$ 7,355,438	$ (754,115)
Net Additions	$ 24,828,660	$ 21,357,909	$ 3,190,371	$ 24,548,280	$ (280,380)
In Service Date	31-Dec-22	31-Dec-22	31-Mar-23		

	Revenue Requirement				Variance
Revenue Requirement	$ 875,610	$ 868,713			$ (6,897)
Projected Rate Rider Revenue		$ 852,614			
Refund (-) or Collection		$ 16,100			

Question:

"After PUC was approved for its SSG Project ICM Application, the total amount of federal NRCan funding was not the same as when PUC originally submitted its application. The total amount of NRCan grants available to PUC was reduced by $754,115 in 2022, and therefore the amount available to PUC for NRCan funding was reduced proportionately."

a) Please clarify whether the provision that "[U]nder the Contribution Agreement, NRCan agreed to fund the lesser of 25% of total Project costs incurred or $10,626,500." (EB-2020-0249 Decision and Order April 29, 2021, page 5).
b) Please show how the NRCan funding is derived as an amount of 25% of the project costs.
c) Please provide the most current correspondence from NRCan detailing the amount of subsidy they are providing this project.

Response:

a) The Contribution Agreement (CA), Amendment No.1 - SSG NRCan Agreement - December 2019, was filed with the amended ICM Application as Appendix AA4-2. The

screen clip in the figure below is an excerpt from the agreement that would relate to the reference noted and the funding of the lesser of 25% of eligible project expenditures or the $10.6M.

> 8. Paragraph 6.1 of the Agreement is revoked and replaced by the following:
>
> **6.1 Contribution**
>
> Notwithstanding any other provision of this Agreement, the Contribution shall not in any circumstances exceed the lesser of:
>
> a) Twenty Five percent (25%) of Total Project Costs incurred: or
> b) Ten Million Six Hundred Twenty Six Thousand Five Hundred Dollars ($10,626,500)

b) The NRCan funding is derived from the calculation shown in the table below, which is part of the CA referenced, is 25% of $42,506,000 = $10,626,500.
(Note that the project scope and cost estimate at the time of the 2019 CA was revised/lowered in the project scope of work and cost estimate that was in the amended ICM application which was $33M). The current funding maximum in the CA Amendment No.4 is $7,658,222.

Approved Budget ($)	2018-19	2019-20	2020-21	2021-22	2022-23	TOTAL ($)
Canada (NRCan)	$ 6,653,000	$ 1,000,000	$ 500,000	$ 1,773,500	$ 700,000	$10,626,500
ELIGIBLE EXPENDITURES						
Professional, Scientific and Contracting	$ 13,293,104	$ 1,272,604	$ 600,000	$ 15,000,000	$ 12,340,292	$42,506,000
Total by Fiscal Year:	$13,293,104	$1,272,604	$600,000	$15,000,000	$12,340,292	
Total Eligible Expenditures						$42,506,000

c) The most current NRCan correspondence for the contribution agreement is Amendment No. 4 from October 2022. The contribution is a maximum of $7,658,222. Please see Appendix IR3- 20221006_GISG_3030_Signed Amendement_No.4

VECC – 7

Reference: Exhibit 2, pg. 58

Question:

a) Did PUC seek to also delay implementation of the SSG ICM rate rider? If not, please explain why not and provide the correspondence to the OEB noting the delay in this project.

Response:

Please refer to VECC-4.

VECC – 8

Reference: Exhibit 2, DSP 5.3.6.2.1 /Appendix H / EB-2020-0249/2018-0219

Question:

"*2. PUC Distribution shall file an updated Distribution System Plan at the time of its next rebasing application which demonstrates how the SSG Project is being accommodated through the re-prioritization of other capital expenditures.*"

a) As compared to the prior years - 2018 through 2020 - PUC choose to expend in 2022 larger amounts on switchgear ($1,325,632) and Distribution Stations ($1,815,709). Similarly in 2023 the Utility is forecast to spend more than past averages on voltage conversion ($863,670) and overhead renewal ($1,485,864). In light of the large investments in SSG and Sub 16 why was more effort was not made to reduce capital spending in the new rate plan so as to mitigate against rate increases caused by capital investment?

Response:

As described in the last paragraph on p90 of the DSP section 5.3.6.2.1 (Exhibit 2, p198), in 2022, PUC directed approximately $3.5M of COS dollars to station renewal of assets that would benefit both the DSP ACA objectives and the SSG objectives. This investment was primarily for two transformers and a 34.5kV switchgear at Substation 20, and transformers at Substations 2 and 11. Due to NRCan grant funding received for the SSG project, the PUC will receive a 25% savings on that $3.5M dollar investment. The balance of other capital investments proposed over the 2023-2027 COS period is informed by the outcome of the ACA and is necessary to prevent a significant gap from opening between the recommended and actual investments over the longer term. With respect to pacing of expenditures year over year, please refer to general comments in the response to OEB Staff-32 that may provide additional insight into how PUC has proposed its capital spending.

VECC – 9

Reference: Exhibit 2, DSP, section 5.3.6.2.3, pg. 93-96

Question:

Table 5.3-29: Customer Net Benefit Summary

	Top of Dead Band	Bottom of Dead Band	Scenario 1	Scenario 2	Scenario 3	Scenario4
Measured (estimate) VVO Consumption Savings	16,324,838	14,327,652	13,350,394	16,822,310	782,551	29,750,110
PUC Annual Consumption	604, 623,538	606,565,655	607,598,147	603,161,981	603,161,981	603,161,981
PUC Consumption without SSG (projection from LF)	620,948,376	620,893,307	620,948,541	619,984,291	603,944,531	632,912,091
% Savings	2.70%	2.36%	2.20%	2.79%	0.13%	4.93%
PUC Cost of Power Paid	$69,302,488	$69,302,488	$69,302,488	$69,302,488	$69,302,488	$69,302,488

	Top of Dead Band	Bottom of Dead Band	Scenario 1	Scenario 2	Scenario 3	Scenario4
Average $/kWh	0.1146	0.1143	0.1141	0.1149	0.1149	0.1149
PUC Cost of Power Paid without SSG consumption savings	$71,173,655	$70,939,478	$70,825,230	$71,235,348	$69,392,402	$72,720,735
Customer Energy Savings	$1,871,167	$1,636,990	$1,522,742	$1,932,860	$89,914	$3,418,247
Dollar Savings from Loss Factor consumption reduction	$79,664	$79,664	$79,664	$79,664	$79,664	$79,664
Total purchased power savings	**$1,950,831**	**$1,716,654**	**$1,602,406**	**$2,012,524**	**$169,578**	**$3,497,911**
Additional revenue from increased SSG asset base	$1,755,460	$1,755,460	$1,755,460	$1,755,460	$1,755,460	$1,755,460
Benefit of reduced capital expenditures with SSG	($304,390)	($304,390)	($304,389)	($304,388)	($304,388)	($304,388)
Additional O&M expenses due to SSG implementation	$296,400	$296,400	$296,400	$296,400	$296,400	$296,400

Operating efficiency benefits due to SSG implementation	($30,816)	($30,816)	($30,816)	($30,816)	($30,816)	($30,816)
Change In Revenue Requirement	$1,716,654	$1,716,654	$1,716,655	$1,716,656	$1,716,656	$1,716,656
Annual net benefit to customers	**$234,177**	**$ 0**	**($114,249)**	**$295,868**	**($1,547,078)**	**$1,781,255**

"*PUC has engaged an SSG contractor to develop the methodology, in collaboration with PUC, for calculating the SSG Project performance metrics as outlined in PUC's ICM Application (EB-2018- 0219/EB-2020-0249). PUC will file the methodology and targets for each category as soon as it becomes available."*

"First, PUC will measure VVO consumption (kWh) savings on an annual basis. The methodology for calculating VVO savings is being developed in collaboration with PUC's SSG contractor which will be used as an input."

a) When is the SSG related report expected to be completed?
b) In the absence of a Board approved methodology for VVO calculations what is the basis for entries to the proposed deferral account?
c) In the example reproduced above is the bottom line entitled "*Annual net benefit to customers*." Are the amounts in the various scenarios examples of the amounts that would be booked in the proposed VVO account?
d) Are the VVO balances proposed to accumulate over the rate period or be disposed of on an annual basis?
e) Please explain how row 3: "*PUC Consumption without SSG (projection from LF)"* is calculated.
f) Please explain how the row entitled: *"Benefit of reduced capital expenditures with SSG"* is calculated.

Response:

Response to "(a)" and "(b)":

PUC has filed its supplementary filing as Appendix H_Sault Smart Grid_ Performance Metrics_OEB Order No 6. 20221026, which outlines how PUC will be developing the methodology for the calculation. PUC intends to comply with the OEB's direction in EB-2020-0249/EB-2018-0219 to file a report, within 18 months of SSG Project completion, to show the actual benefits of the SSG Project, broken down by customer class.

c) No, the Annual Net Benefit line is not the amounts that are being proposed as an entry to the VVO account. Table 5.3-30. Reproduced below, is the associated journal entries with each scenario.

Journal Entry				
	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
4080 Distribution Revenue	$57,124		$773,539	
1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings	$57,124		$773,539	
to record the reduction in savings to PUC customers.				
1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings		$30,846		$773,539
4080 Distribution Revenue		$30,846		$773,539
to record the increase in savings to PUC customers.				

d) The VVO balances will accumulate over the rate period and be proposed for disposition at PUC's next COS Rate Application.

e) The line PUC Consumption without SSG (projection from LF) is the total of the two lines above.

f) The line entitled: *"Benefit of reduced capital expenditures with SSG"* is taken from PUC's Amended ICM Application (EB-2018-0219/EB-2020-0249) Appendix entitled" "PUC_App_AA5_App_1JTC1_1 CAPEX Deferral Value Cal_Revised from Early UDM est_20201029".

VECC – 10

Reference: Exhibit 2, DSP, pg. 17

Question:

a) Please provide the 2023 capital and operating costs of the Green Button program.

Response:

a) The 2023 capital costs of the Green Button program are $80,000. The annual operating costs are $21,000.

VECC – 11

Reference: Exhibit 2, DSP, pg. 30

Question:

Table 5.2-14: Customer Hours Interrupted Numbers by Cause Codes – Excluding MEDs

Cause Code	2017	2018	2019	2020	2021	Total CHI	Percent Share
0-Unknown/Other	5,593	3,715	2,061	1,315	10,183	22,866	8%
1-Scheduled Outage	2,946	6,311	6,695	4,245	3,311	23,507	8%
2-Loss of Supply	0	0	2,869	0	0	2,869	1%
3-Tree Contacts	12,032	1,561	3,765	10,295	9,196	36,849	13%
4-Lightning	3,733	64	5,891	0	919	10,607	4%
5-Defective Equipment	9,546	19,757	11,658	42,838	19,240	103,039	35%
6-Adverse Weather	6,210	5,628	8,523	13,462	11,189	45,012	15%
7-Adverse Environment	0	0	259	0	40	299	0%
8-Human Element	59	2,974	1,161	376	123	4,693	2%
9-Foreign Interference	7,990	2,892	8,681	14,826	7,286	41,676	14%
Total	**48,109**	**42,902**	**51,563**	**87,357**	**61,487**	**291,418**	**100%**

a) What are the most common causes of defective equipment outages? How does the DSP address those issues?
b) Please explain the inordinately high number of hours caused by defective equipment related outages in 2020.

Response:

a) Please see the table below for the breakdown of the number of Defective Equipment outages for the years 2018-2021 by asset type sub cause codes. The most common are distribution transformers and conductors. The Defective Equipment value in Table 5.2-12 of the DSP included major event days in the value for 2020. The actual value should be 173. The Defective Equipment value in Table 5.2-14 of the DSP included major event days in the value. The actual value without the major events should be 27,166.

The DSP for the 2023-2027 period proposes a number of programs to address findings from these outage statistics:

- Transformer Failures: A program to replace a significant number of distribution transformers is proposed. This will address the primary issue of PCB removal but will also eliminate a many older end-of-life transformers.
- Conductor failures: A restricted conductor and voltage conversion programs serve to eliminate older and more prone to failure conductors from the system. Additionally, the replacement of deteriorated poles has some impact in that conductors are properly sagged and tensioned as poles are replaced.

Number of Outages					
Defective Equipment	**2018**	**2019**	**2020**	**2021**	**Grand Total**
Arrestor	6	1		1	8
Conductor - Primary	19	25	38	22	104
Conductor - Secondary	17	29	35	10	91
Conductor - Termination	6	25	16	11	58
Insulator	3	2	3		8
Pole or Guy Wire			4	2	6
Recloser	1	1			2
Switch - Breaker	2	1		2	5
Switch - Cable Riser		1			1
Switch - Fused	13	3	6	2	24
Switch - Kabar			2	3	5
Switch - Solid Blade		4	1		5
Transformer - Distribution	4	19	61	23	107
Transformer - Padmount		1	3	3	7
Transformer - Submersible	3	10	4	10	27
Grand Total	**74**	**122**	**173**	**89**	**458**

b) The CHI for defective equipment in 2020 should be 27,166 when removing major events days. MED on Sept 29th was inadvertently not subtracted from the final CHI numbers.

VECC – 12

Reference: Exhibit 2, Material Investment Narrative (PDF pg. 252)

Question:

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018 *	2019 *	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	(1)	65	81	416	299	376	382	388	409	382
Contributions	0	6	(18)	(80)	(63)	(75)	(78)	(80)	(81)	(83)
Capital (Net)	(1)	70	63	336	236	301	304	308	328	299

Please explain why the amounts shown in the table above and noted in the section Material Investment Narrative as "*Customer Demand- New Subdivisions*" does not reconcile to the similar titled category of *"New Services and Subdivisions*" in Appendix 2-AA (Updated Excel).

Response:

The Material Investment Narrative only discusses New Subdivisions of $376,237 where the Chapter 2 Appendices has grouped New Services/Upgrades and New Subdivisions together for a total of $1,630,750. The New Services/Upgrades Material Narrative starts on page 244.

VECC – 13

Reference: Exhibit 2 Material Investment Narrative (PDF pg. 263)

Question:

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	257	557	296	640	663	864	0	0	0	0
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	257	557	296	640	663	864	0	0	0	0

a) Please explain why the amounts shown in the table above and noted in the section Material Investment Narrative as "*OH Renewal – Voltage Conversion*" does not reconcile (for years 2018-2021) to the similar titled category of "*Voltage Conversion*" in Appendix 2-AA (Updated Excel).

Response:

a) The Chapter 2 Appendices 2-AA aggregates the OH and UG Voltage Conversion whereas the Material investment narratives have OH Voltage Conversion. Please see the comparison Chart below:

	2018	2019	2020	2021
OH Renewal Voltage Conversion	257	557	296	640
UG Voltage Conversion	622	373	68	-6
Chapter 2 Appendices 2-AA	879	930	363	634

VECC – 14

Reference: Exhibit 2, Material Investment Narrative (PDF pg. 319)

Question:

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	79	68	61	5	0	401	89	91	95	89
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	79	68	61	5	0	401	89	91	95	89

a) Please explain why the amounts shown in the table above and noted in the section Material Investment Narrative as "*UG Renewal - Vaults*" does not reconcile to the similar titled category of *"UG Renewal*" in Appendix 2-AA (Updated Excel).

Response:

a) In 2018, the Chapter 2 Appendices includes an additional $3k for other general projects and programs for UG renewal that is not related to UG Renewal – Vaults. In 2019, the Chapter 2 Appendices includes an additional $13k for other general projects and programs for UG renewal that is not related to UG Renewal – Vaults. In 2020, the Chapter 2 Appendices includes an additional $65k for PM Switchgear for UG renewal that is not related to UG Renewal – Vaults. In 2021, the Chapter 2 Appendices includes an additional $59k for Direct Buried Cables for UG renewal that is not related to UG Renewal – Vaults. In 2022, the Chapter 2 Appendices includes $136k for other general projects and programs in UG Renewal that is not related to UG Renewal - Vaults. In 2023, the Chapter 2 Appendices includes an additional $31k for other general projects and programs that is not related to UG Renewal – Vaults.

VECC – 15

Reference: Exhibit 2, Material Investment Narrative (PDF pg. 673)

Question:

Table 2: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	0	0	0	0	0	295	68	61	0	0
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	295	68	61	0	0

> *"PUC periodically purchases or renews various tools and equipment that are used through its testing and inspection programs. In general, PUC purchases its tools through two methods depending upon the application of the tool. For tools that are exclusively for use in the electrical distribution system, PUC buys tools directly, with larger tools being recorded as a one-time capital expenditure. The tools proposed for 2023-2027 in this narrative all fall into that category. For more generic tools that have applications inside and outside of the electrical distribution system, PUC's affiliate company PUC Services Inc. purchases and owns the tools. They are then charged out to the various PUC affiliate companies in proportion to the amount that they are used by each affiliate. For the historical period 2018-2022 there were no tools purchased directly by PUC Distribution Inc. so no historical information is available for comparative purposes*."

a) Please explain what items constitutes the purchase of tools in 2023, 2024 and 2025 (presumed by the above explanation as made exclusively electricity use).

Response:

The following tools, for exclusive use by the LDC on the electrical distribution system, are slated for purchase 2023-2025:

1

1C500-1	***General - Tools***	***Year***
1C500-1-2	Tools - Stations	
	Injection Tester	2023
	Transformer Oil Drying Equipment	2023
	IR Camera	2024
	VR/Transformer Test Equipment	2025
	Recloser Tester	2025

2

VECC – 16

Reference: Exhibit 2, Appendix 2-AA Material Investment Narrative (PDF pg. 319)

Question:

a) Please identify which material investments narratives provide an explanation for Appendix 2-AA spending categories:
    i. 2022: Switchgear P&C (line 37) Distribution Station (line 40)
    2023 OH Renewal (line 41)

Response:

The items in Line 40 of Appendix 2-AA (Switchgear P&C) is represented by the material narrative entitled System Renewal, Stations Renewal – Switchgear, Protection & Control Renewals, starting on page 310 of 673 of the pdf file (Exhibit 2).

The items in Line 41 of Appendix 2-AA (OH Renewal) is represented by:

- the material narrative entitled OH Renewal – Transformers (PCBs), starting on page 283 of 673 of the pdf file. ($711k)
- the material narrative entitled OH Renewal – Poles, starting on page 304 of 673 of the pdf file. ($602k)
- the material narrative entitled OH Renewal – General Asset, starting on page 341 of 673 of the pdf file. ($172k)

VECC – 17

Reference: Exhibit 2, Appendix 2-AA

Question:

a) Please revise Appendix 2-AA to:
   i. Show projects by the sub-categories of System Access, System Renewal, System Service and General Plant and specifically delineating SSG and Substation 16 project cost;
   ii. Showing a row in each category for capital contribution amounts;
   iii. Expand the detail in Appendix 2-AA so as to Identity and cross -reference project descriptions with those project descriptions/details shown in the Material Investment Narrative.
   iv. Adding a column to show the most current spending for 2022 for each project or miscellaneous category of projects.

Response:

i. PUC has added the sub-categories to appendix 2-AA in the revised PUC_2023_Filing_Requirements_Chapter2_Appendices_20221128 filed in excel format with these IR Responses. In addition to the categories mentioned above PUC has separated the ICM's into its own miscellaneous category.

ii. PUC does not have the capital contribution information for 2018 to 2020 by category but does have the information by asset type which is provided in the table below. The 2018 to 2020 capital contribution values are shown in a separate miscellaneous category and the 2021 to 2023 capital contribution values are updated in Appendix 2-AA.

	2018	**2019**	**2020**
Overhead Contributed Capital	($368,096)	($887,489)	($522,098)
Underground Contributed Capital	($42,070)	($167,447)	($114,394)
Transformer Station Contributed Capital	($20,866)	($56,907)	($21,674)
	($431,033)	**($1,111,843)**	**($658,166)**

iii. PUC has revised the chapter 2 Appendices 2-AA to show the connection between the categories and the material narratives. Many categories had to be split to show the amounts that needed to be separated to tie to the material narratives.

This can all be viewed in the revised PUC_2023_Filing_Requirements_Chapter2_Appendices_20221128 filed in excel format with these IR Responses.

iv. PUC has updated this on the Chapter 2 Appendices 2-AA.

Exhibit 3 – Operating Revenue

VECC – 18

Reference: Exhibit 3, pg. 9

Question:

The Application states:

"*The most important piece to note here is PUC sees a drop of 16.8% of its GS>50 customers in 2021. PUC reviews the consumption of the GS<50 and GS>50 rate classes in the fall of each year to determine if any customers are required to shift classes based on their consumption. Once PUC analyzed the GS>50 consumption of each customer in the fall of 2020, almost all customers from that 16.8% drop shifted to the GS<50 class – the GS>50 saw a drop of 62 customers and GS<50 saw an increase of 68 customers. However, over time these customers should start to see a return to pre-pandemic levels of consumption*." (Emphasis added)

a) Based on the fall reviews undertaken in 2011 through 2019, please provide a schedule that sets out for each review how many customers were reclassified at the start of the next year: i) from GS<50 to GS>50 and ii) from GS>50 to GS<50.
b) How much of the 2021 change in customer count for the GS<50 and GS>50 classes were due to the reclassification of customers in the fall of 2020 and how much was due to the addition of new customers/current customers ceasing operations?
c) Did PUC review the consumption of the GS<50 and GS>50 classes in the fall of 2021?
    i. If yes, how many customers were reclassified: i) from the GS>50 class to the GS<50 class and ii) from the GS<50 class to the GS>50 class?
d) Has PUC completed its fall 2022 review the consumption of the GS<50 and GS>50 classes?
    i. If yes, how many customers were reclassified: i) from the GS>50 class to the GS<50 class and ii) from the GS<50 class to the GS>50 class?
e) Please provide a schedule that sets out the customer/connection count by customer class for the most recent 2022 month available and also for the same month in 2021.
f) Have the consumption levels for those customers that were classified from GS>50 to GS<50 in the fall of 2020 started "to see a return to pre-pandemic levels of consumption"?
    i. If yes, please provide the change in consumption for this group that demonstrates this return.

Response:

a) The following chart outlines the customers reclasses from 2011 to 2019 for the GS<50 and GS>50 rate classes.

	2011	2012	2013	2014	2015	2016	2017	2018	2019
Reclass to <50	7	72	0	0	1	0	10	11	2
Reclass to >50	11	4	6	4	2	1	15	1	0

b) The 2021 change in customer count occurred from an analysis conducted in the spring of 2021 and all customers were switched by year end which shows up in the 2021 customer count.

PUC has created a chart for the breakdown of customer who switched accounts and new or cancelled accounts. PUC is unable to obtain the amount of customers who ceased operations. PUC obtained the number of new accounts opened, but that new account might be just a new occupant at that business. This same logic applies to Cancelled accounts in the chart below.

	GS<50	GS>50
Switched GS>50 to GS<50	73	(73)
Switched GS<50 to GS>50	(10)	10
New Account or Occupant	418	11
Cancelled Account or Occupant	(413)	(10)
total	68	(62)

c) As mentioned in “b” above, the review occurred in the spring of 2021 which resulted in the ending customer count as shown in 2021.

d) Yes, PUC has completed a review for 2022 which has resulted in 12 customers switching from GS<50 to GS>50 and 10 customers switching from GS>50 to GS<50. The net result is an addition of 2 customers to the GS>50 customer count.

e) Please refer to OEB Staff-53(b).

f) PUC is unable to make the determination if the consumption levels for those customers that were classified from GS>50 to GS<50 in the fall of 2020 have started to see a return to pre-pandemic levels of consumption since it does not have a full years' worth of consumption data without some form of provincial lockdown restrictions. PUC’s

consumption is highest during winter months and the last lockdown occurred in January and February of 2022. However, PUC reviewed the list of customers who switched from GS>50 to GS<50 and think approximately 30 more will switch back to the large GS rate class which mainly consists of restaurants, school board accounts, churches, gyms, and certain retail establishments.

VECC – 19

Reference: Exhibit 3, pg. 9 - Load Forecast Model, COVID analysis Tab (line 31) and Rate Class Customer Model (line 35)

Question:

The. Application states:

> "*In order to predict the number of customers for the 2023 test year, PUC uses a 10-year geomean and applies this geomean to the last year of actual customer count. Since PUC, saw an abnormal drop in number of customers from GS>50 and traced those customers to the GS<50, it was determined that some kind of adjustment was needed*."

a) Please explain why the Average of the Growth Rates for the years 2012-2019 was used to normalize the GS<50 and GS>50 customer counts for 2020 and 2021 (per the COVID analysis Tab) but the Geomean of the Growth Rates for the years 2012-2021 was then used to forecast the customer counts for 2022 and 2023 (per the Rate Class Customer Model Tab). Why wasn't the Geomean used in both cases? Alternatively, why wasn't the Average used for both?

Response:

a) The 2012-2019 average growth rates are very similar to the Geomean of those years. PUC chose this method as it felt it reflect a more accurate customer count that would occur. However, PUC agrees using the Geomean is also a good result. PUC has revised table 3-6 below to provide the Geomean. Then PUC has provided a second table for a comparison of the results. There is a very minimal difference in using the 2012-2019 average growth rate versus the 2012-2019 geomean.

Table 3-6: Normalized Small and Large General Service Customer Count

	GS<50			GS>50		
	GS<50	Growth Rate	Variance Trend	GS>50	Growth Rate	Variance Trend
2011	3,366			403		
2012	3,448	1.0244	2.4%	366	0.9082	-9.2%
2013	3,474	1.0075	0.8%	373	1.0191	1.9%
2014	3,464	0.9971	-0.3%	370	0.9920	-0.8%
2015	3,431	0.9905	-1.0%	373	1.0081	0.8%
2016	3,414	0.9950	-0.5%	361	0.9678	-3.2%
2017	3,417	1.0009	0.1%	361	1.0000	0.0%
2018	3,414	0.9991	-0.1%	362	1.0028	0.3%
2019	3,388	0.9924	-0.8%	362	1.0000	0.0%
2020	3,355	0.9903		370	1.0221	
2021	3,423	1.0203		308	0.8324	
2012 - 2019 Average			0.0866%			-1.2753%
2012 - 2019 Geomean		1.0008			0.9867	

Comparison of 2012 – 2019 Average Growth Rate Vs. Geomean

	GS<50			GS>50		
	Geomean Result	2012 - 2019 Avg Growth Rate Result	Variance	Geomean Result	2012 - 2019 Avg Growth Rate Result	Variance
2020	3,391	3391	0	357	357	(0)
2021	3,394	3394	0	352	353	1
2022	3,396	3397	1	348	348	0
2023	3,399	3400	1	343	344	1

VECC – 20

Reference: Exhibit 3, pg. 7-11

Question:

The Application states (pg. 7, 8 and 11):

"*PUC completed the regression analysis using actual data as of year-end 2021. Using the variables explained above produced predicted purchases of 558,517,707 kWh for the 2023 test year*."

The Application states (pg. 8):

"*Overall PUC has seen a general decline in the consumption for all rate classes over the past 10 years. However, in 2020 and 2021 PUC sees a dip in the GS<50 and GS>50 consumption which is believed to be related to the COVID-19 pandemic*."

The Application states (pg. 11):

"*PUC had to consider this adjustment in its overall purchased power for the each year before running the regression analysis again. The result is an adjustment to metered consumption in 2020 of 17,547,504 kWh and an adjustment in 2021 of 18,218,336 kWh. Once this adjustment is added to the actual yearly consumption to get a "COVID normalized" yearly consumption, its then grossed up for the loss factor. This results in normalized yearly purchases which will be used in the power purchased model regression analysis presented in section 2.1.3.1*."

a) Please provide a copy of the regression model developed using the actual data as of year-end 2021.
b) As opposed to adjusting the purchased power values for 2020 and 2021 did PUC consider including in the regression model one or more independent variables to capture the impact of the COVID-19 pandemic?
    i. If not, why not"
    ii. If yes, what were the results and why were they rejected?

Response:

a) PUC has provided the regression model using actual data entitled: "PUC_2023_Load Forecast – With Regression Analysis_20221128_VECC 20a." Please note the geomean used in the Rate Class Customer Model tab is applied to the 2021 actual customer count in this version.

b) PUC did not consider using a regression model with one or more independent variables to capture the impact of COVID-19 pandemic. The use of COVID normalization was the solution that provided a result that reflects what PUC is continuing to see in terms of consumption. PUC is open to suggestions on trying other scenario to capture the impacts of COVID-19.

VECC – 21

Reference**:** Exhibit 3, pg. 9 - Load Forecast Model, COVID analysis Tab (line 14) and Rate Class Energy Model Tab (line 54)

Question:

a) Please explain why the Average of the Growth Rates for the years 2012-2019 was used to normalize the GS<50 and GS>50 consumption for 2020 and 2021 (per the COVID analysis Tab) but the Geomean of the Growth Rates for the years 2012-2021 was then used to forecast each class' consumption for 2022 and 2023 (per the Rate Class Energy Model Tab). Why wasn't the Geomean used in both cases? Alternatively, why wasn't the Average used for both?

Response:

a) PUC has provided the same tables for VECC-19 for VECC-21 but reflecting the consumption comparison for the 2012-2019 Average Growth Rate vs. 2012-2019 Geomean. PUC agrees that using the Geomean also reflects a good result for normalizing the 2020 and 2021 Consumption. PUC didn't use the Geomean across all scenarios as the 2012-2019 Average Growth rate was very similar to the Geomean.

Table 3-5: Normalized Small and General Service Consumption

	GS<50			GS>50		
	GS<50	Growth Rate	Variance Trend	GS>50	Growth Rate	Variance Trend
2011	101,728,299			255,968,368		
2012	97,479,014	0.9582	-4.2%	254,314,087	0.9935	-0.6%
2013	95,827,695	0.9831	-1.7%	259,048,750	1.0186	1.9%
2014	99,153,426	1.0347	3.5%	258,807,830	0.9991	-0.1%
2015	95,701,162	0.9652	-3.5%	254,784,565	0.9845	-1.6%
2016	92,174,996	0.9632	-3.7%	249,955,178	0.9810	-1.9%
2017	91,035,995	0.9876	-1.2%	245,166,376	0.9808	-1.9%
2018	92,759,999	1.0189	1.9%	241,817,729	0.9863	-1.4%
2019	91,718,380	0.9888	-1.1%	240,708,316	0.9954	-0.5%
2020	90,568,262	0.9875		238,882,521	0.9924	
2021	89,432,556	0.9875		237,070,574	0.9924	
2012 - 2019 Average			-1.2540%			-0.7585%
2012 - 2019 Geomean		0.9871			0.9923	

2012-2019 Average Growth Rate vs. 2012-2019 Geomean

	GS<50			GS>50		
	Geomean Result	**2012 - 2019 Avg Growth Rate Result**	**Variance**	**Geomean Result**	**2012 - 2019 Avg Growth Rate Result**	**Variance**
2020	90,538,481	90,568,262	29,782	238,865,921	238,882,521	16,600
2021	89,373,759	89,432,556	58,797	237,037,628	237,037,628	-
2022	88,224,021	88,311,101	87,080	235,223,329	235,239,676	16,346
2023	87,089,074	87,203,709	114,635	233,422,917	233,455,361	32,444

VECC – 22

Reference: Exhibit 3, pg. 21-22 - Load Forecast Model, Power Purchased Model Tab

Question:

a) It is noted that the regression analysis produces a negative coefficient for the customer count variable which is intuitively incorrect. Also, the t-statistic for this variable suggests it is not statistically significant. Based on these results, why did PUC include "customer count" as one of the variables in its regression model?
b) It is noted that the historical customer count values change every 3 months for the period 2012-2017. However, for the subsequent years the values are the same for all the months in a given year. Please explain why this is this case.
c) Please provide an alternative regression model and load forecast for 2023 which excludes "customer count" as one of the explanatory variables.

Response:

a) Including the customer count is an oversight by PUC. PUC agrees that customer count is statistically insignificant, and it has been removed from the regression model in revised regression model entitled "PUC_2023_Load Forecast – With Regression Analysis_20221128_staff54d".

b) PUC no longer counted customer count on a monthly basis and started counting on a yearly basis only in line with the requirements for RRR filing section 2.1.2 Customer Count.

c) Please see the regression analysis mentioned in response to question "a".

VECC – 23

Reference 1: Exhibit 3, pg. 21-22 and 28-32
Reference 2: Exhibit 4, pages 57-58
Load Forecast Model, Power Purchased Model Tab
2023 LRAMVA Workform, Tab 4, 5 and 7

Question:

a) Please provide the any Persistence Reports prepared by the IESO setting out the persisting savings (through to 2023) for CDM programs offered by PUC in 2012 through 2019.
b) It is noted that the Trend variable in PUC's regression model has a negative coefficient. Would PUC agree that one of the reasons for this is the impact of CDM programs offered by PUC during the 2012-2021 period?
    i. If not, why not?
c) It is noted that the value for Trend variable continues to increase monthly for the forecast years 2022 and 2023. Given that PUC also makes an adjustment for the impact of CDM from program offered by the IESO (and others) over after 2021 (plus ½ of the 2021 impact), please explain why this does not result in a double counting of the impact of CDM.
d) Please provide an alternative forecast for 2023 where the trend variable is held constant over the 2022 and 2023 period at its December 2021 value.

Response:

a) IESO's reports on persistence of 2011-2013 and 2014 results have been uploaded. The 2015-2017 persistence results are in the 2017 final CDM results report already filed, and persistence to 2020 of savings in the April 2019 P&C reports, already filed, are shown in that report.

b) PUC would agree that CDM may form part of the reason on the impact of the trend variable. However, PUC believes there are also other unquantifiable impacts such as:
    i. Community trend of shifting from electric to gas heat;
    ii. Improvements to home insulation;
    iii. Voltage conversion, conductor replacements; and
    iv. Declining economic activity in bricks and mortar businesses. PUC had Walmart in the Station Mall close in 2019. Additional retailers and food court businesses have closed without replacement of new companies.

c) The trend variable captures the impact of declining consumption from a variety of factors, such as those mentioned above and continues that declining trend into 2022 and 2023. The CDM adjustment captures the impacts of programs after 2021. By continuing the trend variable into 2022 and 2023, PUC agrees that there is some overlap between the CDM adjustment and trend variable, but the amount cannot be quantified.

d) PUC has provided the regression analysis in the excel model entitled: "PUC_2023_Load Forecast – with Regression Analysis_20221128_VECC23d". PUC also excluded the number of customers since it has agreed with OEB Staff and VECC's observations that it is statistically insignificant.

VECC – 24

Reference: Exhibit 3, pg. 28-32

Question:

The Application include the following Table:

Table 3-28: Annual adjustment required to forecast for CDM in 2023-2027 (kWh)

Program	PUC manual adjustment for CDM (kWh)			
	Residential	GS<50	GS>50	Total
Program	1,080,723	3,730,287	5,508,418	10,319,429
Less 1/2 of estimated 2021 savings	(90,266)	(311,566)	(460,081)	(861,912)
Climate Action Incentive Fund	-	1,798,141	2,661,234	4,459,375
Green Municipal Fund	-	91,929	136,055	227,984
Greener Homes Grant	1,434,227	-	-	1,434,227
Post 2024 IESO Programs	206,360	712,285	1,051,813	1,970,459
Sub-total	**2,631,046**	**6,021,077**	**8,897,439**	**17,549,562**
Proposed loss factor	4.62%			
Total CDM results forecast	**2,752,600**	**6,299,251**	**9,308,501**	**18,360,352**
Adjustment to match load forecast	-40%	-3%	-25%	
CDM adjustment to load forecast	**1,643,785**	**6,084,747**	**7,026,072**	**14,754,604**

a) Are the savings set out in the "Program" line those resulting from the 2021-2024 Framework described on pages 30-31?
   i. If not, what do they represent?
b) Please provide the supporting calculations deriving the values in the "Program" line and indicate the sources of all data used. Please also provide copies or links to the source documents for all data used.
c) Please provide the supporting calculations for the "Less ½ of estimated 2021 savings" line. If not provided in response to part (b), please also provide the derivation of the full 2021 savings by customer class, including copies or links to the sources of all data used.
d) With respect to the "Climate Action Incentive Fund" line, please provide the calculations supporting the PUC total of 4,459,375 kWh and the allocation to customer classes. Please indicate the sources of all data used and provide copies or links to the source documents.
e) With respect to the "Greener Homes Grant" line, please provide the calculations supporting the PUC total of 1,434,227 kWh. Please indicate the sources of all data used and provide copies or links to the source documents.
f) With respect to the "Green Municipal Fund" line, please provide the calculations supporting the PUC total of 227,984 kWh and the allocation to customer classes. Please

indicate the sources of all data used and provide copies or links to the source documents.

g) With respect to the "Post 2024 IESO Programs" line, please provide the calculations supporting the PUC total of 1,970,459 kWh and the allocation to customer classes. Please indicate the sources of all data used and provide copies or links to the source documents.

h) Please explain why the resulting values are increased by a loss factor and the basis for the 4.62% used.
    i. If the IESO forecast is at the generation level, wouldn't the values need to be decreased and wouldn't the loss factor need to also include transmission losses?

i) Please explain the basis and provide the numerical derivation of the "Adjustment to match load forecast" line. Please indicate the sources of all data used and provide copies or links to the source documents.

Response:

a) The savings in the row "Program" are the savings associated with 2021-2024 IESO CDM programs.

b) Overall projected savings from the 2021-2024 IESO CDM programs are estimated in IESO's Annual Planning Outlook detailed table on Figure 17 of the document here: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Dec2021/Demand-Forecast-Module-Data.ashx . These savings were allocated to customer classes based on a breakdown of IESO's CDM plan from here: https://www.ieso.ca/-/media/Files/SaveOnEnergy/2021-2024-CDM-Framework-Program-Plan.ashx The savings were reproduced in Table 3-26 of PUC's application.

Table 3-27 of PUC's application shows the cumulative savings of the values in Table 3-26, taking only half of the 2021 values since part of the 2021 persisting savings will already be captured in the actual PUC load data used in the load forecast. The savings were allocated to rate classes as shown on Table 3-27. The Small Business Program is targeted at GS<50 customers and the Energy Affordability Program is targeted at low-income residential customers. Other programs are allocated across the general service customers in the same proportion as seen in PUC's retrofit program in 2015-2019, and this allocation was used for other programs. That results in the overall allocation across rate classes of 7.3%, 22.7% and 50.7% for the Residential, GS<50 and GS>50 rate classes respectively, as shown

on Table 3-27 of the application. Going from the province to PUC was done according to the values in the following table:

	Residential (low-income persons)	Residential (metered GWh)	GS<50 (metered GWh)	GS>50 (metered GWh)
PUC Distribution Inc.	11,585	298	85	227
Province	1,898,975	43,245	12,532	60,783
PUC share	0.61%	0.69%	0.68%	0.37%

Sources: Low-income population from 216 census LIM-AT
Metered GWh from OEB 2020 Yearbook of Electricity Distributors

From these values, all the values in the "Program" line are calculated. For example, for the residential rate class, 2.43 TWh (from Table 3-25) * 7.3% residential * 0.61% PUC's share of low-income persons equals 1,080,723 kWh (input numbers rounded).

c) These are calculated as described above. As an example, for the residential sector: 543 GWh (from Table 3-26) /2 * 7.3% *0.61% = 120,748. Then the difference is corrected between the cumulative value for 2023 in the CDM plan (1912.9 GWh) and in the planning outlook (1,430 GWh) yielding 90,266 kWh.

d) Savings from the climate fund are estimated on Figure 17, as mentioned above. The Climate Action Incentive Fund is targeted at business customers with up to 599 employees (https://www.canada.ca/en/environment-climate-change/services/climate-change/carbon-pollution-pricing-proceeds-programming/climate-action-incentive-fund/small-medium-enterprises-project-stream.html) and the MUSH sector. For this analysis, the allocation across general service rate classes has been in proportion to the energy sold according to the OEB's Electricity Distribution Yearbook. So, the calculations are:

- For GS<50 0.98 TWh * 85 GWh/ (85 GWh + 227 GWh) * 0.68% = 1,798,141 kWh and
- For GS>50 0.98 TWh * 227 GWh/ (85 GWh + 227 GWh) * 0.37% = 2,661,234 kWh and
- Total for PUC = 1,798,141 + 2,261,234 = 4,459,375 kWh
- Where 0.98 TWh is from Table 3-25
    - 85 GWh, 227 GWh, 0.37% and 0.68% are from the allocation table above.

(Input numbers are rounded in this description.)

e) The annual savings in Table 3-25 of the application are from Figure 17 of the Planning Outlook spreadsheet. The annual average savings from the Greener Homes Grant is 0.21 TWh. From the table above 0.69% of electricity use in the residential sector in Ontario is in the PUC. That equals 1,434,227 kWh.

f) This is calculated in the same way as the Climate Action Incentive Fund using the same sources.

g) Projected future savings from the post 2024 IESO programs are set out on Figure 18 of the Planning Outlook spreadsheet referenced above and are reproduced in Table 3-25 of the application. The 0.46 TWh annual savings in Table 3-25 are allocated to PUC and rate classes as described above for the 2021-2024 programs.

h) The loss factor actually used is 1.0462%, not 4.62%. These savings are at the customer level and need to be adjusted for distribution losses.
    i. IESO typically measures conservation savings at the customer level, and PUC would expect the federal government to do the same.

i) Please refer to OEB Staff-58.

VECC – 25

Reference**:** Exhibit 3, pg.28

Question:

The Application states:

> "*On December 20, 2021, the OEB issued a report Conservation and Demand Management Guidelines for Electricity Distributors which provided updated guidance on the role of CDM for regulated LDCs. PUC has reviewed these guidelines which resulted in a manual adjustment to the load forecast for CDM. This CDM adjustment has been made to reflect the impact of CDM activities that are expected to be implemented from 2023 to 2027 within PUC's service territory based on its share of electricity use within the province, the IESO's 2021-2024 Conservation Demand Management Framework, and the IESO Planning Outlook*".

a) Please explain why it is necessary to adjust the load forecast for 2023 for savings from CDM initiatives that will be implemented in the years 2024-2027.
b) If adjustments for CDM savings from programs/projects implement in 2024-2027 are included in the 2023 load forecast, would it not also be appropriate to adjust the 2023 load forecast to account for other factors that will impact load in the 2024-2027 period?

Response:

a) The load forecast will be in effect until the next COS rate application, which is expected to be for rate year 2028. Between now and then, as the data shows, CDM efforts will be ramping up. As there is no mechanism to offset or to adjust for losses that would result from these increases in conservation efforts in 2024-2027, it would be unreasonable to consider only the CDM level in 2023.

b) PUC would agree that it would be appropriate to adjust for other factors that will impact load in the 2024-2027 period. However, PUC is not aware of any other factors that will impact load in the 2024-2027 period, therefore no adjustment is required.

VECC – 26

Reference: Exhibit 3, pg. 32-34

Question:

a) Given the acknowledged impact of the COVIC-19 pandemic on GS>50 consumption in 2020 and 2021 plus the fact the class' kW/kWh ratios for those years are lower than in previous years, why is it reasonable to include 2020 and 2021 in the determination of the average kW/kWh ratio for this class?

Response:

a) Excluding 2020 and 2021 kW/kWh ratio is another option that can be explored; however, PUC did not think that the drop from .2470 to .2408 and .2443 for 2020 and 2021 respectively, is not a significant enough a drop. To keep things consistent with the approach to the load forecast and a COVID-19 adjustment, PUC is willing to make this adjustment to its final load forecast.

Exhibit 4 – Operating Costs

VECC – 27

Reference: Exhibit 4, pg. 9

Question:

"Given the uncertainty surrounding the impact of rising inflation rates, PUC notes this will require further assessment during the proceeding as the situation evolves."

a) Please explain what, if any amendment PUC is proposing to its application and clarify when it intends to make that amendment.

Response:

a) Please refer to OEB Staff-61.

VECC – 28

Reference: Exhibit 4, pg. 12

Question:

"Green Button incremental initiative costs for 2022 have been recorded in the generic Account 1508 Deferral Account, however, PUC has included costs in OM&A for the 2023 Test year. The result is 2023 OM&A costs that are slightly above the IRM formula."

a) What amount (if any) of Green Button costs are included in Appendix 2-JA and 2-JC?

Response:

a) Please refer to OEB Staff-64.

VECC – 29

Reference: Exhibit 4, pg. 14

Question:

"PUC did track and allocate the costs related to COVID additional activities in the approved COVID-10 Deferral and Variance account in 2020 and subsequently reversed these costs in 2021 based the guidance issued by the OEB in June 2021. In this respect, PUC acknowledges that the COVID-19 pandemic had to be taken into consideration while reviewing historical actual results presented in this Exhibit for the 2020 and 2021 fiscal years as they are not typical years."

a) Please identify the amount of COVID-19 related costs included in each year in Appendix 2-JC

Response:

a) COVID related costs were deferred and recorded in Acct 1509 in 2020. After the review in 2021, the amount was reversed and is included in Administration as the reversed expenses were Admin salary costs.

VECC – 30

Reference: Exhibit 4, pg. 21

Question:

Please provide the tree trimming-right of way expenses for each year 2018 through 2023 (forecast).

Response:

The table below provides the tree trimming expenses:

Year	2018 APPROVED	2018	2019	2020	2021	2022 BUDGET	2023 TEST
5135 - Right of Way	$ 693,011	$ 621,970	$ 617,322	$ 651,631	$ 824,518	$ 772,070	$ 851,608

VECC – 31

Reference: Exhibit 4, pg. 23, 28

Question:

Table 4-9: 2023 COS Application Cost Estimates

Cost of Service Application Costs	Total COS	Amortized over 5 Years
Incremental operating expenses associated with staff resources allocated to this application.	$ 126,366	$ 25,273
Consultants' costs (legal, DSP, Shared Services, LRAM)	$ 430,634	$ 86,127
Intervenor costs (4)	$ 100,000	$ 20,000
OEB application costs	$ 20,000	$ 4,000
Settlement conference costs (virtual)	$ 3,000	$ 600
	$ 680,000	**$ 136,000**

a) Please show the amounts expended to date in each one of these cost categories.
b) Please explain the nature of incremental staff costs (line 1) and specifically explain why including these as amortized costs does not constitute "double counting" of past internal staff costs.
c) What was the amount of regulatory cost amortized as part of the prior cost of service application and over what years what it amortized?

Response:

a) Refer to OEB Staff-80.

VECC – 32

Reference: Exhibit 4, pg. 27

Question:

Maintenance Overhead Lines

2023 Test Year vs 2018 Approved – $376,200
PUC experienced a shift in the amount of expenses in maintenance overhead line from 2018 Board Approved to 2023 Test Year. The increase is a result of additional labour, materials, trucking, and external contractor costs allocated to these OM&A accounts, in 2023, as compared to the 2018 Board Approved amounts.

Using Appendix 2-JC as a reference, please identity where the "shift" of costs to Maintenance Overhead was from and what associated reduction resulted from that "shift" in this category of spending.

Response:

The inflationary impact of overhead lines maintenance from the 2019 Board Approved to 2023 Test Year is $161.7k. The remaining increase is the result of a shift of costs from underground maintenance, transformers maintenance and overhead lines operations.

VECC – 33

Reference: Exhibit 4, pg. 12

Question:

Table 4-13: Management Salary Increases

Year	Wage Increase
2018	1.8%
2019	1.8%
2020	1.9%
2021	1.5%
2022	5.0%

a) Why does the management salary increase in 2022 (5%) significantly exceed that of the bargaining units (2.0%)?
b) What is the estimated management increase for 2023?
c) Have any positions in management exceeded a 5% increase in any of the years 2022 through 2023? If yes how many positions exceeded increases of 5%?

Response:

a) The management salary increase for 2022 is based PUC's management compensation policy for economic increases which utilizes the November Ontario Consumer Price Index (CPI). Five percent (5.0%) was the November 2021 Ontario CPI. PUC management increases are policy driven and intentionally not tied to bargaining unit increases as it creates an obvious conflict.

   The bargaining unit increase was based on collective bargaining between PUC management and the Power Workers Union CUPE Local 1000 effective May 1, 2021 – April 30, 2024.

b) Please refer to OEB Staff-71(b).

c) No management team member received more than a 5.0% economic increase in 2022.

VECC – 34

Reference: Exhibit 4, Table 4-11, and Table 4-16

Question:

a) Total capitalized OM&A is relatively stable as between 2022 and 2023 (as shown in Table 4-11) yet total compensation capitalized is much higher in 2022 than in 2023 ($3.1M and $2.4M respectively as shown in Table 4-16). What accounts for this apparent discrepancy?

Response:

Table 4-11 Capitalized OM&A provides the overhead labour, trucking, and materials (excluding direct capitalized labour). Whereas Table 4-16 is all labour, direct, and overhead. The discrepancy is the direct labour amounts. Total compensation in Table 4-16 is higher in 2022 than in 2023 due to the SSG project.

VECC – 35

Reference: Exhibit 4, pg. 39

Question:

a) Please provide a table a listing/description of the management and non-management positions and the number of FTEs in that position, for the year 2018 (year-end) and 2023 (proposed year-end).
b) Please identify any positions for which 90% or more of the person's time/compensation is allocated to PUC.

Response:

a) Below is a table of PUC Services allocated labour to PUC by FTE split between management and non-management by department.

b) PUC Services allocates certain dedicated resources to PUC. Positions for which 90% or more would include Line Operators, Stations & Metering, Engineering, Rates and Regulatory Affairs Officer, and Special Projects staff such as those for SSG. All other resources are allocated based on services provided to PUC.

	Last Rebasing Year (2018 Actuals)	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Number of Employees (FTEs including Part-Time)						
Management (including executive)	19	18	18	21	21	23
Non-Management (union and non-union)	63	62	60	57	57	58
Total	**82**	**80**	**78**	**78**	**78**	**81**
Management (including executive)						
MGT by Department	**19.24**	**17.98**	**17.84**	**21.00**	**21.00**	**23.00**
Executive	3.50	1.92	2.01	2.71	2.71	2.97
Communications	0.92	0.86	1.21	1.09	1.09	1.20
Conservation & Demand	0.79	(0.02)	-	0.28	0.28	0.31
Customer Experience	2.31	1.64	1.14	1.86	1.86	2.04
Engineering	1.95	2.29	2.18	2.35	2.35	2.57
Environmental Operations	-	-	0.14	0.05	0.05	0.06
Facilities	0.50	0.48	0.48	0.53	0.53	0.58
Financial Services	2.38	2.20	2.00	2.40	2.40	2.63
Human Resources	0.07	1.34	1.24	0.97	0.97	1.06
Information Security		0.20	0.42	0.34	0.34	0.37
Information Technology	0.84	0.75	0.69	0.83	0.83	0.91
Line Operations	2.88	3.17	2.63	3.17	3.17	3.47
Purchasing & Stores	0.52	0.64	0.64	0.66	0.66	0.72
Safety & Environment	0.43	0.46	1.21	0.77	0.77	0.84
Stations and Metering	1.70	1.68	1.58	1.81	1.81	1.99
Special Projects	3.79	3.43	3.38	3.87	3.87	4.24
Non-Management by Department	**62.60**	**61.87**	**60.49**	**57.00**	**57.00**	**58.00**
Conservation & Demand		-	0.26	0.12	0.12	0.12
Customer Experience	8.22	8.97	7.75	7.62	7.62	7.76
Engineering	7.36	7.67	7.70	6.94	6.94	7.07
Environmental Operations	0.21	-	0.11	0.10	0.10	0.10
Facilities	1.33	1.11	1.80	1.30	1.30	1.32
Financial Services	3.98	2.85	2.50	2.85	2.85	2.90
Fleet	1.55	1.54	1.50	1.40	1.40	1.43
Human Resources	0.46			0.42	0.42	0.43
Line Operations	21.04	21.54	20.86	19.38	19.38	19.72
Locates	3.29	3.53	2.50	2.85	2.85	2.90
Purchasing & Stores	2.64	2.00	1.96	2.02	2.02	2.05
Safety & Environment	0.98	0.70		0.77	0.77	0.78
Stations and Metering	8.11	9.52	9.58	8.31	8.31	8.46
Special Projects	3.34	3.07	3.11	2.91	2.91	2.96
Summer Student	0.09		0.14	0.10	0.10	0.11

Exhibit 5 – Cost of Capital

VECC – 36

Reference: Exhibit 5, Tab 1, Schedule 2 / Appendix 2-OB

Question:

a) Please update Appendix 2-OA and 2-OB for the OEB's October 20, 2022, new cost of capital parameters.
b) Please provide the incremental revenue requirement for this adjustment.

Response:

a) Appendix 2-OA and 2-OB have been updated for the OEB's October 20, 2022, COC parameters in the excel file entitled "PUC_2023_Filing_Requirements_Chapter2_Appendices_20221128"

b) The incremental revenue requirement for this adjustment alone is $1,043,195.

VECC – 37

Reference: Exhibit 5, pg. 6

Question:

"*Loan number 6 is an estimated drawdown of $20,200,000 on the $30,000,000 credit facility. Loan payable number 6 is to be finalized with OILC. It is anticipated to be a 20-year debenture with a estimated fixed interest rate of 5.00% used for rate making purposes. Security is in the form of a fourth ranking general security agreement and a guarantee and assignment of shares from the company's shareholder, PUC Inc*."

a) Other than its affiliated debt all of the third-party debt of PUC has been issued by Infrastructure Ontario. What efforts has PUC made in order to ascertain that the SSG financing – currently estimated at 5% is the least cost alternative?
b) For the SSG financing note showing a start date of January 1, 2023 please clarify when the interest rate agreement is expected to be finalized.

Response:

a) PUC has historically always sought out the least cost alternative when pursuing outside debt financing to support its capital requirements. In addition to discussions with its current financing partners, Infrastructure Ontario ("IO") and RBC Royal Bank, PUC has received financing proposals from major banks including Scotiabank, TD Canada Trust, and CIBC. In early 2019, PUC went to the financial markets in search of a solution for the anticipated financing requirements of its future capital infrastructure reinvestments, including SSG. After reviewing multiple proposals, it was determined that IO was the least cost alternative and PUC executed a financing agreement to open a revolving credit facility for $30 million. Additionally, PUC frequently tests the market by seeking indicative rates from the various lenders noted above to ensure the leveraging with IO remains competitive.

b) The financing for SSG is expected to be finalized (i.e. locked into a term loan) in Q2/Q3 of 2023, however, construction financing for SSG has commenced in 2022 with drawdowns in support of the work in progress. These drawdowns are subject to a floating construction interest rate prior to the conversion to a term loan.

VECC – 38

Reference: Exhibit 5, pg. 8

Question:

PUC is over leveraged financing $86,346,526 in long-term debt (Appendix 20OB) while its capital structure for ratemaking purposes provides for maximum amount of Long-term debt of $76,209,945 or a difference of $10,136,300.

a) Please update Appendix 2-OB to show the weighted cost of long-term debt based on removal of $10,136,300 from the last issued debt (i.e., Line 6 - $20 million).
b) Please recalculated appendix 2-OA to show the result of using the revised long-term debt cost rate.

Response:

a) PUC has updated appendix 2-OB for the removal of $10,136,300 from the last issued date. Below is the comparison of the as submitted versus the update. This results in a change of $506,815 in interest.

Year 2023

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	23-Jun-05	No Term	$ 26,534,040	3.49%	$ 926,038.00
2	Loan - Smart Meter Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jul-13	15	$ 2,344,765	3.82%	$ 89,570.03
3	Loan - PUC Admin Building	Infrastructure Ontario	Third-Party	Fixed Rate	1-Oct-13	25	$ 16,012,864	4.57%	$ 731,787.88
4	Loan	Infrastructure Ontario	Third-Party	Fixed Rate	16-Jun-16	25	$ 12,210,836	3.47%	$ 423,716.02
5	Loan $5.8MM drawdown	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jan-21	15	$ 5,156,998	2.11%	$ 108,812.66
6	Loan $4.0MM drawdown	Infrastructure Ontario	Third-Party	Fixed Rate	1-Mar-22	15	$ 3,885,023	3.65%	$ 141,803.33
7	Loan - SSG financing	Infrastructure Ontario	Third-Party	Fixed Rate	1-Jan-23	20	$ 20,200,000	5.00%	$1,010,000.00
Total							$ 86,344,526	3.97%	$3,431,727.92

Year 2023

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	23-Jun-05	No Term	$ 26,534,040	3.49%	$ 926,038.00
2	Loan - Smart Meter Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jul-13	15	$ 2,344,765	3.82%	$ 89,570.03
3	Loan - PUC Admin Building	Infrastructure Ontario	Third-Party	Fixed Rate	1-Oct-13	25	$ 16,012,864	4.57%	$ 731,787.88
4	Loan	Infrastructure Ontario	Third-Party	Fixed Rate	16-Jun-16	25	$ 12,210,836	3.47%	$ 423,716.02
5	Loan $5.8MM drawdown	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jan-21	15	$ 5,156,998	2.11%	$ 108,812.66
6	Loan $4.0MM drawdown	Infrastructure Ontario	Third-Party	Fixed Rate	1-Mar-22	15	$ 3,885,023	3.65%	$ 141,803.33
7	Loan - SSG financing	Infrastructure Ontario	Third-Party	Fixed Rate	1-Jan-23	20	$ 10,063,700	5.00%	$ 503,185.00
Total							$ 76,208,226	3.84%	$2,924,912.92

b) PUC has recalculated Appendix 2-OA and has provided the results in the table below:

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last OEB-approved year and the test year.

Test Year: 2023

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$76,209,945	3.84%	$2,924,979
2	Short-term Debt	4.00% (1)	$5,443,567	1.17%	$63,690
3	**Total Debt**	60.0%	$81,653,512	3.66%	$2,988,669
	Equity				
4	Common Equity	40.00%	$54,435,675	8.66%	$4,714,129
5	Preferred Shares		$ -		$ -
6	**Total Equity**	40.0%	$54,435,675	8.66%	$4,714,129
7	**Total**	100.0%	$136,089,187	5.66%	$7,702,798

1
2

Exhibit 6 – Revenue Deficiency

VECC – 39

Reference 1**:** Exhibit 6, pg. 26 & 28
Reference 2: Chapter 2 Appendices, Appendix 2-H

Question:

a) Please provide the basis for the forecast revenues for Account 4210 from Building Charges for 2022 and 2023 and explain why the revenues are less than in previous years and declining over the period 2021-2023.
b) Please provide the calculation for the 2022 and 2023 forecast revenues for Account 4210 from Pole Rentals.
c) Please explain the sources for the revenues forecast for Account 4235 (Miscellaneous Service Revenues).
d) Please explain why there are Revenues from Merchandising (#4325) but no Costs and Expenses of Merchandising (#4330).

Response:

a) The basis of the calculation of the building return charge for 2018-2022 is using PUC's last approved Cost of Capital (COC) parameters from its 2018 COS Rate Application. The COC parameters are applied to the average net book value of the building. Since the average NBV of the building is declining each year due to minimal additions from 2018 to 2022, the resulting revenue for building charge has been declining. For 2023, PUC used the OEB's Cost of Capital parameters as of October 28, 2021, for its submission on August 31, 2022. This has since been updated for the OEB's revised Cost of Capital Parameters released on October 20, 2022. This has increased the building return charge. PUC has also changed the 2023 building additions from $577,035 to $282,246. There has been $294,789 reclassified to account 1940 Tools, Shop and Garage Equipment for the value of the Omicron Injection Tester.

b) PUC has provided the 2022 and 2023 forecast for pole rentals in the table below. The table below also includes the revised forecast included with the filing of these interrogatories.

	2022			2023	2023	
Pole Rentals	# Joint Poles	2022 Rate Used	2022 Trial Balance amount	2023 Forecast	2023 Revised Rate	2023 Forecast
Total Joint Use Poles	19,371	$34.76	$673,335.96	$686,802.68	$36.05	$698,324.55

c) The sources of revenue forecasted for account 4235 is occupancy charge, returned cheques, collection charge, microFIT and other miscellaneous charges.

d) The revenues from merchandising (4325) account are the markup billed on contributed capital billings. Contributed capital amounts invoiced are recognized up to the total project costs (amount put into service) but the excess is in account 4325, therefore, there are no costs in 4330.

VECC – 40

Reference**:** Exhibit 6, pg. 31

Question:

The Application states:

"*Account 4245 – Government and other assistance directly credited to income has seen a steady increase until 2022. In 2022, the NRCan funding received is added to rate base significantly increasing the amount recorded in this account in 2022 and 2023*".

a) What was the basis for NRCan funding received?

Response:

a) The NRCan funding is the government grant received for the SSG project.

Exhibit 7 – Cost Allocation

VECC – 41

Reference: Exhibit 7, pg. 4-5

Question:

The Application states:

> "*PUC has reviewed its weighting factors from its 2018 COS Application and discussed with staff to determine that there have been no changes. Labour, materials, and outside costs required to perform the specific tasks below were estimated to determine each rate class factor*." (Emphasis added)

a) Please provide the calculations supporting the Service weighting factors (per Table 7-1) for each customer class.
b) Please provide the calculations supporting the Billing and Collecting weighting factors (per Table 7-2) for each customer class.
c) Please provide the calculations supporting the Meter Reading weighting factors (per Table 7-4) for each customer class.

Response:

a) Please see below for the derivation of the proposed values for the Service Weighting Factors:

	Residential OH	Residential UG	Residential Tota	<50kW OH	<50kW UG	<50kW Total	>50kW OH	>50kW UG	>50kW Total	Streetlights	Sentinel Lights	Unmetered
Quantity of Connections	16,173	10,339	26,513	1,272	1,143	2,415	23	274	297	8,037	12	22
Approx. $/Connection	$ 895.00	$ 3,220.00	NA	$ 1,310.00	$ 456.00	NA	$ 1,310.00	$ 456.00	NA	$ 62.50	$ 62.50	$ 62.50
Value	$ 14,474,987	$ 33,293,005	$ 47,767,992	$ 1,665,778	$ 521,265	$ 2,187,043	$ 30,241	$ 125,002	$ 155,243	$ 502,313	$ 750	$ 1,375
Avg Asset Cost			$ 1,801.71			$ 905.72			$ 522.33	$ 62.50	$ 62.50	$ 62.50
CIS # Services			30,134			3,394			353	8,037	12	22
Total Value			$ 54,292,676			$ 3,074,001			$ 184,383	$ 502,313	$ 750	$ 1,375
% of total			93.52%			5.29%			0.32%	0.87%	0.00%	0.00%
Value of 1855			$ 8,116,787			$ 459,565			$ 27,565	$ 75,096	$ 112	$ 206
Cost per Service			$ 269.36			$ 135.41			$ 78.09	$ 9.34	$ 9.34	$ 9.34
Ratio			1.00			0.7			0.4	0.05	0.05	0.05

b) Please see below for the derivation of the proposed values for Billing and Collecting Weighting Factors:

Billing and Collecting Weighting Factors							
# of Customers	33,611	30,340	3,400	344	4	1	25
Collection Allocation % - Based on Bad Debt %		68%	14%	19%	0%	0%	0%
Accounts	**2018 Budget Total**	**Residential**	**GS<50**	**GS>50**	**Street Light**	**Sentinel**	**USL**
5315 - Billing - Based on # of customer	$357,552	$334,772	$37,516	$3,796	$43	$11	$266
5320 - Collections Cash Portion - Based on # of Customers	$74,603	$67,343	$7,547	$764	$9	$2	$55
5320 - Collections Arrears Portion - Based on % of Bad Debt	$85,944	$58,012.48	$11,860	$16,158	$0	$0	$0
Total Cost	**$518,099**	**$460,127**	**$56,923**	**$20,717**	**$51**	**$13**	**$321**
Scale (Total Cost/# Customers)		15.166	16.742	60.223	12.858	12.858	12.858
Weighting Factor		**1.0**	**1.1**	**4.0**	**0.8**	**0.8**	**0.8**

c) The table below provides the meter reading weighting factors. Please note there is an update to the GS>50 rate class. The 19.81 was an older meter reading weight factor that wasn't update during version updates of the model.

	Total Costs (2023 Test	**Residential 30,340**	**GS<50 3,400**	**GS>50 344**
Meter Reading Costs Distributed Evenly across all rate classes	$ 337,151	9.89	9.89	9.89
Meter Reading Costs Allocated Directly to	$ 20,400			59.30
Total Cost per meter		9.89	9.89	69.19
Weighting Factor		**1**	**1**	**7.00**
Assigned Meter Reading Costs		**$300,116.22**	**$ 33,632.01**	**$ 23,802.77**

VECC – 42

Reference: Exhibit 7, pg 8-13, Load Forecast Model, Rate Class Energy Model Tab (Row 66)

Question:

a) Please confirm that PUC's demand profile methodology assumes that, for each month of the year, all weather sensitive customer classes (i.e., Residential, GS<50 and GS>50) have the same percentage of load that is weather sensitive (e.g., for each of the three classes 39% of January load is assumed to be sensitive to the level of HDD).

b) If confirmed, please indicate if PUC has undertaken any analysis to support this assumption (i.e., that all classes have the same degree of weather sensitivity) and, if yes, please provide.

c) If confirmed, please explain why, in the Load Forecast Model, the GS>50 class was assumed to have a different weather sensitivity than the Residential and GS<50 classes.

Response:

a) PUC confirms the demand profile methodology assumptions are correct.

b) PUC does not have additional analysis to support this assumption but is willing to make a weather sensitive adjustment if deemed necessary by OEB Staff and Intervenors.

c) PUC has used the same weather sensitivity from its 2018 COS Rate application.

VECC – 43

Reference: Exhibit 7, pg. 7

Question:

a) Please provide a revised version of the Updated Cost Allocation Model (20221012), using the same load forecast but demand allocators based on the load profiles used in PUC's 2018 COS Application.

Response:

a) PUC has provided a revised version of the Cost Allocation Model using the 2018 demand allocators. The file is titled "PUC_Updated 2023 CoS_Cost Allocation Model_20221012_2018 demand allocators". A comparison of this version to the (20221012) version is shown in the table below:

Supporting File	Residential	GS<50	GS>50	Street Light	Sentinel	USL
PUC Updates 2023 COS Cost Allocation Model_20221012	$17,308,629	$ 3,520,893	$ 6,467,592	$ 349,718	$ 52,109	$ 53,258
PUC Updates 2023 COS Cost Allocation Model_20221012_**2018 Demand Allocators**	$17,417,138	$ 3,729,604	$ 6,155,314	$ 345,339	$ 52,521	$ 52,283
Change	$ (108,509)	$ (208,711)	$ 312,278	$ 4,379	$ (412)	$ 975

VECC – 44

Reference: Exhibit 7, pg. 16, RRWF, Cost Allocation Tab

Question:

The Application states (page 16)

> "*Three rate classes were chosen to change the revenue-to-cost percentages from the default presented in the 2023 Cost allocation model. First the General Service <50kW rate class was adjusted down to 110%. This amount was allocated to General Service >50kW and Street Light rate class in unity bringing them both up to 95.07%. PUC ran these changes through the bill impacts model and feels that the bill impacts presented in Exhibit 8 are still reasonable for all rate classes*."

a) Despite the above referenced statement, the proposed revenue to cost ratios set out in the Application (Table 7-17) and in the RRWF are the same as the status quo ratios from the Cost Allocation Model. Please reconcile and clarify PUC's proposal with respect to the 2023 revenue to cost ratios.

Response:

a) PUC is not proposing to change the revenue to cost ratio from the status quo ratios.

Exhibit 8 – Rate Design

VECC – 45

Reference 1: Cost Allocation Model (20220831)
Reference 2: Cost Allocation Model (20221012)

Question:

a) Were there any changes to the base revenues to be recovered from each customer class or the resulting proposed distribution rates by customer class as a result of PUC's Response to Staff Questions (20221012)?
b) If yes, please provide an updated RRWF with the revised Cost Allocation and Rate Design Tabs.

Response:

a) No, there were no changes to base revenues to be recovered from each customer class or the resulting proposed distribution rates by customer class. All that changed as a result of these error checking question updates was the revenue to expense ratios which still fell inside the policy ranges for each rate class.

b) N/A

VECC – 46

Reference: Exhibit 8, pg. 7, Updated Cost Allocation Model, Tab O2

Question:

a) Please confirm that, for the Sentinel Class, the monthly Service Charge is billed on a per customer basis.

b) Please confirm that, in the Cost Allocation Model, the Minimum System with PLCC Adjustment value for the Sentinel class is calculated on a per connection basis.

c) If parts (a) and (b) are confirmed, please restate the Minimum System with PLCC Adjustment value for the Sentinel class on a per customer basis.

Response:

a) The monthly service charge is not calculated on a per customer basis, it is on a per connection basis.

b) PUC confirms that the minimum system with PLCC adjustment value for the Sentinel class is calculated on a per connection basis.

c) N/A

VECC – 47

Reference: Exhibit 8, pg. 10-11, RTSR Workform, Tabs 3 and 5

Question:

a) With respect to Tab 3, what year is the RRR data regarding usage by customer based on?
b) With respect to Tab 5, what year is the Network billing units based on?

Response:

a) This is the 2021 RRR data.

b) This is also 2021 data for the Network billing units.

VECC – 48

Reference: Exhibit 8, pg. 11, 2023 Proposed Tariffs

Question:

a) Will the PUC update its 2023 Proposed Tariffs to reflect any future Board Decision regarding the Retail Service Charges for 2023?

Response:

a) Please refer to OEB Staff-101.

VECC – 49

Reference: Exhibit 8, pg. 13-14, 2023 Proposed Tariffs

Question:

a) Will the PUC update its 2023 Proposed Tariffs to reflect any future Board Decision regarding the Pole Rental Charges for 2023?

Response:

a) Please refer to OEB Staff-101.

VECC – 50

Reference: Exhibit 8, pg. 15

Question:

a) Do either the A(1) or A(2) values include the kWh pertaining to distributed generation directly connected to the distributor's own distribution network?

Response:

a) Yes, the values in A(1) and A(2) include the kWh pertaining to distributed embedded generation directly connected to PUC's own network.

VECC – 51

Reference 1: Exhibit 8, pg. 12-13
Reference 2: Exhibit 9, pg. 14

Question:

a) How is the "refund" provided to customers through Embedded Generation Rate Rider funded and accounted for? Are the amounts paid to customers recorded in Account 1580: RSVA – Wholesale Market Service Charge?

Response:

a) Account 1580 is used to record the difference between the amounts charged by IESO for wholesale market services and the amount billed to PUC customers using the Board Approved rates. The Embedded Generation Rate Rider is included in Account 1580 to offset against the variances.

With the 2018 COS, the parties agreed that PUC would create an Embedded Generation Adjustment (EGA) rate rider for account 1580 RSVA Wholesale Market Service Charge Account. This rate rider is designed to address the systematic over collection of the Wholesale Market Service Rate (WMS) and Rural or Remote Electricity Rate Protection charge (RRRP) from its customers relative to its obligations to the Independent Electricity System Operator (IESO). The over collection is driven, in part, by embedded generation for which PUC is not required to pay WMS or RRRP to the IESO. The parties agreed that a rate rider would be used to refund the amount of the WMS and RRRP charges times the forecasted energy from embedded generation. Any remaining under or over collection would continue to be booked to account 1580.

Customers receive a rate rider credit when billed, the offset amount is recorded in 1580 and offset against the variance in this account.

Exhibit 9 – Deferral and Variance Accounts

VECC – 52

Reference: Exhibit 9, pg. 20

Question:

The Application states:

"*PUC requests disposition of the balances in account 1518 – RCVA Retail and account 1548 – RCVA STR in this Application and to discontinue these accounts after April 1, 2023 on the assumption that PUC's 2023 rates are approved effective May 1, 2023. PUC has forecasted activity for 2022 through to April 30, 2023, based on historical averages for the past 2 years of activity*." (Emphasis added)

a) Please clarify, is PUC proposing to discontinue these accounts after April 1, 2023, or after April 30, 2023?

Response:

a) PUC is proposing to discontinue these accounts after April 30, 2023 (typo).

VECC – 53

Reference 1: Exhibit 9, Table 9-4
Reference 2: Exhibit 1, Table 1-12

Question:

The Board made the following findings in the Report Regulatory Treatment of Impacts Arising from the COVID-19 Emergency, EB-2020-0133
June 17, 2021:

Given the evidence to date, the OEB is expecting applications to be filed only on an exceptional basis for costs not related to mandated government or OEB-initiated programs; and utilities should generally have been able to manage pandemic-related impacts within existing budgets.

The OEB will not expand the scope of this Exceptional Pool beyond the impacts suggested in the Staff Proposal.

These were listed in the Report as:

- *Implementation costs of emergency time-of-use (TOU) rates42 and deferred global adjustment charges for electricity distributors*
- *Implementation and administration costs of CEAP and CEAP-SB*
- *Increased LEAP EFA funding*
- *Lost revenues from certain reduced/waived specific service charges46*

The following shows the amounts sought for recovery by PUC:

Table 9-12: Account 1509 COVID-19 Incremental Expense Detail

Acct 1509	Balance
Incremental billing expenses	$ 577
Incremental labour	$ 250,166
Waived Interest	$ 119,153
Additional LEAP funding	$ 13,133
Principal	**$ 383,029**
Carrying Costs	$ 18,738
Balance	**$ 401,767**

a) Please assign each category shown for Account 1509 to the allowed exceptional categories provided in the Board's Report.
b) With respect to incremental labour please provide each job classification and the amount allocated from that position.

Response:

a) The assignment has been provided below:

	Balance	**Assignment**
Incremental billing expenses	$ 577	*Implementation costs of emergency time-of-use (TOU) rates*
Incremental labour	$ 250,166	*Implementation and Administration:* • *costs of emergency time-of-use (TOU) rates* • *deferred global adjustment charges for electricity distributors* • *CEAP and CEAP-SB* • *LEAP EFA funding* • *Lost revenues from certain reduced/waived specific service charges*
Waived Interest	$ 119,153	*Lost revenues from certain reduced/waived specific service charges*
Additional LEAP funding	$ 13,133	*LEAP EFA funding*
Principal	**$ 383,029**	
Carrying Costs	$ 18,738	
Balance	**$ 401,767**	

b) With respect to incremental labour, below is the job classification and the amount allocated from that position:

PUC Services Inc. Personnel	Amount
Customer Care staff	$ 71,747
Executive	$ 29,334
Communications Coordinator	$ 1,226
Manager - Billing & Special Projects	$ 59,464
Manager - Corporate Communications	$ 5,863
Director, Finance	$ 17,864
Assistant Controller	$ 54,733
Customer Care	$ 9,934
	$ 250,166

1

2

VECC – 54

Reference: Exhibit 9, Tab 1, Schedule 1, pg. 4

Question:

With respect to the Sub 16 project PUC explains: *"PUC has over collected $23,605. This amount falls below the materiality threshold and PUC is not proposing to reconcile this amount through a Group 2 Account disposition*."

a) PUC's materiality threshold is $135,000 (Exhibit 1, page 45). On this basis PUC appears to be claiming other "immaterial" amounts with respect to both Group 1 and Group 2 accounts (e.g., 1548 $65,199 etc.). Please explain this apparent exception to Board policy.

Response:

a) PUC has corrected this oversight and included the amount with the revised Group 2 account claims in Tab2b, row 59 and 60 of the "PUC_2023_DVA Continuity Schedule_20221128".

The Consumer Council of Canada (CCC) Interrogatories

Exhibit 1 - Administrative

CCC – 1

Reference: Exhibit 1

Question:

Please provide the allowed and actual ROE achieved for each year 2018-2021.

Response:

See the table provided below:

Performance Year	Profitability: Regulatory Return on Equity - Deemed	Profitability: Regulatory Return on Equity - Achieved
2021	9.00%	7.60%
2020	9.00%	8.75%
2019	9.00%	8.87%
2018	9.00%	4.25%

CCC – 2

Reference: Exhibit 1, pg. 11

Question:

Please provide all materials provided to PUC's Board of Directors regarding this Application. Please provide all materials provided to PUC's Board of Directors when seeking approval of the current 2023-2027 Business Plan.

Response:

Materials provided the PUC's Board of Directors regarding this Application, as well as when seeking approval of the current 2023-2027 Business Plan are attached as Appendix IR14 to these responses.

CCC – 3

Reference: Exhibit 1, pg. 12

Question:

The evidence states that PUC continues to build on partnerships with other LDCs and organizations to strengthen the utility. Please provide a complete list of the partnerships with other LDCs. Please provide the nature of the proposed partnerships and provide any contractual arrangements with these LDCs. Does PUC currently intend to enter into any partnerships during the 2023-2027 period? If so, please explain the nature of those relationships

Response:

PUC has the following partnerships with other LDCs:

North Eastern Distributors Buying Consortium ("NEDBC")
PUC is a long-time member of the NEDBC, a Northern Ontario purchasing consortium. In addition to PUC, other member LDCs of the NEDBC include North Bay Hydro, Greater Sudbury Utilities, Chapleau Public Utilities, Northern Ontario Wires, Espanola Regional Hydro, and Algoma Power. Benefits of the group include bulk purchasing discounts as a result of the consortium representing a customer base in the top ten in the province. Saved time due to the shared preparation of major tenders for electrical equipment is also a benefit. Shared purchases include transformers, poles, wire, hardware, switches, insulators, PCB piping and rubber goods.

Ecobility Inc. ("Ecobility")
Established in 2014, Ecobility (formerly CustomerFirst Inc.) is a partnership of 5 Ontario based utility companies including PUC, Greater Sudbury Utilities, North Bay Hydro, Northern Ontario Energy Inc., and Newmarket-Tay Hydro. Ecobility's mandate is delivering a full range of clean energy programs helping its business, utility and government clients achieve their energy management goals.

17 Trees Inc. ("17 Trees")
17 Trees is a partnership with Greater Sudbury Utilities and North Bay Hydro established in 2019. The primary objective of the 17 Trees partnership is to ensure the utilities have a

qualified vegetation management contractor available to meet the demands of their respective forestry programs.

At the present time, PUC does not have any additional proposed partnerships with LDCs and is not aware of any additional proposed partnerships that may occur during the 2023-2027 period.

CCC – 4

Reference: Exhibit 1, pg. 15

Question:

Why has PUC not included the ICM application for Sub-station 16 and the Sault Smart Grid project in its calculation of the revenue deficiency? If they are excluded, why are they identified as one of the "main drivers of the 2023 revenue requirement"? Please explain how the $5,863,234 increase in revenue was derived. Please explain how the $3,918,555 revenue deficiency was calculated.

Response:

PUC did include the ICM application in the calculation of revenue deficiency. As Exhibit 1, page 15 outlines, the $5,863,234 is the revenue deficiency which includes both ICM's and the revenue deficiency generated from the decrease in load forecast. If the effects of the ICM's on revenue deficiency is removed, it represents a $4,783,203 revenue deficiency. Removing the effects of the decrease in load forecast further changes the revenue deficiency to $3,918,555.

CCC – 5

Reference: Exhibit 1, pg. 21

Question:

Please recast Table 1-5 – OEB Approved vs 2023 Test year Capital Expenditures to include 2018-2021 actual numbers.

Response:

The Table has been updated below.

Table 1-5: 2018 OEB Approved vs. 2023 Test Year Capital Expenditures (Revised November 28, 2022)

Planned Capital Expenditures	2018 OEB Approved	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Budget	2023 Test	2023 Test vs 2018 Approved $	Change %
System Access	$ 1,540,849	$ 1,889,775	$ 2,475,349	$ 2,363,573	$ 1,737,482	$ 1,836,000	$ 2,339,499	$ 798,650	51.83%
System Renewal	$ 3,761,033	$ 3,599,000	$ 3,172,000	$ 3,397,000	$ 8,891,666	$ 6,629,000	$ 4,598,966	$ 837,933	22.28%
System Service	$ 86,294	$ 73,000	$ -	$ -	$ 154,381	$ 28,713,000	$ 3,190,371	$ 3,104,077	3597.09%
General Plant	$ -	$ 14,132	$ 188,072	$ 123,887	$ 593,022	$ -	$ 577,035	$ 577,035	0.00%
Total Expenditures, Gross	**$ 5,388,176**	**$ 5,575,907**	**$ 5,835,421**	**$ 5,884,460**	**$ 11,376,552**	**$ 37,178,000**	**$ 10,705,871**	**$ 5,317,695**	**98.69%**
Capital Contributions	$ (450,000)	$ (431,000)	$ (1,112,000)	$ (658,000)	$ (585,806)	$ (7,848,000)	$ (592,500)	$ (142,500)	31.67%
Total Expenditures, Net	**$ 4,938,176**	**$ 5,144,907**	**$ 4,723,421**	**$ 5,226,460**	**$ 10,790,746**	**$ 29,330,000**	**$ 10,113,371**	**$ 5,175,195**	**104.80%**

CCC – 6

Reference: Exhibit 1, pg. 22

Question:

Please recast Table 1-6 – Board approved vs 2023 Test Year OM&A to include 2018-2021 actual numbers.

Response:

The Table has been updated below.

Table 1-6: 2018 Board Approved vs. 2023 Test Year OM&A

	2018 Last Rebasing Year OEB Approved	2018 Last Rebasing Year Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year	Variance 2022 Brdige Approved vs. 2023 Test Year	Variance %
Operations	$ 4,029,899	$ 3,679,895	$ 4,151,756	$ 4,074,970	$ 3,935,625	$ 4,028,374	$ 4,434,334	$ 405,960	10.1%
Maintenance	$ 2,106,659	$ 2,329,918	$ 2,150,490	$ 2,359,394	$ 2,471,213	$ 2,652,070	$ 2,846,131	$ 194,060	7.3%
Billing and Collecting	$ 1,416,684	$ 1,381,283	$ 1,354,435	$ 1,333,216	$ 1,370,350	$ 1,237,795	$ 1,290,441	$ 52,646	4.3%
Community Relations	$ 620,355	$ 595,226	$ 640,859	$ 574,049	$ 635,277	$ 697,054	$ 753,359	$ 56,305	8.1%
Administrative and General	$ 3,002,559	$ 3,264,474	$ 2,831,111	$ 2,798,172	$ 3,645,134	$ 3,540,744	$ 4,209,436	$ 668,692	18.9%
Total	**$ 11,176,156**	**$ 11,250,796**	**$ 11,128,652**	**$ 11,139,800**	**$ 12,057,598**	**$ 12,156,038**	**$ 13,533,701**	**$ 1,377,663**	**11.3%**
%Change (year over year)		0.7%	-1.1%	0.1%	8.2%	0.8%	11.3%	$ 2,357,545	**21.1%**

CCC – 7

Reference: Exhibit 1, pg. 25

Question:

Please update the application to reflect the OEB's updated cost of capital parameters.

Response:

PUC has updated the application to reflect the OEB's October 2022 updated cost of capital parameters.

CCC – 8

Reference: Exhibit 1, pg. 38

Question:

PUC has committed to publishing annual updates on its website showing the actual benefits of the SSG project, broken down by customer class. When is the first report expected? Please provide the format of that report.

Response:

PUC will be publishing annual SSG benefit updates aligning with the RRR reporting cycle for 2023 commencing in April 2024. The format of the report for customers has not been developed yet and had been intended to be finalized in Q1 2024.

PUC would be open to any references, guidelines, or suggestions on formatting of the website report.

CCC – 9

Reference: Exhibit 1, pg. 39

Question:

Please provide a list of all of the changes made to PUC's Conditions of Service.

Response:

Below is a list of the changes made to PUC's Conditions of Service:

Section		Change compared to previous version
1.2	-	Related Codes and Governing Laws - added related codes and governing laws to existing list
1.4	-	Amendments to Changes - reworded section
1.5	-	Contact information – added contact information
1.8	-	Disputes – added Embedded generators and updated contact information
2.1.7.1	-	Standard Form of Contract – updated section re: New of Modified service
2.2.1	-	Disconnection for Arrears – updated section for PUC's process
2.3.7.2	-	Meter Location – clarified location (removed restriction on not more than 3m back from front of building) and added where there is potential for damage to a meter, Customer shall safeguard
2.3.7.4	-	Current Transformer Boxes – added location should be reviewed and approved by PUC
2.3.7.7	-	Meter Reading – added PUC shall have the right to install remote reading technology on customer premises
2.3.7.9	-	Totalizing Meter Reads – added totalizing is done by MIST meters connected to phone lines, communications equipment must be present
2.4.2.1 - 2.4.2.6	-	Amount of Deposit/Deposit Waived for Customers/Form of Security Deposit/Deposits Refunded and Goo d Payment History – updated to align to new changes relating to OEB amendments to customer services rules
3.0.3.2	-	Underground Primary Cables – added cable cost to the Customer
-	-	Service Removal – added that items paid for by Customer remain on site
3.3.6.1	-	Group-Operated Switch – added that switch will be supplied within the pad mount transformer where feasible
3.3.6.3	-	Drawings – added Site Plan must be updated and sent to PUC
3.4.1.4	-	Contribution Cap for Residential Subdivisions – removed section
Section 4	-	Glossary of Terms – added sources for Definitions and added/updated definitions as required
Appendix C	-	Electric Services Connection Charges – updated chart
Appendix F	-	Economic Evaluation for System Expansion – removed form

CCC – 10

Reference: Exhibit 1, pg. 40

Question:

Please explain the difference between PUC Distribution Inc. and Sault Ste. Marie Electric Distribution System and provide the rationale for this corporate structure.

Response:

The PUC Corporate Structure chart in Exhibit 1 shows the company structure and demonstrates that Sault Ste. Marie Electric Distribution System (infrastructure assets) are owned by PUC.

CCC – 11

Reference 1: Exhibit 1, pg. 42
Reference 2: Exhibit 4, pg. 33

Question:

The Executive Team at PUC Services Inc. is comprised of the CEO, CFO. Executive Lead Operations & Engineering, VP of Electrical Operations and Engineering, VP Corporate Services, and the VP of Special Projects:

a) Please provide the results of the MEARIE Group Management Salary Survey administered by Korn Ferry hay Group.
b) What are the relative responsibilities of the Executive Lead Operations and Engineering and VP of Electrical Operations.
c) What is the total compensation cost for the Executive Team for 2023? How much of the cost is allocated to PUC Distribution Inc.?

Response:

a) The 2020 MEARIE Management Salary Survey can be found within the case record for OEB File No. EB-2021-0016 per the following link:
https://www.rds.oeb.ca/CMWebDrawer/Record/746505/File/document

b) The accountabilities of the Executive Lead Operations and Engineering are more comprehensive as they also include accountabilities for Water Treatment, Water Distribution and Wastewater treatment for the City of Sault Ste. Marie. In addition, this individual is accountable for the provision of Water and Wastewater services for many communities around Sault Ste. Marie including, but not limited to, Blind River, Desbarats, Richard's Landing, Serpent River, Pronto, local school boards, etc.

The VP of Electrical Operations reports to the Executive Lead Operations and Engineering and is accountable for the Electric Distribution in the City of Sault Ste. Marie. This structure was established as part of a transition and succession plan.

c) The question seeking total Executive Compensation to be paid by PUC Services for 2023 is outside the scope of this application. PUC Services provides the workforce necessary to not only operate PUC, but its other affiliates not related to the LDC.
With regards to the forecasted executive compensation allocated from PUC Services to PUC in 2023:

- Specific to Exhibit 4, the budgeted compensation cost in operations that was allocated for the Executive Team of PUC Services to PUC for 2023 was $377k.
- The budgeted compensation cost in capital that was allocated for the Executive Team of PUC Services to PUC for 2023 was $462k.

CCC – 12

Reference: Exhibit 1, pg. 58

Question:

Over 25% of customers are currently enrolled in e-billing. What is the expected take up over the 2023-2027 period?

Response:

Please refer to OEB Staff-3(b).

Exhibit 2 – Rate Base

CCC – 13

Reference: Exhibit 2, pg.8

Question:

Please provide forecast compared to actual depreciation amounts for the years 2018 to 2022.

Response:

Below is the comparative table:

Account	Description	2018	2019	2020	2021	2022 FORECAST
5705	Amortization Expense	3,864,131	4,010,672	4,153,218	3,842,226	4,703,440
5725	Amortization Expense	(82,576)	(101,862)	(123,987)	(140,229)	-
	Total	3,781,554	3,908,810	4,029,231	3,701,996	4,703,440
	Correction recorded in 2021				230,268	(230,268)
		3,781,554	3,908,810	4,029,231	3,932,264	4,473,172
5705	Amortization Expense	3,783,960	3,900,000	4,100,000	4,226,423	4,473,172
	Variance to Budget	(2,406)	8,810	(70,769)	(294,159)	-

CCC – 14

Reference: Exhibit 2, pg.11

Question:

Voltage conversion costs for Laronde Avenue were higher than approved.

a) Please provide the forecast capital and in-service amounts compared to actuals by year.
b) Please provide the original in-service date compared to actual.
c) Please provide the cost drivers for the higher cost.

Response:

a) This project was originally budgeted at $531,603 and estimated to be completed in 2018. Actual project costs were $ 682,411 and completed December 3, 2018, with some additional minor site restoration costs in 2019. It is noted that although this individual project budget has a variance of 28%, for the overall System Renewal category with a budget of $3.761M and actual of $3,651M, the variance was 3% as noted in Table 5.4-3 on p101 of the DSP (Exhibit 2, p209). When planning and budgeting individual projects, cost estimates completed are Class C (plus or minus 30 percent) as there is a high degree of uncertainty about potential project conditions and exact scopes until preliminary engineering gets underway. Because of this, PUC carefully and actively manages work execution to ensure individual project budgets, annual budgets, program budgets and OEB category budgets are all reviewed and balanced quarterly, annually, and over the 5-year COS period so that the overall actual expenditures align with the proposed objectives laid out initially for the COS period.

b) In the material narrative for this project, in Appendix G of the 2018-2022 DSP (filed with these IR responses as Appendix XX – PUC DSP 2018-03-21), the in-service date is projected as August 31, 2018. All actual work was completed by December 3, 2018. It is noted that timing of this and many other projects throughout a calendar year may vary from plan with respect to start and finish dates when there is limited bearing on costs or risks. PUC's project managers work carefully to balance projects and priorities throughout the year to optimize and maximize the use of available resources.

c) The primary drivers for the higher project cost were related to contractor challenges with directional drilling and excavation working around additional infrastructure in close proximity (gas, water), and associated restoration costs.

CCC – 15

Reference: Exhibit 2, pg.43

Question:

PUC follows the Kinetrics Report for all assets categories except accounts 1730 Transmission Overhead Conductors, and 1808 Buildings and Fixtures.

For each exception, please identify whether PUC's useful life is above or below Kinectrics' useful life values.

Response:

Please refer to Chapter 2 appendices – Appendix 2-BB.

PUC's useful life for account 1730-Transmission Overhead Conductors is below the Kinetrics value. PUC has componentized account 1808-Buildings and Fixtures in accordance with IFRS (International Financial Reporting Standards). As such, there are useful lives of certain components that are below the Kinetrics single useful life value.

CCC – 16

Reference: Exhibit 2, pg.58

Question:

With respect to the ICM for Substation 16, PUC indicates the project has a revised total cost of $6,020,119, a variance of $1,291,890 from the ICM submission.

a) The lowest bidder's price was $608k higher than the estimated construction cost that was part of the OEB ICM submission. Please provide a detailed breakdown of the construction cost components in the OEB ICM submission compared to actuals and explain the increases.
b) During demolition of the original substation transformer oil was found in the ground that needed remediation. The associated costs for this unforeseen environmental cleanup were $160,000. Please provide PUC's risk assessment for the project.
c) The actual design of the distribution lines near Sub 16, which also includes two road crossings, verified riser cable locations, and resulted in additional road, driveway, and Hub Trail restoration costs than anticipated. The station riser cable duct bank costs were $327,000 higher than what was estimated as part of the ICM submission. Please provide a breakdown of the cost components of the two designs (ICM submission compared to final).
d) The project was delayed one year due to COVID-19, which resulted in additional costs of $176,000 for labour and material cost increases, as well as unanticipated equipment storage and handling expenditures. Please explain the unanticipated equipment storage and handling expenditures and the associated costs.
e) Please provide a breakdown of the contingency used for the project.

Response:

a) Please see response to OEB Staff-24(a).
b) Please see response to OEB Staff-24(c).
c) Please see response to OEB Staff-24(d).
d) Please see response to OEB Staff-24(f).

e) There was no global contingency defined for the project, accordingly, no breakdown can be provided. The estimated contingency was built into the project tasks line items or components by Consultants who are subject matter experts and were responsible to develop these amounts for project estimating.

CCC – 17

Reference: Exhibit 2, pg. 66

Question:

The amount of NRCan grant available was reduced by $754,115 in 2022 due to a delay in timing of project approval from the resubmission of the application to, and approval from, the OEB. The amount of Federal NRCan funding available was reduced and therefore the amount allocated to PUC ended up being slightly under the original estimate of 25.00%. This resulted in PUC adjusting the Gross project spend to $31,903,718, a reduction of $1,034,495. The net project spend in 2022 is now $21,357,909.

a) Please provide details on how timing impacted the NRCan funding available.
b) Please explain the adjustments made to reduce the Gross project spend and the impact on the overall cost and benefits of the project.
c) What is the impact on the projected benefits resulting from the reduction in the NRCan funding.

Response:

a) The impact both initially in the first part of 2021 and forecast to follow, of the COVID pandemic on many of the NRCan program participants, with restrictions on travel and supply chain concerns was recognized by NRCan. The NRCan Smart Grid program offered an extension to participants in need for eligible funding to extend to March 31, 2023. However, there were some funding restrictions applied based on timing of expenditures already incurred to date of the participants and PUC was one of the projects impacted. The loss of funding of $754,115 referenced above was part of this Impact of the delayed expenditure and one year extension. PUC has made steps to manage scope and project delivery to maintain the approved net capital target.

b) The Reliability benefit from the Distribution Automation (DA) was not part of the economic evaluation of the project. Reductions in the DA scope do not impact the economic benefit for the customer. The Distribution Automation DA scope of work for feeder automation has been reduced to maintain the approved net capital target. The reliability benefit is now forecast to be approximately 55% of what was originally forecast. **Also refer to OEB Staff-26(c).**

c) The impact of the reduction in NRCan funding was part of the need for the DA reduction in (b) above. The DA reduction will impact the reliability benefit estimate but not the net benefit economic analysis provided for the project.

CCC – 18

Reference: Exhibit 2, App. C, pg. 11

Question:

PUC indicates it has also purchased electric vehicles to reduce its carbon footprint.

a) Please provide details on the electric vehicles purchased to date including timing and costs.
b) Please discuss PUC's plans to purchase electric vehicles over the period 2023 to 2027 and the proposed budget.

Response:

a) PUC Services currently has 3 Electric Vehicles (EV) purchased. Two Volkswagen e-golfs were purchases in 2019 for $39k each. In 2022, a Ford Mustang Mach-E was purchased for $59k.

b) In 2023 – 2027 the plan adds EV vehicles each year based on supply chain availability. PUC expects 4 EV purchases in 2023 and hope to continue replacement of retiring gas-powered vehicles as availability allows.

CCC – 19

Reference: Exhibit 2, App. C, pg.27, Table 5.2-12

Question:

a) Please provide a breakdown of Scheduled Outages for the years 2018 to 2021 by sub cause codes.
b) Please provide a breakdown of Defective Equipment for the years 2018 to 2021 by asset type sub cause codes.

Response:

a) Please see table below for the breakdown of the number of Scheduled Outages for the years 2018-2021 by asset type sub cause codes.

Number of Outages					
Scheduled Outages	**2018**	**2019**	**2020**	**2021**	**Grand Total**
New Connection		1	1		2
Scheduled - House or Equipment Move	1	2		1	4
Scheduled - Maintenance or Repair	122	149	148	63	482
Scheduled - Relocating	12	3			15
Scheduled - Switching		6	4	1	11
Scheduled - Tree Trimming	4	2	1	2	9
Scheduled - Voltage Conversion	15	21	3	42	81
Grand Total	**154**	**184**	**157**	**109**	**604**

b) Please see the table below for the breakdown of the number of Defective Equipment outages for the years 2018-2021 by asset type sub cause codes. The Defective Equipment value in Table 5.2-12 of the DSP included major event days in the value for 2020. The actual value should have been reported as 173 versus the 174 shown.

Number of Outages					
Defective Equipment	**2018**	**2019**	**2020**	**2021**	**Grand Total**
Arrestor	6	1		1	8
Conductor - Primary	19	25	38	22	104
Conductor - Secondary	17	29	35	10	91
Conductor - Termination	6	25	16	11	58
Insulator	3	2	3		8
Pole or Guy Wire			4	2	6
Recloser	1	1			2
Switch - Breaker	2	1		2	5
Switch - Cable Riser		1			1
Switch - Fused	13	3	6	2	24
Switch - Kabar			2	3	5
Switch - Solid Blade		4	1		5
Transformer - Distribution	4	19	61	23	107
Transformer - Padmount		1	3	3	7
Transformer - Submersible	3	10	4	10	27
Grand Total	**74**	**122**	**173**	**89**	**458**

CCC – 20

Reference: Exhibit 2, App. C, pg.29, Table 5.2-13

Question:

Please provide a breakdown of Defective Equipment for the years 2018 to 2021 by asset type sub cause codes.

Response:

Please see the table below showing Number of Customer Interruptions for Defective Equipment sub cause codes for the years 2018-2021. The Defective Equipment value in Table 5.2-13 of the DSP included major event days in the value for 2020. The actual value should have been reported as 21,673 versus the 31,039 shown.

Sum of NumCustomers					
Defective Equipment	**2018**	**2019**	**2020**	**2021**	**Grand Total**
Arrestor	783	1360		3	2146
Conductor - Primary	6947	9745	14098	10673	41463
Conductor - Secondary	26	114	782	125	1047
Conductor - Termination	1147	1382	126	63	2718
Insulator	576	763	1227		2566
Pole or Guy Wire			689	12	701
Recloser	631	57			688
Switch - Breaker	1899	4		1372	3275
Switch - Cable Riser		43			43
Switch - Fused	1612	966	2003	266	4847
Switch - Kabar			808	156	964
Switch - Solid Blade		1465	1031		2496
Transformer - Distribution	30	158	410	770	1368
Transformer - Padmount		1	77	14	92
Transformer - Submersible	79	1444	422	870	2815
Grand Total	**13730**	**17502**	**21673**	**14324**	**67229**

CCC – 21

Reference: Exhibit 2, App. C, pg.30, Table 5.2-14

Question:

Please provide a breakdown of Defective Equipment for the years 2018 to 2021 by asset type sub cause codes.

Response:

Please see the table below showing Customer Interruption Hours for Defective Equipment sub cause codes for the years 2018-2021. The Defective Equipment value in Table 5.2-14 of the DSP included major event days in the value for 2020. The actual value should have been reported as 27,166 versus the 42,838 shown.

Sum of CustomerInterruptio					
Defective Equipment	**2018**	**2019**	**2020**	**2021**	**Grand Total**
Arrestor	684	1111		1	1796
Conductor - Primary	10237	6127	18916	14051	49331
Conductor - Secondary	106	167	1322	164	1759
Conductor - Termination	2028	619	166	96	2909
Insulator	2790	1514	1218		5523
Pole or Guy Wire			859	28	887
Recloser	105	113			218
Switch - Breaker	1069	8		487	1564
Switch - Cable Riser		42			42
Switch - Fused	2284	1275	3682	149	7391
Switch - Kabar			27	532	559
Switch - Solid Blade		1594	69		1662
Transformer - Distribution	59	284	570	1566	2479
Transformer - Padmount		2	107	12	120
Transformer - Submersible	395	316	232	2152	3096
Grand Total	**19757**	**13173**	**27166**	**19240**	**79336**

CCC – 22

Reference: Exhibit 2, pg.39

Question:

PUC states "Since PUC leases its motor vehicle assets rather than owning them, PUC's fleet-related investment needs are relatively small. General plant investments are discretionary in nature."

a) Please provide PUC's motor vehicle leasing costs for the years 2018 to 2027.
b) Please explain any significant variation in costs year over year.

Response:

a) Following the guidelines set in the Full Absorption Cost Allocation Review completed by BDR North America Inc. that was filed with the application as Appendix B, the following table provides the motor vehicle leasing costs for PUC from PUC Services for 2018 to 2023 budget as proposed in this application. PUC does not have values beyond the test year.

	Annual Leasing Costs
2018 Actual	$443,466
2019 Actual	$429,275
2020 Actual	$437,719
2021 Actual	$431,029
2022 Budget	$564,579
2023 Budget	$626,953

b) The increase from 2021 to 2022 is the result of the replacement of an end-of-life RBD and single bucket truck. The increase from 2022 to 2023 is the result of the replacement of an end-of-life dump truck and small RBD.

CCC – 23

Reference: Exhibit 2, App. C

Question:

PUC engaged the consulting services of METSCO to assist with the completion of its DSP for the 2023-2027 period. METSCO previously completed PUC's 2018 DSP.

a) Please provide a copy of the previous DSP in EB-2017-0071.
b) Please discuss any significant changes in methodology between Metsco's 2021 Asset Condition Assessment (ACA) and the previous ACA in EB-2017-0071.

Response:

a) PUC has provided a copy of the previous DSP filed in EB-2017-0071 as Appendix IR15 – PUC DSP 2018-03-21.

b) METSCO's previous ACA report in EB-2017-0071 was conducted utilizing data received up until the second and third quarter of 2016 whereas the 2021 ACA was based on condition data recorded up to September 2021. Significant changes in increasing the scope to cover more asset classes and increasing the data availability used in Health Index Formulations (HIF) have been made between 2016 and 2021. The following tables summarize the significant changes between the 2016 and 2021 ACA reports.

Table 1: Significant Changes to Station Health Index Formulations

Station Asset Class	Notes	# Of Condition Parameters in Health Index Formulation	
		2016 ACA	2021 ACA
Station Power Transformers	Number of condition parameters increased.	4	20
Station Switchgear	Number of condition parameters increased.	4	9
34.5 kV TS Circuit Breaker	Previously covered under Station Switchgear asset class; number of condition parameters increased.	4	11
Station Buildings	Previously covered under "Other Station Assets" asset class; number of condition parameters increased.	4	5

Station Fences	Previously covered under "Other Station Assets" asset class; number of condition parameters increased.	4	6

Table 2: Changes to Station Asset Classes

Station Asset Class	Notes	2016 ACA	2021 ACA
115-kV Switches	Added to ACA	Not included in ACA	Included in ACA
Station Riser Cables	Added to ACA	Not included in ACA	Included in ACA
Station Battery Banks and Chargers	Added to ACA	Not included in ACA	Included in ACA

Table 3: Significant Changes to Distribution Health Index Formulations

Distribution Asset Class	Notes	# Of Condition Parameters in Health Index Formulation	
		2016 ACA	2021 ACA
Wood Poles	Previously covered under the "Overhead Lines" asset class; number of condition parameters increased.	3	4
Overhead Primary Conductors	Previously covered under the "Overhead Lines" asset class; 2021 ACA shows the age assessment.	Part of Overhead Line asset class overall HI.	Age assessment only
Distribution Transformers (Pad-mount, Pole-mount)	Changes to the condition parameters used within the HIF.	HIF utilizes age and visual inspection results	HIF utilizes age and historical peak loading data
Pad-mounted Distribution Switchgear	Previously covered under the "Disconnect Switches and Cut-outs" asset class; number of condition parameters increased.	2	9

Table 4: Changes to Distribution Asset Classes

Distribution Asset Class	Notes	2016 ACA	2021 ACA
Steel Poles	No change	Not included in ACA	Age Assessment included
Manholes and Vaults	Previously conducted age assessment under the "Underground Concrete Chambers" asset class. These were not assessed in 2021	Included in ACA	Not included in ACA
Fused Disconnect Switches (cut-outs)	Previously described under "Distribution Switches and Cut-outs" asset class; however, no age or condition assessment was conducted in 2016	Not assessed	Age assessment included
Load-break Switches	Previously described under "Distribution Switches and Cut-outs" asset class;	Not assessed	Age assessment included

	however, no age or condition assessment was conducted in 2016		
Underground Switches (Junction Boxes)	Previously described under "Distribution Switches and Cut-outs" asset class; however, no age or condition assessment was conducted in 2016	Not assessed	Included in ACA
Submersible Transformers	Previously conducted an age assessment only; now includes Health Index formulation	Age assessment only	Included in ACA
Underground Primary Cables	Previously covered age assessment only under "Cables, Splices and Terminations" asset class.	Age assessment only	Included in ACA

1
2
3

CCC – 24

Reference: Exhibit 2, App. C, pg. 42

Question:

Due to the absence of test results, the health index formulation of underground cables only involved using the service age of the cable as well as the circuit's historical failures during the last five years. Please provide the historical failure data referred to above for the years 2018 to 2021.

Response:

PUC outage statistics currently do not differentiate underground component failures, so it cannot extract cable failures from the failure of other components, such as insulators, elbows, or connectors.

CCC – 25

Reference: Exhibit 2, App. C, pg. 10

Question:

Please provide the historical failure data for the years 2018 to 2021 for wood poles, overhead primary conductors, polemount transformers, padmount transformers, submersible transformers, and distribution switchgear.

Response:

The table below illustrates the available information for the quantity of assets replaced between 2018 and 2022 (to November 17, 2022) under the forced renewal budget indicating specific assets replaced due to failure. The cause of asset failure can vary and includes elements such as natural asset failures, overloaded transformers, and vehicle accidents.

Asset	2018-2022
Poles	74
Pole Mount Transformers	51
Minipad Transformers	3
Pad Mount Transformers	16
Submersible Transformers	20

CCC – 26

Reference: Exhibit 2, App. C, App. A Material Investment Narratives, OH Renewal – Transformers (PCBs), pg.2

Question:

Table 1 Historical and Forecast Capital expenditures indicates no spending for the years 2018 to 2022.

a) Please confirm PUC has not replaced any overhead pole mounted transformers with PCB concentrations greater than 50 ppm replaced to date.
b) If yes to part a) please explain why these replacements weren't scheduled to take place in prior years to smooth out the cost impact.

Response:

a) PUC has not actively replaced OH transformers with PCB concentrations greater than 50ppm to date. Some transformers have been replaced via failures and through unrelated programs (ex. Restricted wire, voltage conversion, deteriorated poles, etc.) These transformers have not been specifically tracked to confirm the levels of PCBs above 50 ppm but are handled by stores accordingly to comply with regulations.

b) PUC continues to assess all system risks and evaluate associated costs. Higher risk projects have been occurring in previous years resulting In the OH transformer replacement program being concentrated between 2023-2025. A detailed account of the risks considered and how timing of the OH Renewal – Transformers (PCBs) program was selected are provided in responses to OEB Staff-42(b) and (c). Reasons for the pacing of this program and others are addressed in OEB Staff-32.

CCC – 27

Reference: Exhibit 2, App. C, App. A Material Investment Narratives, OH Renewal -Voltage Conversion, pg.3

Question:

In 2023, PUC proposes to retire the remaining network equipment operating at 4.16 kV from the grid, upgrade all the remaining line sections to 12.47 kV, and replace Substation 4 with a 34.5 kV switch point. The spending in 2023 is greater than the average spend in the previous 5 years.

Please explain why this work could not span more than one year.

Response:

This project was scheduled to all be completed in the first year of the COS primarily associated with the many general reasons outlined in the response to OEB Staff-32. One of the specific reasons given there for voltage conversion, as bullet 4 in that response is as follows “Some investments are placed earlier due to higher risk levels where assets are already at end of life so risk levels would go up if deferred (voltage conversion is an example where pushing out the remaining conversion linework scheduled in 2023 would necessitate that the two remaining end of life 4160V stations would have their retirement deferred)”.

CCC – 28

Reference: Exhibit 2, App. C, App. A Material Investment Narratives, OH Renewal - Restricted Conductor, pg.3

Question:

a) Please provide the replacement quantities of #6 copper overhead primary conductor for the years 2018 to 2026.
b) Please explain the increase in costs in 2022, 2024 and 2026.

Response:

a) The table below illustrates the length of #6 copper overhead primary conductor that was reported replaced between 2018 and 2022 and what is projected to be replaced from 2023 to 2026. Note that the lengths of conductors removed/replaced and reported at the time of project completion and therefore costs overlapping calendar years may not be indicative of the year over year cost to replace.

Year	1 Phase Replaced (m)	3 Phase Replaced (m)
2018(Actuals)	3352	0
2019 (Actual)	2640	0
2020 (Actuals)	6274	2772
2021 (Actuals)	1295	0
2022 (YTD Actuals)	3510	0
2023 (Est.)	1310	0
2024 (Est.)	4600	0
2025 (Est.)	1820	0
2026 (Est.)	2780	0

b) The annual costs of the OH Renewal – Restricted Conductor has been proposed to increase in upcoming years to reflect the program risk and requirement to eliminate the hazard, and the availability of other programs coming to completion such as voltage conversion. Additionally, PUC manages our annual budgets considering many items including, but not limited to integrated resource plans. Balancing the annual system renewal costs while maintaining a levelized resource plan is critical to ensure work is completed in an efficient manner. With regards to how PUC paces this program and others more generally, please refer to OEB Staff-32.

CCC – 29

Reference: Exhibit 2, App. C, App. A Material Investment Narratives, OH Renewal – Poles, pg.1

Question:

As of 2021, 4.7% (590) wood poles are in poor condition and 4.6% (574) wood poles are in very poor condition. PUC plans to replace approximately 60 wood poles per year.

a) Please provide the number of wood poles replaced for the years 2018 to 2022.
b) Please discuss if PUC has considered a pole refurbishment program. If not, why not.

Response:

a) The list below identifies the quantity of deteriorated poles replaced by year within the OH Renewal – Poles program.

Year	Poles Replaced
2018	33
2019	41
2020	48
2021	26
2022 (To Date)	45

b) PUC currently performs multiple functions to refurbish and extend the life of wood poles including:
   - Preservation treatment using boron rods and pesticide;
   - Composite pole filler to react to woodpecker holes; and
   - Pole top extensions to accommodate increased separations on the pole or as a cost-effective means to address pole top damage.

CCC – 30

Reference: Exhibit 2, App. C, App. A Material Investment Narratives, Stations Renewal - Switchgear, Protection & Control Renewals, pg.1

Question:

PUC is proposing to replace two breakers per year for the forecast period with new vacuum style breakers that meet the latest standards and industry accepted technology type. For the test year, 2023, the two replacement breakers will be installed at Substation 1. For the years 2024-2027, two breakers per year will be replaced at other stations which are selected prior to each year.

a) Please provide the scope of work for 2022.
b) Please discuss any delays in completing the work in 2022.
c) Please provide the spending year to date for 2022.

Response:

a) The scope of work for 2022 is to replace one failed breaker at Substation 19.

b) PUC is expecting receipt of the breaker for Substation 19 in late November or early December 2022 to install the breaker in 2022. Work is minimal to complete the installation and there are no expected delays in completing the work provided the unit arrives on schedule from the manufacturer.

c) There are no costs to-date, but the cost of the breaker will be $65,650 plus internal installation labour and internal overheads, all expected to be incurred by the end of 2022.

CCC – 31

Reference: Exhibit 2, App. C, App. A Material Investment Narratives, UG Renewal – Vaults, pg.3

Question:

PUC proposes to spend $401,000 in 2023 compared to an average of approximately $90,000 for the years 2024 to 2027.

Please explain the scope of work and increase in spending in 2023.

Response:

The proposed increased spending in 2023 is to accommodate a specific vault that has become challenging. A large vault structure located in a heavily trafficked parking lot has shown signs of deterioration and temporary fixes have been completed to mitigate the hazard. The vault requires complete rejuvenation/replacement to remove the hazard. With regards to amount and timing of costs and pacing of spend please refer to OEB Staff-47.

CCC – 32

Reference: Exhibit 2, App. C, App. A Material Investment Narratives, Stations Renewal - Building & Fence Repairs, pg.1

Question:

a) Please explain the increase in spending over the period 2023 to 2027 compared to 2018 to 2022.
b) Please explain the increase in the level of spending in 2023 compared to future years 2024 to 2027.

Response:

a) As summarized in Table 1 of the material investment narrative, the total 2018-2022 historical 5-year spend for this item was $206k whereas the proposed 5-year budget for 2023-2027 is $554k. The increased needs identified for the proposed plan were primarily associated with two factors:
    - A significant increase in copper theft from fences and in stations over the past 2-3 years. Although recently installed cameras are expected to help with this going forward, replacement will require review and testing to determine what is missing, possibly engineering design, and ultimately replacement.
    - Of the station buildings identified in Figure 4-45 of the ACA, p83 (Exhibit 2, p648), six have a health index below the DAI threshold and proposed capital associated with sandblasting and painting units amongst these is included in the plan. Paint in these 40–50-year-old metalclad enclosure type buildings is known to have lead paint content and costs are reflective of the associated environmental controls and work methods required to complete the work.

b) The increase in 2023 spending compared to 2024-2027 is due to a deficiency identified by ESA. PUC must install exhaust fans with climate controls to its eight metalclad substations.

CCC – 33

Reference: Exhibit 2, App. C, App. A Material Investment Narratives, Tools & Equipment, pg.1

Question:

Please provide the cost of the Omicron Injection Tester in 2023.

Response:

Including consideration for inflation and internal overheads, $106,626 was allocated for the Omicron Injection Tester. Also, for further information on the rationale for this purchase, please refer to OEB Staff-51.

CCC – 34

Reference: Exhibit 2, App. C, App. A Material Investment Narratives: OH Renewal - General Asset

Question:

The general asset renewal tasks included under this program represent small projects over the forecast period that are not considered emergency repairs, do fit within the existing program categories, and do not warrant additional program categories. This includes Removal, cleanup, and disposal of pole butts General Overhead Tasks:

a) Please explain the increase in spending for 2023 to 2027 compared to 2018 to 2021.
b) Please provide the spending to date for 2022.

Response:

a) Pole butt removal and disposals occur well after the installation portions of a project has been completed. To efficiently close and reconcile projects, the cost of removal and disposal of poles has been included within this project. The increased cost compared to the previous application period includes the following:
    - Disposal of pole butts containing creosote in an environmentally friendly manner for regulatory compliance, beyond historical requirements;
    - Removal of pole butts required more vacuum truck work to expose utilities within 1m of pole prior to removal; and
    - Addressing approx. 500 poles that are outstanding from previous years, levelized over this application period.

b) Spending-to-date for 2022 is $228,940 which includes all projects in the general category and overheads.

CCC – 35

Reference 1: Exhibit 2, App. C, App. A
Reference 2: Appendix 2-AA

Question:

The capital projects in Appendix 2-AA do not reflect the breakdown in Appendix A Material Investment Narratives.

Please map the Material Investment Narratives to the projects in Appendix 2-AA.

Response:

Please refer to VECC-17.

CCC – 36

Reference 1: Exhibit 2, App. C, App. A
Reference 2: Appendix 2-AA

Question:

a) Please add a column for 2018 Board Approved to Appendix 2-AA.
b) Please add a column for 2022 year to date Actuals.
c) Please provide an excel version of Appendix 2-AA including parts a) and b).
d) Please provide a breakdown of the projects included in Overhead Renewal.
e) Please provide a breakdown of the projects included in Underground Renewal.

Response:

a) PUC has added a 2018 Board Approved Column to Appendix 2-AA.

b) PUC has added a column for 2022 year to date actuals in Appendix 2-AA.

c) PUC has filed the revised chapter 2 appendixes in live excel format.

d) Overhead Renewal is further broken down into its subcategories, as shown highlighted yellow in the following table:

Year of Proposed Investment		2023	2024	2025	2026	2027	2023-2027
Overhead Distribution System	Planned OH line reconstruction - Voltage Conversion Projects	$ 863,670	$ -	$ -	$ -	$ -	$ 863,670
	Planned OH line reconstruction - Replacement of Unsafe Poles	$ 602,123	$ 610,825	$ 621,349	$ 654,628	$ 611,375	$ 3,100,300
	Planned OH line reconstruction - Replacement of restricted conductor	$ 361,525	$ 1,287,823	$ 516,885	$ 834,105	$ -	$ 3,000,338
	Planned OH line construction - General Asset Renewal	$ 172,483	$ 174,976	$ 177,991	$ 187,524	$ 175,134	$ 888,107
	Replacement of distribution transformers upon failure (Reactive or Planned)	$ 711,258	$ 721,537	$ 733,968	$ -	$ -	$ 2,166,763
	Unplanned OH line renewal - Emergency repairs upon failures	$ 276,106	$ 279,123	$ 283,824	$ 300,361	$ 277,022	$ 1,416,435
	Subtotal - OH line renewal work	**$ 2,987,165**	**$ 3,074,285**	**$ 2,334,016**	**$ 1,976,618**	**$ 1,063,530**	**$ 11,435,614**

e) Underground Renewal is further broken down into its subcategories, as shown highlighted yellow in the following table:

DSP Renewal

Year of Proposed Investment		2023	2024	2025	2026	2027	2023-2027
Underground Distribution System	Planned UG cable replacement - Voltage Conversion Projects	$ -	$ -	$ -	$ -	$ -	$ -
	Planned UG cable replacement - Direct Buried cable with high failure rates	$ -	$ -	$ -	$ 289,809	$ 270,661	$ 560,470
	Planned UG cable replacement - Cable in Duct with high failure rates	$ -	$ -	$ -	$ -	$ -	$ -
	Pad mounted transformer renewal - Reactive or Planned?	$ -	$ -	$ -	$ -	$ -	$ -
	Planned Pad mounted switchgear renewal	$ -	$ 114,530	$ 58,251	$ 61,371	$ 57,316	$ 291,469
	Planned Pad mounted Junction Box (K-bar) renewal	$ -	$ -	$ -	$ -	$ -	$ -
	Planned Reconstruction of Underground vaults	$ 401,415	$ 89,079	$ 90,613	$ 95,467	$ 89,159	$ 765,733
	Planned renewal of UG Distribution System assets - General	$ 31,361	$ 31,814	$ 32,362	$ 34,095	$ 31,842	$ 161,474
	Unplanned UG Distribution renewal - Emergency repairs upon failures	$ 376,327	$ 381,766	$ 388,343	$ 409,143	$ 382,109	$ 1,937,688
	Subtotal - UG Distribution renewal work	**$ 809,103**	**$ 617,188**	**$ 569,570**	**$ 889,885**	**$ 831,088**	**$ 3,716,834**

CCC – 37

Reference: Appendix 2-BA

Question:

a) Please explain the increase in O&M between 2021 actuals and 2023 forecast.
b) The average spend on System Renewal over the 2023 to 2027 period is $3.7 million. The forecast spend for 2023 is $4.6 million. Please summarize the drivers of the increase in spending in 2023 compared to the average.

Response:

a) The primary driver for this increase is inflation impacts on labour and non-labour cost and added positions in support of SSG.

b) Pacing of work across the five-year COS period was generally based on factors discussed in detail in our response to OEB-Staff-32. Descriptions of the associated projects and programs are provided in the DSP, p107, Table 5.4-10, p109 Table 5.4-11, p111, Table 5.4-12 and p5.4-13, Table 5.4-13 (Exhibit 2, p215 to p219). Significant contributing specific projects or programs that are above the average in their categories over the five years, along with the associated drivers are as follows:

2023 Capital Project or Program Above 5 Year Average Investment Level	Underlying Reasons and Drivers
System Access – Joint Use	Joint Use is projected to increase for 2023/24 to accommodate the provincial rural broadband initiative and then return to more typical values thereafter. The underlying requirement is driven by external customer demand.
System Renewal - Planned OH line reconstruction - Voltage Conversion Projects	2023 is expected to be the final year to complete a long running (20~30 year) initiative of converting all 4.16kV to 12.47kV. 0$ are carried in 2024-2027. The main underlying drivers are safety and system reliability, as described in the DSP, Appendix A Material Investment Narrative, System.

	Renewal, OH Renewal – Voltage Conversions, sixth page (Exhibit 2, p295-96).
System Renewal - Replacement of distribution transformers	2023-2025 have significant spends whereas 2026-2027 is $0. This with respect to replacing any transformers containing PCBs by the 2025 federal regulatory deadline.
System Renewal - Planned Reconstruction of Underground vaults	2023 includes the replacement of a major vault in a downtown area, Manhole 123. The need is primarily with respect to public safety and described in the DSP, Appendix A Material Investment Narrative, System Renewal, UG Renewal – Vaults, fourth page (Exhibit 2, p321).

1

CCC – 38

Reference: Exhibit 2, App. C, App. H, pg.13

Question:

Table 0-2 provides the overall Asset Condition Assessment results by asset class based on Health Index Distribution (%).

Please recast Table 0-2 with the data expressed as Health Index Distribution asset quantities and provide an excel version of the table.

Response:

Please see the recast Table 0-2 with the data expressed as Health Index Distribution asset quantities.

Asset Class	Population	Units	Health Index				
			Very Good	Good	Fair	Poor	Very Poor
Distribution Assets							
Wood Pole	12,548	Qty	3153	5531	2699	590	573
Steel Pole	57	Qty	Age Only				
Overhead Primary Conductor	614.9	km	Age Only				
Underground Primary Cable	123	km	19	20	33	34	16
Pole-Mount Transformer	4806	Qty	1277	1187	1741	239	273
Pad-Mount Transformer	939	Qty	284	162	447	33	14

Submersible Transformer	468	Qty	89	26	225	91	37
Distribution Switchgear	26	Qty	12	12	2	0	0
Fused Switches	1536	Qty	Age Only				
Disconnect Switches	905	Qty	Age Only				
Substation Assets							
Power Transformer	26	Qty	3	7	15	1	0
Medium Voltage Switchgear (12.47-kV)	13	Qty	0	0	3	3	0
Medium Voltage Switchgear (4.16-kV)	3	Qty	Age Only				
Medium Voltage Switchgear (34.5-kV)	14	Qty	Age Only				
Station Service Transformer	17	Qty	Age Only				
Substation Battery	14	Qty	10	1	3	0	0
Substation Buildings	10	Qty	2	1	1	0	0
Station Fences	14	Qty	8	6	0	0	0
Station Riser Cables	94	Qty	0	56	11	1	0
TS Assets							
Power Transformer	8	Qty	0	3	5	0	0
34.5-kV TS Circuit Breaker	22	Qty	0	0	5	5	0
Station Battery	3	Qty	2	1	0	0	0
Station Fences	2	Qty	2	0	0	0	0
115-kV Switches	12	Qty	0	2	0	6	2

CCC – 39

Reference: Exhibit 2, App. C, App. H, pg.9, Table 0-1

Question:

With respect to poor condition assets with a Health Index Score of 0-30%, Metsco indicates the implications are the asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment.

a) Please explain how PUC uses this information to decide which assets to potentially replace and/or repair.
b) Please explain how PUC's proposed plans reflect the decision to refurbish the asset and the corresponding budget.

Response:

a) Assets identified as being in 'very poor' with a Health Index (HI) of 0-30% as described in Table 0-1 of the ACA are the highest priority candidates for replacement within the current 5-year COS period. To prioritize the investments, the methodology described in Section 5.3.3 of the DSP, p77-83 (Exhibit 2, p185-191) is applied with respect to the candidate assets. As described in 5.3.3.3.2, prioritizing is a risk management-based exercise and gives specific examples where deferral may be an option for some assets if the determined impact is low. Asset investment needs are weighed in this way, and ranked considering the factors identified in Table 5.3-1, p36 of the DSP (Exhibit 2, p144), and exemplified in Table 5.4-16, p128 (Exhibit 2, p236).

b) PUC uses the asset health information gained from the ACA and the methodologies described in answer CCC-39(a) above to essentially get from the 'needs' list for renewal to the 'to do' list for the DSP period. It explores solutions and estimates associated costs for those solutions. The goal is to seek the optimum balance i.e.: minimum total cost point as illustrated graphically in Figure 5.3-48, p77 of the DSP (Exhibit 2, p185). The process and methodology, and all the many factors considered are illustrated in Figure 5.3-1, p38 of the DSP (Exhibit 2, p146).

CCC – 40

Reference: Exhibit 2, App. C, App. H, pg. 90-95

Question:

Metsco provides several recommendations for PUC. Please provide PUC's response to each recommendation including timelines.

Response:

In response to METSCO's ACA recommendations, PUC has, or plans to take the steps summarized in the table below:

Recommendation	PUC Action/Response	Timelines
Asset Intervention Strategies (replacements, refurbishments, enhancements) – long term planning, bundling of projects to achieve economies	These processes and strategies are already in place within the Engineering and Planning groups; continuous improvement in these areas will be achieved by setting aside time specifically to plan, create written strategies and plans, continue to train staff, and research evolving industry technologies and resources	Ongoing, continuous improvement
Health Index Improvements – adding conditional parameters to improve HI formulations to continually improve the ACA framework over long term	During this COS cycle, updates to GIS platform from Geometric Networks to Utility Networks, add data registers to any existing forms and registers to allow collection of additional recommended information	GIS within this COS cycle, data enhancement ongoing with additions to existing forms and processes for 'low hanging fruit', the balance through continuous improvement thereafter
Data Collection Improvements – improved data collection, more granular data collection	During this COS cycle, updates to GIS platform from Geometric Networks to Utility Networks, add data registers to any existing	GIS within this COS cycle, data enhancement ongoing with additions to existing forms and processes for 'low hanging fruit', the balance

	forms and registers to allow collection of additional recommended information	through continuous improvement thereafter
Data Collection Improvements – Full 115kV Transmission Lines assessment	Scheduled and budgeted for	This COS cycle

1

CCC – 41

Reference: Exhibit 2, App. C, App. H

Question:

Please discuss any changes in project prioritization in the proposed capital plan due to the results of the ACA.

Response:

A formal asset condition process has been the key source of information that informs and drives the asset investment for the past two COS cycles. Although the current ACA differs somewhat in that it has more granularity and data than the plan in the previous cycle, it has not identified any need for dramatic change or to pivot and change the priority of projects for this COS cycle. What has changed is that a number of critical priorities have been addressed due to being well informed and are now behind us. And new more critical priorities for this COS cycle and the future cycles are coming into cleared sight for planning.

HI improved to a balanced HI and risk level 2018-2022:

- Voltage conversion program for 4.16kV plant – now mostly retired
- Distribution station HI levels at a good level due to Subs 16, acceleration via SSG project

New targets of focus to improve HI and lower risk for 2023-2027 and beyond:

- Distribution transformers through PCB program
- Accelerated restricted wire replacement
- Underground vaults and cables
- 115kV transformer stations TS1, TS2 – identify long term renewal plan

Exhibit 4 – Operating Costs

CCC – 42

Reference: Exhibit 4

Question:

Please indicate whether the 2023 OM&A amounts include any costs related to COVID-19. If so, please set out those costs.

Response:

No, there are no COVID-19 related costs in 2023 OM&A.

CCC – 43

Reference: Exhibit 4

Question:

Please provide a complete list of all productivity initiatives and associated savings included in the 2023 OM&A amounts.

Response:

Please refer to OEB Staff-5.

CCC – 44

Reference: Exhibit 4, pg. 6

Question:

Please provide all budget directives provided to employees for the 2023 Rate Application. To what extent are employees required to embed productivity in the budgets?

Response:

Budget directives provided to employees for the 2023 COS Rate Application were:

- Non-labour expenses for all department budgets are built using previous year actuals, current year forecast and current year budgets as the base. Significant variances in spending from prior years must be explained.
- To identify and justify any new initiatives or positions not included in the 2018 COS.
- Labour rate increases of 2.0% for union and 3.0% for management.

For productivity embedded in the 2023 budget, please refer to OEB Staff-5.

CCC – 45

Reference: Exhibit 4, pg. 23

Question:

Please break out the $430,634 in Consultants Costs setting out the cost of each consultant/legal contract. Were these subject to an RFP process? If not, why not. Please indicate the nature of the costs identified as "Incremental operating expenses associated with staff resources related to this application". Why are these costs separately identified?

Response:

Please refer to OEB Staff-80(ii).

BLG, Metsco and Indeco were not subject to an RFP process as the consultants were experts in their field and had specific history and experience with PUC's last COS. PUC felt that the cost of updating past reports by using the same advisory was the most cost-efficient vendor selection for this COS. BDR was selected though an RFP process.

Incremental operating expenses associated with staff resources related to this application are specific services provided by PUC Services staff in the application preparation work. This is separated from the annual ongoing services provided for purposes of the COS rate application cost deferral over 5 years.

CCC – 46

Reference: Exhibit 4, pg. 28

Question:

PUC has added a System Operations Engineer position in support of the SSG Project. Are the costs of this employee included in the overall SSG cost/benefit analysis? If not, why not?

Response:

Yes, the System Operations Engineer position is included in the overall SSG cost/benefit analysis.

CCC – 47

Reference: Exhibit 4, pg. 23 and 28

Question:

The approved regulatory costs for the previous application were $397,894. What were the actual costs? Please explain the significant increase in regulatory costs for 2023.

Response:

The costs are shown in Chapter 2 Appendices, tab 2-M. The increase in 2023 is due to the additional Regulatory position.

CCC – 48

Reference: Exhibit 4, pg. 34

Question:

Please explain the rationale for the 5% increase in Management Salaries in 2022. What is the increase in 2023? Does it relate to salaries alone or benefits as well?

Response:

Please refer to VECC-33(a). The management salary increase for 2023 is forecasted to be 3.0% and is applied to base salaries only. Benefits are applied per the rates as set out by the benefit provider that is awarded through a tendering process.

Environmental Defence (ED) Interrogatories

Exhibit 2 – Rate Base

ED – 1

Reference: Distribution System Plan

Questions:

a) Please describe how PUC sizes new equipment to ensure it will be able to handle the future load from electrification.
b) For the three largest capital spending items in the distribution system plan, please provide the following:
    i. What is the approximate threshold of electric vehicle penetration (%) in the relevant area at which point an additional upgrade would be required to the proposed investment?
    ii. What is the approximate threshold of the percentage of customers that electrify their fossil fuel heating with high-efficiency cold climate heat pumps in the relevant area at which point an additional upgrade would be required to the proposed investment?
    iii. What is the approximate threshold of the percentage of customers that electrify both their vehicles and fossil fuel heating in the relevant area at which point an additional upgrade would be required to the proposed investment?

These questions will require a number of assumptions to be made to provide an answer. Please make and state those assumptions as necessary. To address uncertainties, please state all caveats and/or provide a range of possible figures. An order-of-magnitude answer on a best-efforts basis is sufficient.

Response:

a) Please refer to the DSP section 3.2.4 and 3.3 where methodology information is available (Exhibit 2, p85-91). Section 4.1.1 of the DSP also states that "PUC Distribution's distribution system has adequate capacity to connect all anticipated loads and generation customers during the next five-year period. Currently, there are no applications in queue from distributed generation customers waiting to be connected to the grid under any

IESO REG programs; and all previous requests received to date have been successfully connected to the system."

With respect to being able to handle the future load from electrification, DER and EVs, PUC has taken the following approach for the COS period. Much of the PUC distribution system was built out with capacity based on electric heating promoted in the 1960s and 1970s when the city population peaked around 81,000. From the 1980s through present where the population is closer to 75,000, there has been a decline in load of approximately 0.5% per year over the 40 years due to promotion of natural gas heating, accompanied by CDM initiatives. In order to support electrification, DER and EVs for the next 5-year period, PUCs strategy is to leverage the freed up capacity from the aforementioned load decline. Depending upon the acceleration of adoption of these new technologies, a different strategy may be required in the longer term.

Additionally, PUC's design philosophy as it builds out and renews stations is to take a modular/flexible approach with a standardized substation. Being a smaller municipality, and given its relatively low load density, PUC has taken a strategy of using a standard design and 20MVA size for all stations equally across its service territory. Capacity is then matched to demand by adjusting the location of the stations to match past, current, and anticipated future load. The 34.5kV supply lines and 12kV outgoing lines throughout the distribution system are highly looped, so the ability exists to move and rebalance load as growth happens in particular areas.

Further functionality for analysis and planning is available through having data available from smart meters, SCADA telemetry, and our forthcoming SSG ADMS functionality to conduct comprehensive periodic load rebalancing and future buildout planning.

Finally, as PUC has built out and renewed its distribution system over the past 10 years, modern microprocessor-based protection systems and ethernet-based fibre networking has been established. As of last year, all 34.5kV and 12kV stations in the system have had these upgrades and are fully ready to support automation, reverse power flow and distributed renewable energy integration. In fact, PUC is currently operating with approximately 63MW of embedded solar generation and 7MW/MWh of battery storage.

b) To respond to the request to select 'the three largest capital spending items in the distribution system plan,' a number of projects have been excluded as they do not directly apply to the question being asked because they do not pertain to the circuits of the distribution system (eg: Buildings, Tools, GIS, pole replacements, transformer stations). Based on the projects identified for the test year in Table 5.4-15 on page 127 of the DSP, only one project was believed to be applicable for selection; OH Renewal – Voltage Conversion ($864k)

i. The Voltage Conversion area is described in the DSP, Appendix A Material Narrative entitled OH Renewal – Voltage Conversion. This area involves 82 customers, primarily residential. The project will involve the replacement of 4.16kV transformers to 12.47kV as well as overhead primary conductors. Transformation is sized in accordance with USF standards and EV capacity in accordance with those guidelines is taken into account. Furthermore, transformers purchased and installed have the ability to withstand 150% of nameplate rating without deterioration indefinitely. If they become too small to serve an area, they can almost always be swapped out for a unit one or two sizes larger and PUC's primary and secondary networks are sized to standard size conductors and capacity exists to support growth as well. Generally, on PUC's network, it is believed that electrification will not become an issue until reaching a threshold of 15-25% load.

ii. PUC expects if 50% of customers in the project area were to convert to heat pumps, that transformers may need to be swapped out units from stores for one size larger, but circuit conductors and overall system capacity would still be adequate. However, circuit conductors and overall system capacity could support 100% after the transformer swaps were completed.

iii. This could be fully accommodated with transformer swaps identified in (ii).

ED – 2

Reference: Distribution System Plan

Question:

a) We are trying to explore the ballpark impact on unit costs that might arise from possible large increases in demand from electrification. If annual and peak demand were to double over the next decade, but the load factor were to remain constant, would the additional distribution infrastructure costs lead to increases or decreases in unit distribution costs (i.e. total distribution costs per MW peak demand or total distribution costs per MWh of annual demand)? Please explain why and comment as best as you can on the order of magnitude. We understand that no concrete answer can be provided – directional and order of magnitude commentary is sufficient.

Response:

a) PUC is unable to provide the requested information as it has not performed research or analysis on a doubling of annual and peak demand over the next decade, even on a preliminary basis, and is outside the scope of the issues list in this proceeding.

ED – 3

Reference: Distribution System Plan

Questions:

a) What percent of PUC's customers are on restricted feeders?
b) Please provide a list of investments in the DSP that PUC considers as potential candidates for a non-wires alternative (NWA), including CDM.
c) Will PUC consider implementing any cost-effective NWAs prior to the expiry of its DSP in 2027?
d) If PUC implements an NWA in lieu of a currently planned capital project, how would it account for the change in costs, including any migration of capital costs to operating costs?

Response:

a) Although PUC does not have exact loading information to determine exact numbers of customers on restricted feeders, it can state generally that it is the exception to the rule so would be only in the order of two percent or less. The PUC network is built out with standard conductor sizes, has experienced negative load growth as described in response to question 1, has a highly looped system, and has a low load density across almost all of its service area.

b) All projects for the DSP period are summarized in Table 5.4-11 of the DSP, p109 (Exhibit 2, p217). Of those the following would have elements of MWA or CDM as bulleted here:
    i. Voltage conversion – reduction in I^2R line losses, transformation losses
    ii. Restricted Conductor – reduction in I^2R line losses
    iii. Transformers (PCBs) - reduction in transformation losses
    iv. Outside of the COS application, the SSG project underway includes VVO with expected system wide loss reductions.

c) Although PUC did not discover any opportunities for NWA when planning for the forecast period, PUC Engineers always consider this as a design possibility at all stages of planning. Most of this 5-year period of the COS involves the direct replacement of end-of-life assets where NWAs solutions could not be found.

d) PUC has not explored this aspect to date but would expect to do so should it propose a significant NWA solution.

ED – 4

Reference: Distribution System Plan

Questions:

a) Please describe and itemize all proposed spending to enable the implementation of DER's by DER's customers.
b) The market for DERs is rapidly changing, as are the regulatory processes and technology for connecting them to the grid. If PUC decides between now and 2027 that additional DER-enabling investments should be made before the end of the DSP, which are not part of the proposed DSP, how would PUC cover those costs?

Response:

a) All projects and programs that involve renewal of wires and transformation generally achieve this as described in some of earlier answers to Environmental Defense above. Specifically, these include, from Table 5.4-11, p109 of the DSP (Exhibit 2, p217):
    i. Voltage Conversion
    ii. Restricted Conductor
    iii. General Asset Renewal
    iv. Transformers, PCBs

b) PUC believes its existing network is ready for considerable further penetration of DER without upgrade and currently has a penetration rate of 70MW. Our response to ED-1(a) provides more detail. If additional capacity was required, PUC would consult the market rules and the Distribution System Code for guidance on technical requirements and for guidance on permissible methods to recover any costs e.g.: expansions, enhancements, etc.

ED – 5

Reference: Distribution System Plan

Questions:

a) Please file a copy of any reports in PUC's possession containing forecasts for the numbers of electric vehicles in PUC's service area.
b) Please file a copy of any reports in PUC's possession on the impacts of electric vehicles on (i) utility revenue and (ii) utility costs.
c) What is PUC's best estimates of the number and percent of electric cars in its service area total and incremental between now and 2030?
d) Please describe all steps that PUC is taking or considering to encourage customers to charge their cars at off-peak times.
e) Please describe all steps that PUC is taking or considering to encourage customers to use their car batteries to off-set the peak load of their building via bi-directional chargers.
f) Please estimate the impact on PUC's revenues and costs as a result of electric vehicles over 2023-2027. Please consider whether PUC will experience additional revenues than costs as described in the following Synapse energy study: https://www.synapse-energy.com/sites/default/files/EVs-Driving-Rates-Down-8-122.pdf. Please explain the response.
g) What investments is PUC making over 2023-2027 to accommodate an expansion of electric vehicles? Please describe these and provide the dollar total.
h) Does a residential customer need to notify or seek approval from PUC before installing a high-speed electric vehicle charger? Please explain and provide any relevant excerpts from the relevant document containing said requirement.
i) Does a residential customer need to notify or seek approval from PUC before installing a high-speed bi-directional electric vehicle charger (under 10 kW) that does not export to the grid? Please explain and provide any relevant excerpts from the relevant document containing said requirement.
j) Can PUC require a residential customer to make a financial contribution toward distribution system upgrades necessary to allow the customer to install a high-speed one-directional EV charger? If yes, would PUC do so? Please explain.
k) Can PUC require a residential customer to make a financial contribution toward distribution system upgrades necessary to allow the customer to install a high-speed bi-directional EV charger (non-exporting)? If yes, would PUC do so? Please explain.
l) Generally speaking, what protective devices would be needed for a residential customer to install a bi-directional EV charger that is not meant to export to the grid to ensure that there is no damage in the event of a grid outage?
m) Is PUC obligated to undertake the upgrades necessary for residential customers to install EV chargers if they choose to do so?
n) How many electric vehicles will PUC buy over 2023-2027?

o) How many electric vehicle chargers will PUC buy over 2023-2027?

Response:

a) PUC is not in possession of and is not aware of any such reports for its service area.

b) Although it has kept abreast of the development of EVs through participation in associations and online resources, PUC is not in possession of any such reports on the impacts of electric vehicles on (i) utility revenue and (ii) utility costs.

c) PUC does not have sufficient data on either the number or percentage of electric cars in its service area, total or incremental, to provide an estimate between now and 2030. The information requested requires a level of effort that greatly outweighs the probative value of the information, if any, and may be outside the scope of this proceeding.

d) PUC is doing customer outreach via social media and its website to encourage customers to transition to electric vehicles and inform on the costs associated with charging at different times. PUC has planned further outreach to show customers that overnight or off-peak times are the most cost-effective and convenient time to charge. Please see the following link:
https://ssmpuc.com/ev/

e) At this current time with no direction from ESA on how to safely accomplish bi-directional charging and since most automotive manufacturers are not currently allowing bi-directional charging (other than Ford, specifically the F150), PUC has not been encouraging the use of bi-directional charging.

f) PUC does not expect additional revenues from the Residential customer class in relation to EV's since it charges fully fixed rates. Any EV's that are being charged by General Service customers would cause a slight increase to PUC's volumetric component of its distribution revenue. However, PUC believes that currently and over the next 5 years, this amount would be minimal since there is a low adoption rate for EV's within the Northern Ontario climate. Additionally, if PUC does experience higher than expected EV adoption over the next 5 years, additional costs for system upgrades to accommodate additional load in certain parts of the service territory may be required. PUC will continue to monitor its system needs and adjust as required in consideration of EV adoption rates.

g) To support integration of EV, PUC has not proposed any incremental investment over the COS period, however it has applied some of the system planning and design considerations identified in ED-1(a) and made the associated very modest incremental investments to do so over the past approximately 10 years.

h) No, a residential customer does not need to explicitly advise PUC if they are installing a charger. Existing processes address the matter on the system at a local feeder level in that; (i) if the charger does not prompt the need for the customer to do a service upgrade under OESC rules, then the PUC upstream secondary infrastructure should be adequate to support, and (ii) if the charger does prompt the need for the customer to do a service upgrade under OESC rules, then PUC would update any secondary and transformation to suit the new service sizing, which includes an allowance for chargers in the USF standards that are applied.

i) PUC does not have a special requirement or require customers to seek approval. PUC's understanding is that all such CSA listed EV products, similar to anti-islanding for solar inverter chargers, have technology to not generate back to the grid without the presence of a utility supply 60Hz signal present. There is therefore no risk of back feed to create a hazard for utility workers. Furthermore, all PUC feeders are equipped with modern microprocessor-based protections configured to allow for embedded generation on the feeders.

j) For residential customers, PUC would treat any expansion requirements with the same rules and charges it applies to a customer requesting a service upgrade for any other reasons. If required, the costs of any secondary or primary distribution system equipment enhancements would be borne by the utility and charged to its Customer Demand – Services & Subdivisions capital account.

k) Please refer to "j" above.

l) Please refer to "i" above.

m) PUC's interpretation of the DSC and relevant regulations has led us to the approach identified in "h" above.

n) It is PUC's goal to replace as many as light duty vehicles as possible with EV's. However, it has been a challenge sourcing the replacements of our light duty vehicles with EV's. Our goal remains to replace up to 20 light duty vehicles with EV's, but this is entirely dependent on the availability of EV's within our service territory.

o) PUC has purchased the required chargers for EV's in 2022, utilizing an NRCan 50% funding contribution.

ED – 6

Reference: Distribution System Plan, 5.3.2.1.3

Questions:

a) Does PUC quantify and consider the potential value of distribution loss reductions for different options when procuring equipment (e.g., transformers) and deciding on the details of demand-driven capital projects (e.g., the type and sizing of conductors)? If yes, please explain how and provide documentation detailing the methodology used.
b) If PUC is considering the value to its customers of distribution loss reductions for planning purposes, how does it calculate the dollar value ($) of said loss reductions (kWh)? Is the value calculated based only on the HOEP or on all-in cost of electricity (e.g., including the GA)?
c) Further to the above question, Hydro Ottawa and Burlington Hydro use the all-in cost of electricity. If PUC's practice differs, please explain whether there are aspects of its system that would justify this.
d) Please provide a table showing PUC's annual historic (past 5 years) and forecast (future 5 years) losses as a percent of annual consumption and as a ratio to the peak demand.
e) What would a reasonable target be for PUC's average losses over 2023-2027 as a percent of annual consumption?
f) Has PUC completed studies to determine cost-effective measures to reduce losses? If yes, please file those.

Response:

a) PUC does consider losses in the purchase of transformation and its tender documents contain a loss calculation that aims to buy the best value formula. An excerpt from the tender document follows.

> **LOSS EVALUATION**
> The manufacturer shall note that in evaluation of the tenders, the Owner will calculate the present value of the quoted transformer losses (in Canadian dollars) and add it to the quoted price using the following formula:
>
> C = 5.9 L1 + 1.7 L2
>
> Where:
> C = cost added to transformer price to determine total value;

L1 = No-load loss (W); and
L2 = Transformer Full load-loss at 85 deg. C (W).

If measured losses exceed guaranteed values, the above formula will be used to determine penalty to be paid by manufacturer.

PUC also has considered losses in its execution of a voltage conversion program from 4.16kV to 12kV which is expected to be completed by 2023.

b) PUC has not analyzed the impacts at this level of detail.

c) PUC cannot comment on this question as it does not analyze the impacts of losses at the level of detail presented in "b".

d) PUC has provided a table showing the past 5 years historical losses as a percent of annual consumption and a ratio to the peak demand in the table below. PUC does not have a 5-year forecast of these same numbers as it does not forecast peak demand.

	2017	2018	2019	2020	2021
Total Consumption	652,970,471	666,736,298	660,423,172	640,745,749	628,757,114
Losses	30,427,958	33,038,371	28,477,358	27,113,550	24,438,602
Peak Demand	125,843	128,698	132,939	112,941	111,904
Loss % vs Annual Consumption	4.66%	4.96%	4.31%	4.23%	3.89%
Loss Ratio Vs Peak Demand	241.8	256.7	214.2	240.1	218.4

Please note PUC's loss factor is calculated as total consumption with losses divided by total consumption without losses which gives a different value than that shown in the table above. Please refer to the chapter 2 Appendices 2-R for the calculation.

e) PUC estimates its test year loss factor which is 4.62% based on historical loss factor information but PUC does not forecast any future-years loss factor.

The SSG Project, already filed with the OEB, approved and under construction proposes the use VVO to achieve loss reductions in the order of 2.5%. Other than SSG, no other studies or projects are being considered presently and no additional reports are available.

ED – 7

Reference: Distribution System Plan, s. 5.3.5 (Smart Grid Project)

Question:

a) Table 5.3-28 provides the NPV of annual net benefits and the NPV of projected reliability benefits. Is there overlap between the tables? Please provide the NPV of all quantifiable benefits, including reliability benefits, and a breakdown of each item included therein.
b) Please provide an update of PUC Undertaking Responses - JTC1.8 from the smart grid ICM case, which calculated the 10-year carbon price savings of avoided GHG emissions, accounting for Ontario's plans to increase gas generation.

Response:

a) There is no overlap between the tables. The NPV of annual benefits is specifically related to VVO consumption savings and the NPV of projected reliability benefits is from the Distribution Automation. The breakdown of each item included in the NPV of Annual net benefit to customers is presented in SEC-12 from PUC's Sault Smart Grid ICM Application (EB-2018-0219/EB-2020-0249). This has been attached as Appendix IR12 –PUC SSG ICM IRR's_SEC 12_20210126.

b) Updated GHG and carbon tax values were calculated using same process as above reference with latest available data per IESO Annual Planning Outlook (2021) and The Atmospheric Fund (TAF) Ontario Emissions (2021) reports. The IESO forecast for GHG is about 7.5% higher in the 2021 report as compared to the 2020 report for the period (2023-2032). The TAF marginal emission factor has come down from 4.32 to 3.97.

Federal Carbon Tax Update

1. Minimum National Carbon Pollution Price Schedule (2023-2030)

Canada's minimum national price on carbon pollution for explicit price-based systems (i.e., systems that directly set a price on emissions) is $65 per tonne of GHG emissions [3] calculated in carbon dioxide equivalent (CO_2e) in 2023, and increases by $15 per year to $170 per tonne CO_2e in 2030 according to the following schedule:

Year	2023	2024	2025	2026	2027	2028	2029	2030
Minimum Carbon Pollution Price ($ CAD/tonne CO_2e)	$65	$80	$95	$110	$125	$140	$155	$170

https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html#toc3

			2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Carbon Tax/tonne			$ 65	$ 80	$ 95	$ 110	$ 125	$ 140	$ 155	$ 170	$ 170	$ 170
GHG using AEF												
10 yr	11,319	TCO2e	920	854	937	1,205	1,189	1,198	1,185	1,258	1,326	1,248
10 yrs Carbon Tax	$ 1,500,971		$ 59,781	$ 68,346	$ 89,014	$132,522	$148,660	$167,666	$183,604	$213,791	$225,416	$212,172
GHG using MEF												
10 yr	44,910	TCO2e	3,649	3,390	3,718	4,780	4,719	4,752	4,700	4,990	5,261	4,952
10 yrs Carbon Tax	$ 5,955,466		$237,197	$271,179	$353,183	$525,815	$589,843	$665,254	$728,495	$848,266	$894,392	$841,842

The GHG calculation using AEF (annual GHG over Annual System Energy) results are:
GHG savings 10 years (2023-2032) 11,319 TCO2e with AEF
Carbon tax savings 10 years (2023-2032) $1,500,971 with AEF

Using a Marginal Emissions Factor (MEF):
GHG savings 10 years (2023-2032) 44,910 TCO2e with MEF
Carbon tax savings 10 years (2023-2032) $5,955,466 with MEF

ED – 8

Reference: Distribution System Plan

Question:

a) Please review the Sustainable Brooklin project proposed by Elexicon Energy in EB-2022-0024. Would PUC consider pursuing a similar project between 2023 and 2027?

Response:

a) PUC has reviewed the report. Although its system is currently not experiencing any constraints from a loading perspective to presently warrant such an investment, this would certainly be a method PUC would want to explore in future should it be faced with similar circumstances as Elexicon Energy.

ED – 9

Reference: Distribution System Plan

Questions:

For all of the below questions, please provide an answer on a best-efforts basis and please make and state any assumptions and caveats as necessary.

a) Please provide any analysis that PUC has produced or reviewed to examine heat pumps as a replacement for resistance electric heating as a way to reduce distribution costs (e.g. as part of an NWA).
b) Please complete the following tables

Response:

a) PUC does not have any analysis that examines heat pumps as a replacement for resistance electric heating.

b) Please complete the following table:

	2022	2027
Total Customers		
Residential	30,237	unknown
Commercial (GS<50)	unknown	unknown
Industrial (GS>50)	unknown	unknown
Customers with Electrical Space Heating		
Residential	unknown	unknown
Commercial	unknown	unknown
Industrial	unknown	unknown
Annual Consumption (kWh) for Resistance Space Heating for Average Customer		
Residential	unknown	unknown
Commercial	unknown	unknown
Industrial	unknown	unknown
Peak Demand (kW) for Resistance Space Heating for Average Customer		
Residential	unknown	unknown
Commercial	unknown	unknown
Industrial	unknown	unknown
Annual Consumption (kWh) for Resistance Water Heating for Average Customer		
Residential	unknown	unknown
Commercial	unknown	unknown

Industrial	unknown	unknown
Peak Demand (kW) for Resistance Water Heating for Average Customer		
Residential	unknown	unknown
Commercial	unknown	unknown
Industrial	unknown	unknown

Please complete the following table:

Electricity Use – Typical Customer After Conversion to Heat Pumps									
	Average Annual Electricity Consumption – Resistance Heating (kWh)			Average Annual Electricity Consumption (ccASHP & HPWP, HSPF Region 5=10[3]) (kWh)			Average Annual Electricity Consumption (GSHP & HPWP, sCOP=5) (kWh)		
	Total – Space/Water	Space Heating	Water Heating	Total – Space/Water	Space Heating	Water Heating	Total – Space/Water	Space Heating	Water Heating
Average or Typical Single-Family Residential Customer	unknown	unknown	unknown	unknown	unknown	unknown	unknown	unknown	unknown

Please complete the following table:

Winter Peak Demand – Typical Customer After Conversion to Heat Pumps									
	Average Peak Demand – Resistance Heating (kW)			Average Peak Winter Demand (ccASHP & HPWP, HSPF Region 5=10[4]) (kW)			Average Peak Winter Demand (GSHP & HPWP, sCOP=5) (kWh)		
	Total – Space/Water	Space Heating	Water Heating	Total – Space/Water	Space Heating	Water Heating	Total – Space/Water	Space Heating	Water Heating
Average or Typical Single-Family Residential Customer	unknown	unknown	unknown	unknown	unknown	unknown	unknown	unknown	unknown

Please complete the following table:

Summer Peak Demand – Typical Customer After Conversion to Heat Pumps			
	Average Peak Demand – Traditional Central AC (kW)	Average Peak Winter Demand (ccASHP & HPWP, HSPF Region 5=10[5]) (kW)	Average Peak Winter Demand (GSHP & HPWP, sCOP=5) (kWh)

[3] Equivalent to ~sCOP=2.9 (2.96516)
[4] Equivalent to ~sCOP=2.9 (2.96516)
[5] Equivalent to ~sCOP=2.9 (2.96516)

	Total – Space/Water	Space Cooling	Water Heating	Total – Space/Water	Space Cooling	Water Heating	Total – Space/Water	Space Cooling	Water Heating
Average or Typical Single-Family Residential Customer	unknown	unknown	unknown	unknown	unknown	unknown	unknown	unknown	unknown

Please complete this table of cooling efficiencies:

i) It is unknown if the question is asking for SSM specific data or in general.
ii) All data taken from the Energy star website, therefore standard systems are of higher efficiency.
iii) At this time EnergyStar does not show hybrid systems separately.
iv) At this time Energystar does not have a specific category for cold climate heat pump

Cooling Efficiencies of Various Equipment Types			
		SEER	EER
Central air conditioners	Average of current stock (best estimate, PUC customers or Ontario average)	unknown	unknown
	Standard unit	15	12
	Energy Star rated	16	12.5
	Energy Star – Most efficient of 2021	18	13
Air source heat pumps	Standard unit	15	12
	Energy Star rated	16	12.5
	Energy Star – Most efficient of 2021	20	12.5
Air source heat pumps in hybrid systems (if different)	Standard unit	unknown	unknown
	Energy Star rated	unknown	unknown
	Energy Star – Most efficient of 2021	unknown	unknown
Ground source heat pumps – closed loop	Standard unit	19	18
	Energy Star rated	37	33.8
	Energy Star – Most efficient of 2021	37	33.8
Ground source heat pumps – open loop	Standard unit	22	21
	Energy Star rated	64	56
	Energy Star – Most efficient of 2021	64	56
Cold climate heat pumps – variable speed	Standard unit	unknown	unknown
	Energy Star rated	unknown	unknown
	Energy Star – Most efficient of 2021	unknown	unknown

School Energy Coalition (SEC) Interrogatories

Exhibit 1 - Administrative

SEC – 1

Reference: Exhibit 1

Question:

Please provide a revised version of the RRWF to reflect the OEB's 2023 cost of capital parameters.

Response:

PUC has filed a revised version of the RRWF which reflects the OEB's 2023 Cost of Capital parameters with these IR responses.

SEC – 2

Reference: Exhibit 1

Question:

Please provide copies of all benchmarking studies, reports, and analyses that the Applicant has undertaken or participated in since its last rebasing application, that are not already included in the application.

Response:

Throughout the application and the IR responses, PUC believes it has filed all required documents/studies/reports etc. undertaken or participated in since it's last rebasing application.

SEC – 3

Reference: Exhibit 1

Question:

Please provide a copy of all documents that were provided to the Board of Directors in approving the underlying budgets contained in this application.

Response:

Please refer to CCC-2.

SEC – 4

Reference: Exhibit 1

Question:

Please provide details of all productivity and efficiency measures the Applicant has undertaken since its last rebasing application in 2018. Please quantify the savings and explain how they were calculated.

Response:

Please refer to OEB Staff-5(a).

SEC – 5

Reference: Exhibit 1

Question:

Please provide details of all productivity and efficiency measures the Applicant plans to undertake in the test year. Please quantify the savings and explain how they were calculated.

Response:

Please refer to OEB Staff-5(b).

SEC – 6

Reference: Exhibit 1

Question:

Does the Applicant have a corporate scorecard or similar document? If so, please provide a copy for each year beginning in 2018. If the Applicant does not, please explain how its Board of Directors measures the company and management's performance.

Response:

PUC does not have a corporate scorecard. Instead, PUC's Board of Directors relies on the targets and metrics measured by the OEB's scorecard for the utility. In addition, PUC has a Management Services agreement with PUC Services for the management and operational oversight of the PUC. The Board of Directors of PUC relies on the corporate scorecard of PUC Services to measure the performance of the management staff.

SEC – 7

Reference: Exhibit 1, pg.95

Question:

The Applicant states: "In 2023, PUC is projecting higher actual costs due to the reporting required for Sub-16 ICM and SSG ICM. Both ICM's are reported as capital expenditure in 2023 as per the RRR filing requirements and therefore inflate PUC's actual costs for that year. PUC expects its actual costs to stabilize in 2024, thus bringing back down its efficiency percentage. Additionally, it should be noted that PUC has additional costs and savings that are not accounted for in the PEG model.":

a) Please confirm that if the ICM costs that are reported as capital expenditures in 2023 were recorded in the year they were incurred, the Applicant's actual costs for those years would be higher, and its cost efficiency assessment (actual costs as compared to predicted costs) would have been higher.
b) Please explain, and quantify, the additional costs and savings the Applicant believes are not accounted for in the PEG model.
c) The Applicant has provided a 'revised cost efficiency percentage' removing a number of cost items from the actual cost calculation. Please provide a detailed breakdown of the adjustment made to actual costs and the rationale for each.

Response:

a) PUC can confirm this is an accurate statement.

b) The PEG model considers actual consumption and peak demand in the calculation of expected predicted costs in a given year. The PEG model does not take into account the dollar value of savings for customer from PUC's SSG project. Combined, these values can have a significant effect on the results of PUC's efficiency assessment. For example, using the 2020_benchmarking Forecast model_20221026, the following scenarios use a different combination of VVO consumption savings and cost of power in a given year and show the effects on PUC's 2023 efficiency result and the 3-year average used to determine PUC's Stretch Factor Group Ranking.

Scenario	Consumption Savings	Cost of Power	Efficiency Result	3 Year Average	Group
Default PEG Model	0.00%	-	12.00%	4.81%	3
1	4.00%	120,000,000	-4.05%	-0.71%	2
2	4.00%	90,000,000	-0.24%	0.72%	3
3	4.00%	70,000,000	2.53%	1.64%	3
4	2.00%	120,000,000	4.00%	2.13%	3
5	2.00%	90,000,000	6.00%	2.80%	3
6	2.00%	70,000,000	7.31%	3.24%	3

If PUC were to consider these same effects in 2024-2027, it would be much higher as those years PUC does not have the influx in capital spending that is required to be reported from its two ICM applications.

c) The only adjustment made to the PUC_2023 Benchmarking Forecast Model_20221026 was a reduction of energy consumption savings of $1,950,831 from the actual costs in row 158. This has been removed in the chart above for the row that says default PEG model. Therefore, by removing the $1,950,831 adjustment it results in a 12% efficiency result for 2023.

SEC – 8

Reference: Exhibit 1, Appendix B, pg.14

Question:

With respect to Applicant's financial budget and projections contained in its Business Plan, please explain why the Applicant is forecasting an ROE for each year between 2023 and 2027, below the deemed ROE amount. Please provide the underlying calculations for the projected ROE amount.

Response:

PUC is forecasting an ROE below the deemed ROE amount because new rates do not come into effect until May 1, 2023, and therefore PUC is earning revenue at a lower rate for 4 months of the year. Additionally, PUC has higher actual interest costs as compared to the interest included in revenue requirement, lowering PUC's actual ROE for 2023-2027.

Exhibit 2 – Rate Base

SEC – 9

Reference: Exhibit 2, pg.60

Question:

Please explain why the Applicant's Sub 16 true-up reconciliation is not the difference between the projected revenue collected versus an actual revenue requirement calculation, including half-year ruled applied to the year the project went in-service (2021). Regardless of your answer, please provide a calculation that provides such a reconciliation.

Response:

PUC has provided a revised Table 2-25A, with the option outlined by SEC. PUC would agree that this is a fair reconciliation of the Substation 16 true up and reflect the Net Book Value of Substation 16 assets brought into rate base in 2022.

Table 2-25A: Sub 16 Revenue Requirement Reconciliation (Revised November 28, 2022)

	2020	2021	2022	Total
Approved Revenue Requirement ($4.73M)	$213,870	$237,816	$237,816	$689,502
Revised Revenue Requirement ($6.02M)		$320,556	$356,932	$677,488
Projected Revenue Collection to April 30, 2023	$219,497	$283,220	$210,389	$713,107
			Refund (-) or Collection A-C	**$ (23,605)**
			Refund (-) or Collection (revised Nov 28, 2022) B-C	**$ (35,618)**

SEC – 10

Reference: Exhibit 2, pg.65

Question:

With respect to the Sault Smart Grid project:

a) Please provide an update on the project, including a copy of the most recent internal project update or similar document.
b) Please explain the relationship between the reduction in the NRCAN grant and the reduction on the gross project spending.

Response:

a) Please refer to the attached October staff report to PUC Board in Appendix IR13.

b) The SSG project is being planned and executed so as to not exceed the ICM net capital expenditure after NRCan contribution. The reduced NRCan funding has a direct impact in a need to reduce the gross project spending proportionally to maintain the same net of capital contribution project expenditure. See also CCC 17.

SEC – 11

Reference: Exhibit 2

Question:

Please provide a revised version of Appendix 2-AB on an in-service addition basis.

Response:

Appendix 2-AB is based on an in-service addition basis. 2022 is based on budgeted in-service additions and the amounts will not be known until year end.

SEC – 12

Reference: Exhibit 2, DSP, pg. 14-15

Question:

Please detail which actions listed in Table 5.2-3 are being undertaken by the Applicant.

Response:

None, all of these actions are the responsibility of the upstream transmitter, Hydro One.

SEC – 13

Reference: Exhibit 2, DSP, pg.29-30

Question:

Please explain the significant increase in unknown/other CI and CHI numbers in 2021.

Response:

PUC experienced an unusual number of outages where a root cause was not discovered that led to additional patrolling of equipment and power lines before closing in the circuits. There is a good probability that these outages were caused by tree or animal contacts but after patrolling the lines, no clear evidence of such was found. Weather, habitual patterns of animals, and vegetation growth vary year to year which can cause an abundance or lack of animal and tree related outages activity.

SEC – 14

Reference: Exhibit 2, DSP, pg.72-75

Question:

The Applicant has reproduced data collection recommendation tables from the METSO Asset Condition Assessment. Please explain, which recommendations the Applicant plans to implement and the timeline to do so. If there are recommendations the Applicant does not intend to implement, please explain why not.

Response:

Please refer to CCC-40.

SEC – 16

Reference: Exhibit 2, DSP, Pg. 92-96

Question:

With respect to the VVO Linkage to ROE proposal:

a) [p.96] With respect the table:
   i. Please update the table for the OEB's 2023 approved ROE.
   ii. Please recast the '2023 VVO linked ROE' and Reduction in ROE line to show the impact, not compared to the Applicant's overall ROE, but ROE associated with the Sault Smart Grid project only.

b) [p.95] The Applicant states that "PUC will measure VVO consumption (kWh) savings on an annual basis. The methodology for calculating VVO savings is being developed in collaboration with PUC's SSG contractor which will be used as an input. The very top line of Table 5.3-29 shows assumption of what that input might be for the purposes of this calculation and the VVO linkage to ROE." Please confirm that the Applicant is not seeking approval for a specific methodology for calculating VVO savings. If confirmed, please explain when the OEB will assess the methodology.

c) [p.95] Please provide potential methodologies being considered for calculating the VVO consumption savings.

d) [p.95] Please provide a breakdown of the calculation of each aspect of the change in revenue requirement amounts in the table.

e) [p.95] Please confirm the proposal would operate annually until at least the Applicant's next rebasing application. If confirmed, please explain what numbers in the table would change in each year after 2023, and on what basis.

Response:

a)
   i. Table 5.3-29 which shows the VVO linkage to ROE calculation has been updated in OEB Staff-27. OEB Staff-27(b) shows a detailed explanation of the how the calculation was completed for the existing table. Then OEB Staff-27(d) shows the table updated with 2023 ROE of 9.36%.

ii. PUC has updated Table 5.3-30 to include the reduction in ROE on SSG assets only for the original submission and the reduction in ROE on SSG assets based on the 2023 ROE of 9.36%. This first revision of Table 5.3-30 shows the original submission update to include 2023 VVO linked to ROE of SSG assets only and reduction in ROE of SSG assets only.

Table 5.3-30: Accounting Entries for the DVA in Example Scenario Revision 1

Journal Entry							
		Top of Dead Band	**Bottom of Dead Band**	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
4080 Distribution Revenue				$57,124		$836,065	
1508 Other Regulatory Assets, Sub-account Incremental SSG Costs				$57,124		$836,065	
to record the reduction in savings to PUC customers.							
1508 Other Regulatory Assets, Sub-account Incremental SSG Costs					$30,846		$836,065
4080 Distribution Revenue					$30,846		$836,065
to record the reduction in savings to PUC customers.							

VVO Linkage to ROE							
		Top of Dead Band	**Bottom of Dead Band**	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
2023 Board Approved Rate Base		$ 136,089,187	$ 136,089,187	$ 136,089,187	$ 136,089,187	$ 136,089,187	$ 136,089,187
2023 Board Approved Net Income		$ 5,095,179	$ 5,095,179	$ 5,095,179	$ 5,095,179	$ 5,095,179	$ 5,095,179
2023 VVO linked Net Income		$ 5,095,179	$ 5,095,179	$ 5,038,055	$ 5,126,025	$ 4,259,114	$ 5,931,244
2023 Board Approved ROE		9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
2023 VVO linked ROE		9.36%	9.36%	9.26%	9.42%	7.82%	10.90%
Reduction in ROE		0.00%	0.00%	-0.10%	0.06%	-1.54%	1.54%
Additions to Table							
2023 VVO Linked to ROE of SSG Assets Only		9.36%	9.36%	8.72%	9.71%	0.00%	18.72%
Reduction or Increase in ROE of SSG Asset only		0.00%	0.00%	-0.64%	0.35%	-9.36%	9.36%

The second revision of Table 5.3-30 updates the table for the 2023 ROE of 9.36%. Please note that in updating the ROE to 9.36% it changes the maximum upside/downside to $836,065 as shown in Appendix IR1 – Additional Revenue from increased SSG Asset Base. It also changes the additional revenue requirement in the table shown in Staff-27(d) from $1,755,460 to $1,986,663. In order to hit the maximum downside cap, refunding customers $836,065, PUC would have to achieve 0% VVO savings. Additionally, PUC would need to share in difference of annual net benefit to customer of 51/49 in order to fully refund the $836,065. This same ratio has been applied to the maximum upside to make it symmetrical.

Table 5.3-30: Accounting Entries for the DVA in Example Scenario Revision 2

Journal Entry							
		Top of Dead Band	**Bottom of Dead Band**	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
4080 Distribution Revenue				$57,124		$836,065	
1508 Other Regulatory Assets, Sub-account Incremental SSG Costs				$57,124		$836,065	
to record the reduction in savings to PUC customers.							
1508 Other Regulatory Assets, Sub-account Incremental SSG Costs					$30,846		$836,065
4080 Distribution Revenue					$30,846		$836,065
to record the reduction in savings to PUC customers.							

VVO Linkage to ROE							
		Top of Dead Band	**Bottom of Dead Band**	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
2023 Board Approved Rate Base		$ 136,089,187	$ 136,089,187	$ 136,089,187	$ 136,089,187	$ 136,089,187	$ 136,089,187
2023 Board Approved Net Income		$ 5,095,179	$ 5,095,179	$ 5,095,179	$ 5,095,179	$ 5,095,179	$ 5,095,179
2023 VVO linked Net Income		$ 5,095,179	$ 5,095,179	$ 5,038,055	$ 5,126,025	$ 4,259,114	$ 5,931,244
2023 Board Approved ROE		9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
2023 VVO linked ROE		9.36%	9.36%	9.26%	9.42%	7.82%	10.90%
Reduction in ROE		0.00%	0.00%	-0.10%	0.06%	-1.54%	1.54%
Additions to Table							
2023 VVO Linked to ROE of SSG Assets Only		9.36%	9.36%	8.72%	9.71%	0.00%	18.72%
Reduction or Increase in ROE of SSG Asset only		0.00%	0.00%	-0.64%	0.35%	-9.36%	9.36%

b) PUC is not seeking approval for the methodology in calculating VVO Savings. PUC has shown the methodology it will be using the in supplementary filing filed on October 26, 2022, as "Appendix H_Sault Smart Grid_Performance Metrics_OEB Order No.6_20221026". Contained within that document is Appendix A which describes the methodology that PUC will be using.

c) Please refer to the supplementary filing on the methodologies and targets as Appendix H to Exhibit 2 of the 2023 COS Application (EB-2022-0059) on October 26, 2022. Please also refer to OEB Staff-27.

d) Please refer to Appendix IR1 – Additional Revenue from increased SSG asset base for a detailed calculation of the revenue requirement included in table 5.3-29.

e) PUC can confirm that the proposal would operate annually until at least its next rebasing application, at which time the accumulated balance in the associated DVA would be brought forward for disposition. PUC filed a draft accounting order as Appendix B to Exhibit 9 in relation to the VVO linkage to ROE proposal where the mechanics for the table calculations are explained in detail. Only the VVO savings would change from one year to the next.

SEC – 17

Reference: Exhibit 2, DSP, pg.101

Question:

With respect to the 2018 system access variance:

a) Please include the variance between the two major projects that discussed (i.e. Black Road widening, and make-ready FTTH work).
b) Please explain why the make-ready FTTH work was not covered by capital contributions from Bell.

Response:

a) During the previous rate application, the scope of the Black Road widening project was unknown, and the Bell FTTH project was not foreseen. The variance schedule noted below indicates the projects at times within the previous cost of service period.

Project	Plan at COS	Project Estimate	Actual	Variance %
Black Road	$274	$562	$720	28%
Black Road Contributed Capital	$50	$168	$182	8%
Black Road Net	$224	$394	$538	37%
FFTH	$0	$0	$152	100%
FFTH Contributed Capital	$0	$0	$99	100%
FFTH Net	$0	$0	$53	100%

b) A significant capital contribution was received from Bell as part of the FTTH project, increasing PUC's annual capital contributions for 2018 above the budgeted value for joint use work within the System Access category. Some elements which involved renewal of end-of-life assets or correction of existing system deficiencies were non-recoverable.

SEC – 18

Reference: Exhibit 2, DSP, pg.109

Question:

Please provide a table that shows for each major asset category, the number of assets replaced (or planned to be replaced) each year between 2018 and 2027.

Response:

The information requested requires a level of effort and cost that outweighs the probative value of the information. It would be a significant undertaking to provide a table that shows the number of assets replaces (or planned to be replaced) for each major asset category in the year between 2018 and 2027. It is not feasible to complete this request in the allotted time.

To be of assistance, PUC will point to other sections of the DSP, such as pages 130 to 133 (Exhibit 2, pages 238-241) that provides some of what PUC believes is being sought out. For example, these pages inform that Voltage Conversion includes 22km of 4.16kV line and retirement of 2 substations, and that PUC plans to replace about 60 deteriorated wood poles per year as part of its *OH Renewal – Poles* program. Additional available information can also be found in each specific narrative (Appendix A of the DSP, Exhibit 2, pages 243-346), where for example, the *Overhead Renewal - General Assets* program states as it relates to the cleanup and disposal of pole butts that over the forecast period, PUC is proposing to remove approximately 150 poles per year that cannot be removed at the time of replacement, clean up an additional 100 poles per year, and dispose of all poles in an environmentally acceptable manner (Exhibit 2, page 342).

SEC – 19

Reference: Exhibit 2, DSP

Question:

Please provide a revised version of Appendix 2-AB that includes additional columns to show year-to-date actuals for 2022, and year-to-date actuals at the same point in time in 2020 and 2021. These additional columns should exclude the impact of spending on the SSG Project.

Response:

Please refer to VECC-17.

SEC – 20

Reference: Exhibit 2, DSP, Appendix A

Question:

The Applicant has provided 'Material investment Narratives' documents for material 2023 projects. Please provide similar documents for all material projects undertaken between 2019 and 2022.

Response:

The information requested requires a level of effort that greatly outweighs the probative value of the information, if any. It took PUC months to complete the material capital project narratives for the test year projects, which information is set out in DSP, and which provides a clear evidentiary basis upon which to assess the material capital projects in the test year. It is simply not feasible to complete similar narratives for all capital projects for all years between 2019 and 2022 in the allotted time. Moreover, the Section 5.4.2.1(A) of the Chapter 5 Filing Requirements does not require PUC to provide this information and PUC anticipates that signification additional cost will be incurred drafting these additional Material Investment Narratives. Please refer to PUC's past DSP(s).

SEC – 21

Reference: Exhibit 2, DSP, Appendix A, OH-Renewal Poles

Question:

For each year between 2018 and 2027, how many poles did the Applicant replace (or plan to be replaced) as part of the 'OH Renewal – Poles' program.

Response:

The table below identifies the quantity of deteriorated poles replaced by year within the OH Renewal – Poles program.

Year	Poles Replaced
2018	33
2019	41
2020	48
2021	26
2022	60 (45 completed to date)
2023	60
2024	60
2025	60
2026	60
2027	60

Exhibit 3 – Operating Revenue

SEC – 22

Reference: Exhibit 3

Question:

For each rate class, please provide the 2022 year-to-date number of actual customers.

Response:

Please refer to OEB Staff-53(b).

Exhibit 4 – Operating Costs

SEC – 23

Reference: Exhibit 4, Appendix 2-JC

Question:

Please provide a revised version of Appendix 2-JC that includes additional columns to show year-to-date actuals for 2022, and year-to-date actuals at the same point in time in 2020 and 2021.

Response:

Please refer to OEB Staff-60.

SEC – 24

Reference: Exhibit 4, pg.12

Question:

The Applicant notes that it has recorded costs related to the Green Button implementation in its 2023 OM&A budget. Please confirm that as a result as of January 1, 2023, it will no longer be eligible to record any incremental costs related to Green Button in the relevant generic 1508 sub-account.

Response:

PUC confirms it will incur an incremental cost of $80,000 in capital related to the implementation of its Green Button Initiative. PUC is proposing to update the models to record this $80,000 in Account 1980 2023 capital additions.

At this stage, all amounts are recorded in 1508 Sub-Account Green Button Initiative. PUC confirms that no incremental OM&A costs will be recorded in account 1508 Sub-account – Green Button Initiative as the incremental OM&A costs have been included in its 2023 Test Year Budget.

SEC – 25

Reference: Exhibit 4, pg.20-21

Question:

With respect to COVID costs:

a) Please confirm, that for accounting purposes, the Applicant recognized a decrease in OM&A costs related to COVID costs of $805,463 (as the amounts were originally booked to a deferral account) in 2020, and an equal increase of OM&A costs in 2021 (when the accounting entry was reversed), a more accurate reflection of actual OM&A costs incurred (as compared to those reflected in the evidence) would result in an increase of OM&A costs of $805,463 in 2020 and decrease of OM&A costs of $805,463 in 2021.
b) If the above is confirmed, is this accounting also reflected in Appendix 2-K? If so, please provide a version of Appendix 2-K that shows costs by year they were actually incurred, not the accounting treatment of those costs.

Response:

a) PUC confirms OM&A costs were recognized using the accounting treatment noted.

b) No, this accounting is not reflected in Appendix 2-K.

SEC – 26

Reference: Exhibit 4, pg.23

Question:

Please provide a breakdown of consultant costs related to the Applicant's cost of service application.

Response:

Please refer to OEB Staff-80.

SEC – 27

Reference: Exhibit 4, pg.23

Question:

Please provide a breakdown of the 'general inflation and items below the materiality' category of costs into each of 'general inflation' and 'items below the materiality'.
Please provide an explanation of all assumptions used in forecasting the 'general inflation' costs.

Response:

The categories of costs below materiality are shown in Table 4-10. Please refer to Ex.4, pg. 9.

SEC – 28

Reference: Ex.2, pg.95; 2-JC

Question:

The Applicant notes that there is an additional O&M expense of $296,400 related to the SSG implementation. Please provide the incremental O&M expenses related to the SSG project in each of 2022 and 2023 and provide a breakdown of those costs by 2-JC category.

Response:

The incremental OM&A expenses related to the SSG implementation are all in 2023. The table below provides a summary of the additional costs by the same categories as Board Appendix 2-JC.

Category	Program	2023
Operations	Load Dispatching	$130,174
Operations	Stations - Operations	$79,674
Maintenance	Stations - Maintenance	$86,584
		$296,432

SEC – 29

Reference: Exhibit 4, pg. 64-65

Question:

With respect to management salaries:

a) When was the last salary structure review undertaken and when is the next one scheduled to be undertaken?
b) What is the management salary increase forecast for 2023 and was it included in the test year budget?
c) Please quantify the total impact of any forecast increase in the 2023 management salaries.
d) Are non-union and non-management (as categorized by Appendix 2-K) salaries determined in the same way as management salaries? If not, please explain how they are determined and what increase is forecast for 2023.

Response:

a) Please refer to OEB Staff-71(a).

b) Please refer to OEB Staff-71(b).

c) As part of the management services contract, PUC Services provides the workforce necessary to operate PUC. The impact of the forecast increase in the 2023 management salaries specific to that workforce is $69k.

d) Please refer to VECC-33(c).

SEC – 30

Reference: Exhibit 4, pg.31-36, Appendix 2-K

Question:

With respect to non-management salaries, based on the information in Appendix 2-K, the Applicant is forecasting an increase in per FTE costs between 2022 and 2023, which are 16.5% (total salary and wages) and total compensation of 14.2%. Based on the information in the evidence provided regarding compensation, it is unclear why these increases are so high. Please provide a detailed explanation of the basis of these increases.

Response:

Please refer to OEB Staff-72.

Exhibit 5 – Cost of Capital

SEC – 31

Reference: Exhibit 5, pg.4

Question:

With respect to the promissory note payable to PUC Inc., the Applicant states "In this application, the interest rate on this note will be based on the Board's cost of capital parameter for long term debt for 2023 cost of service rate applications issued October 28, 2021, which is 3.49%". Is the proposal to set the interest rate at 3.49% or to update it to reflect to the issuance of the OEB's most recent cost of capital parameters in October 2022?

Response:

PUC has updated the 3.49% to the OEB's most recent cost of capital parameters as of October 2022. The revised rate is 4.88%.

SEC – 32

Reference: Exhibit 5, pg.6

Question:

Please provide further details regarding the expected interest rate on the credit facility with OILC (referenced as loan number 6).

Response:

The credit facility with OILC referenced as loan number 6 has not been finalized.

SEC – 33

Reference: Exhibit 5, pg.10

Question:

Please provide the Applicant's forecast 2022 regulatory return on equity.

Response:

PUC is forecasting a 2022 regulatory return on equity of 8.5%.

Exhibit 6 – Revenue Deficiency

SEC – 34

Reference: Exhibit 6, pg.17

Question:

With respect to Accelerated CCA:

a) The Applicant states "PUC used the 2018 actual additions as the basis of its CCA calculation and entry for 2018-2022." Please explain what is meant by this.
b) In so far as the Applicant has not done so, please provide a revised version of Table 6-14 that provides the impact of accelerated CCA based on actual additions in each year. Please provide the CCA continuity schedules for each of the old rules and AIIP scenarios used to calculate the increase in CCA.

Response:

Please refer to OEB Staff-89 for both "a" and "b".

SEC – 35

Reference: Exhibit 6, Appendix 2-H

Question:

Please provide a revised version of Appendix 2-H that includes additional columns to show year-to-date actuals for 2022, and year-to-date actuals at the same point in time in 2020 and 2021.

Response:

PUC has revised Appendix 2-H to include additional columns to show year to date actuals for 2022, and year to date actuals at the same point in time in 2020 and 2021.

Exhibit 9 – Deferral and Variance Accounts

SEC – 36

Reference: Exhibit 9, pg.31

Question:

Please provide the basis for the calculation of the incremental labour amount of $250,166.

Response:

Please refer to OEB Staff-106.

Appendix IR1

Additional Revenue from Increased SSG Asset Base

Cost of Capital Paramets	2023 (COC Updated)	2023
Deemed Short-Term Debt	4.79%	1.17%
Deemed Long-Term Debt	4.88%	3.97%
Return on Rate Base -Equity	9.36%	8.66%

Projected Capital Additions		
TX Station Annual Fixes	$ 3,190,271	$ 3,190,271
Tx Station Major Rebuild		

Current Revenue Requirement	2023	2023
Opening Cost	$ 21,357,909	$ 21,357,909
Gross Capital Additions	$ 3,190,271	$ 3,190,271
Accumulated Depreciation	$ 300,224	$ 300,224
Net Book Value Beginning of Year	$ 21,057,685	$ 21,057,685

Eligible Incremental Capital for ACM/ICM Recovery	2023	2023
Amount of Capital Projects Claimed	$ 21,057,685	$ 21,057,685
Depreciation Expense	$ 644,050	$ 644,050
CCA	$ 1,886,429	$ 1,886,429
Year End NBV for CCA Purposes	$ 16,908,531	$ 16,908,531

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base			2023	2023
Incremental Capital			$ 24,247,956	$ 24,247,956
Depreciation Expense (prorated to Eligible Incremental Capital)			$ 644,050	$ 644,050
Incremental Capital to be included in Rate Base (average NBV in year)			$ 22,330,795	$ 22,330,795
	% of capital structure			
Deemed Short-Term Debt	4.00%	**E**	$ 893,232	$ 893,232
Deemed Long-Term Debt	56.00%	**F**	$ 12,505,245	$ 12,505,245
	Rate (%)			
Short-Term Interest		**I**	$ 42,786	$ 10,451
Long-Term Interest		**J**	$ 610,256	$ 496,458
Return on Rate Base - Interest			$ 653,042	$ 506,909
	% of capital structure			
Deemed Equity %	40.00%	**N**	$ 8,932,318	$ 8,932,318
	Rate (%)			
Return on Rate Base -Equity		**O**	$ 836,065	$ 773,539
Return on Rate Base - Total			$ 1,489,107	$ 1,280,448

Amortization Expense		2023	2023
Amortization Expense - Incremental	**C**	$ 644,050	$ 644,050

Grossed up Taxes/PILs				
Regulatory Taxable Income		**O**	$ 836,065	$ 773,539
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		**S**	$ 644,050	$ 644,050
Deduct CCA (Prorated to Eligible Incremental Capital)			$ 1,886,429	$ 1,886,429
Incremental Taxable Income			$ (406,314)	$ (468,840)
Current Tax Rate	26.5%	**X**		
Taxes/PILs Before Gross Up			$ (107,673)	$ (124,243)
Grossed-Up Taxes/PILs			$ (146,494)	$ (169,038)

Incremental Revenue Requirement		2023	2023
Return on Rate Base - Total	**Q**	$ 1,489,107	$ 1,280,448
Amortization Expense - Total	**S**	$ 644,050	$ 644,050
Grossed-Up Taxes/PILs	**Z**	$ (146,494)	$ (169,038)
Incremental Revenue Requirement		$ 1,986,663	$ 1,755,460

Appendix IR2

PUC_App _AA14 Copy_
VVM Energy Savings Est for
ICM 20200120_20220811

Energy Savings Estimated from VVM System

1. Table below is from 2023 CoS application with normalized load forecast.

2018 CoS Rate Application Data						Loss Factor	1.0462	
	Total Base Revenue Requirement	Class %	Number of Customers	2023 Test Year Weather Normal kWh (Load Forecast)	Class %	kW	2018 Test Year Weather Normal (kWh w/LF)	Class %
Res	$ 15,291,103	61.37%	30,340	274,738,681	47.47%		287,431,608	47.47%
GS<50kW	$ 3,768,919	15.13%	3400	79,051,528	13.66%		82,703,708	13.66%
GS>50kW	$ 5,498,738	22.07%	344	221,450,388	38.26%	547,687	231,681,396	38.26%
Sentinel lights	$ 43,297	0.17%	317	193,841	0.03%	566	202,796	0.03%
Street lights	$ 262,895	1.06%	8037	2,459,994	0.43%	7,200	2,573,646	0.43%
USL	$ 50,271	0.20%	25	878,528	0.15%		919,116	0.15%
	$ 24,915,223	100.00%		578,772,961	100%		605,512,272	100%

2. VVM Energy Savings estimate is only applicable to customers on the 12.5 kV distribution network with intended design & application.

3. A reduction of the energy consumption above in the GS>50kW customers connected to the 34.5kV subtransmission network is thus needed .

4. The 7 customers for above annual energy consumption was totaled across two years and an average of 41,744,343.60 kWh used.

5. Note: as actual consumption in period was above Normalized this creates a more conservative estimate on total energy saved by VVM.

6. The Table below shows where the reduction applied results in 617,414,773 kWh energy for VVM targeted customers on the LV customers.

2023 CoS Rate Application Data - adjusting 34.5kV load						Loss Factor	1.0462			
	Total Base Revenue Requirement	Class %	Number of Customers	2023 Test Year Weather Normal kWh (Load Forecast)	Class %	kW	2018 Test Year Weather Normal (kWh w/LF)	Class %	Reduce GS>50kW 34.5kV (no VVM)	LV Feeder Energy Consumption Base for VVM
Res	$ 15,291,103	61.37%	30,340	274,738,681	47.47%		287,431,608	47.47%		287,431,608
GS<50kW	$ 3,768,919	15.13%	3,400	79,051,528	13.66%		82,703,708	13.66%		82,703,708
GS>50kW	$ 5,498,738	22.07%	344	221,450,388	38.26%	547,687	231,681,396	38.26%	40,278,071	191,403,326
Sentinel lights	$ 43,297	0.17%	317	193,841	0.03%	566	202,796	0.03%		202,796
Street lights	$ 262,895	1.06%	8,037	2,459,994	0.43%	7,200	2,573,646	0.43%		2,573,646
USL	$ 50,271	0.20%	25	878,528	0.15%		919,116	0.15%		919,116
	$ 24,915,223	100.00%		578,772,961	100%		605,512,272	100%	17.4%	565,234,201

7. The Cost of Power forecast from the 2018 CoS rate Applcation was used in original application for estimating energy $ savings.

2023 CoS Cost of Power (CoS Application)

	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU		GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Cost of Power (COP*)	**$69,302,488**	$33,311,708	$9,496,043	$26,076,189	$0		$0	$0	$290,018	$23,051	$105,480
(*) gross w/loss factor											
REDUCE GS>50kW by 17.7%				$ 4,533,375							
Revised COP Estimate for VVM customers	**$64,769,113**	$33,311,708	$9,496,043	$21,542,814	$0		$0	$0	$290,018	$23,051	$105,480

8. Table below uses the current Cost of Power forecast with updated IESO rates as provided below and the 16.3% reduction in energy from the GS>50kW class kWh used to get balance for VVM customers.

2021 CoS Cost of Power (uses 2021 IESO rates)

	Total	Residential	GS <50	GS>50-Regular	GS> 50-TOU		GS >50-Intermediate	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load
Cost of Power (COP*)	**$69,302,488**	$33,311,708	$9,496,043	$26,076,189	$0		$0	$0	$290,018	$23,051	$105,480
(*) gross w/loss factor	*$ 0.1145 Avg rate*										
REDUCE GS>50kW by 16.3%				$ 4,533,375							
Revised COP Estimate for VVM customers	**$64,769,113**	$33,311,708	$9,496,043	$21,542,814	$0	$0	$0	$0	$290,018	$23,051	$105,480

9. Next table describes the VVM energy and $ savings estimated to be achieved by the VVM system.

ENTER VALUES	***CVR factor***	0.9			System Energy Loss Savings Estimate kWh		2.60%	695,222			
	Voltage Savings	3.0	volts		Using avg $/kWh from COP		$ 0.1146	$ 79,664			
	Energy Savings	2.7	%								
Total $'s saved with VVM	**$1,748,766**	$899,416	$256,393	$581,656	$0	$0	$0	$0	$7,830	$622	$2,848
Total VVM w/Syst losses included	***$1,828,430***										
Total kWh saved with VVM	**15,261,323**	7,760,653	2,233,000	5,167,890	-	-	-	-	69,488	5,476	24,816
Total kWh saved with losses incl.	***15,956,546***										

Appendix IR3

2022106_GIS_3030_Signed Amendment_ No 4

DEPARTMENT OF NATURAL RESOURCES

RENEWABLE ENERGY AND SMART GRID DEPLOYMENT PROGRAMS

SMART GRID DEPLOYMENT PROGRAM

AMENDMENT NO. 4 TO THE REPAYABLE CONTRIBUTION AGREEMENT

THIS AMENDING AGREEMENT is made in duplicate

BETWEEN:

HIS MAJESTY THE KING IN RIGHT OF CANADA ("Canada"), represented by the Minister of Natural Resources,

AND:

PUC DISTRIBUTION INC., a corporation, incorporated under the laws of Ontario (the "**Proponent**").

WHEREAS Canada and the Proponent entered into a Contribution Agreement signed by Canada on December 19, 2018, and by the Proponent on December 11, 2018 (the Agreement); and amended by Canada on December 18, 2019, and by the Proponent on November 18, 2019 (Amendment #1); and amended by Canada on February 21, 2021, and by the Proponent on December 16, 2020 (Amendment #2); and amended by Canada on March 7, 2022, and by the Proponent on February 3, 2022 (Amendment #3).

WHEREAS the Proponent is requesting an amendment to increase the Contribution amount, and update the Fiscal Year allocations and Eligible Expenditure amounts.

AND WHEREAS Canada and the Proponent wish to amend the Agreement;

NOW, THEREFORE, Canada and the Proponent agree as follows:

1. Paragraph 6.1 of the Agreement is revoked and replaced by the following:

   Notwithstanding any other provision of this Agreement, the Contribution shall not in any circumstances exceed the lesser of:

   a) Twenty Five percent (25%) of Total Project Costs incurred; and
   b) Seven Million Six Hundred Fifty Eight Thousand Two Hundred Twenty Two Dollars ($7,658,222).

2. Paragraph 2.5 of the Agreement is revoked and replaced by the following:

   2.5 The Proponent represents and warrants that it has not, nor has any person offered or promised to any official or employee of His Majesty the King in Right of Canada, for or with a view to obtaining this Agreement any bribe, gift or other inducement and it has not nor has any person on its behalf employed any person to solicit this Agreement for a commission, fee or any other consideration dependent upon the execution of this Agreement.

3. Paragraph 6.2 of the Agreement is revoked and replaced by the following:

   6.2 The Fiscal Year allocations for the Contribution are as follows:

2018-2019	Four Hundred Ninety Three Thousand One Hundred Four Dollars ($493,104)
2019-2020	One Million Dollars ($1,000,000)
2020-2021	Two Hundred Eleven Thousand Two Hundred Twenty Two Dollars ($211,222)
2021-2022	One Million Nine Hundred Seventy Four Thousand Dollars ($1,974,000)
2022-2023	Three Million Nine Hundred Seventy Nine Thousand Eight Hundred Ninety Six Dollars ($3,979,896)
Total:	**Seven Million Six Hundred Fifty Eight Thousand Two Hundred**

Twenty Two Dollars ($7,658,222).

Any reallocation of the Contribution amounts in whole or in part from one Fiscal Year to another shall require a written amendment signed by the Parties.

4. Paragraph 6.6 of the Agreement is revoked and replaced by the following:

6.6 The Proponent represents that no other federal, provincial, territorial or municipal government assistance, other than those described below and listed in Schedule B (Budget and Eligible Expenditures), has been or will be provided in respect of the Total Project Costs incurred:

Canada:	Seven Million Six Hundred Fifty Eight Thousand Two Hundred Twenty Two Dollars ($7,658,222).
Other Federal:	Zero Dollars ($0)
Provincial:	Zero Dollars ($0)
Territorial:	Zero Dollars ($0)
Municipal:	Zero Dollars ($0)
Total Government Funding:	Seven Million Six Hundred Fifty Eight Thousand Two Hundred Twenty Two Dollars ($7,658,222).

The Proponent shall advise the Minister promptly of any change in the Total Government Funding listed above during the term of this Agreement.

5. Paragraph 7.7 of the Agreement is revoked and replaced by the following:

7.7 Where for any reason the Minister determines that the amount of the Contribution disbursed exceeds the amount to which the Proponent is entitled or the Proponent is not entitled to the Contribution, the Proponent must repay to Canada no later than thirty (30) days from the date of the Minister's notice, the amount of the overpayment or the amount of the Contribution disbursed. If the amount is not repaid by its due date, interest accrues at the Interest Rate for the period beginning on the due date and ending on the day before the day on which repayment to Canada is received. Any such amount is a debt due to His Majesty the King in Right of Canada and is recoverable as such.

6. Paragraph 7.8 of the Agreement is revoked and replaced by the following:

7.8 Without limiting the scope of the set-off rights provided for under the *Financial Administration Act*, it is understood that the Minister may set off against any amount that may be payable to the Proponent pursuant to this Agreement, any amounts owed and past due by the Proponent to His Majesty the King in Right of Canada under any legislation or contribution agreements and the Proponent shall declare to the Minister all amounts outstanding in that respect when making any claim under this Agreement.

7. Schedule B is revoked and replaced by the attached Schedule B.

8. All other terms and conditions of the Agreement remain in full force and in effect.

9. This Amending Agreement comes into force when signed by the Parties.

IN WITNESS WHEREOF this Amending Agreement has been executed on behalf of **His Majesty the King in right of Canada** by an officer duly authorized by the Minister of Natural Resources and on behalf of the **Proponent**, by an officer duly authorized on its behalf.

HIS MAJESTY THE KING IN RIGHT OF CANADA

_____ _____

Date Debbie Scharf
Assistant Deputy Minister
Low Carbon Energy Sector

PUC DISTRIBUTION INC.

Sept 27, 2022 _____

Date Robert Brewer
President, CEO

SCHEDULE B

To the Agreement between

HIS MAJESTY THE KING IN RIGHT OF CANADA

And

PUC DISTRIBUTION INC.

BUDGET AND ELIGIBLE EXPENDITURES

1. Subject to the limitations set out in the ***Contributions Article***, Eligible Expenditures shall be approved in accordance with Treasury Board Guidelines associated with the execution of the various activities as described in Schedule A (Statement of Work).

Approved Budget ($)	2018-19	2019-20	2020-21	2021-22	2022-23	TOTAL ($)
The Program (NRCan Contribution)	**$ 493,104**	**$ 1,000,000**	**$ 211,222**	**$ 1,974,000**	**$ 3,979,896**	**$7,658,222**
ELIGIBLE EXPENDITURES						
Professional, Scientific, Technical and Contracting	**$ 493,104**	**$ 1,272,604**	**$ 422,444**	**$ 8,698,993**	**$ 24,301,007**	**$35,188,152**
Total by Fiscal Year:	**$493,104**	**$1,272,604**	**$422,444**	**$8,698,993**	**$24,301,007**	
				Total Eligible Expenditures		**$35,188,152**

INELIGIBLE COSTS		
INELIGIBLE EXPENDITURES**		
Incurred before Eligible Expenditure Period (between June 13, 2018 and August 28, 2018)		$300,000
		$300,000
IN-KIND COSTS		
		$0
	Total Ineligible Costs	**$300,000**
	TOTAL PROJECT COSTS	**$35,488,152**

Source of Contributions:	Percentage (%)	Cash ($)	In-Kind ($)		Total ($)
Canada (NRCan - Smart Grid Deployment Program)	**22%**	$7,658,222	N/A		**$7,658,222**
The Proponent	**78%**	$27,829,930	$0		**$27,829,930**
TOTAL	**100%**	**$35,488,152**	**$0**		**$35,488,152**

NOTE: the following limitations apply to the approved budget above:

a) In accordance with the departmental GST/PST/HST certification form, the reimbursable Provincial Sales Tax, the Goods and Services Tax and the Harmonized Sales Tax costs must be net of any tax rebate to which the Proponent is entitled.

b) Ineligible costs, such as the reimbursable portion of Federal and Provincial Taxes, and expenditures incurred before or after the Eligible Expenditure Period, are considered towards Total Project Costs; however, they are not eligible for reimbursement.

c) In-kind costs are those contributions of goods or services provided by the Proponent or other contributors that are considered towards Total Project Costs; however; they are not eligible for reimbursement.

d) Non-permissible costs, which cannot count toward Total Project Costs under the Program, include:

a. Costs incurred before or after the Total Project Costs period;
b. Land acquisition costs and associated real estate fees;
c. Cost of leasing land, building and other facilities;
d. Financing charges and interest payments on Project loans;
e. Legal fees;
f. Project Proposal preparation costs;
g. Costs associated with the protection of Intellectual Property;

h. General repair and maintenance of existing Project and related structures; and
i. Salary benefits and incentives unrelated to the Project, like employee bonuses.

2. Notwithstanding the ***Amendments Article***, provided the Contribution for any given Fiscal Year is not exceeded, the Proponent may adjust any cost allocated by Eligible Expenditure as listed above by up to twenty percent (20%) of that cost without providing notice to Canada. At the time of submitting a claim for payment, the Proponent must provide Canada with a revised budget.

   The Proponent may submit a written request to Canada to make an adjustment greater than twenty percent (20%). The request must include a revised budget. This request is subject to the approval in writing by Canada's representative identified in the ***Notices Article***.

Appendix IR4

ED-1 IRR Response_ GHG Environmental Defence

Environmental Defence

ED-1

Reference: p. 20

Preamble: N/A

Question:

(a) The SSG project will result in energy savings and reduced losses. How much GHG emissions (t CO2e) will be avoided over (i) 10 years, (ii) 20 years, and (iii) 40 years. Please make and state assumptions as necessary. Please assume the average carbon content of electricity forecasted by the IESO in its latest annual planning outlook.

(b) The benefits summary estimates savings from avoided distribution system losses. In valuing these savings, did the utility account for the fact that losses are greatest at the time of system peak, and therefore at the time when electricity is the most expensive? If not, please provide a revised estimate that accounts for this, with any caveats as necessary.

(c) Please recreate table 1 on the assumption that electricity demand is 50% higher (e.g. due to the future electrification of fossil fuels used in transportation and space heating).

(d) Please provide a table showing total distribution system losses for the most recent 5 years available, including the 5-year average, in kWh, % of consumption, and % of peak demand. Please provide the forecast total distribution system losses following the implementation of the project as a 5-year average, in kWh, % of consumption, and % of peak demand.

Response:

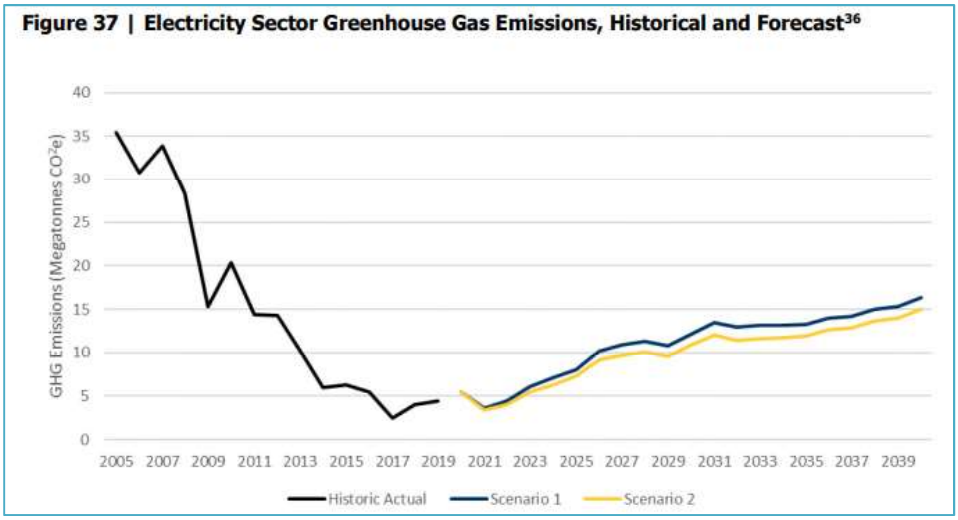
(a) The IESO Annual Planning Report (Dec 2020) was used for base data on historical and forecast energy and GHG emissions. The IESO report did note that they expected GHG emissions to be rising over time as noted in graph below from that report.

The referenced average carbon content of electricity above was not found directly in the IESO report so the following approach was developed.

From the Annual Planning Outlook excel data tables, using the Scenario 2 GHG output forecast (Megatonnes CO2e) in Figure 37 from 2022-2040 and divide that by the

Scenario 1 total annual energy demand (TWh) in Figure 2 from 2022-2040 – an annual carbon intensity (Megatonnes CO2e per TWh) for the Ontario electricity grid can be calculated – and then use that intensity value (an Annual Emission Factor or AEF) to calculate the multi-year savings. Note: Scenario 2 has a lower GHG value than Scenario 1.

Figure 37 | Electricity Sector Greenhouse Gas Emissions, Historical and Forecast[36]



The GHG calculation using the AEF (annual GHG over Annual system energy) provides the results shown below.

GHG Savings 10 years (2023-2032) 10,361 TCO_2e with AEF

GHG Savings 20 years (2023-2042) 24,010 TCO_2e with AEF
(assumed 2 additional years to IESO forecast at same level as 2040)

Further to the above question an average calculation of emissions is likely understating the GHG savings potential of energy efficiency savings. The next section provides a view of savings potential from a marginal generation perspective as the last generation dispatched is often a higher GHG source.

A report (*https://taf.ca/wp-content/uploads/2019/06/A-Clearer-View-on-Ontarios-Emissions-June-2019.pdf*) published by The Atmospheric Fund (TAF) in 2019 developed energy savings emission factors from IESO published data and their own methodology suggested use of a Marginal Emissions Factor (MEF) to quantify GHG savings from energy efficiency savings. As PUC has not completed any analysis on the time of day energy

savings the referenced report was used to develop an MEF factor as a ratio to the Annual Emissions Factors from this report to apply against the IESO data.

Historical and forecast data for energy and GHG was utilized from the IESO report to calculate an AEF by year was then used to calculate an MEF (this was calculated using a ratio of AEF and MEF from the TAF Report - 2018 Annual MEF of 134 divided by the Annual MEF of 31). This ratio was applied to the IESO AEF data above to forecast emissions for the 10 and 20 years with calculated results shown below.

GHG Savings (10 years) 44,784 TCO_2e with MEF

GHG Savings (20 years) 103,786 TCO_2e with MEF

(b) No. PUC Distribution does not have the data necessary to calculate the savings at peak times. This is something that PUC Distribution would be willing to attempt to measure and monitor should the SSG Project be approved.

(c) Table 1 has been recreated with the assumption that electricity demand is 50% higher resulting in an updated Cost of Power of $123,769,027. This has translated into an increased net benefit to customers of $1,734,460 which can be reviewed in the table below. Please note that this table also show a decease in additional revenue from SSG asset base from $1,754,862 to $1,751,221. This is a result of an update to CWIP rates.

Appendix IR5

2023 COS Accounting Order – SSG VVO Linkage to ROE

PUC Distribution Inc.

2023 Cost of Service Application – Sault Smart Grid Project Voltage / VAR Optimization Linkage to Return on Equity

EB-2022-0059

Accounting Order

Account 1508 Other Regulatory Assets

Sub-accounts Incremental VVO Savings or Costs

August 31, 2022

DRAFT

PUC Distribution Inc. - 2023 Cost of Service Application – Sault Smart Grid Project VVO Linkage to ROE

Accounting Order – Account 1508 Other Regulatory Assets

As part of the Ontario Energy Board's ("OEB") decision on the Sault Smart Grid project (EB-2018-0219/EB-2020-0249) ("SSG"), PUC Distribution Inc. ("PUC") was required to file all available information on the proposed SSG performance metrics that it intends to track, along with proposed targets, in its next rebasing application. The OEB required PUC to include an appropriate metric and targets to symmetrically link the Voltage / VAR Optimization ("VVO") performance of SSG to PUC's allowable Return on Equity ("ROE") for this Project. PUC is proposing to do this through the use of a 1508 – Other Regulatory Assets Sub Account where it shares in 50% of the costs and savings to customers. The following describes the calculation that links VVO % savings to ROE and the corresponding sample journal entries for the sharing of incremental savings or costs to customers.

VVO Link to ROE

The following steps, as outlined in Table 1, details the methodology PUC will use to calculate the revised net benefit to customers based on actual annual consumption savings and actual year COP.

Table 1 Scenarios Calculating Customer Net Benefit[1]

	Formulas	Top of Dead Band	Bottom of Dead Band	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Measured (estimate) VVO Consumption Savings	A	16,324,838	14,327,652	13,350,394	16,822,310	782,551	29,750,110
PUC Annual Consumption	B	604,623,538	606,565,655	607,598,147	603,161,981	603,161,981	603,161,981
PUC Consumption without SSG (projection from LF)	D = A+B	620,948,376	620,893,307	620,948,541	619,984,291	603,944,531	632,912,091
% Savings	E = A/B	2.70%	2.36%	2.20%	2.79%	0.13%	4.93%
PUC Cost of Power Paid	C	$ 69,302,488	$ 69,302,488	$ 69,302,488	$ 69,302,488	$ 69,302,488	$ 69,302,488
Avg $/kWh	F = C/B	0.1146	0.1143	0.1141	0.1149	0.1149	0.1149
PUC Cost of Power Paid without SSG consumption savings	G = D*F	$ 71,173,655	$ 70,939,478	$ 70,825,230	$ 71,235,348	$ 69,392,402	$ 72,720,735
Customer Energy Savings ($)	H = G-C	$ 1,871,167	$ 1,636,990	$ 1,522,742	$ 1,932,860	$ 89,914	$ 3,418,247
Dollar Savings from Loss Factor consumption reduction (Appendix AA14)	(I)	$ 79,664	$ 79,664	$ 79,664	$ 79,664	$ 79,664	$ 79,664
Total purchased power savings	J = H+I	**$ 1,950,831**	**$ 1,716,654**	**$ 1,602,406**	**$ 2,012,524**	**$ 169,578**	**$ 3,497,911**
Additional revenue from increased SSG asset base	K	$ 1,755,460	$ 1,755,460	$ 1,755,460	$ 1,755,460	$ 1,755,460	$ 1,755,460
Benefit of reduced capital expenditures witth SSG	L	($304,390)	($304,390)	($304,389)	($304,388)	($304,388)	($304,388)
Additional O & M expenses due to SSG implementation	M	$ 296,400	$ 296,400	$ 296,400	$ 296,400	$ 296,400	$ 296,400
Operating efficiency benefits due to SSG implementation	N	($30,816)	($30,816)	($30,816)	($30,816)	($30,816)	($30,816)
Change In Revenue Requirement	O = K+L+M+N	$ 1,716,654	$ 1,716,654	$ 1,716,655	$ 1,716,656	$ 1,716,656	$ 1,716,656
Annual net benefit to customers	P = J-O	$ 234,177	-$ 0	-$ 114,249	$ 295,868	-$ 1,547,078	$ 1,781,255

1 – These numbers are for illustration purposes only. The actual amount will vary given the VVO kWh savings from year to year.

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First, PUC will measure VVO consumption (kWh) savings on an annual basis. The methodology for calculating VVO savings is being developed by in collaboration with PUC's SSG contractor which will be used as an input. The very top line of Table 1 shows assumption of what that input might be for the purposes of this calculation and the VVO linkage to ROE. These consumption savings are added back to PUC's actual total consumption in each year to determine the resulting VVO savings as a percentage. This is shown in the top four rows of Table 1 above.

Next, the cost of power of $69,302,488 is divided by the actual consumption to obtain and average cost per kWh. This average cost per kWh is multiplied by PUC's consumption without VVO savings to get the COP customer would have paid in absence of the VVO savings. The methodology then must be adjusted for PUC's loss factor. As such, the calculation compares the approved loss factor to PUC's actual loss factor. As outlined in PUC's SSG Project ICM Application (EB-2018-0219/2020-0249) in Appendix AA14, it was noted that a reduction in loss factor would occur as a result of the SSG project. PUC will use Appendix AA14 yearly to input the additional dollar savings from loss factor.

The final step is to review the revenue requirement calculation for SSG included in rates. The benefit of reduced future capital expenditures, as described in EB-2018-0219/2020-0249 is $234,177 in each year moving forward. Additional O&M expenses of $296,400 and operating efficiency savings of $30,816 are also factored in, resulting in a total cost to customers (through rates). The calculated energy savings from VVO in the first step is compared to the calculated costs through revenue requirement of the SSG Project. The difference is the net benefit/(disadvantage) to customers.

PUC proposes a band where the breakeven point, 2.36% is the low end of the band, with the upper limit being 2.70%..

This methodology is illustrated in Table 1, with the third column showing the VVO savings target of 2.70%, the high end of the dead band, and the fourth column showing the lower end of dead band (i.e., customer breakeven) at 2.36% VVO savings.

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Only when the VVO consumption savings in a year are outside of the established dead band (2.36% to 2.70%), is a DVA entry triggered. Below the dead band, incremental costs to rate payers are shared 50/50 between ratepayers and PUC. Above the dead band, incremental savings to ratepayers are shared 50/50 between ratepayers and PUC. Scenario 1 shows a VVO savings of 2.20%, which results in incremental costs to customer of $114,249. PUC proposes to share 50/50 in those costs, causing a credit of $57,124 to the new DVA account. Scenario 2 shows a VVO savings of 2.79%, which results in incremental savings to customers of $295,868. The dollar value of VVO savings at the top end of the dead band ($234,177) is subtracted from this, resulting in $61,692 that is shared 50/50 with ratepayers and PUC. This creates a debit entry to the new DVA account for $30,846. Table 2 below shows the accounting entries for the DVA account for scenarios 1-4 in Table 1 above.

Table 2 – Accounting Entries for Scenarios 1-4[1]

Journal Entry				
	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
4080 Distribution Revenue	$57,124		$773,539	
1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings	$57,124		$773,539	
to record the reduction in savings to PUC customers.				
1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings		$30,846		$773,539
4080 Distribution Revenue		$30,846		$773,539
to record the increase in savings to PUC customers.				

1 – These numbers are for illustration purposes only. The actual amount will vary given the VVO kWh savings from year to year.

Additionally, PUC is proposing a symmetrical maximum upside and downside equal to the ROE of the SSG assets. The ROE will be calculated using the OEB's Cost of Capital Parameters issued October 20, 2022 and the average net book value of SSG assets included in rate base for its 2023 Cost of Service Rate Application (Eb-2022-0059).

1) Account 1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings

This account shall be used to record incremental VVO costs to customers when the VVO percentage savings multiplied by the cost of power results in an amount that is less than zero dollars savings to customers. The costs that are below zero dollars will be shared 50/50 between ratepayers and PUC.

This account shall also be used to record incremental VVO savings to customers when the dollar savings is more

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than two times the VVO dollar savings at 2.70%. The savings that are above this threshold will be shared 50/50 between ratepayers and PUC.

2) Account 1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings Carrying Charges

Carrying charges calculated on the year end balance shall be recorded in this sub account. Carrying charges shall be calculated using simple interest applied to the opening balances in the account and shall be recorded monthly in a separate carrying charges sub account. The interest rate shall be the rate prescribed by the Board.

A sample of the accounting entries has been provided in Appendix 1 below.

Appendix 1: 1508 Other Regulatory Assets – Incremental VVO Costs or Savings Journal Entries

1508 Other Regulatory Assets – Incremental VVO Savings	$XX	
4080 Distribution Revenue		$XX
To record the incremental savings to customers		

4080 Distribution Revenue	$XX	
1508 Other Regulatory Assets – Incremental VVO Costs		$XX
To record the incremental costs to customers		

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Appendix IR6

2020-04-21
Recommendation for
Payment #3 Invoice
59433

RECOMMENDATION FOR PAYMENT

Contract #:[i]	Payment #: 3	Prepared By:	Mike Orr
Acceptance Date:[ii]	21 April, 2020	Invoice #	59433
Contract Description:[iii]	Sub 16 - Substation Transformers		

Contractor:[iv] Virginia Transformer Corp.
Address: 220 Glade View Drive, N.E.
Roanoke, Virginia 24012

Original Value of Contract:[v]	$	939,368.00	excluding HST
Estimated Value of Change Orders:[vi]			excluding HST
Estimated Total Contract Value:	**$**	**939,368.00**	excluding HST

This is to certify that certain works have been done and materials delivered on the above mentioned contract and that the above Contractor is now entitled to payment as shown below:

Value of Contract Work and Materials Previously Certified:[vii]		$	441,684.00
Value of Work and Materials Certified, This Report:[viii]		$	220,842.00
Total Value of Work Certified to Date:		$	662,526.00
Holdbacks			
Less 0% Statuatory Holdback:[ix]		$	-
Statuatory Holdback Released:[x]			
Less 0% Other holdback (% of contract value) :[xi]		$	-
Other holdback Released:[xii]			
Less Payments to Date (#) (excluding HST):[xiii]		$	(441,684.00)
Amount Now Due:		$	220,842.00
13% HST		$	28,709.46
Recommended Payment :[xiv]		**$**	**249,551.46**

ALLOCATION OF COSTS [xv]

Work Order	Purchase Order	Work Order Description	Amount
EST3707-6	15089	**Sub 16 Rebuild**	**$220,842.00**

~~Prepared By~~	Certified for Payment	Approved	Approved	Approved
				
Engineering Dept.	Engineering Dept.	V.P. Operations & Engineering	V.P. Finance	President

2020-04-21

Instructions per footnotes as described on electronic document.
K:\0300 Work Orders & Projects\EST\EST3707 - Sub 16 Rebuild\1 Administration\2 Accounts & Billing\Virginia Transformer\Recommendation for Payment - PO 15089

PROGRESS PAYMENT AUTHORIZATION

Contractor: Virginia Transformer

Project Name: PUC Sub 16 Rebuilt

Siemens P.O. #: 15089

PPA #: 03

Period ending: 23-Feb-20

Contractor Invoice #: 59433

CONTRACT STATEMENT

Original Contract Price	$939,368.00
Approved Change Orders (attach list)	
Adjusted Contract Price	$939,368.00

PAYMENT STATEMENT

Value of Work Completed		$662,526.00
Holdback at 10 %	$0.00	
less Holdback released	$0.00	
Holdback Retained		$0.00
Value of Work Completed, net of holdback	Line A	$662,526.00
less Line A from previous Application		$441,684.00
Amount Recommended for Payment, this Application		$220,842.00
HST @ 13%		$28,709.46
Other Provincial Tax		

AMOUNT PAYABLE THIS APPLICATION $249,551.46

For use by Colliers Project Leaders Inc.

Colliers Project #: 860558

Billed with Colliers Invoice #: N/R

Reviewed By: Yes

Authorised By: Dillon Baratta, P. Eng. (print)

Signature: Dillon Baratta (signature)

Date: April 21, 2020

Worker's Compensation: Yes

Statutory Declaration: N/R

Certificate of Payment: N/R

Certificate of Publication: N/R

Special Payment Instructions:

Colliers Document # 860558-0061(1.0)

VIRGINIA TRANSFORMER CANADA, INC.

"The Commitment Company"

1 First Canadian Place
100 King Street West, Suite 1600 · Toronto, Ontario Canada M5X 1G5
Reg. 822923777RT0001

INVOICE
59433
DATE
2/23/20

BILL TO:

11160
PUC Services
accounts.payable@ssmpuc.com
500 Second Line East
Post Office Box 9000
Sault Ste. Marie, ON P6A 6P2
Canada

SHIP TO:

SALES ORDER NO.	ORDERED BY	ORDER DATE	CUSTOMER P.O. NO.	FOB
D274		8/26/19	PO-15089	DDP

ITEM NO.	SERIAL NO.	DESCRIPTION	QTY ORD.	QTY SHIP	UNIT PRICE	EXTENDED TOTAL
1		10000/13300 kVA 34.5-12.47kV with LTC	2		$441,684.00	
		50.00% Upon Shipment		1		$220,842.00
		13% HST				$28,709.46
		INVOICE TOTAL				$249,551.46

INVOICE

THIS INVOICE CONTAINS THE ONLY TERMS AND CONDITIONS, WITH RESPECT TO THE SALE OF THE ABOVE DESCRIBED GOODS, TO WHICH THE SELLER AGREED PER OUR CONFIRMATION OF ORDER. THE COMPANY RESERVES THE RIGHT TO REFUSE TO FULFILL ALL OF OUR OBLIGATIONS IF THE PAYMENT IS NOT RECEIVED PER OUR TERMS OF SALE.

Appendix IR7

2020-04-21
Recommendation for
Payment #4 Invoice
60215 – MP Signed

RECOMMENDATION FOR PAYMENT

Contract #:[i]	Payment #: 4	Prepared By:	Mike Orr
Acceptance Date:[ii]	23 June, 2020	Invoice #	60215
Contract Description:[iii]	Sub 16 - Substation Transformers		

Contractor:[iv] Virginia Transformer Corp.
Address: 220 Glade View Drive, N.E.
Roanoke, Virginia 24012

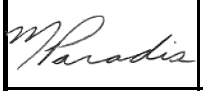
Original Value of Contract:[v]	$	939,368.00	excluding HST
Estimated Value of Change Orders:[vi]			excluding HST
Estimated Total Contract Value:	**$**	**939,368.00**	excluding HST

This is to certify that certain works have been done and materials delivered on the above mentioned contract and that the above Contractor is now entitled to payment as shown below:

Value of Contract Work and Materials Previously Certified:[vii]		$	662,526.00
Value of Work and Materials Certified, This Report:[viii]		$	220,842.00
Total Value of Work Certified to Date:		$	883,368.00
Holdbacks			
Less 0% Statuatory Holdback:[ix]		$	-
Statuatory Holdback Released:[x]			
Less 0% Other holdback (% of contract value) :[xi]		$	-
Other holdback Released:[xii]			
Less Payments to Date (#) (excluding HST):[xiii]		$	(662,526.00)
Amount Now Due:		$	220,842.00
13% HST		$	28,709.46
Recommended Payment :[xiv]		**$**	**249,551.46**

ALLOCATION OF COSTS [xv]

Work Order	Purchase Order	Work Order Description	Amount
EST3707-6	15089	**Sub 16 Rebuild**	**$220,842.00**

~~Prepared By~~	Certified for Payment	Approved	Approved	Approved
				
Engineering Dept.	Engineering Dept.	V.P. Operations & Engineering	V.P. Finance	President

2020-06-23

Instructions per footnotes as described on electronic document.
K:\0300 Work Orders & Projects\EST\EST3707 - Sub 16 Rebuild\1 Administration\2 Accounts & Billing\Virginia Transformer\Recommendation for Payment - PO 15089

PROGRESS PAYMENT AUTHORIZATION

Contractor: Virginia Transformer | PPA #: 04

Project Name: PUC Sub 16 Rebuilt | Period ending: 24-May-20

Siemens P.O. #: 15089 | Contractor Invoice #: 60215

CONTRACT STATEMENT

Original Contract Price	$939,368.00	
Approved Change Orders (attach list)		
Adjusted Contract Price	$939,368.00	

PAYMENT STATEMENT

Value of Work Completed		$883,368.00
Holdback at 10 % less Holdback released	$0.00	
Holdback Retained	$0.00	
Value of Work Completed, net of holdback		$0.00
less Line A from previous Application	Line A	$883,368.00
Amount Recommended for Payment, this Application		$662,526.00
HST @ 13%		$220,842.00
Other Provincial Tax		$28,709.46
AMOUNT PAYABLE THIS APPLICATION		$249,551.46

For use by Colliers Project Leaders Inc.

Colliers Project #:	860558	Worker's Compensation	Yes
Billed with Colliers Invoice #:	N/R	Statutory Declaration	N/R
Reviewed By:	Yes	Certificate of Payment	N/R
Authorised By:	Dillon Baratta, P. Eng. (print)	Certificate of Publication	N/R
Signature	(signature)	Special Payment Instructions	
Date:			

Colliers Document # 860558-0067(1.0)

860558-0067

colliersprojectleaders.com

VIRGINIA TRANSFORMER CANADA, INC.

1 First Canadian Place

100 King Street West, Suite 1600 · Toronto, Ontario Canada M5X 1G5

"The Commitment Company"

Reg. 822923777RT0001

INVOICE 60215

DATE 5/24/20

BILL TO:

11160

PUC Services
accounts.payable@ssmpuc.com
500 Second Line East
Post Office Box 9000
Sault Ste. Marie, ON P6A 6P2
Canada

SHIP TO:

SALES ORDER NO.	ORDERED BY	ORDER DATE	CUSTOMER P.O. NO.	FOB
D274		8/26/19	PO-15089	DDP

ITEM NO.	SERIAL NO.	DESCRIPTION	QTY ORD.	QTY SHIP	UNIT PRICE	EXTENDED TOTAL
1		10000/13300 kVA 34.5-12.47kV with LTC 50.00% Upon Shipment	2	1	$441,684.00	$220,842.00
		13% HST				$28,709.46
		INVOICE TOTAL				$249,551.46

INVOICE

THIS INVOICE CONTAINS THE ONLY TERMS AND CONDITIONS, WITH RESPECT TO THE SALE OF THE ABOVE DESCRIBED GOODS, TO WHICH THE SELLER AGREED PER OUR CONFIRMATION OF ORDER. THE COMPANY RESERVES THE RIGHT TO REFUSE TO FULFILL ALL OF OUR OBLIGATIONS IF THE PAYMENT IS NOT RECEIVED PER OUR TERMS OF SALE.

Appendix IR8

2020-04-21
Recommendation for
Payment #4 Invoice
60215

RECOMMENDATION FOR PAYMENT

Contract #:[i]	Payment #: 4	Prepared By:	Mike Orr
Acceptance Date:[ii]	23 June, 2020	Invoice #	60215
Contract Description:[iii]	Sub 16 - Substation Transformers		

Contractor:[iv] Virginia Transformer Corp.
Address: 220 Glade View Drive, N.E.
Roanoke, Virginia 24012

Original Value of Contract:[v]	$	939,368.00	excluding HST
Estimated Value of Change Orders:[vi]			excluding HST
Estimated Total Contract Value:	**$**	**939,368.00**	excluding HST

This is to certify that certain works have been done and materials delivered on the above mentioned contract and that the above Contractor is now entitled to payment as shown below:

Value of Contract Work and Materials Previously Certified:[vii]		$	662,526.00
Value of Work and Materials Certified, This Report:[viii]		$	220,842.00
Total Value of Work Certified to Date:		$	883,368.00
Holdbacks			
Less 0% Statuatory Holdback:[ix]		$	-
Statuatory Holdback Released:[x]			
Less 0% Other holdback (% of contract value) :[xi]		$	-
Other holdback Released:[xii]			
Less Payments to Date (#) (excluding HST):[xiii]		$	(662,526.00)
Amount Now Due:		$	220,842.00
13% HST		$	28,709.46
Recommended Payment :[xiv]		**$**	**249,551.46**

ALLOCATION OF COSTS [xv]

Work Order	Purchase Order	Work Order Description	Amount
EST3707-6	15089	**Sub 16 Rebuild**	**$220,842.00**

Prepared By	Certified for Payment	Approved	Approved	Approved
Engineering Dept.	Engineering Dept.	V.P. Operations & Engineering	V.P. Finance	President

Instructions per footnotes as described on electronic document.

K:\0300 Work Orders & Projects\EST\EST3707 - Sub 16 Rebuild\1 Administration\2 Accounts & Billing\Virginia Transformer\Recommendation for Payment - PO 15089

PROGRESS PAYMENT AUTHORIZATION

Contractor: Virginia Transformer | PPA #: 04

Project Name: PUC Sub 16 Rebuilt | Period ending: 24-May-20

Siemens P.O. #: 15089 | Contractor Invoice #: 60215

CONTRACT STATEMENT

Original Contract Price	$939,368.00	
Approved Change Orders (attach list)		
Adjusted Contract Price	$939,368.00	

PAYMENT STATEMENT

Value of Work Completed		$883,368.00
Holdback at 10 % less Holdback released	$0.00	
Holdback Retained	$0.00	
Value of Work Completed, net of holdback		$0.00
less Line A from previous Application	Line A	$883,368.00
Amount Recommended for Payment, this Application		$662,526.00
HST @ 13%		$220,842.00
Other Provincial Tax		$28,709.46
AMOUNT PAYABLE THIS APPLICATION		$249,551.46

For use by Colliers Project Leaders Inc.

Colliers Project #:	860558	Worker's Compensation	Yes
Billed with Colliers Invoice #:	N/R	Statutory Declaration	N/R
Reviewed By:	Yes	Certificate of Payment	N/R
Authorised By:	Dillon Baratta, P. Eng. (print)	Certificate of Publication	N/R
Signature	(signature)	Special Payment Instructions	
Date:			

Colliers Document # 860558-0067(1.0)

860558-0067

colliersprojectleaders.com

VIRGINIA TRANSFORMER CANADA, INC.

1 First Canadian Place

100 King Street West, Suite 1600 · Toronto, Ontario Canada M5X 1G5

"The Commitment Company"

Reg. 822923777RT0001

INVOICE 60215

DATE 5/24/20

BILL TO:

11160

PUC Services
accounts.payable@ssmpuc.com
500 Second Line East
Post Office Box 9000
Sault Ste. Marie, ON P6A 6P2
Canada

SHIP TO:

SALES ORDER NO.	ORDERED BY	ORDER DATE	CUSTOMER P.O. NO.	FOB
D274		8/26/19	PO-15089	DDP

ITEM NO.	SERIAL NO.	DESCRIPTION	QTY ORD.	QTY SHIP	UNIT PRICE	EXTENDED TOTAL
1		10000/13300 kVA 34.5-12.47kV with LTC 50.00% Upon Shipment	2	1	$441,684.00	$220,842.00
		13% HST				$28,709.46
		INVOICE TOTAL				$249,551.46

INVOICE

THIS INVOICE CONTAINS THE ONLY TERMS AND CONDITIONS, WITH RESPECT TO THE SALE OF THE ABOVE DESCRIBED GOODS, TO WHICH THE SELLER AGREED PER OUR CONFIRMATION OF ORDER. THE COMPANY RESERVES THE RIGHT TO REFUSE TO FULFILL ALL OF OUR OBLIGATIONS IF THE PAYMENT IS NOT RECEIVED PER OUR TERMS OF SALE.

Appendix IR9

Recommendation for Payment #3 Siemens Invoice #95633388 2020-06-26 MP Signed

RECOMMENDATION FOR PAYMENT

Contract #:[i]	Payment #: 3	Prepared By:	Mike Orr
Acceptance Date:[ii]	26 June, 2020	Invoice #	95633388
Contract Description:[iii]	Sub 16 - 15kV & 35kV Switchgear		
Contractor:[iv]	Siemens Canada Limited		
Address:	1577 North Service Rd. E Oakville, ON L6H 0H6		

Original Value of Contract:[v]	$	1,135,751.00	excluding HST
Estimated Value of Change Orders:[vi]			excluding HST
Estimated Total Contract Value:	**$**	**1,135,751.00**	excluding HST

This is to certify that certain works have been done and materials delivered on the above mentioned contract and that the above Contractor is now entitled to payment as shown below:

Value of Contract Work and Materials Previously Certified:[vii]		$	341,502.30
Value of Work and Materials Certified, This Report:[viii]		$	341,502.30
Total Value of Work Certified to Date:		$	683,004.60
Holdbacks			
Less 0% Statuatory Holdback:[ix]		$	-
Statuatory Holdback Released:[x]			
Less 0% Other holdback (% of contract value) :[xi]		$	-
Other holdback Released:[xii]			
Less Payments to Date (#) (excluding HST):[xiii]		$	(341,502.30)
Amount Now Due:		$	341,502.30
13% HST		$	44,395.30
Recommended Payment :[xiv]		**$**	**385,897.60**

ALLOCATION OF COSTS [xv]

Work Order	Purchase Order	Work Order Description	Amount
EST3707-6	15289	**Sub 16 Rebuild**	**$341,502.30**

Prepared By	Certified for Payment	Approved	Approved	Approved
Engineering Dept.	Engineering Dept.	V.P. Operations & Engineering	V.P. Finance	President

2020-07-16

Instructions per footnotes as described on electronic document.

K:\0300 Work Orders & Projects\EST\EST3707 - Sub 16 Rebuild\1 Administration\2 Accounts & Billing\Siemens\Recommendation for Payment - PO 15289

PROGRESS PAYMENT AUTHORIZATION

Contractor: Siemens | PPA #: 03

Project Name: PUC Sub 16 Rebuilt | Period ending: 5-Jun-20

Siemens P.O. #: 15289 | Contractor Invoice #: 95633388

CONTRACT STATEMENT

Original Contract Price	$1,138,341.00	
Approved Change Orders (attach list)	-$2,590.00	(PCN #01A and PCN #02A)
Adjusted Contract Price	$1,135,751.00	

PAYMENT STATEMENT

Value of Work Completed		$683,004.60
Holdback at 10 %	$0.00	
less Holdback released	$0.00	
Holdback Retained		$0.00
Value of Work Completed, net of holdback	Line A	$683,004.60
less Line A from previous Application		$341,502.30
Amount Recommended for Payment, this Application		$341,502.30
HST @ 13%		$44,395.30
Other Provincial Tax		

AMOUNT PAYABLE THIS APPLICATION $385,897.60

For use by Colliers Project Leaders Inc.

Colliers Project #: 860558

Billed with Colliers Invoice #: N/R

Reviewed By: Yes

Authorised By: Dillon Baratta, P. Eng. (print)

Signature: Dillon Baratta (signature)

Date: June 24, 2020

Worker's Compensation	Yes
Statutory Declaration	N/R
Certificate of Payment	N/R
Certificate of Publication	N/R
Special Payment Instructions	

Colliers Document # 860558-0068(1.0)

SIEMENS

* Repeat printout *

INVOICE

Siemens Canada Limited
1577 North Service Road East
Oakville, ON
L6H 0H6
GST/HST#:868220450RT0001 PST#:868220450TR0009

PLEASE REMIT PAYMENTS TO:	
Siemens Canada Limited	
CAD Funds: P.O. Box 4219, Station A Toronto, ON M5W 5N1 / CA	US Funds: Dept. 2877 Carol Stream IL, USA

BILL TO (605345)

SAULT STE MARIE/WATER UTILITY
PUC INC
PO Box 9000
SAULT STE MARIE ON P6A 6P2

SOLD TO (644372)

PUC SERVICES INC
PO BOX STN MAIN
PO Box 9000
SAULT STE MARIE ON P6A 6P2

SHIP TO: (605345)

PUC INC
SAULT STE MARIE/WATER UTILITY
500 SECOND LINE E
SAULT STE MARIE ON P6B 4K1

INVOICE NO.	DATE
95633388	05-Jun-2020
CUSTOMER PO#	**DELIVERY NOTE NO.**
15289	

WAYBILL / CARRIER NAME	
SIEMENS ORDER NO.	**ORDER DATE**
1696932	25-Oct-2019
A/R CONTACT	
Yiheng Lu	
A/R CONTACT TEL. NO.	**A/R CONTACT FAX**
905-580-7669	905-465-1456
TAX EXEMPTION/REGISTRATION NO(s):	

ITEM	MATERIAL	DESCRIPTION	QTY	PRICE	PRICE UNIT		VALUE
		Milestone #3 (30%) - Upon readiness of shipment of GIS from factory in Germany					
000001	8DA10 8DA10	8DA10 GIS 9 sections	1 EA	575,011.00	CAD	1 EA	172,503.30
	ECL: 9X9999	ECCN: 9X9999 Country of Origin: Germany					
000002	8DA10 8DA10	8DA10 GIS 6 sections 38kV	1 EA	452,855.00	CAD	1 EA	135,856.50
	ECL: 9X9999	ECCN: 9X9999 Country of Origin: Germany					
000003	8DA10 8DA10	Cable Termination Kit	1 EA	4,802.00	CAD	1 EA	1,440.60
	ECL: 9X9999	ECCN: 9X9999 Country of Origin: Germany					

NOTE:
A service charge of 2% per month
(26.8% per annum) is payable on balances.

PAYMENT TERMS: (Net 30 days)
Net Amount Due 05-Jul-2020

SIEMENS

INVOICE

Siemens Canada Limited
1577 North Service Road East
Oakville, ON
L6H 0H6
GST/HST#:868220450RT0001 PST#:868220450TR0009

PLEASE REMIT PAYMENTS TO:	
Siemens Canada Limited	
CAD Funds: P.O. Box 4219, Station A Toronto, ON M5W 5N1 / CA	US Funds: Dept. 2877 Carol Stream IL, USA 60132-2877

INVOICE NO.	DATE
95633388	05-Jun-2020
CUSTOMER PO#	**DELIVERY NOTE NO.**
15289	

ITEM	MATERIAL	DESCRIPTION	QTY	PRICE	PRICE UNIT	QTY	VALUE
000004	8DA10 8DA10	Future Expansion Switch	1 EA	8,995.00	CAD	1 EA	2,698.50
	ECL: 9X9999	ECCN: 9X9999	Country of Origin: Germany				
000005	8DA10 8DA10	Installation and Commissioning	1 EA	90,273.00	CAD	1 EA	27,081.90
	ECL: 9X9999	ECCN: 9X9999	Country of Origin: Germany				
000006	8DA10 8DA10	Spare Parts	1 EA	6,405.00	CAD	1 EA	1,921.50
	ECL: 9X9999	ECCN: 9X9999	Country of Origin: Germany				

		Items total		341,502.30
HST	13.000 %		341,502.30	44,395.32
		Final Net Amount:	CAD	385,897.62

These items are controlled by the U.S. Government (when labeled with "ECCN" unequal "N") and authorized for export only to the country of ultimate destination for use by the ultimate consignee or end-user(s) herein identified. They may not be resold, transferred, or otherwise disposed of, to any other country or to any person other than the authorized ultimate consignee or end-user(s), either in their original form or after being incorporated into other items, without first obtaining approval from the U.S. Government or as otherwise authorized by U.S. law and regulations. Items labeled with "ECL unequal "N" are subject to Canadian export authorization when being exporting out of Canada. Items without label or with label "ECL:N" / "ECCN:N" or label "ECL:9X9999 / ECCN: 9X9999", may require authorization from responsible authorities depending on the final end-use, or the destination. Further, depending on the origin of the products and destination, additional Canadian export control regulations may apply.

Note: Call your A/R Contact to discuss ways to streamline your payment process ... it can save your company time and money.

Appendix IR10

Recommendation for Payment #4 Siemens Invoice # 95681448 2020-08-25

RECOMMENDATION FOR PAYMENT

Contract #:[i]	Payment #: 4	Prepared By:	Mike Orr
Acceptance Date:[ii]	25 Aug, 2020	Invoice #	95681448
Contract Description:[iii]	Sub 16 - 15kV & 35kV Switchgear		

Contractor:[iv] Siemens Canada Limited
Address: 1577 North Service Rd. E
Oakville, ON L6H 0H6

Original Value of Contract:[v]	$	1,135,751.00	excluding HST
Estimated Value of Change Orders:[vi]			excluding HST
Estimated Total Contract Value:	**$**	**1,135,751.00**	excluding HST

This is to certify that certain works have been done and materials delivered on the above mentioned contract and that the above Contractor is now entitled to payment as shown below:

Value of Contract Work and Materials Previously Certified:[vii]		$	683,004.60
Value of Work and Materials Certified, This Report:[viii]		$	341,502.30
Total Value of Work Certified to Date:		$	1,024,506.90
Holdbacks			
Less 0% Statuatory Holdback:[ix]		$	-
Statuatory Holdback Released:[x]			
Less 0% Other holdback (% of contract value) :[xi]		$	-
Other holdback Released:[xii]			
Less Payments to Date (#) (excluding HST):[xiii]		$	(683,004.60)
Amount Now Due:		$	341,502.30
13% HST		$	44,395.30
Recommended Payment :[xiv]		**$**	**385,897.60**

ALLOCATION OF COSTS [xv]

Work Order	Purchase Order	Work Order Description	Amount
EST3707-6	15289	**Sub 16 Rebuild**	**$341,502.30**

~~Prepared By~~	Certified for Payment	Approved	Approved	Approved
Engineering Dept.	Engineering Dept.	V.P. Operations & Engineering	V.P. Finance	President

2020-08-26

Instructions per footnotes as described on electronic document.
K:\0300 Work Orders & Projects\EST\EST3707 - Sub 16 Rebuild\1 Administration\2 Accounts & Billing\Siemens\Recommendation for Payment - PO 15289

PROGRESS PAYMENT AUTHORIZATION

Contractor:	Siemens	PPA #:	04
Project Name:	PUC Sub 16 Rebuilt	Period ending:	20-Jul-20
Siemens P.O. #:	15289	Contractor Invoice #:	95681448

CONTRACT STATEMENT

Original Contract Price	$1,138,341.00	
Approved Change Orders (attach list)	-$2,590.00	(PCN #01A and PCN #02A)
Adjusted Contract Price	$1,135,751.00	

PAYMENT STATEMENT

Value of Work Completed			$1,024,506.90
Holdback at 10 %	$0.00		
less Holdback released	$0.00		
Holdback Retained			$0.00
Value of Work Completed, net of holdback		Line A	$1,024,506.90
less Line A from previous Application			$341,502.30
Amount Recommended for Payment, this Application			$341,502.30
HST @ 13%			$44,395.30
Other Provincial Tax			

AMOUNT PAYABLE THIS APPLICATION $385,897.60

For use by Colliers Project Leaders Inc.

Colliers Project #:	860558	Worker's Compensation	Yes
Billed with Colliers Invoice #:	N/R	Statutory Declaration	N/R
Reviewed By:	Yes	Certificate of Payment	N/R
Authorised By:	Dillon Baratta, P. Eng. (print)	Certificate of Publication	N/R
Signature	Dillon Baratta (signature)	Special Payment Instructions	
Date:	August 25, 2020		

Colliers Document # 860558-0068(1.0)

SIEMENS

INVOICE

Siemens Canada Limited
1577 North Service Road East
Oakville, ON
L6H 0H6
GST/HST#:868220450RT0001 PST#:868220450TR0009

PLEASE REMIT PAYMENTS TO:	
Siemens Canada Limited	
CAD Funds: P.O. Box 4219, Station A Toronto, ON M5W 5N1 / CA	US Funds: Dept. 2877 Carol Stream IL, USA

BILL TO (605345)

SAULT STE MARIE/WATER UTILITY
PUC INC
PO Box 9000
SAULT STE MARIE ON P6A 6P2

SOLD TO (644372)

PUC SERVICES INC
PO BOX STN MAIN
PO Box 9000
SAULT STE MARIE ON P6A 6P2

SHIP TO: (605345)

PUC INC
SAULT STE MARIE/WATER UTILITY
500 SECOND LINE E
SAULT STE MARIE ON P6B 4K1

INVOICE NO.	DATE
95681448	20-Jul-2020
CUSTOMER PO#	**DELIVERY NOTE NO.**
15289	

WAYBILL / CARRIER NAME	
SIEMENS ORDER NO.	**ORDER DATE**
1696932	25-Oct-2019
A/R CONTACT	
Yiheng Lu	
A/R CONTACT TEL. NO.	**A/R CONTACT FAX**
905-580-7669	905-465-1456
TAX EXEMPTION/REGISTRATION NO(s):	

ITEM	MATERIAL	DESCRIPTION	QTY	PRICE	PRICE UNIT		VALUE
		Milestone #4 (30%) - Upon readiness of shipment or when it is placed into storage					
000001	8DA10 8DA10	8DA10 GIS 9 sections	1 EA	575,011.00	CAD	1 EA	172,503.30
	ECL: 9X9999	ECCN: 9X9999	Country of Origin: Germany				
000002	8DA10 8DA10	8DA10 GIS 6 sections 38kV	1 EA	452,855.00	CAD	1 EA	135,856.50
	ECL: 9X9999	ECCN: 9X9999	Country of Origin: Germany				
000003	8DA10 8DA10	Cable Termination Kit	1 EA	4,802.00	CAD	1 EA	1,440.60
	ECL: 9X9999	ECCN: 9X9999	Country of Origin: Germany				

NOTE:
A service charge of 2% per month
(26.8% per annum) is payable on balances.

PAYMENT TERMS: (Net 30 days)
Net Amount Due 19-Aug-2020

SIEMENS

INVOICE

Siemens Canada Limited
1577 North Service Road East
Oakville, ON
L6H 0H6
GST/HST#:868220450RT0001 PST#:868220450TR0009

PLEASE REMIT PAYMENTS TO:	
Siemens Canada Limited	
CAD Funds: P.O. Box 4219, Station A Toronto, ON M5W 5N1 / CA	US Funds: Dept. 2877 Carol Stream IL, USA 60132-2877

INVOICE NO.	DATE
95681448	20-Jul-2020
CUSTOMER PO#	**DELIVERY NOTE NO.**
15289	

ITEM	MATERIAL	DESCRIPTION	QTY	PRICE	PRICE UNIT		VALUE
000004	8DA10 8DA10	Future Expansion Switch					
			1 EA	8,995.00	CAD	1 EA	2,698.50
	ECL: 9X9999	ECCN: 9X9999	Country of Origin: Germany				
000005	8DA10 8DA10	Installation and Commissioning					
			1 EA	90,273.00	CAD	1 EA	27,081.90
	ECL: 9X9999	ECCN: 9X9999	Country of Origin: Germany				
000006	8DA10 8DA10	Spare Parts					
			1 EA	6,405.00	CAD	1 EA	1,921.50
	ECL: 9X9999	ECCN: 9X9999	Country of Origin: Germany				

	Items total		341,502.30
HST	13.000 %	341,502.30	44,395.32
	Final Net Amount:	CAD	385,897.62

These items are controlled by the U.S. Government (when labeled with "ECCN" unequal "N") and authorized for export only to the country of ultimate destination for use by the ultimate consignee or end-user(s) herein identified. They may not be resold, transferred, or otherwise disposed of, to any other country or to any person other than the authorized ultimate consignee or end-user(s), either in their original form or after being incorporated into other items, without first obtaining approval from the U.S. Government or as otherwise authorized by U.S. law and regulations. Items labeled with "ECL unequal "N" are subject to Canadian export authorization when being exporting out of Canada. Items without label or with label "ECL:N" / "ECCN:N" or label "ECL:9X9999 / ECCN: 9X9999", may require authorization from responsible authorities depending on the final end-use, or the destination. Further, depending on the origin of the products and destination, additional Canadian export control regulations may apply.

Note: Call your A/R Contact to discuss ways to streamline your payment process ... it can save your company time and money.

Your clearance(s) / Vos certificats de décharge

We confirm that the business(es) listed below are active and in good standing with us.
Nous confirmons que la ou les entreprises énumérées ci-dessous sont actives et que leurs comptes sont en règle.

Contractor legal or trade name / Raison sociale ou appellation commerciale de l'entrepreneur	Contractor address / Adresse de l'entrepreneur	Contractor NAICS Code and Code Description / Code du SCIAN de l'entrepreneur et description	Clearance certificate number / Numéro du certificat de décharge	Validity period (dd-mmm-yyyy) / Période de validité (jj-mmm-aaaa)
SIEMENS CANADA LIMITED / SIEMENS	1577 NORTH SERVICE RD EAST, OAKVILLE, ON, L6H0H6, CA	561612: Security guard and patrol services 334512: Measuring, medical and controlling devices manufacturing 237130: Power and communication line and related structures construction 335311: Power, distribution and specialty transformers manufacturing 335312: Motor and generator manufacturing 416110: Electrical wiring and construction supplies merchant wholesalers 007040: Non-Exempt Partners and Executive Officers in Construction - G4 416120: Plumbing, heating and air-conditioning equipment and supplies merchant wholesalers 238220: Plumbing, heating and air-conditioning contractors 334110: Computer and peripheral equipment manufacturing 238299: All other building equipment contractors	A0000GYNFI	20-Aug-2020 to 19-Nov-2020

Under Section 141 of the *Workplace Safety and Insurance Act*, the WSIB waives our right to hold the principal (the business that has entered into a contractual agreement with the contractor/subcontractor) liable for any unpaid premiums and other amounts the contractor may owe us for the validity period specified.
Aux termes de l'article 141 de la *Loi sur la sécurité professionnelle et l'assurance contre les accidents du travail*, la WSIB renonce à son droit de tenir l'entrepreneur principal (l'entreprise qui a conclu une entente contractuelle avec l'entrepreneur ou le sous-traitant) responsable de toute prime impayée et autre montant que l'entrepreneur pourrait lui devoir pour la période de validité indiquée.

WSIB Head Office: 200 Front Street West
Toronto, Ontario, Canada M5V 3J1

Siège social : 200, rue Front Ouest
Toronto (Ontario) Canada M5V 3J1

1-800-387-0750 | TTY/ATS 1-800-387-0050
employeraccounts@wsib.on.ca | wsib.ca

Appendix IR11

Recommendation for Payment #5 Siemens Invoice #95787512 2020-09-29

RECOMMENDATION FOR PAYMENT

Contract #:[i]	Payment #: 5	Prepared By:	Mike Orr
Acceptance Date:[ii]	29 Sept, 2020	Invoice #	95787512
Contract Description:[iii]	Sub 16 - 15kV & 35kV Switchgear		
Contractor:[iv]	Siemens Canada Limited		
Address:	1577 North Service Rd. E Oakville, ON L6H 0H6		

Original Value of Contract:[v]	$	1,138,341.00	excluding HST
Estimated Value of Change Orders:[vi]	$	84,560.40	excluding HST
Estimated Total Contract Value:	**$**	**1,222,901.40**	excluding HST

This is to certify that certain works have been done and materials delivered on the above mentioned contract and that the above Contractor is now entitled to payment as shown below:

Value of Contract Work and Materials Previously Certified:[vii]		$	1,024,506.90
Value of Work and Materials Certified, This Report:[viii]		$	53,523.40
Total Value of Work Certified to Date:		$	1,078,030.30
Holdbacks			
Less 0% Statuatory Holdback:[ix]		$	-
Statuatory Holdback Released:[x]			
Less 0% Other holdback (% of contract value) :[xi]		$	-
Other holdback Released:[xii]			
Less Payments to Date (#) (excluding HST):[xiii]		$	(1,024,506.90)
Amount Now Due:		$	53,523.40
13% HST		$	6,958.04
Recommended Payment :[xiv]		**$**	**60,481.44**

ALLOCATION OF COSTS [xv]

Work Order	Purchase Order	Work Order Description	Amount
EST3707-6	15289	**Sub 16 Rebuild**	**$53,523.40**

Prepared By	Certified for Payment	Approved	Approved	Approved
Engineering Dept.	Engineering Dept.	V.P. Operations & Engineering	V.P. Finance	President

Instructions per footnotes as described on electronic document.

K:\0300 Work Orders & Projects\EST\EST3707 - Sub 16 Rebuild\1 Administration\2 Accounts & Billing\Siemens\Recommendation for Payment - PO 15289

Appendix IR12

PUC SSG ICM IRR_Sec 12

2021-01-25

SEC-12

Reference: App. p. 20, 21, 50

Preamble: N/A.

Question: The Applicant notes that certain of the benefits of the SSG Project are estimated over a very long term and averaged or present valued, such as reliability and avoided capital spending. Certain of the costs and benefits will also have specific patterns of application, such as PILs (lower at the beginning, higher later on) and cost of capital (higher at the beginning, but declining as rate base declines). Please provide a continuity schedule showing, for each of the costs and benefits in Table 1, the forecast annual impact on customers from 2022 to 2041, i.e. showing and aggregating the pattern of each of the costs and benefits over time.

Response:

PUC Distribution has provided a schedule showing the customer net benefit from 2022 to 2041.

This results in a NPV of annual net benefit to customers of $12,506,291 and NPV of projected reliability benefits of $25,864,956, to a total NPV benefits of $38,371,247). The following assumptions were used in the calculation of this table:

- NPV at 6% discount rate.
- Ontario's 2017 Long-Term Energy Plan was used to forecast the increased cost of power from 2022 to 2041. This increase is a projection of the customers total bill increase based on a 750kwh customer.
- PUC Distribution did not apply any change in the price of its Transmission Network, Wholesale Market Service charge, RRRP charge and Smart Meter Entity Charge
- In the calculation of revenue requirement, PUC Distribution used cost of capital parameters from its 2018 Cost of Service Application.
- Additional OM&A expenses and operating efficiency benefits were adjusted by 1.90% per year which aligns with inflationary rate for PUC's 2021 IRM less the stretch factor of 0.30%.
- Additional revenue from increases SSG asset base was calculated each year by using Tab 9 of the ICM model. In 2028, the computer software would become fully depreciated. PUC has not included a calculation for the replacement of computer software in 2028.

- A projected energy savings of 2.7% was used for all years for Base Scenario 1, 2% was used for all years for Scenario 2 and 4% was used for Scenario 3 (see below).

The Snapshot below represent the Net benefit table from 2022 to 2041. Please note that in 2022 the difference between the CCA used ($1,361,480) for revenue requirement, and the CCA for tax purposes ($3,684,077) would create a credit to customers in the 1592 variance account. This benefit has not been factored into the total Net benefit to customers.

Customer Net Benefit from 2022 to 2041
(Base Scenario 1 – 2.7% projected energy savings)

Customer Net Benefit Summary	2022	2023	2024	2025	2026
Cost of Power - updated to current estimate (not including GS>5(	$ 77,574,554	$ 82,564,360	$ 88,666,180	$ 91,961,163	$ 94,531,250
Projected energy savings with SSG implementation	2.70%	2.70%	2.70%	2.70%	2.70%
Projected customer energy savings through SSG	$ 2,094,513	$ 2,229,238	$ 2,393,987	$ 2,482,951	$ 2,552,344
Projected system loss energy savings through SSG	$ 98,821	$ 105,177	$ 112,950	$ 117,148	$ 120,422
Total purchased power savings	$ 2,193,334	$ 2,334,415	$ 2,506,937	$ 2,600,099	$ 2,672,765
Additional revenue from increased SSG asset base	$ 875,610	$ 2,069,976	$ 2,070,214	$ 2,066,371	$ 2,058,773
Benefit of reduced capital expenditures with SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 296,400	$ 302,032	$ 307,770	$ 313,618	$ 319,577
Operating efficiency benefits due to SSG implementation	($30,816)	($31,402)	($31,998)	($32,606)	($33,226)
Change In Revenue Requirement	$ 836,804	$ 2,036,216	$ 2,041,596	$ 2,042,992	$ 2,040,734
Annual net benefit to customers	$ 1,356,530	$ 298,199	$ 465,341	$ 557,107	$ 632,031
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	$ 2,017,000	$ 2,017,000	$ 2,017,000
Total projected benefit to customers	$ 3,373,530	$ 2,315,199	$ 2,482,341	$ 2,574,107	$ 2,649,031
NPV of Annual Net Benefit to customers	**$ 12,506,291**				
NPV of Projected Relaibaility Benefits	**$ 25,864,956**				
Total	**$ 38,371,247**				

Customer Net Benefit Summary	2027	2028*	2029	2030	2031
Cost of Power - updated to current estimate (not including GS>5(	$ 97,178,439	$ 99,912,392	$ 102,713,447	$ 105,606,102	$ 104,612,957
Projected energy savings with SSG implementation	2.70%	2.70%	2.70%	2.70%	2.70%
Projected customer energy savings through SSG	$ 2,623,818	$ 2,697,635	$ 2,773,263	$ 2,851,365	$ 2,824,550
Projected system loss energy savings through SSG	$ 123,794	$ 127,124	$ 130,845	$ 134,530	$ 133,264
Total purchased power savings	$ 2,747,612	$ 2,824,758	$ 2,904,108	$ 2,985,894	$ 2,957,814
Additional revenue from increased SSG asset base	$ 1,941,702	$ 1,827,295	$ 1,821,830	$ 1,813,675	$ 1,803,046
Benefit of reduced capital expenditures with SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 325,649	$ 331,836	$ 338,141	$ 344,565	$ 351,112
Operating efficiency benefits due to SSG implementation	($33,857)	($34,500)	($35,156)	($35,824)	($36,504)
Change In Revenue Requirement	$ 1,929,103	$ 1,820,241	$ 1,820,425	$ 1,818,027	$ 1,813,264
Annual net benefit to customers	$ 818,508	$ 1,004,518	$ 1,083,683	$ 1,167,868	$ 1,144,551
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	$ 2,017,001	$ 2,017,002	$ 2,017,003
Total projected benefit to customers	$ 2,835,508	$ 3,021,518	$ 3,100,684	$ 3,184,870	$ 3,161,554
	*does not include replacement for computer equipment.				

Customer Net Benefit Summary					
	2032	2033	2034	2035	2036
Cost of Power - updated to current estimate (not including GS>5(	$ 105,596,171	$ 105,596,171	$ 104,603,125	$ 103,620,010	$ 104,593,294
Projected energy savings with SSG implementation	2.70%	2.70%	2.70%	2.70%	2.70%
Projected customer energy savings through SSG	$ 2,851,097	$ 2,851,097	$ 2,824,284	$ 2,797,740	$ 2,824,019
Projected system loss energy savings through SSG	$ 134,517	$ 134,517	$ 133,252	$ 132,000	$ 133,239
Total purchased power savings	$ 2,985,614	$ 2,985,614	$ 2,957,536	$ 2,929,740	$ 2,957,258
Additional revenue from increased SSG asset base	$ 1,790,140	$ 1,775,140	$ 1,758,214	$ 1,739,515	$ 1,719,185
Benefit of reduced capital expenditures with SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 357,783	$ 364,581	$ 371,508	$ 378,567	$ 385,760
Operating efficiency benefits due to SSG implementation	($37,198)	($37,905)	($38,625)	($39,359)	($40,107)
Change In Revenue Requirement	$ 1,806,336	$ 1,797,427	$ 1,786,707	$ 1,774,333	$ 1,760,448
Annual net benefit to customers	$ 1,179,278	$ 1,188,187	$ 1,170,829	$ 1,155,407	$ 1,196,810
Annual projected reliability benefit to customers	$ 2,017,004	$ 2,017,005	$ 2,017,006	$ 2,017,007	$ 2,017,008
Total projected benefit to customers	$ 3,196,282	$ 3,205,192	$ 3,187,835	$ 3,172,414	$ 3,213,818

1

Customer Net Benefit Summary					
	2037	2038	2039	2040	2041
Cost of Power - updated to current estimate (not including GS>5(	$ 105,576,311	$ 106,569,158	$ 107,571,934	$ 108,584,737	$ 109,607,668
Projected energy savings with SSG implementation	2.70%	2.70%	2.70%	2.70%	2.70%
Projected customer energy savings through SSG	$ 2,850,560	$ 2,877,367	$ 2,904,442	$ 2,931,788	$ 2,959,407
Projected system loss energy savings through SSG	$ 134,492	$ 135,756	$ 137,034	$ 138,324	$ 139,627
Total purchased power savings	$ 2,985,052	$ 3,013,124	$ 3,041,476	$ 3,070,112	$ 3,099,034
Additional revenue from increased SSG asset base	$ 1,697,355	$ 1,674,144	$ 1,649,664	$ 1,624,015	$ 1,597,291
Benefit of reduced capital expenditures with SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 393,089	$ 400,558	$ 408,168	$ 415,924	$ 423,826
Operating efficiency benefits due to SSG implementation	($40,869)	($41,645)	($42,436)	($43,243)	($44,064)
Change In Revenue Requirement	$ 1,745,185	$ 1,728,667	$ 1,711,006	$ 1,692,306	$ 1,672,663
Annual net benefit to customers	$ 1,239,867	$ 1,284,457	$ 1,330,470	$ 1,377,806	$ 1,426,371
Annual projected reliability benefit to customers	$ 2,017,009	$ 2,017,010	$ 2,017,011	$ 2,017,012	$ 2,017,013
Total projected benefit to customers	$ 3,256,876	$ 3,301,467	$ 3,347,481	$ 3,394,818	$ 3,443,384

2

Scenario 2 - Projected Energy Savings at 2%

As part of its sensitivity analysis, PUC Distribution has performed the same analysis as above for a scenario where projected energy savings at 2% for all years. All other assumptions made in the base scenario above are the same. This results in a NPV of annual net benefit to customers of $3,729,534 and NPV of projected reliability benefits of $25,864,956, to a total NPV of benefits of $29,594,490)

Customer Net Benefit Summary					
	2022	**2023**	**2024**	**2025**	**2026**
Cost of Power - updated to current estimate (not including GS>50 on	$ 77,574,554	$ 82,564,360	$ 88,666,180	$ 91,961,163	$ 94,531,250
Projected energy savings with SSG implementation	2.00%	2.00%	2.00%	2.00%	2.00%
Projected customer energy savings through SSG	$ 1,551,491	$ 1,651,287	$ 1,773,324	$ 1,839,223	$ 1,890,625
Projected system loss energy savings through SSG	$ 98,821	$ 105,177	$ 112,950	$ 117,148	$ 120,422
Total purchased power savings	$ 1,650,312	$ 1,756,464	$ 1,886,274	$ 1,956,371	$ 2,011,047
Additional revenue from increased SSG asset base	$ 875,610	$ 2,069,976	$ 2,070,214	$ 2,066,371	$ 2,058,773
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 296,400	$ 302,032	$ 307,770	$ 313,618	$ 319,577
Operating efficiency benefits due to SSG implementation	($30,816)	($31,402)	($31,998)	($32,606)	($33,226)
Change In Revenue Requirement	$ 836,804	$ 2,036,216	$ 2,041,596	$ 2,042,992	$ 2,040,734
Annual net benefit to customers	$ 813,508	-$ 279,752	-$ 155,322	-$ 86,621	-$ 29,688
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	$ 2,017,000	$ 2,017,000	$ 2,017,000
Total projected benefit to customers	$ 2,830,508	$ 1,737,248	$ 1,861,678	$ 1,930,379	$ 1,987,312
NPV of Annual Net Benefit to customers	**$ 3,729,534**				
NPV of Projected Relaibaility Benefits	**$ 25,864,956**				
Total	**$ 29,594,490**				

Customer Net Benefit Summary					
	2027	**2028***	**2029**	**2030**	**2031**
Cost of Power - updated to current estimate (not including GS>50 on	$ 97,178,439	$ 99,912,392	$ 102,713,447	$ 105,606,102	$ 104,612,957
Projected energy savings with SSG implementation	2.00%	2.00%	2.00%	2.00%	2.00%
Projected customer energy savings through SSG	$ 1,943,569	$ 1,998,248	$ 2,054,269	$ 2,112,122	$ 2,092,259
Projected system loss energy savings through SSG	$ 123,794	$ 127,124	$ 130,845	$ 134,530	$ 133,264
Total purchased power savings	$ 2,067,363	$ 2,125,371	$ 2,185,114	$ 2,246,652	$ 2,225,524
Additional revenue from increased SSG asset base	$ 1,941,702	$ 1,827,295	$ 1,821,830	$ 1,813,675	$ 1,803,046
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 325,649	$ 331,836	$ 338,141	$ 344,565	$ 351,112
Operating efficiency benefits due to SSG implementation	($33,857)	($34,500)	($35,156)	($35,824)	($36,504)
Change In Revenue Requirement	$ 1,929,103	$ 1,820,241	$ 1,820,425	$ 1,818,027	$ 1,813,264
Annual net benefit to customers	$ 138,259	$ 305,131	$ 364,689	$ 428,625	$ 412,260
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	$ 2,017,001	$ 2,017,002	$ 2,017,003
Total projected benefit to customers	$ 2,155,259	$ 2,322,131	$ 2,381,690	$ 2,445,627	$ 2,429,263
	*does not include replacement for computer equipment.				

Customer Net Benefit Summary					
	2032	2033	2034	2035	2036
Cost of Power - updated to current estimate (not including GS>50 on	$ 105,596,171	$ 105,596,171	$ 104,603,125	$ 103,620,010	$ 104,593,294
Projected energy savings with SSG implementation	2.00%	2.00%	2.00%	2.00%	2.00%
Projected customer energy savings through SSG	$ 2,111,923	$ 2,111,923	$ 2,092,063	$ 2,072,400	$ 2,091,866
Projected system loss energy savings through SSG	$ 134,517	$ 134,517	$ 133,252	$ 132,000	$ 133,239
Total purchased power savings	$ 2,246,440	$ 2,246,440	$ 2,225,314	$ 2,204,400	$ 2,225,105
Additional revenue from increased SSG asset base	$ 1,790,140	$ 1,775,140	$ 1,758,214	$ 1,739,515	$ 1,719,185
Benefit of reduced capital expenditures with SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 357,783	$ 364,581	$ 371,508	$ 378,567	$ 385,760
Operating efficiency benefits due to SSG implementation	($37,198)	($37,905)	($38,625)	($39,359)	($40,107)
Change In Revenue Requirement	$ 1,806,336	$ 1,797,427	$ 1,786,707	$ 1,774,333	$ 1,760,448
Annual net benefit to customers	$ 440,105	$ 449,013	$ 438,607	$ 430,067	$ 464,657
Annual projected reliability benefit to customers	$ 2,017,004	$ 2,017,005	$ 2,017,006	$ 2,017,007	$ 2,017,008
Total projected benefit to customers	$ 2,457,109	$ 2,466,018	$ 2,455,613	$ 2,447,074	$ 2,481,665

1

Customer Net Benefit Summary					
	2037	2038	2039	2040	2041
Cost of Power - updated to current estimate (not including GS>50 on	$ 105,576,311	$ 106,569,158	$ 107,571,934	$ 108,584,737	$ 109,607,668
Projected energy savings with SSG implementation	2.00%	2.00%	2.00%	2.00%	2.00%
Projected customer energy savings through SSG	$ 2,111,526	$ 2,131,383	$ 2,151,439	$ 2,171,695	$ 2,192,153
Projected system loss energy savings through SSG	$ 134,492	$ 135,756	$ 137,034	$ 138,324	$ 139,627
Total purchased power savings	$ 2,246,018	$ 2,267,140	$ 2,288,473	$ 2,310,019	$ 2,331,781
Additional revenue from increased SSG asset base	$ 1,697,355	$ 1,674,144	$ 1,649,664	$ 1,624,015	$ 1,597,291
Benefit of reduced capital expenditures with SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 393,089	$ 400,558	$ 408,168	$ 415,924	$ 423,826
Operating efficiency benefits due to SSG implementation	($40,869)	($41,645)	($42,436)	($43,243)	($44,064)
Change In Revenue Requirement	$ 1,745,185	$ 1,728,667	$ 1,711,006	$ 1,692,306	$ 1,672,663
Annual net benefit to customers	$ 500,833	$ 538,473	$ 577,467	$ 617,713	$ 659,117
Annual projected reliability benefit to customers	$ 2,017,009	$ 2,017,010	$ 2,017,011	$ 2,017,012	$ 2,017,013
Total projected benefit to customers	$ 2,517,842	$ 2,555,483	$ 2,594,478	$ 2,634,725	$ 2,676,130

2

Scenario 3 - Projected Energy Savings at 4%

As part of its sensitivity analysis, PUC Distribution has performed the same analysis as above for a scenario where projected energy savings at 4% for all years. All other assumptions made in the base scenario above are the same. This results in a NPV of annual net benefit to customers of $28,805,983 and NPV of projected reliability benefits of $25,864,956, to a total NPV of benefits of $54,670,939)

Customer Net Benefit from 2022 to 2041
(Scenario 3 - 4% projected energy savings)

Customer Net Benefit Summary					
	2022	2023	2024	2025	2026
Cost of Power - updated to current estimate (not including GS>50 on	$ 77,574,554	$ 82,564,360	$ 88,666,180	$ 91,961,163	$ 94,531,250
Projected energy savings with SSG implementation	4.00%	4.00%	4.00%	4.00%	4.00%
Projected customer energy savings through SSG	$ 3,102,982	$ 3,302,574	$ 3,546,647	$ 3,678,447	$ 3,781,250
Projected system loss energy savings through SSG	$ 98,821	$ 105,177	$ 112,950	$ 117,148	$ 120,422
Total purchased power savings	$ 3,201,803	$ 3,407,752	$ 3,659,597	$ 3,795,594	$ 3,901,672
Additional revenue from increased SSG asset base	$ 875,610	$ 2,069,976	$ 2,070,214	$ 2,066,371	$ 2,058,773
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 296,400	$ 302,032	$ 307,770	$ 313,618	$ 319,577
Operating efficiency benefits due to SSG implementation	($30,816)	($31,402)	($31,998)	($32,606)	($33,226)
Change In Revenue Requirement	$ 836,804	$ 2,036,216	$ 2,041,596	$ 2,042,992	$ 2,040,734
Annual net benefit to customers	$ 2,364,999	$ 1,371,536	$ 1,618,002	$ 1,752,602	$ 1,860,937
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	$ 2,017,000	$ 2,017,000	$ 2,017,000
Total projected benefit to customers	$ 4,381,999	$ 3,388,536	$ 3,635,002	$ 3,769,602	$ 3,877,937
NPV of Annual Net Benefit to customers	**$ 28,805,983**				
NPV of Projected Relaibaility Benefits	**$ 25,864,956**				
Total	**$ 54,670,939**				

Customer Net Benefit Summary					
	2027	2028*	2029	2030	2031
Cost of Power - updated to current estimate (not including GS>50 on	$ 97,178,439	$ 99,912,392	$ 102,713,447	$ 105,606,102	$ 104,612,957
Projected energy savings with SSG implementation	4.00%	4.00%	4.00%	4.00%	4.00%
Projected customer energy savings through SSG	$ 3,887,138	$ 3,996,496	$ 4,108,538	$ 4,224,244	$ 4,184,518
Projected system loss energy savings through SSG	$ 123,794	$ 127,124	$ 130,845	$ 134,530	$ 133,264
Total purchased power savings	$ 4,010,931	$ 4,123,619	$ 4,239,383	$ 4,358,774	$ 4,317,783
Additional revenue from increased SSG asset base	$ 1,941,702	$ 1,827,295	$ 1,821,830	$ 1,813,675	$ 1,803,046
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 325,649	$ 331,836	$ 338,141	$ 344,565	$ 351,112
Operating efficiency benefits due to SSG implementation	($33,857)	($34,500)	($35,156)	($35,824)	($36,504)
Change In Revenue Requirement	$ 1,929,103	$ 1,820,241	$ 1,820,425	$ 1,818,027	$ 1,813,264
Annual net benefit to customers	$ 2,081,828	$ 2,303,379	$ 2,418,958	$ 2,540,747	$ 2,504,519
Annual projected reliability benefit to customers	$ 2,017,000	$ 2,017,000	$ 2,017,001	$ 2,017,002	$ 2,017,003
Total projected benefit to customers	$ 4,098,828	$ 4,320,379	$ 4,435,959	$ 4,557,749	$ 4,521,522
	*does not include replacement for computer equipment.				

Customer Net Benefit Summary					
	2032	2033	2034	2035	2036
Cost of Power - updated to current estimate (not including GS>50 on	$ 105,596,171	$ 105,596,171	$ 104,603,125	$ 103,620,010	$ 104,593,294
Projected energy savings with SSG implementation	4.00%	4.00%	4.00%	4.00%	4.00%
Projected customer energy savings through SSG	$ 4,223,847	$ 4,223,847	$ 4,184,125	$ 4,144,800	$ 4,183,732
Projected system loss energy savings through SSG	$ 134,517	$ 134,517	$ 133,252	$ 132,000	$ 133,239
Total purchased power savings	$ 4,358,364	$ 4,358,364	$ 4,317,377	$ 4,276,800	$ 4,316,971
Additional revenue from increased SSG asset base	$ 1,790,140	$ 1,775,140	$ 1,758,214	$ 1,739,515	$ 1,719,185
Benefit of reduced capital expenditures with SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 357,783	$ 364,581	$ 371,508	$ 378,567	$ 385,760
Operating efficiency benefits due to SSG implementation	($37,198)	($37,905)	($38,625)	($39,359)	($40,107)
Change In Revenue Requirement	$ 1,806,336	$ 1,797,427	$ 1,786,707	$ 1,774,333	$ 1,760,448
Annual net benefit to customers	$ 2,552,028	$ 2,560,937	$ 2,530,670	$ 2,502,467	$ 2,556,523
Annual projected reliability benefit to customers	$ 2,017,004	$ 2,017,005	$ 2,017,006	$ 2,017,007	$ 2,017,008
Total projected benefit to customers	$ 4,569,032	$ 4,577,942	$ 4,547,676	$ 4,519,474	$ 4,573,531

1

Customer Net Benefit Summary					
	2037	2038	2039	2040	2041
Cost of Power - updated to current estimate (not including GS>50 on	$ 105,576,311	$ 106,569,158	$ 107,571,934	$ 108,584,737	$ 109,607,668
Projected energy savings with SSG implementation	4.00%	4.00%	4.00%	4.00%	4.00%
Projected customer energy savings through SSG	$ 4,223,052	$ 4,262,766	$ 4,302,877	$ 4,343,389	$ 4,384,307
Projected system loss energy savings through SSG	$ 134,492	$ 135,756	$ 137,034	$ 138,324	$ 139,627
Total purchased power savings	$ 4,357,544	$ 4,398,523	$ 4,439,911	$ 4,481,714	$ 4,523,934
Additional revenue from increased SSG asset base	$ 1,697,355	$ 1,674,144	$ 1,649,664	$ 1,624,015	$ 1,597,291
Benefit of reduced capital expenditures with SSG	($304,390)	($304,390)	($304,390)	($304,390)	($304,390)
Additional O & M expenses due to SSG implementation	$ 393,089	$ 400,558	$ 408,168	$ 415,924	$ 423,826
Operating efficiency benefits due to SSG implementation	($40,869)	($41,645)	($42,436)	($43,243)	($44,064)
Change In Revenue Requirement	$ 1,745,185	$ 1,728,667	$ 1,711,006	$ 1,692,306	$ 1,672,663
Annual net benefit to customers	$ 2,612,359	$ 2,669,856	$ 2,728,906	$ 2,789,408	$ 2,851,271
Annual projected reliability benefit to customers	$ 2,017,009	$ 2,017,010	$ 2,017,011	$ 2,017,012	$ 2,017,013
Total projected benefit to customers	$ 4,629,368	$ 4,686,866	$ 4,745,917	$ 4,806,420	$ 4,868,284

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Appendix IR13

Sec-10 Exhibit_Staff Report-SSG Update 2021021 PUCD

INFORMATION NOTE

SUBJECT: **SAULT SMART GRID (SSG) PROJECT UPDATE**

PRESENTED TO: **PUC DISTRIBUTION INC. BOARD**

MEETING DATE: **OCTOBER 26, 2022**

Update since September 2022 Board Information Note.

Project & Schedule

The overall scope of work and final cost the project and remains on target for net capital expenditure budget of $24.5M.

Construction in progress across 5 station sites with three currently offline. Testing & commissioning has started at Sub 21 and will continue week of Oct 24th with Sub 1 to immediately follow. Both stations are planned for in service within two weeks. Planned return to service delays have required changes to schedule but also mitigated where possible with additional resources to be deployed by the EPC contractor. Station construction for last one or two sites is anticipated to potentially extend into January.

The Distribution Automation scope of work engineering is in progress in a number of areas including line work engineering design and planning with a number of meetings over last month. PUC planning efforts have included PUC line crew involvement in make ready work where efficiencies can be achieved in both construction and regulatory approval requirements. Programming of sim cards and modems for reclosers is near completion which will utilize the new PUC APN communication network. Preliminary schedule in development and depending on confirmation of material aiming for make ready work to commence in November.

The Survalent SCADA technical and software development work continues. Progress and schedule have been meeting expectations. Outage Management System implementation planning continues with broad PUC department involvement. Communication testing to for SCADA to new station equipment controllers is also in progress (test unit in PUC shop).

H&S project management and field crew performance has been meeting expectations. Site specific safety assessments and orientations have continued as planned and construction work in progress with no injuries or high-risk incidents. PUC continued placing a focus on field safety performance. H&S Plan score of 71% is still in “room for improvement” range driven by documentation record backlog but no significant risk areas of concern.

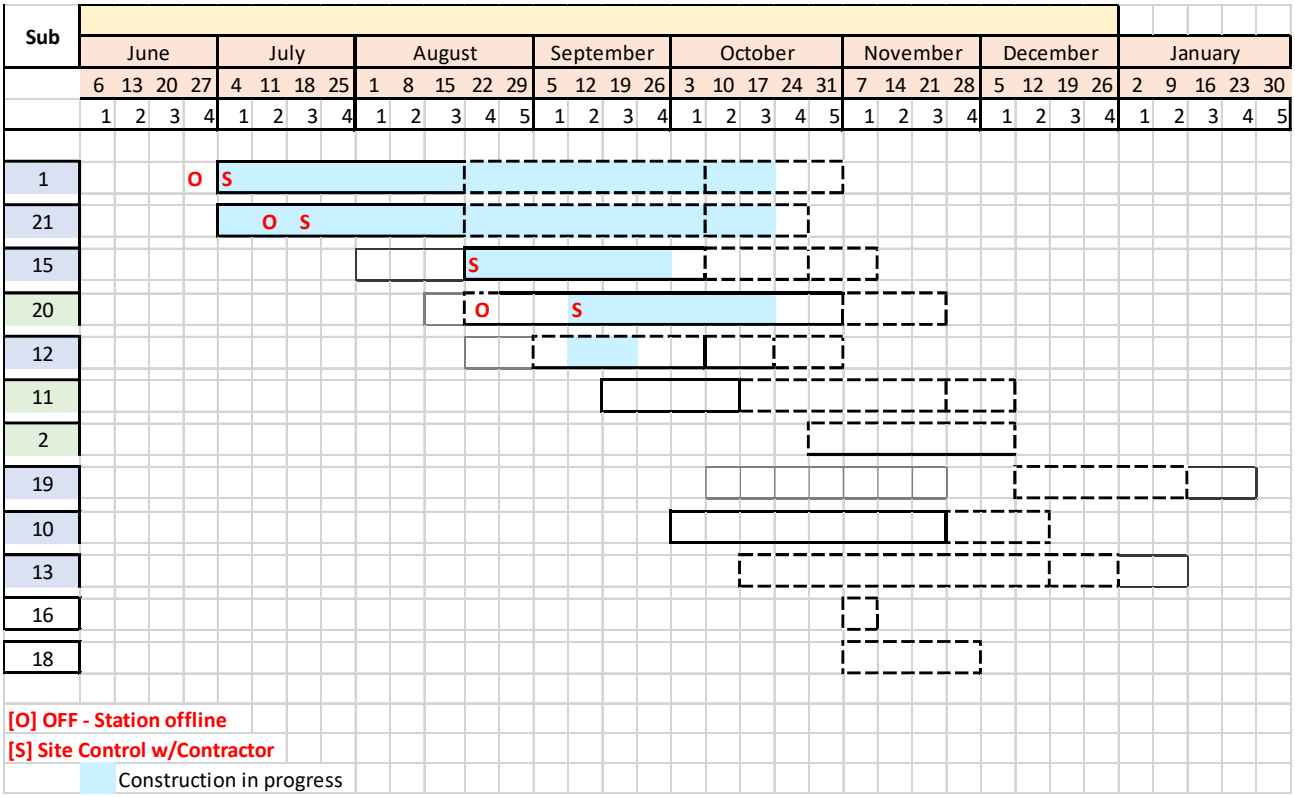
Prepared by: **Kevin Bell**
Date: **October 23, 2023**

Submitted by: **Kevin Bell**
Date: **October 26, 2022**

PUC Board Update – SSG Project

Financial (Net Capital)	Date					Notes:
Budget	April 29, 2021	$ 24.5	(M)			*OEB ICM Approval*
Actual Spend to Date	September 30, 2022	$ 10.9	(M)			*Finance Report*
Project Total Forecast	May 12, 2022	$ 24.5	(M)			

Construction	*Contractor VVO Construction Recovery Schedule*					***Notes:***
VVO (12 Stations)	**Target Date**	**Qty in Progress Plan**	**Qty in Progress Actual**	**Qty Complete Plan**	**Qty Complete Actual**	*Sub 16 - already in service by PUC*
Stations In Service ("live"/fixed assets)	December 31, 2022	6/11	5/11	2/11	0/11	*as of August 31, 2022*
Stations in VVO Operation (100%)	March 31, 2023	0/12	0/12	0/12	0/12	
DA (16-24 Feeders)	***Construction Schedule TBD***					
Feeders In Service ("live"/fixed assets)	December 31, 2022	0/TBD	0/TBD	0/TBD	0/TBD	
Feeder in Automation Operation	March 31, 2023	0/TBD	0/TBD	0/TBD	0/TBD	



ERM/RMC Key Risk Indicators	Description of KRI	Reporting Period	High Cost Zone	Lower	Target Zone	Higher	Yellow Zone	Red Zone	Trend
					100% +/-10%	90%-75%	75%-60%	<60%	
H&S Plan	Monthly audit score on 14 factors of the plan.	Sep 2022					71%		⇧
		Aug 2022					70%		⇧
		July 2022					69%		start

Appendix IR14

Items Provided to PUC Board of Directors

FOR APPROVAL

SUBJECT:	**PUC DISTRIBUTION INC. BUSINESS PLAN**
PREPARED FOR:	**BOARD OF DIRECTORS – PUC SERVICES. INC., PUC DISTRIBUTION INC., PUC INC.**
MEETING DATE:	**AUGUST 10, 2022**

Reference/Background:

Every five years, PUC Distribution Inc. ("PUCD") files a Cost of Service Rate Application ("COS") with its' regulator The Ontario Energy Board ("OEB") seeking approval for Distribution rates it can charge its customers. It is an exhaustive process that encompasses the efforts of many resources (internal and external) spanning approximately eighteen months of preparation.

The last PUCD COS that was approved by the OEB was in 2018. The next COS is scheduled to be filed by PUCD by August 31, 2022 for May 1, 2023 rates. Although the COS itself is quite extensive containing thousands of pages of descriptions/analytics/verifications, what is being brought forward for approval to the PUC Services Inc. ("PUCS"), PUCD and PUC Inc. ("PUCI") Boards of Directors is the Business Plan that gets included as an Appendix. This Business Plan spans 2023-2027 and presents the amount of revenue, capital and operating, maintenance and administrative expenses ("OM&A") required to be able to justify PUCD's proposed rates.

Discussion:

The 2023-2027 Business Plan that will be appended to the COS is attached for your review. It reflects PUCD's focus to be sustainable while balancing reliability and affordability for its customers. Management remains committed to being prudent in its expenditures and investments throughout the five year-period while not sacrificing the excellent service customers have come to rely on. Although the Business Plan is currently being finalized based on financial modelling that remains fluid until submission, the core elements are being brought forward for approval with the caveat that no material changes will need to be made. Should that transpire, additional approvals will be brought forward to the Boards as required.

Business Plan Highlights include:

1. *Identification & Mitigation Strategies for the following Risks:*
    a. Weather
    b. Local Economy & Credit
    c. Equipment Failure
    d. Regulatory

e. Human Resources
f. Technology
g. Business Continuity

2. Financial Projections:

Description ($ M)	2023 Test	2024 Projection	2025 Projection	2026 Projection	2027 Projection
Net Income	$3.12	$3.60	$3.75	$3.90	$4.07
Distribution Revenue	$23.78	$25.28	$25.79	$26.30	$26.83
OM&A Expenses	$13.53	$14.20	$14.48	$14.77	$15.06
Capital Expenditures (net)	$10.11	$7.24	$7.47	$6.61	$10.79

3. Customer Bill Impacts:

Average monthly Total Bill	Current Approved Rates	Proposed Rates	Change $	Change %
Residential Customer (750 kWh)	$ 122.56	$ 126.28	$ 3.72	3.03%
Small General Customer (2,000 kWh)	$ 309.53	$ 323.16	$ 13.63	4.40%
Large General Customer (145 kw)	$ 9,533.29	$ 9,335.77	$ (197.52)	-2.07%

Distribution Rate only Impact	Current Approved Rates	Proposed Rates	Change $	Change %
Residential Customer (750 kWh)	$ 35.88	$ 42.48	$ 6.60	18.39%
Small General Customer (2,000 kWh)	$ 80.27	$ 95.49	$ 15.22	18.96%
Large General Customer (145 kw)	$ 1,244.61	$ 1,440.10	$ 195.49	15.71%

Overall, management and staff believe that the PUCD Business Plan as presented supports a successful COS.

Resolutions:

1. That the Board of PUC Services Inc. accepts as information the PUCD Business Plan;

2. That the Board of PUC Services Inc. recommends to the Board of PUC Distribution Inc. that they approve the PUCD Business Plan;

3. That the Board of PUC Distribution Inc. accepts the recommendation of the Board of PUC Services Inc., that they approve the PUCD Business Plan;

4. That the Board of PUC Distribution Inc. recommends that the Board of PUC Inc., its sole shareholder, approve the PUCD Business Plan; and

5. That the Board of PUC Inc. accepts the recommendation of the Board of PUC Distribution Inc., that they approve the PUCD Business Plan.

Prepared by: **Kelly McLellan**
Date: **August 5, 2022**

Submitted by: **Kelly McLellan**
Date: **August 5, 2022**

Attachment: **PUCD Business Plan**

PUC DISTRIBUTION

Five Year Business Plan

2023 Budget and 2024-2027 Projections



August 2022

www.ssmpuc.com

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1. Executive Summary

PUC Distribution Inc. ("PUC") has developed this business plan to address the expectations of the Ontario Energy Board ("OEB")'s "Handbook for Utility Rate Applications," issued October 13, 2016. It outlines how key challenges associated with PUC's service areas, PUC's core values, and the preferences of PUC's customers have been integrated into its Cost-of-Service Rate Application ("COS") and Distribution System Plan ("DSP") in a manner that is consistent with the outcomes of the OEB's Renewed Regulatory Framework ("RRF"). This business plan also summarizes PUC's target and forecasted performance with respect to performance metrics to ensure that PUC delivers its strategic objectives.

PUC's vision is to improve communities through curiosity and innovation. Today more than ever, PUC's focus is on a sustainable company which is developing strategies to lower its carbon footprint, support communities, and offer excellent customer service.

This 2023-2027 business plan is reflective of that vision, as it balances reliability and affordability for customers and allows PUC to invest in the communities it serves.

All costs and projected revenues have been closely examined and reasonable assumptions respecting growth and expected OEB rate increases have been used. PUC's five (5) year financial projections are provided in Appendix A.

The OEB's framework will continue to challenge PUC's management and staff to find operational savings and efficiencies throughout the organization to achieve reasonable financial results. Although a capital replacement plan is in place, ongoing monitoring of cash flow levels and updated asset condition assessments will necessitate constantly reviewing the plan as more information becomes available to balance sustainability and affordability.

Management remains confident that with a successful outcome to the COS, the financial challenges will not hinder PUC's goals of exceeding the service quality indicators as detailed on the local distribution company ("LDC") scorecard, improving customer communication and advocacy, replacing infrastructure in an effective and prudent manner, maintaining rates at a reasonable level, and providing a return to the shareholder.

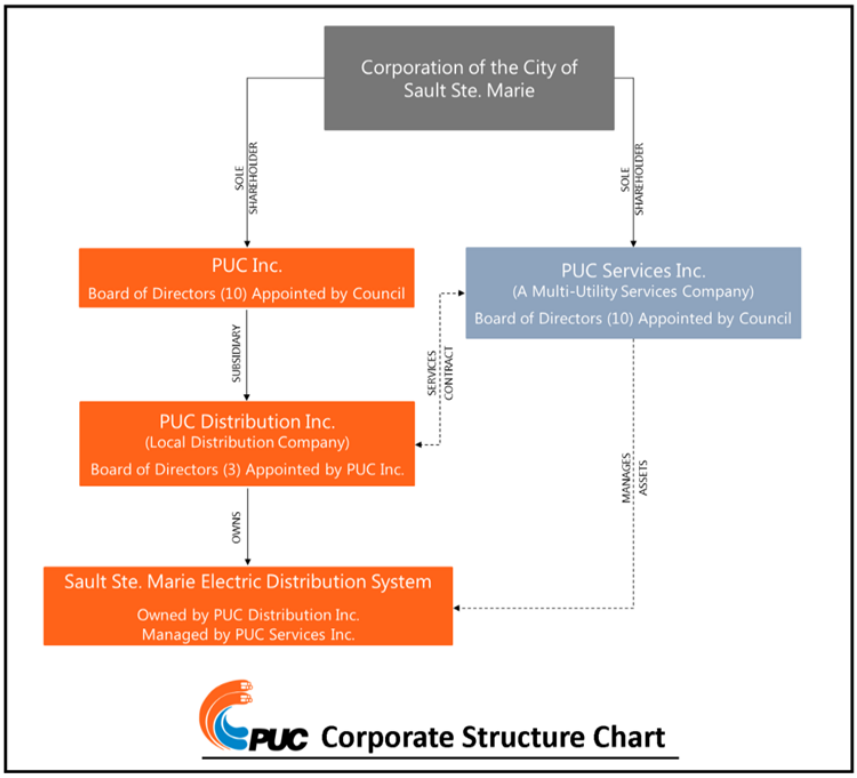
2. Overview and Ownership

PUC is an LDC licensed to distribute electricity in its service territory which includes most of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. In addition to distributing electricity, PUC is the default supplier of energy to customers within its service territory that do not contract with a retailer for their energy supply.

In accordance with Section 142 of the Electricity Act, 1998 the existing electricity assets of the City of Sault Ste. Marie Public Utilities Commission were transferred to PUC, a “for profit” corporation incorporated under the Ontario Business Corporations Act. PUC is 100% owned by PUC Inc., a holding company owned 100% by the City of Sault Ste. Marie (“the City”). The transfer was completed in 2000 and as required by Bill 210 in 2003, the City, through a Council resolution, affirmed that the electric utility should remain an OBCA “for profit” corporation.

PUC must operate its business in compliance with all applicable laws, including the Electricity Act, 1998, the Ontario Energy Board Act, 1998, the Ontario Business Corporations Act, and the rules, policies and requirements of the OEB including the Distribution System Code, the Affiliate Relationships Code, the Retail Settlement Code, the Standard Supply Service Code, the Accounting Procedures Handbook and Uniform System of Accounts, as well as the applicable Rate Handbook and Filing Requirements.

PUC, through its affiliate PUC Services Inc., operates using a shared services model. PUC regularly updates the allocation model as validated through a third-party provider (BDR – 2021). This model provides significant efficiency benefits across all of the utilities under the PUC umbrella. PUC Services Inc. shares certain resources with affiliates to create economies of scale and scope. The corporate structure and ownership of PUC is illustrated in the diagram below.



The Business is structured and operated to earn returns permitted under the provincial regulatory framework. PUC has its rates approved by the OEB. Although PUC does not pay corporate income taxes, as a municipally owned licensed LDC in the province of Ontario, PUC is required to remit Payments in Lieu of Taxes (PILS) to the province. The amount payable is generally calculated based on Federal and Provincial tax rules for corporations.

As of 2022, PUC serves an area of approximately 342 square kilometers, with a combined population of approximately 75,300. The service territory includes approximately 33,865 customers.

3. COS Filing

A COS, scheduled to be filed by PUC on August 31, 2022, for May 2023 rates, sets a price for a service based on the costs to provide it. The OEB will approve the revenue for PUC's 2023 year based on the sum of a prescribed rate of return on rate base (net fixed assets and working capital); operating, maintenance and administration ("OM&A") expenses; depreciation, interest expense; and tax. Distribution rates for the subsequent four years are limited to inflationary increases with a productivity adjustment and as a result, the COS Application will set the basis for the next five years of distribution revenue.

The OEB will review the COS Application through a public process. Documents are posted on the OEB's website and updated as the OEB reviews the application. Consumer groups and other affected groups (intervenors) may also take part in the process and provide comments. A series of clarification questions will be exchanged between the parties – PUC and intervenors/OEB staff. A full hearing may also ensue. The process will likely continue into 2023 in advance of the OEB's final decision on the application.

A successful COS outcome is critical to PUC's success, and management is committed to ensuring the following COS objectives are met:

- Incorporate customer interests and preferences
- Ensure all assets are constructed, operated and maintained in a condition which is safe for all employees, contractors, and the public
- Demonstrate ongoing continuous improvement while delivering on system reliability and quality objectives
- Demonstrate value for money
- Replace deteriorated aging infrastructure where warranted
- Address innovation and grid modernization

- Ensure reasonable distribution rates
- Effectively manage risk – financial, operational, cyber security, regulatory, privacy
- Ensure public policy responsiveness

4. Mission and Strategic Objectives

In 2020, PUC undertook a process to develop a strategic plan that would provide the company with clarity and direction, connecting PUC's vision for the future with its strategic objectives. The process, which included participation from community members, employees, PUC's shareholder, and the Board of Directors, resulted in updates to PUC's Mission, Vision, and Core Values



The PUC Mission, Vision and Core Values were further refined to ensure alignment with the OEB's Renewed Regulatory Framework for Electricity Distributors ("RRFE"). It is a performance-based approach identifying four desirable outcomes:

RRFE Performance Outcomes	Strategy	Strategic Objectives
Customer Focus	Build a customer-centric organization	Services are provided in a manner that responds to identified needs and preferences of customers.
Operational Effectiveness	Build a future company that is sustainable Maximize value	Continuous improvement in productivity and cost performance is achieved while LDC delivers on system reliability and quality objectives.
Public Policy Responsiveness	Regulatory Compliance	LDC delivers on obligations mandated by governments.
Financial Performance	Financial integrity and accountability Drive profitable and sustainable growth	Financial viability is maintained and savings from operational effectiveness are sustainable.

In conjunction with the Mission, Vision, and Core Values, PUC has set three strategic Focus Areas and Aspirations:



Focus Area & Aspiration	Strategic Long-Term Goals	Strategy to Achieve Success	Objectives
Customers "Our customers trust us"	Achieve and maintain an exceptional customer satisfaction rating Meet or exceed all OEB scorecard targets	Improve service quality management (responsiveness, entrepreneurial, high quality) Advance customer focus (customer satisfaction, communication, engagement, education)	Achieve OEB scorecard targets Increase MyPUC app usage
Employees "Our Employees Appreciate us"	Recognized as one of Canada's top 100 Employers A culture of safety excellence	Implement leading organizational transformation (employee engagement, operational excellence, talent management) Continuous improvement of safety culture and performance through an Integrated Safety Management Program	Continue accountability leadership training for all staff Develop a diversity, equity, and inclusion strategy Zero high-risk lost time incidents Zero high-risk employee safety incidents Contractor safety program
Shareholder "Our Shareholder Commends us"	Achieve OEB deemed return on equity for shareholder Achieve infrastructure sustainability Continuous productivity/business process improvement Increase enterprise value	Ensure sustainability of assets and system Productivity/business process improvements Explore permitted business opportunities	Achieve infrastructure sustainability File cost of service rate application Complete Sault Smart Grid (SSG) project Continuous productivity/business improvements

PUC's focus on sustainability has been an effective way to increase innovation capability, reduce the company's carbon footprint and enable significant growth. By weighing all decisions through this lens, PUC has identified, pursued, and launched several new opportunities that are rooted in community partnerships and innovative ideas.

5. Key Success Factors

The following five key success factors will help PUC create a best-in-class utility:

1. ***Completion of a DSP*** – This comprehensive engineering plan outlines PUC's asset management strategy and capital expenditure plans over a five-year horizon. PUC's plan provides clarity, direction and focus connecting PUC's vision for the future to its core strategies and strategic objectives. Customers, Employees, and Shareholders are the focus and at the forefront of PUC's DSP.

   In addition to the core values above, the fundamental objective of PUC's asset management program is to manage planning and engineering prudently and efficiently. This entails ensuring the design, inspection, maintenance, replacement, and retirement of all distribution assets are done in a sustainable manner that maximizes safety and customer reliability, while optimizing asset lifecycle costs.

2. ***People, Culture and Safety Strategy*** – Succession planning, employee growth and engagement will ensure that PUC has the right people in the right jobs over the coming years. Human resources and safety policies will position PUC as one of the top employers in Canada. Safety is always a top priority in PUC's plans and budgets. This includes both safety for the public and the safety of PUC employees.

   PUC is dedicated to creating a welcoming environment that encourages and promotes diversity, cross-culture working experiences and strong relationships within the community and with partners. PUC will strive to demonstrate leadership and foster a workplace culture where all employees feel empowered to bring their authentic selves to the workplace and do their best work.

3. ***Customer-Centric*** – With its COS, PUC reached out to customers through the biennial customer satisfaction survey as well as through specific COS surveys to gather feedback and confirmation on how PUC is doing. PUC is continually looking for ways to create positive experiences for customers, while at the same time encouraging behaviour that is more responsive to energy conservation. This has resulted in the launch of the MyPUC app, along with other consistent, proactive communication methods that are conducive to two-way interaction. A summary of PUC's customer engagement and how it impacts this business plan is provided in Appendix B.

4. ***Financial Success*** – PUC strives to produce consistent, allowable earnings, with returns that meet the expectation of PUC's Shareholder. The focus is on growing value through

investment and innovation. PUC continues to build on partnerships with other LDCs and organizations to strengthen the utility.

5. ***Innovation*** – Building on the strong culture of innovation PUC has created throughout the organization, PUC will engage all staff to look for ways to improve efficiency and reduce costs through innovation. This includes initiatives such as "'becoming paperless" with creating electronic forms, promoting e-billing to customers, and also improving efficiencies in how we operate.

6. Key Challenges, Risks and Mitigation

PUC continues to set risk management as a top priority. It has implemented an Enterprise-wide Risk Management (ERM) program whereby the Senior Leadership Team become Risk Owners for one or more risks. They assume full accountability for successful management of their risk(s), including actions plans for risk mitigation and report on progress regularly. Over the COS horizon, the corporate risk register will continue to be reviewed to ensure that risks with a potential to affect the organization from a safety, reputation, financial and personnel perspective are identified and addressed. This will enable PUC to deliver on its commitments as presented with the COS.

The following business risks have been identified, and mitigation strategies are in place:

Weather

Mitigation of material weather-related impacts on costs (e.g., ice storms, high winds, etc.) can be achieved in different ways, including by improving the resiliency of PUC's assets through design changes and proactive management of right-of-way. Risk exposure can also be reduced through a request for a z-factor adjustment application before the OEB. The current materiality threshold for z-factor adjustments is 0.5% of distribution revenue, which for PUC is approximately $0.1 million per event.

Weather-related impacts on distribution revenue, as well as energy conservation efforts, cannot be mitigated in the short term, although evidence will be presented in the COS to mitigate the future impact of a weather-related declining revenue trend. Such evidence would generally include the presentation of weather-normalized data as a basis for determining customer-specific volumetric distribution charges. In addition, the transition to a fully fixed monthly charge for residential customers was completed in 2020, resulting in approximately 67% of distribution revenue being fixed monthly.

Local Economy and Credit Risks

LDCs in general are challenged to mitigate short-term impacts on distribution revenue resulting from declining consumption and poor economic conditions. These aspects are considered to be normal business risks for LDCs and must be taken into consideration as part of the development of the load forecast underlying the COS.

As part of its COS, PUC will provide a load forecast derived from a multi-factor, single-equation econometric model. The model includes such parameters as weather (heating degree-days, cooling degree-days), number of customers, calendar variables (days in month, number of peak hours), and a trend variable. LDCs are exposed to revenue fluctuations during the IRM rate periods from variances between actual loads and the load forecasts underlying distribution rates at the time of the COS filing.

PUC faces credit risk primarily from non-payment of hydro bills by large commercial account customers. The company's revenue is earned from a broad base of customers; it does not earn a significant amount of revenue from any single customer. Although not a direct customer of PUC, the performance of the City's largest employer poses a material risk to PUC because of its impact on residents and businesses that are customers of PUC.

PUC's top ten customers represent 6% of distribution revenue, which exposes PUC to credit risk from these customers. However, of the top ten customers, only one is a private corporation, the remainder are federal, provincial, or municipal government entities which reduces the credit risk. Additionally, a systemic downturn could also expose PUC to credit risk from other customer classes. To deal with this risk, PUC has adopted credit policies as permitted by OEB regulation that result in a reasonable level of credit risk mitigation. PUC does not provide significant electric supply to the major industries in the municipality, however, financial difficulties at these companies could adversely affect the entire community and thus the distribution utility.

Equipment Failure

Equipment failures have an effect on service reliability to customers. By recently completing an Asset Management Plan ("AMP") and a DSP, PUC has adopted a systematic plan to replace its aging infrastructure. Equipment failure risk is managed through such programs as the annual tree-trimming program, infrared surveys of plant and equipment, non-destructive pole testing and treatment, oil testing of power transformers, and by maintaining an adequate inventory of replacement parts.

Regulatory Risk

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that significantly reduce the rate of return that can be earned by electricity distributors. In addition, the ability to maintain the distribution system depends on, among other factors, the OEB allowing recovery of the OM&A and capital costs required in the future. Lower rates arising from these types of changes could result in distribution earnings and cash flow being lower than the rate increases assumed in the Business Plan.

Failing to continually be aware of and applying changing government regulations is also a corporate risk. The company monitors developments in the electricity industry and relies on the Electricity Distributors Association ("EDA") to monitor and act on its behalf. Consultants with expertise in certain fields are utilized as required. Further, PUC is a member of the Utilities Standards Forum ("USF") and actively participates in various Regulatory Working Groups as a means to keep abreast of changes in Regulations, provide insight on emerging issues and network industry best practices.

In the past, OEB amendments to regulations, codes and guidelines have been experienced in the following areas such as:

- Restrictions on disconnecting electric services for non-payment;
- Length of advance notice prior to a disconnection;
- Bill due dates and late payment charges;
- Security deposits;
- Allocation of payments;
- Equal monthly billing plans; and
- Arrears payment arrangements.

Management continues to monitor the OEB's amendments to customer service rules and will analyze the financial impact of any changes required by the OEB in a timely manner.

Human Resources Risk

Acquisition and retention of human resources to support existing operations and new business requirements remain a continuous risk to manage. PUC Services Inc., like others in the utility services industry, faces a significant number of retirements over the next several years. The retirement of individuals in technical, trades and management positions will result in the loss of a significant pool of expertise, therefore where

practical replacements are hired in advance of projected retirements to promote the transfer of knowledge. Further, management and staff have committed to making a priority to develop and implement a talent strategy that attracts and retains qualified candidates to meet the company's recruitment needs.

As part of the management services contract, PUC Services Inc. provides the workforce necessary to operate PUC. Labour disruptions can affect ongoing operations. Collective agreements with the union employees in PUC Services Inc. are in effect until April 30, 2024.

Technology Risk

The use and complexity of the company's electronic infrastructure continue to increase, and its reliability and security are critical to all areas of operation. As part of the management service contract with PUC Services Inc., an information technology (IT) department oversees networks, voice over internet protocol communications, enterprise software, smart meter operation, systems security, and other emerging IT issues. Further, PUC Services Inc., has established a dedicated Information Security (IS) department that reports directly to the President & CEO. This department oversees the cybersecurity configuration of all systems and network devices within the technology infrastructure. It monitors all cyber alerts and ensures mitigating solutions are in place to protect confidentiality, integrity, and availability of all data and applications. It delivers a corporate-wide staff training program to address cybersecurity issues and is actively participating in the USF's Cybersecurity and Privacy working groups. PUC completed the Cybersecurity implementation plan developed to meet the requirements of the OEB Cyber Security Framework. PUC continues to strive for full compliance with the recommended measures and reporting requirements to mitigate cyber security risks.

Business Continuity Risk

Business Continuity Planning (BCP) is an important part of PUC's risk management strategy. During the COVID pandemic, PUC's Business Continuity Plan was challenged and updated to ensure PUC could continue to operate safely and efficiently. Every department in the organization was involved in the process of creating systems of prevention and recovery to ensure PUC's goal of enabling ongoing operations and delivery of essential services to customers was met. This process included comprehensive tabletop exercises that took into account critical resource planning, alternate facilities, mission essential functions, succession planning and worker and public safety procedures.

7. Financial Performance Projections

This report summarizes PUC's estimated results for 2022 and 2023 budgets (test year budget) and 2024 – 2027 projections.

The Business Plan is based on the following assumptions and constraints:

1. A distribution revenue increase in 2023 of approximately $4.1M based on the estimated increase as a result of the COS to be submitted (rebased recovery of requested OM&A expenses, depreciation expense and PILs expense, plus a return on asset base as prescribed by the OEB).
2. An annual distribution revenue increase in 2024 to 2027 of 2.0% based on the estimated Incentive Rate Mechanism (IRM) annual increase leading up to the next COS in 2028. The projections are also based on historical consumption levels.
3. Subsequent to 2023, expense increases are estimated at 2.0% per year.
4. Prudent investment in distribution plant so that ratepayers can continue to be provided with excellent service and reliability.
5. Continued improvement to customer communication and engagement to best serve customers.
6. Long-term view of return on shareholder investments.
7. Continuing to seek improvements in productivity in order to provide current and future mandated levels of service to customers at a cost at inflation or less.
8. Managing economic and political uncertainty.
9. Reducing the debt-to-equity ratio over a number of years to the OEB deemed level of 60/40%.

PUC High-Level Financial Budgets and Projections:

PUC's Financial Plan summary is provided in Appendix A. The Plan provides for prudent and sustainable investment in core business operations and subject to certain material risks, results in the following metrics:

Description	2023 Test	2024 Projection	2025 Projection	2026 Projection	2027 Projection
Liquidity: Current Ratio	0.89	1.01	1.07	1.23	1.14
Debt to Equity Ratio	2.36	2.24	2.11	1.99	1.85
Projected Return on Equity	6.80%	7.61%	7.50%	7.29%	7.14%
Deemed Return on Equity	8.66%	8.66%	8.66%	8.66%	8.66%
Interest payments to S/H	$1.62M	$1.62M	$1.62M	$1.62M	$1.62M
Dividends to S/H	$0.61M	$0.61M	$0.61M	$0.61M	$0.61M

PUC's future target is to achieve its deemed return on equity while maintaining liquidity and leverage ratios that are relatively consistent with historical levels.

The Business Plan provides for prudent and sustainable investment in core business operations. The achievement of this plan is subject to obtaining approval for rates in 2023 as requested and to business risks as noted above. Following is a summary of the five-year financial plan that is attached in Appendix A:

Description ($ M)	2023 Test	2024 Projection	2025 Projection	2026 Projection	2027 Projection
Net Income	$3.12	$3.60	$3.75	$3.90	$4.07
Distribution Revenue	$23.78	$25.28	$25.79	$26.30	$26.83
OM&A Expenses	$13.53	$14.20	$14.48	$14.77	$15.06
Depreciation	$5.43	$5.67	$5.85	$6.04	$6.47
Capital Expenditures (net)	$10.11	$7.24	$7.47	$6.61	$10.79
Working Capital	($5.97)	($3.20)	($2.10)	($0.01)	($2.45)

Net Income

Overall, net income is increasing from 2023 to 2027 as a result of the rebasing of distribution rates. The 2023 budget includes only a portion of the increase, as it is anticipated that the rate increase will take place on May 1, 2023. Net income increases again in 2024 as the rebased rates will be effective for the entire year. The principal driver of the increase in net income in 2023 corresponds to the significant capital investments over the past five years leading to an increase in rate base.

Distribution Revenue

The 2023 planned distribution revenue has been determined based on re-setting the distribution rates that PUC charges its customers to be applied for with the OEB in PUC's 2023 COS. It is expected that PUC will file its application with the OEB on August 31, 2022. Revenue is based on PUC's budget for OM&A and depreciation expenditures, payments in lieu of taxes, and an allowable regulatory return on capital. PUC is requesting that the OEB approve an average increase to its 2023 distribution rates of 18% when compared to 2022 rates. This increase is mainly driven by the return on rate base, and associated depreciation due to the increase in Net Book Value of capital assets.

Preliminary bill impacts indicate that a typical Residential customer consuming on average, 750 kWh per month, would see their total bill increase by about 3.03%. Bill impacts for the typical General Service customer consuming on average, 2,000 kWh per month, would see their total bill increase by about 4.4%. However, the final bill impacts that will be requested from the OEB are not known yet as PUC is still working on preparing its application, and the application will be subject to review by the OEB and intervenors through the rate application process. The outcome of the rate proceeding may result in OEB approving a different revenue requirement than is originally requested.

PUC is preparing a strong case, supported by third-party expert reports to justify the need for rate increases. PUC needs to continue investing in people, technologies, and processes to support its customers and to operate a sustainable business that provides a safe and reliable service expected by its customers. The COS provides justification for the level of expenditures needed to run PUC effectively, in addition to providing value to its customer base and earn its regulated rate of return.

Operating Expenses

The average non-labour OM&A inflation rate in the 2023 test year is 3.0% per year and 2.0% in 2024 through 2027. The 2.0% for 2024 through 2027 is the benchmark that the Bank of

Canada is striving to achieve. Therefore, this is applied to both revenue and expenditures so that any change to inflation will be stabilized in the financial forecast.

A collective agreement was ratified in March 2022, providing the terms and conditions of employment for unionized staff within PUC from April 1, 2021, to April 30, 2024. Annual general union and non-union labour inflation is assumed to be 2.0% for the years 2023-2027.

The following table provides the 2023 to 2027 sources of OM&A expenditures.

Description ($M)	2023 Test	2024 Projection	2025 Projection	2026 Projection	2027 Projection
Operations	$7.28	$7.43	$7.57	$7.73	$7.88
Billing and Collecting	$2.04	$2.08	$2.13	$2.17	$2.21
Administrative	$4.21	$4.68	$4.78	$4.87	$4.97
Total OM&A	**$13.53**	**$14.19**	**$14.48**	**$14.77**	**$15.06**

Working Capital

Working capital remains at a low level through the earlier years of the projection period. Elevated capital expenditures, including SSG and the Substation 16 rebuild, in addition to current debt service obligations, have outweighed cash generated from operations and new borrowings. PUC's challenge is to continue to provide service to customers in the regulated rate environment where revenue increases are capped at less than inflation and ever-evolving regulations increase OM&A expenses in a local economy that is not expanding. An increase in working capital will be attained through lower capital expenditures and additional financing.

Despite the moderate rate increases expected in the IRM years, management believes that it can deliver PUC's capital plan and manage costs effectively and in a manner that continues to deliver quality distribution service safely and reliably for ratepayers. The Business Plan reflects managed increases in expenditures with due regard for the following:

- Expectations set by the OEB regarding the nature and magnitude of expenditures.
- Prioritization of investments in the context of requirements for distribution system renewal and the needs of PUC's ratepayers.
- Advancement of business processes through replacement or new investments in information technology systems and technology-based processes.
- Continued improvement to customer engagement and communication.
- Customer affordability.
- A reasonable rate of return for the shareholder.

PUC's target for the forecast period is to balance inflationary OM&A cost increases with productivity and efficiency improvements, consistent with the price-cap adjustment factors inherent in the OEB's IRM rate-setting framework.

Capital Expenditures

PUC's overall system planning, and capital expenditure planning process ensures PUC continues to provide safe, reliable, and efficient distribution of electricity to its customers. Capital investments are required to maintain adequate security of supply to meet customer needs, as well as to replace end-of-life assets. PUC has updated its DSP and AMP that both identify areas of the distribution system that should be the focus of resources in order to maintain reliable service to customers. In 2022, capital expenditures include the substantial completion of the SSG as part of System Service assets.

Planned Capital Expenditures

Planned Capital Expenditures ($M)	2022 Budget	2023 Test	2024 Projection	2025 Projection	2026 Projection	2027 Projection
System Access	$ 1.84	$ 2.34	$ 2.67	$ 2.79	$ 2.49	$ 2.36
System Renewal	$ 6.63	$ 4.60	$ 4.24	$ 3.44	$ 3.55	$ 2.57
System Service	$ 28.71	$ 3.19	$ 0.13	$ 0.84	$ 0.75	$ 5.86
General Plant	$ -	$ 0.58	$ 0.81	$ 1.03	$ 0.43	$ 0.63
Total Expenditures, Gross	$ 37.18	$ 10.71	$ 7.85	$ 8.11	$ 7.22	$ 11.42
Capital Contributions	$ (7.85)	$ (0.59)	$ (0.62)	$ (0.64)	$ (0.61)	$ (0.62)
Total Expenditures, Net	**$ 29.33**	**$ 10.11**	**$ 7.24**	**$ 7.47**	**$ 6.61**	**$ 10.79**

Financing

No changes have been made to the current financial structure in this financial plan. Debt to equity, which includes shareholder debt, is currently 69% debt and 31% equity in comparison to the deemed debt to equity of 60/40%. The interest payment to the shareholder remains at $1.62M throughout the projection period. The financial plan results in a debt-to-equity level of 70/30% by 2023, falling to 65/35% by 2027.

8. Revenue Requirement/Revenue Deficiency

PUC's COS is intended to set rates that will recover the 2023 base revenue requirement identified in the table below. The following illustrates that revenues at current rates are insufficient to recover this revenue requirement, resulting in a net revenue deficiency of $4.07M, confirming the need for PUC to proceed with its scheduled COS.

Revenue Deficiency Determination ($M)

Description	Current Rates	Proposed Rates
Revenue		
Revenue Deficiency from below		**$ 4.07**
Distribution Revenue	$ 20.84	$ 20.84
Other Operating Revenue offsets	$ 2.75	$ 2.75
Total Revenue	**$ 23.59**	**$ 27.66**
Costs and Expenses		
Operating Expenses	$ 19.37	$ 19.37
Deemed Interest Expense	$ 3.09	$ 3.09
Total Costs and Expenses	**$ 22.46**	**$ 22.46**
Utility Income Before Income Taxes	**$ 1.13**	**$ 5.20**
Income Taxes:		
Corporate Income Taxes	$ (0.59)	$ 0.49
Total Income Taxes	**$ (0.59)**	**$ 0.49**
Utility Net Income	**$ 1.72**	**$ 4.71**
Utility Rate Base	$ 135.93	$ 135.93
Actual Return on Rate Base	3.54%	5.74%
Target Return - Equity on Rate Base	5.74%	
Deficiency/Sufficiency in Return on Equity	-2.20%	
Revenue Deficiency/(Sufficiency) after tax	$ 2.99	
Gross Revenue Deficiency/(Sufficiency)	**$ 4.07**	

PUC has incorporated these final projections for 2024 and its effect on revenue requirement on its scorecard metrics provided in Appendix C.

9. Bill Impacts

Based on a new revenue requirement of $27.6M in 2023, the following table outlines the bill impacts for the following rate classes:

Average monthly Total Bill	Current Approved Rates	Proposed Rates	Change $	Change %
Residential Customer (750 kWh)	$ 122.56	$ 126.28	$ 3.72	3.03%
Small General Customer (2,000 kWh)	$ 309.53	$ 323.16	$ 13.63	4.40%
Large General Customer (145 kw)	$ 9,533.29	$ 9,335.77	$ (197.52)	-2.07%

Distribution Rate only Impact	Current Approved Rates	Proposed Rates	Change $	Change %
Residential Customer (750 kWh)	$ 35.88	$ 42.48	$ 6.60	18.39%
Small General Customer (2,000 kWh)	$ 80.27	$ 95.49	$ 15.22	18.96%
Large General Customer (145 kw)	$ 1,244.61	$ 1,440.10	$ 195.49	15.71%

Incorporated in the overall monthly bill impact is the effect of the following major components of the electricity bill:

- Distribution rates (monthly service charge and volumetric rates);
- Disposition of deferral and variance accounts:
- Revised Retail Transmission rates;
- Regulatory Charges; and
- Loss Factors.
- Revised Embedded Generation Rate Rider Refund
- Rate Rider Refund for Loss Carry forwards
- VVO Consumption Savings from Sault Smart Grid

Overall PUC believes that the bill impacts are reasonable for its customers and properly aligns its rising costs with affordable rates.

10. Conclusion

This 2023-2027 Business Plan for PUC reflects its focus on being sustainable while balancing reliability and affordability for customers. Overall, the plan supports a successful COS, and management remains committed to being prudent in its expenditures and investments throughout the five-year period while not sacrificing the excellent service customers have come to rely on.

Appendix A - Financial Projections

PUC Distribution Inc.
Balance Sheet

	For the Year Ending December 31											
	2022 Budget		2023 Budget		2024 Projected		2025 Projected		2026 Projected		2027 Projected	
Assets												
Current Assets	$21,518,045		$22,847,794		$25,951,171		$27,475,780		$31,527,525		$29,249,329	
Future Taxes	$0		$0		$0		$0		$0		$0	
Net Fixed Assets	$131,086,455		$135,426,047		$136,987,384		$138,611,506		$139,151,077		$143,705,283	
Regulatory Assets	$9,437,146		$9,437,146		$9,437,146		$9,437,146		$9,437,146		$9,437,146	
	$	162,041,646	$	167,710,987	$	172,375,701	$	175,524,432	$	180,115,747	$	182,391,758
Liabilities												
Current Liabilities	$27,912,361		$28,224,789		$28,390,228		$28,599,927		$29,583,468		$29,662,991	
Notes Payable	$83,669,826		$86,520,291		$88,030,694		$87,831,397		$88,148,560		$86,886,200	
Deferred Revenue	$7,034,528		$7,034,528		$7,034,528		$7,034,528		$7,034,528		$7,034,528	
Regulatory Liabilities	$696,821		$696,821		$696,821		$696,821		$696,821		$696,821	
Deferred tax liabilities	$1,989,000		$1,989,000		$1,989,000		$1,989,000		$1,989,000		$1,989,000	
	$121,302,537		$124,465,429		$126,141,271		$126,151,674		$127,452,377		$126,269,540	
Shareholder Equity												
Common Shares	$20,062,107		$20,062,107		$20,062,107		$20,062,107		$20,062,107		$20,062,107	
Retained Earnings	$20,677,002		$23,183,451		$26,172,323		$29,310,651		$32,601,263		$36,060,111	
	$	40,739,109	$	43,245,558	$	46,234,430	$	49,372,758	$	52,663,370	$	56,122,218
Total Liabilities and Shareholder Equity	$	162,041,646	$	167,710,987	$	172,375,700	$	175,524,432	$	180,115,747	$	182,391,758

PUC Distribution Inc.
Statement of Comprehensive Income

	For the Year Ending December 31									
	2022 Budget	2023	Budget	2024	Projected	2025	Projected	2026	Projected	2027	Projected
Revenue											
Net Electricity Distribution Revenue	$ 20,336,375	$	23,782,600	$	25,281,653	$	25,787,286	$	26,303,032	$	26,829,093
Other Revenue	$ 2,509,522	$	2,750,265	$	2,770,628	$	2,791,398	$	2,812,583	$	2,834,192
	$ 22,845,897	$	26,532,865	$	28,052,281	$	28,578,684	$	29,115,615	$	29,663,284
Expenses											
Operations	$ 6,680,445	$	7,280,465	$	7,426,074	$	7,574,596	$	7,726,088	$	7,880,609
Billing and Collecting	$ 1,934,849	$	2,043,800	$	2,084,676	$	2,126,370	$	2,168,897	$	2,212,275
Administrative	$ 3,540,744	$	4,209,435	$	4,684,217	$	4,777,902	$	4,873,460	$	4,970,929
Operating Expenses	$ 12,156,038	$	13,533,701	$	14,194,968	$	14,478,867	$	14,768,444	$	15,063,813
Depreciation	$ 4,473,172	$	5,425,413	$	5,669,538	$	5,850,310	$	6,037,171	$	6,201,589
Property Taxes andLEAP	$ 369,215	$	415,575	$	423,887	$	432,364	$	441,012	$	449,832
Operating and Depreciation	$ 16,998,425	$	19,374,689	$	20,288,392	$	20,761,541	$	21,246,627	$	21,715,234
Income from Operating	$ 5,847,472	$	7,158,177	$	7,763,889	$	7,817,143	$	7,868,988	$	7,948,050
Interest Expense	$ 3,094,507	$	3,943,634	$	4,053,307	$	3,952,721	$	3,847,818	$	3,753,730
Income before taxes	$ 2,752,965	$	3,214,543	$	3,710,582	$	3,864,422	$	4,021,170	$	4,194,320
Income taxes	$ 84,299	$	98,013	$	111,631	$	116,013	$	120,479	$	125,392
Net Income	$ 2,668,666	$	3,116,529	$	3,598,951	$	3,748,408	$	3,900,692	$	4,068,928
Opening Retained Earnings	$ 18,456,616	$	21,125,282	$	24,241,812	$	27,840,763	$	27,840,763	$	31,589,172
Net Income	$ 2,668,666	$	3,116,529	$	3,598,951	$	3,748,408	$	3,900,692	$	4,068,928
Dividends	$ -	$	-	$	-	$	-	$	-	$	-
Closing Retained Earnings	$ 21,125,282	$	24,241,812	$	27,840,763	$	31,589,172	$	31,741,455	$	35,658,100

PUC Distribution Inc.
Statement of Working Capital

	For the Year Ending December 31 2022 Budget	2023 Budget	2024 Projected	2025 Projected	2026 Projected	2027 Projected
Opening Working Capital	($7,342,222)	($6,678,829)	($5,973,935)	($3,201,437)	($2,096,226)	($11,563)
Net Income	$ 2,668,666	$ 3,116,529	$ 3,598,951	$ 3,748,408	$ 3,900,692	$ 4,068,928
Add Depreciation	$ 4,473,172	$ 5,425,413	$ 5,669,538	$ 5,850,310	$ 6,037,171	$ 6,201,589
Less Net Capital Expenditures	$23,097,501	$9,765,005	$7,230,875	$7,474,433	$6,576,741	$10,755,796
Add Loan Proceeds	$ -	$ -	$ 4,000,000	$ 4,000,000	$ 5,500,000	$ 4,000,000
Less Principle Repayments	$2,011,730	$2,324,158	$2,489,597	$2,699,296	$3,682,837	$3,762,360
Ending Working Capital	$ (25,309,615)	$ (10,226,050)	$ (2,425,918)	$ 223,553	$ 3,082,058	$ (259,202)
Working Capital	($6,678,829)	($5,973,935)	($3,201,437)	($2,096,226)	($11,563)	($2,448,805)

Appendix B - Customer Engagement

As a trusted utility provider for over 100 years, PUC is continually looking for ways to create positive experiences for customers, while at the same time encouraging behaviour that is more responsive to energy conservation. PUC is always striving to use innovation to improve communication – and trust - with customers. PUC recognizes that as the utility industry evolves, so do their customers' needs and expectations.

PUC's five-year strategic direction provides clarity, direction and focus connecting PUC's vision to improve communities through curiosity and innovation, with the company's core strategies and strategic objectives. Customers are one of PUC's three areas of strategic focus, along with employees and PUC's shareholder. PUC's strategic long-term goal is to achieve and maintain an exceptional satisfaction rating, and strategies to achieve success in this area include advancing customer communications and engagement, and creating an improved, ease of use experience.

Over the past five years, improving communications, community relations and the overall customer experience have been identified as strategic priorities for the company. Through this focused approach, PUC has been able to effectively engage with customers through meaningful, two-way communication, and improve upon the customer experience through a "one-stop-shop" methodology for first point of contact.

In 2020, PUC developed a new brand promise to customers that states "we lead the way through innovation and compassion to deliver outstanding service every single day." Combined with PUC's core value of being 'customer-centric,' PUC has continually demonstrated their commitment to engaging customers over the past five years.

PUC uses various communication tactics to best serve its customers, such as:

- Digital Platforms (i.e., Mobile App, PUC website, Customer Connect Portal, social media, and digital advertising);
- Traditional Platforms (i.e., phone and mail, media, print, radio advertising);
- Community Outreach (i.e., attendance at community events, townhalls, open houses, school safety program); and
- Customer Surveys.

Through regular customer engagement surveys, PUC has been able to incorporate important customer feedback when evaluating PUC's priorities moving forward. Surveys have also provided

opportunities for education and awareness regarding PUC's operations, improvements to service and strategic initiatives.

Since PUC's last cost of service application filing, it has engaged customers in the following eight surveys:

1. Two (2) UtilityPULSE Customer Satisfaction Surveys (2019, 2021)
2. Four (4) Customer Pulse surveys (in 2020)
3. Two (2) Cost of Service-related surveys (2021, 2022)

As each survey is analyzed, several common themes have surfaced, providing PUC with greater insight into the needs and wants of customers. Those common themes include:

- Customers want improved communications;
- Customers place a high value on energy saving initiatives and PUC lowering their carbon footprint;
- Customers place a high value on reliability, cyber security, and upgrades to infrastructure;
- Customers place high importance on reasonable electricity rates.

Below provides a more detailed summary of the surveys conducted, and how PUC has responded.

<u>UtilityPULSE Customer Satisfaction Surveys</u>

In 2019 and 2021, PUC conducted its biennial Customer Satisfaction Surveys with UtilityPulse. The objective of these surveys is to capture perceptions about customer needs and wants as well as gather information to support discussions and improve the customer experience at every level in the organization.

During the period of September 2019, 400 customers completed a telephone interview, providing a confidence level of 95% (+/- 4.9%). The survey represented 85% residential and 15% commercial.

PUC received a Credibility and Trust Rating of 87% and an Overall Satisfaction Rating of 94%. From this survey, customers expressed that the following should be priorities for PUC:

- Pro-actively maintaining and upgrading equipment
- Reducing response times to outages
- Investing in projects to reduce the environmental impact of the utility's operations
- Investing more in the electricity grid to reduce outages

Based on this feedback, PUC has made significant investments through the Sault Smart Grid project that will result in upgrades to equipment, a reduction in the response times to outages, a reduction in the number of outages and a reduction PUC's environmental impact through more efficient energy consumption. In addition, PUC has purchased electric vehicles and developed a plan to further electrify their fleet to lower maintenance and fuel costs and lower their carbon footprint.

PUC received an A rating. PUC received a score of 83% on the customer centric engagement index (CCEI), compared to 82% in Ontario.

From this survey, customers expressed that the following should be priorities for PUC:

- Movement to more digitization
- Improvements to communication (more pro-active approaches)
- Better prices and lower rates
- Simplified billing
- Enhance cyber security measures

Based on this feedback, PUC has put in place a digitization strategy, with a goal of going paperless by 2024. Since the initiative was launched in 2019, PUC has reduced day to day printing dramatically, increased on-line payments to vendors, enhanced the customer experience by providing flexibility, and restructured processes internally for employees to promote efficiencies. Some specific examples include the promotion of e-billing for customers, the development of the MyPUC App, the elimination of printed paystubs, an increase in Electronic Fund Transfers from 8% to over 40%, and the development of an online employee portal, Dayforce.

PUC has improved pro-active communications through the development of the MyPUC App, and the increased use of social media platforms and PUC's website. For example, in addition to ATLAS phone notifications, the MyPUC app and website now display information on planned power outages in advance, so that customers can properly prepare for the interruption.

PUC recognizes the threat that cyber security represents and is taking measures to mitigate that risk. PUC has made significant investments in cyber security infrastructure, including the addition of a Manager of Information Security.

In order to simplify billing, PUC has continued to encourage customers to sign up for preauthorized payments, e-billing and the MyPUC App. Lastly, PUC has made significant investments through the Sault Smart Grid project that will result in average customer savings of 2.7%.

<u>Customer Pulse Surveys</u>

In 2020, PUC conducted four online pulse surveys throughout the year to provide education and gain insight into how to better serve customers related to PUC's strategic and long-term planning. The message to customers was as follows:

"New Advances in technology are changing the way we distribute electricity, and as a result, are providing new options for customers. With new technologies, customers will be better equipped to exercise more control on their energy consumption, and technological advances mean safer options and an eventual decrease in the price of electricity.

All of this is possible, but it requires investments today so electricity will continue to be safe, reliable, and affordable for tomorrow."

Based on the results of those surveys, it was noted that PUC should:

- Look at ways to create energy savings for customers.
- Consider increasing bills if it means improvements to reliability, efficiency, and communications. The graph below displays this, as 72.12% customers stated they would place a value between $0.50 - $2.00 on future bills to improve reliability, efficiency, and communications.
- Make major investments in how PUC operates to reduce their carbon footprint. The first graph below displays that 60% customers stated reducing PUC's carbon footprint by making major investments in how it operates is either extremely or very important. The second graph below displays that 67% of customers stated that it is either extremely important or very important that PUC play a role in the community to promote the reduction of greenhouse gas emissions.
- Improve and enhance the customer experience. The graph below displays that 82.95% of customers stated they would like to see improvements to communication related to power outages.
- Look at ways to improve electrical reliability. The graph below displays that 72.64% of customers rated reliability as a 10 (on a scale from 1-10, 10 being the most important).

Through the increased use of social media platforms and website, and the development of the MyPUC App, PUC has made major efforts to be more pro-active with customer communications. For example, in addition to ATLAS phone notifications, the MyPUC app and website now display information on planned power outages in advance, so that customers can properly prepare for the interruption.

Cost of Service-related surveys

In 2021 and 2022, PUC conducted two online Customer Engagement Surveys. The purpose of surveys was to provide customers with a better understanding of the details behind PUC's proposed rate increase, along with an opportunity to share their feedback into future investment decisions at PUC which will inform PUC's Cost of Service Application.

The first survey (part one of two) was conducted in August-September 2021. 906 customers completed an online survey. Based on the results of this survey, it was noted that PUC should:

- Explore more options for customer communications and energy savings tools. The graph below shows that 38.96% of customers would like PUC to move ahead with an online chat portal. The second graph below shows that 74.56% of customers would be interested in tools to help decide between tiered and time-of-use pricing. The graph below shows that 44.12% of customers would like a notification when they hit certain consumption levels. All of these examples reflect customer's desire for new tools to support customer communications and energy savings.
- PUC should invest in maintaining reliable electricity services. The graph below shows that maintaining reliable electricity services is the number one priority for customers.
- Improved communications through pro-active measures like the MyPUC App, website tools and more consistent use of social media platforms, PUC has been able to get in front of issues (including outages) for a better overall customer experience. Customers can now access information on planned outages, news updates, changes in electricity rates, etc. on multiple platforms, thereby improving a customer's overall experience with PUC.

Building from the results of the first survey, the second survey (part two of two) was conducted in May-June 2022. 816 customers completed an online survey during a three-week time period between May 20th and June 10th 2022.

PUC should focus its priorities on delivering reasonably priced electricity prices and ensuring safe and reliable electricity services. Finding show that 92.15% of customers ranked either delivering reasonably priced electricity prices or ensuring safe and reliable electricity services as their top priority.

PUC should provide a variety of options for customers when accessing services, with a focus on online tools. In the graph below, customers noted that the MyPUC mobile app, the online self-serve options for managing their account and the availability of call centre staff are the most important options when accessing services.

PUC should provide both reliable information and services regarding the adoption of electric vehicles. In the graph below, 63.11% of customers stated they would like PUC to provide chargers for residential and commercial customers through rental or purchase programs, and 70.71% and 70.83% would like PUC to provide information on government incentives and more general reliable information on electric vehicles, respectively.

By having a presence in the community, developing, and improving upon communication channels and engaging customers through meaningful surveys, PUC has been able to effectively gather information from customers when making decisions. Improving upon the overall customer experience has been a top priority for PUC over the past five years, as demonstrated by the many innovations and improvements that have been made. Ensuring that customer voices are heard has pushed PUC leadership to be innovative and make smart decisions that are in the best interests of its customers, its employees, and its shareholder.

Appendix C - Scorecard Metrics

As part of its business plan PUC assess its performance in each of the OEB's performance outcomes over the last five years, how improvements are being made and its projections for continuous improvements. The following is a summary of the of PUC's 2021 OEB scorecard results for Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance.

Customer Focus

Service Quality

PUC continuously has met OEB approved target for New Services Connected on Time, Scheduled Appointment Met on Time, and Telephone Class Answered on Time. The table below summarizes the previous five (5) years historical results.

PUC is able to achieve high levels of compliance in new services connected on time due to its existing workflow process and expects this to continue into 2023 with a target for this metric of 90%.

Performance Year	New Residential/Small Business Services Connected on Time (Target: 90%)	Scheduled Appointments Met on Time (Target: 90%)	Telephone Calls Answered on Time (Target: 65%)
2021	97.60%	99.92%	71.13%
2020	100.00%	100.00%	68.88%
2019	100.00%	98.65%	72.43%
2018	99.12%	98.48%	77.70%
2017	96.67%	97.62%	79.88%

PUC has consistently met the number of scheduled appointments on time even with the increasing demand in the category. PUC will continue to excel in this category with a target of 90% in 2023.

PUC has had fluctuations in its results for telephone calls answered on time over the last five (5) years. PUC has been working on balancing the high demand in call volume while trying to maintain lower costs for its customers. PUC will continue to look to different avenues to communicate with its customers such as its Mobile App and Customer Chat function to help alleviate the high demand. PUC believes these initiatives will help alleviate the call volumes and improve PUC's results in this category over time. PUC 's target for this metric is 65%.

Customer Satisfaction

PUC's billing accuracy and first contact resolution has and continuous to achieve high level results with an average over 99%. PUC has been improving as of late on its customer satisfaction results. The below table summarizes the past five (5) years.

Performance Year	Billing Accuracy (Target: 98%)	First Contact Resolution	Customer Satisfaction Survey Results
2021	99.97%	99.63%	88%
2020	99.96%	99.76%	92%
2019	99.98%	99.82%	92%
2018	99.97%	99.80%	80%
2017	99.94%	99.74%	80%

PUC continues to strive for high performance in this category. PUC's target in 2023 is 98%, 99% and 85% respectively for billing accuracy, first contact resolution and customer satisfaction survey results.

Operational Effectiveness

Safety

Component A – Public Awareness of Electrical Safety

The Public Awareness of Electrical Safety measure is determined by public survey. The purpose of the survey is to monitor the effort and impact LDC's are having on improving public electrical safety for the Distribution Network. This public safety survey is intended to be conducted every two (2) years. The questions on the survey are standardized across the province.

PUC's third safety awareness survey was conducted in 2020 and resulted in a score of 85%. This was consistent with the previous Safety survey.

PUC continues to look for every opportunity to communicate and engage with the public to promote electrical safety awareness within PUC's service area. Through participation with the Association of Electrical Utility Professionals ("AEUSP"), PUC has contributed to the production of a series of electricity safety videos for television broadcast in various Ontario markets including its own service area.

PUC promotes electrical safety awareness in a variety of other forms. The importance of awareness of electrical hazards is conveyed throughout the community via safety related communications in newspapers, on the radio and at public events. Detailed hazard awareness presentations are made available to external contractors and joint use parties. In the broader community, public safety presentations are provided to elementary school students.

PUC's target for this category is 85% in 2023.

Component B – Compliance with Ontario Regulation 22/04

Ontario Regulation 22/04 establishes objective based electrical safety requirements for the design, construction and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the Regulation requires the approval of equipment, plans and specifications and the inspection of construction before new assets are put into service. Component B includes an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. ESA evaluates these elements in order to determine the status of compliance.

For the past ten (10) years, PUC was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This success was achieved through PUC's strong commitment to safety and adherence to regulatory requirements, company policies and procedures.

PUC's target for this metric in 2023 is to have zero (0) safety non-compliance.

Component C – Serious Electrical Incident Index

Section 12 of Ontario Regulation 22/04 specifies the requirement to report to ESA any serious electrical incident of which they become aware within 48 hours after the occurrence. As assessed by ESA, in the 2021 reporting period, there were zero reportable serious electrical incidents.

PUC remains strongly committed to both the safety of staff and the general public. PUC regularly provides its customers with electrical safety information via its website, social media, and bill inserts. Additionally, PUC continues to make significant maintenance and capital infrastructure investments to enhance system safety and reliability.

PUC's target for this metric in 2018 is to have zero (0) serious electrical incidents reported.

System Reliability

In recent year PUC has seen a slight increase in its SAIDI and SAIFI results. Ongoing efforts to improve reliability, with a focus on effective maintenance activities and replacing aging infrastructure as indicated in PUC's Distribution System Plan, form part of PUC's strategies. PUC is also in the process of completing its Sault Smart Grid project installation, which once fully commissioned, is expected to help improve its reliability results. Since 10 substations and multiple circuits will be turned off at different stages of the construction project, it is anticipated that potential outages will impact more customers or may take longer to remediate, possibly resulting in a short-term reliability performance

metric decline for the end of 2022 and the first quarter of 2023. Still in 2023, PUC's target for SAIDI is 1.62 and SAIFI is 1.42.

Performance Year	Average Number of Hours Power to Customer is Interrupted (SAIDI)	Average Number of Times Power to Customer is Interrupted (SAIFI)
2021	1.81	1.32
2020	2.12	1.74
2019	1.45	1.55
2018	1.27	1.28
2017	1.43	1.21

Asset Management

Distribution System Plan Implementation Progress

Consistent with industry best practices, PUC invests in its distribution system to ensure the safe and reliable delivery of electricity; and upgrades or replaces equipment to be able to serve customers on a continuous basis. The DSP, which covers the five-year period 2018-2022, was filed with the OEB as part of the 2018 Cost of Service Application. Prior to 2018, the OEB scorecard indicated 'In Progress' in the Performance Category of Asset Management to reflect this activity.

For years 2018 and onwards, PUC has established a metric which expresses performance by comparing the ratio of cumulative actual capital expenditures to date against cumulative planned capital expenditures to date for the period starting January 1, 2018 and ending on December 31 of each score card year. The ratio is then expressed as a percentage. The metric measures the LDCs overall performance completing capital work and includes all elements identified in the DSP inclusive of System Access, System Renewal, System Service and General Plant. The metric will include the cumulative expenditures for all previous years within the 5-year rate application period 2018-2022. So, for example the 2021 scorecard will show a cumulative percent expenditure for the first three years of the 2018-2022 rate application period. In effect, the metric gives a snapshot at the end of each year as to how closely the LDC is tracking to their plans in achieving the overall 5-year plan. PUC intends to file a new DSP covering the 2023 to 2027 period as part of its 2023 Cost of Service application.

The calculated value for this performance metric for 2021 is 104%. The year-over-year increase in the score reported for this metric (90% in 2020 versus 79% in 2019) - was attributable the planned rescheduling of a distribution station rebuild project (Substation 16) from 2019 to 2020/2021.

PUC has prepared a 2023-2027 DSP for its 2023 Cost of Service Application. As an ongoing target to meet the requirements of this DSP, PUC will continue to revisit and revise its capital spending based on system needs, cash flow forecasting, and the overall DSP plan itself.

Cost Control

Efficiency Assessment

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC ("PEG") on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs.

The table below summarizes the distribution of all distributors across the five (5) groupings for 2021:

Distribution of Distributors

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	13
2	Actual costs are 10% to 25% below predicted costs	More Efficient	15
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	23
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	4
5	Actual costs are 25% or more above predicted costs	Least Efficient	2

Since PUC's last rebasing application in 2018, it has been working towards improvement in its efficiency performance. In 2019 PUC moved from group 4 to group 3. The table below shows PUC's actual vs predicted costs from the PEG Benchmarking model since 2017 and its resulting Group Ranking. In 2019, PUC moved from group 4 to group 3 and has remained there. PUC has completed a prediction of 2022 and 2023 based on its OM&A and Capital Budget for those respective years.

Year	Actual Costs	Predicted Costs	Cost Efficiency Assessment	3 Year Average	Stretch Factor Assisngment Group
2023 Projection	$32,966,739	$28,341,910	15.1%	6.0%	3
2022 Projection	$25,198,794	$24,943,099	1.0%	1.3%	3
2021 Actual	$23,585,229	$23,172,578	1.8%	2.8%	3
2020 Actual	$22,723,503	$22,474,823	1.1%	4.9%	3
2019 Actual	$23,450,122	$22,196,232	5.5%	8.3%	3
2018 Actual	$23,190,013	$21,371,771	8.2%	11%	4
2017 Actual	$22,600,176	$20,196,516	11.2%	13.8%	4

In 2023 PUC is projecting higher actual costs due to the reporting required for Substation 16 ICM and Sault Smart Grid ICM. Both ICM's are reported as capital expenditure in 2023 as per the RRR filing requirements and therefore inflate PUC's actual costs for that year. PUC expects its actual costs to stabilize in 2024, thus bringing back down its efficiency percentage. Additionally, it should be noted that PUC has additional costs and savings that are not accounted for in the PEG model.

Included in PUC's operating, maintenance and administrative expenses is a charge from PUC Services that is based on depreciating and financing of the vehicles, tools, computer equipment, office equipment etc. that is utilized to provide services to PUC. For utilities that own the vehicles and equipment to service their customers, these expenses are included in depreciation and financing costs. As the total costs would be the same, removing the depreciation and financing costs from PUC's operating costs would better align costs comparisons in the PEG model with other utilities.

In 2023, PUC's Sault Smart Grid will be live creating savings for customers that are not accounted for in this PEG model due to the unique, innovative nature of the project. Rather than SSG improving PUC's Financial Performance, it improves the financial performance for its customers, saving them an estimated 2.70% on the cost of power. Depending on what the actual cost of power in a year is, this will save customers approximately $1.7M.

After taken into consideration the influx in capital spending reported in 2023 from SSG and Substation 16, the charge from PUC Services to PUC and the SSG consumption savings for customers, the following table represents a revised calculation of actual costs and efficiency percentage.

Revised Cost Efficiency Percentage

Year	Actual Costs	Predicted Costs	Cost Efficiency Assessment	3 Year Average	Stretch Factor Assisngment Group
2023 Projection	$28,057,472	$28,341,910	-1.0%	0.6%	3

PUC's target is to remain in Stretch Factor Assignment Group 3.

Total Cost Per Customer

Total cost per customer is calculated as the sum of PUC's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e., under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC serves. PUC's cost performance results, from 2017 to 2021, have increased from $673 to $696 per customer. Overall, the company's total cost per customer has increased on average by 3.42% per annum over the period 2017 through 2021. For the period of 2017 to 2021, the total cost per customer on average has increased by approximately 0.84% per year. PUC will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. The company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2021 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC's capital spending plans.

As with PUC's efficiency ranking above, this calculation uses PUC's actual costs in calculating the total cost per customer. In 2023, PUC is projecting an outlier year in actual costs due to the reporting of Substation 16 and Sault Smart Grid as Capital additions being added to rate base. This will inflate PUC's total cost per customer to $967 for 2023 and should return to more normalized levels in 2024. The table below shows PUC's historical results and projections for 2022 and 2023.

Year	total cost Per customer
2023 Projection	$967
2022 Projection	$741
2021 Actual	$696
2020 Actual	$673
2019 Actual	$697
2018 Actual	$690
2017 Actual	$673

After taken into consideration the influx in capital spending reported in 2023 from SSG and Substation 16, the charge from PUC Services to PUC and the SSG consumption savings for customers, the following table represents a revised calculation of total cost per customer.

Year	total cost Per customer
2023 Projection	$823

PUC's target is a total cost per customer of $823 after excluding costs for SSG, Substation 16, and non-operational costs discussed above.

Total Cost Per Km of Line

This measure uses the same total cost that is used in the cost per customer calculation above. The total cost is divided by the kilometers of line that the company operates to serve its customers. PUC's cost performance results, from 2017 to 2021, have increased from $30,541 to $31,915 per km of line.

PUC continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per km of line has increased 4.50% since 2017 with the increase in capital and operating costs. For the period of 2017 to 2021, the total cost per km of line has increased by approximately 0.90% per year. A summary of the results is provided in table below.

Year	Total cost per Km of Line (revised)	Total cost per Km of Line
2023 Projection	$38,018	$42,252
2022 Projection	$34,145	$34,145
2021 Actual	$31,915	$31,915
2020 Actual	$30,791	$30,791
2019 Actual	$31,775	$31,775
2018 Actual	$31,338	$31,338
2017 Actual	$30,541	$30,541

PUC is projecting a spike in 2023 for the same reasons mentioned above. After adjusting for the increased costs due to SSG, Substation 16 and non operating costs discussed above, PUC is projecting a target of $38,018 in 2023.

Public Policy Responsiveness

Connection of Renewable Generation

- Renewable Generation Connection Impact Assessments Completed on Time

  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority. PUC received no renewable generation CIA applications in 2021.

- New Micro-embedded Generation Facilities Connected on Time

  PUC connected three net-metered facilities in 2021 on time, in which the application and offer to connect for one were completed at the end of 2020 and two were completed fully in 2021.

Financial Performance

Financial Ratios

PUC's historical financial ratios for liquidity, Debt to Equity, and Deemed vs Achieve ROE is presented in the table below.

Performance Year	Liquidity: Current Ratio	Leverage: Total Debt to Equity Ratio	Profitability: Regulatory Return on Equity - Deemed	Profitability: Regulatory Return on Equity - Achieved
2021	0.8	2.10	9.00%	7.60%
2020	0.99	2.07	9.00%	8.75%
2019	0.94	2.03	9.00%	8.87%
2018	1.33	2.02	9.00%	4.25%
2017	1.62	2.04	8.98%	1.78%

PUC's current ratio has trended down in recent years, although this is misleading since it is being skewed by certain affiliate transactions. Specifically, the Current ratio is affected by how PUC funds its capital expenditures and the timing of financing arrangements. Going forward PUC will look at obtaining financing prior to year end which will shift more of the current liability to long term debt and improve the presentation of its current ratio. PUC's target for this category is one (1).

Debt to equity has remained at a level close to 2:1. PUC will be undergoing additional financing for the completion of the Sault Smart Grid project. This will increase debt to equity in 2023 to approximately 2.36. PUC expects this will fall below 2:1 starting in 2025. PUC's target for this category in 2023 is 2.36:1.

Return on Equity has stabilized just below the deemed ROE embedded in existing rates of 9% in recent years with a slight dip in 2021 due to the realization of COVID related expenses. PUC will be rebasing its rates in 2023 with rates effective May 1, 2023. As of August 2022, the deemed Return on Equity as part of the OEB's Cost of Capital Parameters is 8.66%. PUC expects the Cost of Capital Parameters to undergo an increase due to the rising cost of inflation. The OEB will issue its revised numbers in the fall of 2022 at which time PUC will revise its projected ROE.

PUC 2022 Cost of Service Application Documents can be found at the link below:

https://ssmpuc.com/electricity/rates/ontario-energy-board-rate-application/

Appendix IR15

PUC DSP 2018-03-31

PUC Distribution Inc.



Distribution System Plan

2018-2022

Prepared by

METSCO
MAKING IT POSSIBLE

March 21, 2018

File: PUC DSP 2018-03-21 final.docx

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1 Introduction

PUC Distribution Inc. (PUC Distribution) has prepared this Distribution System Plan ("DSP") in accordance with the Ontario Energy Board's ("OEB's") Chapter 5 - Consolidated Distribution System Plan Filing Requirements, dated March 28, 2013 (the "Filing Requirements") as part of its 2018 Cost of Service Application (the "Application").

PUC Distribution is licenced to distribute electricity in its service territory which includes most of the City of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. Its service territory covers a service area of approximately 342 square kilometers, with a combined population of approximately 75,300. The service territory includes approximately 29,700 residential customers and approximately 3,800 general customer services for a total of approximately 33,500 customers.

The DSP was prepared to provide to the OEB and all interested stakeholders:

- An overview of PUC Distribution's asset planning objectives and goals;
- A review of PUC Distribution's operational performance in the five-year historical period;
- A preview of PUC Distribution's planned expenditures for the forecast period aimed at improving its asset-related performance to achieve the four performance outcomes established by the OEB; and
- A detailed justification of PUC Distribution's planned capital expenditures in the test year.

This DSP covers a planning horizon of five years starting in the test year, which is 2018 in the case of this filing. Employing this long-term approach requires PUC Distribution to consider future customer needs and any required changes to its distribution system in advance, thereby enhancing PUC Distribution's ability to plan ahead and respond to the evolving needs of customers in a timely manner, while managing and leveling the impacts of these expenditures on consumer rates to maintain affordability of its service.

Taking a performance-based approach for regulating electricity distributors under the Renewed Regulatory Framework for Electricity (RRFE), the OEB has established the following four performance outcomes to be achieved by electricity distributors:

- **Customer Focus:** services are provided in a manner that responds to identified customer preferences;
- **Operational Effectiveness:** continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

- **Public Policy Responsiveness:** utilities deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and

- **Financial Performance:** financial viability is maintained; and savings from operational effectiveness are sustainable

PUC Distribution's vision is to be recognized as a progressive electric distribution company committed to delivering value, innovation, prosperity and excellence. In order to accomplish this, PUC Distribution's mission is to provide cost effective, efficient, safe and reliable delivery of high quality energy services and solutions consistent with customer needs and preferences. Our DSP has been informed and influenced through multiple avenues of customer engagement although system asset investment decisions are still primarily influenced by condition based factors to ensure a safe system and maintain or enhance reliability which customers value very highly. Our most recent customer survey focused on the Cost of Service application and the rate increase being sought in our application. Background on cost drivers and cost increases since our last application in 2012 were part of the education and feedback areas brought forward to customers. An integrated approach has been employed for investment planning with all of the investments pertaining to the following categories planned and optimized together:

- System Access,

- System Renewal,

- System Service, and

- General Plant.

As defined by OEB in its Chapter 5 filing requirements,

System Access investments are modifications to a distributor's distribution system a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system;

System Renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services;

System Service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements including smart grid development; and

General Plant investments are modifications, replacements or additions to a distributor's assets that are not part of its distribution system; including land and buildings; tools and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities.

The DSP contents are organized using the Ontario Energy Board's Chapter 5 - Consolidated Distribution System Plan Filing Requirements. Section 2 provides an overview of the DSP and describes the process employed in its development, i.e. stakeholder consultations, collaboration with municipal/regional governments and transmitters, performance measurements and monitoring metrics. Section 3 describes in detail the asset management process employed to determine the scope of capital investments into asset sustainment and prioritize these investments into various assets. Section 4 documents the overall capital expenditure plan covering System Access, System Renewal, System Service, and General Plant, including justification for investments. Section [5.4.2] of the OEB's DSP filing requirements mandates detailed description of projects to be provided above the Distributor's materiality threshold.

The materiality threshold for PUC Distribution is $90,000 and detailed descriptions of specific projects exceeding the materiality threshold are provided in Section 4.5.2 and Appendix G. Other pertinent information relevant to this DSP is included in the Appendices.

2 Distribution System Plan [5.2]

Throughout this document, section headings are followed by references in square brackets, e.g.: [5.2], to cross reference the information provided in the DSP back to the OEB requirements, as indicated in the OEB document 'Filing Requirements for Electricity Transmission and Distribution Applications – Chapter 5 – Consolidated Distribution System Plan Filling Requirements'.

2.1 DSP Overview [5.2.1]

2.1.1 How Key Elements of the DSP Support Planning Objectives

Key elements of the DSP that affect its rates proposal, especially prospective business conditions driving the size and mix of capital investments needed to achieve planning objectives [5.2.1 a]

Table 1 shows at a glance the customer mix served by PUC Distribution. In addition to the customer count indicated in the table, additional loads served from the distribution system include approximately 9314 streetlights and 295 unmetered scattered loads.

Table 1: Customer Count by Type

Customer Type	# of Customers
Residential	29708
GS<50	3419
GS>50	360
Total	33487

As indicated in Figure 1, the customer base of PUC Distribution is comprised of approximately 89% residential and 11% general service customers.

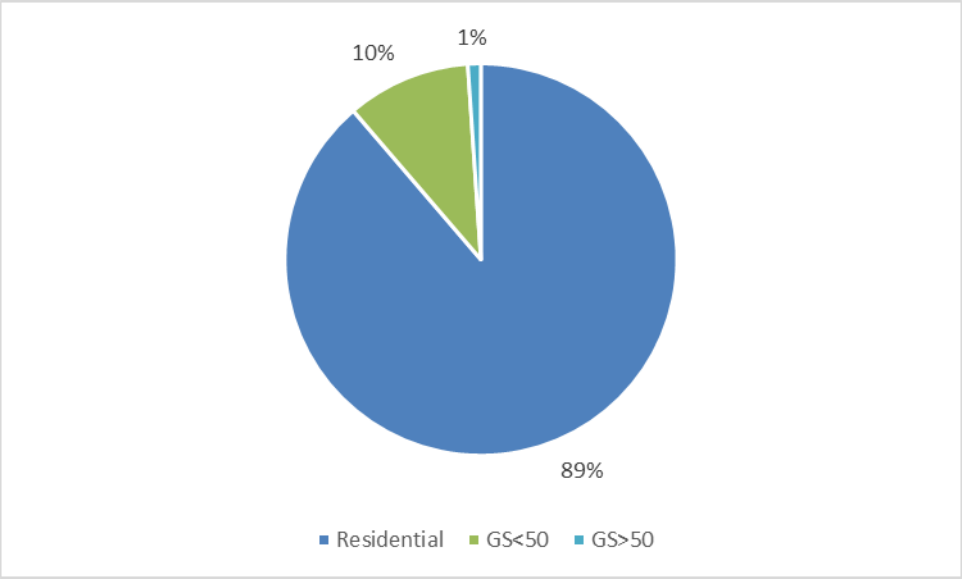


Figure 1: Customer Mix by Type

Historically, the local economy in PUC Distribution's service territory has been dominated by steelmaking. This industry has not experienced growth over the recent past and therefore, there hasn't been significant growth in the region's population. This trend is expected to continue during the next five-year period, covered by this DSP. Historically, electricity has been used for space heating in this region and therefore load on the electricity distribution grid peaks during the winter. For example, during the period from 2010 to 2014, the winter peak load was approximately 55% higher than the summer peak load. Shifting of space heating from electricity to natural gas, combined with the multiple energy conservation and demand management (CDM) initiatives implemented by residential and general service customers and expansion of natural gas distribution network in the region, has resulted in a steady decline in the peak demand on the electrical grid and this trend is expected to continue. There are currently no capacity constraints in the supply system that would prevent connection of anticipated load or generation customers during the next five years and therefore no investments are required to mitigate capacity constraints during that period. During recent years, the community has invested a significant amount of effort to diversify the local economy and these diversification efforts have resulted in development and growth of a call center industry. There has been significant effort to grow the tourism industry, with development of a major Casino in the downtown. The corporate head office of Ontario Lottery and Gaming Corporation (OLG) is also located in Sault Ste. Marie and Sault Ste. Marie has become a regional hub to provide services for the surrounding rural communities. Availability of reliable electricity supply at affordable prices is an essential ingredient, needed for the region's diversification efforts to succeed.

A significantly large portion of the existing infrastructure employed on PUC Distribution's supply network has reached a service age beyond its typical useful life. Through a recently

completed asset condition assessment exercise, a significantly large fraction of critical power supply infrastructure components employed at distribution stations, overhead lines and underground distribution system have been determined to be in "poor" or "very poor" operating condition. In the absence of major investments into asset renewal, the existing infrastructure presents high risk of failure in service, affecting supply system reliability and public safety. However, renewal and replacement of all infrastructure components determined to be in "poor" or "very poor" condition during the next five years, would be difficult to manage through PUC Distribution's resources and it would lead to unaffordable increase in retail rates.

Given that the highest priority concern from almost all customer engagement activities is the high cost of electricity bills and an increasing worry over affordability followed by the importance placed on reliability and customer communications, our challenge is to seek an optimized balance of these somewhat opposing factors. Therefore, in preparing this DSP, PUC Distribution has focused on prioritizing the investments into renewal of the most critical infrastructure components, to achieve the balance required between keeping the power supply reliability from degrading while maintaining the electricity distribution rates at affordable levels. Advanced technology will be incorporated in system design selectively, where benefits outweigh the costs, during implementation of asset renewal projects, to meet the current and future needs of the customers, to improve operating efficiency and to support the integration of renewables and smart grid technologies.

The capital investment plan is discussed in detail in Section 4, but a summary of the proposed investment is presented in Table 2 below to provide context as to the level of proposed investment under each category:

Table 2: Proposed Capital Investments During the DSP Implementation Period

	2017	2018	2019	2020	2021	2022
System Access	$ 1,271,457	$ 1,511,028	$ 1,615,276	$ 2,086,480	$ 1,603,804	$ 1,560,434
System Renewal	$ 3,372,227	$ 3,761,033	$ 6,905,898	$ 3,296,444	$ 4,532,889	$ 7,092,642
System Service	$ 38,236	$ -	$ -	$ -	$ -	$ -
General Plant	$ -	$ 86,294	$ 54,629	$ 61,932	$ 59,853	$ 55,100
Total Capital Expenditure	$ 4,681,920	$ 5,358,355	$ 8,575,803	$ 5,444,856	$ 6,196,546	$ 8,708,176
System O&M Expenditure	$ 5,856,582	$ 6,212,629	$ 6,305,819	$ 6,400,406	$ 6,496,412	$ 6,593,858

Although a majority of the investments proposed in this DSP fall in the System Renewal category, the overall capital investment plan incorporates investment to the appropriate degree in each of the four general categories: (1) System Access; (2) System Renewal; (3) System Service and (4) General Plant.

The planned investments into System Access are intended to facilitate modest anticipated growth to allow connection of new customers to the grid, meeting requests of existing customers for increase in service size and meeting PUC Distribution's regulatory obligations for relocating distribution lines when requested by the municipality and for re-calibration and renewal of the revenue meters in compliance with the Measurement Canada regulations. The indicated investments in the System Access category represent net expenditure by PUC Distribution, after third party contributions have been subtracted from the total cost.

The planned investments into System Renewal are intended to mitigate a number of specific prevailing risks to distribution system reliability, public safety and adverse environmental impacts, due to very poor condition of some key assets, the in-service failure of which would lead to severe consequences.

Although no planned investments have been included in the System Service category, a number of investments in the renewal category, particularly those involving station rebuilds, line rebuilds and SCADA and protection upgrades, will also introduce smart grid features, including opportunities for greater automation, improved access for connection of renewable generation and improved access for joint-use of distribution facilities. Therefore, these investments can be considered to serve multiple roles: System Access and System Service in addition to System Renewal.

PUC Distribution leases its motor vehicle assets rather than owning them, therefore a relatively small capital investment is required for renewal of General Plant, needed to cover minor building renewal items. The scope and timing of the investments in each category has been determined by taking into account all information available at the time of preparation of the distribution plan.

System Access

The planned investments in the System Access category include expenditure required by PUC Distribution to meet its regulatory obligations. These investments consist of four main components:

- new subdivisions, new services and upgraded services to meet customer needs;
- line relocations required in conjunction with municipal road reconstruction programs;
- investments to add new meters and maintain existing revenue meters compliant with regulations; and
- "make-ready work", related to joint use applications by 3rd party telecommunications companies.

During the past five years, demand for new services has been relatively flat and there has not been a significant change in the number of customers served by PUC Distribution. There was

modest growth in residential subdivision development in PUC Distribution's service territory, during 2012 and 2013, but extremely limited subdivision development activity took place from 2014 to 2016. During the past three years, demand for new services in existing subdivisions has also decreased moderately likely due to the economic difficulties encountered by the steel industry, which remains the major driver of local economy in PUC Distribution's service territory. At present, there is no backlog of customers requiring new services within PUC Distribution service areas.

A modest recovery in the local economy is anticipated during the next five years, primarily driven by macro-economic factors, resulting in a small increase in requests for new services from the existing levels. Discussions with developers indicate minimal growth in 2017 and modest growth in 2018 and 2019. There are presently two residential subdivision developments being planned for 2018 and 2019, and these will require capital investments in System Access category to meet the requests for new services.

Road reconstruction projects undertaken in the municipality require relocation of some power distribution lines, requiring capital investments by PUC Distribution, from time to time. PUC Distribution has employed the City's 5-year development plan to estimate capital expenditure required for line relocates and rebuilds to accommodate municipal infrastructure projects. The municipal development plans are subject to change, so there is some risk that the actual required expenditure in this category may be different from the amounts indicated in the DSP.

All existing residential and general service customers (< 50 kW) were equipped with smart meters between 2009 and 2010. PUC Distribution owns approximately 33,500 revenue meters, installed on its customers' premises for the purpose of measuring electric consumption and demand of connected load for the purpose of billing. PUC Distribution plans to sample 600 meters in 2019, 200 in 2020 and 80 in 2021 all in accordance with Measurement Canada's "S-S-05—Performance Requirements Applicable to Meters Granted a Conditionally Lengthened Initial Reverification Period under S-EG-01" - sample its meter population to acquire an extension of up to 8 years. In addition, revenue meters will also be required to replace meters failed in service and based on the historic experience, the failure rate of revenue meters is expected to be approximately 0.6% per year. PUC Distribution is also required to equip all general service customers with >50kW to <500kW demand with MIST meters.

There are also steady requests from communication network companies that share PUC Distribution's network for "make ready work" and flow of such requests is anticipated to continue at the same pace. However there exists the possibility for an extremely significant demand change with relatively short notice as was experienced in the previous rate application period due to a 'fibre to the home' project that covered a large portion of PUC Distribution's system. The System Access category investments, therefore, also includes an allowance for the net contribution required from PUC Distribution.

System Renewal

PUC Distribution engaged METSCO Energy Solutions in 2016 to perform a comprehensive condition assessment of all distribution system assets and develop an asset management plan to mitigate risks associated with in-service failure of assets. The asset condition assessment, included in Appendix B, provides detailed results of the asset condition assessment initiative completed in 2016.

As described in greater detail in Section 3.2.3, those assets, the condition of which has already reached a state of impairment that they present a very high risk of failure in service are assigned "very poor" condition and those assets with significant impairment causing performance to degrade below acceptable level and presenting a high risk of failure in service in the absence of major repair or rehabilitation or renewal, are assigned "poor condition".

The scope of capital investments planned in the System Renewal category has been determined with the objective of keeping power supply reliability from deteriorating below an acceptable level. In order to keep the overall investment envelope for this DSP within a range, which would not result in retail rates escalations beyond the affordability of PUC Distribution's customer base and which could be successfully implemented without stretching beyond limit PUC Distribution's financial resources; investments required for renewal and rehabilitation of the assets found in "very poor" or "poor" condition have been spread out over a time period of longer than five years and assets with highest consequence of failure in service, have been prioritized for renewal or rehabilitation, during the next five years. Prioritized investments into asset renewal and rehabilitation included in this DSP are summarized below:

Due to the advanced service age, combined with "poor" and "very poor" operating condition of a vast majority of the power transformers, switchgear, protection and control equipment and other miscellaneous assets employed at both of the 115/34.5 kV transformer stations (TS-1 and TS-2), both stations require complete rebuilds with new power transformers, switchgear, protection and control equipment. However, rebuilding of these two transformer stations requires significant front-end planning and engineering to comprehensively assess all available alternatives with the objective of selecting the optimal alternative for re-development. Each of these stations employ equipment redundancies in their design, each station with four power transformers, which presently allows PUC Distribution to manage the reliability risk even during an 'N-1' contingency. Therefore, this 5-year DSP does not include funding to cover the construction cost of these two transformer stations, but includes capital investment required to perform a planning and engineering study to review all practical development options through completion of conceptual designs to identify the optimal station development alternative, for implementation during 2023 to 2027. Refurbishment options are not feasible as asset deterioration is broad-based at these two sites. Current observations indicate that a significant 'total rebuild' capital investment will need to be made to fully address the matter at least at one of the two sites during

2023-2027 rate application period and at the second during either that same or the subsequent 5-year period.

The condition of the power transformers and switchgear at seven of the twelve existing 34.5/12.5 kV as well as both remaining 4.2 kV distribution stations has been determined to be in “poor” or “very poor” condition. This DSP includes funding for upgrade of the distribution lines supplied from the 4.2 kV stations to 12.5 kV stations, which would allow the last remaining 4.2 kV stations to be retired from service after the voltage upgrade of distribution lines has been completed. It also includes provision for rebuilding two distribution stations during the five-year implementation period; one of which will replace both the 4.2 kV stations and the second will replace one of the existing 34.5/12.5 kV stations. These distribution station rebuild projects have been prioritized by taking into consideration the relative risk of equipment failures and the anticipated consequences of equipment failures on supply system reliability, public safety and operating costs. Subsequent to station renewal in this DSP and the recent retirement of Substation 14, five distribution stations will remain for inclusion in the renewal program during the next two DSP periods (2023 to 2032).

For the two transformer stations and the distribution stations found in “poor” or “very poor” condition but not included in the renewal program in the current DSP, PUC Distribution plans to manage the risk of equipment failures through proactive monitoring and testing of equipment. Accordingly, this DSP includes funding for proactive repair, refurbishment and component replacement activities as an outcome of station inspections as well as to address unplanned equipment failures. Annual funds budgeted are based on the past 5 years expenditures and are intended to maintain system reliability at current levels. In the event of a major equipment failure such as the loss of a distribution station or feeder, contingency plans are in place to ensure that load can be readily transferred to an alternate supply while repairs or replacements are completed. This risk based refurbishment strategy allows PUC Distribution to minimize expenditures over the life cycle of the assets, while meeting targeted performance levels including system reliability.

PUC Distribution’s primary overhead distribution network employs approximately 391 km of 3-phase and approximately 230 km of 1-ph lines. Approximately 28.5% of the overhead lines will reach the end of their typical useful life during the next five years. As the lines approach the end of their design life, all line components including wood poles, mounting hardware and conductors experience degradation of strength and pose a high risk of failure in service when subjected to design loading during wind and ice storms. To mitigate this risk, these lines will require rebuild with new poles and conductors. However, rather than proposing re-construction of all overhead lines that have reached the end of their design life, this DSP includes a small subset of the lines, prioritized for renewal based on the risk of failure in service. The lines included for renewal in this DSP have been prioritized by considering the impact of critical component failures on public safety, supply reliability and operating costs. Accordingly, in this

DSP priority for line re-construction has been given to: (a) replacement of poles in "very poor condition, (b) line sections built with restricted conductor, and (c) line sections determined to be in "very poor" condition and currently operating at 4 kV, which will undergo voltage upgrade upon reconstruction.

Copper and aluminum conductors with smaller cross-section area, and more specifically #6 AWG and #4 AWG (copper or aluminum) conductors have lower tensile strength in relation to larger conductors typically used in overhead line construction. Under tension, the tensile strength of these smaller cross-section conductors further degrades with service age. These conductors are known to fail in service and when they fail it creates a very serious safety risk for public when live conductors fall to the ground. #6 and #4 AWG conductors are no longer used for applications requiring conductor tensioning over full spans, and virtually all Canadian utilities have adopted programs to proactively phase out lines built previously with restricted conductors.

PUC Distribution had identified approximately 8 km of 3-phase lines and approximately 60 km of 1-phase lines on its distribution network, constructed with restricted conductors and adopted a program to phase out restricted conductor lines starting in 2010. Up to the end of 2015, approximately 26% of the lines with restricted conductor had been phased out. Work on reconstruction of the remaining lines with restricted conductor is scheduled to continue during this 5-year DSP, with a target date of 2027 for complete elimination of all restricted conductor lines from the network.

There are approximately 12,600 wood poles and about 80 other types of poles (including steel, concrete and fiberglass) employed on PUC Distribution's overhead lines. In 2016, approximately 328 poles had reached the service age of more than 60 years and an additional 857 poles had reached the service age more than 50 and less than 60 years. Wood poles experience degradation in strength due to wood decay with service age, but the relationship between pole strength and service age is not linear. In order to identify poles in "very poor" condition PUC Distribution periodically conducts in-situ testing of poles and these poles are then targeted for replacement. This DSP provides funding for annual renewal of approximately 30 poles determined to be in "very poor" condition.

Overhead lines employed on the 4 kV distribution system are the oldest infrastructure components on PUC Distribution's power supply network. Most of these lines have reached a service age of 50 or 60 years, well past their design life and they present the highest risk of failure in service. PUC Distribution has been gradually removing the 4 kV lines from its network by rebuilding the lines with voltage upgrades to 12.5 kV. This DSP provides funding for the voltage upgrade program with a target date of 2022 for completion of the program.

Because the planned overhead line renewal programs described in paragraph (iv), (v) and (vi) above target a sub-set of the overhead lines determined to be in "poor" or "very poor" condition,

it is expected that some line sections would experience failures during storms and require emergency repairs to restore power. Therefore, this DSP includes funding to perform emergency repairs and refurbishment upon line failures in service.

For overhead distribution transformers, a "run to failure" strategy is proposed, where a transformer is replaced only after failure. This DSP includes investments to replace distribution transformers after they fail. Current PCB regulations in Canada permit the use of distribution transformers containing PCB content in oil of up to 50 parts per million and this use can continue up to December 31, 2025. All distribution transformers must be below 50 parts per million after December 31, 2025. To comply with this regulation, distribution utilities will need to either (a) test all suspect transformers (purchased prior to 1984) for PCB content and replace those containing PCBs above the threshold, or (b) replace all suspect transformers (purchased prior to 1984). This DSP includes budgetary provision for testing suspect distribution transformers for PCB content but replacing transformers that fail the PCB test have been deferred to beyond 2022.

The underground distribution network at PUC Distribution employs approximately 75 km. of 3-phase cable circuits and approximately 47 km of 1-phase and 2-phase cable circuits. Approximately 25% of the cable has reached service age of greater than 40 years. There are no practical tests available which could be economically performed in field to accurately assess the remaining useful life of cables. However, XLPE insulated cables, which are typically employed on underground distribution systems; generally begin to experience an increase in failure rates when they get past 40 years of service age. It is also noteworthy that a vast majority of the cables installed prior to 1990 were installed in direct buried configuration. Cable failures in direct buried configurations have significantly larger impact on reliability than failures that occur where cables are installed in duct. All cable circuits past 40 years of service age are considered in poor condition. This DSP includes funding for proactive replacement of only a part of underground cables determined to be in very poor and poor condition, with priority given to direct buried cable circuits as well as in voltage conversion areas. However, it is expected the underground cables will require more significant 'ramping up' of investment beyond 2022 to keep the failures rates at acceptable levels.

Most of the cables employed on 4 kV system are past their 40-year typical useful service life and these cables are planned to be removed from service when these service areas are upgraded to 12.5kV.

For switching of underground circuits, PUC Distribution Inc. employs live-front pad-mounted switchgear as well as K-bar junction boxes. Based on the service age and visual inspections, five of the pad mounted switchgear units and 89 of the K-bar units were determined to be in poor or very poor condition in 2016. This DSP includes funding for the replacement of two pad-

mounted switchgear units but no funding for renewal of the K-bar units. Upon renewal, the live front switchgear will be replaced with dead front switchgear, providing enhanced worker safety.

PUC Distribution's underground distribution system employs concrete chambers for various functions, including cable pull-boxes and manholes, mounting bases for switchgear and K-bar junctions, submersible transformer vaults, splice vaults and general-purpose equipment vaults. Approximately 23% of the chambers are currently more than 50 years old. Physical inspections of the concrete structures indicate a large percentage of these old vintage chambers are functionally obsolete. The submersible transformer vaults and splice vaults present a challenge in that outages are required to safely complete maintenance work thereby increasing costs and inconveniencing customers. Accordingly, funds have been included to make progress in the replacement of these vaults.

System Service

Because the existing plant has adequate capacity without any constraints to allow connection of new loads and generation from renewables during the next five years, this DSP does not include investments to mitigate capacity constraints.

General Plant

Approximately 5 years ago PUC consolidated all of its administrative offices and operational buildings into a newly constructed integrated facility and the retired aging facilities were put up for sale. For the most part the new facility is in excellent condition and meets all functional needs so only minimal incremental building infrastructure investments have been considered in this DSP. The entire motor vehicle fleet used for operations is owned by PUC Distribution Inc.'s non-regulated affiliate services company PUC Services Inc. Consequently, a modest level of capital investment for building improvements and refurbishment is required in this area. Investments in General Plant are aimed at improving worker productivity, operating efficiency and employee safety.

Key Benefits of Investments

The capital investments planned for the 2018 to 2022 period are expected to yield the following benefits:

The investments into System Access category would allow PUC Distribution to meet its obligations to serve new customers, relocate lines in public right-of-way, upon receipt of requests for such services, perform "make ready" work for allowing third party attachments of electricity distribution poles and to have adequate supply of revenue meters to comply with the requirements of the Distribution System Code and Measurement Canada.

The investments into System Renewal will reduce the risk of critical assets' failure in service and help sustain the reliability at acceptable levels and ensure public safety. These investments will also help avoid an increase in operating costs by eliminating the increase in extent of emergency repairs upon asset failures. Retiring from service the distribution system infrastructure operating at 4 kV will eliminate duplication in spare part requirements and will result in improved operating efficiency.

Investments in General Plant are aimed at improving worker productivity, operating efficiency and employee safety.

2.1.2 Sources of Cost Savings Derived from Good Planning

Sources of cost savings expected to be achieved over the forecast period through good planning and DS Plan execution [5.2.1 b]

Cost savings have been considered through good planning and will be achieved through execution of this distribution plan:

Through careful evaluation of the risks, projects are prioritized for implementation to mitigate higher level risks during this DSP implementation period, while deferring the projects with lower level risks or risks that can be managed through alternative cost-effective mitigation measures. For example, although equipment at both of the transformer stations has been determined to be in poor and very poor condition, due to redundancy in their design, it has been possible to defer the approximately $25 million of the required investments for their rebuild. All practical options will be explored through a comprehensive planning and engineering study to identify the optimal station development alternative with highest economic value, for implementation. Subsequent to the implementation of this DSP, approximately $22 million of investments required for redevelopment of the five remaining distribution stations, where the equipment has been determined to be in poor condition has been deferred and priority has been given to address only the stations where incidents of equipment failure present risk of the highest consequence. In case of the underground distribution system, cables in direct buried configurations present higher risk upon failure in relation to cables installed in duct and therefore have been a given a priority in the cable renewal program and the required investments for renewal of cables in poor condition but installed in duct have been deferred. Cost savings derived from these initiatives have not been quantified because the value is based on the frequency and severity of equipment end of life failures, variables which are not measurable. However it is reasonable to expect that the 'bathtub curve' effect for reliability relied upon in asset life cycle planning across many industries is applicable in the case of these assets and that they are presently reaching the end of their cycle.

The reliability improvements through investments into infrastructure renewal will yield cost savings for customers through avoided power interruptions. Also, the deferral of investments,

where possible, will yield savings in interest and depreciation costs, which will help reduce escalation in retail rates. Estimates of the deferred capital expenditures are provided in paragraph (a) above. PUC Distribution is unable to quantify the customer savings due to capital deferrals and also from avoided power interruptions at this time because customer reliability valuation surveys have not been performed.

Investments into System Renewal will reduce the number of in-service failure of assets and thus reduce the risk of emergency repair costs from going up. Considering the poor and very poor condition of infrastructure, in the absence of the investments proposed under System Renewal in this DSP, the emergency repair costs are expected to accelerate during the next five years.

Investments into infrastructure renewal will reduce the number of catastrophic equipment failures causing damage, the potential for injury to the public and reduce the risk of third party claims against PUC Distribution. It is impossible to predict the quantity of equipment failures that will result in third party claims and any associated costs or savings.

Proposed investments into General Plant will ensure efficiency of operations and reduce the risk of operating costs from going up. No savings are expected to result from this investment category but are expected to maintain worker productivity and work place safety at required levels.

2.1.3 Period Covered by DSP

Period covered by the Distribution System Plan (historical and forecast) [5.2.1 c]

This DSP covers a 5-year forecast period from 2018 to 2022. It includes historic financial expenditure for five complete years (2012 to 2016) and historic operating performance of PUC Distribution from 2012 to 2016.

2.1.4 Vintage of Information

Vintage of information on investment drivers used to justify investments identified in the application [5.2.1 d]

The Asset Management Plan as presented in Appendix B was finalized on September 30, 2016. This DSP is premised upon information contained in that document and is supplemented with additional information available from asset renewal projects completed as of September 30, 2017.

2.1.5 Important Changes to the Distributor's DSP

Indication of important changes to the distributor's asset management processes (e.g. enhanced asset data quality or scope; improved analytic tools, process refinements; etc.) since the last DS Plan filing [5.2.1 e]

This is PUC Distribution's first DSP under the new filing requirements. The methodology employed to support the level of investments and prioritize the investments into specific project categories differs from the methodology used in PUC Distribution's previous submission to OEB, in the following ways:

Enhanced Methodology

- The methodology used for prioritizing investments in this DSP, employs an objective, risk-based approach, which results in determining the scope and timing of investments to match the level of risk intended to be mitigated through the investment. To achieve improvements in this area over previous methodologies, Engineering resources were focused to a greater extent on developing associated programs and plans in areas including voltage conversion, restricted conductor replacement and station rebuilds.

- For evaluation of the risk associated with aging assets, all available data relevant to the present condition of assets, i.e. demographic information, results of field inspections and in-situ testing has been used. This methodology has been enhanced by including better quality and more extensive asset condition data collected over the past five years.

New Methodology

- The methodology used for investment planning in this DSP integrates customer preferences and creates an optimal balance between the service levels provided by the distribution assets and the cost of services, meeting customers' needs of reliable power supply at affordable prices. The previous asset management plan did not consider customer feedback through a formal customer engagement process.

2.1.6 Interdependency of DSP to Ongoing Activities or Future Events

Aspects of the DS Plan that relate to or are contingent upon the outcome of ongoing activities or future events, the nature of the activity (e.g. Regional planning process) or event (Board decision, LTLT) and the expected dates by which such outcomes are expected or will be known [5.2.1 f]

None of the investments proposed in the DSP are contingent upon the outcome of ongoing activities or future events. The level of actual investments for System Access may slightly deviate year-to-year from the proposed investment levels, depending upon the number of

stakeholder requests received for services, but such deviations are expected to be minor and the overall expenditure level during the next five years is not expected to be significantly different from what is proposed in this DSP. Since none of the investments involve addressing constraints in the transmission system or upstream distribution system and since there are no embedded distributors served from PUC Distribution's distribution system, the regional planning process has no impacts on this distribution plan and proposed investments.

2.2 Coordinated Planning with Third Parties [5.2.2]

Before preparing this DSP, PUC Distribution has consulted with all stakeholders affected by the DSP, with the objective of accurately assessing their needs and to confirm the adequacy of existing capacity of the distribution system; so that the investments could be focused into areas of the greatest need. The results of coordinated planning with third parties are documented in this section, by addressing the following questions for each consultation:

- the purpose of the consultation;
- whether the distributor initiated the consultation or was invited to participate in it;
- the other participants in the consultation process;
- the nature and prospective timing of the final deliverables, that are expected to result from or otherwise be informed by the consultation; and
- an indication of whether the consultation has or is expected to affect the distributor's DS Plan as filed and if so, a brief explanation as to how.

This distribution plan has been prepared through a coordinated planning process with all major stakeholders. The stakeholders consulted by PUC Distribution during preparation of the DSP include:

- customers;
- municipal governments;
- CDM program partners; and
- OPA/IESO

2.2.1 Description of Consultations [5.2.2 a]

2.2.1.1 Customer Engagement

Purpose of Consultation

PUC Distribution conducts customer consultations to gather customers' opinions related to its services and to ensure that the customers' needs and preferences are taken into account during development of long term plans. PUC Distribution has conducted both formal and informal community engagement activities with its customers over the last five (5) years.

Who Initiated the Consultation?

All consultations with the customers were initiated by PUC Distribution, either through its own staff or through consultants.

Other Participants in Consultations

Other participants included residential and general service customers.

Nature and Timing of Final Deliverables

The final deliverables from these consultations are included in the form of stand-alone reports in Appendix C and Appendix H.

Consultations Impact on this DSP

Customer feedback has been integrated into the preparation of this DSP. While a vast majority of PUC Distribution customers are fully satisfied and pleased with the power supply reliability, a majority of the customers are also sensitive to an increase in retail rates. Customer sensitivity to the retail rate increases has been taken into consideration in this DSP, by accepting some risk of asset failures in service and by deferring a number of projects in the asset renewal category and only including a relatively small number of projects in the current investment plan, which present the highest risk of asset failures during the next five years.

Brief Description of Customer Engagements

PUC Distribution believes that customer engagement is the backbone of its community-driven operations. PUC Distribution recognizes that providing opportunities for customers to share their feedback will not only strengthen their relationship with them, but also, improve the overall customer experience.

As a local distribution company (LDC), PUC Distribution understands that its role in planning for the future of the electrical distribution system involves more than just measuring equipment service life. It requires including customers in the planning process to ensure that they have

considered their needs and preferences when it comes to developing long term plans. To that end, PUC Distribution is committed to growing and expanding on the success of its existing community service and customer engagement initiatives.

PUC Distribution has increased formal and informal community engagement activities with its customers over the last five (5) years. Those engagement opportunities identified a number of customer needs and preferences, along with room for improvements to be made. The areas identified that needed the most attention included improving customer communications, increasing customer consultations, maintaining or improving reliability and growing energy literacy in the community. Although many new ideas continue to be explored we have successfully implemented a number of improvement initiatives over the past five years that have been directly related to customer feedback and expectations.

2.2.1.2 Municipal Government Consultations

Purpose of Consultation

PUC Distribution interacts with the City of Sault Ste. Marie administration to coordinate infrastructure planning within its service territory, so that new connections to customers can be connected in a timely manner and projects involving line relocates to facilitate road reconstruction projects can be planned. PUC Distribution staff attends formal meetings with the City and other municipal stakeholders and local utilities, annually, to review budgets and work plans for the coming year and the coming 5 years. Other 'ad hoc' coordination sessions occur on an 'as needed' basis with the city and development stakeholders to look for synergies on specific projects and initiatives such as subdivision, commercial and institutional developments

Who Initiated the Consultation and Other Participants?

The annual coordination meetings are generally initiated by the City's administration and PUC Distribution along with other utilities participating in them. For large developments in the city, PUC Distribution is invited to Development Assistance Review Team (DART) meetings on a regular basis early in the planning stage. Additionally, PUC Distribution is included and invited to comment on all rezoning, severance and building applications allowing PUC Distribution to identify requirements early in the development stage.

Other Participants in Consultations

Other participants include general service customers, developers, other utilities including gas and telecommunications.

Nature and Timing of Final Deliverables

The final deliverables from these consultations are in form of the development information such as plans and associated schedules, which are received during the meetings.

Consultations Impact on this DSP

The information obtained from the municipality has been used to identify investment level requirements in the System Access category, proposed in this DSP (subdivisions, joint use and general services).

2.2.1.3 Consultations with CDM Program Partners

Purpose of Consultation

The purpose of PUC Distribution's consultations with energy conservation and demand management (CDM) program partners is to implement the province of Ontario's policy on energy conservation and peak demand reduction on the electricity grid.

Who Initiated the Consultation and Other Participants?

PUC Distribution participates in periodic consultations initiated by IESO and also initiates consultations with its customers to promote and encourage energy conservation and identify and implement opportunities for demand management.

Nature and Timing of Final Deliverables

The final deliverables from these consultations are the leads for specific CDM opportunities, which are then pursued by PUC Distribution for implementation.

Brief Description of the Consultation

PUC Distribution has been offering IESO (formerly OPA) prescribed save-ON-energy CDM programs since 2011. As per the Minister of Energy's directive on Conservation and Demand Management dated March 31, 2014, PUC Distribution collaborated with CustomerFirst, a group of local distribution companies (LDCs) that have submitted a joint plan to the IESO under the new conservation framework.

PUC Distribution is committed to helping its customers understand their energy usage and reduce their environmental footprint by offering programs that enable them to become more energy efficient. PUC Distribution has a conservation target of 26.4 Gigawatt hours by the end of 2020. Results for 2016 show progress of 55% towards that target. This achievement was made possible through on-going consultations with customers, prompting a strong participation by PUC Distribution's commercial and industrial customers in retrofit and energy auditing programs. Residential customers also participated in sufficiently large numbers in saveONenergy coupon events opting to replace lights in their homes to more energy efficient ones, as well purchasing other energy efficient equipment. PUC Distribution's collaborative efforts with the residents and business owners within its service territory made the achievement of substantial energy savings possible. Notable projects include the conversion of the City's street lighting

system from HPS to LED, not only in Sault Ste. Marie but also Prince Township and Batchewana First Nations. Municipal parking lots followed suit with upgrading their parking lot lighting to LED, while small businesses began changing their florescent lamps and incandescent bulbs to efficient LED tubes and lamps.

As a member of CustomerFirst, PUC Distribution is part of a joint Conservation (CDM) Plan that has been approved by the IESO. The joint plan will achieve 141,877 MWh of savings which is equal to the combined targets that were allocated to each CustomerFirst member under the new framework. Through the CustomerFirst joint CDM Plan, PUC Distribution will continue to work collaboratively with the other CustomerFirst utilities to find efficiencies and reduce costs. The group will be sharing resources and working together in all areas of CDM including sales, marketing, customer and project support to provide value to ratepayers.

PUC Distribution remains committed to providing its customers with cost effective conservation programs to help them save electricity and lower their electricity bills. PUC Distribution will continue to innovate new ways to promote and support customers in reducing their consumption today and for the future. The CDM program has been effective in curtailing the rise in peak demand on the distribution system and this is one of the reasons why no investments are needed in the System Service category. In order to more effectively engage the residential customers into energy conservation programs, the effort will result in a slight increase in O&M expenditure from prior years' spending levels.

PUC Distribution actively participated in the saveONenergy CDM programs from 2011-2014, which were extended into 2015 to allow transition to a new 6-year framework. In complying with the Minister of Energy's directive on Conservation and Demand Management dated March 31, 2014, PUC Distribution collaborated with CustomerFirst, a group of LDCs, to submit a joint plan to the IESO to reduce peak demand under the new conservation first framework. As a member of the CustomerFirst LDCs, PUC Distribution continues to participate in evaluation of the conservation delivery, its impact of anticipated load growth as well as evaluation of the benefits of collaboration with LDCs in the partnership. Based on the results of customer consultations, a higher emphasis on residential conservation programs will be placed in the future, as the previous framework provided limited opportunities for energy conservation by the residential customer class.

Consultations Impact on this DSP

The consultations with CDM Program Partners have helped the peak demand on PUC Distribution's grid from increasing, and as a result the need for any associated investments has been avoided in this DSP.

2.2.1.4 IESO Consultations

Purpose of Consultation

The purpose of these consultations is to share information with IESO to facilitate and coordinate the connection of REG connections.

Who Initiated the Consultation and Other Participants?

The consultation was initiated by PUC Distribution in conjunction with preparation of this DSP. A renewable generation (REG) plan was prepared by PUC Distribution and submitted to IESO. IESO reviewed the REG plan and provided a comment letter.

Nature and Timing of Final Deliverables

PUC Distribution prepared and submitted the REG plan to IESO for review in November 2017. IESO provided a comment letter in December upon completion of its review, which is included in Appendix D.

Brief Description of the Consultation

PUC Distribution has been conducting communications in relation to the existing distributed generation connections connected to its network under OPA's RESOP, FIT and micro-FIT contracts as well as new applicants wishing to connect new renewable generation plant to PUC Distribution's network.

PUC Distribution has been a leader in actively promoting and facilitating Ontario's Green Energy program, which has resulted in the City of Sault Ste. Marie acquiring the title of the Alternative Energy Capital of North America. PUC Distribution has solar generation contribution of approximately 63MW connected to its distribution system, which results in near zero or net export conditions during their peak producing summer months when the distribution network is near its minimum load.

PUC Distribution has also worked closely with IESO in the integration of bulk energy storage on the grid. In April 2014, a private developer approached PUC Distribution to explore the possibility of connecting a 7MW/7MWh fast ramping energy storage facility to the provincial transmission system. The request was prompted by an IESO proposal call for such a project to be connected somewhere in the northeastern region. The facility was to be an experimental IESO venture to determine if bulk battery storage is an effective way to provide voltage stabilization and reactive power support in an environment with a relatively high ratio of renewable energy to traditional generation and a highly variable load/generation mix. PUC Distribution immediately recognized potential benefits for many stakeholders and developed terms of reference for a project to support connection at their St. Mary's transformer station TS1. The project proceeded successfully and the facility was put into operation in the fall of 2017.

To make the distribution grid more friendly to distributed generation and to provide customers greater access and control on their energy usage, PUC Distribution is also implementing affordable initiatives for smart grid development in a phased manner, to improve the stability and reliability of renewable generation connections and to meet customers' future needs. All of the customers have been equipped with smart meters. As the assets in existing distribution stations reach the end of their service life, during rebuilding of the distribution stations, modern automated switching and SCADA controlled devices are incorporated in the design.

Impact of the Consultation on this DSP

Because no constraints have been identified in PUC Distribution's grid preventing connection of renewable generation (REG) to the distribution grid, the consultations with IESO have not resulted in any investments proposed in this DSP to facilitate REG connections.

2.2.2 Regional Planning Process [5.2.2 b]:

Purpose of Consultation

The purpose of this consultation was to facilitate transmission system planning by identifying critical infrastructure needs of the transmission grid during the next 10 years from 2014 to 2023

Who Initiated the Consultation and Other Participants?

This consultation was initiated by the Hydro One Sault Ste. Marie LP (H1 SSM) (previously Great Lakes Power Transmission (GLPT), the lead transmitter. All electricity distributors in the region participated in the consultation as well as the IESO and OPA.

Nature and Timing of Final Deliverables

The final deliverable of this consultation was the Regional Infrastructure Planning Report, which is included in Appendix E.

Brief Description of the Consultation

PUC Distribution belongs to the "East Lake Superior Region (ELS-Region)", for which Hydro One Sault Ste. Marie LP (H1 SSM) (previously Great Lakes Power Transmission (GLPT) is the lead transmitter and primarily responsible for steering the regional planning in this region.

In response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013, regional infrastructure planning was triggered by H1 SSM on October 12, 2014 and was completed on December 12, 2014. PUC Distribution participated in the planning process and provided required data to H1 SSM. The scope of this planning initiative was to identify critical infrastructure needs of the transmission grid during the next 10 years from

2014 to 2023. The assessment included a review of transmission system connection facilities capacity which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and asset sustainment plans. A copy of the Regional Infrastructure Planning report is attached in Appendix E.

The regional planning report concludes the existing transmission infrastructure in the region supplying the PUC Distribution's supply network has sufficient capacity and the circuit loading on all 115 kV circuits remain within the assessment criteria limits throughout the study period.

Impact of the Consultation on this DSP

Consultations with the transmitter did not lead to any impact on the capital investments proposed in this DSP.

2.2.3 IESO Comment Letter [5.2.2 c]

PUC Distribution's Renewable Energy Generation (REG) Plan outlining the plan to support connection of renewables and smart grid technologies for the period 2018-2022 was provided to IESO in December 2017. The plan indicates the PUC Distribution grid is presently very well positioned to support all forecast REG connections over the next five years and no associated infrastructure investment is required during that period. The IESO acknowledged that PUC Distribution's system shows no concerns caused by local or regional issues that should constrain additional growth of REG as projected. The plan and response letter are attached in Appendix D.

2.3 Performance Measurement for Continuous Improvement [5.2.3 a to c; 5.4.3a]

In order to continually improve its operating performance, PUC Distribution continually measures and monitors its performance. The performance indicators employed by PUC Distribution in measuring its operating performance have evolved over the years and these are currently fully aligned with OEB's "Scorecard – Performance Measures" for electricity distributors, as listed below:

1) service quality;
2) customer satisfaction;
3) safety;
4) system reliability;
5) asset management;

6) cost control;

7) financial ratios;

8) conservation and demand management; and

9) connection of renewable generation.

For each of the performance indicators listed above, PUC Distribution has adopted the standard measurement metrics, used by OEB in its "Scorecard – Performance Measures". For definitions of the performance measures, please refer to Appendix F. The OEBs first year requiring LDCs to submit scorecards was for 2013 with the corresponding Management Discussion & Analysis introduced in 2014. Accordingly, only scorecards for 2013 and forward have been included.

PUC Distribution's operating performance during five years from 2012 to 2016, as reported in the 2016 Scorecard, is summarized in the following sections:

2.3.1 Service Quality

PUC Distribution measures and monitors service quality to ensure continued improvement, to achieve a level satisfactory to its customers and in accordance with its core value of being responsive to customer needs. OEB's directive to measure and report on service quality is the motivation for service quality measurements. PUC Distribution has aligned its service quality indicators and their measurement metrics with those mandated by OEB.

PUC Distribution monitors its service quality by measuring the following service quality indicators: (a) new residential services connected on time, (b) scheduled appointments met on time, and (c) telephone calls answered on time. The key purpose for tracking this metric is to determine how well PUC Distribution is able to meet its customers' requests for service in a timely manner. As indicated in Table 3, PUC Distribution's has met the performance target for each performance metric during each of the past five years.

Table 3: Service Quality Performance

Service Quality Metric	Target	Actual				
		2012	2013	2014	2015	2016
New LV Connections (<700 V) on time	90.0%	95.8%	96.5%	93.0%	97.2%	98.9%
Meeting Scheduled Appointments on time	90.0%	98.4%	97.1%	95.4%	97.4%	98.3%
Telephone accessibility (Answering calls within 30 seconds)	65.0%	74.6%	80.9%	81.9%	82.3%	81.3%

As a minimum performance standard for the connection of new services, new low-voltage (< 750 volts) services must be connected within 5 working days from the day on which all conditions of service are satisfied, including electrical safety inspection.

As a minimum standard, when it is necessary to meet a customer at the customer's premises or work site to conduct utility business, customers must be offered a choice of morning or afternoon appointments. The appointments must be met at least 90% of the time. If the appointed time cannot be met the customer must be notified.

As a minimum standard, incoming calls to the general inquiry telephone number must be answered within 30 seconds, at least 65% of the time.

No new investments are proposed in this DSP in response to PUC Distribution's performance on this metric.

2.3.2 Customer Satisfaction

PUC Distribution measures and monitors its customer satisfaction level to ensure customer needs are clearly understood and responded to. OEB's directive to report on customer satisfaction levels is the motivation for customer satisfaction monitoring and reporting. PUC Distribution has aligned its customer satisfaction indicators and their measurement metrics with its core value of being responsive to customer needs and with those of the OEB.

Three different OEB defined metrics are employed for customer satisfaction measurement: first contact resolution, billing accuracy and customer satisfaction surveys. The first two performance indicators were introduced by OEB in 2014 and the third performance indicator - "customer satisfaction surveys" was introduced in 2015. The key purpose for tracking First Contact Resolution is to determine how effectively customers' concerns are resolved by PUC Distribution. The key purpose for tracking Billing accuracy is to monitor PUC Distribution's performance in preparing and presenting the electricity bills to its customers accurately. PUC Distribution's performance during the past three years is indicated in Table 4 and as shown PUC Distribution's performance exceeds the defined targets.

Table 4: Customer Satisfaction Performance

Service Quality Metric	Target	Actual				
		2012	2013	2014	2015	2016
First Contact Resolution	N/A	N/A	N/A	99.89%	99.92%	99.58%
Billing Accuracy	98%	N/A	N/A	99.83%	99.36%	99.97%
Customer Satisfaction Suvey	N/A	N/A	N/A	N/A	79%	80%

PUC Distribution's First Contact Resolution was measured by tracking the number of electric related calls which were escalated to a Senior Customer Care Representative or Supervisor/Manager.

Accurate bills issued expressed as a percentage of total bills issued. It is calculated as: = (Total number of bills issued for the year – Number of inaccurate bills issued for the year) / Total number of bills issued for the year. This requirement must be met at least 98% of the time on a yearly basis.

PUC Distribution engaged a consultant to conduct our customer satisfaction surveys.

No new investments are proposed in this DSP in direct response to PUC Distribution's performance on this metric.

2.3.3 Safety

PUC Distribution measures and monitors safety related to its infrastructure and operations with the objective of minimizing the risk of accidents and injuries. OEB's directive to report on safety indicators is the motivation for monitoring safety performance. PUC Distribution has aligned its safety performance indicators and their measurement metrics with those mandated by OEB and consistent with its own core values.

Three different safety performance indicators are in use: level of public safety awareness, compliance with Ontario Regulation 22/04 and serious electrical incident index.

Table 5 summarises PUC Distribution's safety performance over the past five years, based on compliance with Regulation 22/04 and serious electrical incident index. The third measurement metric for this performance indicator – "level of public awareness of electrical safety" was introduced in 2015 and performance levels for this metric are not available for years prior to 2015. The purpose for tracking Level of Compliance with Reg. 22/04 is to monitor PUC Distribution's performance in complying with Ontario Regulation 22/04, which specifies the safety requirements to be met by Electricity Distributors in Ontario. The purpose of tracking Incident Index is to benchmark PUC Distribution's performance in operating its distribution lines safely; the metric monitors normalized number of incidents involving safety violations.

To improve public safety of power distribution systems, Regulation 22/04 was introduced in the province of Ontario in 2005. Since that time PUC Distribution has participated, as required, in an annual audit to assess compliance with the regulation. The auditor provides an assessment of compliance using one of the four designations: i) C – complies, ii) NI – Needs Improvement iii) NC – Non-compliance, iv) N/A – not applicable. As shown in Table 5, PUC Distribution has been found to be compliant with Regulation 22/04 in each of the past four years.

The 2016 results pertaining to the Serious Electrical Incident Index show a marked improvement from previous years in each of the (a) number of general public incidents and (b) rate per 10, 100, 1000km of line.

Table 5: Safety Performance

Safety Performance Indicator		2012	2013	2014	2015	2016
Level of Public Awareness		N/A	N/A	N/A	86%	86%
Level of Compliance with Ontario Regulation 22/04		NI	C	C	C	C
Serious Electrical Incident Index	Number of General Public Incidents	3	1	3	1	0
	Rate per 10,100,1000 km of line	0.407	0.135	0.405	0.134	0.000

To improve the level of public awareness about electrical safety, PUC Distribution employs a number of programs, including periodic electrical safety discussions at schools and relaying electrical safety messages to public through radio and print media. To maintain compliance with Regulation 22/04, strict project management procedures are followed; ensuring distribution systems are designed and constructed following approved engineering standards, meeting all applicable codes. All distribution system infrastructure is systematically inspected and tested when required and plans for repair or renewal of assets presenting safety risks are prepared and implemented.

Infrastructure assets found in poor and very poor condition present a high risk of failure in service. Maintaining public safety and ensuring PUC Distribution continues to meet its obligation to comply with the safety regulations is a driver for many of the projects included in the System Renewal category. For example, the following material projects, summarized in Table 22 to be implemented during the test year are intended to improve both safety and reliability performance:

Projects #5, #6, #7, #8, #9, #10, #11, #12 and #13.

2.3.4 System Reliability

PUC Distribution measures and monitors the reliability of power supply to its customers with the objective of maintaining reliability levels meeting its customers' needs. OEB's directive to report on supply system reliability is the motivation for monitoring supply system reliability. PUC Distribution has aligned its reliability performance indicators and their measurement metrics with those prescribed by the OEB. Currently, two reliability performance indicators are tracked on the OEB score card: System Average Interruption Frequency Index (SAIFI) and

System Average Interruption Duration Index (SAIDI). PUC Distribution's targets and actual performance in terms of SAIDI and SAIFI are summarized in Table 6. The table indicates reliability performance under three scenarios:

(a) By including all power interruptions

(b) By excluding interruptions due to loss of supply (OEB was monitoring reliability performance in this format from 2013 to 2015), and

(c) By excluding interruptions due to loss of supply and major climatic events (OEB started monitoring reliability in this format in 2016).

"Major Events" are defined by OEB as the events beyond the control of the distributor and are uunforeseeable, unpredictable; unpreventable; or unavoidable. Such events disrupt normal business operation occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, they take significantly longer than usual to repair, and they affect a substantial number of customers.

The OEB has established targets for SAIFI and SAIDI, against which actual performance is measured by PUC Distribution. There are no established targets for CAIDI. Targets and results are illustrated in Table 6. The following serves to identify the methodology used by the OEB to establish the annual targets for SAIFI and SAIDI:

- For 2012 there were no established targets for SAIDI and SAIFI
- For the years 2013 and 2014: targets were set to achieve the range of the actual minimum and maximum values over the 2009 to 2012 timeframe, by excluding interruptions due to loss of supply; results were within or better than the prescribed limits;
- For 2015: targets were set based on the fixed 5-year average from 2010 to 2014, by excluding interruptions due to loss of supply; SAIFI was below the target and SAIDI was above; and
- For 2016: targets were set based on the fixed 5-year average from 2010 to 2014, by excluding interruptions due to loss of supply and major events; results were better than the targets.

Table 6: Reliability Performance

(a) With all power interruptions Included

	2012	2013	2014	2015	2016
SAIDI Target	N.A.	N.A.	N.A.	N.A.	N.A.
SAIDI Actual	1.65	2.65	1.19	3.35	2.53
SAIFI Target	N.A.	N.A.	N.A.	N.A.	N.A.
SAIFI Actual	2.17	3.53	1.21	1.84	2.21
CAIDI Target	N.A.	N.A.	N.A.	N.A.	N.A.
CAIDI Actual	0.76	0.75	0.98	1.82	1.14

(b) With Interruptions due to loss of supply excluded

	2012	2013	2014	2015	2016
SAIDI Target	N.A.	1.65-2.92	1.65-2.92	2.07	N.A
SAIDI Actual	1.65	2.48	1.19	3.35	2.46
SAIFI Target	N.A.	2.17-3.61	2.17-3.61	2.50	N.A.
SAIFI Actual	2.17	2.67	1.21	1.84	2.11
CAIDI Target	N.A.	N.A.	N.A.	N.A.	N.A.
CAIDI Actual	0.76	0.93	0.98	1.82	1.17

(c) With interruptions due to loss of supply and major events excluded

	2012	2013	2014	2015	2016
SAIDI Target	N.A.	N.A.	N.A.	N.A.	1.86
SAIDI Actual	1.65	1.42	1.19	1.37	1.49
SAIFI Target	N.A.	N.A.	N.A.	N.A.	2.32
SAIFI Actual	2.17	1.78	1.21	1.03	1.41
CAIDI Target	N.A.	N.A.	N.A.	N.A.	N.A.
CAIDI Actual	0.76	0.80	0.98	1.33	1.06

- SAIDI = (Total Customer Hours of Interruptions – Total Customer Hours of Interruptions caused by Loss of Supply events)/ Average Number of Customers Served.
- SAIFI= (Total Customer Interruptions – Interruptions caused by Loss of Supply events) / Average Number of Customers Served
- CAIDI = SAIFI/SAIDI

As shown in Table 6, there is significant year over year variation in SAIDI and SAIFI performance over the past five years. Equipment failures in service have been the predominant cause of outages on PUC Distribution's supply network during the past several years. All of the investments included under System Renewal category, are aimed at replacing assets in very poor and poor condition, with priority given to renewal of those assets that present the highest risk of failure in service with most serious consequences. For example Table 22 shows the prioritized list of the material projects to be implemented during the test year. From that table, the following projects are intended to keep supply system reliability from degrading below the acceptable range:

Project #5, #6, #7, #8, #9, #10, #11, #12, and #13.

Out of a total of 13 material projects planned to be implemented during the test year, nine are aimed at preventing reliability from deteriorating through replacement of assets, determined to be at the end of their useful service life. Considering the large impact of substation equipment and feeder trunk line failures on reliability, the risk of a prolonged power outage will remain on the horizon until renewal of all assets determined to be in poor or very condition has been completed.

2.3.5 Asset Management

PUC Distribution monitors the effectiveness of its asset management practices to ensure planned projects related to infrastructure renewal, refurbishment and maintenance aimed at preventing asset impairment in service and to reduce the risk of asset failures in service, are implemented as planned on a timely basis. PUC Distribution's corporate strategy to achieve success requires the sustainability of assets and systems. The corresponding 2018 objectives include the achievement of budgeted capital programs and is the motivation for monitoring this performance indicator. Furthermore, good asset management practices align with PUC Distribution's core value of being responsive to customer's needs including service delivery and system reliability.

To measure the effectiveness of its asset management program, PUC Distribution measures the system plan implementation progress by comparing work accomplishment to plan as well as the actual capital and operating expenditure against the budget, analyzing the reasons for variance and taking corrective action, when required.

Table 7 shows the program level variance in PUC Distribution's actual expenditure from its planned expenditure during the past five years. All amounts shown are net of contributed capital from customers.

Although no historical expenditures are indicated in the System Service category, a number of investments are grouped in the renewal category which is considered the primary driver. More specifically this includes station rebuilds, voltage regulation, reclosers, line rebuilds, SCADA

improvements and protection upgrades. These upgrades introduced smart grid features, including opportunities for greater automation, improved access for connection of renewable generation and improved access for joint-use of distribution facilities. Therefore, these investments can be considered to serve multiple roles: System Access and System Service in addition to System Renewal which was the primary driver.

Table 7: Program Level Variance – Budget Vs Actual Spending

	2012			2013			2014		
	Budget	Actual	Variance	Budget	Actual	Variance	Budget	Actual	Variance
System Access	1,132,235	7,938,036	6,805,801	1,068,766	2,310,000	1,241,234	2,957,353	2,531,753	(425,600)
System Renewal	6,042,853	4,821,060	(1,221,793)	6,525,051	6,082,921	(442,130)	3,813,022	3,753,603	(59,419)
System Service	-	-	-	-	-	-	-	-	-
General Plant	17,802,500	23,269,373	5,466,873	1,313,518	2,028,344	714,826	175,445	375,693	200,248
Total Capital Expenditure	24,977,588	36,028,469	11,050,881	8,907,335	10,421,265	1,513,930	6,945,820	6,661,049	(284,771)
System O&M Expenditure	6,259,122	5,852,889	(406,233)	6,153,732	5,992,120	(161,612)	5,529,970	5,773,408	243,438

	2015			2016		
	Budget	Actual	Variance	Budget	Actual	Variance
System Access	1,265,490	1,549,411	283,921	1,214,680	1,211,917	(2,763)
System Renewal	4,752,934	4,639,948	(112,986)	4,542,992	4,243,808	(299,184)
System Service	-	-	-	-	-	-
General Plant	68,653	66,532	(2,121)	0	82,630	82,630
Total Capital Expenditure	6,087,077	6,255,891	168,814	5,757,672	5,538,355	(219,317)
System O&M Expenditure	5,819,316	5,977,598	158,282	5,955,321	5,977,871	22,550

2.3.5.1 Variance Analysis - Capital Expenditure

Capital Expenditure Variations in 2012

Table 7 indicates that in 2012, the actual expenditure in the "System Access" category exceeded the budget by over $6.8 million. This variation is related to the smart metering project – Although the installation work was physically substantially complete at the end of 2010, the costs were not capitalized until 2012.

The actual expenditure in "General Plant" category exceeded the budget by over $5.5 million. This variation in expenditure is related to the construction of the new office building, which was budgeted in 2011, but most of the work on it was completed in 2012.

The variation of ($1.2 million) in the "System Renewal" category was primarily due to delays experienced during the reconstruction of the 12kV substation Sub 10. Engineering resource constraints, equipment deliveries and poor winter weather were primary contributors to pushing completion of this project out into 2013.

Capital Expenditure Variations in 2013

Table 7 indicates that in 2013, the actual expenditure in the System Access category exceeded the budget by over $1.2 million. This variance was primarily a result of the utility having to support a substantially large and unplanned for joint-use project for one of the major telecommunications companies sharing space on its overhead infrastructure. A significant volume of make-ready work was completed to allow them to attach their fiber optic cables on PUC Distribution overhead poles. The scale of the project also led to resource constraints so that some projects in the System Renewal were not completed.

The actual expenditure in General Plant category exceeded the budget by approximately $720,000. This variation in expenditure was solely related to the construction of the new office building referred to above in 2012 for which a number of small remaining outstanding items and deficiencies were not completed until early 2013.

In the System Renewal category actual expenditure was less than the budget by approximately $440,000. This was primarily attributable to resource constraints experienced due to the joint use fibre project discussed in the System Access category above.

Capital Expenditure Variations in 2014

In 2014, the variation in overall capital expenditure from the budget was insignificantly small – less than 4% of the budget.

The actual expenditure in the System Access category was less than the budgeted amount by about 14%. This was attributable to a combination of two factors. Firstly, continuation of the

large joint-use fibre project (that was mentioned in the section above) started in 2013 was budgeted for in 2014. However, as the project progressed, circumstances changed for the telecommunications company and they canceled the project at approximately the half-way point. This had the effect of being significantly underspent on associated make-ready work. The second lesser impacting, but mitigating factor was higher than anticipated customer demand and the addition of City reconstruction projects that required additional infrastructure relocation.

In the System Renewal category, the actual expenditure was less than the budget by 2%.

The actual expenditure in General Plant category exceeded the budget by approximately $200,000. This variation in expenditure is related to the purchase and installation of furnishings, fit-ups and equipment (FF&E) for the newly constructed office building that were not anticipated at the time of budgeting the project.

Capital Expenditure Variations in 2015

In 2015, the overall capital expenditure exceeded the budget by approximately 3% and this variation was caused primarily by an overrun of $285,000 in the System Access category. PUC Distribution was required to relocate lines to facilitate municipal projects for which information was not available in advance of preparing the 2015 budget.

Capital Expenditure Variations in 2016

In 2016, the variation in overall capital expenditure from the budget was small – less than 4% of the budget.

In the System Renewal category, the actual expenditure was less than the budget amount by about 7%, primarily due to equipment failures, leaking transformers and deteriorated poles.

2.3.5.2 Variance Analysis for O&M Expenditure

As shown in Figure 2, the variations in annual O&M expenditure from the budget are rather modest, ranging from -6.5% to +4%. During 2012 and 2013, due to the unexpected increase in the System Access category of capital projects consuming the limited resources of PUC Distribution, some of the maintenance activities planned for 2012 and 2013 were deferred to 2014 and 2015, which resulted in the variance.

There is an overall 2.1% increase in actual O&M expenditures from $5.85 million to $5.98 million over the 2012-2016 period.

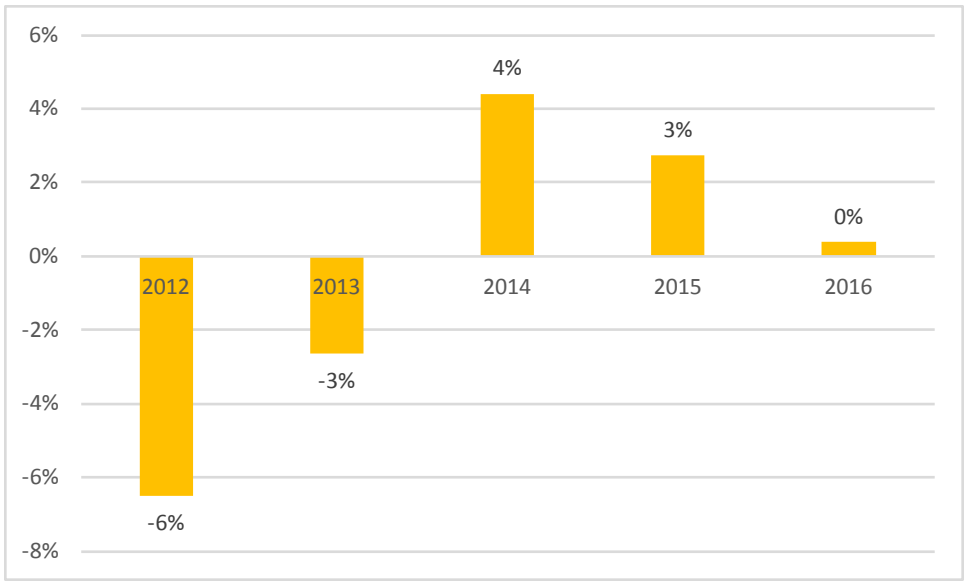


Figure 2: Variation in Actual O&M Expenditure from Budget

2.3.5.3 Initiatives to Reduce Project Variance in Future

Due to variability and uncertainty in the number of requests received for unplanned work under the System Access category, variance in actual expenditure from the planned amount cannot be eliminated. PUC Distribution intends to reduce such variances, through improved resource planning and project management.

A proactive project management approach was implemented between 2014 and 2016, to ensure continuous improvement in resource planning and project management on capital projects. Project and budget status meeting are held frequently throughout the year. Annual reviews are performed to identify reasons for variance and long-term corrective action is taken through implementation of or modification to existing processes and designs.

A review of the capital spending from 2014 to 2016 confirms that the recently implemented proactive project management initiative is yielding intended results with overall variances between -4% and +3%.

There are no capital investments proposed in this DSP related to PUC Distribution's performance on this performance measure.

2.3.6 Cost Control

PUC Distribution measures and monitors the cost efficiency for distributing electricity and serving customers within its service territory, with the purpose of benchmarking its recent performance and remaining economically efficient in the future. OEB's directive to measure and

report on cost efficiencies as well as PUC Distribution's own vision and mission statements are the motivation for cost controls. PUC Distribution has aligned its cost control indicators and their measurement metrics with those prescribed by OEB.

PUC Distribution measures and reports on the following cost efficiency indicators, including its cost efficiency ranking among peers, total cost per customer and total cost per km of line; which are discussed here as follows:

2.3.6.1 Efficiency Assessment

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs.

Table 8 summarizes the OEB rankings of the local electricity distributors based on cost efficiency in 2016:

Table 8: LDC Rankings Based on Cost Efficiency

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	6
2	Actual costs are 10% to 25% below predicted costs	More Efficient	14
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	32
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	13
5	Actual costs are 25% or more above predicted costs	Least Efficient	3

In 2016, for the fourth year in a row, PUC Distribution was placed in Group 4. PUC Distribution's efficiency performance based on the PEG model was over the predicted costs by 14% in 2016 compared to 16.2% in 2015.

Included in PUC Distribution's operating, maintenance and administrative expenses is a charge from PUC Services that is based on depreciating and financing of the vehicles, tools, computer equipment, office equipment etc. that is utilized to provide services to PUC Distribution. For utilities that own the vehicles and equipment to service their customers, these expenses are included in depreciation and financing costs. As the total costs would be the same, removing the depreciation and financing costs from PUC Distribution's operating costs would better align costs comparisons in the PEG model with other utilities. Projections for 2017 indicate that PUC Distribution would still be in Group 4 after removing the non-operating type costs from the PEG calculation. However, PUC Distribution's efficiency ranking improves to Group 3 in 2018 through to the end of the projection period in 2021 with the removal of the non-operating costs from the calculation.

PUC Distribution's target for 2018 is to improve efficiency performance in order to be rated as a Group 3 utility after the removal of the non-operating costs from the PEG calculation.

2.3.6.2 Total Cost per Customer

Total cost per customer is calculated as the sum of PUC Distribution's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC Distribution serves. Figure 3 shows PUC Distribution performance during the past five years, based on total OM&A cost per customer.

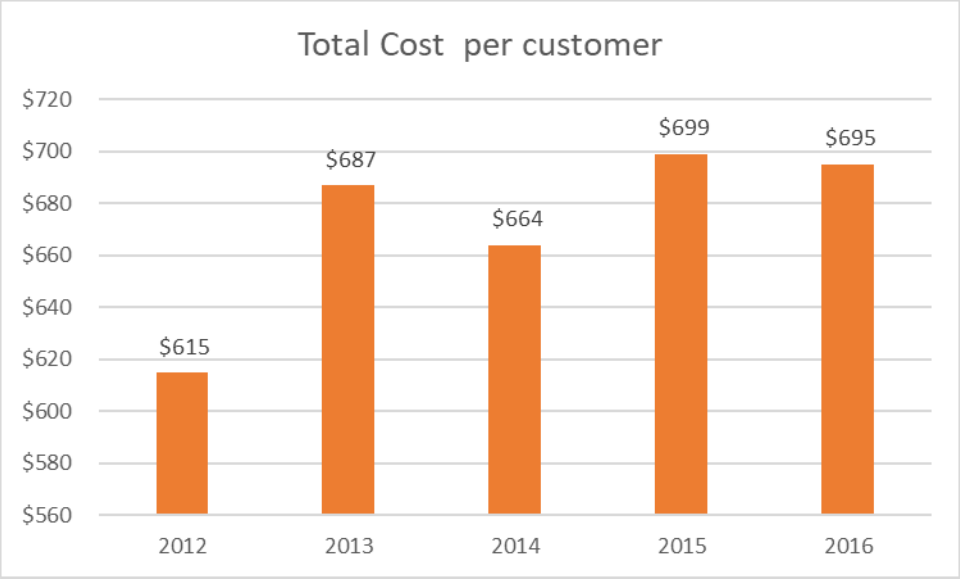


Figure 3: Operating Efficiency Performance (Total Cost per Customer)

Overall, the company's Total Cost per Customer has increased on average by 3.26% per annum over the period 2012 through 2016. For the period of 2013 to 2016, the Total Cost per Customer has increased by approximately 0.40% per year. The cost performance result for 2016 is $695 per customer which is a 0.57 % decrease over 2015.

PUC Distribution will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. The company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2016 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC Distribution's capital spending plans.

PUC Distribution's target for this metric in 2018 is $664 excluding the non-operating costs discussed above.

2.3.6.3 Total Cost per km of Line

This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometers of line that the company operates to serve its customers. Figure 4 shows PUC Distribution's performance based on total Capital and OM&A cost per km and cost per customer.



Figure 4: Operating Efficiency Performance (Total Cost per km)

PUC Distribution continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per km of line has increased an average of 3.45% since 2012 with the increase in capital and operating costs.

For the period of 2013 to 2016, the Total Cost per km of Line has increased by approximately 0.40% per year. PUC Distribution's total cost per km in 2016 was $31,314, which represents a 0.20% decrease over 2015. PUC Distribution's target for this metric in 2018 is $30,274 excluding the non-operating costs discussed above.

2.3.7 Financial Ratios

PUC Distribution measures and monitors the financial ratios for the business corporation, to ensure financial stability and economic efficiency to sustain its corporate operations in a responsible manner, providing services required by its customers in an effective and cost-efficient manner and providing a reasonable return on equity to its shareholders.

Monitoring and tracking these metrics both meets the OEB's directives pertaining to financial ratios and aligns with PUC Distribution Inc.'s own vision and mission statements.

PUC Distribution's financial ratios during the past five years are summarized in Figure 5 through Figure 7.

2.3.7.1 Liquidity: Current Ratio (Current Assets/Current Liabilities)

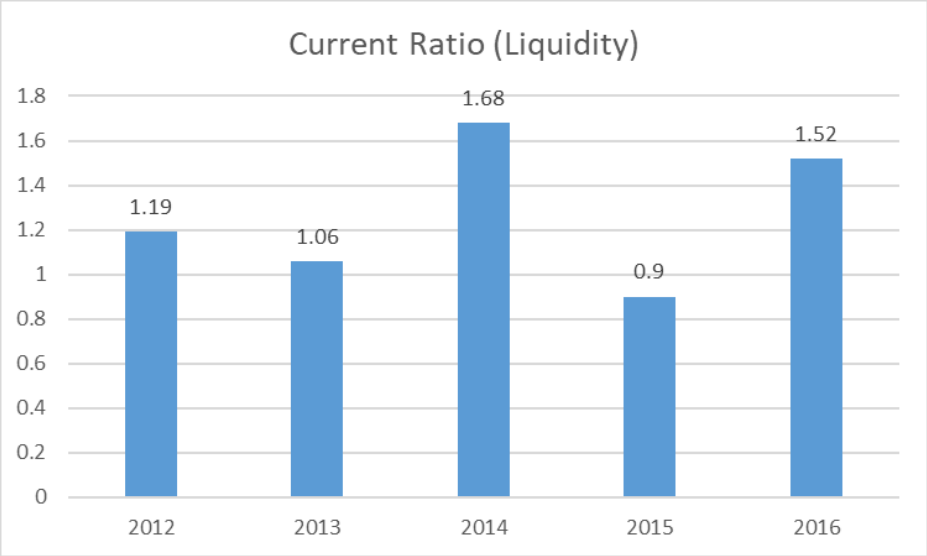


Figure 5: Current Ratio

As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short-term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations. PUC Distribution's current ratio has increased from 0.90 in 2015 to 1.52 in 2016. By increasing over 1, PUC Distribution is in a good position to cover the company's short-term debts and financial obligations.

2.3.7.2 Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio

The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt to equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring. PUC Distribution has a debt to equity structure of 70% to 30% that approximates the deemed 60% to 40% capital mix as set out by the OEB – this translates to a 2016 debt to equity ratio of 2.34. PUC Distribution's long-range plan is to push the debt to equity towards the 60/40 level.

Figure 6 shows the overall debt/equity ratio and over the past five years PUC Distribution has maintained an average debt/equity ratio of 2.21. The following factors have contributed towards an increase in debt/equity ratio during the past five years:

- Reduced Return on Equity, since the last Cost of Service rate application in 2013, which has resulted in a lower equity position than anticipated.
- Loans from Infrastructure Ontario in 2013 (~$21 million) and 2015 ($15 million) have substantially increased PUC Distribution's long-term debt.
- PUC Distribution has a $26.5 million Note Payable to its parent (City of Sault Ste. Marie).

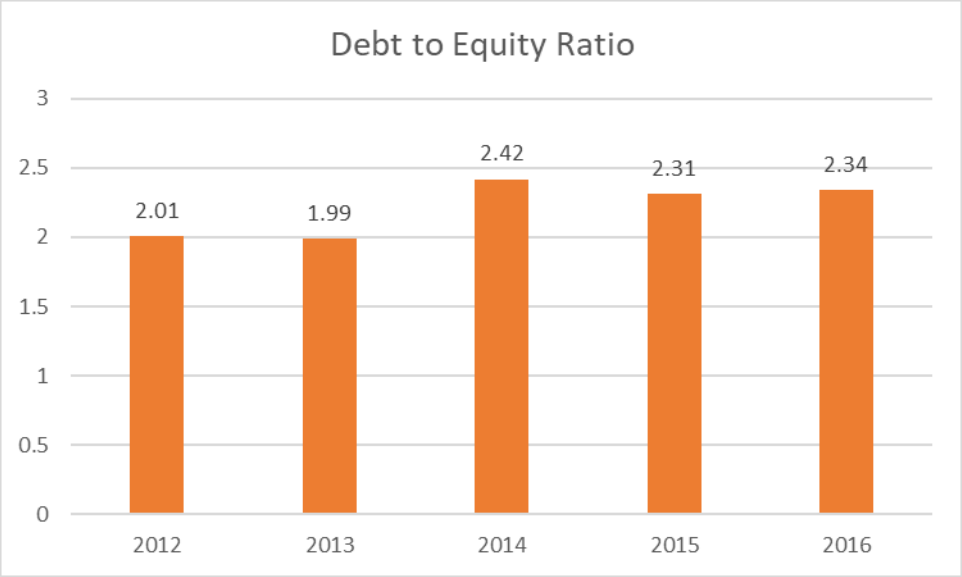


Figure 6: Total Debt to Equity Ratio

2.3.7.3 Profitability: Regulatory Return on Equity – Deemed (included in rates)

PUC Distribution's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 8.98%. The OEB allows a distributor to earn within +/- 3 percentage points of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

2.3.7.4 Profitability: Regulatory Return on Equity – Achieved

PUC Distribution's return on equity in 2016 at 0.98% was more than 3 percentage points lower than the expected return of 8.98%. The variance in return on equity is the result of PUC Distribution's OM&A expenses in 2016 being approximately $1.4 million higher than included in the approved 2013 cost of service rate application. PUC Distribution's OM&A request for the 2013 Cost of Service rate application was $10.93; however this amount was reduced through the settlement process to the approved amount of $9.95. Although PUC Distribution did not receive approval for the full amount requested in rates for OM&A expenses in its last cost of service rate application in 2013, due to increased regulatory requirements and costs deemed necessary to service customers, PUC Distribution's expenditures in 2013 were $11.16 million compared to the approved amount in rates of $9.95 million. The increase of $1.21 million from 2012 to 2013 is detailed below in Table 9:

Table 9 - Incremental OM&A from 2012 to 2013

Area	Amount	
Labour	$444,000	Line and Engineering Dept. labour for capital projects was high in 2012 which required the delay in operating and maintenance programs that were resumed in 2013 (Line $298k, Engineering $88k), Meter Dept. labour was temporarily redirected to the smart meter project in 2012 but resumed regular operating and maintenance programs in 2013 ($72k)
Management Labour	$248,000	Engineering P&C Engineer not filled for full year in 2012, higher level of capital effort in 2012 for smart meters, etc.
Line clearing	$188,000	2012 was a low year for line clearing costs – was highly dependent on area to be cleared and number of contractors bidding – line clearing areas were revised in 2016 to a more consistent annual area and program moved from 3 years to 4 years
Bad Debts	$74,000	Increased cost of energy to customers has increased the amount of customer's bills – number of write-offs and amounts per w/o

		are higher
New Building Operating expenses – property taxes	$244,000	New building occupied in 2013 – resulted in higher property taxes
New Building Operating expenses – other operating expenses	$117,000	New building occupied in 2013 – resulted in higher operating costs – utilities, janitor, etc.
Misc.	-$105,000	
	$1,210,000	

Subsequent to the increase in 2013, OM&A expenses have increased marginally from $11.16 million in 2013 to $11.36 million in 2016. This equates to a three year average annual increase of 0.6%.

In addition, PUC Distribution did not increase its rates in one year of the current IRM rate period and postponed its Cost of Service rate application due to the local economic circumstances.

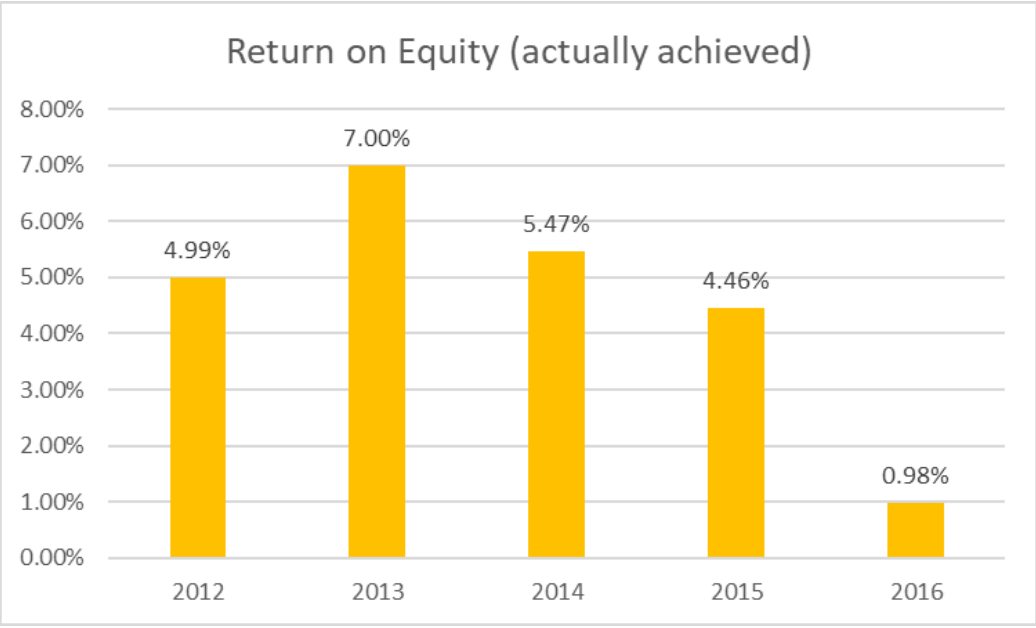


Figure 7: Regulatory Return on Equity

2.3.8 Conservation and Demand Management (CDM)

PUC Distribution measures and monitors its progress in implementing CDM program to ensure continued progress in meeting the assigned targets for its service territory for energy conservation and demand reduction. OPA/IESO's policy and guidelines and OEB's directive to comply with these policies and guidelines is the motivation for monitoring and reporting on the progress in meeting CDM targets. PUC Distribution reports on the CDM progress using IESO/OPA approved report formats. Furthermore, CDM initiatives are aligned with PUC Distributions core values of innovation and responsiveness. In conjunction with the CustomerFirst collaborative innovative approaches are implemented for the delivery of CDM programs to customers. This multi-utility approach also serves to ensure that collaborative programs are responsive to customer needs.

PUC Distribution has been actively participating in the province's energy conservation and demand management (CDM) programs, engaging all customer groups within its service territory. CDM continues to play a critical role in helping customers manage their electricity costs, while making a positive contribution in de-accelerating the rate of global warming and reducing the peak demand on the distribution grid. PUC Distribution participates in a number of IESO's incentive programs designed to reduce energy use and to promote effective environmental conservation. The current Save on Energy conservation framework has started to gain considerable momentum in PUC Distribution's service territory and a number of CDM programs have been successfully implemented.

Table 10 and Table 11, respectively, show the savings in peak demand and energy use, achieved during the first tranche of the program, from 2011 to 2014. CDM targets were redefined in 2015. Table 12 shows the performance achieved in relation to the new 2020 target for energy savings.

As indicated in those tables, PUC Distribution's proactive engagement in energy conservation and demand management programs has contributed significantly to province's CDM targets and more specifically in curtailing the peak demand on its distribution grid. The reduction in demand has resulted in no investment requirements to address any capacity constraints on the distribution network.

Table 10: PUC Distribution's Net Peak Demand Savings at End User Level 2011-14 (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	0.7	0.7	0.7	0.6
2012 - Verified†	0.0	0.8	0.8	0.8
2013 - Verified†	0.0	0.1	1.1	1.0
2014 - Verified†	0.0	0.0	0.0	0.9
Verified Net Annual Peak Demand Savings Persisting in 2014:				3.3
PUC Distribution Inc. 2014 Annual CDM Capacity Target:				5.6
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				59.5%

†Includes adjustments to previous years' verified results

Table 11: PUC Distribution's Net Energy Savings at End User Level 2011 – 14 (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	2.7	2.7	2.7	2.6	10.9
2012 - Verified†	-0.2	2.7	2.7	2.7	7.9
2013 - Verified†	0.0	0.3	3.9	3.9	8.1
2014 - Verified†	0.0	0.0	-0.05	3.7	3.7
Verified Net Cumulative Energy Savings 2011-2014:					30.5
PUC Distribution Inc. 2011-2014 Annual CDM Energy Target:					30.8
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					99.1%

†Includes adjustments to previous years' verified results

Table 12: PUC Distribution's Net Incremental Energy Savings 2015-2020 (kWh)

Year	Residential kWh	Non-Residential kWh	Local LDC Programs	LDC Innovation Pilots	IESO Verified Total (kWh)	OEB Target (kWh to 2020)	% of 2020 Target Achieved (Cumulative)
2015	1,969,397	3,431,349	0	0	5,400,746	26,410,000.00	20%
2016	3,822,336	5,307,038	0	270	9,129,644		55%

2.3.9 Renewable Generation (REG) Connections

PUC Distribution measures and monitors its progress in facilitating and implementing the renewable generation connections requested by customers in its service territory. OEB's directives follow the province's broader policy to encourage and facilitate REG connections and are the motivation for monitoring this performance indicator. PUC Distribution measures its operating performance for REG connections by confirming if the REG connection requests are processed within the time period specified by OEB as indicated in Table 13. Customers realize benefits associated with REG connections in the form of cost savings which is consistent with PUC Distributions strategic goal of delivering improved customer satisfaction.

Table 13: PUC Distribution's REG Connection Performance

	2012	2013	2014	2015	2016	Target
REG Connection Impact Assessments completed on Time	-	-	-	0%	100%	-
New Micro-Embedded Generation Facilities Connected on Time	-	100%	100%	100%	-	90%

PUC Distribution has proactively participated in Ontario's Green Energy program, by facilitating the connection of Renewable Energy Generation (REG) to the distribution grid. PUC Distribution currently has approximately 63MW of REG connected to its distribution system, which on occasion results in net export conditions during summer months when the distribution network is near its minimum load.

Section 25.37 of the Electricity Act, 1998 requires that connection assessments for renewable energy generation facilities be completed by electricity distributors within prescribed timelines, and it also requires distributors to report quarterly to the Board on their ability to meet those timelines. Ontario Regulation 326/09 (Mandatory Information re Connections) sets out details regarding the timing of, and reporting on, connection assessments. Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority. All requests received in 2016 for connecting REG connections under province's FIT program have been successfully connected by PUC Distribution.

For generation facilities that are 10 kW or less, the OEB established a connection measure in amendments to the Distribution System Code that came into effect on June 13, 2013 (EB-2012-0246). A distributor shall connect an applicant's micro-embedded generation facility to its distribution system within 5 business days of which all applicable service conditions are satisfied, 90 percent of the time on a yearly basis, or at such later date as agreed to by the customer.

100% of the requests received to date for micro-FIT (<10kW) generation facilities have been successfully connected within the OEB mandated time period. No REG connection requests have been turned down due to capacity constraints.

3 Asset Management Process [5.3]

This section describes in detail PUC Distribution's asset management process and the direct links between the asset management process and the expenditure decisions that comprise the capital investment plan covered by this DSP.

3.1 Asset Management Process Overview [5.3.1]

3.1.1 Corporate Goals, Asset Management Objectives, and Investment Prioritization [5.3.1a]

In developing and implementing the asset management plan, PUC Distribution has aligned its key objectives with its corporate vision, mission and core values. PUC Distribution's vision is to be recognized as a progressive electric distribution company committed to delivering value, innovation, prosperity and excellence. PUC Distribution's mission is to provide cost effective, efficient, safe and reliable delivery of high quality energy services and solutions consistent with customer needs and preferences. Its core values are:

- **Responsive** – We believe that to be recognized as the leading service provider we need to not only respond quickly to our customers' needs but also anticipate and be proactive with our service delivery

- **Ownership** – to promote organizational excellence, everyone is empowered to take individual accountability and inspired to assume personal responsibility within the organization

- **Safety** – PUC Distribution has been and will continue to be a strong advocate for safety within our community. Safety is our top priority and we will never compromise on the safety of our employees or our community

- **Innovative** –We believe that in order to succeed in advancing a climate of innovation we must seek out new approaches or technologies, and apply ingenuity and creativity when confronting challenges

- **Entrepreneurial** – We recognize that exploring new business ventures and diversifying our service offerings is the best way to ensure we not only earn a fair return for our shareholder, but grow and add value as a community owned asset.

In conjunction with its mission, vision and core values, PUC Distribution has established the focus areas, corporate strategic goals and strategies to achieve the goals identified in Table 14:

Table 14: PUC Distribution's Focus Areas, Goals & Strategies

Focus Area	Strategic Goals	Strategy to Achieve Goal
Customers	Achieve A+ customer satisfaction Rating Meet or exceed all score card targets	Improve customer focus, customer satisfaction, communication, engagement and education Improve service quality
Employees	Be recognized as one of Canada's top 100 employers Organization Safety Excellence	Implement P3S0 organizational transformation - proactive employee engagement and training Continuous improvement of safety culture and performance
Shareholder	Achieve OEB deemed return on equity Increase value of company	Ensure sustainability of assets and system Productivity/business process improvements Explore permitted business opportunities

To achieve these strategic goals the key objectives on which the asset management plan is based have been ranked on a scale of 1 to 5. For further clarity, objectives ranked as a 1 have been classified as having the lowest priority for investment while those given a ranking of 5 are classified as having the highest priority. The ranking is meant to score the objectives on a relative basis. The following tactical objectives are intended to support and align with the broader strategic goals referenced above:

- ✓ Ensuring investment plans are aligned with the corporate goals - Ranking 5
- ✓ Ensuring investment plans are cost effective - Ranking 5
- ✓ Ensuring investment plans provides value to the customers - Ranking 5
- ✓ Ensuring investment plans are responsive to public policy - Ranking 5

- ✓ Maintaining public and employee safety - Ranking 5
- ✓ Maintaining reliability commensurate with customer needs - Ranking 5
- ✓ Providing customer service quality to satisfy customer needs - Ranking 5
- ✓ Maintain safe and ergonomic work place, tools and equipment - Ranking 5
- ✓ Controlling costs - minimizing asset life cycle costs - Ranking 4
- ✓ Minimizing risk of in-service failures - Ranking 4
- ✓ Minimizing environmental risks, - Ranking 4
- ✓ Aligning the DSP with regional planning objectives - Ranking 3
- ✓ Facilitating new renewable generation connections; - Ranking 3
- ✓ Facilitating the smart grid development - Ranking 2

Because there are no pending applications for connecting renewable generation, a lower ranking for investments into smart grid development and facilitating renewable generation connections has no significant adverse impact. Similarly, none of the investments proposed in this DSP conflict with the regional planning objectives and therefore lower ranking of the regional planning objectives has no adverse impact.

3.1.2 Asset Management Process Components [5.3.1 b]

3.1.2.1 Asset Management Strategy

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. Investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when “right sized” investments are planned and implemented into new assets involving system extension or capacity upgrades or renewal, rehabilitation, repair or preventative maintenance of existing assets, based on a “just-in-time” approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized, while fully addressing customer service quality and needs.

3.1.2.2 Investment Prioritization Process

As described previously in Section 1, Capital investments into infrastructure assets are classified into four categories, as defined in OEB's Chapter 5 filing requirements and these include: System Access, System Renewal, System Service and General Plant.

System Access Investments

System Access investments facilitate modifications to the distribution system infrastructure, to allow connection of new load or generation customers to the grid, permit joint-use of distribution infrastructure by allowing telecommunication companies to install their service equipment on power lines or underground ducts and allowing relocation of distribution infrastructure installed in public right-of-ways to permit road reconstruction projects. System Access investments are a regulatory obligation for distribution companies (as defined in the Distribution System Code and PUC Distributions Conditions of Service) and therefore these System Access investments receive the highest priority in the overall investment envelope.

To establish the investment level required for System Access, the scope of the required work in this category was identified by estimating the number of anticipated requests for new services both on existing developed streets and in new planned subdivision developments, through direct contact with customers and land developers as well as from the information collected from the municipal planning department. Information related to municipal road reconstruction projects requiring relocation of lines was also obtained from the municipal authorities. Local telecommunication companies were consulted to determine the scope of "make-ready" work for joint-use lines. This category also includes investments needed to comply with the OEB directive to equip all general service customers with >50kW and <500kW demand with MIST meters.

System Service Investments

System Service investments facilitate modifications to the distribution system to ensure that system assets continue to meet their functional needs, efficiently and safely. Electricity distribution companies must invest into capacity upgrades, when required to remove supply system constraints and to ensure electricity delivery at consumer connection points meets the applicable power quality standards (as defined in CSA standards, Distribution System Code). System Service investments may also be required to meet customers' evolving needs for services e.g. introduction of smart grid features to give customers greater access to manage their energy use, improve automation, reduce power restoration times upon asset failures and facilitate connection of renewable generation to the grid. Once it is determined that the existing system is no longer able to meet customers' functional needs, or distribution system standards, these investments become mandatory, gaining the same priority level as the System Access investments.

In order to assess the required level of System Service investments, ability of the distribution grid to supply the existing and anticipated load and generation customers was analysed. PUC Distribution has implemented a number of smart grid features during the previous years, such as smart meters, digital protection systems, voltage regulators and remote-controlled substation switchgear to facilitate automation. System Service investments include input from customers to drive investment decision making. Examples include implementation of voltage regulation improvements and recloser installations in response to customer feedback and needs. As indicated in Section 4, a number of investments under System Renewal will also serve the dual purpose of providing benefits typically derived from System Service investments. As such, there are no investments proposed in this DSP, specifically triggered by System Service objectives.

General Plant Investments

General Plant investments are modifications, replacements or additions to the assets that are not a part of the distribution system comprised of land and buildings used to support day-to-day business and operations activities. PUC Distribution leases its motor vehicle assets rather than owning them, therefore as indicated in Section 4.1.2, and a relatively small level of capital investment is required for renewal of General Plant, equipment and workplace buildings. Additionally, all of PUC Distribution works out of a single consolidated facility which was recently constructed in 2012/2013. General Plant projects are identified and assessed using a combination of inspections, policies and expert knowledge. Investments into building repairs are based on identified deficiencies through inspections of building interior and exterior, doors and fixtures, HVAC, parking lots, security system and building mechanical systems.

System Renewal Investments

System Renewal investments involve replacing and/or refurbishing existing distribution system assets to extend the service life of assets, thereby maintaining the ability of the distribution system to provide customers with a safe and reliable supply of electricity in accordance with customer feedback and prescribed standards and codes (e.g.: Distribution System Code, OEB Scorecard metrics, CSA standards). As the existing assets age, their operating condition degrades and eventually reaches a level where the risk of assets failing in service becomes unacceptable. Since a significantly large part of PUC Distribution's infrastructure assets have been determined to be in poor or very poor condition, prioritization of investments in the System Renewal category, required a comprehensive risk assessment approach, which is described below in detail.

Figure 8 summarizes the flow chart used to sift through the assets, to objectively identify the assets that present the highest risk of in-service failures so that the investments could be targeted into assets that present the highest risk.

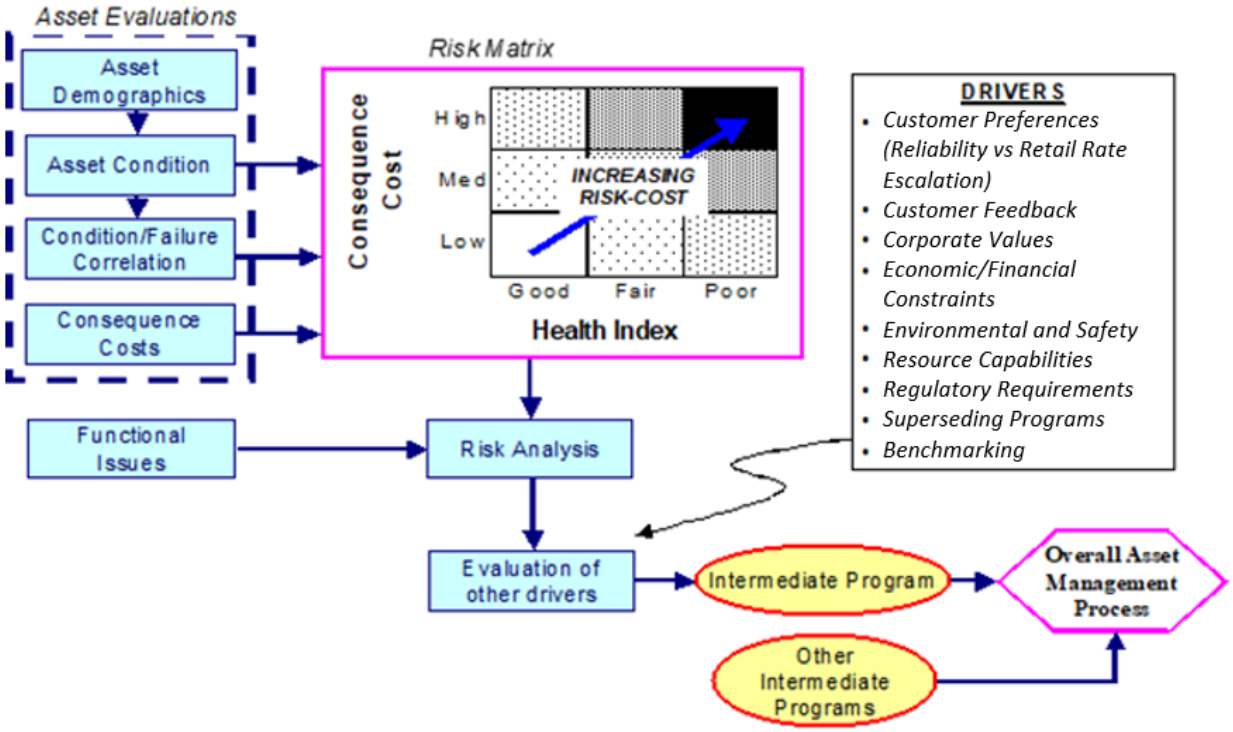


Figure 8: Flow Chart for Asset Management Plan

As shown in Figure 8, for establishing the overall investment level for System Renewal and prioritization of assets selected for renewal, condition assessment of all assets installed in stations, overhead lines and underground distribution systems, was performed by utilizing all available data, indicative of assets' operating condition and probability of failure. The asset condition assessment task was performed under the supervision of the "Engineering and Operations" division.

Data Sets

The data sets employed in prioritization of the investments include:

a) Asset registers, a geographical information system (GIS) station single line diagrams and operating maps, indicating line lengths, conductor sizes, equipment ratings and service age of assets

b) Station peak loading data, indicating equipment capacities and maximum load

c) Equipment inspection data sets, indicating operating condition of distribution system assets, and

d) Substation test result data sets

e) Asset condition assessment report (attached at Appendix B)

While data sets listed under a), b) and c) are maintained and updated by PUC Distribution's Operations and Engineering staff, data sets listed under d) and e) were compiled by third-party contractors and consultants.

Process Description

The asset management process employed for prioritization of investments is described in detail in Appendix B and is briefly summarized below.

Using asset demographic information from PUC Distribution's data sets as an input, service age profiles were developed for all categories of distribution system assets, including distribution stations, as well as the overhead and underground distribution system. PUC Distribution has been maintaining accurate records of station loading for more than 15 years. During preparation of the asset management plan in 2016, historic loading trends were analyzed and anticipated loading levels for distribution stations during the next five years were compared with the station ratings, to identify the potential for distribution system constraints. Results of physical inspections of distribution system performed by PUC Distribution staff were reviewed and supplemented by additional inspections of high risk assets performed by a third-party Professional Engineer. By taking into account asset demographic information, results of physical inspections and in-situ testing, the condition of each major asset in service was assessed. Numeric health indices, normalized to a scale of 100, were used to express the health and condition of assets; and this procedure allowed separation of the assets in "very good", "good" and "fair" condition that require minimal risk mitigation from those in "poor" and "very poor" condition, as illustrated by means of example in Figure 9, which summarizes the condition assessment of wood poles. For all distribution system assets a detailed Asset Condition Assessment is contained in Appendix B.

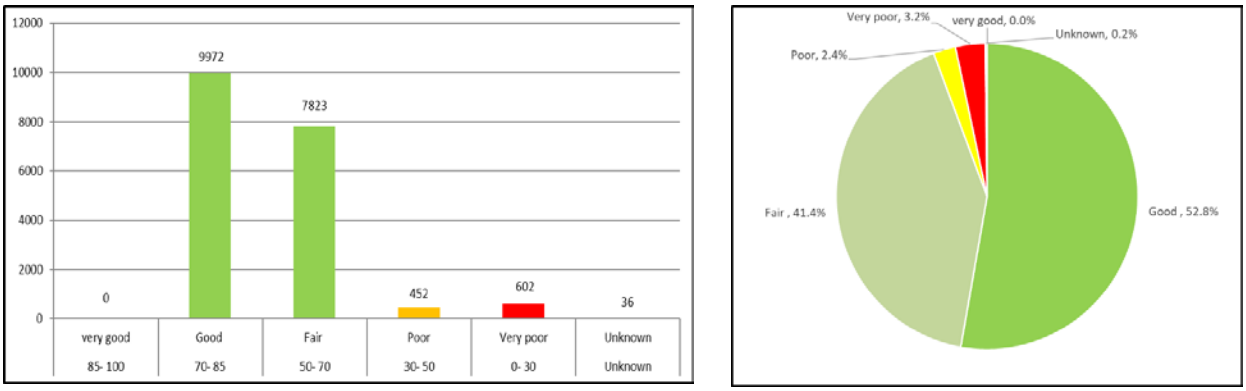


Figure 9: Illustrative Example – Condition Assessment of Wood Poles

For assets determined to be in poor or very poor condition, consequences of asset failures were assessed and those requiring renewal/rehabilitation were ranked in order of priority, with highest consequence of failure being assigned the highest priority. Economic analysis was carried out to determine the optimal response for risk mitigation, by taking into account the cost and life extension provided by renewal and rehabilitation.

In addition to the asset condition and risk assessment, customer engagement sessions were held under the direction of the Customer Engagement and Business Development division to receive feedback and determine customer preferences for service quality level and retail rate escalation. This information was employed by the Finance and Corporate Support division, to establish the overall spending envelope to be applied to the four investment categories. By subtracting the higher priority investments for System Access, System Service and General Plant, available investment level for asset renewal during the DSP period was established by the Operations and Engineering Division. And finally, from the prioritized list of projects, prepared previously through the risk based approach, considered in conjunction with the drivers identified in Figure 8 (i.e.: customer preferences, customer feedback, etc.), a list of projects to be included in the DSP was developed, which could be implemented within the available budget.

3.2 Overview of Assets Managed [5.3.2]

3.2.1 Key Features of the Distribution Service Area [5.3.2 a]

3.2.1.1 Distribution Service Area

PUC Distribution's service territory as shown in Figure 10 includes most of the City of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. Its service territory covers a total service area of approximately 342 square kilometers, including a rural service area 284 square kilometres and an urban service area of 58 square kilometres. The combined population served is approximately 75,300. The service territory includes approximately 29,700 residential customers and approximately 3,800 general customer services for a total of approximately 33,500 customers.

Of the total 743 circuit kilometres of line, 621 kilometres are overhead while the remaining 122 kilometres are underground.

3.2.1.2 Economic Growth

According to Statistics Canada census data, the City of Sault Ste. Marie's has experienced about a 2.1% decline in population between 2011 and 2016. The pace of economic growth is not expected to change during the next 5-year period, covered by the DSP.

3.2.1.3 Climate

The climate is typical of most towns in Northern Ontario and reaches temperature extremes of -40˚C during winter and +40˚C in summer. The normal monthly temperatures vary from -15˚C during winter and +25˚C in summer, with approximately 10 days of precipitation in a month. Both overhead and underground distribution systems are employed in PUC Distribution's service territory. The presence of a number of different soil types, the Canadian Shield, numerous clays, and muskeg often make excavation activities a challenge, particularly for installation of underground distribution systems. The region is vulnerable to commonly occurring strong wind storms, lake-effect snow and ice loading from Lake Superior, which poses a challenge to overhead lines. PUC Distribution's entire service territory is located within the CSA heavy loading area as described in CSA 22.3 No. 1-15 Overhead Systems. Accordingly, the corresponding CSA referenced heavy loading conditions of radial thickness of ice; horizontal wind loading and temperature are accounted for in line designs. Lines with the highest risk of failure consequences are included in the asset renewal program proposed in this DSP.

3.2.1.4 Electrical Loading

Electrical loading on the grid peaks during the winter in this region. Due to expansion of the natural gas distribution network and implementation of the CDM programs over the recent past, winter peak loading on the electricity grid has reduced, while the relatively small decline in the population has resulted in a modest increase during summer peak loading. As a result, the overall peak demand on the electricity has been trending downwards and no capacity constraints are anticipated during the next five years.

Although a number of investments in the System Renewal category will introduce many smart grid features during rebuild of the system and therefore will provide benefits typically provided by investments in System Service category, there are no investments in this DSP, for which System Service is considered the sole motivation and therefore no investments are shown in the System Service category.

3.2.1.5 System Voltage Levels (Voltage Conversion)

Approximately 25 years ago, PUC Distribution started a program to gradually upgrade its distribution system from 4.2 kV to 12.5kV. When the existing 4.2 kV infrastructure reaches the end of its service life, rather than like for like replacement of 4.2 kV rated equipment with 4.2 kV rated equipment, the voltage is upgraded to 12.5 kV, which results in greater operating efficiency. A vast majority of the distribution system has already been upgraded to 12.5 kV and at present relatively small pockets of service area with 4.2 kV network remain. Most of the existing distribution infrastructure operating at 4.2 kV is at the end of its service life and the poor condition of equipment has been resulting in frequent equipment failures with adverse impacts on reliability. Maintaining a distribution system with two operating voltages also results in

duplication of lines and economic inefficiencies due to system energy losses. Therefore, this DSP includes investments to retire the remaining network equipment operating at 4.2 kV from the grid and upgrade all of the remaining line sections to 12.5 kV.

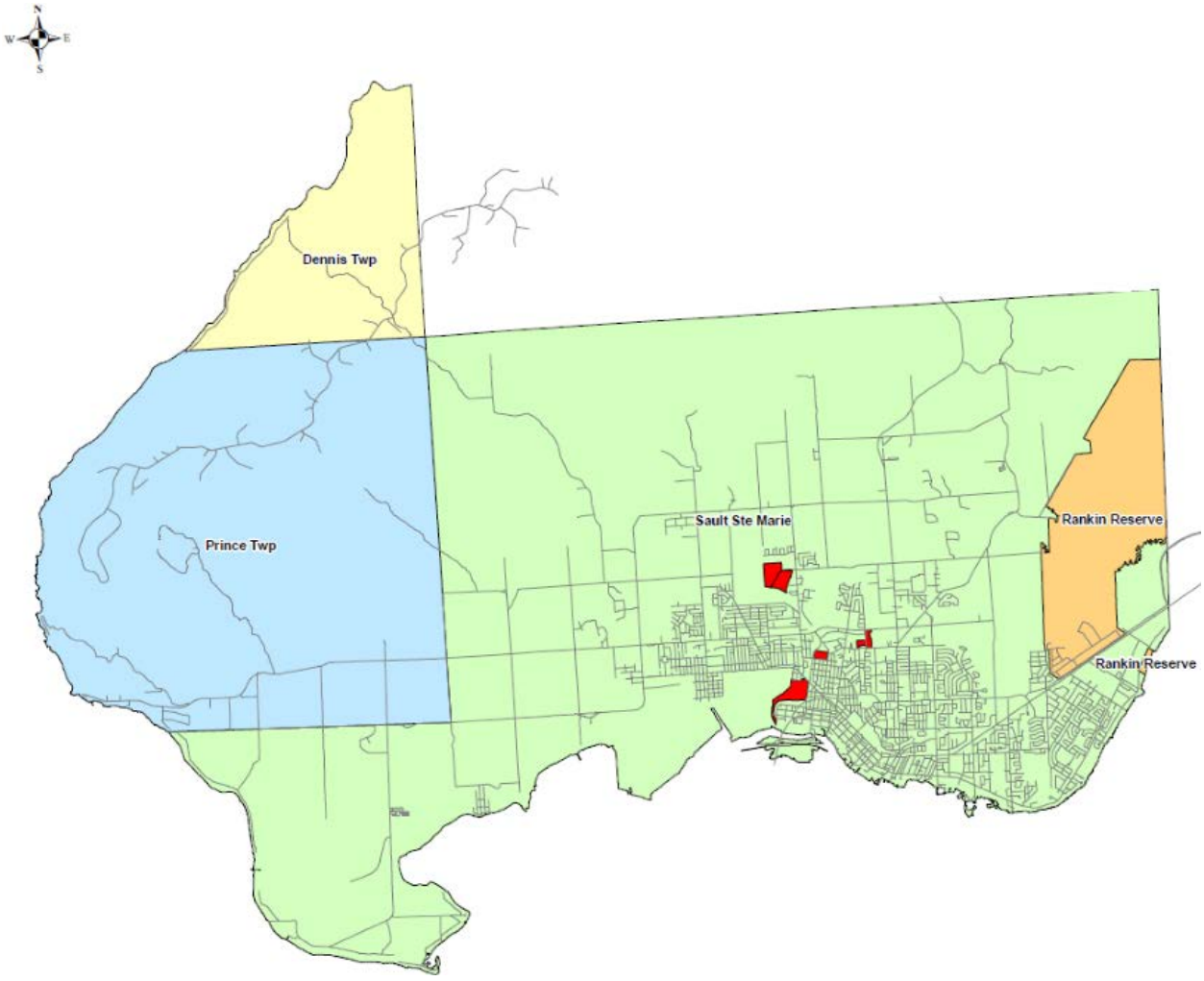


Figure 10: PUC Distribution Service Territory

3.2.2 Description of System Configuration [5.3.2 b]:

PUC Distribution owns and operates two transformer stations - TS1 and TS2, which step down power received from the transmitter at 115 kV to 34.5 kV. The 34.5 kV feeders supply a total of 12 distribution stations, which step down power from 34.5 kV to 12.5 kV. There are also two additional distribution stations; one of which steps down from 34.5kV to 4.2kV, the second steps down from 34.5kV to both 12.5kV and 4.2kV. A third 12.5kV to 4.2kV station, Substation 14 has been recently been retired. The remaining two 4.2 kV distribution stations are planned to be retired from service, upon completion of the distribution voltage upgrade program, during the

next five years. Figure 11 below shows the geographic locations of transformer stations and distribution stations, within the PUC Distribution's service territory.



Figure 11: Distribution Station Locations

Table 15 shows the power transformer ratings and number of 34.5 kV feeders at each of the 115/34.5 kV transformer stations.

Table 15: 115/34.5kV Substation Ratings

Transformer Station	Capacity	Number of 34.5 kV Feeders
TS 1	4x30 MVA	5
TS 2	4x30 MVA	5

In addition to the four outgoing feeders, TS-1 also supplies Substation 19, which is located at the same site as TS-1. Both transformer stations are also equipped with power factor correction shunt capacitors. TS-1 employs shunt capacitors of 20 MVAR rating as well as a recently

installed IESO controlled 7MW/+/-7MVAr/7MWh energy storage facility to provide dynamic Volt/VAR control. TS-2 employs shunt capacitors of 40 MVAR rating.

Table 16 shows the power transformer ratings and number of feeders at each of the distribution stations.

Table 16: Substation Ratings

12 kV Stations	Capacity	Number of 12.5 kV Feeders
Substation 1	2x10 MVA	4
Substation 2	2x10 MVA	4
Substation 4	1x10 MVA	2
Substation 10	2x10/13.3 MVA	4
Substation 11	2x10 MVA	4
Substation 12	2x10 MVA	4
Substation 13	2x10 MVA	4
Substation 15	2x10 MVA	4
Substation 16	2x7.5 MVA	4
Substation 18	2x7.5 MVA	4
Substation 19	2x10 MVA	4
Substation 20	2x10 MVA	4
Substation 21	2x10 MVA	4

4.2kV Stations	Capacity	Number of 4.2 kV Feeders
Substation 4	1x10 MVA	2
Substation 5	2x5 MVA	2

Major assets employed on the overhead and underground distribution network are summarized in Table 17. As indicated, the power supply network employs overhead lines operating at 115kV, 34.5 kV, 12.5 kV, 7.2 kV, 4.2 kV and 2.4 kV as well as low voltage (LV), i.e. less than 750V, and it employs insulated cable circuits installed in duct and direct buried configurations, operating at 34.5kV, 12.5 kV, 7.2 kV, 4.2 kV and 2.4 kV.

Table 17: PUC Distribution's Distribution System Assets

Asset	Quantity	Units
3-Phase 115 kV Overhead lines	15.5	km
3-Phase 34.5 kV Overhead lines	74.4	km
3-Phase 12.5 kV Overhead lines	278	km
3-Phase 4.2 kV Overhead lines	23.5	km
3-Phase LV Overhead lines	38.7	km
1-Phase 7.2 kV Overhead lines	219.4	km
1-Phase 2.4 kV Overhead lines	8.3	km
1-Phase LV Overhead lines	42.1	km
Number of poles on OH lines	12683	#
34.5 kV, 3-ph, UG, Cable Circuits	24.5	km
12.5 kV, 3-ph, UG, Cable circuits	49.2	km
7.2 kV, 1-ph, UG, Cable circuits	45.6	km
4.2 kV, 3-ph, UG, Cable circuits	1.4	km
2.4 kV, 1-ph, UG, Cable circuits	1.4	km
Number of 1-ph pole mounted transformers	5167	#
Number of 3-ph pad mounted transformers	547	#
Number of 1-ph pad mounted transformers	391	#
Number of submersible transformers	517	#
Number of pad-mounted switchgear	23	#
Number of K-bar Units	130	#
Number of concrete structures (pads and vaults)	1041	#

Table 18 provides information on the number of feeders that are installed in overhead (OH) or underground (UG) or mixed OH/UG configurations.

Table 18: Number of Feeders Installed in OH or UG Configurations

(a) 35 kV Feeders

Source Station	Total Number of Feeders	Number of OH Feeders	Number of UG Feeders	Number of Mixed OH/UG Feeders
TS-1	5	5	0	0
TS-2	5	2	0	3

(b) 12.5 kV Feeders

Source Station	Total Number of Feeders	Number of OH Feeders	Number of UG Feeders	Number of Mixed OH/UG Feeders
DS-1	4	1	1	2
DS-2	4	2	1	1
DS-4	2	2	0	0
DS-10	4	4	0	0
DS-11	4	3	0	1
DS-12	4	1	1	2
DS-13	4	3	0	1
DS-15	4	2	1	1
DS-16	4	1	0	3
DS-18	4	1	0	3
DS-19	4	2	0	2
DS-20	4	2	0	2
DS-21	4	0	0	4

(c) 4.2 kV Feeders

Source Station	Total Number of Feeders	Number of OH Feeders	Number of UG Feeders	Number of Mixed OH/UG Feeders
DS-4	2	1	0	1
DS-5	2	2	0	0

3.2.3 Asset Demographics and Condition Assessment [5.3.2 c]:

The asset management plan, prepared in September 2016 and attached as a stand-alone report in Appendix B, provides complete demographic and asset condition information on fixed assets employed in PUC Distribution's substations, overhead distribution network and the underground distribution system. The asset condition assessment report documents the condition of all major assets in units of health indices and provides ranking of assets in designations rated "very good", "good", "fair", "poor" and "very poor". In determining the health indices of assets, all available information relevant to the assets' health, including age, results of visual inspections and results of diagnostic testing when available, have been utilized.

"Very Good" asset condition represents brand new asset in perfect operating condition, with no impairment. "Good condition" indicates an asset with service life equal to less than 25% of its typical useful life and with no impairment and no noticeable drop in operating performance. "Fair Condition" indicates an asset with service life equal to more than 25% but less than 80% of its typical useful service life, with normal wear and asset operating performance within acceptable tolerances and no significant impairment. "Poor Condition" signifies an asset with

service life greater than 80% of its typical useful service life, appreciable wear or significant impairment in asset condition causing its performance to degrade below acceptable levels and presenting high risk of asset failure unless major repairs or asset rehabilitation is performed to restore asset condition to "Fair". "Very Poor Condition" signifies an asset with serious impairment to its critical components and the asset presents very high risk of failure. Assets in "very poor" condition cannot be economically repaired and renewal is the only option to restore their operating condition.

All of the information provided in the following sections on asset condition is based on the asset condition assessment performed in September 2016.

3.2.3.1 Condition Assessment of Substation Assets:

In substations, power transformers and switchgear (complete with protection and control equipment) are the critical components, essential to safe and reliable operation of station functions. Figure 12 and Figure 13, reproduced below from the AM Condition Assessment report, indicate the existing condition of power transformers and switchgear employed at PUC Distribution's 115/34.5 kV transformer stations and 34.5/12.5 kV distribution stations.

Due to the advanced service age, combined with "poor" or "very poor" operating condition of a vast majority of the power transformers and switchgear sets employed at both of the 115/34.5 kV transformer stations (TS-1 and TS-2), both of these stations require complete rebuild with new power transformers, switchgear, protection and control equipment. Rebuilding of these two transformer stations requires significant front-end planning and engineering before construction can begin, to ensure that supply system security is not adversely impacted during construction. Planning is also required to comprehensively assess all available development alternatives with the objective of selecting the optimal alternative for re-development meeting the future needs of PUC Distribution's customers during the next 40-50 years. Therefore, capital investment into a planning and engineering study with the objective of reviewing all practical development options through completion of conceptual designs and recommending the optimal transformer station development alternative for implementation is proposed in this DSP.

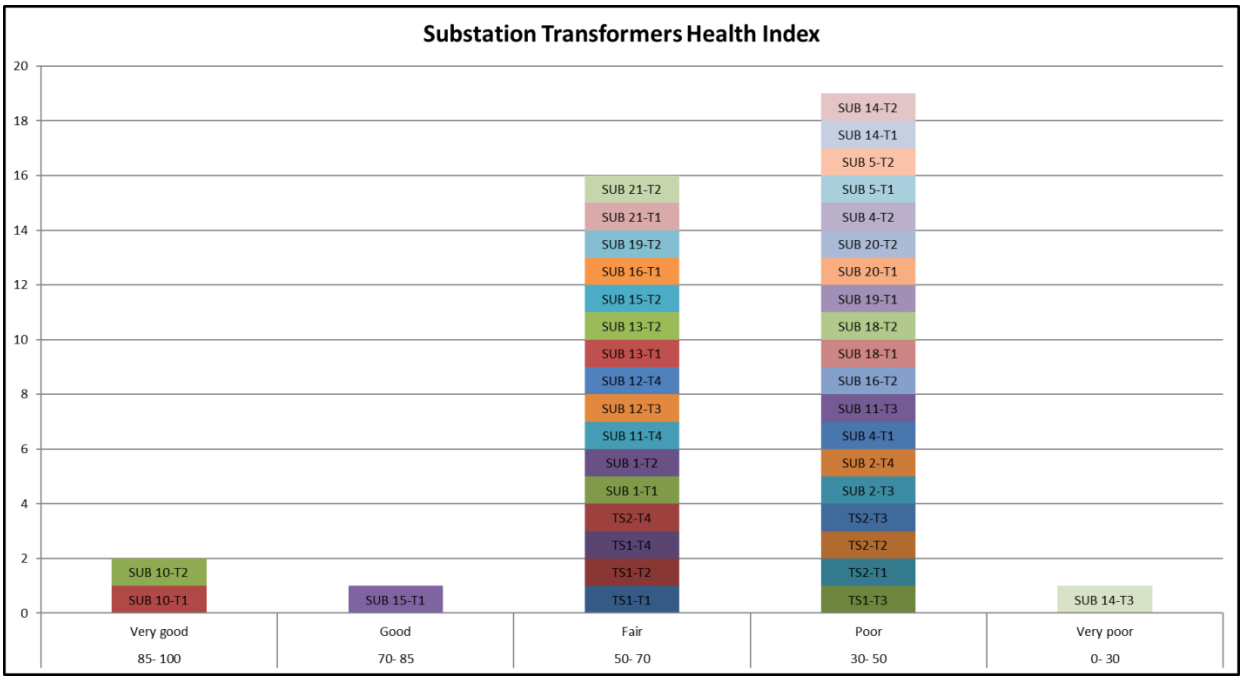


Figure 12: Substation Power Transformers - Condition Assessment

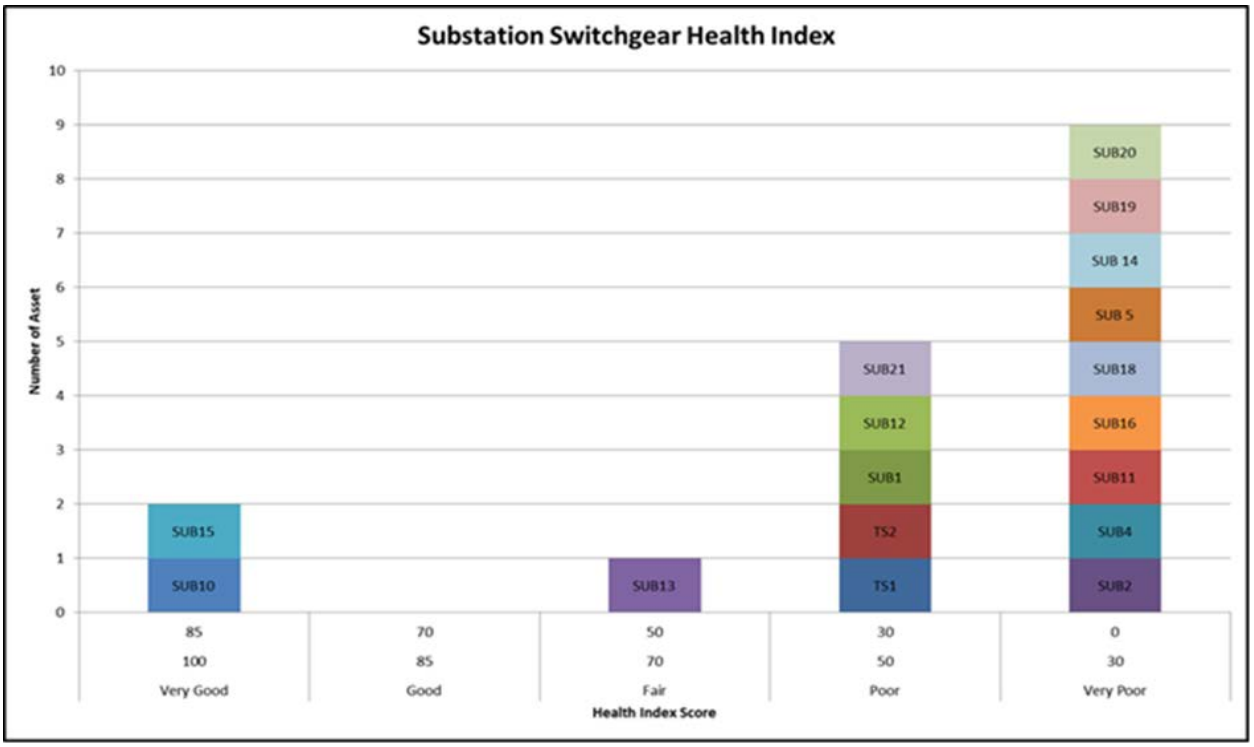


Figure 13: Substation Switchgear - Condition Assessment

Due to the “poor” or “very poor” condition of the power transformers, switchgear and other associated assets at seven of the twelve existing 34.5/12.5 kV distribution stations, these stations have been determined to be in “poor” or “very poor” condition, requiring complete rebuild of these stations during the next 10 years. However, given current revenue levels and lack of projected customer load growth it will be necessary to gradually ramp up the distribution station rebuild initiative over a longer period of time. This DSP includes capital investments for rebuild of two of the stations during next five years, those that present the highest risk of failure. The rebuild of remaining stations in “poor” or “very poor” condition has been deferred, for inclusion in subsequent DSPs.

For the two transformer stations and the distribution stations determined to be in “poor” or “very poor” condition but not included in the renewal program in the current DSP, PUC Distribution plans to manage the risk of equipment failures through proactive monitoring and testing of equipment and performing repairs, refurbishment and replacement of components when they fail, and this DSP includes funding for repair, refurbishment and component replacement activities.

3.2.3.2 Condition Assessment of Overhead Line Network Assets:

PUC Distribution’s overhead distribution network employs approximately 391 km of 3-phase and approximately 230 km of 1-ph lines, all operating at 115kV, 34.5 kV, 12.5kV, 7.2kV, 4.2kV and 2.4 kV. Figure 14 and Figure 15, respectively, show the age profile of overhead lines and as shown, approximately 28.5% of the overhead lines will reach the end of their design service life of 45 years during the next five years. As the lines approach the end of their design life, all line components including wood poles, mounting hardware and conductors experience degradation of strength and pose a high risk of failure in service when subjected to design loading during wind and ice storms. To mitigate this risk, these lines will require rebuild with new poles and conductors.

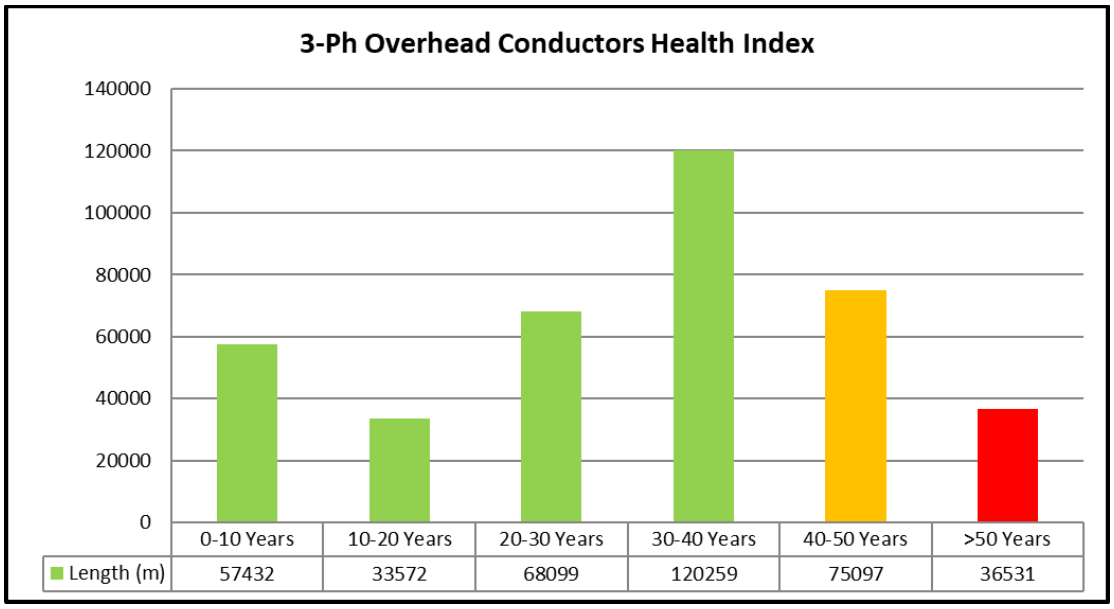


Figure 14: Age Profile – 3-Ph MV Overhead Lines

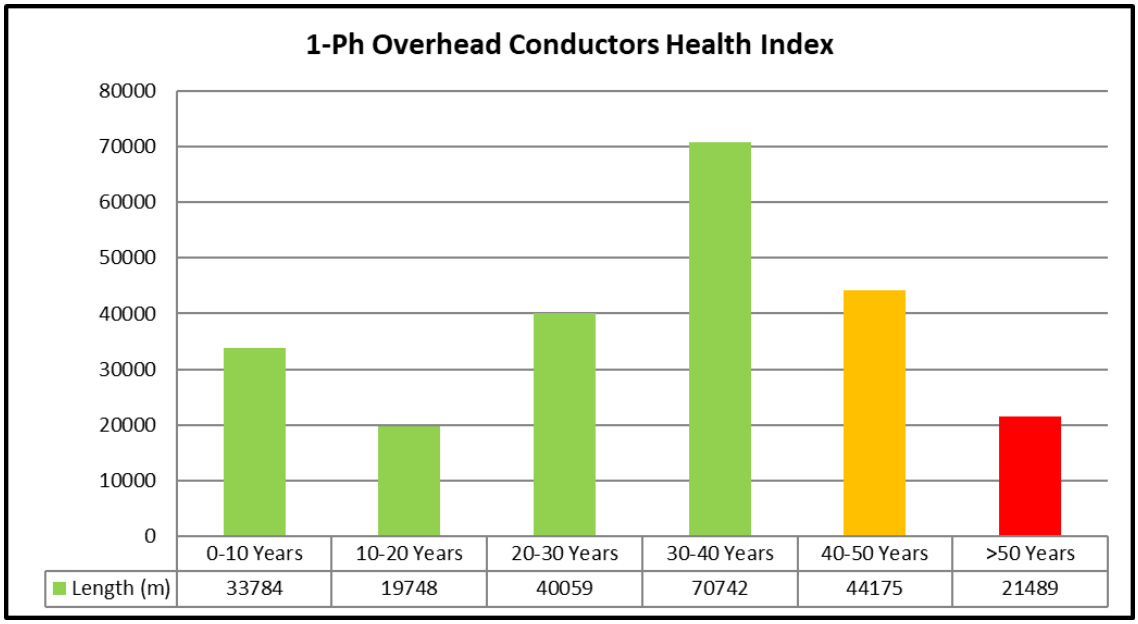


Figure 15: Age Profile – 1-Ph, MV Overhead Lines

Rather than proposing re-construction of all overhead lines that have reached the end of their design life, this DSP includes a small subset of the lines determined to be at the end of their service life. The lines included in the DSP for renewal have been prioritized by taking into account the probability of failure of a line section and the impact of line failures on public safety, supply reliability and operating costs. Since weakened poles with reduced structural strength,

line sections with restricted conductors with reduced tensile strength, and the lines operating on 4.2 kV system, which are well past the end of their typical useful life, pose the highest risk of failure in service, priority for overhead line renewal has been given to projects, involving:

- line sections with poles in "very poor" condition,
- line sections built with restricted conductor, and
- lines determined to be in "very poor" condition and currently operating at 4 kV, which will undergo voltage upgrade upon reconstruction.

There are approximately 12,600 wood poles and about 83 other types of poles (including steel, concrete and fiberglass) employed on PUC Distribution's overhead lines. In order to identify poles in "poor" or "very poor" condition PUC Distribution periodically conducts in-situ testing of poles. The existing condition of the poles in 2016 is indicated in Figure 16. This DSP proposes renewal of approximately 30 poles, annually, determined to be in "very poor" condition, through pole testing.

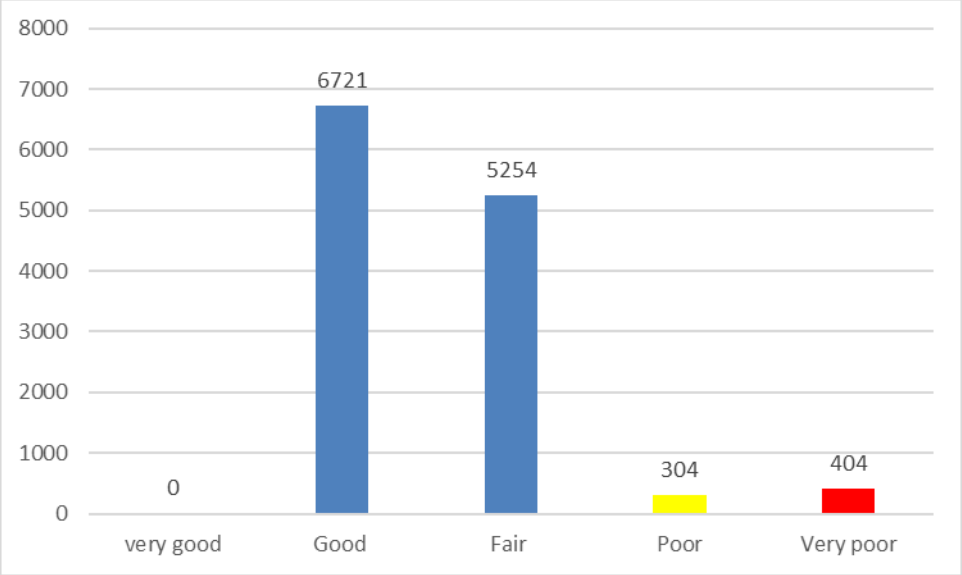


Figure 16: Overhead Line Pole - Condition Assessment

Copper and aluminum conductors with smaller cross-section area, and more specifically #6 AWG and #4 AWG (copper or aluminum) conductors have lower tensile strength in relation to larger conductors typically used in overhead line construction. Under tension, the tensile strength of these smaller cross-section conductors further degrades with service age. These conductors are known to fail in service and when they fail, the downed lines pose a very serious safety risk for public. #6 AWG and #4 AWG conductors are no longer used for applications requiring conductor tensioning over full spans on overhead lines, and virtually all Canadian

utilities have adopted programs to proactively phase out lines built previously with restricted conductors.

As shown in Figure 17 and Figure 18, PUC Distribution had identified approximately 8 km of 3-phase lines and approximately 60 km of 1-phase lines on its distribution network, constructed with restricted conductors and adopted a line renewal plan to phase out the restricted conductor on lines starting in 2009. On the PUC Distribution system the restricted conductor is primarily #6AWG copper. Up to the end of 2015, approximately 26% of the lines with restricted conductor had been phased out. Work on rebuilding of the remaining lines with restricted conductor is scheduled to continue during this 5-year DSP, with a target date of 2027 for complete elimination of all restricted conductor lines from the network. The lines for renewal are prioritized based on their location and the risk of public exposure to the downed lines.

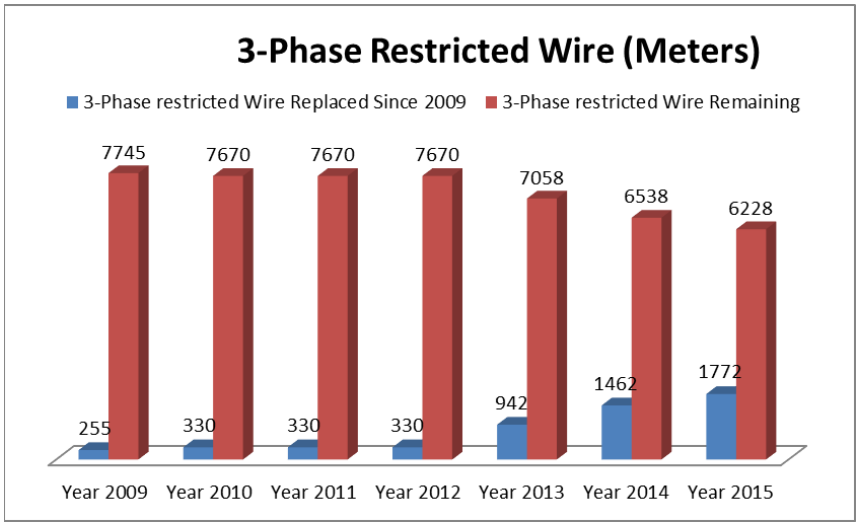


Figure 17: 3-Phase Lines with Restricted Wire on PUC System

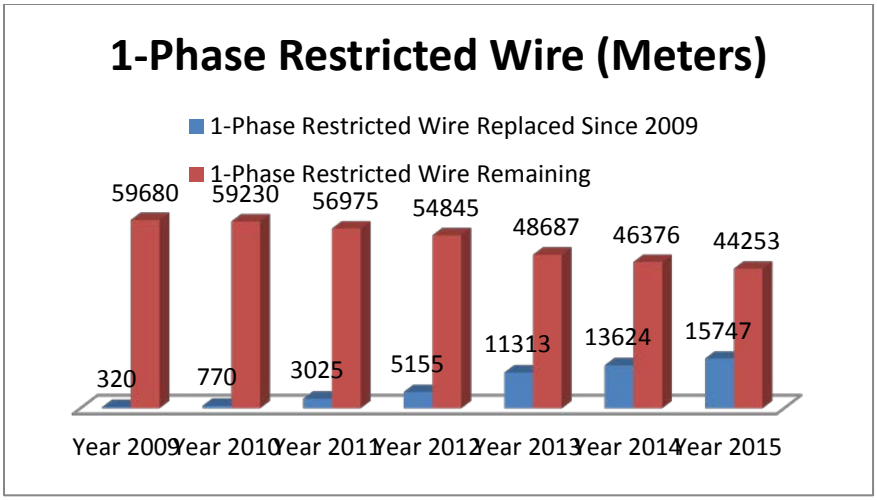


Figure 18: 1-Phase Lines with Restricted Wire on PUC System

Overhead lines employed on 4 kV distribution system are the oldest infrastructure components on PUC Distribution Inc.'s power supply network. Most of these lines have reached a service age of 50 or 60 years, well past their design life and they present the highest risk of failure in service. PUC Distribution has been gradually retiring from service the 4 kV lines at the end of their service life and rebuilding the lines with voltage upgrade to 12.5 kV. This DSP provides funding for rebuilding of 4 kV lines with voltage upgrade and when the proposed projects are implemented, it would allow PUC Distribution to retire all infrastructure operating at 4 kV by 2022.

Because the planned overhead line renewal projects described above, target only a subset of the lines determined to be in poor and very poor condition, this DSP also includes modest funds for renewal of components that are identified to be in unsafe condition during one-third plant inspections in accordance with the DSC as well as for emergency repairs and renewal of components that fail in service.

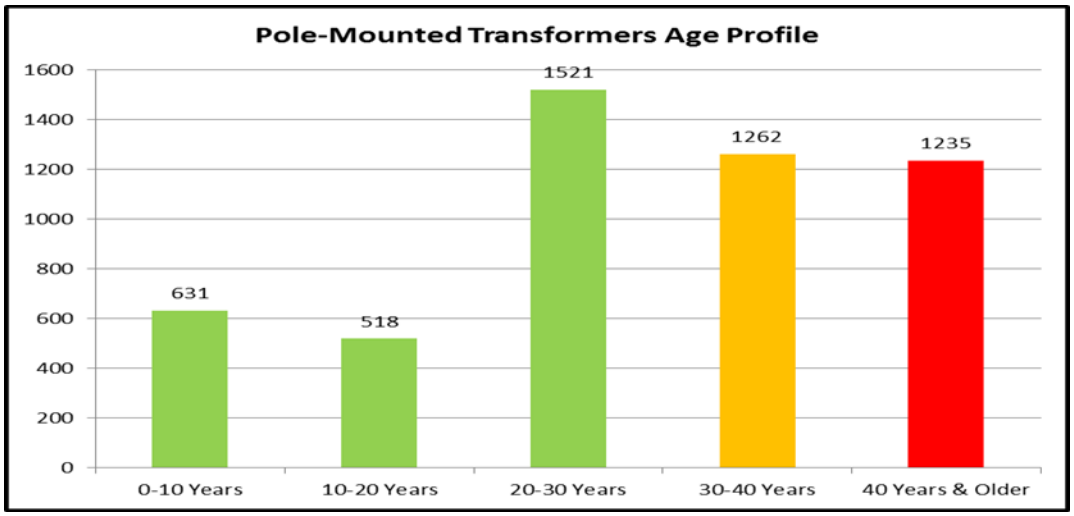


Figure 19: Age Profile of Pole-Mounted Distribution Transformers

Figure 19 indicates the age profile of pole mounted distribution transformers employed on the overhead distribution network. PUC Distribution employs "run-to-failure" strategy for distribution transformers due to the relatively low impact of transformer failures on reliability. Current PCB regulations in Canada permit the use of pole mounted distribution transformers containing PCB content in oil of over 50 parts per million and this use can continue up to December 31, 2025. Beyond that date, all distribution transformers must have a PCB level below 50 parts per million. To comply with this regulation, distribution utilities will need to either (a) test all suspect transformers (purchased prior to 1980) for PCB content and replace those containing PCBs, or (b) replace all suspect transformers (purchased prior to 1984). This DSP includes budgetary provision for testing suspect distribution transformers for PCB content but replacing transformers that fail the PCB test have been deferred to beyond 2022.

3.2.3.3 Condition Assessment of Underground Distribution Assets:

The underground distribution network at PUC Distribution employs approximately 75 km. of 3-phase cable circuits and approximately 47 km of 1-phase circuits. Figure 20 shows the age profile of distribution cable on 3-phase circuits, operating at 34.5 kV and 12.5 kV and Figure 21 shows the age profile of single phase and two-phase cable circuits, operating at 12.5 kV circuits. As shown, approximately 25% of the cable has reached service age of greater than 40 years. There are no practical tests available which could be economically performed in field to accurately assess the remaining useful life of cables. However, XLPE insulated cables, which are typically employed on underground distribution systems generally begin to experience an increase in failure rates when they get past 40 years of service age. It is also noteworthy that a vast majority of the cables installed prior to 1990 were installed in direct buried configuration. Cable failures in direct buried configurations have significantly larger impact on reliability than failures that occur where cables are installed in duct. All cable circuits past 40 years of service

age are considered in poor condition. This DSP includes some funding for proactive replacement of underground cables with priority given to direct buried cable circuits as well as in voltage conversion areas. However, it is expected this will require more significant 'ramping up' of investment beyond 2022 to keep a failures rates level.

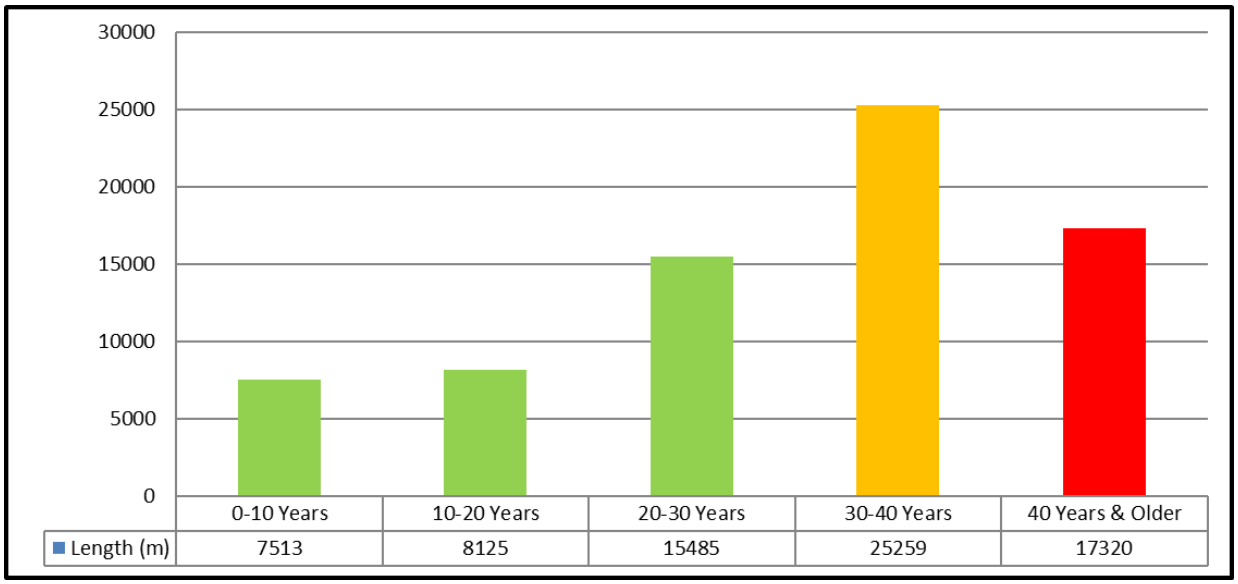


Figure 20: Age Profile of 3-Phase Cables on 34.5 kV and 12.5 kV System

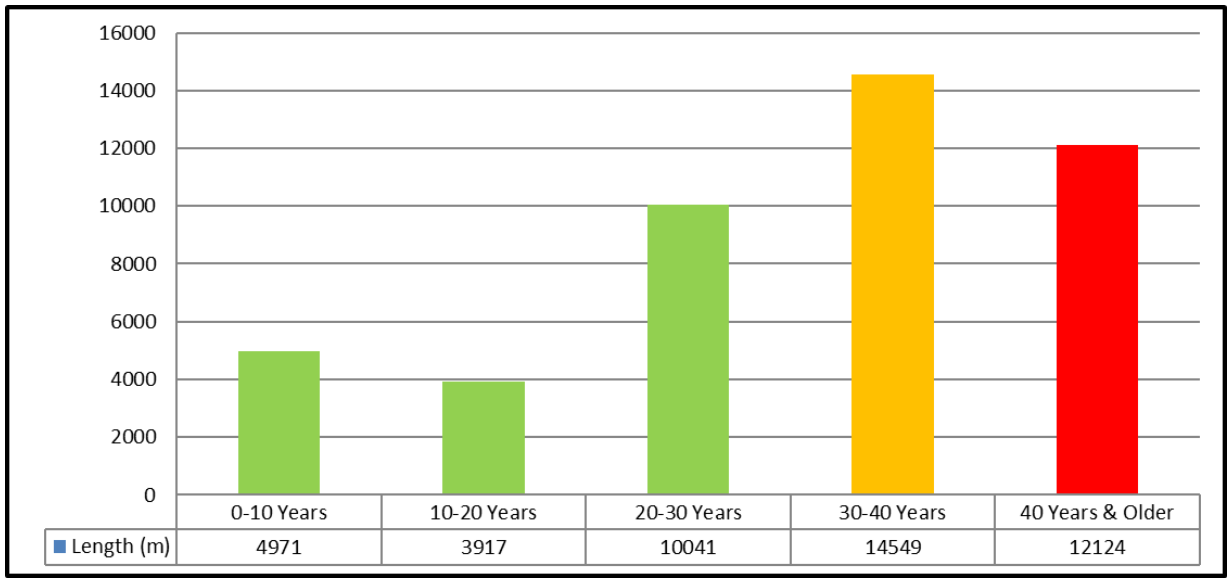


Figure 21: Age Profile of 1-Phase Cables on 12.5 kV System

Figure 22 and Figure 23, respectively, show the age profile of distribution cables employed on 3-phase and 1-phase circuits operating at 4.2 kV. As indicated, a majority of these cables are

already past their 40-year typical useful service life. These cables will be removed from service when these service areas are upgraded to 12.5 kV and funding has been provided in this DSP for their renewal. The relatively small amount of cable circuits, with service age of less than 20 years on 4.2 kV system, are rated for use on 12.5 kV (in anticipation of the voltage conversion) and these circuits will remain in service after voltage conversion.

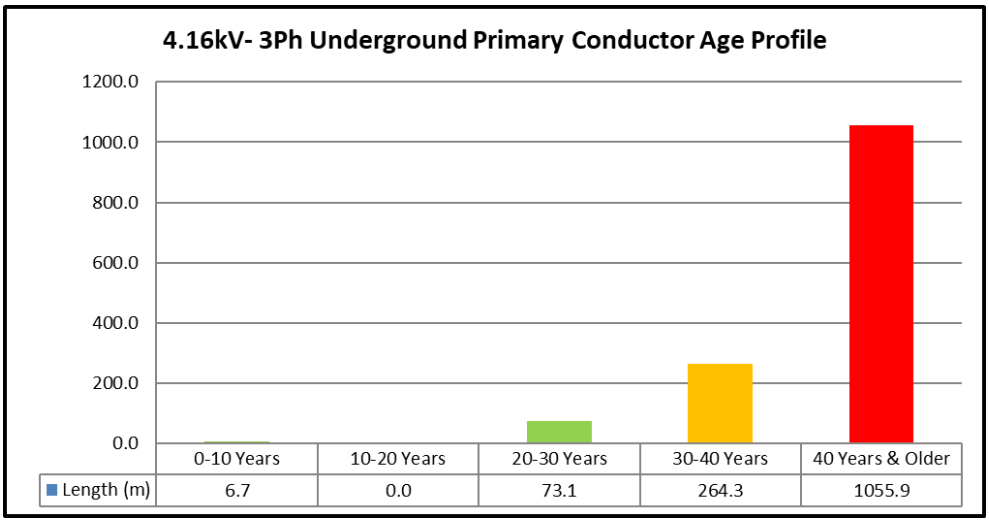


Figure 22: Age Profile of 3-Phase Cables on 4.2 kV System

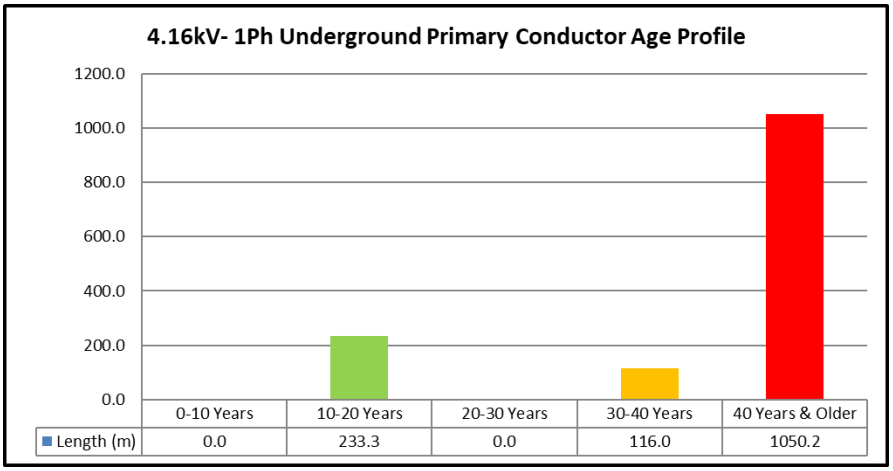


Figure 23: Age Profile of 1-Phase Cables on 4.2 kV System

Figure 24, Figure 25 and Figure 26, respectively, show the age profile of 3-ph pad-mounted transformers, 1-ph pad-mounted transformers and 1-ph submersible vault mounted transformers employed by PUC Distribution to serve customers supplied from the underground distribution system.

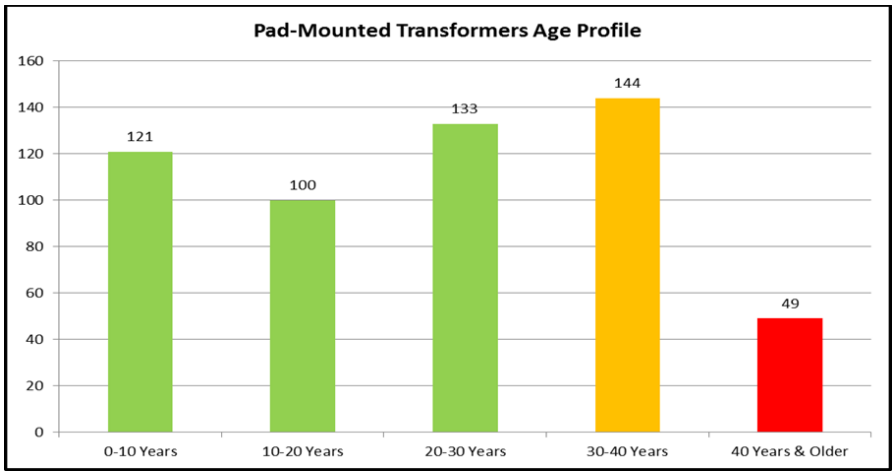


Figure 24: Age Profile of 3-Phase Pad-mounted Distribution Transformers

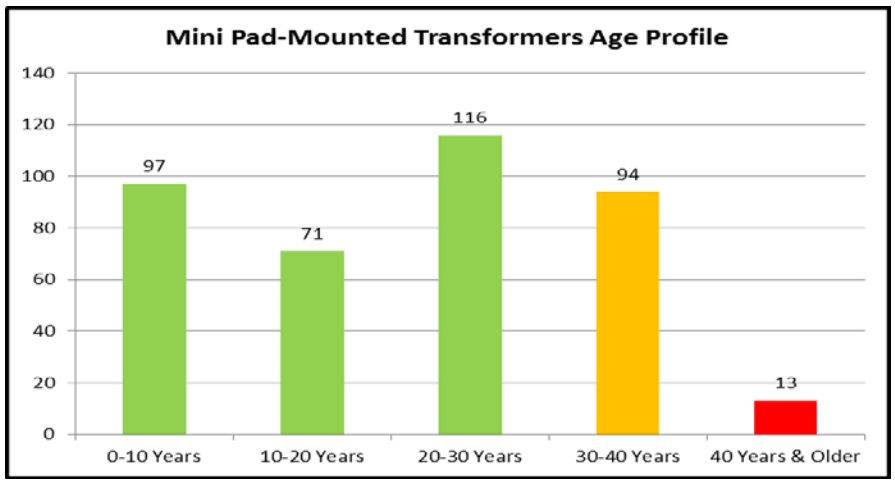


Figure 25: Age Profile of 1-Phase Pad-mounted Distribution Transformers

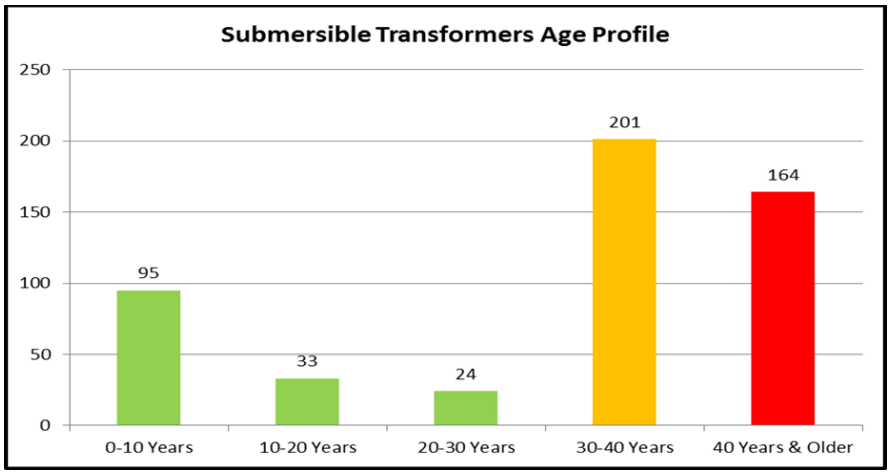


Figure 26: Age Profile of Vault-mounted Submersible Distribution Transformers

The Distribution System Plan does not target proactive replacement of distribution transformers, but rather a reactive approach, meaning transformers will be replaced after they have experienced a failure in service.

For switching of underground circuits, PUC Distribution Inc. employs live-front pad-mounted switchgear as well as 'K-bar' junction units. Based on the service age and visual inspections, five of the pad mounted switchgear units were determined to be in "poor" or "very poor" condition in 2016, as shown in Figure 27. This DSP includes funding for renewal of the pad-mounted switchgear found in very poor condition. Upon renewal, the live front switchgear will be replaced with dead front switchgear, providing enhanced worker safety.

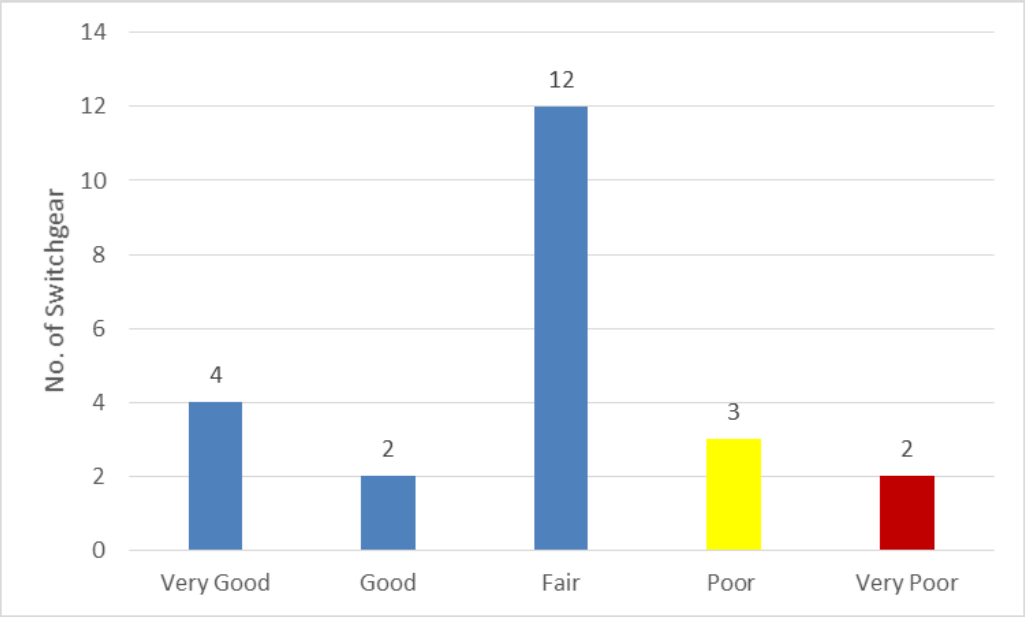


Figure 27: Condition Assessment of Pad-Mounted Switchgear

Figure 28 shows the age profile of junction units. As shown, 89 of the junction units had reached a service age of more than 35 years and these units will exceed the typical useful design life of 40 years during the next five years. During one-third plant inspections performed in compliance with Regulation 22/04, condition of the junction units will be assessed for safety and the DSP contains a modest budget to replace those found in unsafe operating condition.

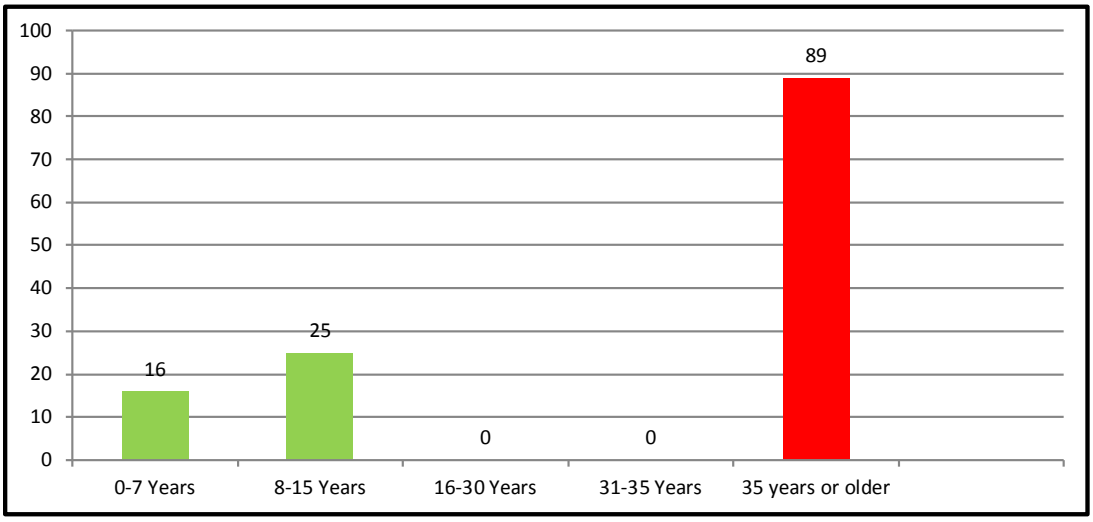


Figure 28: Age Profile of K-bar Units

PUC Distribution's underground distribution system employs concrete chambers for various functions, including cable pull-boxes and manholes, mounting bases for switchgear and K-bar junctions, submersible transformer vaults, splice vaults and general-purpose equipment vaults. As shown in Figure 29, approximately 23% of the chambers are currently more than 50 years old. Physical inspections of the concrete structures indicate, a large percentage of these old vintage chambers are functionally obsolete. From the point of view of worker safety, the submersible transformer vaults and splice vaults present a challenge in that outages are required to complete maintenance work increasing costs and inconveniencing customers. Accordingly, funds have been included to make progress in the replacement of these vaults.

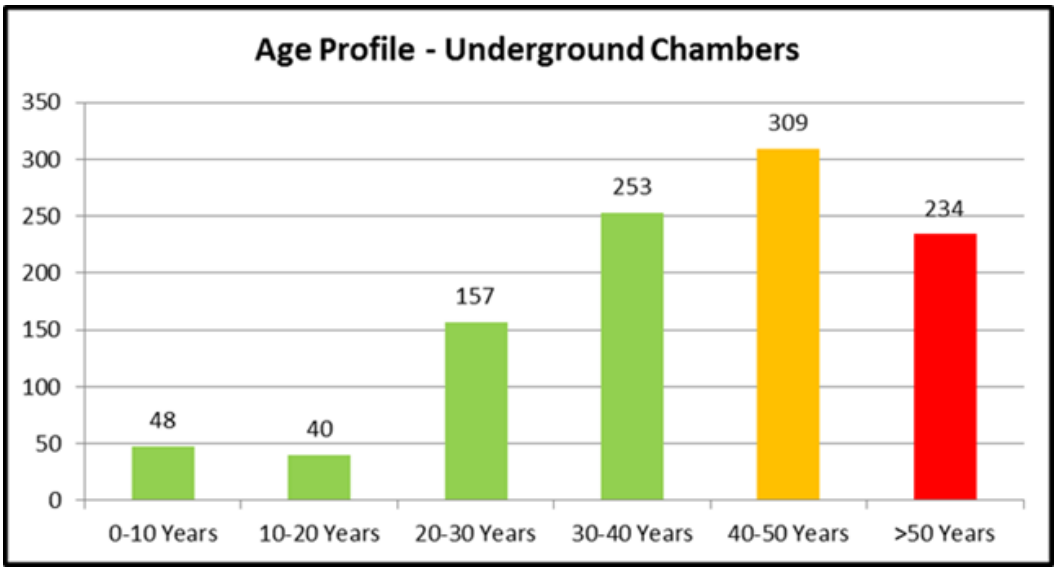


Figure 29: Age Profile of Underground Chambers

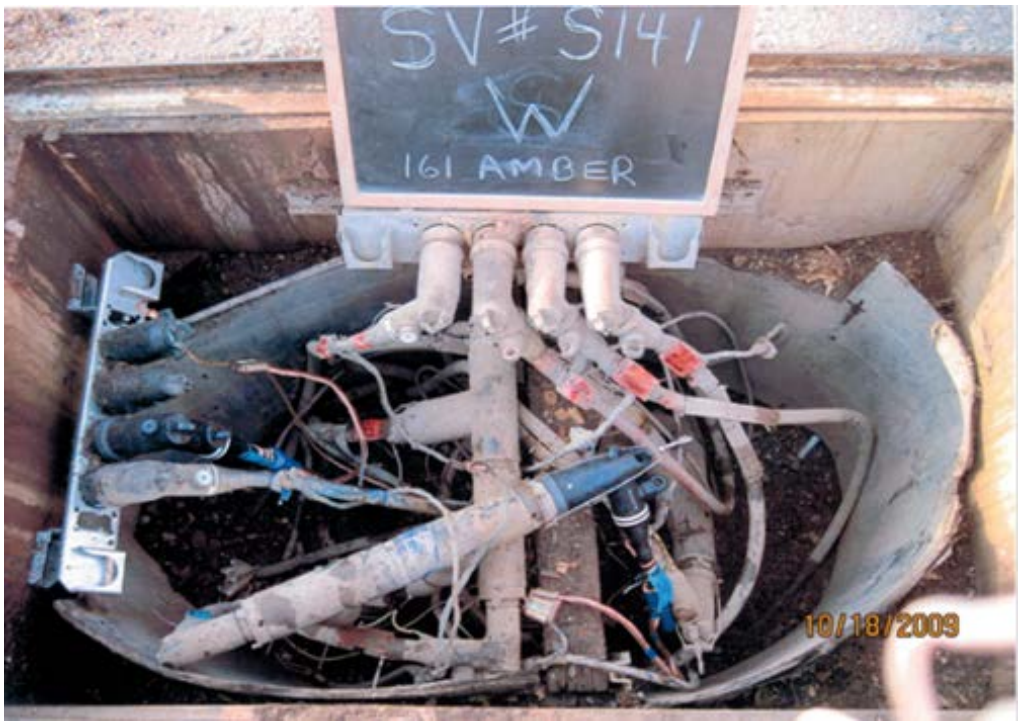


Figure 30: Typical Switching/Splice Vault on PUC Distribution System

The submersible transformer vaults and splice vaults of inadequate size and without concrete floors, as shown in Figure 30, present the highest risk to workers and therefore, have been given a priority for reconstruction in this DSP. After reconstruction, these vaults will be converted to vaults to support pad mounted equipment, mounted above grade.

In addition to the planned underground distribution System Renewal projects described above, this DSP also includes modest funds for emergency repairs and renewal of components that fail in service, during the next five years.

3.2.4 Capacity Assessment of Existing System [5.3.2 d]:

The chart in Figure 31 shows the historic peak load during each month over the past five years supplied from the PUC Distribution's supply network. As shown, the electrical load served by the supply system peaks during the winter season, typically in the month of January. The peak load served from the system during summer months, is typically about 55% less than the winter peak load. This prevailing seasonal loading pattern is desirable for avoiding equipment overloads, because loading capacity of the power equipment is higher during the winter months due to lower ambient temperature, when peak load occurs.

The figure also indicates a negative time trend in peak electrical demand on the distribution network. The peak load served from the system has experienced a decrease at the rate of

approximately 2.8%, annually, due to a number of reasons, including the multiple CDM initiatives implemented by residential and general service customers, expansion of natural gas distribution network in the region and shifting of heating loads from electric heat to gas heating, and relatively slow growth in overall number of customers. Data in this figure was compiled in December 2016.

Figure 32 shows the forecasted peak electrical demand for the service area, based on which regional demand forecasts and planning have been completed and as indicated the peak demand served from the distribution network is expected to decrease from the current levels. Data in this figure was compiled in September 2014.

Table 19 indicates the peak load during the most recent winter of January 2017 for each of the power transformers and as indicated the peak loads are well within equipment nameplate ratings and there are no capacity constraints in the system. Due to negative time trend in peak demand, no capacity constraints are anticipated during the next five-year period covered by this DSP. Data in this table was compiled in June 2017.

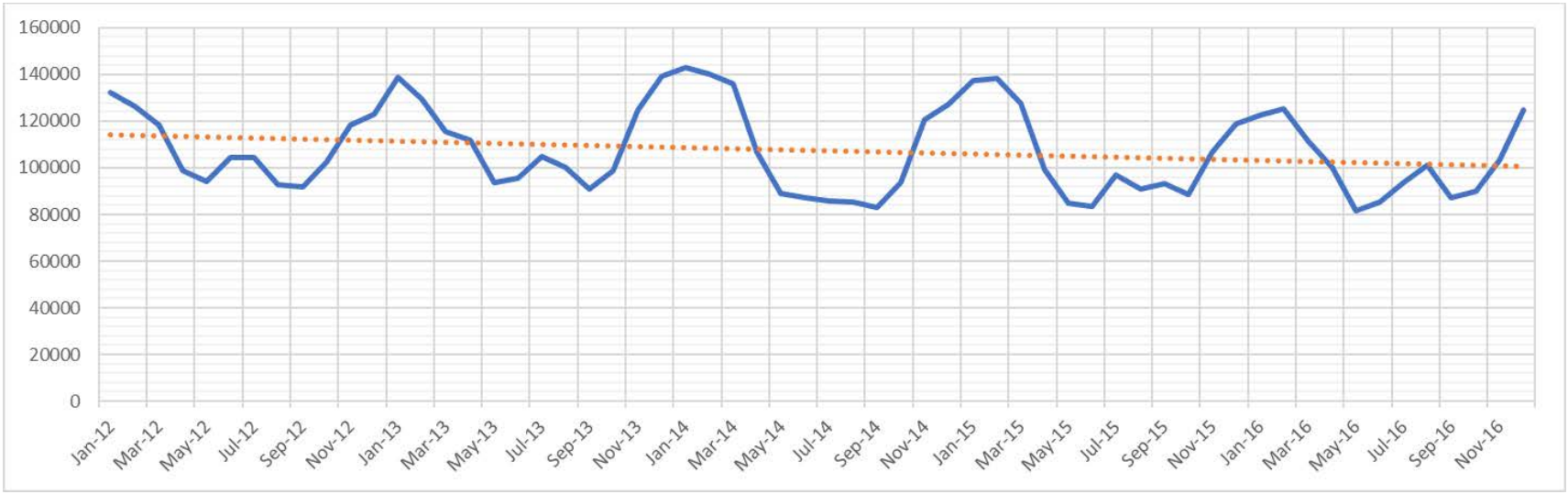


Figure 31: PUC Distribution Service Territory – Past Five Year System Loading

		Peak Load (Net = Gross - DG - CDM)																		
TS Name or DP	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					Long Term Forecast (MW)					Power Factor
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2015	2026	2027	2028	
Tarentorus T.S. (TS2)	Gross Peak Load				37.1	37.1	37.1	37.0	37.0	37.0	37.0	37.0	36.9	36.9	36.9	36.9	36.9	36.8	36.8	0.967
GL1TA(non-coincident)	Net Load	21.1	37.1	0.1																
Tarentorus T.S. (TS2)	Gross Peak Load				51.7	51.6	51.6	51.6	51.5	51.5	51.5	51.5	52.1	51.4	51.4	51.3	51.3	51.3	51.3	0.967
GL2TA(non-coincident)	Net Load	48.1	24.0	51.7																
St. Mary's T.S. (TS1)	Gross Peak Load				52.4	52.3	52.3	52.3	52.2	52.2	52.2	52.2	52.1	52.1	52.1	52.0	52.0	52.0	52.0	0.967
GL1SM(non-coincident)	Net Load	41.3	34.9	52.4																
St. Mary's T.S. (TS1)	Gross Peak Load				60.5	60.5	60.5	60.4	60.4	60.4	60.3	60.3	60.3	60.2	60.2	60.2	60.1	60.1	60.1	0.967
GL2SM(non-coincident)	Net Load	39.3	36.2	35.1																
Total PUC	Gross Peak Load				139.3	139.2	139.2	139.1	139.1	139.0	139.0	138.9	138.8	138.8	138.7	138.7	138.6	138.6	138.5	0.967
(coincident peak)	Net Load	149.9	132.2	139.2																0.967

Figure 32: PUC Distribution Service Territory – Peak Demand Forecast

Table 19: 34.5kV/12.5 kV Substation Ratings and Loading Level

Station #	Transformer #	Transformer MVA	Peak Load MVA	% Transformer Loading
TS-1	T1	30	16.33	54%
	T2	30	16.61	55%
	T3	30	19.22	64%
	T4	30	19.52	65%
TS-2	T1	30	19.73	66%
	T2	30	19.91	66%
	T3	30	14.03	47%
	T4	30	14.27	48%

Station #	Transformer #	Transformer MVA	Peak Load MVA	% Transformer Loading
Sub 1	T1	10	4.85	49%
	T2	10	3.68	37%
Sub 2	T3	10	7.31	73%
	T4	10	2.18	22%
Sub 4	T1	10	4.15	42%
	T2 (4kV)	10	1.68	17%
Sub 5	T1 (4kV)	5	0.05	1%
	T2 (4kV)	5	0.05	1%
Sub 10	T1	13.3	3.87	29%
	T2	13.3	4.74	36%
Sub 11	T1	10	4.64	46%
	T2	10	4.00	40%
Sub 12	T1	10	4.29	43%
	T2	10	4.94	49%
Sub 13	T1	10	5.76	58%
	T2	10	4.74	47%
Sub 14	T1	3	0.08	3%
	T2	3	0.08	3%
	T3	3	0.08	3%
Sub 15	T1	10	1.82	18%
	T2	10	2.95	30%
Sub 16	T1	7.5	6.57	88%
	T2	7.5	4.14	55%
Sub 18	T1	7.5	4.91	65%
	T2	7.5	5.01	67%
Sub 19	T1	10	2.57	26%
	T2	10	8.82	88%
Sub 20	T1	10	3.33	33%
	T2	10	6.45	65%
Sub 21	T1	10	4.91	49%
	T2	10	4.69	47%

3.3 Asset Lifecycle Optimization Policies and Practices [5.3.3]

In preparing the DSP, PUC Distribution's overarching objective was to develop a capital and preventative maintenance investment plan, which would result in optimal operating performance to meet various stakeholder needs and ensure regulatory compliance, while minimizing life cycle costs, as shown in Figure 33.

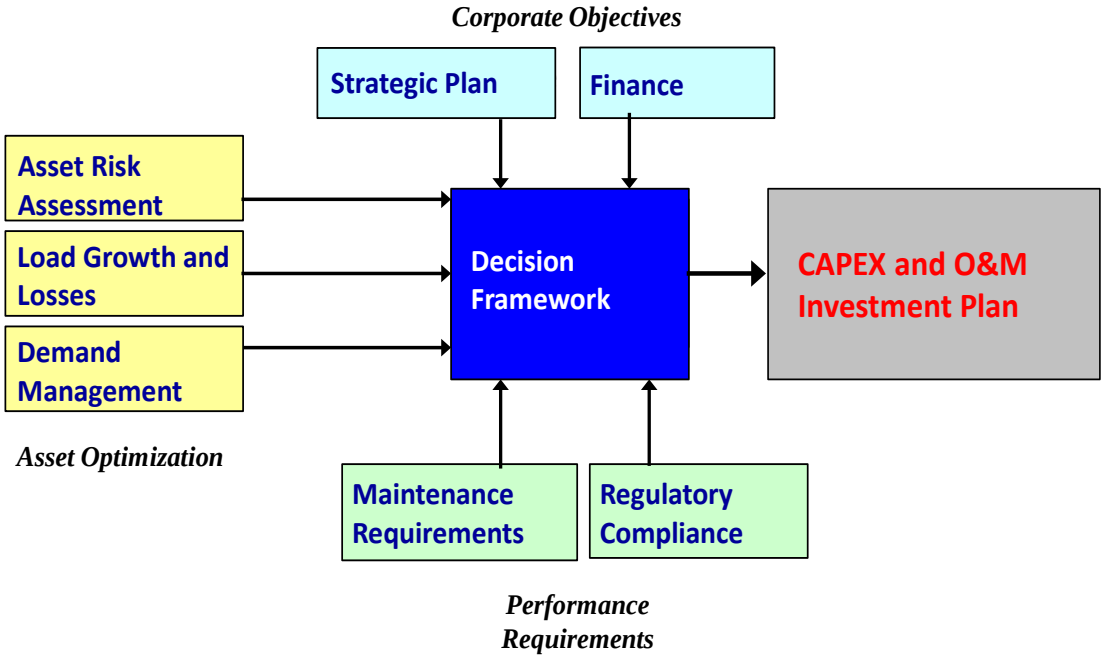


Figure 33: Multi-Prong Decision Framework

The life cycle optimization policies and procedures employed by PUC Distribution include determining the optimal time and scope of the most effective risk mitigation option, through trade-offs between capital expenditure, preventative maintenance and reactive maintenance. Figure 34 shows the basic decision support model employed by PUC Distribution in preparing this distribution plan, to determine the scope and timing of the investments. With increase in an asset's service age, its operating condition degrades, thus increasing the risk of the asset failing in service. In the absence of any intervention in form of asset renewal or asset refurbishment or repair, the consequential risk cost would continue to increase. When a risk mitigation intervention is implemented through an investment, the risk cost curve resets, triggering a benefit in form of reduced risk. In preparing the DSP, the timing and size of investments have been selected to minimize the "Total Cost" of the risk and the risk mitigation initiatives.

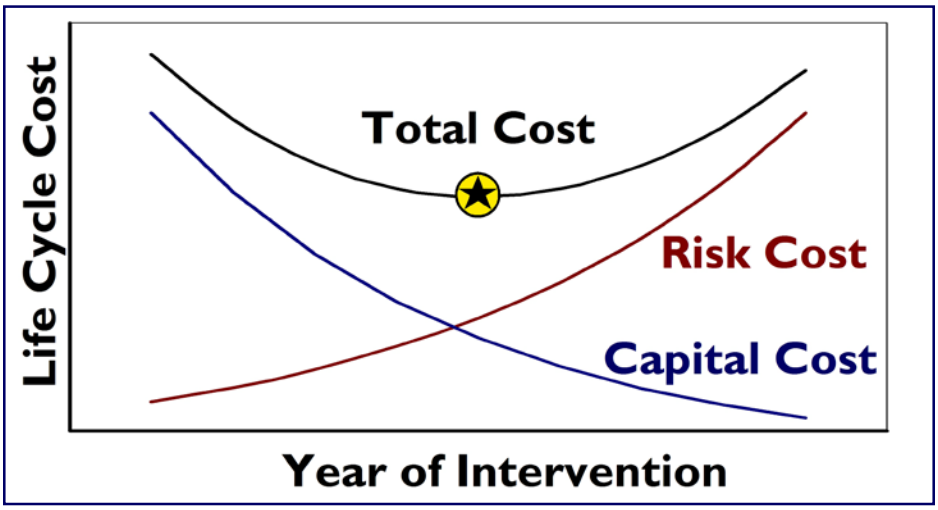


Figure 34: Risk Based Decision Support System

Figure 35 illustrates the impact of maintenance activities in extending the service life of an asset.[1] In Figure 35, Maintenance Policy 1 represents a reactive maintenance policy, in which no planned maintenance is carried out and asset components are repaired or refurbished only after they break down or reach a stage that they fail to perform their intended functions. Maintenance Policy 2 represents, proactive asset maintenance, in which condition of an asset's components are assessed periodically through inspections, testing and recent asset performance and maintenance activities are proactively performed to prevent impairment in asset performance with the intent of extending the economic service life of assets. Under Maintenance Policy 2, Optimization is carried out with the objective of minimizing overall life cycle costs of electricity distribution assets, while meeting the required performance levels, by taking into account all available information relevant to the condition of assets. As shown in Figure 35, Maintenance Policy 2 would be economically efficient, so long as the incremental asset value achieved through an assets' life extension is greater than the incremental maintenance cost resulting from Policy 2.

Following this value concept, PUC Distribution's maintenance planning criteria is rooted in adopting a maintenance policy that results in lowest life cycle cost for assets. For those assets, where the incremental value obtained in form of extended asset life is greater than the cost of maintenance activities, Policy 2 is adopted. These assets include high value power equipment installed in stations. Periodic inspections at more frequent intervals are performed and

[1] "Predicting Future Asset Condition Based on Current Health Index and Maintenance Level" Thor Hjartarson, Shawn Otal, IEEE 11th International Conference on Transmission & Distribution Construction, Operation and Live-Line Maintenance, 2006, ESMO, Oct. 20

maintenance activities are scheduled by taking into account the condition of assets. For lower value assets, maintenance activities are performed in a reactive mode and the scope of repairs is limited to rectifying deficiencies found during safety inspections. Periodic asset inspections and testing provide valuable information on assets' health and probability of assets' failures, allowing appropriate risk management initiatives to be implemented over the lifecycle of each asset.

As an example PUC Distribution has employed this model as follows for in-situ testing of wood poles. All poles are tested and inspected on a seven year cycle. Poles that are determined to be in acceptable condition are deemed satisfactory until the next test cycle. Poles that exhibit significant deterioration but are still structurally sound are treated or maintained using boron rods to extend their service life. Poles that are more significantly deteriorated are scheduled for replacement.

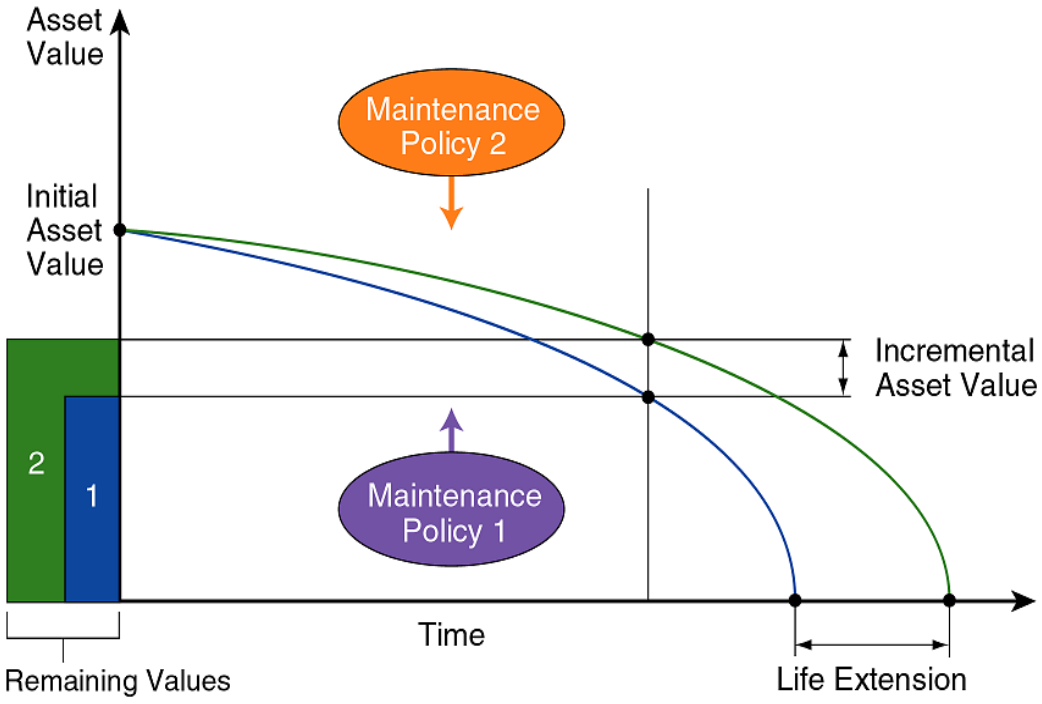


Figure 35: Risk Based Decision Support System

PUC Distribution's Operations & Maintenance ("O&M") programs are designed to follow the guidelines set out in the OEB's Appendix-C DSC for the inspection and maintenance of all key distribution system assets. PUC Distribution reviews its O&M programs annually in order to best align with our capital programs and aligning the program with the best industry practices and standards. Inspection and testing of assets is critical for the prioritization of operations and

maintenance spending and optimization of the total life cycle asset cost. The results of inspections and testing are used to identify and prioritize system rehabilitation projects, resulting in selection of the optimal decision to either replace, repair or do-nothing. Assets for which replacement is identified as the optimal solution are included in the capital plan for replacement. For assets where replacement during the next five years is not determined to be the optimal solution, PUC Distribution's O&M programs include minor repairs and maintenance work designed to economically extend the life of assets. In both cases, planned replacement projects and planned operations and maintenance activities are selected in order to align with the budget envelopes by optimizing the scope and timing of work during project prioritization and selection processes.

PUC Distribution employs the results of visual inspections, in-situ testing and service age of assets to determine the condition of assets by deriving a health index for each asset. The health index is related to the probability of failure for the asset by relating the health of the asset to an effective age and corresponding known failure curve. The probability of failure data is multiplied by the consequences of failure for assets within a project area to arrive at a risk score. Consequences of failure are derived from the analysis of each project area and classification in terms of potential impacts to worker and public safety, the environment, reliability and operational effectiveness that could arise if a failure event occurs. Once the risk of each project area has been established it is placed into a prioritization and selection process that determines which projects require action and the extent of the action that is necessary to minimize unacceptable risks.

Risk is factored into the selection and prioritization of capital expenditures during the prioritization process. Assets with unacceptably high risk scores are monitored closely and plans are included in project scope to alternatively maintain, refurbish or replace the assets to reduce the risk to an acceptable level. It is noteworthy that some assets carry an inherently higher risk than others, for example, power transformers at stations have a higher nominal risk level associated with them in relation to pole mount transformers. Assets with low health indices and higher consequence risk are given a priority for replacement, while assets with low health indices but lower consequence risk are given a lower priority for replacement. The top projects in each category are identified in the prioritization process and scrutinized using further investigation and expert opinion to eliminate data inconsistencies and determine appropriate scopes of work.

3.3.1 Preventative Maintenance and Safety Inspections

Proper maintenance is essential to prolong asset lifecycles and maintain system reliability. PUC Distribution's maintenance program employs equipment manufacturer's recommendations as well as best industry practices in determining the scope and frequency of maintenance on power equipment. Maintenance programs comply with all regulated requirements as prescribed in the Distribution System Code. In distribution and transformer stations, where applicable,

maintenance also meets IESO and NERC requirements and is completed in accordance with associated elements from the Transmission System Code and best practice IEEE guidelines. Many new requirements have been introduced due to the recent implementation of an IESO mandated under-frequency load shedding (UFLS) scheme.

3.3.1.1 Preventative Maintenance of Critical Equipment in Substations

PUC Distribution's planned substation maintenance schedule is summarized in Table 20.

Table 20: Substation Preventative Maintenance

	Visual Inspection of Assets	Testing of Insulating Oil Samples, and Infrared Scanning	DC System Maintenance	Full Off-line Substation Maintenance (Annual Cycle Tests)
Distribution Stations	Monthly	Annually	Quarterly	Once in six years
Transformer Stations	Weekly	Annually	Quarterly	Once in four years

Monthly inspections at distribution substations and weekly inspections at transformer stations include the following tasks;

- Inspect substation security (gates locked, fence condition, warning signs and emergency contact information posted).
- Inspect substation yard and building condition, including vegetation growth, snow bank accumulation, garbage, vandalism, etc.
- Inspect substation electrical safety, including fence grounds, bonds, equipment grounds, insulators, foundations, ancillary equipment, metal clad fastenings and corrosion related impairment of assets
- Power Transformer Inspections, including checking and recording oil level, oil temperature, equipment grounds, feeder load readings (Amps)
- Inspect Access and Egress Riser Poles
- Verify AC voltage to Battery Banks
- Inspect Batteries

- Inspect and record Relay Voltage, Amps etc.

The annual cycle maintenance of substation equipment includes thorough inspection, testing and maintenance of all power equipment installed at substations. The substation is taken out of service typically for an extended period to perform maintenance. The station maintenance work includes;

- Oil Testing of Transformers (standard 5 part ASTM and DGA)
- Clean and lubricate switches and fusing
- Conduct Insulation Resistance Testing
- Protection Relays are injection tested to verify settings and ensure operating times adhere to the manufacturers specifications
- Clean and lubricate switchgear, ensure proper operation
- Conduct IR scans of all high voltage electrical equipment (insulators, switches, cables, connections and riser poles)
- Oil Testing of Transformers (standard 5 part ASTM and DGA)
- DC System batteries are maintained as per manufacturers specifications on a quarterly basis at all distribution and transformer stations

3.3.1.2 Vegetation Management Program

PUC Distribution's service territory is divided into 4 sections in order to delineate the areas for the purpose of maintaining safe clearance of trees and branches from distribution system lines and equipment. Vegetation growth around distribution system lines is managed according to our Utility Vegetation Management program on a 4-year cycle by attending to each section in succession on a yearly basis.

- Line clearing activities are predominantly completed via a contract that specifies removal of vegetation growth within 3m of primary conductors and 1.5m of secondary conductors. Identification and removal of danger trees, as well as brushing and herbicide treatment of right-of-way where appropriate are included to ensure a comprehensive program.
- Substation herbicide treatment (as required)

During 1/3 plant inspections PUC Distribution line crews sometimes identify dead or unstable trees that could impact public safety or system reliability. The identified "danger" trees are then removed by PUC Distribution line crews or facilitated during the contract period depending on urgency. Although danger tree and customer requested removals are predominantly completed

within the scope of an outside contract, PUC Distribution line crews will also perform work to maintain safe clearances throughout the year in response to urgent safety or reliability issues or storm damage. All customer requests for tree related issues are tracked as Customer Service Orders through the Customer Information System.

3.3.1.3 Safety Inspections of Overhead and Underground Distribution Assets

PUC Distribution lines and underground distribution system plant are inspected on a 3-year cycle, to comply with the Distribution System Code requirements. One third of the distribution assets employed on PUC Distribution's supply network are inspected each year. Structural defects, clearance issues and electrical problems and hazards are identified through visual inspections and where problems are revealed, either repair work is scheduled or capital work is planned, as needed. Where the inspections determine an immediate hazard to the public, immediate follow up action is taken to mitigate the problem.

4 Detailed Capital Investment Plan [5.4]

This section summarizes PUC Distribution's capital expenditure plan, which has been developed to meet PUC Distribution's strategic corporate objectives. The capital expenditure plan was developed based on the outputs of the risk-based asset management process, described in detail in Section 3 Projects have been divided into the four categories as outlined in the OEB Filing Requirements.

4.1 Key Information about Capital Expenditure Plan [5.4.1]

4.1.1 Distribution System Capability to Connect New Load or Generation [5.4.1a]

As previously described in Section 3.2, PUC Distribution's distribution system has adequate capacity to connect all anticipated loads and generation customers during the next five-year period, covered by this DSP. Currently there are no applications in queue from distributed generation customers waiting to be connected to the grid under any IESO REG programs; and all previous requests received to date have been successfully connected to the system.

4.1.2 Summary of Annual Capital Expenditures by Investment Category [5.4.1b]

The capital investments (net of contributed capital) for the bridge year (2017) and the forecast period (2018 to 2022) are summarized in Table 21. Additional detailed information on the proposed capital projects exceeding the materiality threshold for projects in the test year (2018) is provided in Table 22 and Appendix G.

Table 21: Proposed Capital Investments during DSP Implementation Period

	2017	2018	2019	2020	2021	2022
System Access	$ 1,271,457	$ 1,511,028	$ 1,615,276	$ 2,086,480	$ 1,603,804	$ 1,560,434
System Renewal	$ 3,372,227	$ 3,761,033	$ 6,905,898	$ 3,296,444	$ 4,532,889	$ 7,092,642
System Service	$ 38,236	$ -	$ -	$ -	$ -	$ -
General Plant	$ -	$ 86,294	$ 54,629	$ 61,932	$ 59,853	$ 55,100
Total Capital Expenditure	$ 4,681,920	$ 5,358,355	$ 8,575,803	$ 5,444,856	$ 6,196,546	$ 8,708,176
System O&M Expenditure	$ 5,856,582	$ 6,212,629	$ 6,305,819	$ 6,400,406	$ 6,496,412	$ 6,593,858

Table 21 shows the planned capital investments broken down into each of the four general categories: System Access, System Renewal, System Service, and General Plant.

The planned investments into System Access are intended to facilitate the anticipated growth and allow connection of new customers to the grid, meeting requests of existing customers for increase in service size, meeting PUC Distribution's regulatory obligations for relocating distribution lines when requested by the municipality, for joint use make-ready work for telecommunications and for re-calibration and renewal of the revenue meters in compliance with the Measurement Canada regulations. A modest recovery in the local economy is anticipated during the next five years, resulting in a small increase in requests for new services from the existing levels. There are presently two residential subdivision developments being planned for 2018 and 2019, and these will require capital investments in System Access category to meet the requests for new services. Road reconstruction projects undertaken in the municipality require relocation of some power distribution lines, requiring capital investments by PUC Distribution. PUC Distribution has employed the City's 5-year development plan to estimate capital expenditure required for line relocates and rebuilds to accommodate municipal infrastructure projects. The planned System Access investments include funding for residential revenue meters, required to replace meters failed in service as well as to equip all general service customers with >50kW to <500kW demand with MIST meters. The planned investments in this category also include funding for "make ready work" to allow joint sharing of the distribution facilities by the communication network companies. The indicated investments in the System Access category represent net expenditure by PUC Distribution, after third party contributions have been subtracted from the total cost.

The planned investments into System Renewal are intended to mitigate a number of specific prevailing risks to distribution system reliability, safety and adverse environmental impacts, due to very poor condition of some key assets, the in-service failure of which would lead to significant negative outcomes. As described in greater detail in Section 3.2.3, those assets, the condition of which has already reached a state of impairment that they present a very high risk of failure in service are assigned "very poor" condition and those assets with significant impairment causing performance to degrade below acceptable level and presenting a high risk of failure in service in the absence of major repair or rehabilitation or renewal, are assigned "poor condition". The scope of capital investments planned in the "System Renewal" category has been determined with the objective of keeping power supply reliability from deteriorating below the acceptable level, as indicated by SAIFI and SAIDI targets. In order to keep the overall investment envelope for this DSP within a range, which would not result in retail rates escalations beyond the affordability of PUC Distribution's customer base and which could be successfully implemented without stretching beyond limit PUC Distribution's financial resources; investments required for renewal and rehabilitation of the assets found in "very poor" or "poor" condition have been spread out over a time period of longer than five years and assets with highest consequence of failure in service, have been prioritized for renewal or rehabilitation, during the next five years.

Although no planned investments have been included in the System Service category, a number of investments in the renewal category, particularly those involving station rebuilds and voltage upgrade, will also introduce smart grid features including opportunities for greater automation, improved access for connection of renewable generation and improved access for joint-use of distribution facilities. Therefore, these investments can be considered to serve a dual role: System Renewal as well as System Service.

PUC Distribution leases its motor vehicle assets rather than owning them, therefore a relatively small capital investment is required for renewal of General Plant, needed to cover minor building renewal items. The scope and timing of the investments in each category has been determined by taking into account all information available at the time of preparation of the distribution plan.

The capital investments proposed for the 2018 to 2022 period are expected to yield the following benefits:

i. The investments into the System Access category would allow PUC Distribution to meet its obligations to serve new customers, relocate lines in public right-of-way, upon receipt of requests for such services, perform "make ready" work for allowing third party attachments of electricity distribution poles and to have adequate supply of revenue meters to comply with the requirements of the Distribution System Code and Measurement Canada.

ii. The investments into the System Renewal will reduce the risk of critical assets' failure in service and help sustain the reliability at acceptable levels and ensure public safety. These investments will also help avoid an increase in operating costs by eliminating the increase in extent of emergency repairs upon asset failures. Retiring from service the distribution system infrastructure operating at 4 kV will eliminate duplication in spare part requirements and will result in improved operating efficiency.

iii. Investments in General Plant are aimed at improving worker productivity, operating efficiency and employee safety.

Planned investments into O&M are aimed at providing customer services matching the service quality and power supply reliability targets. These investments not only including funding for power restoration with adequate speed, following interruptions, but also include funding for safety inspections, tree trimming, equipment testing to prevent and reduce the incidents of power interruptions. O&M investments also including funding for preventative maintenance of high value assets to prevent asset impairment and ensure the assets don't fail pre-maturely.

4.1.3 Capital Expenditure Relation to Asset Management Plan [5.4.1c]

The capital expenditure proposed in this DSP and summarized in Table 21 is in response to the following primary drivers:

- System Access;
- System Renewal;
- System Service; and
- General Plant Upgrades.

System Access Investments

System Access investments comprise about 24% of the proposed capital investments during the forecast period [Table 21]. The planned investments in the System Access category are required for PUC Distribution to meet its regulatory obligations inclusive of the Distribution System Code and PUC Distribution's Conditions of Service and are, therefore, mandatory expenditures. Planned investments in this category are included to connect new generation and load customers, permit service upgrades requested by customers, allow line relocates in response to requests from municipalities, support joint-use installations by third party communications parties and fund investments into revenue metering. Planned expenditure into System Access in 2020 is markedly greater than the rest of the years to allow for the needed investments to facilitate calibration and replacement of revenue meters and equipping customers with a demand greater than 50kW with meters capable of supporting 'Metering Inside the Settlement Timeframe' (MIST) to comply with the recent changes in regulatory requirements. PUC Distribution has considered a number of factors from their asset management and capital expenditure process to determine the allocation of investment in System Access:

- Consultation with major stakeholders including customers, municipal governments, CDM program partners and the OPA/IESO. These consultations allowed PUC to coordinate infrastructure planning with the City of Sault Ste. Marie and identify investment level requirements required to support projects for subdivisions, joint use and general services.
- Consultation with existing customers both residential and general service, through formal and informal community engagement activities. The reports from these consultations inform the PUC's understanding of current and future electrical needs and helps PUC plan the system accordingly in support of System Access investments.

Due to the fact that planned investments in the System Access category are mandatory, the full annual estimated expenditures have been included. Investments in the remaining three categories (System Renewal, System Service and General Plant) have been prioritized utilizing the asset

management strategy described in Section 3 and have been allocated the balance of available capital funds premised on the available financial envelope.

System Renewal Investments

System Renewal investments contribute the largest portion, at 75%, of the proposed capital investment budget Table 21. Planned investments into System Renewal are based on reducing the risk associated with asset failures to optimal levels, based on the results of asset condition assessment which is included in Appendix B. The asset health information is also one of the inputs for the prioritization process described in Section 3.1.2 Consultations with existing customers and the resulting information about customer preference is taken into account to ensure that only the projects with the highest risk of failure in the next five years are included in the System Renewal plan. While, optimal risk considerations required the System Renewal investments to be greater than the planned amount indicated in Table 21, the investment level in this category was reduced from the optimal amount to keep retail rate escalation from reaching an unacceptable level. Furthermore as indicated in Table 22 forced overhead and underground renewal are mandatory for the purpose of restoring service to customers. Investments into System Renewal during 2019 and 2022 are significantly greater than the rest of the years because they includes investments for a distribution station rebuild during each of these years.

System Service Investments

Although no planned investments have been included in the System Service category, a number of investments in the renewal category, particularly those involving station rebuilds and voltage upgrades, will also introduce smart grid features including opportunities for greater automation, improved access for connection of renewable generation and improved access for joint-use of distribution facilities. Therefore, these investments can be considered to serve a dual role: System Renewal as well as System Service.

General Plant

General Plant makes up only about 1% of the proposed capital investment budget. PUC Distribution leases its motor vehicle assets rather than owning them, therefore a relatively small capital investment is required for renewal of General Plant, needed to cover equipment and minor building renewal items.

4.1.4 Material Capital Expenditure Projects/Activities [5.4.1d]

Proposed investments during the test year into individually identifiable projects, exceeding the materiality threshold for PUC Distribution are summarized in Table 22. The table also provides an indication of the spending level by category (System Access, System Renewal) for projects above the materiality threshold in relation to the total spending, including projects above and below the materiality threshold.

Priority rankings for each of the projects above the threshold of materiality have been determined using a two-step process. Firstly, utilizing the methodology presented in Section 3.1.2., a shortlist of the most critical projects was determined for the test year. This shortlist of projects was then ranked by applying a second set of refinement criteria also aligned with the same methodology. The refinement criteria and the relative weighting of each is identified below;

- **Public safety** (40%) - safety risks and consequences of equipment failure
- **Customer outage impact** (10%) - quantity of customers affected and duration of outage
- **Customer value per dollar** (15%) - quantity of customers affected as a function of total project cost
- **System Service improvements** (10%) - projects exhibit value in supporting the OEB System Service category as a secondary driver to System Renewal e.g.: station upgrades will support the connection of REG through new protective equipment upgrades
- **Project interdependence** (25%) - projects that, if not completed, would negatively impact the ability to complete future planned projects

System Access investments are a regulatory obligation for distribution companies (as defined in the Distribution System Code and PUC Distribution's Conditions of Service) and therefore the first four projects in Table 22 in the System Access category, received the highest priority in the overall investment envelope. System Renewal is the primary driver for the next 9 projects planned to be implemented during the test year. Out of these the first two projects involve renewal of assets in a reactive mode, e.g. replacing a distribution transformer or underground cable etc. after an asset has failed in service, in order to restore power. These projects also received the highest priority score, because their implementation is mandated in order for PUC Distribution to fulfill its regulatory obligations to supply electricity to all customers connected to the grid. The next seven projects, listed in order of priority, involve proactive asset renewal to prevent failure of critical assets in service.

As described in detail, in Section 4.1.8, all of the material System Renewal projects in Table 22 re in response to customer preference. Of those customers willing to consider additional costs the highest preference was towards replacement of aging equipment to maintain or improve

reliability. Therefore, the focus of the investments proposed in this DSP is to preserve the existing supply security and reliability levels and prevent them from degrading. In addition, the Substation 16 rebuilt project takes advantage of technology based solutions to improve operational efficiency and potential to integrate additional distributed generation and complex loads. Detailed descriptions for each of these projects exceeding the threshold of materiality are provided in Appendix G.

Table 22: Proposed Capital Investments during Test Year - Projects over Materiality Threshold

Category	#	Project Code	Project Description	Priority Ranking	Planned Expenditure in 2018
System Access	1	1C100-1	Customer Demand - Services	1	$ 912,047
	2	1C100-2	Customer Demand - New Subdivisions	1	$ 107,153
	3	1C100-3	Customer Demand - Joint Use	1	$ 97,153
	4	1C100-4	Customer Demand - City Projects	1	$ 224,305
			Total (Material Projects Only)	-	$ 1,340,658
			Grand Total (Material and Non-material)	-	$ 1,511,028
System Renewal	5	1C200-1-1	Forced Overhead Renewal	1	$ 252,343
	6	1C200-1-2	Forced Underground Renewal	1	$ 308,593
	7	1C300-3-7 - A	Substation 16 Rebuild	2	$ 419,687
	8	1C300-1-2	Overhead Renewal - Poles	3	$ 314,765
	9	(2018) 1C300-1-4C	Overhead Renewal - Restricted Wire (Wallace Terr., 2nd, 5th, 6th Ave., Devon Rd. & Woodcroft Ave.)	4	$ 433,676
	10	(2018) 1C300-2-4	Underground Renewal - Voltage Conversion (Laronde Ave., Koprash Crt.)	5	$ 531,603
	11	(2018) 1C300-1-4B	Overhead Renewal - Restricted Wire (Red Pine Drive - North of Pnt. Of Pins)	6	$ 349,739
	12	(2018) 1C300-1-3A	Overhead Renewal - Voltage Conversion (MacDonald Ave - Lake St. to Moluch St.)	7	$ 288,020
	13	(2018) 1C300-1-4A	Overhead Renewal - Restricted Wire (Carpin Beach Rd - Base Line to Herkimer, Phase 1 of 2)	8	$ 185,155
			Total (Material Projects Only)	-	$ 3,083,581
			Grand Total (Material and Non-material)	-	$ 3,761,033
Total Expenditure on Material Projects During Test Year					**$ 4,424,239**
Total Expenditure on Capital During Test Year (System Access, System Renewal, System Service and General Plant Inclusive)					**$ 5,358,355**

The project prioritization criteria along with scoring to determine project priority rankings are shown in Table 23. Some details as to how the specific projects for the test year were scored are as follows:

Sub 16 Rebuild – Phase II of III

Other than safety, all of the remaining criteria contributed significantly to making this the highest priority planned project. This station serves approximately 2400 customers therefore outage impacts, and customer value for dollar received corresponding high ratings. This project also brings value in the form of improved System Service; protective relays and communications technology will allow for the future connection of REG and smart grid opportunities.

Deteriorated Poles

The predominant criteria that served to rank deteriorated poles as the second highest priority project was public safety due to the potential failure mode of this asset class.

Restricted Wire Projects

Three restricted wire projects were identified in the test year above the materiality threshold. They are ranked fourth, sixth and eighth in terms of overall priority. Public safety impact is the predominant driver. The differentiator between projects in this category is premised on number of customers impacted by each project and the corresponding value for money.

Voltage Conversion

There are two voltage conversion projects selected for construction in 2018 that are ranked fifth and seventh. Project interdependence was the primary criteria that impacted the scoring. These projects need to proceed to allow the retirement of two end-of-life 4.16kV substations (Substations 4 and 5). These and are planned for removal from service during the latter part of the 2018-2022 rate application period.

Table 23: Prioritizing Matrix for Test Year Projects over Materiality Threshold

Rank	Primary Factor[10]	Area	Program	Project	Public Safety Impact				Outage Customer Impact				Customer Value for $				System Service Improvements				Project Interdependance				Score
					Weight			40.0%	Weight			10.0%	Weight			15.0%	Weight			10.0%	Weight			25.0%	
					R	C	PSI	PSI (n)	QTY	HRS	COI	COI (n)	$K	C	CV	CV (n)	QTY	SIV	SSI	SSI (n)	SQI	FI	PI	PI (n)	
1	Customer Preference	System Access	N/A	N/A	Ranked as first priority as these are non discretionary																				N/A
1	Customer Preference	Forced Renewal (System Renewal)	N/A	N/A																					N/A
2	Customer Preference, Technology Based	Planned Projects & Programs (System Renewal)	DX Stations	Sub 16 Rebuild - Phase II of III	2	5	10	1.0%	2417	3	7251	8.3%	420	2417	5.8	10.5%	2417	5	12085	9.5%	5	10	50.0	7.4%	36.7%
3	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Poles - Det. Poles	10	10	100	9.7%	160	1.5	240	0.3%	210	160	0.8	1.4%	160	1	160	0.1%	1	5	5.0	0.7%	12.2%
4	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Rest. Wire - Wallace Terrace/2nd Ave./5th Ave./6th Ave./Devon Rd./Woodcroft Ave.	7.5	10	75	7.3%	254	3	762	0.9%	442	254	0.6	1.0%	254	1	254	0.2%	5	1	5.0	0.7%	10.1%
5	Customer Preference	Planned Projects & Programs (System Renewal)	UG Renewal	Volt. Conv. - Laronde/Koprash	1	1	1	0.1%	79	1.5	119	0.1%	542	79	0.1	0.3%	79	1	79	0.1%	5	10	50.0	7.4%	8.0%
6	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Rest. Wire - Red Pine Dr. (N of Pnt of Pins)	7.5	10	75	7.3%	32	3	96	0.1%	357	32	0.1	0.2%	32	1	32	0.0%	3	1	2.5	0.4%	8.0%
7	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Volt. Conv. - MacDonald (Lake to Moluch)	1	1	1	0.1%	26	1.5	39	0.0%	294	26	0.1	0.2%	26	1	26	0.0%	5	10	50.0	7.4%	7.7%
8	Customer Preference	Planned Projects & Programs (System Renewal)	OH Renewal	Rest. Wire - Carpin Beach Rd. (Base Line to Herkimer) PH 1 of 2	5	10	50	4.9%	12	6	72	0.1%	189	12	0.1	0.1%	12	1	12	0.0%	1	1	1.0	0.1%	5.2%

Notes Regarding Ranking Methodology

1) Public Safety Impact (PSI) due to failure = Risk (R) x Consequence (C) where (R = (1 = low, 10 = high)= - 1, C = (1 = low, 10 = high)
2) Customer Outage Impact (COI) = (Qty Customers Affected (QTY) x anticipated outage hours/year (HRS))
3) Customer Value (CV) = Cutomers Served (C) / $100,000($K)
4) System Service Improvements (SSI) = Qty Customers Affected (QTY) x Service Improvement/Enhancement Value (SIV) factor, (1 = low, 5 med, 10 = high)
5) Project Interdependence (PI) = Impact of a project not proceeding negatively impacting the ability to complete other future planned work = (SQI = service quality impact x FI = financial impact), values (1 = low, 10 = high)
6) Score = Sum of five factors above (Public Safety, Outage Customer Impact, Customer Value after weighting each equally (ie: 20%) allowing for a maximum atainable score of 100%
7) (n) represents a normalized score where for the ranked projects, each is normalized to a scale of 0%-20%
8) Rank is determined by placing Scores for all planned capital projects in a rank ordered list. A rank of 1 represents the highest priority. Non-discretionary customer demand work and capital work driven by unplanned repairs have all been weighted equally and assigned a Rank of 1
9) It is noted that the projects within this matrix are those previously screened through the Asset Management Plan process and they therefore represent only the most critical projects identified and prioritized throug that process
10) Primary Factor categories include (a) Customer Preference, (b) Technology Based and (c) Innovative Process

4.1.5 Impact of Regional Planning Process [5.4.1e]

The regional planning process identified no system constraints in the upstream system and has no impact on the investments proposed in this DSP.

4.1.6 Impact of Customer Engagement Activities on DSP [5.4.1f]

As described in Section 2.1.1, during customer engagement sessions, a vast majority of PUC Distribution's customers have generally indicated satisfaction with the current reliability and service quality levels. Even so, it was also identified that the customer priority and preferences were directed at improving reliability, better communications and consultations (including related to outages and projects) and a managed approach to infrastructure renewal (replace before failure respecting safety and large reliability impacts). Customer surveys also indicated sensitivities towards rising electricity prices and indicated preference to lower electricity rates. Of those customers willing to accept additional costs, the highest preference was towards replacement of aging equipment to maintain or improve reliability and lower preference to smart grid features allowing customers opportunities to manage their electricity use.

In view of this feedback, this DSP has been prepared to keep the retail rate escalations at a modest level, by accepting a greater level of risk of asset failures in service where impacts can be mitigated through spares and alternative supply. In view of the customer sensitivities to rising electricity prices, only a subset of the assets determined to be in "poor" or "very poor" condition have been prioritized and included in this DSP for renewal or refurbishment. Because the peak demand in this service territory is expected to decrease rather than increase, no investments are proposed in this DSP for capacity upgrades or smart grid features allowing customers greater access to control their electricity use or curtail peak demand.

Based on customer feedback, the focus of this DSP has been on the need to prudently plan investments to maintain utility operations at optimal level.

4.1.7 Distribution system development [5.4.1g]

Because no capacity constraints currently exist in the distribution system and none are expected to arise during the next five years for connecting load or generation customers, no investments are proposed into system capacity upgrades. There are presently no applications in queue for REG connections. There is adequate capacity in the system to accept all projected generation connection requests for the coming 5 years.

4.1.8 Distribution system development [5.4.1h]

As described previously in Section 2.1.1, during customer engagement sessions, a vast majority of PUC Distribution's customers have indicted satisfaction with the current reliability and customer service levels. Customer surveys also indicated sensitivities towards rising electricity

prices and indicated preference to lower electricity rates. Of those customers willing to consider additional costs the highest preference was towards replacement of aging equipment to maintain or improve reliability. Therefore, the focus of the investments proposed in this DSP is to preserve the existing supply security and reliability levels and prevent them from degrading. Project budgets also reflect the increased emphasis on communications and engagement with customers throughout the project cycle from planning through execution to closure.

PUC Distribution has implemented tools to address customer preferences with respect to data access and visibility. For example, the Customer Connect software application implemented in conjunction with the introduction of smart meters allows customers visibility into their consumption usage on a daily and hourly basis.

Keeping in view the customer's preference for low electricity prices, no investments are proposed in this DSP for smart grid initiatives or pilot projects to provide additional data access and visibility from the current level at this time. As mentioned earlier, PUC Distribution's distribution system already has adequate capacity to accept distributed generation customers and PUC Distribution is proactively participating in the province's CDM program for load management. Because the peak demand in the region has been decreasing and this trend is expected to continue, investments into technology to reduce peak demand would yield low benefits in this service territory. PUC Distribution is already employing technology-based opportunities to improve operational efficiency, asset management and the integration of distributed generation and complex loads and no additional investments are considered necessary in this area.

Sault Smart Grid Project

PUC Distribution has been exploring an innovative and large scale system smart grid project for a few years that could provide significant benefit to our customers. The project would include elements for distribution automation, voltage control and improved customer care and outage management capabilities. The project conceptually has included a "no net bill increase" hurdle for customers as a primary evaluation criteria recognizing the high concern for customers on current costs for electricity. To meet this hurdle a significant level of financial support is being sought and will be needed for internal project approval. It is anticipated that PUC Distribution would be utilizing the Incremental Capital Module process for this project should the analysis and financial feasibility criteria, including the "no net bill increase" be achieved. Should the project funding applications be approved and OEB approval attained, and subject to final PUC Board of Directors approval this 2 to 3 year project would represent a substantial advancement in smart grid technologies being implemented by PUC Distribution.

4.2 Capital Expenditure Planning Process Overview [5.4.2]

For reference, the capital expenditure for projects above the materiality threshold in the test year are shown in Table 22.

4.2.1 Planning Objective, Criteria and Assumptions [5.4.2 a]

The capital expenditure plan proposed in this DSP has been developed by ensuring that the DSP objectives are aligned with its corporate goals, using the feedback from customer engagement sessions, conclusions of the asset management plan and the regional grid planning as an input, which allowed alignment of the overall corporate vision, mission statement and values with the proposed investment plan.

PUC Distribution's investment planning objectives into each investment categories are listed below:

1) Ensure appropriate level of investment allocation to meet the regulatory obligations of the System Access such as metering, system relocations for municipal road work, future system requirements for residential, commercial and industrial load customers as well as generation customers and joint-use customer requests. ;
2) Ensure adequate level of objectively prioritized investments into distribution System Renewal to maintain optimal risk levels related to asset failures in service, particularly those impacting safety, reliability and environment, as determined through the continued condition assessment of assets;
3) Ensure the acceptable level of expenditures required to maintain sufficient system capacity to meet existing and future capacity demand levels, including adequate capacity to allow connection of renewable generation;
4) Ensure proper allocation of investments into General Plant assets to maintain employee safety and productivity.
5) Review overall expenditures to ensure retail rate impacts and adjust spending as required to ensure retail rates remain affordable.

Because the distribution system has adequate capacity to allow connection of anticipated load and generation customers, no REG investments are proposed for system capacity upgrades to accept new generation or load customers. Because there are no capacity related system constraints and no investments are required to mitigate capacity constraints, use of non-distribution system alternatives to relieve system capacity or operational constraints is not necessary. The Regional Planning Process has been completed and it did not identify any issues requiring any investments by PUC Distribution. A copy of the Regional Infrastructure Planning Report is included in Appendix E. Also, because customers have indicated preference for lower electricity prices no investments are proposed in this DSP for smart grid initiatives or pilot projects to provide additional data access and visibility from the current level. As mentioned

earlier, PUC Distribution is proactively participating in the province's CDM program for load management.

PUC Distribution has determined that there are a number of important inputs required in order to support investment decisions to ensure the investment level is appropriate and is targeted into the appropriate area. As such, planning criteria inputs are utilized to support investments into each of the four categories, as indicated below:

- Consultation with municipal officials to understand future projects requiring relocation of distribution lines in support of System Access investments;
- Incorporating customer growth forecasting into capital expenditures for anticipated residential and commercial developments in support of System Access investments;
- Ongoing dialogues and open communications between large load general service customers and PUC Engineering department to gain perspective on any changes in their electrical demand in support of System Access investments;
- Asset Condition Assessments to support expenditures related to asset renewal to maintain the system as designed in support of System Renewal investments;
- System capacity assessments to identify requirements for System Service investments; and
- Individual assessments on key areas in General Plant such as buildings and facilities required to support expenditures in General Plant.

The investment requirements to facilitate new customer connections, service upgrades, joint use requests and line relocates in response to municipal requests are difficult to predict accurately, so the expenditure requirements in these categories have been estimated based on knowledge of past expenditures and knowledge gained through stakeholder engagement.

The overarching objective of PUC Distribution's asset management plan is to identify and implement the optimal time and scope of investments into asset maintenance, refurbishment and replacement. Each of the asset management objectives described in Section 3.1 are considered during prioritization of the investments into System Renewal, with appropriate weights assigned to each objective, as indicated. A prioritized list of the projects above the materiality threshold and planned to be implemented during the test year is provided in Table 22.

4.2.2 Policy for Relieving System Capacity and Operational Constraints [5.4.2 b]:

Because the distribution system has adequate capacity to allow connection of anticipated load and generation customers, no REG investments are proposed for system capacity upgrades to accept new generation or load customers.

The peak system demand is expected to decrease and not increase. Because there are no capacity related system constraints and no investments are required to mitigate capacity constraints, use of non-distribution system alternatives to relieving system capacity or operational constraints is not necessary. The Regional Planning Process has been completed and it did not identify any issues requiring any investments by PUC Distribution.

Also, because customers have indicated preference for lower electricity prices no investments are proposed in this DSP for smart grid initiatives or pilot projects to provide additional data access and visibility from the current level. As mentioned earlier, PUC Distribution is proactively participating in the province's CDM program for load management.

4.2.3 Processes, Tools and Methods to Select, Prioritize and Pace Projects [5.4.2 c]:

Please refer to Section 3.1.1 and 3.1.2, where processes, tools and methods used to select, prioritize and pace different categories of investments are described in greater detail. In addition reference to Appendix H will provide detail of mechanisms used to engage customers in identifying their needs, priorities and preferences and the relationship to the projects listed for the DSP test year where applicable.

A brief summary of the processes, tools and methods used to identify, select, prioritize and pace projects in each investment category is provided below:

4.2.3.1 System Access

Identification

Projects are identified through contact with customers wishing to connect new services, service upgrades, requests from municipal landowners to relocate assets to accommodate road reconstruction or requests for services from joint use communication companies. As described in greater detail in Section 2.2.1.1, Appendix C and Appendix H, customer engagement sessions have generally indicated high customer satisfaction for delivery of services under System Access category and therefore no changes are considered necessary to the existing processes.

Selection

Investments into System Access projects are non-discretionary in nature and are required to fulfil PUC Distribution's regulatory obligations and projects in this category.

Prioritization

Given that these projects are mandatory, they are therefore given the highest priority for implementation. Project prioritization is based on the expected date when all service requirements are fulfilled by the customer and consideration of the customer's schedule for implementation, as identified through regular contact between both parties.

Pacing

For new service additions or service upgrades, projects are planned and executed to ensure that low voltage connections are completed within 5 days of the fulfillment of all service conditions and high voltage services are connected within 10 days of the fulfillment of all service conditions. In the case of make-ready work for communication company applications, pacing is premised on the terms and conditions of joint-use agreements as well as ongoing consultations. Road reconstruction projects are paced through close coordination with the City planning and engineering departments and in accordance with the associated project schedules.

4.2.3.2 System Renewal

PUC Distribution identifies asset repair, refurbishment and replacement requirements through asset condition assessment as described in more detail in Section 3. Projects have been identified, selected, prioritized and paced using the decision matrix presented in Figure 8, which is fully aligned with PUC Distribution's corporate goals, and as summarized below:

Identification

By taking into account all relevant information related to assets' operating condition, including service age, physical condition, results of visual inspections and testing, recent failure rates of similar assets in service, condition of all infrastructure assets were assessed and expressed on a normalized index in the form of a Health Index.

The Health Index was related to probability of failure values for each project, using a weighted average approach, as described in detail in Appendix B and each asset was assigned a health indicator expressed as "very good", "good", "fair", "poor" and "very poor."

Selection

Risk consequence related to reliability, safety, operating efficiency, etc. for each project area with assets found in "poor" or "very poor" condition were identified and calculated by multiplying composite probability of asset failure with consequence of failure. Costs for the scope of work to mitigate risk in each project area are determined, using distribution system estimating data.

Prioritization

A preliminary list of prioritized projects was produced, based on the risk score and risk mitigation cost for each project.

Based on the customer preferences, particularly those related to service quality, reliability, and retail rates, overall capital spending was established to align rate escalation to customer expectations. Budget availability for System Renewal projects was determined by subtracting from the overall capital spending level the higher priority projects in System Access.

The tools used to prioritize investments in this category include a project prioritizing matrix developed using Microsoft Excel.

Pacing

The selected projects on the preliminary project prioritized list were paced for implementation, based on the funding available for asset renewal and by taking into account the resources required for project implementation for the type of work predominantly involved (overhead, underground or substations).

Due to their non-discretionary nature, System Access projects will take priority in the event that there are competing demands with System Renewal projects. The use of a regularly updated integrated resource plan allows this process to be managed in an effective manner with the objective of successfully completing all projects planned for in the DSP.

4.2.3.3 System Service

Identification

Through careful planning processes including system capacity assessments, the development of a REG plan, and participation in preparing a Regional Infrastructure Plan, it has been identified that PUC Distribution's supply network has adequate capacity without any constraints to allow connection of new loads and generation from REG during the next five years. PUC Distribution has implemented a number of smart grid features during the previous years, such as smart meters, digital protection relays, voltage regulators, reclosers and remote-controlled substation switchgear to facilitate automation. A number of investments planned under System Renewal will serve to further expand the smart grid features, typically provided by System Service investments.

During customer engagement sessions, customers have indicated preference for lower retail rates as opposed to additional smart grid features, e.g. providing greater access to customers to manage and control their electricity use.

In view of the above, no investments are planned in this DSP, in the System Service category.

4.2.3.4 General Plant

There is only a small level of investments proposed in this DSP for General Plant category representing 1% of total investment. Approximately 5 years ago PUC consolidated all of its administrative offices and operational buildings into a newly constructed integrated facility and retired all of its aging facilities. For the most part the new facility is in excellent condition and meets all functional needs so only minimal incremental building infrastructure investments have been considered in this DSP. The entire motor vehicle fleet used for operations is owned by PUC Distribution Inc.'s non-regulated affiliate services company PUC Services Inc.

Identification, Selection, Prioritization & Pacing

General Plant projects are identified, selected, prioritized and paced based on cost/benefit analysis, using a combination of inspections, policies and expert knowledge. Investments into building repairs are based on identified deficiencies through inspections of building interior and exterior, doors and fixtures, HVAC, parking lots, security system and building mechanical systems.

4.3 System Capability Assessment for Renewable Energy Generation [5.4.3]

As previously described in Section 2.3.9, PUC Distribution currently has approximately 63MW of REG connected to its distribution system, which on occasion results in net export conditions during summer months when the distribution network is near its minimum load. PUC Distribution also hosts an IESO controlled 7MW/7MWh battery energy storage facility.

PUC Distribution has prepared and submitted a REG Plan to the IESO. The associated IESO comment letter in response to the REG Plan is attached in Appendix D.

4.3.1 Applications for REG Connections Greater than 10kW [5.4.3a]

The connection history for all REG installations connected to the PUC Distribution system over 10kW is summarized in Table 24 below. Of all the applications made, those that were not connected had applications terminated by the applicant and in no case was any application for connection rejected due to unavailable capacity.

Table 24: Summary of REG Applications >10kW

	Application Date		Application MW		Connection Date		Connection MW	
Pre-2013	1985		0.25		1985		0.25	
	4/15/2007		9.95		10/15/2010		9.96	
	4/17/2007		9.95		10/15/2010		9.96	
	6/3/2007		9.95		8/30/2011		9.96	
	6/3/2007		9.95		8/30/2011		9.96	
	6/3/2007		9.95		7/27/2011		9.96	
	6/3/2007		9.95		11/22/2011		9.96	
	7/24/2007		0.045		2008		0.045	
	2007		9.95		N/A		0	
	2007		9.95		N/A		0	
	1/8/2008		0.037		7/8/2008		0.037	
	9/9/2011		0.035		11/23/2012		0.035	
	6/7/2011		0.5		7/20/2011		0.5	
	9/26/2011		0.25		8/29/2012		0.25	
	2/28/2011		0.1		6/9/2011		0.1	
	6/14/2011		0.135		11/14/2011		0.135	
	Quantity	16	Total MW	80.952	Quantity	14	Total MW	61.112
2013	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2014	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2015	2/18/2015		0.1		8/23/2016		0.1	
	Quantity	1	Total MW	0.1	Quantity	1	Total MW	0.1
2016	6/17/2016		0.07		7/20/2011		0.07	
	3/11/2016		0.25		8/29/2012		0.25	
	3/11/2016		0.25		6/9/2011		0.25	
	3/11/2016		0.25		11/14/2011		0.25	
	Quantity	4	Total MW	0.82	Quantity	4	Total MW	0.82
2017	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2013-2017 Totals	Quantity	5	Total MW	0.92	Quantity	5	Total MW	0.92
Grand Total	Quantity	21	Total MW	81.872	Quantity	19	Total MW	62.032

4.3.2 Applications for REG 10kW or less

Currently there are no applications in the queue from REG connections <10kW, under the Micro-FIT program and all requests for Micro-FIT generation received to date have been successfully connected to the system. There appears to be a growing interest in net metering and some discussions about that in conjunction with energy storage behind the meter as the gap closes between Micro-FIT contract pricing and the Residential class load energy costs.

4.3.3 System Capacity to Support REG [5.4.3c]

Primarily based on thermal ratings of conductors and transformers, PUC Distribution has developed and submitted to the IESO, the following table of available capacity, Table 25. The IESO uses this for planning and as an input to preparing a Transmission Availability Table (TAT) which is posted online to assist prospective REG applicants in selecting a site for their project. Table 25 summarizes available capacity at the 34.5kV feeder and station bus levels. It can be seen that at present there is still capacity available for the future connection of approximately 27MW more generation between circuits out of TS1 and TS2 combined.

Table 25: Available System Capacity for Accepting Additional REG Connections

Station	Bus Name	Capacity (MW)	Allocated Capacity (MW)	Available Capacity (MW)	Supply Circuit 1	Supply Circuit 2
TS1	**Total**	**45**	**41.310**	**3.690**	**GL1SM**	**GL2SM**
(St. Mary's)	West	30	21.009	3.690		
	East	30	20.300	3.690		
TS2	**Total**	**45**	**21.663**	**23.337**	**GL1TA**	**GL2TA**
(Tarentorus)	West	30	21.015	8.985		
	East	30	0.647	23.337		

34.5 kV Feeder Name	Bus Connection	Capacity (MW)	Allocated Capacity	Available Capacity (MW)	Notes:
SM-5	West	30	10.214	3.690	TS Limiting (45-D5) MW
SM-7	West	30	9.960	3.690	TS Limiting (45-D5) MW
Sub 19 West	West	N/A	0.835	N/A	no feeder, direct bus connection
SM-9	East	30	10.034	3.690	TS Limiting (45-D5) MW
SM-11	East	30	10.017	3.690	TS Limiting (45-D5) MW
Sub 19 East	East	N/A	0.250	N/A	no feeder, direct bus connection
TS1			**41.310**		
TA-6	West	30	0.139	23.337	TS Limiting (45-D8) MW
TA-7	West	30	20.876	8.985	West Bus Limiting (30-D9) MW
TA-9	East	30	0.028	23.337	TS Limiting (45-D8) MW
TA-10	East	30	0.188	23.337	TS Limiting (45-D8) MW
TA-11	East	30	0.431	23.337	TS Limiting (45-D8) MW
TS2			**21.663**		

4.3.4 Proposed Plan and Investments to Support REG [5.4.3b, d and e]

There are no applications in hand and PUC Distribution is not currently aware of any customers wishing to connect renewable generation plant to the grid.

PUC Distribution has produced a 5 year forecast of future REG connections as part of its Renewable Energy Generation Plan. For the period 2018-2022 projections have been based on:

- local economic and population data
- macro-economic conditions
- awareness of information from IESO and OEB regarding connection rates and programs

Based on those factors, a five year forecast has been established with an anticipated connection of one 250kW generator per year for a total connection of 1.25MW over the next 5 year period.

The PUC Distribution grid is presently very well positioned to support all forecast REG connections over the next five years and no associated infrastructure investment is required during that period.

4.4 Capital Expenditure Summary [5.4.4]

The actual capital and system O&M expenditure for the historic years from 2012 to 2016, as well as the proposed capital and system O&M expenditure for the bridge year (2017), the test year (2018) and the forecast period (2019 to 2022), is summarized in Table 26. For 2017, the data presented in each capital investment category and the system O&M category is the budgeted amount for the full 12 month period.

Table 26 reveals appreciable variations in the historic capital spending levels from one year to the next in each of the categories. The reasons for these variations are described below:

- The expenditure in the "System Access" category in 2012 far exceeds the average annual expenditure in this category for the five historic years. The excess expenditure in 2012 is related to the smart metering project. Although the installation work for the smart metering project was physically substantially complete at the end of 2010, the costs were not capitalized until 2012.

- The expenditure in the "System Access" category during 2015 and 2016 declined significantly in relation to the previous three years. This is related partly due to general slowdown in housing construction activity in this region and partly due to higher than normal requests in 2013 and 2014 for "make ready" work to allow joint-use of the poles lines for one of the major telecommunications companies.

- The expenditure in "System Renewal" category in 2013 is significantly higher in relation to the average expenditure in this category during the five historic years, which is related to the Sub 10 rebuild costs, capitalized during 2013.

- The expenditure in "General Plant" category in 2012 far exceeds the average expenditure in this category during the five historic years. The extraordinary high expenditure in 2012 in this category is related to the construction of the new office building.

As indicated in the System Service category in Table 26, there has been no expenditure during the past five years and minimal funds allocated during the forecast period. However, PUC Distribution has implemented a number of smart grid features on its network, during the previous years, such as smart meters, digital protection systems, voltage regulators and remote-controlled substation switchgear to facilitate automation, but because all of these projects involved replacement of old infrastructure at the end of its service life with new assets, these were

included in the System Renewal category as it was the primary driver. System Service investments include input from customers to drive investment decision making. Examples include implementation of voltage regulation improvements and recloser installations in response to customer feedback and needs. The ability of the distribution grid to supply the existing and anticipated load and generation customers was analysed and it was concluded that there are no anticipated capacity constraints for the forecast period. As such, there are no investments proposed in this DSP, specifically triggered by System Service requirements.

Table 26: Capital and O&M Expenditure Summary

First year of Forecast Period: 2018

CATEGORY	Historical Period (budget & actual)															Bridge	Forecast Period (planned)				
	2012			2013			2014			2015			2016			2017[1]	2018	2019	2020	2021	2022
	Budget	Actual	Var	Budget	Actual	Var	Budget	Actual	Var	Budget	Actual	Var	Budget	Actual[2]	Var						
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000					
System Access	1,132	7,938	601.1%	1,069	2,310	116.1%	2,957	2,532	-14.4%	1,265	1,549	22.4%	1,215	1,212	-0.2%	1,271	1,511	1,615	2,086	1,604	1,560
System Renewal	6,043	4,821	-20.2%	6,525	6,083	-6.8%	3,813	3,754	-1.6%	4,753	4,640	-2.4%	4,543	4,244	-6.6%	3,372	3,761	6,906	3,296	4,533	7,093
System Service	-	-	--	-	-	--	-	-	--	-	-	--	-	-	--	38	-	-	-	-	-
General Plant	17,803	23,269	30.7%	1,314	2,028	54.4%	175	376	114.1%	69	67	-3.1%	-	83	--	-	86	55	62	60	55
TOTAL EXPENDITURE	24,978	36,028	44.2%	8,907	10,421	17.0%	6,946	6,661	-4.1%	6,087	6,256	2.8%	5,758	5,538	-3.8%	4,682	5,358	8,576	5,445	6,197	8,708
System O&M	$ 6,259	$ 5,853	-6.5%	$ 6,154	$ 5,992	-2.6%	$ 5,530	$ 5,773	4.4%	$ 5,819	$ 5,978	2.7%	$ 5,955	$ 5,978	0.4%	$ 5,857	$ 6,213	$ 6,306	$ 6,400	$ 6,496	$ 6,594

Notes to the Table:

1. For 2017 (bridge year), the data presented in each capital investment category and the system O&M category is the budgeted amount for the full 12 month period.
2. All values are net of contributed capital.

Explanatory Notes on Variances

Notes on shifts in forecast vs. historical budgets by category

The capital expenditure during the historic five years, after removing the extra ordinary expenditure related to construction of the office building and upgrade of the revenue meters with smart meters in 2012 and 2013, and it amounts to average annual capital expenditure of $6,680,745. These were excluded on the basis that they represent a one-time capital investment and are not attributable to the normal five-year asset management process applied in the DSP. This compares to the forecast average amount of $6,856,747 for the 2018 to 2022. The five year average (2012-2016) capital expenditure, inclusive of the one-time extraordinary capital expenditures, amounted to $12,981,005. Average annual capital for System Access has been forecast at 88% of historical average actual expenditures (2013-2016). Average annual capital for System Renewal has been forecast at 109% of historical average actual expenditures (2013-2016) due primarily to the planned construction of two substations in the forecast period. General Plant for the forecast period is generally unchanged from 2015 and 2016 actual expenditures.

Notes on year over year Budget vs. Actual variances for Total Expenditures

Refer to Section 2.3.5.1 for a high level summary of the budget versus actual capital variances on an annual basis. The key extraordanary expenditures pertained to the construction of a new office building as well as the upgrade of revenue meters with smart meters. The impacts of these one-time projects primarily impacted 2012 and 2013. There was an overall 2.1% increase in actual O&M expenditures from $5.85 million to $5.98 million over the 2012-2016 period.The variability of budgeted to actual O&M over the 5 year historical period ranged from -6.5% to 4.4%.

Notes on Budget vs. Actual variance trends for individual expenditure categories

In the System Access category, variance trends are contingent upon variable customer demand. For the years 2013 to 2016 for the System Renewal category, the general trend is that actual expenditures are slightly below budget.

The planned capital expenditure for the five-year forecast period, shown in Table 26, indicates capital expenditure by PUC Distribution, net of the customer or third-party contributions. As shown below in Figure 36, the planned expenditure will result in an average annual capital expenditure of approximately $6,856,747 during the period covered by this DSP.

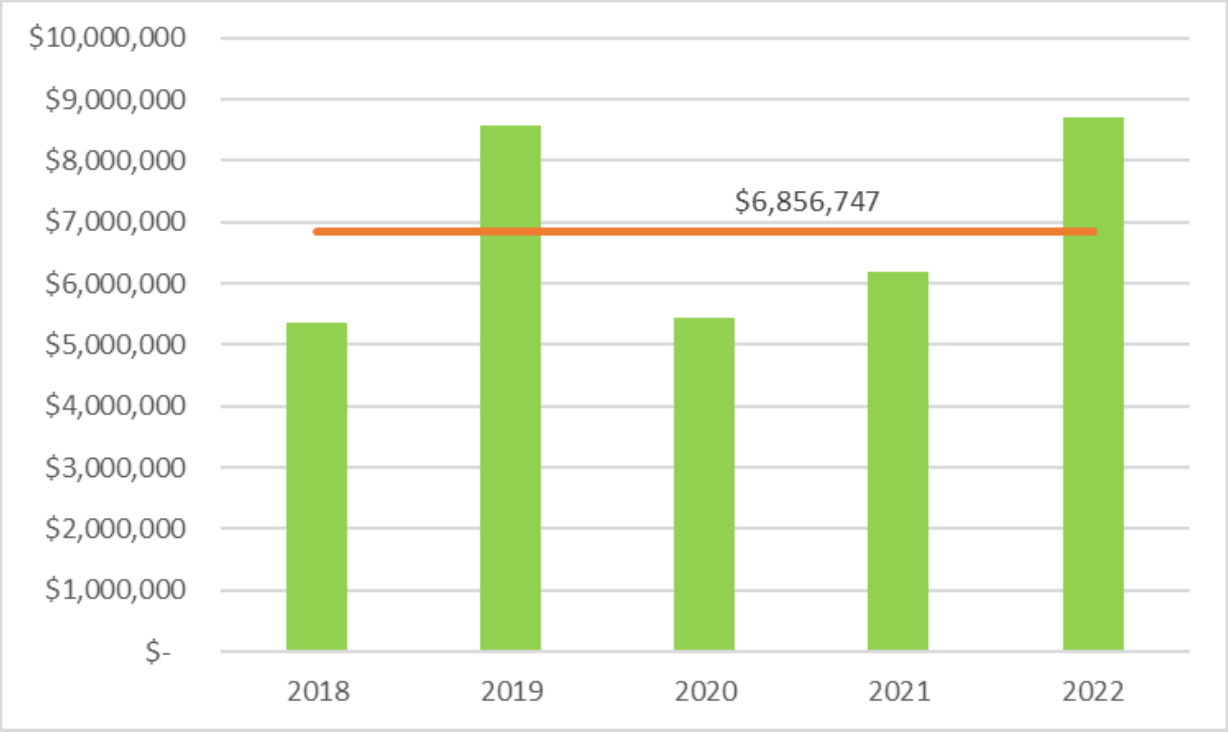


Figure 36: Proposed Capital Expenditure during the DSP Period

Figure 37 shows the capital expenditure during the historic five years, after removing the extra ordinary expenditure related to construction of the office building and upgrade of the revenue meters with smart meters in 2012 and 2013, and as shown it amounts to average annual capital expenditure of $6,680,745. These were excluded on the basis that they represent a one-time capital investment and are not attributable to the normal five-year asset management process applied in the DSP. The five year average (2012-2016) capital expenditure, inclusive of the one-time extraordinary capital expenditures, amounted to $12,981,005. This compares to the forecast average amount of $6,856,747.

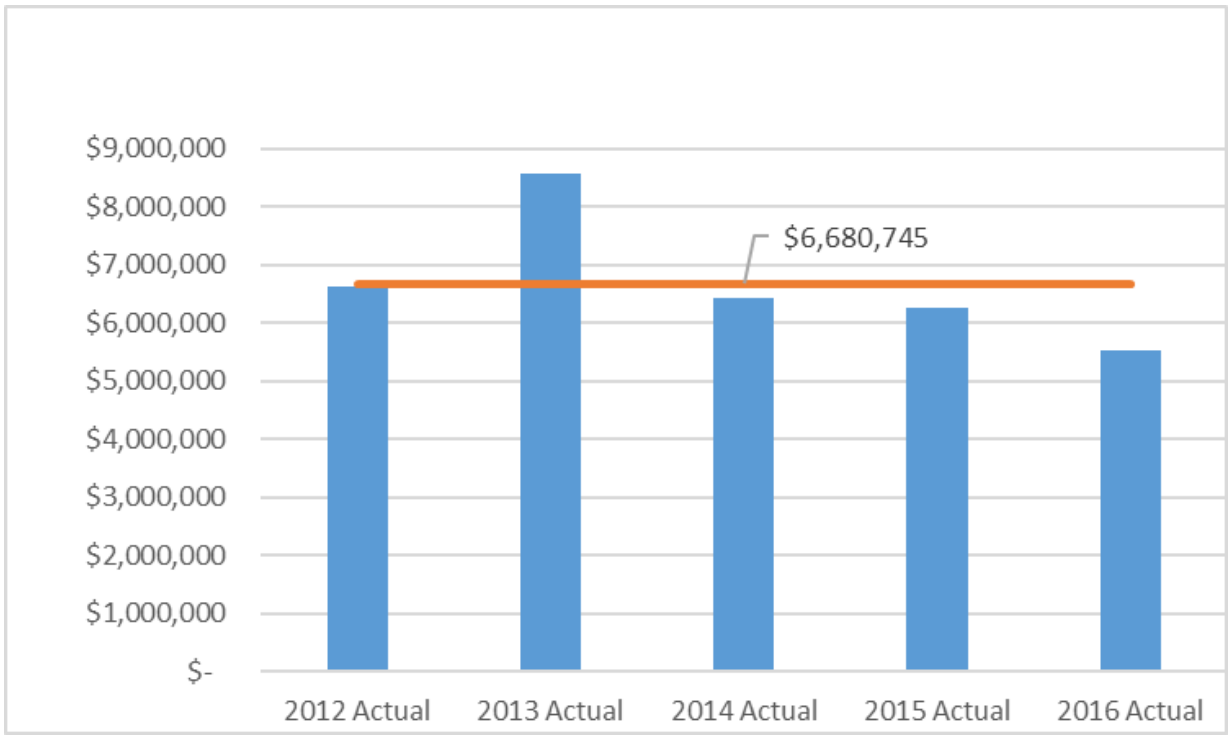


Figure 37: Historic Capital Expenditure (After Removing Office Building and Smart Meter Expenditure)

The proposed average annual expenditure during the DSP period, thus, represents an increase of 2.6% from the average annual capital expenditure during the historic five years. This figure does not account for inflationary increases. The impact of proposed capital expenditure in various categories on system O&M expenditure is described below:

4.4.1.1 System Access

These investments include capital investments to implement customer service requests, joint-use requests from third party communication companies; line relocates to facilitate municipal infrastructure developments, such as road reconstruction projects and investments into revenue metering. It is difficult to accurately determine the quantitative impact of the System Access investments on future O&M expenditure. However, investments into System Access generally result in an increase in future O&M expenditure. To connect new customers, in existing subdivisions, requires additional assets in the form of service lines, underground dips and revenue meters, all of which require safety inspections on a 3-year cycle and therefore, would result in an increase in O&M expenditure. New customers in new subdivisions require additional assets in the form of line extensions and distribution transformers in addition to service lines and revenue meters and thus result in an increase in O&M expenditure.

Equipping all general service customers with MIST meters is a regulatory requirement that will result in an increase in communication costs to each MIST meter and a corresponding increase in annual O&M expenditure.

4.4.1.2 System Renewal

The proposed investments into System Renewal are summarized in Table 21, with project level detail for the test year provided in Table 22 and in Appendix G. As shown, the proposed expenditure includes both reactive expenditures for replacement of the assets that have failed in service, as well as proactive replacement of assets where the risk of an assets' failure in service is unacceptable.

It is not possible to accurately determine the quantitative impact of capital investments on future O&M expenditure qualitatively, but in general when adequate level of investments is maintained into System Renewal to maintain the median age of asset base at the same level as in the previous year, it allows the asset's operating condition to be maintained at the same level as the previous year, preventing asset impairment from progressing further and preventing O&M costs from escalating further. When adequate investments are not made for renewal of assets which are at the end of their economic useful life, it results in an increase in equipment failures in service and an increase in the expenditure into emergency repairs and power restoration. Therefore, when correctly prioritized investments into asset renewal are made for renewal of assets at the end of their useful economic life, they prevent or slow down the rate of escalation of O&M costs in the coming years.

The infrastructure renewal projects involving distribution system operating voltage upgrade from 4.2 kV to 12.5 kV would result in a reduction in O&M expenditure due to the removal of duplicate lines and the replacement of three 4.2 kV distribution stations with a single 12.5 kV station.

4.4.1.3 System Service

Since there are no planned investments in the System Service category there is no expected change in O&M expenditure levels.

4.4.1.4 General Plant

Since the investments in General Plant are quite modest, they are not expected to have any material impact on O&M expenditure level.

4.4.1.5 Historic and Forecast O&M Expenditure

Figure 38 shows PUC Distribution's expenditure into system O&M activities during the historic five-year period. The chart indicates the mean annual O&M expenditure of $5, 914,777.

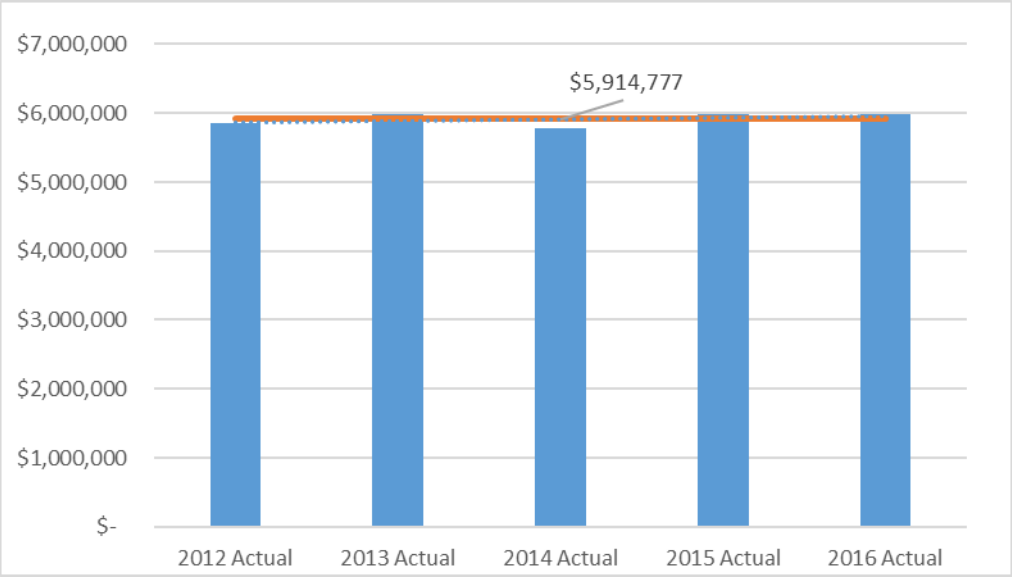


Figure 38: Historic O&M Expenditure

As shown, the deviations in year to year O&M expenditure from the mean are minor – maximum deviation from the mean in any year is less than 2.4%.

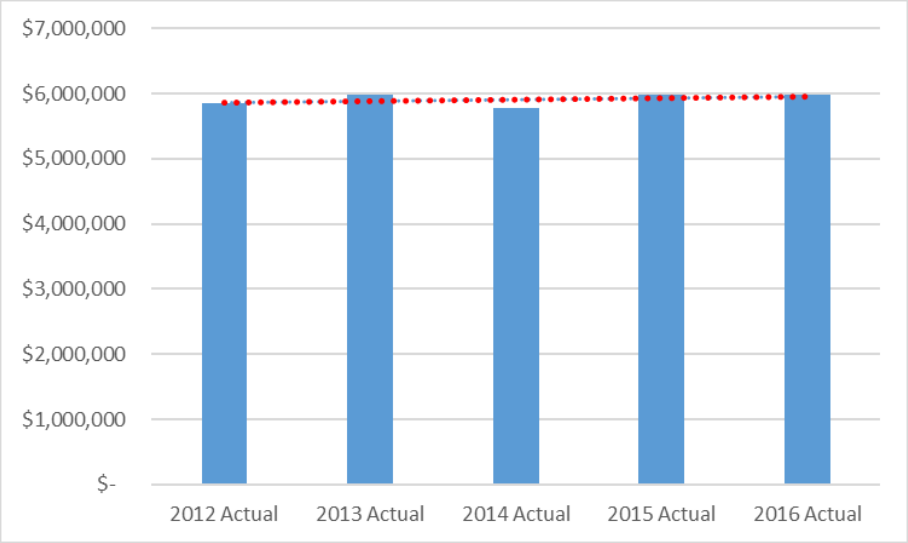


Figure 39: Historic O&M Expenditure with Trend line

Figure 39 shows the historic O&M expenditure with trend line – showing mean annual increase of 0.4% in O&M expenditure.

The forecast O&M expenditure as presented in Table 26 is displayed in Figure 40. Included in the O&M projections from 2019 to 2022 is an annual inflationary increase of 1.5%.

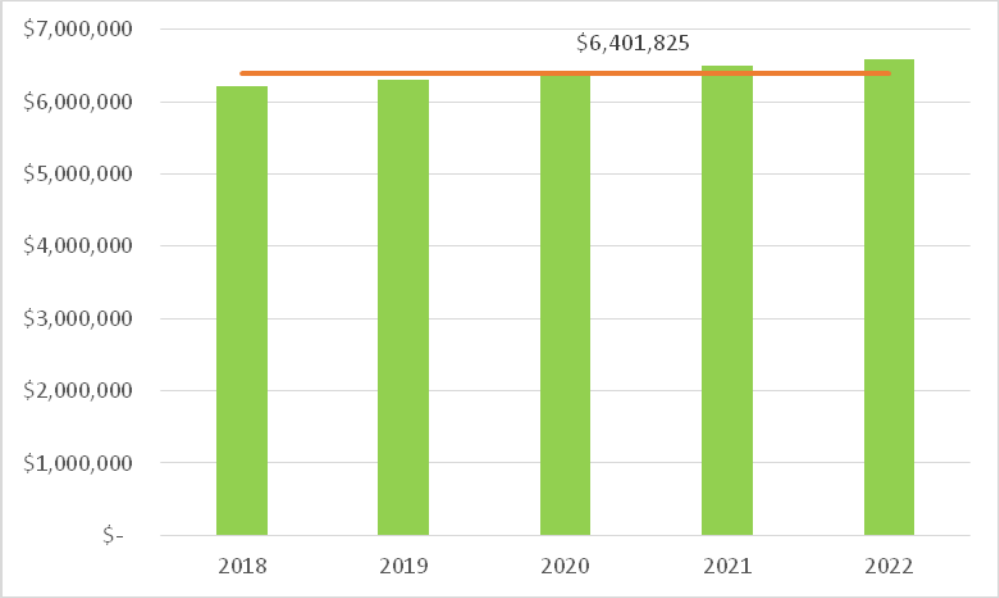


Figure 40: Forecast O&M Expenditure During DSP-Period

4.5 Capital Expenditure Justification [5.4.5]

4.5.1 Overall Plan Expenditure Justification [5.4.5.1]

As described in Section 4.4, the investment portfolio during the forecast period includes investments into System Access, System Service, System Renewal and General Plant upgrades. The capital investment plan proposed in the DSP amounts to a 2.6% increase in average annual expenditure during the forecast 5-year period from the historic 5-year period (after removing the extra ordinary expenditure for building construction and smart meters from the expenditure during the historic years). These were excluded on the basis that they represent a one-time capital investment and are not attributable to the normal five-year asset management process applied in the DSP. The five year average (2012-2016) capital expenditure, inclusive of the one-time extraordinary capital expenditures, amounted to $12,981,005. This compares to the forecast average amount of $6,856,747. Considering inflationary pressures, the overall average forecast spend is consistent with historical spending levels.

Because sufficient system capacity is available to meet existing and future capacity demand levels, including adequate capacity to allow connection of renewable generation and the economically efficient and customer desired smart grid features are being implemented during asset renewal; there are no new investments required in the System Service category.

Expenditure in System Access is driven by the need to meet regulatory obligations. The proposed expenditure level is estimated based on the historic spending levels and the specific information available about planned projects at the time of preparation of this DSP, related to new requests for services, line relocates, joint-use requests, MIST meters and requirements for revenue meter replacement.

Power supply reliability and public safety are the key drivers for the proposed investments into System Renewal. These investments are prioritized and paced based on objective, risk-based criteria, and the methodology employed for prioritization of the investments is aligned with the best industry practices. The investment level in this category has been determined to maintain risk related to asset failures in service, particularly those impacting safety, reliability and environment, at an optimal level.

Investment level into General Plant has been determined based on identified deficiencies through inspections of building interior and exterior, doors and fixtures, HVAC, parking lots, security system and building mechanical systems

For more detailed information on investment drivers and prioritization please refer to Section 2.1, Sections 3.1, 3.2, 3.3, 4.1 and 4.2.

4.5.2 Justification of Projects Exceeding the Materiality Threshold [5.4.5.2]

All capital projects, proposed to be implemented during the test year, with investments level exceeding the materiality threshold, are listed in Table 22 The first four projects in the table fall in the System Access category for which meeting the regulatory obligations is the primary driver and the next 9 projects on the list belong to the System Renewal category, for which supply system reliability and public safety are the primary drivers.

Detailed scope of each project along with its key driver and justification are described in detail in Appendix G and briefly summarized below:

Project #1, #2, #3, and #4 (System Access)

These projects are required to fulfil PUC Distribution's regulatory obligations to provide services. The first project involves fulfilling customer requests for new services or upgrade of existing services. The second project covers requests from land developers involving servicing of multiple lots within subdivisions. The third project covers requests from telecommunication

companies in the City for make ready work to facilitate joint use of distribution infrastructure by third parties. The fourth project involves meeting requests from the municipality to relocate overhead or underground lines installed in the public right-of-way to coordinate with road widening projects.

Project #5 and #6 (System Renewal – Forced)

These two projects involve reactive expenditure to restore power following a power interruption caused by equipment failures by replacing the failed distribution system assets with new equipment. The key drivers for these projects are supply system reliability and public safety, because when equipment has failed in service, the proposed expenditure becomes necessary to restore power and remove the unsafe equipment from service. Project #5 is intended to cover expenditure for renewal of failed assets on overhead lines and Project #6 is intended to cover expenditure for renewal of assets on underground distribution system.

Project #7

This project involves replacement of poles determined to be “unsafe” due to degradation of their structural strength, based on in-situ testing of the poles.

Project #8

This project involves rebuild of distribution station Sub 16. As detailed in the Asset Management Plan, this substation has been determined to be in very poor condition and at the end of life. The power transformers and switchgear at Sub 16 will reach a service age of 50 years by 2019, which is 10 years more than the typical life of this equipment. Due to the state of the existing station infrastructure, the switchgear is deemed to be unsafe to operate while energized and must be isolated and de-energized prior to operation. This results in isolation out on the 34.5kV distribution lines, which can impact system reliability whenever operating the existing Sub 16 is required. The planned Sub 16 rebuild will be a new 34.5kV - 12.47/7.2kV, 26.6MVA municipal substation that will have two incoming 34.5kV supplies, two 10/13.3 MVA power transformers, and four outgoing 12.47kV feeders supplied by arc resistant metalclad switchgear.

Projects #9

This project involves renewal of overhead distribution system assets through rebuilding of the overhead lines currently operating at 4.2 kV. The lines will be rebuilt to operate at 12.5 kV upon completion of the projects. As detailed in PUC Distribution's asset condition assessment report, PUC Distribution has over 30km of 4.16/2.4kV circuits in service, all of which are at the end of their service life. Additionally, the two stations supplying these overhead lines are also beyond their useful service life, requiring replacement. In an effort to streamline system voltages, three 4.2 kV stations will be replaced with a single station producing 12.47/7.2kV distribution voltage. In order to accommodate these station rebuilds, all distribution lines operating at 4.2 kV will be

converted to 12.5 kV. Power system reliability and public safety are the primary driver for these projects, although they will also help reduce operating costs when the two 4.2 kV stations are retired from service.

Projects #10, #11, and #12

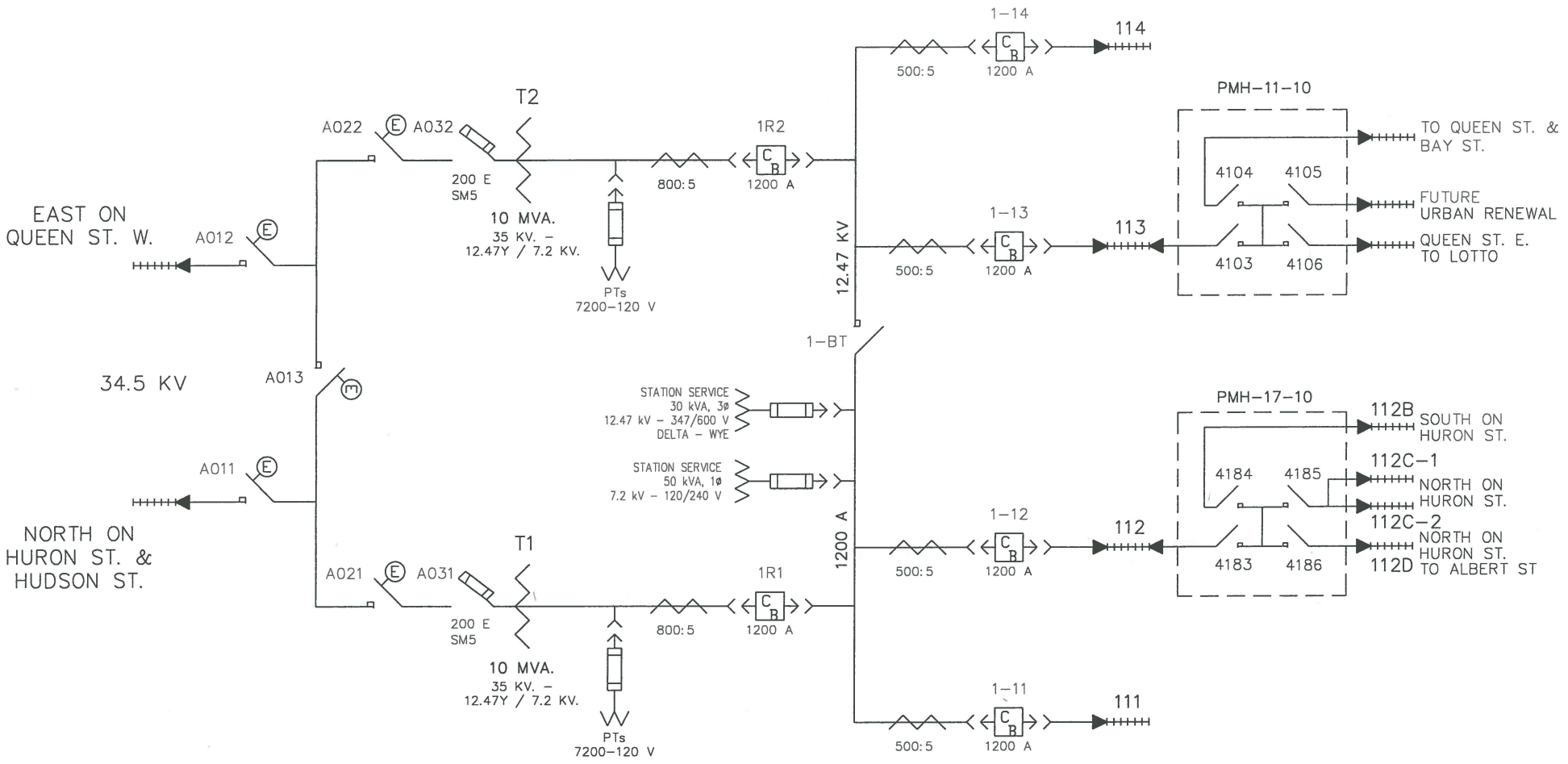
PUC Distribution has identified #6 copper overhead primary conductor as a safety hazard. It is classified by PUC Distribution as "restricted wire". Due to the nature of the conductor, it being small and constructed of copper, its tensile strength is known to degrade over years of use. Due to this, the conductor is prone to failure. Additionally, when the conductor fails, due to its nature, the fault current dissipates quickly and therefore may not trigger the nearest protective equipment. This may cause the conductor to remain energized in an area where staff or the public may come into contact. The conductor is replaced with #2ACSR, along with related insulation and aged infrastructure. The specific project areas covered by these projects have been identified as a high priority. Public and worker safety is the primary investment driver for this project.

Projects #13

This project involves renewal of underground distribution system assets by rebuilding of the existing underground distribution system currently operating at 4.2 kV. The underground lines will be rebuilt to operate at 12.5 kV upon completion of the projects. As detailed in PUC Distribution's asset condition assessment report, PUC Distribution has approximately 3km of 4.16/2.4kV underground circuits in service, all of which are at the end of their service life. Additionally, the 4.2 kV stations supplying these underground lines are also beyond their useful service life, requiring replacement. In an effort to streamline system voltages, three stations will be replaced with a single station producing 12.47/7.2kV distribution voltage. In order to accommodate these station rebuilds, all underground feeder cables operating at 4.2 kV will be converted to 12.5 kV. Power system reliability and public safety are the primary driver for these projects, although they will also help reduce operating costs when the two 4.2 kV stations are retired from service.

Appendix A

Single Line Diagrams



Scale: NTS

No.	Revision	Date	Initial
1	REVISED STATION SERVICE INFO, PTs, BORDER AND DRAWING NUMBER	MAY. 18/06	J.T.

PUC

SUBSTATION #1

SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: JAN. 26/88		
Checked by: K.B.	Date: MAY 18/06		
Approved by:	Date: May 25/06		
Drawing Number: A-ES01-04-001	Rev. 1		

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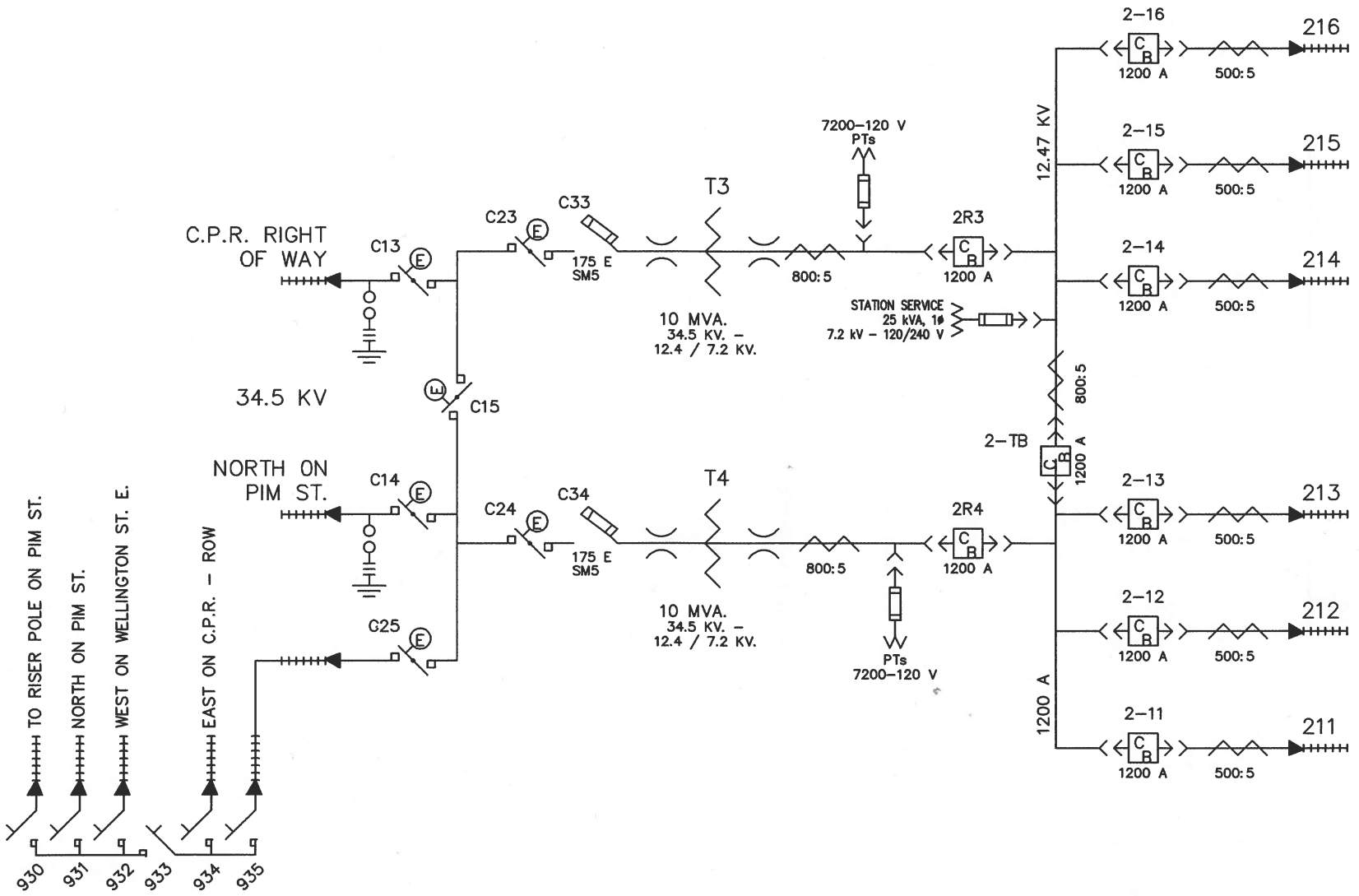


Scale: NTS

No.	Revision	Date	Initial
2	MOVED STATION SERVICE TO OTHER SIDE OF TIE BREAKER	OCT. 18/15	M.P.
1	REVISED BORDER AND DRAWING NUMBER AND ADDED STATION SERVICE.	MAY. 18/06	J.T.

PUC

SUBSTATION #2

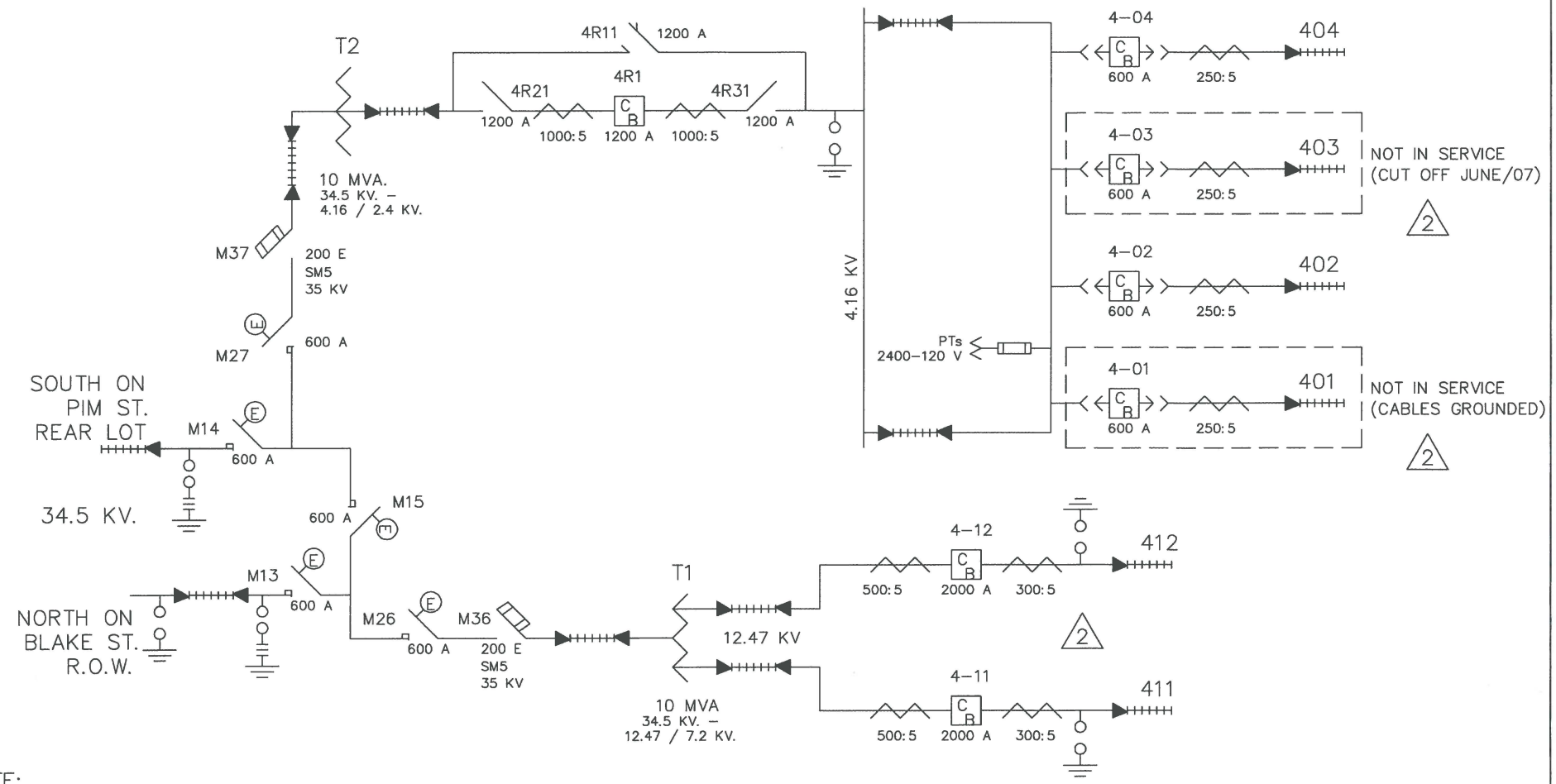
SCHEMATIC DIAGRAM

Drawn by: J.R. Date: JAN. 13/88

Checked by: K.B. Date: MAY 18/06

Approved by: Date: 2018/01/04

Drawing Number: A-ES02-04-001 Rev. 2



NOTE:

STATION SERVICE FED FROM CIRCUIT 411
AT POLE #12103.

Scale: NTS

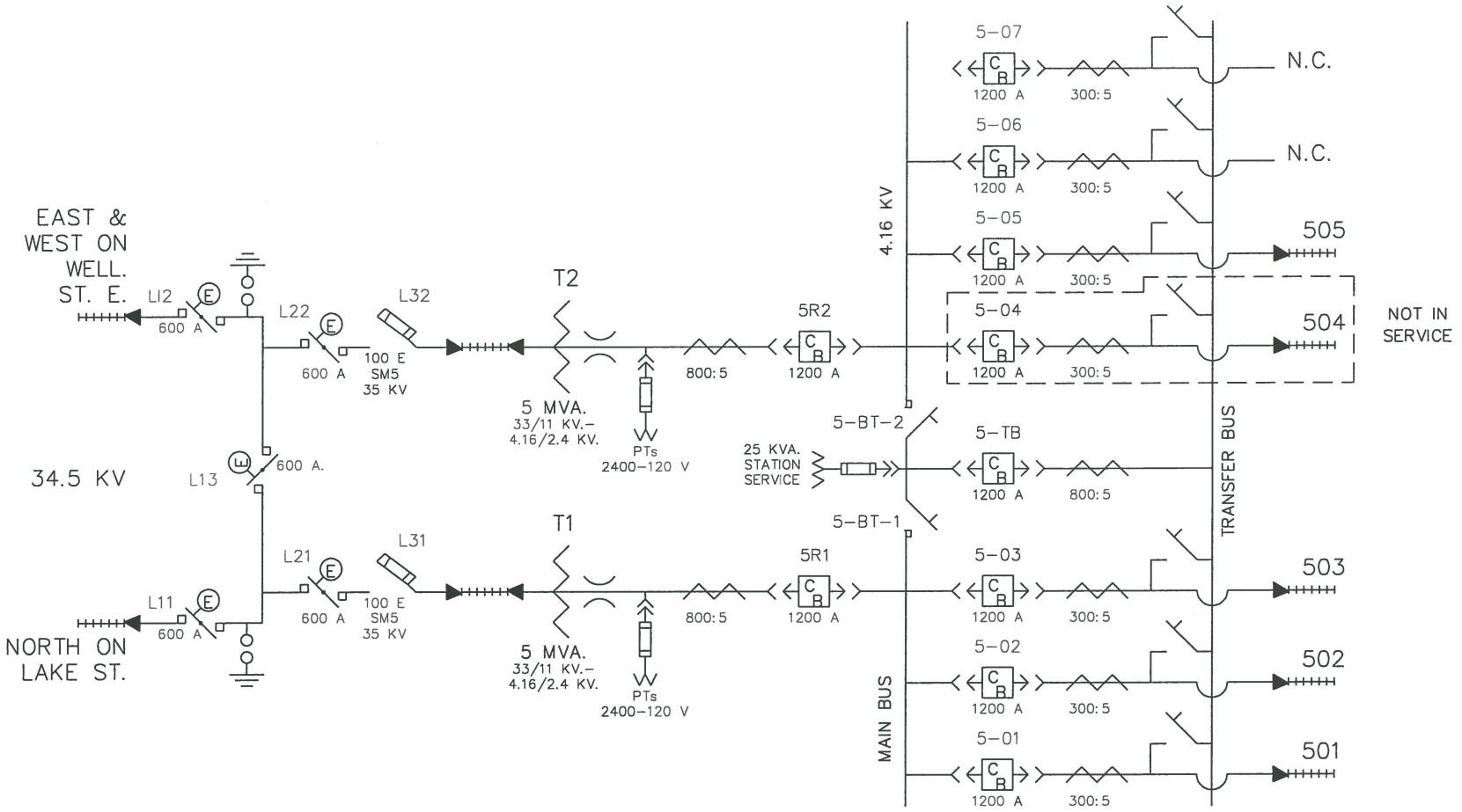
No.	Revision	Date	Initial
2	RELOCATED ARRESTORS AT CCTS. 411, 412. CCTS. 401 & 403 NOW N.I.S.	MAR. 9/16	J.T.
1	REVISED BORDER AND DWG. NUMBER. ADDED PTs AND STA. SERV. NOTE.	MAY 18/06	J.T.

PUC

SUBSTATION #4

SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date: 2016/03/09
Drawing Number: A-ES04-04-001	Rev. 2



No.	Revision	Date	Initial
1	REVISED BORDER AND DWG. NUMBER. REMOVED CCT. 504 FROM SERVICE.	MAY. 18/06	J.T.

PUC

SUBSTATION #5

SCHEMATIC DIAGRAM

Scale: NTS	
Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date: May 25/06.
Drawing Number: A-ES05-04-001	Rev. 1

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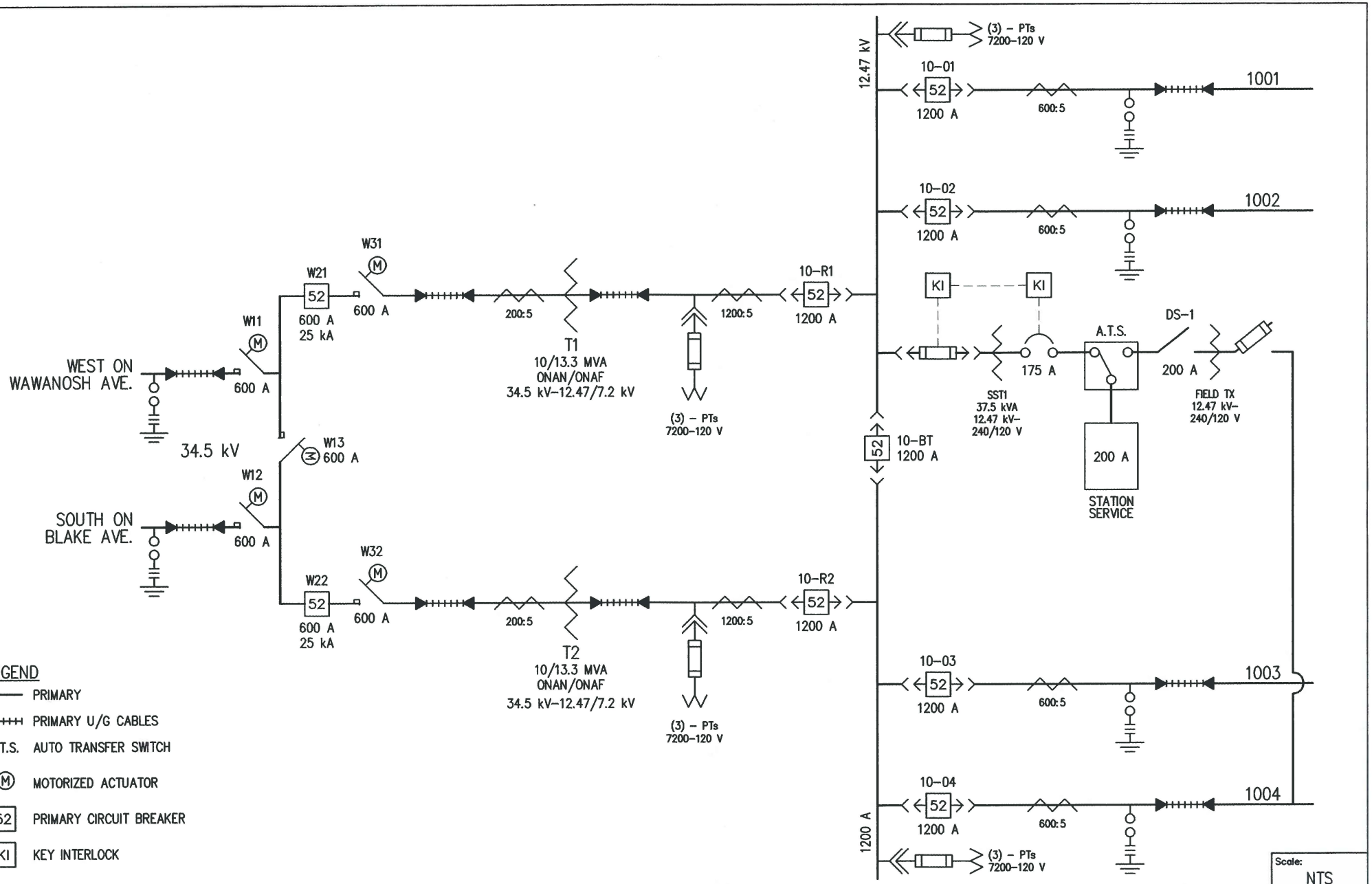


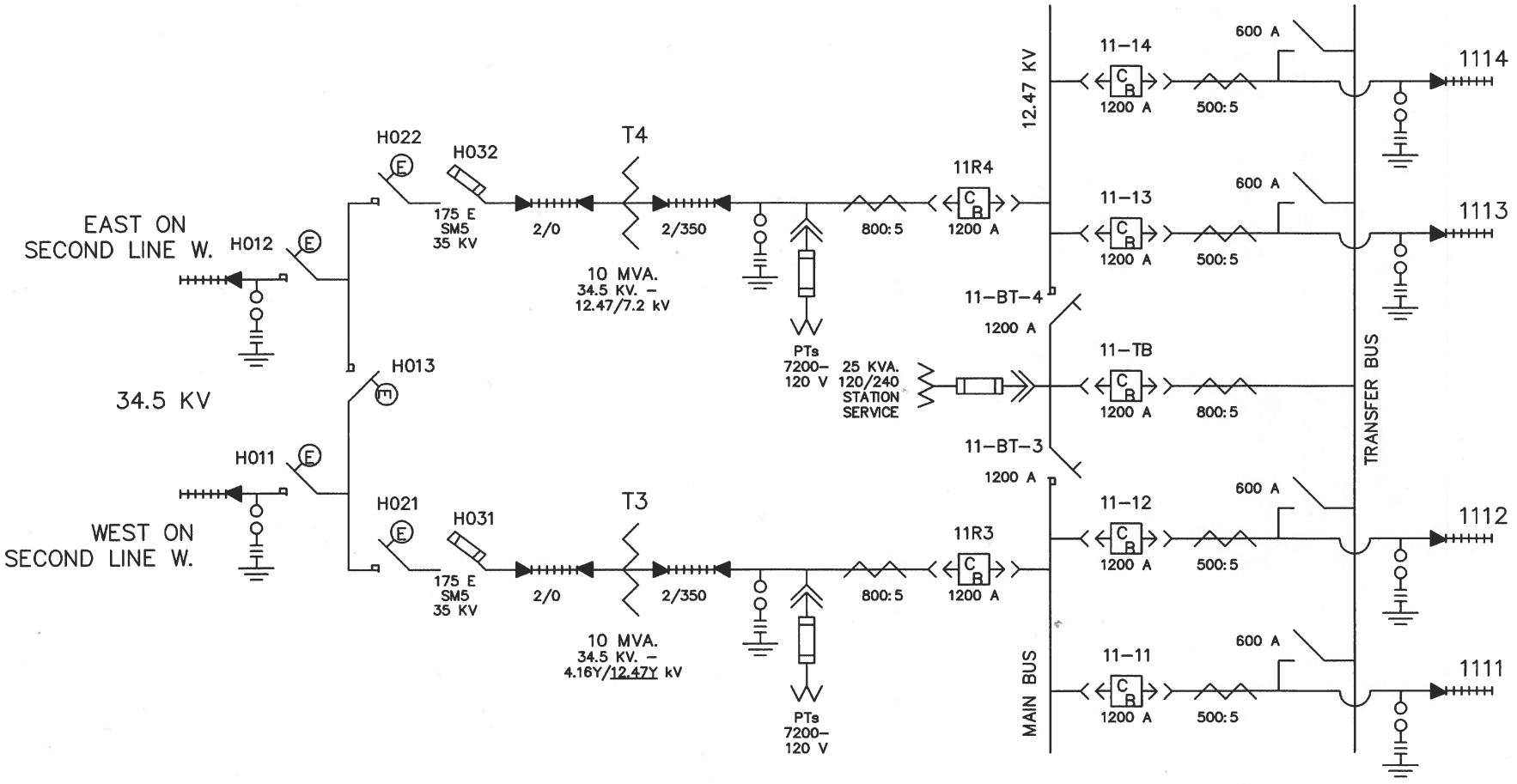
No.	Revision	Date	Initial
2	SUBSTATION REBUILT	NOV. 24/17	J.T.
1	REVISED INCOMING SOURCE AND VOLTAGE, BORDER, DWG. #, PTs AND STA. SERV.	MAY 18/06	J.T.

PUC

SUBSTATION #10

SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date: 2017/11/29
Drawing Number: A-ES10-04-001	Rev. 2
Scale: NTS	



Scale: NTS

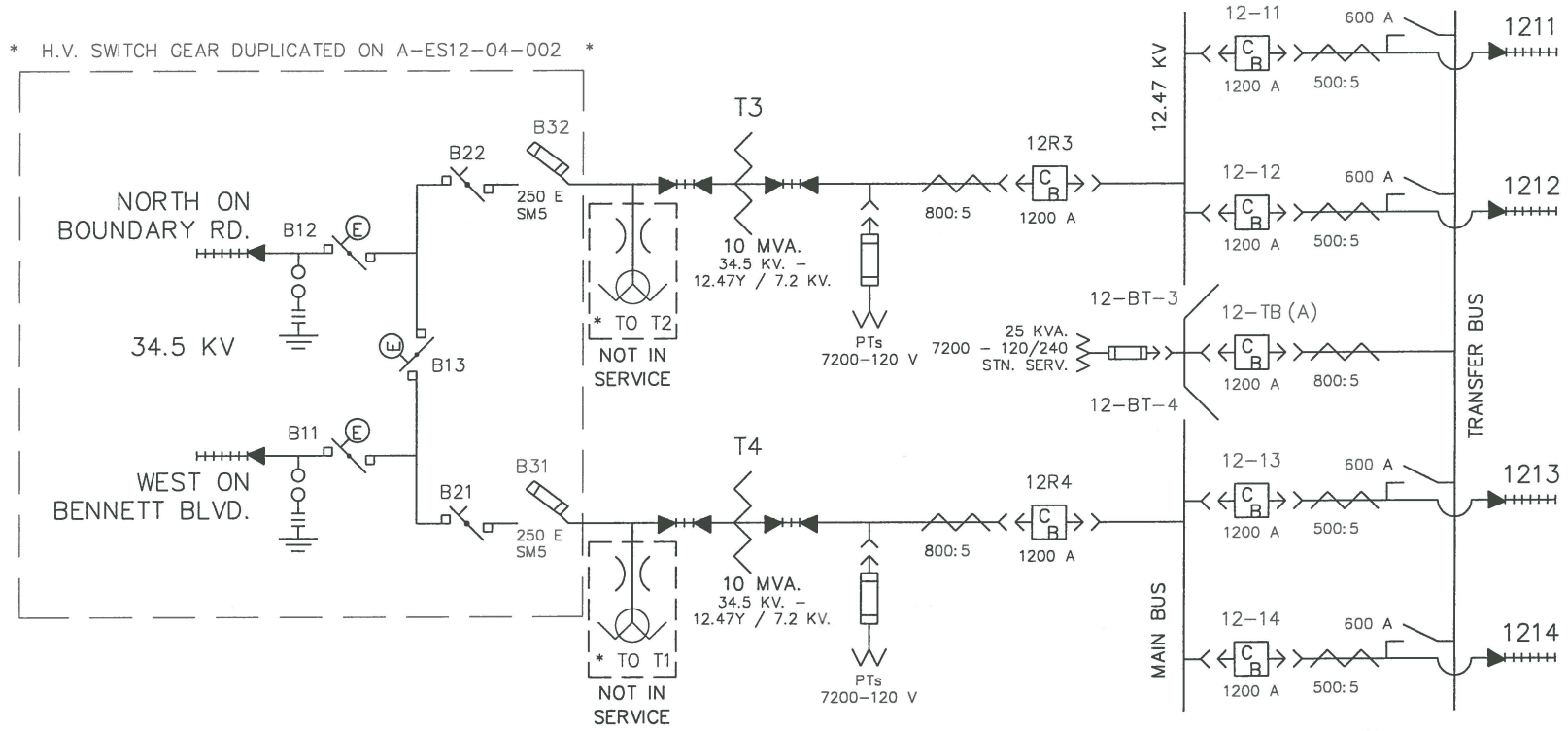
No.	Revision	Date	Initial
2	REVISED VOLTAGE RATING ON T3.	JAN. 4/18	J.T.
1	REVISED BORDER AND DWG NUMBER. REMOVED REFERENCE TO SUB. 6.	MAY 18/06	J.T.

PUC

SUBSTATION #11

SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: SEP. 11/86	
Checked by: K.B.	Date: MAY 18/06	
Approved by:	Date: 2018/01/24	
Drawing Number: A-ES11-04-001	Rev. 2	



No.	Revision	Date	Initial
1	REVISED BORDER AND DRAWING NUMBER. REMOVED T1 & T2 FROM SERVICE.	MAY. 18/06	J.T.

PUC

SUBSTATION #12

SCHEMATIC DIAGRAM 12.47 kV

Scale: NTS

Drawn by: J.R. Date: SEP. 11/86

Checked by: K.B. Date: MAY 18/06

Approved by: [signature] Date: May 25/06.

Drawing Number: A-ES12-04-001 Rev. 1

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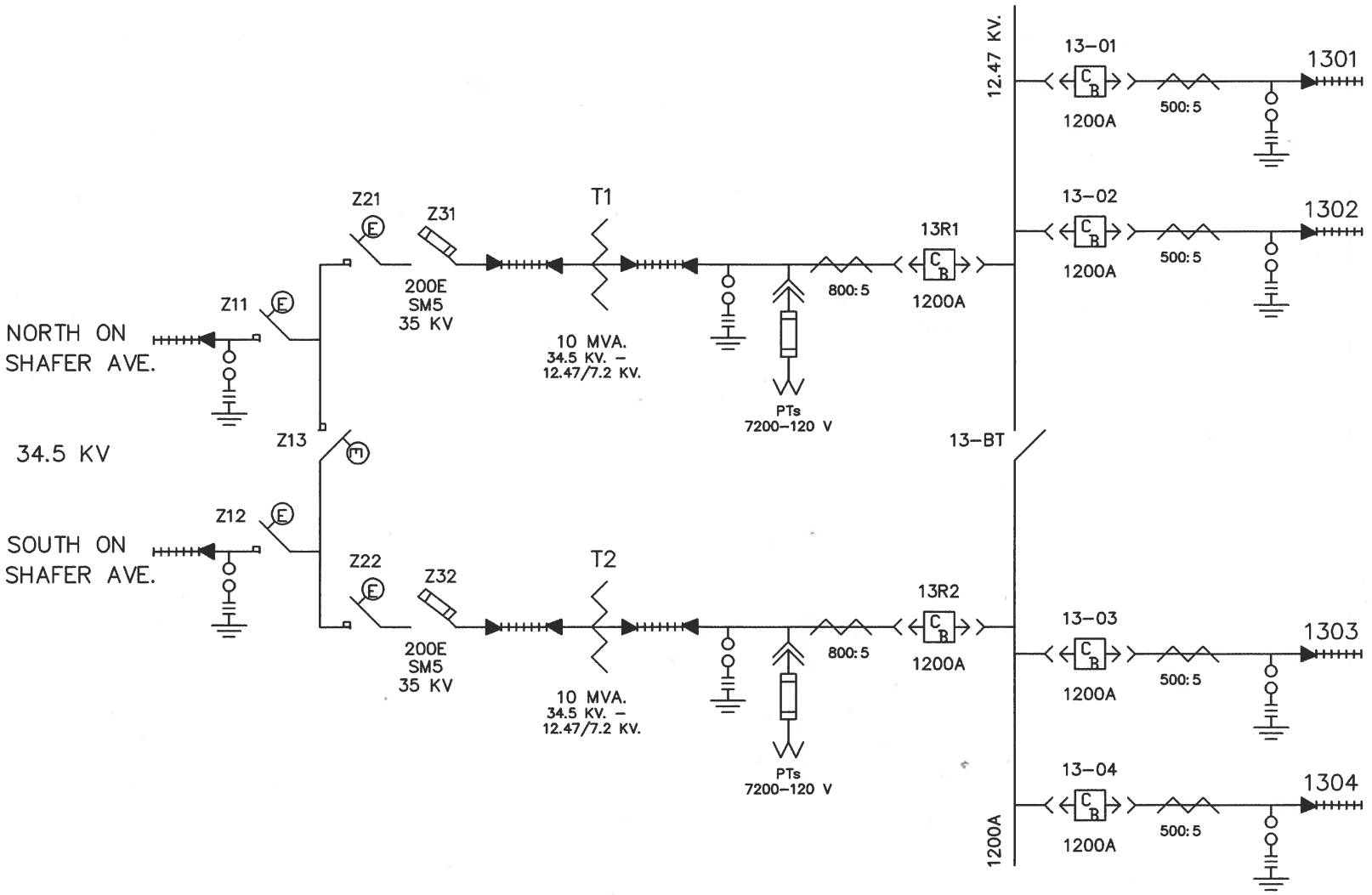


NOTE:
STATION SERVICE NORMALLY FED FROM CIRCUIT 1301
ON SHAFER AVE. TRANSFORMER LOCATED AT
INTERSECTION OF SHAFER AND BAINBRIDGE.

Scale: NTS

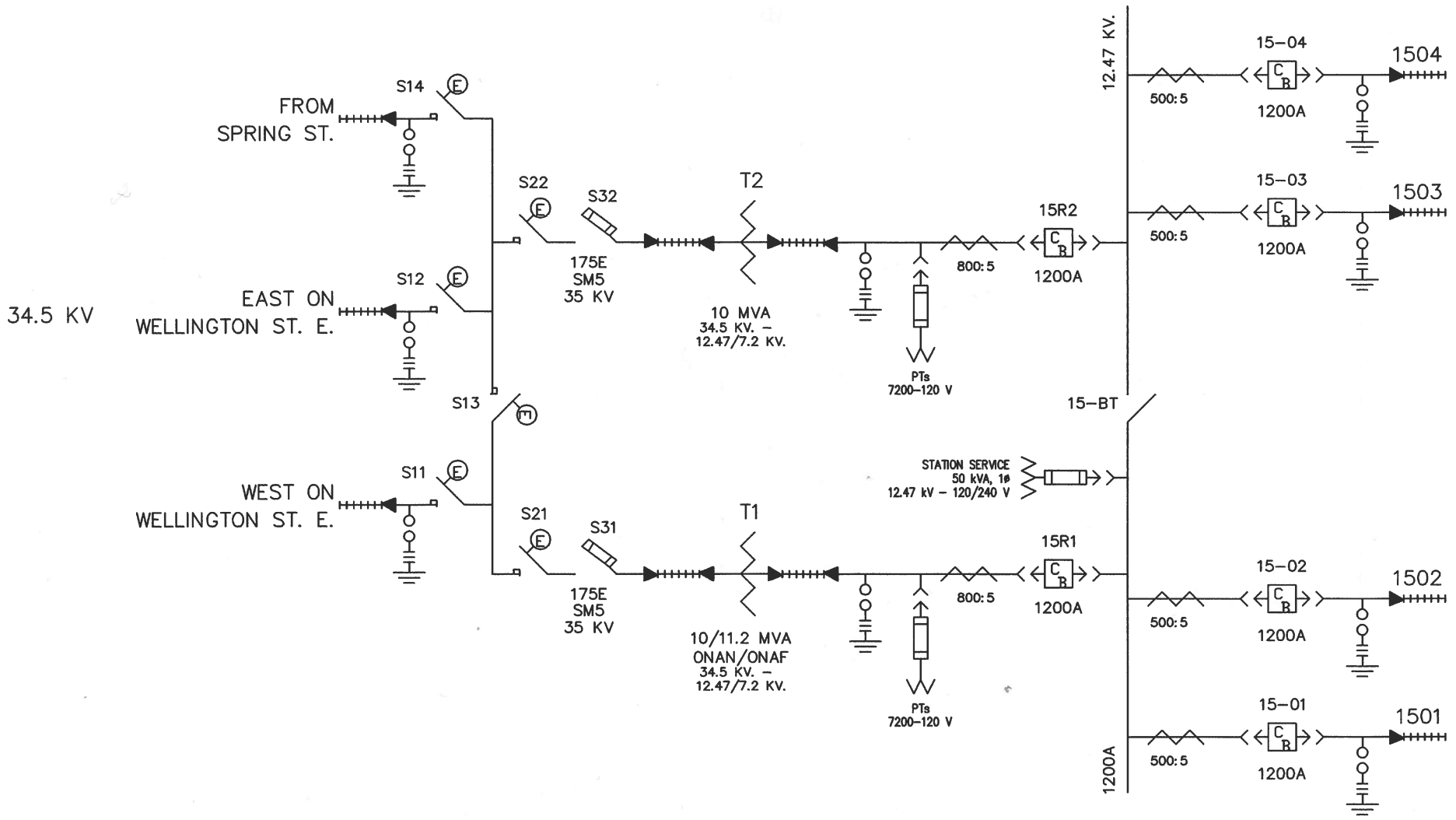
No.	Revision	Date	Initial
2	ADDED STATION SERVICE NOTE	JAN. 4/18	J.T.
1	REVISED BORDER AND DRAWING NUMBER	MAY 18/06	J.T.

PUC

SUBSTATION #13

SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: APR. 10/87
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date: 2018/01/04
Drawing Number: A-ES13-04-001	Rev. 2



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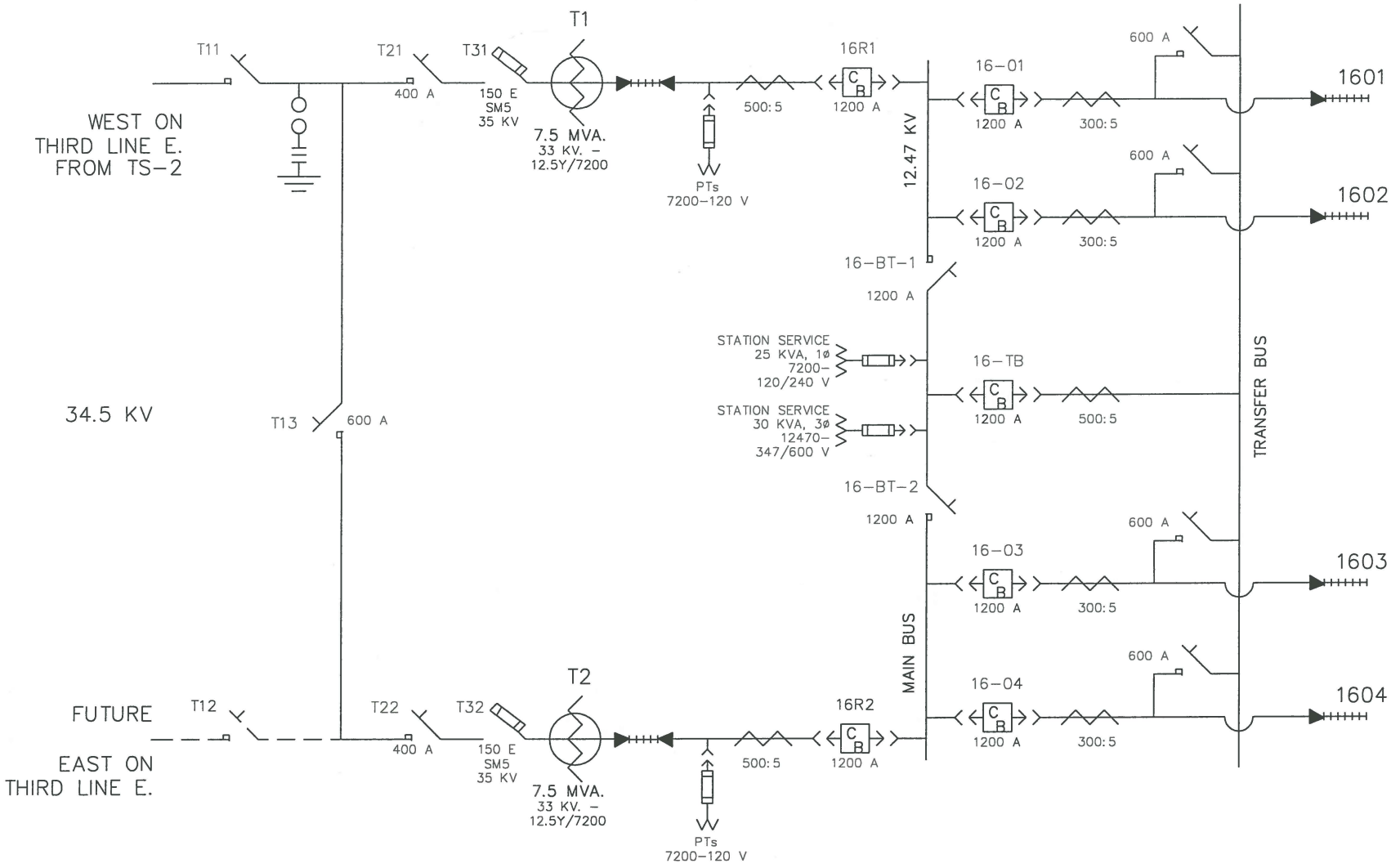
No.	Revision	Date	Initial
2	PLACED T1 IN SERVICE	FEB. 14/13	J.T.
1	REVISED BORDER & DWG No., ADDED STA. SERV. & REVERSED FEEDER CBs & CTs.	MAY. 18/06	J.T.

PUC

SUBSTATION #15

SCHEMATIC DIAGRAM

Drawn by: V.F.	Date: JUN. 15/95	
Checked by: R.H.	Date: FEB. 14/13	
Approved by:	Date: 2018/01/04	
Drawing Number: A-ES15-04-001	Rev. 2	



Scale: NTS

No.	Revision	Date	Initial
1	REVISED BORDER AND DWG. NUMBER. REVISED STATION SERVICE XFMRS.	MAY. 18/06	J.T.

PUC

SUBSTATION #16

SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: SEP. 11/86		
Checked by: K.B.	Date: MAY 18/06		
Approved by:	Date: May 25/06		
Drawing Number: A-ES16-04-001	Rev. 1		

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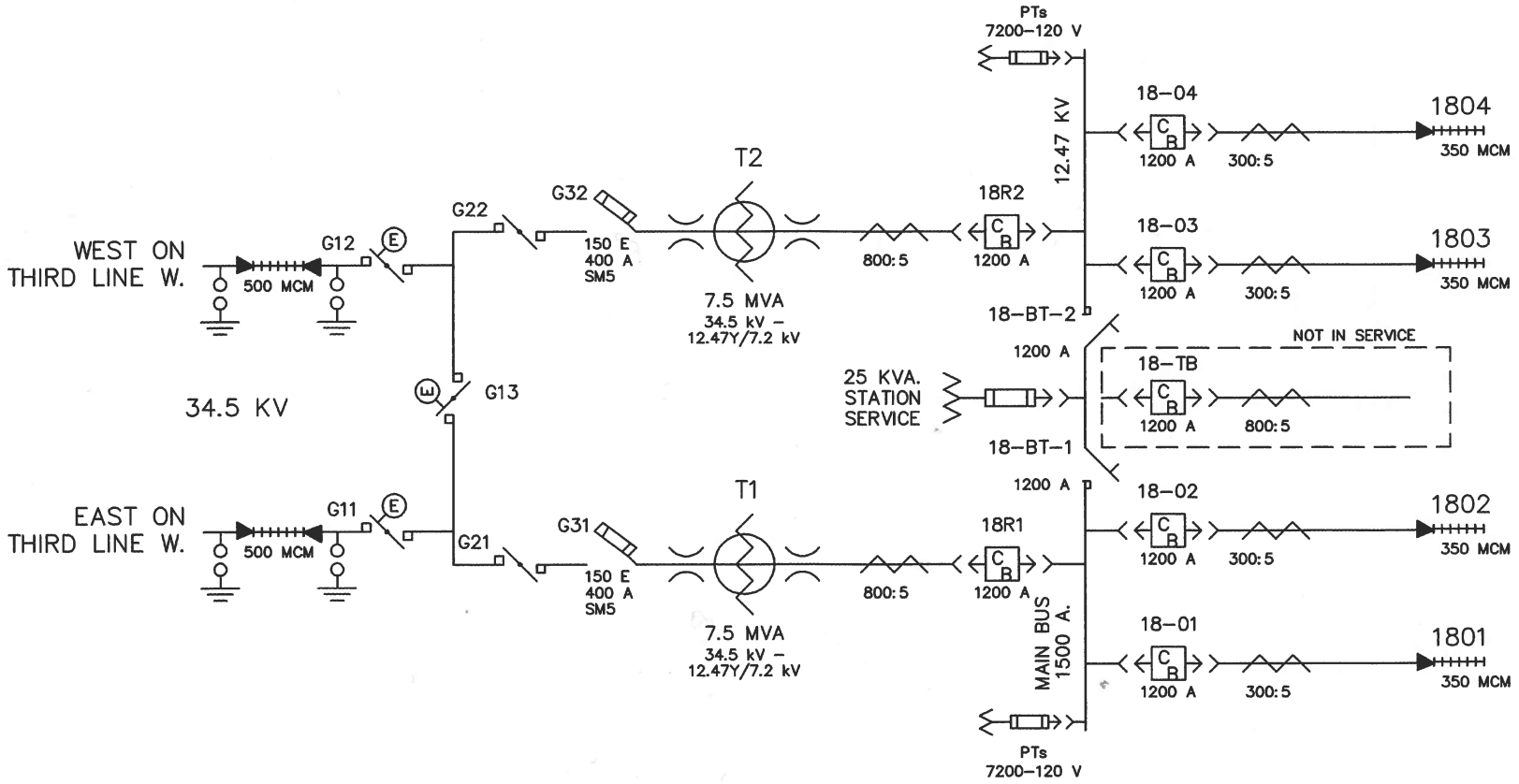

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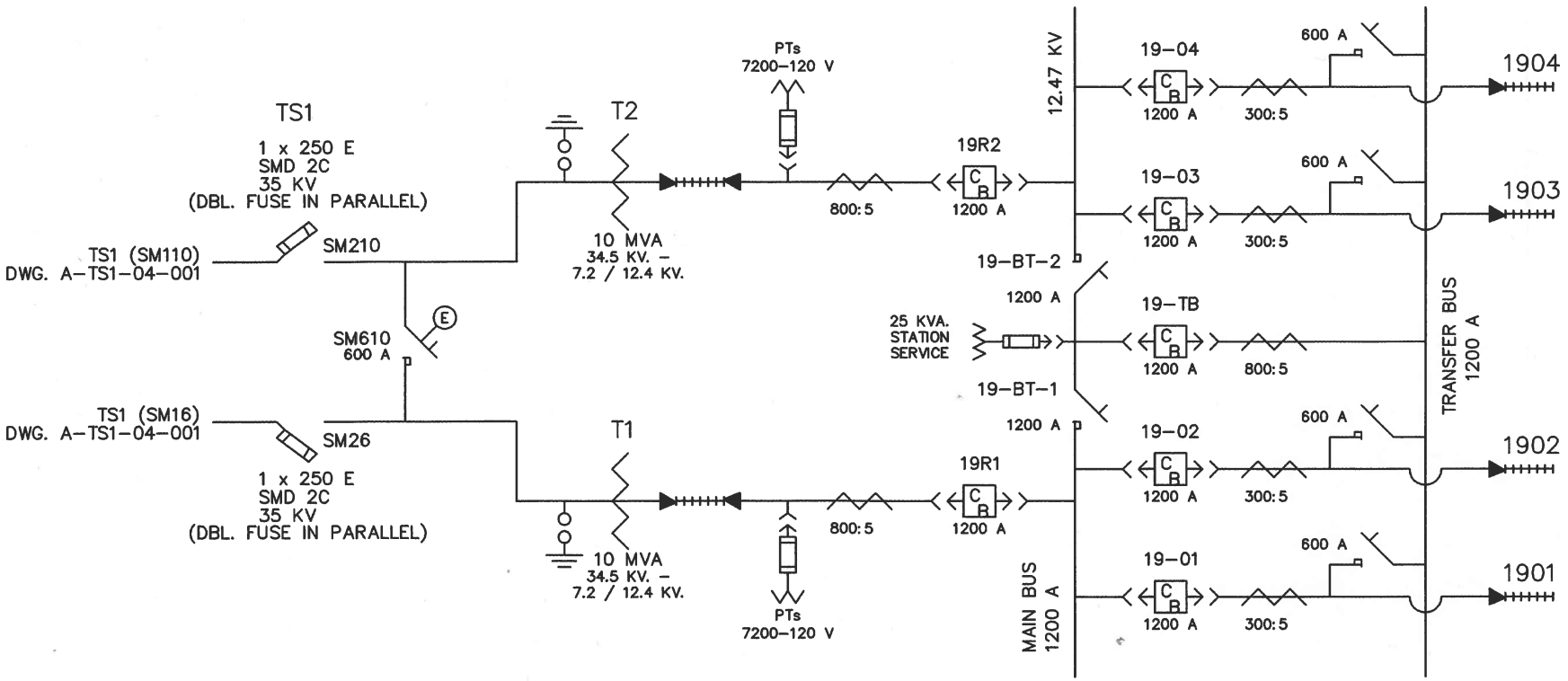
No.	Revision	Date	Initial
2	UPDATED TX RATINGS	JAN. 4/18	J.T.
1	REVISED BORDER AND DWG. No., REMOVED TRANSFER BUS AND SWITCHES.	MAY 18/06	J.T.

PUC

SUBSTATION #18

SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date: 2018/01/04
Drawing Number: A-ES18-04-001	Rev. 2



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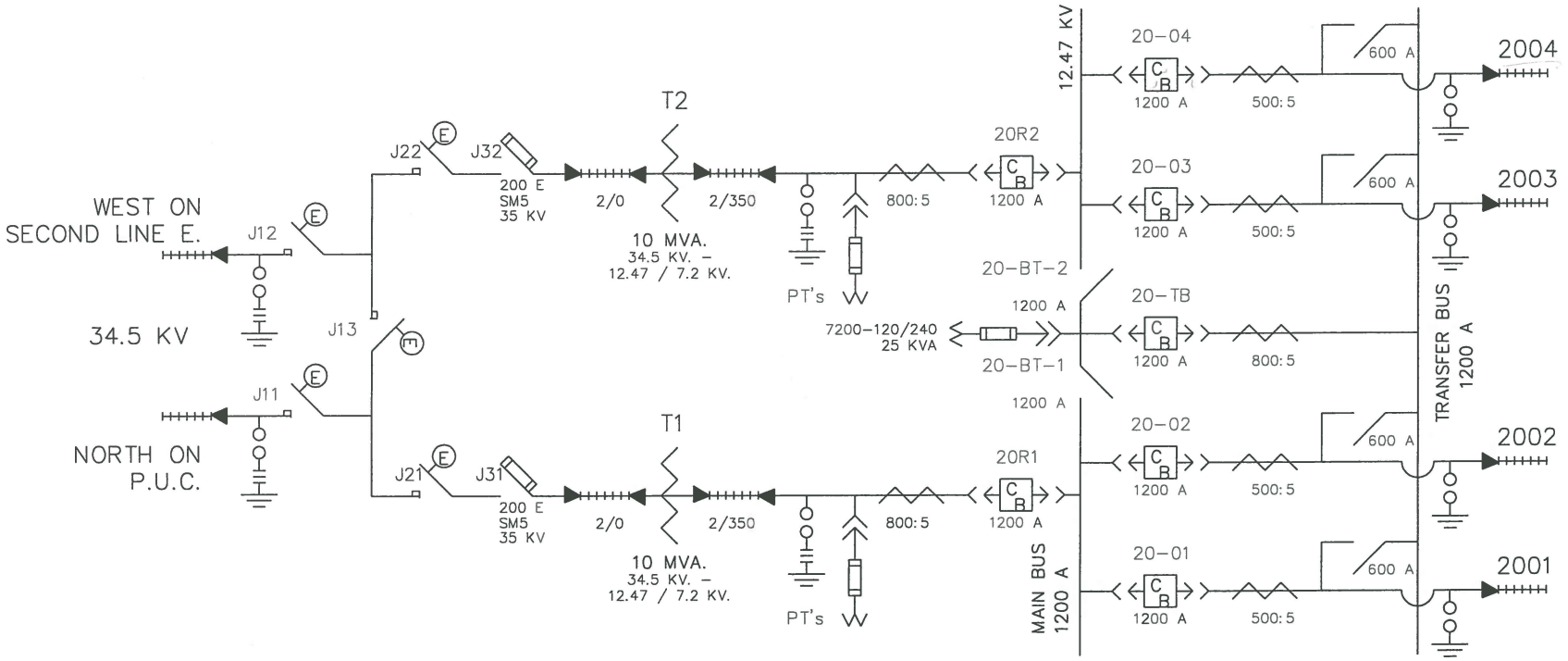
No.	Revision	Date	Initial
2	TS1 CONNECTIONS REVISED	JAN. 4/18	J.T.
1	REVISED BORDER AND DRAWING NUMBER.	MAY 18/06	J.T.

PUC

SUBSTATION #19

SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: JUN 18/86		
Checked by: K.B.	Date: MAY 18/06		
Approved by:	Date: 2018/01/04		
Drawing Number: A-ES19-04-001	Rev. 2		



Scale: NTS

1	REVISED BORDER AND DRAWING NUMBER.	MAY. 18/06	J.T.
No.	Revision	Date	Initial

PUC

SUBSTATION #20

SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 18/06
Approved by:	Date: May 25/06.
Drawing Number: A-ES20-04-001	Rev. 1

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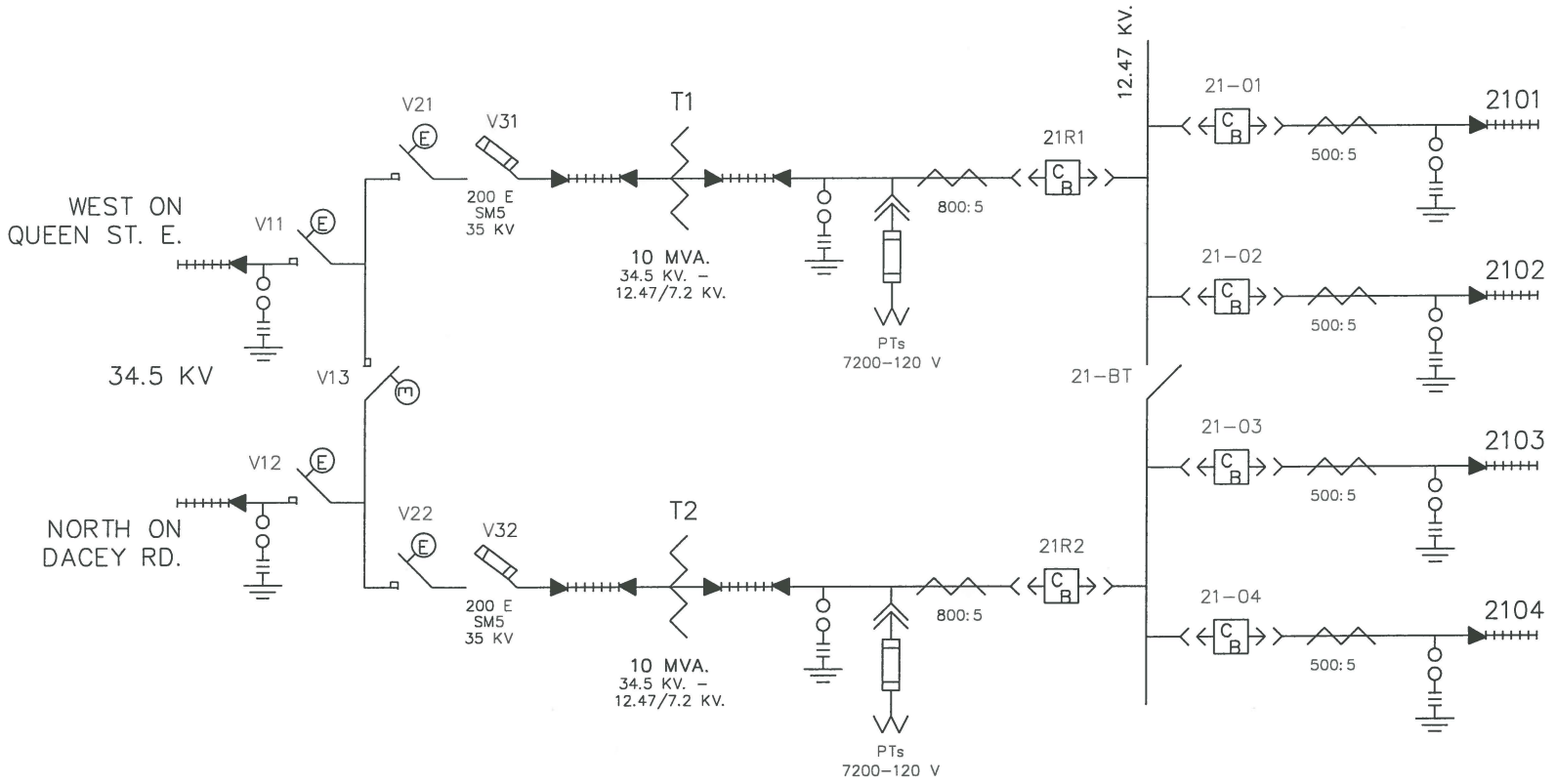

No.	Revision	Date	Initial
1	REVISED BORDER AND DRAWING NUMBER. ADDED PT RATINGS.	MAY. 18/06	J.T.

PUC

SUBSTATION #21

SCHEMATIC DIAGRAM

Scale: NTS	
Drawn by: J.R.	Date: SEP. 11/86
Checked by: K.B.	Date: MAY 18/06
Approved by: [signature]	Date: May 25/06.
Drawing Number: A–ES21–04–001	Rev. 1

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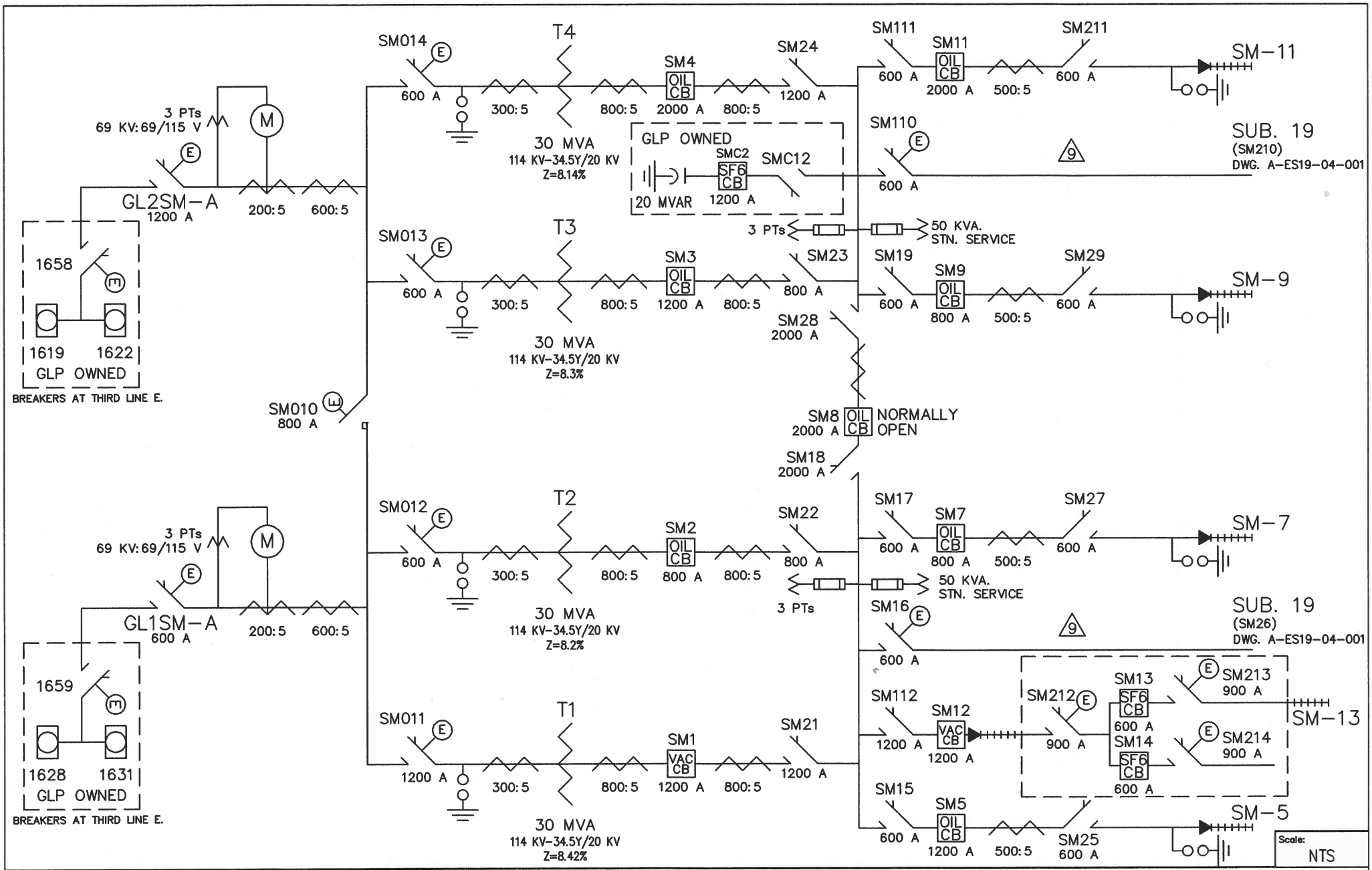


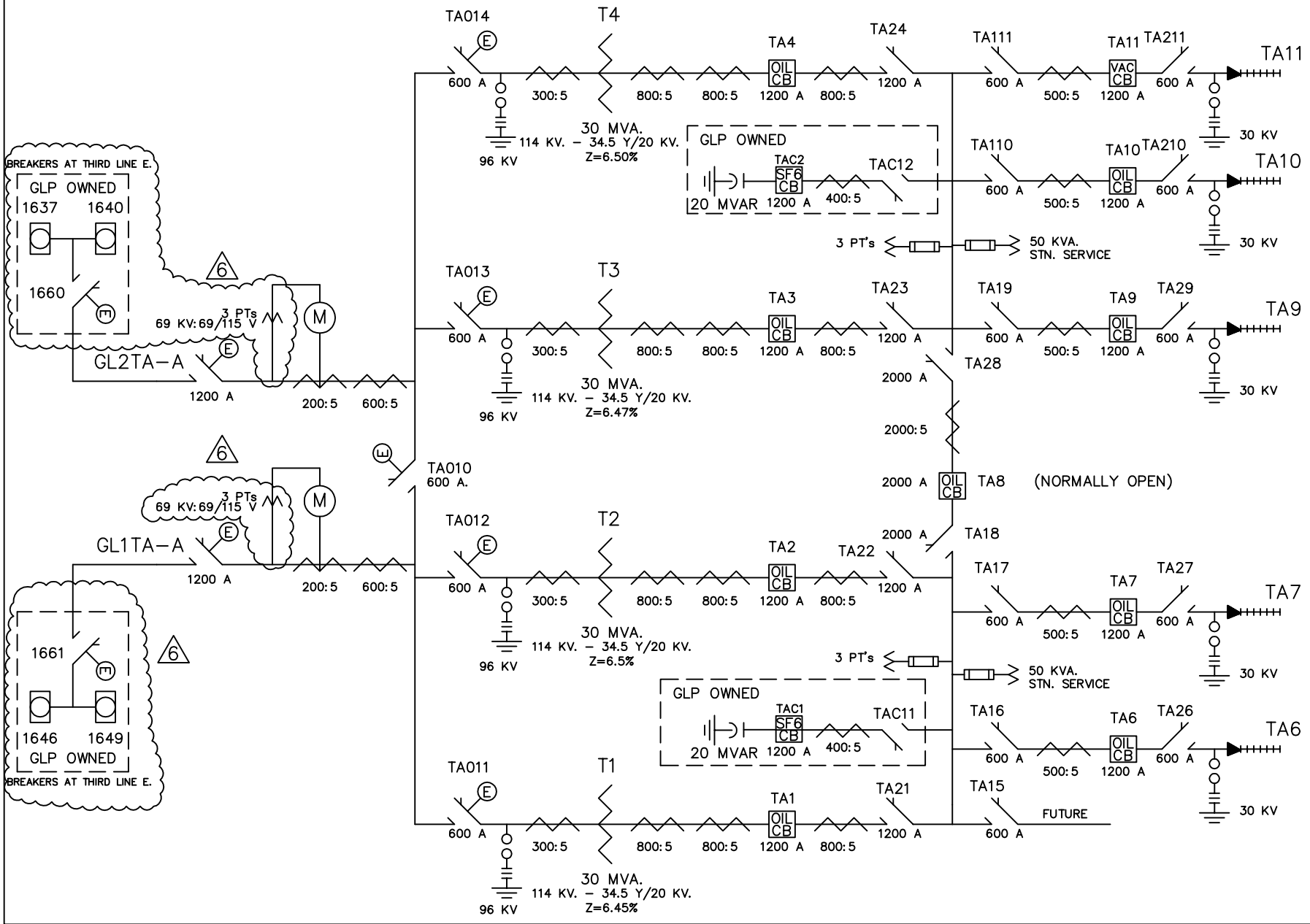
No.	Revision	Date	Initial
9	SUB 19 CONNECTIONS REVISED	JAN. 4/18	J.T.
8	ADDED CBs SM12, SM13 & SM14. REMOVED CB SMC1 & CAP. BANK.	JUL 12/17	J.T.
7	SWITCH REPLACEMENT PROJECT	JUNE 3/13	JFK
6	REVISED GLPT NOMENCLATURE AND ADDED PTs	FEB. 13/13	J.T.
5	REMOVED GROUND SWITCH AND ADDED WHOLESALE METERING	MAY 22/12	J.T.
4	REVISED RATING ON SM21	JUN 23/06	J.T.
3	REVISED RATINGS ON GL2SM-A, SM013, SM24, SM7, SM9 & SM610.	MAY 23/06	J.T.

PUC

TRANSFORMER STATION TS-1

ST. MARY'S TRANSFORMER STATION SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: SEP. 11/86
Checked by: M.P.	Date: JUL. 12/17
Approved by:	Date: 2018/01/04
Drawing Number: A-TS1-04-001	Rev. 9



Scale: NTS

No.	Revision	Date	Initial
6	REVISED GLPT NOMENCLATURE AND ADDED PTs	FEB. 13/13	J.T.
5	REVISED OIL CIRCUIT BREAKER CT RATIOS	MAY 31/12	J.T.
4	ADDED WHOLESALE METERING	MAY 22/12	J.T.
3	REVISED RATING ON TA15.	JUN 23/06	J.T.
2	REMOVED INCOMER CTs, REVERSED CTs & CBs ON CAP BANKS, ADDED TA15 & REVISED TA21	MAY 23/06	J.T.
1	REVISED DWG. # & RATINGS FOR TAC1, TAC2, TA21, TA22 AND TA24	APR. 18/06	J.T.

PUC

TRANSFORMER STATION TS2

TARENTORUS TRANSFORMER STATION SCHEMATIC DIAGRAM

Drawn by: J.R.	Date: SEP. 11/86
Checked by: R.H.	Date: FEB. 13/13
Approved by:	Date:
Drawing Number: A–TS2–04–001	Rev. 6

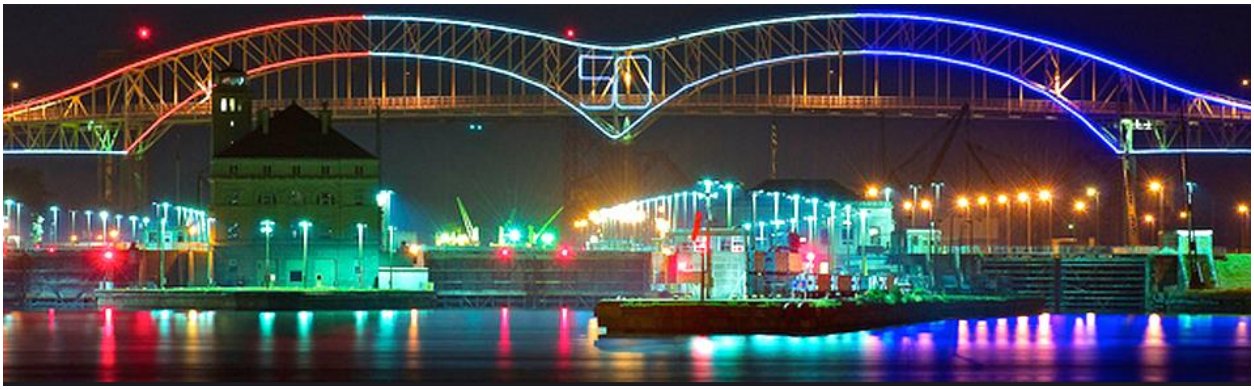
Appendix B

Asset Condition Assessment & Asset Management Plan

Asset Condition Assessment and

Asset Management Plan 2017 – 2021

PUC Distribution Inc.



September 2016

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EXECUTIVE SUMMARY

This report summarizes the results of the Asset Condition Assessment study performed during the second and third quarter of 2016, by METSCO Energy Solutions Inc. on behalf of PUC DISTRIBUTION Inc. The study was performed with the objective of determining the current condition of fixed assets to identify the assets that present unacceptably high risk of failure in service and develop an investment plan for asset renewal, to mitigate the risk.

Decisions involving investment into fixed assets play a major role in determining the optimal performance of a distribution system. A majority of the investments in fixed assets are triggered by either declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets. In either case, investments that are either oversized or made too far in advance of the actual system need result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement are planned and implemented based on a "just-in-time" approach. The risk based Asset Management Strategy, on which this investment plan is based, determines the risk of assets' failure in service, by taking into account assets' service age as well as current asset condition based on test results and inspections.

The study reveals that the power transformers and switchgear employed in PUC DISTRIBUTION's step-down stations present the highest risk of failure in service. As detailed in Section 4.1, out of 39 transformers employed at PUC DISTRIBUTION's stations, 20 have been determined to be in "poor" or "very poor" condition. Station switchgear has also been determined to be in "poor" or "very poor" condition at 14 of the 17 stations, currently supplying PUC's distribution system.

Since the in-service failure of power transformers and switchgear in step-down stations has the largest impact on power supply security and reliability, a long term proactive program is recommended to gradually reconstruct all of the stations, determined to be in poor or very poor condition. In the absence of a proactive plan for renewal, aging infrastructure assets employed at stations and particularly those employed at 115/34.5 kV stations, present an elevated risk of a cascaded equipment failure event, which could potentially lead to a black out of an extended duration and therefore, both of the 115/34.5 kV transformer stations (TS-1 and TS-2) will require rebuild during the next five to ten years. However, to maximize the benefit/cost ratio of this major investment, significant front-end planning and engineering is required to successfully implement the rebuild of these stations. Therefore, we are recommending a planning/engineering study be commissioned to review all practical development options and identify the optimal option for implementation.

For the 34.5 / 12.47 kV stations, we recommend at least two stations be included in the next five-year plan for rebuild, based on the condition of power transformers, switchgear and auxiliary equipment. Although the power transformers and switchgear at each of the three 4 kV distribution stations are also currently in poor and very poor condition, no provision is made in the investment plan for renewal of these stations, as these are recommended to be retired from service.

In case of overhead lines, assets posing a high risk of failure in service can be grouped into three main categories: (a) structurally weak wood poles, (b) copper conductors of #6 AWG cross-section (restricted conductor) and (c) porcelain cut-outs and insulators. Wood poles experience reduction in their structural strength with age, due to a number of factors, including wood rot, termite or wood pecker damage and mechanical damage during storms or vehicular accidents. Poles with reduced strength are identified through non-destructive in-situ testing and when the strength of a pole is determined to fall below its design load, it is identified for replacement. A significant number of overhead lines employ restricted conductors, which have a history of failures in service, due to reduced tensile strength, bringing live conductors down and posing a serious safety risk to public. PUC DISTRIBUTION has been actively rebuilding lines, replacing the restricted conductor during the past five years. This program is recommended to be expedited with the objective of removing all restricted conductor from existing lines during the next 10 years. PUC DISTRIBUTION has been gradually replacing porcelain cut-outs and insulators, which are also known to experience failures in service, during the past five years and this program is scheduled to be completed during 2016. In addition to the above indicated renewal initiatives, some of the existing 4 kV lines will need to be rebuilt through implementation of the voltage upgrade program and some additional lines experiencing high failure rates due to advanced asset age will also require re-construction.

On the underground distribution system, approximately 25% of the cable circuits have reached a service life of greater than 40 years, which is the typical useful life for this type of cable. There are no practical tests available, which could be economically performed in field to accurately assess the remaining useful life of cables, however, cross-linked polyethylene (XLPE) insulated cables generally begin to experience an increase in failure rates when they get past 40-year service age. Therefore, the investment plan includes provision for selectively replacing and rejuvenating cables (through insulation injection where economical) in subdivisions, experiencing high cable failure rates. PUC DISTRIBUTION's underground system employs concrete chambers for various functions, including pre-cast pull-boxes, poured-in-place manholes, concrete vaults and bases for switchgear and K-bar junctions. Approximately 23% of the chambers are currently more than 50 years old. Physical inspections of the concrete structures indicate, a large percentage of these old vintage chambers are functionally obsolete and some are unsafe and will need to be rebuilt. After reconstruction, these vaults should be converted to pads to support pad mounted equipment, mounted above grade. The investment plan also includes provision for replacement of a small number of pad-mounted switchgear and k-bar junction boxes, that are determined to be near the end of their service life.

For distribution transformers, PUC DISTRIBUTION employs a "run-to-failure" strategy and due to the relatively low impact of transformer failures on reliability, this strategy serves well for pole mounted and pad mounted transformers and it is also in line with all other LDCs. However, because vault mounted transformers are not generally replaced with the same type of transformer upon failure, some degree of pre-planning is required to replace these with pad mounted transformers. Therefore, a proactive program is required to replace the submersible transformers with pad mounted transformers.

A vast majority of PUC DISTRIBUTION's electric meters were installed in 2009 and have a seal year of 2019. In order to confirm accuracy of these meters, sample batches of revenue meters will require testing in 2019, in accordance with Measurement Canada's guidelines to acquire an extension of meter seals for 8 more years. To facilitate this, PUC DISTRIBUTION will need to purchase

approximately 400 1-phase meters and approximately 50 3-phase meters. In addition to the above, spare revenue meters would be required to replace meters that fail in service.

An estimate of the overall investment level required to implement the asset renewal program recommended in this report is summarized below. The cost estimates were prepared based on 2016 costs and the costs for future years were projected based on annual inflation rate of 2%.

Asset Renewal	2017	2018	2019	2020	2021	Five Year Total
Total Capital Investment Required	$ 4,088,114	$ 8,497,108	$ 4,465,516	$ 4,510,663	$ 9,062,246	$ 30,623,646
Capital Investment Requirement by Excluding Expenditure into Stations	$ 3,862,898	$ 3,940,156	$ 4,018,959	$ 4,099,338	$ 4,181,325	$ 20,102,677

Implementation of the proposed investment plan for asset sustainment would result in an average annual expenditure of $6,124,729.

1 INTRODUCTION

This report summarizes the results of the Asset Condition Assessment study performed by METSCO Energy Solutions Inc. (METSCO) on behalf of PUC DISTRIBUTION Inc. (PUC DISTRIBUTION) during the second and third quarter of 2016. The study was performed with the objective of establishing the health and condition of fixed assets to identify those assets that present unacceptably high risk of failure in service and to develop an investment plan for asset renewal to mitigate the risk.

This report covers the following assets:

a) Power transformers, switchgear, auxiliary equipment, buildings, fences and ground grids employed at Transformer Stations (TS) and Distribution substations
b) Overhead distribution lines;
c) Underground distribution system;
d) Distribution transformers; and
e) Revenue meters.
f) Facilities (office building)

The capital investment plan provided in this report covers the capital expenditure needed for sustainment of existing assets. Expenditure requirements for system growth and new services are not included in this report but these will be included in the Distribution System Plan, based on the anticipated number of requests for new services and load growth.

The report is organized into six (6) sections including this introductory section. Section 2 describes the general principles of the risk based asset management strategy to achieve optimal operation of the distribution grid. Section 3 describes the methodology for ranking and benchmarking the health of assets. Section 4 documents the results of asset condition assessment exercise and Section 5 presents the capital investment plan for renewal and replacement of assets found in poor or very poor condition. Section 6 reviews the preventative maintenance program.

2 STRATEGIC MANAGEMENT OF DISTRIBUTION FIXED ASSETS

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. A majority of the investments in fixed assets are triggered by either declining performance in the areas of supply system reliability, power quality or safety; or increasing operating and maintenance costs associated with aging assets; or anticipated growth in demand requiring capacity upgrades. In either case, investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investment not made on time when warranted by the system needs raise the risk of performance targets not being achieved and would also result in non-optimal operation. Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a "just-in-time" approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

A risk based Asset Management Strategy, therefore, determines the risk of assets' failure in service, based on the condition of the assets, which is commonly measured with the help of a yard stick of "Asset Health Indices", and computes the valuation of the risk based on the consequences of assets' failure and identifies the optimal risk mitigation alternative through an evaluation of all available options. Asset management covers the full life cycle of a fixed asset, from preparation of the asset specification and installation standards - to the scope and frequency of preventative maintenance during the asset's service life – and finally to the determination of the assets end-of- life and retirement from service. At each stage of an asset's life cycle, decisions are made to achieve the right balance between achieving maximum life expectancy, highest operating performance, lowest initial investment (capital costs) and lowest operating costs. The best-in-class asset management strategies employ integrated processes that allow optimal levels of financial and operating performance to be achieved, using transparent and objective criteria that can easily be audited and inspected by regulators.

PAS-55, a specification for asset management, was developed by the British Standards Institute (BSI) and offers one of the best-in-class strategies for risk management associated with fixed assets of electricity distribution systems. To be compliant with the PAS-55 asset management standard, the asset management approach must contain the essential elements documented in Figure 2.1.

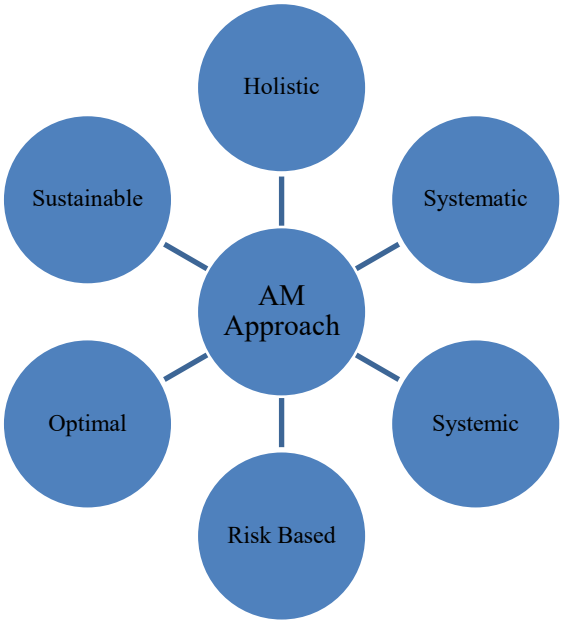

Figure 2-1: Essential Elements of Asset Management Strategy

The overarching objective is to develop capital and preventative maintenance investment plans, which could be implemented over a period of five to ten years to achieve optimal system performance by placing appropriate weights on stakeholder objectives and performance requirements, as shown in Figure 2-2.

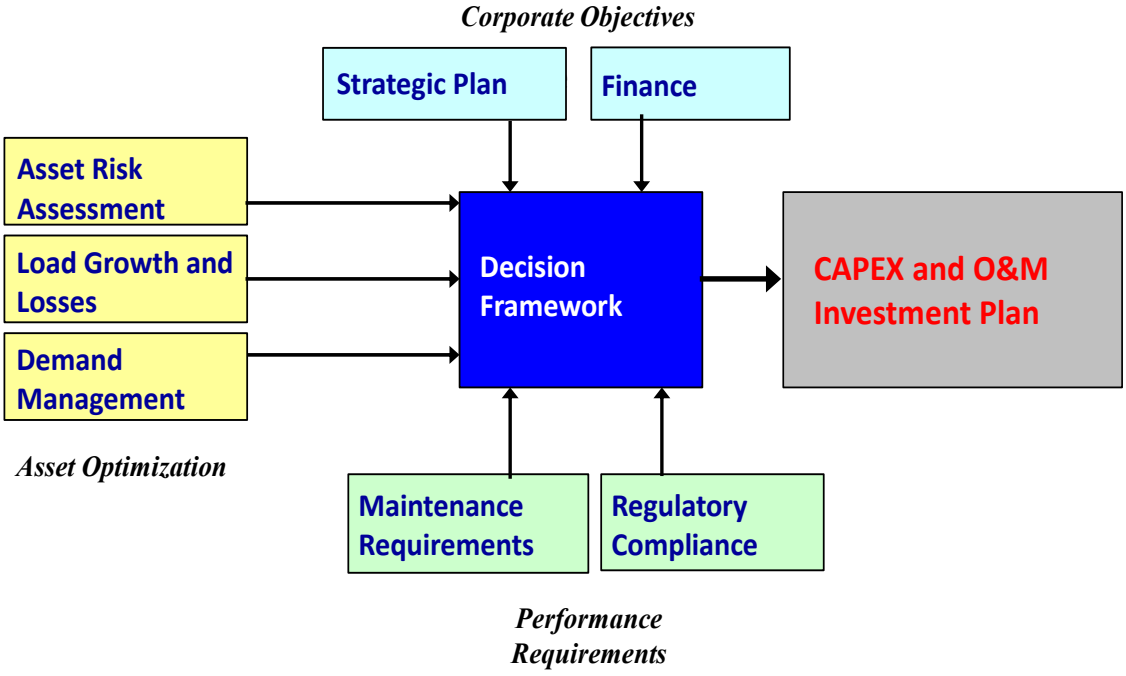

Figure 2-2: Multi-Prong Decision Framework

For regulated transmission and distribution (T&D) businesses, the key considerations in development of a Strategic Asset Management Plan include:

a) Regulatory Compliance
b) Public and Employee Safety
c) Operating Efficiency
d) Reliability and Supply System Security
e) Customer Service Quality
f) Getting Full Life out of Assets
g) Minimizing Asset Life Cycle Costs
h) Minimizing Risk of Premature Failures
i) Minimizing Environmental Risks

Figure 2-3 shows the basic decision support model employed under a risk based strategy. The timing and size of investments are selected to minimize the "Total Cost" of risk and risk mitigation initiatives.

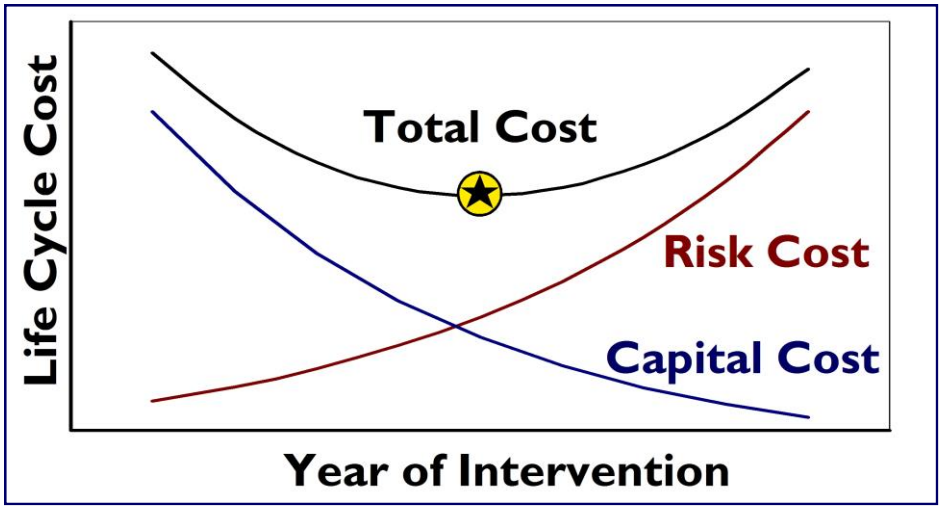

Figure 2-3: Risk Based Decision Support System

Figure 2-4 summarizes a practical matrix to sift through a large number of assets, typically employed on T&D systems to objectively identify assets that present the highest risk of in-service failures so that the investments could be targeted into assets that present the highest risk. Numeric health indices, typically normalized to a scale of 100, are used to express the health and condition of assets, as shown in Figure 2-5 and this allows separation of the assets in good condition that require minimal risk mitigation from those in poor condition, requiring a higher level of investments. This exercise allows development of an investment plan for implementation over a 5 year period.

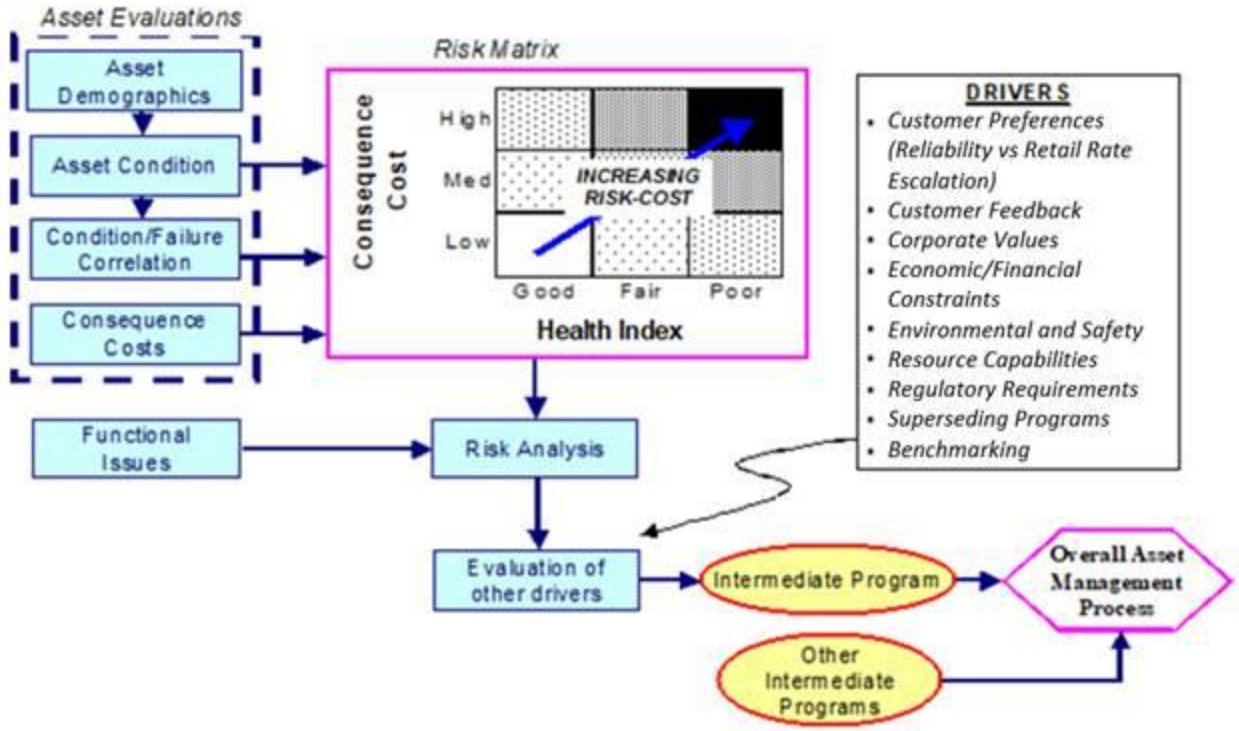

Figure 2-4: Model to Identify Assets with Highest Risks

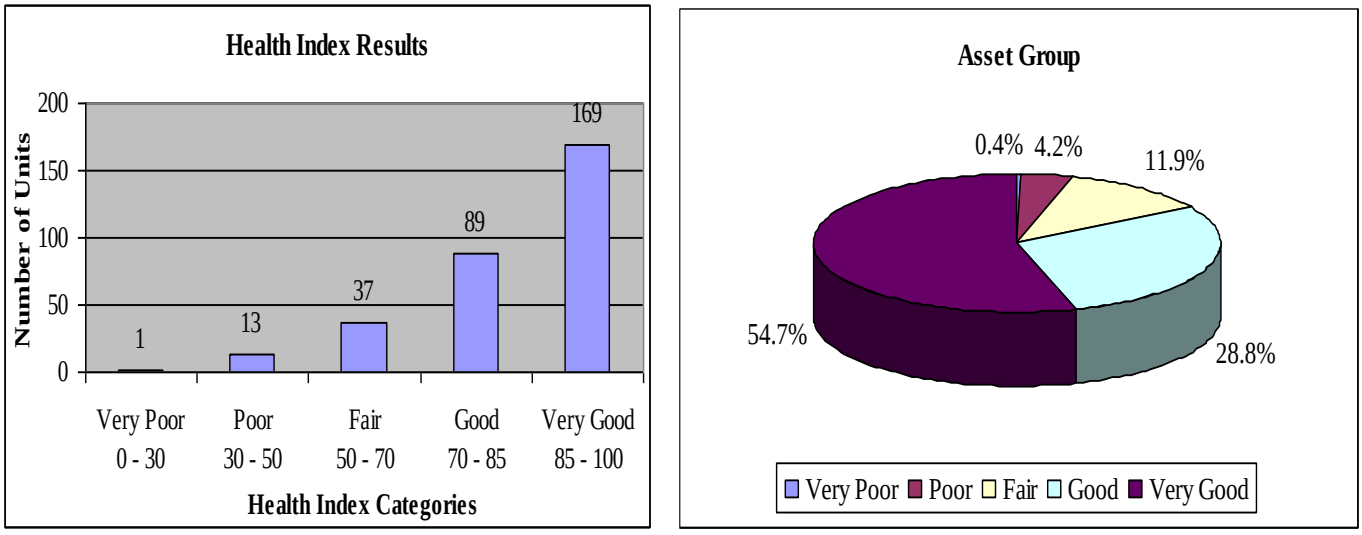

Figure 2-5: Graphs to Identify Assets with Highest Risks

3 ASSET CONDITION ASSESSMENT METHODOLOGY

This section describes in detail an asset condition assessment methodology for different categories of fixed assets employed on the distribution system. Adoption of this methodology would require periodic asset inspections and recording of their condition to identify the assets most at risk, requiring focused investments into risk mitigation.

Asset Condition Assessment methodologies are described below for the following distribution system asset categories:

a) Substations
b) Overhead Lines
c) Underground Lines
d) Distribution Transformers (pole mounted, pad mounted, and submersibles in underground vaults)
e) Distribution Switches and Fused Cut-outs
f) Low Voltage system

Asset health condition indicators and tests shown in the tables are weighted based on their importance in determining the assets end-of-life. For purposes of scoring the condition assessment, the letter condition ratings are assigned the following numbers shown as "factors":

A= 5
B = 4
C = 3
D = 2
E = 1

These condition rating numbers (i.e., A = 5, B = 4, etc.) are multiplied by the assigned weights to compute weighted scores for each component and test. The weighted scores are totaled for each asset. Totaled scores are used in calculating final Health Indices for each asset. For each component, the Health Index calculation involves dividing its total condition score by its maximum condition score, then multiplying by 100. This allows for determining condition category for each asset in groups of "Very Poor", "Poor", "Fair", "Good" and "Very Good" depending upon the resulting score. "Very Good" asset condition represents brand new asset in perfect operating condition. "Good condition" indicates an asset with service life equal to less than 25% of its typical useful life and with no impairment and no noticeable wear. "Fair Condition" indicates an asset with service life equal to more than 25% but less than 80% of its typical useful service life, with normal wear and asset performance within acceptable tolerances and no significant impairment. "Poor Condition" signifies an asset with service life greater than 80% of its typical useful, appreciable wear or significant impairment causing asset performance to degrade below acceptable levels and presenting high risk of asset failure in the absence of major repairs or asset rehabilitation to restore asset condition to "Fair". "Very Poor Condition" signifies an asset with serious impairment to its critical components and presenting very high risk of failure. Assets in "very poor" condition cannot be economically repaired and renewal is the only option to restore their operating condition.

3.1. Substations

The major assets employed in transformer stations and distribution stations include:

- Station Transformers
- Switchgear (Circuit breakers, circuit switchers and reclosers, including protection relays)
- Other assets including station building, fences, ground grids, Bus work, control batteries etc.
- SCADA and Network infrastructure

3.1.1 Condition Assessment Criteria for Station Transformers

The key role of station transformers is to step down transmission or sub-transmission voltage to distribution voltage. PUC DISTRIBUTION has two types of stations: transformer stations and distribution stations. The transformer stations step down from 115 kV to 34.5 kV and the distribution stations step down from 34.5 kV sub-transmission voltages to 12.47 kV or 4.16 kV.

The key components of power transformers installed at transformer and distribution stations include:

- primary and secondary coils, made of copper conductors,
- magnetic core made of low loss iron laminations,
- insulation system, commonly consisting of cellulose paper and mineral oil,
- transformer tank, either sealed or breather type,
- primary and secondary bushings, and
- auxiliary devices.

The most critical component in transformer aging consideration is the insulation system, consisting of mineral oil and cellulose paper. Transformer oil consists of hydrocarbon compounds that degrade with time due to oxidation, resulting in formation of moisture, organic acids and sludge. The oil oxidation rate is a function of operating temperature and degree of contamination with moisture. High operating temperature and presence of moisture content in insulating oil decomposes the insulation to form acids, which causes accelerated degradation of insulation paper. Formation of sludge adversely impacts the cooling efficiency of transformer, resulting in higher operating temperatures and further increasing the rate of oxidation of both the oil and the paper. Condition assessment of transformer oil, through measurement of the dielectric strength, insulation power factor, moisture content, acidity level, and surface tension measurement provides extremely useful information in assessing the health and condition of a transformer.

The paper insulation consists of long cellulose chains, that break up as the paper ages (oxidizes). Tensile strength and ductility of insulation paper are important properties that are determined by the average length of the cellulose chains. As the paper oxidizes, its mechanical strength is gradually reduced, making it weak and brittle. This can lead to sudden insulation failure if the transformer is subjected to a mechanical shock, that are common in normal operating conditions, in form of external faults on lines supplied from the transformer. Insulation degradation and failure can also result from electrical activity inside insulation, such as partial discharge activity, which is initiated if the level of moisture in oil builds up or if other minor defects develop within the insulation. Service age and operating temperature during the service life also provide indication of the condition of insulation system in transformers. Power transformers are known to typically provide a service life of approximately 40 to 45 years.

Partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Computing the Health Index for a transformer requires developing end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) **Age Related Scoring**

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

Table 3-1: Station Transformers – Age Related Health Score

Condition Rating	Station Transformer Age
A	0 to 10 years
B	11 to 20 years
C	21 to 35 years
D	36 to 50 years
E	Older than 50 years

(b) Scoring Based on Loading Level:

The rate of insulation degradation is directly related to the operating temperature and operating temperature is directly related to loading levels. Peak loading level of the transformers expressed in % of nameplate rating can therefore be employed as an indicator of transformer health:

Table 3-2: Station Transformers – Load Related Health Score

Condition Rating	Component Condition
A	Peak load less than 50% of its rating
B	Peak load of 51% to 70% of its rating
C	Peak load of 71% to 85% of its rating
D	Peak load of 86% to 100% of its rating
E	Peak load of greater than 100% of its rating

(c) Scoring Based on Visual Inspections

Visual inspections can provide a good indication of the physical condition of transformers, which can be ranked as indicated below:

Table 3-3: Station Transformers – Health Score Based on Visual Inspections

Condition Rating	Visual Inspections

A	No rust on tank/radiator, no damage to bushings, no sign of oil leaks, forced air cooling fully functional
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank or radiator badly rusted or damage to bushing or significant oil leak
E	Two or more of the above indicated defects or the cooling fans do not work

(d) Scoring Based on Testing of the Insulating Oil

Various insulation tests, including dissolved gas in oil analysis (DGA), dielectric strength or water content measurement test can be interpreted by an expert to rank the overall condition of transformer insulation system:

Table 3-4: Station Transformers – Health Score Based on Oil Tests

Condition Rating	Test Results
A	Test results indicate excellent insulation condition, no indication of moisture, arcing, overheating or degradation of paper
B	Tests indicate normal aging, no concerns about insulation health
C	Tests indicate slightly above average but stable moisture content or presence of arcing overheating related gases
D	Some of the tests indicates significant concerns about insulation condition
E	Two or more of the tests indicate rapidly deteriorating insulation condition

3.1.2 Condition Assessment Criteria for Substation Switchgear

High voltage or medium voltage circuit breakers provide local or remote control for closing and opening of power supply circuits and in conjunction with protective relays provide an important safety function to automatically detect and isolate faulty circuits in order to provide safe, stable and reliable operation with desired selectivity. While its design is significantly different, the recloser employs the same operating principle as a circuit breaker. In case of low short circuit levels, circuit switchers are used in lieu of circuit breakers to provide the same function.

When a circuit breaker interrupts current, an electrical arc is produced in the ionized insulation medium. In order for the circuit breaker action to succeed, the large amount of energy contained in the arc must be successfully extinguished by the breaker's interrupting medium. Depending on the type of arc interrupting medium employed, circuit breakers (or reclosers) are classified as oil circuit breakers, magnetic air circuit breakers, SF-6 circuit breakers or vacuum circuit breakers. In order to

deliver the desired functions, circuit breakers and reclosers are required to possess the following properties and characteristics:

- Highly conductive contact material, capable of withstanding repeated arcs;
- High quality of contact make with extremely low resistance;
- Adequate contacts parting distance in open position for the rated voltage;
- Adequate line to ground insulation for the rated voltage;
- Stable insulating medium, capable of withstanding repeated arcs;
- Fast speed during opening and closing of contacts;
- Appropriate arc blowing techniques to extinguish arcs;
- Adequate energy imparting mechanisms for making or breaking of short circuit currents.

The operating mechanism of circuit breakers and reclosers consists of numerous moving parts that are subject to wear and tear during breaker operation. Because circuit breakers are required to frequently "make" and "break" heavy currents, the contacts are subjected to arcing that accompanies such operations. Each time a circuit breaker opens or closes, the contact surfaces undergo some degradation and degraded contacts produces higher degree of arcing in subsequent operations. Heat produced during contact arcing also decomposes the metal surface from the contacts as well as the insulation medium and the by-products so decomposed are deposited in surrounding insulation materials. The mechanical energy required to generate high contact velocities also results in wear and tear of the mechanical parts in operating mechanism.

A number of factors influence the overall rate of wear and severity of degradation of circuit breakers, including type of the insulating medium, design of the contacts, operating environment, and the duty cycle of the circuit breaker. Load current switching or fault current interruption seldom lead to sudden failure of circuit breakers, but repeated operations result in overall wear and tear which lead to eventual end of life.

Circuit breakers mounted outdoors may experience adverse environmental conditions that may further contribute to the rate and severity of degradation. The following factors represent environmental degradation of outdoor mounted circuit breakers:

- Corrosion of enclosures and metal parts;
- Potential ingress of moisture into operating parts and insulating system;
- Bushing/insulator deterioration under the influence of moisture, fog, ice; and
- Deterioration of mechanical parts;

Oil Circuit Breakers (OCBs) typically have longer current interruption duration compared with other types of designs. Contacts and the insulation medium are therefore subjected to severe arcing, resulting in deterioration of the contact surface as well as insulation. Thus, both contacts and oil degrade more rapidly in case of OCBs than they do in either SF6 or vacuum designs, especially when the OCB undergoes frequent switching operations. Generally, 4 to 8 interruptions under fault or heavy load will cause contact erosion and oil carbonisation, requiring contact maintenance and possibly oil filtration. OCBs have therefore higher operating costs compared to other designs.

Different types of circuit breakers employed on PUC DISTRIBUTION's transformer and distribution stations are described below:

(i) Oil Circuit Breakers (OCB) or Oil Filled Reclosers

In minimum oil circuit breakers, insulating oil provides the role of arc quenching only, but in bulk oil circuit breakers, the insulating oil provides both the arc quenching and the insulation functions. OCBs generally perform well at low ambient temperatures. They also provide long and reliable service life when the number of loading switching or fault interruption operations is infrequent. However, frequent switching fault interruption applications must be accompanied by frequent preventative maintenance. OCBs do not perform well in switching capacitive loads, during switching operations of which high peak recovery voltages are produced.. The manufacture of new OCBs has been discontinued for at least 30 years now. The original equipment manufacturers (OEMs) provided service support and spares for these OCBs until the late 1990s. Many utilities in North America continue to successfully employ older vintages of OCBs on their systems.

(ii) Air Magnetic Circuit Breakers (Air Magnetic Breakers)

Air magnetic breakers employ the magnetic effect of the current in their design, by forcing the electric arc produced during opening on the contacts into an arc chute. The arc chute causes elongation of the arc path and allows cooling, splitting and eventual extinction of the arc. In some designs, an auxiliary puffer is employed to blast air into the arc, which allows successful interruption of low-level currents with weaker magnetic fields. Air magnetic breakers represent the second oldest technology in circuit breaker design, next to OCBs. They are also no longer in manufacture and have been superseded by SF6 and vacuum technologies since the late 1970s.

(iii) Vacuum Circuit Breakers or Reclosers

In a vacuum circuit breaker, vacuum interrupters are employed to make or break load or fault current. Upon separation of the contacts, the current initiates a metal vapour arc discharge and flows through the plasma until the next current zero. The arc is extinguished at current zero and the conductive metal vapour condenses on the metal surfaces during a very short time interval measured in micro seconds. Therefore, the dielectric strength in the breaker builds up very rapidly. The effectiveness of vacuum interrupter depends largely on the material and form of the contacts. In modern designs, oxygen free copper chromium alloy is commonly employed as it is believed to be the best material for the application. This material combines good arc extinguishing characteristic with a reduced tendency to contact welding.

(iv) SF_6 Circuit Breakers

A SF_6 circuit breaker is designed to direct a constant gas flow to the arc that extracts heat from the arc and so allows achieving its extinction at current zero. The gas flow de-ionises the contact gap and establishes the required dielectric strength to prevent an arc re-strike. The direction of the gas flow either parallel or across to the axis of the arc has an influence on the efficiency of the arc interruption process. Research has shown that an axial flow creates a turbulence causing an intensive and continuous interaction between the gas and plasma as current approaches zero. Recent developments concentrated on employing the arc energy itself to create directly the differential pressure needed, without using an external piston. Parallel to the self-pressurising design, the rotating arc SF_6 interrupter was also developed. In this design, a coil sets the arc in rotation while the

quenching medium remains stationary. The relative movement between the arc and the gas is no longer axial but radial; it is a cross-flow mechanism.

Computing the Health Index for circuit breakers requires collection of data on a number of condition indicators:

(a) Age Related Scoring

Service age provides a reasonably good measure of the remaining life of circuit breakers and reclosers. Since the outdoor mounted reclosers, exposed to the weather elements experience a faster rate of aging, two separate sets of criteria are provided for outdoor and indoor mounted circuit breakers / reclosers:

Table 3-5: Outdoor Circuit Breakers or Reclosers – Age Related Health Score

Condition Rating	Age
A	0 to 7 years
B	8 to 15 years
C	16 to 30 years
D	31 to 35 years
E	35 years or older

Table 3-6: Indoor Circuit Breakers – Age Related Health Score

Condition Rating	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years (or
D	31 to 40 years
E	41 years or older

(b) Scoring based on Visual Inspections

Visual inspections can provide a good indication of the physical condition of circuit breakers or reclosers, which can be ranked as indicated below:

Table 3-7: Circuit Breakers – Visual Inspections Based Health Score

Condition Rating	Visual Inspection Indicators
A	No rust on tank/enclosure, no damage to bushings, no leaks, controls and wiring in excellent condition
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation

D	Tank/enclosure badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects or the cooling fans do not work

(c) Scoring Based on Evaluation of the tests

Various interruption chamber tests can be interpreted by an expert to rank the overall condition of breaker insulation system:

Table 3-8: Circuit Breakers and Recloser – Testing Based Health Score

Condition Rating	Test Results
A	Test results indicate excellent condition of contacts, operating mechanism, insulation condition and controls
B	Normal aging, each of the four indicators, identified in A above, within specified limits
C	One of the above four indicators is slightly beyond the specified limits
D	Two or more of the above four indicators beyond the specified limits
E	Two or more of the indicators beyond specifications and cannot be brought to comply with the specifications

(d) Scoring Based on Condition of the protection relay calibration tests

Calibration tests can be interpreted by an expert to rank the overall condition of protection relays:

Table 3-9: Protection Relays – Testing Based Health Score

Condition Rating	Test Results
A	Excellent operating condition, calibration well within specified limits
B	Normal aging, calibration within the specified limits
C	Frequent calibration required, but it is possible to meet specified limits
E	Not possible to calibrate the relays to bring settings to specified limits

3.1.3 Condition Assessment Criteria of Other Key Substation Assets

a) Ground Grids

The purpose of a substation ground grid is to provide a low resistance ground electrode for system neutral, for equipment case grounding and to maintain safe potential gradients within the station yards during abnormal operating conditions, i.e. line-to-ground faults.

The station ground electrode consist of multiple ground rods driven into the ground and located strategically and connected with underground copper conductors to make a mesh of sufficiently low resistance. All feeder neutrals are connected to the electrode. Cases of each piece of power equipment are also bonded to the ground electrode. All fences and gates are bonded to the perimeter ground grid.

Where the ground potential rise (GPR) exceeds safe limits, surface stone of high resistivity is used in the substation yard to maintain step potential within safe limits.

Buried ground rods, conductors and connectors are subject to corrosion, which reduces the effectiveness of the ground electrode with passage of time. Above ground components of the electrode and copper conductors are subject to vandalism and damage. The surface stone can degrade in quality due to growth of weeds.

i. Ground Grid Condition Rating Based on Evaluation of the tests

Table 3-10: Ground Grid – Testing Related Health Score

Condition Rating	Test Results
A	Ground electrode resistance and GPR within safe limits, all electrode components pass integrity test
C	Ground electrode resistance and GPR within safe limits but a few electrode components do not pass integrity test
E	Ground electrode resistance or GPR not within safe limits or many electrode components do not pass integrity test

ii. Rating Based on Condition of Surface Stone

Table 3-11: Ground Grid – Surface Stone Health Score

Condition Rating	Test/Inspection Results
A	Resistivity of Surface Stone >3000 Ohm-m, no sign of vegetation growth
C	Resistivity of Surface Stone marginally less than <3000 Ohm-m, but no sign of vegetation growth
E	Resistivity of Surface Stone significantly less than <3000 Ohm-m, and signs of vegetation growth

b) Substation Fences

The purpose of substation fences is to provide security for substation assets by not allowing entry into the yard to unauthorized people or wild life. To achieve this objective the fence has to be of a minimum height of 1.8 m to comply with the Ontario Electrical Safety Code and topped with three rungs of barbed wire covering a height of 0.3 m. The fence must be secured with posts of adequate strength and should limit the crawl space between the fence and ground to 0.1 m or less. Where a substation fence connects into another steel fence, an insulated section should be added to prevent transfer of harmful potential to remote locations. The fence should be grounded and bonded throughout. The gates should be lockable and locked and warning signs should be provided.

The common degradation mode for station fences are rusting and corrosion, damage to fence posts and gates, soil erosion increasing the crawl space under the fence and vandalism to damage and deface warning signs. The following criteria is recommended for condition assessment of station fences:

Table 3-12: Ground Grid – Fences Health Score based on Visual Inspections

Condition Rating	Inspections
A	No deficiencies in the fence
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

c) Substation Buildings

Substation buildings provide protection to critical substation assets, i.e. circuit breakers and protection relays against weather elements. While the switchgear is commonly located on the main floor, the basements serve as an oversized manhole to provide exit for feeder cables.

The common degradation mode for substation buildings is deterioration of roofs, sidings, doors and windows. A small leak in the roof can cause a lot of harm to electrical equipment and defeat the very purpose of the substation building.

The health and condition of a substation building can be measured through visual inspections:

Table 3-13: Substation Buildings Health Score

Condition Rating	Inspections
A	No deficiencies in the building
C	Only minor deficiencies
E	Major deficiencies requiring immediate attention

3.1.4 Health Index Formulation for Substation Equipment

Since each piece of substation equipment can be independently replaced or rehabilitated, rather than developing an overall health index for substations, methodology for developing health indices for key substation assets is provided below:

For purposes of formulating the Health Index for major substation assets, it is proposed to assign the following weights to various health index criteria described in the previous sections:

Table 3-14: Station Transformers – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of transformer	A - E	5	6	30
2	Peak loading	A - E	5	4	20
3	Visual inspection	A - E	5	2	10
4	Testing	A - E	5	8	40
	Total				100

Table 3-15: Station Switchgear (Circuit breaker / Recloser) Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age	A - E	5	6	30
2	Visual inspection	A - E	5	4	20
3	Breaker Testing	A - E	5	6	30
4	Protection Relay Testing	A - E	5	4	20
	Total				100

Table 3-16: Other Station Asset Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Ground Grid	A - E	5	8	40
2	Surface Stone	A - E	5	8	20
3	Fences	A - E	5	4	20
4	Buildings	A - E	5	4	20
	Total				100

3.2. Overhead Lines

Condition assessment methodologies for the following components employed on overhead lines are discussed below:

- Poles
- Insulators
- Hardware
- Conductors and splices

3.2.1. Condition Assessment Criteria for Poles, Insulators and Pole Hardware:

a) Poles:

As wood is a natural material, its degradation processes are different from other assets on distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage and effects of weather. Fungi attack both external surfaces and the internal heartwood of wood poles. The process of fungal decay requires the presence of fungus spores in the presence of water and oxygen. For this reason, the area of the pole most susceptible to fungal decay is at and around the ground line, although pole rot is also known to begin at the top of the pole. To prevent the decay of wood poles, utilities treat them with preservatives before installation. Wood preservatives have two basic functions:

- keep out moisture that supports fungi by sealing the surfaces, and
- kill off the fungal spores.

Most power companies install only fully treated wood poles these days, however this was not always the case and the lines constructed 40 years ago or earlier may not have been constructed with fully treated poles but only butt treated poles may have been used. Typically, fully treated poles are expected to provide a longer service life in relation to butt treated poles.

The following factors represent some of the more critical factors affecting wood pole strength as poles age:

- Original type and class of wood pole;
- Original defects in wood (e.g. knots, cracks or rot);
- Rate of decay in service life which depends on type of treatment and environmental conditions;
- Pole damage by woodpeckers, insects, and other wildlife; and
- Wood burns.

Several types of damage can also deform bolt holes in poles. Generally, such deformities do not present immediate problems. However, in some cases deformed holes can result in both failure of the structure and failure of other components attached to the pole. Bolts also can become loose, elongated, bent, cracked, sheared/broken and lost.

Visual inspection can detect the following types of wood pole damage readily:

- Fibre damage that may occur when wind hits a wood pole with force beyond the pole's bearing capacity;
- Partial damage that may result when objects hit wood poles and reduce effective pole circumference. If the damage affects only part of a pole's cross-section the utility may keep the pole in service with a reduced factor of safety.
- Wood splits from various causes that may accelerate the end of a pole's life, depending upon the extent of the split damage;
- Mis-orientation from excessive transverse forces that may result in pole tilting as well as "stretching" (i.e., loosening) and breaking of guys and guying systems;
- Burning from conductor faults and insulator flashovers that may damage wood poles, wooden support cross-braces and timber, reducing the ability of these structures to withstand mechanical stress changes or causing their complete loss through fire; and
- Wood cracks that may hold moisture and cause decay or weaken the structures through freeze/thaw forces during winter.

Utilities have sought objective and accurate means to assess pole condition and remaining life, as a result of which, a wide range of wood pole assessment and diagnostic tools and techniques has developed. These include techniques designed to apply traditional probing and hammer tests in more controlled, repeatable and objective ways. Indirect and non-destructive techniques such as ultrasonics, X-rays, and electrical resistance have received widespread testing.

b) Condition Assessment Criteria for Insulators

The types of insulators and configurations typically used in distribution systems include dead-end, suspension, post and pin types. The insulating portion may consist of porcelain or polymer. The metallic parts usually are made from zinc coated ductile or malleable iron. Both electrical and mechanical stresses may affect insulators. Degradation and eventual failure generally result from the loss of either dielectric or mechanical strength. Mechanical loading on suspension and line post insulators consists of a combination of tensile, torsional, cantilever, vibration and compression forces resulting from factors such as conductor vibration and galloping, accumulation of high density snow or ice, and sudden ice shedding. Line post, strut and pin type insulators are unique since they may experience a combination of cantilever, transverse and tensile forces simultaneously. Impact or contact induced damage also may occur.

Contamination of insulator surface with road salt, freezing rain, and snow accumulation may induce flashovers resulting in dielectric failure of insulators. Electrical flashovers can cause both external and internal damage to porcelain and composite insulators. Visual inspection can detect the following external insulator damage readily:

- Broken porcelain from the shell caused by a flashover (lightning) or impact damage (vandalism);
- Flashover burn markings on the porcelain shell resulting from burns/arcing damage/galvanizing;

Latent damages, typically internal to the porcelain shell, metal fitting and hardware include:

- Internal cracks under the metal cap or inside the porcelain head from lightning flashovers or line galloping, which in essence cause electrical shorts in the insulator that can distort the insulator string's voltage profile;
- Radial cracks (come from cement growth) through the porcelain shell;

Composite insulators consist of a glass fibre reinforced rod covered in either EPDM or silicone rubber weather sheds with appropriate end fittings. While the composite insulators offer a great range of mechanical strengths and much lower weight than other types of insulators, the EPDM or silicone rubber material also is soft and easily cut, ripped or punctured by sharp objects. The integrity of the sheath and weather sheds is critical. Failure commonly occurs when moisture enters into the glass fibre rod area.

Noticeable damage to insulator includes cuts, splits, holes, erosion, tracking, or burning of the rubber shed and sheath material, plus separation or degradation of the rubber sheath material where it meets the metal end fittings. Any signs of power arc, lightning damage, or corrosion on the metal end fittings also indicate deterioration of the component.

c) Condition Assessment Criteria for Metal Cross Arms or Hardware

Degradation or reduction in strength of insulator hardware may occur due to the following:

- Loss of galvanization and corrosion of steel members;
- Loss in strength due to fatigue;
- Loosening of hardware due to conductor vibrations; or
- Hardware failure during major storm events.

Close-up visual inspections generally can determine the extent of degradation. Laboratory testing can further corroborate results of visual investigations.

3.2.2. Ranking Condition of Poles, Insulators and Pole Hardware

The condition assessment process includes scoring based on multiple parameter criteria as described below:

a) Age Related Score:

Since the service age provides a reasonably good measure of the remaining strength of wood poles, cross arms, hardware and insulators, it is employed as an assessment parameter, with the following scores:

Table 3-17: Overhead Lines – Age Related Health Score

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 60 years
E	Older than 60 years

b) Scoring Based on Preservative Treatment of Wood Poles

Since the rate of pole degradation is affected by the effectiveness of the preservative treatment, wood pole treatment is employed in Health Index formulation of line sections, as indicated in the table below:

Table 3-18: Overhead Lines – Pole Treatment Based Health Score

Condition Rating	Type of Pole Treatment
A	Fully Treated
C	Butt Treated
E	No Treatment

c) Condition Rating Based on Visual Examinations of Pole Line Components

Different components of the pole line, including wood poles, cross-arms, hardware, insulators and pole grounding are visually inspected by qualified staff during line patrols. By taking into account the results of these inspections, the health and condition of each component is scored in accordance with the following table:

Table 3-19: Overhead Lines – Visual Inspections Based Health Score

Condition Rating	Component Condition
A	Component is in "as new" condition
B	Component has normal wear expected with age
C	Component has many minor problems or a major problem that requires close attention and monitoring
D	Component has many problems and the potential for its failure would rapidly escalate unless preventative maintenance is performed
E	Component has damaged/degraded beyond repair and will require replacement

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3.2.3. Condition Assessment Criteria for Conductors

a) Condition Assessment Criteria for Line Conductors:

Conductors allow flow of current through them facilitating the movement of power from substations to customers' premises. Overhead line conductors are typically supported on wood pole structures to which they are attached by insulators suitable for the voltage at which the lines operate. The conductors on a line are sized by taking into account the amount of current to be carried. The maximum current carrying capacity of conductors is determined by their thermal rating. However distribution line conductors are commonly sized to provide the right balance between energy loss in conductors (copper loss) and the capital cost of conductors. As a result the distribution lines often operate under loads significantly below the thermal rating of the conductors.

Overhead line conductors must have adequate tensile strength, enabling them to be stretched between poles. Distribution lines typically have span length of 40 m to 60 m. Three different types of conductors are commonly used on distribution lines:

- Aluminium Conductors Steel Reinforced (ACSR),
- Aluminium Stranded Conductors (ASC),
- Aluminium Alloy Conductors (AAC).

Steel reinforced aluminium conductors have galvanized steel core strands that supply most of their tensile strength. The steel core has both tensile and ductile properties, allowing the core to withstand both longitudinal forces and bending movements without failure. AAC conductors cost less in relation to ACSR conductors, but their tensile strength is significantly lower than those of the ACSR conductors. Both the price and tensile strength of AAC conductors lie in between those of ASC and ACSR conductors.

As current passes through the conductors, the resistance causes its temperature to rise, the temperature change is proportional to the square of the load current passing through the conductor. The rise in temperature causes the conductor to lengthen and sag between points of support, reducing the height of the conductor above ground. Although it seldom happens on distribution lines, line operation at loads beyond conductors' thermal rating of approximately 90° C may lead to annealing of conductors, resulting in permanent loss of its tensile strength.

To provide their intended functions on distribution lines, conductors must retain both their conductive properties and mechanical (i.e., tensile) strength. Aluminium conductors have three primary modes of degradation; corrosion, fatigue and creep. The rate of each degradation mode depends on several factors, including the size and construction of the conductor as well as environmental and operating conditions.

Generally, corrosion represents the most critical life-limiting factor for ACSR conductors. Environmental conditions affect degradation rates from corrosion. Both aluminium and zinc-coated steel core conductors are susceptible to corrosion from chlorine-based pollutants, even in low concentrations, but the rate of corrosion of steel core is significantly greater than that of aluminium. While fatigue degradation is a serious concern for transmission lines that are strung with significantly higher tension, it is commonly not a serious issue for distribution lines.

Overloaded lines operating beyond their thermal capacity can suffer from a loss of tensile strength due to annealing at elevated operating temperatures. Each elevated temperature event adds cumulative damage to the conductors. After loss of 10% of a conductor's rated tensile strength, significant sag occurs, requiring either re-sagging or replacement of the conductor. ACSR conductors can withstand greater annealing degradation compared to ASC.

Phase to phase power arcs can result from conductor galloping during severe storm events. This can cause localized burning and melting of a conductor's aluminium strands, reducing strength at those sites and potentially leading to conductor failures.

Other forms of conductor damage include:

- Broken strands (i.e., outer and inners)
- Strand abrasion
- Elongation (i.e., change in sags and tensions)
- Burn damage (i.e., power arc/clashing)
- Bird-caging.

On distribution lines, constructed to CSA standards, it is rare for conductors on entire line sections to experience degradations described above. Although laboratory tests are available to determine the degree of corrosion and assess the tensile strength and remaining useful life of conductors, distribution line conductors rarely require testing. Conductors on distribution lines often outlive the poles and are not usually on the critical path to determine end of life for a line section.

The only exception to the above rule might be where small copper conductors susceptible to frequent breakdowns are in use or where line conductors are too small for line loads resulting in sub optimal system operation due to high line loss.

b) Condition Assessment Criteria for Splices

Conductor splices generally have a larger cross-sectional area than the conductor itself. When properly installed, splices should outlast the conductor. However, when improperly installed, splices can reduce a conductor's life. Improperly crimped splices represent the weakest link in conductors under tension.

In extreme cases, splice failures lead to excessive conductor annealing that may cause the conductor's strands to be pulled from the compression splice. Any strand damage that occurs during splice installation may lead to localized weakening of the conductor and premature splice failure. Failure to use non-oxidizing grease in splices also may lead to the development of hot spots and splice failure.

3.2.4. Ranking Condition of Conductors and Splices through Multiple Criteria

Computing the Health Index for overhead line conductors and splices requires developing end-of-life criteria for conductors. The condition assessment process includes scoring based on the risk of conductors breaking and falling.

Since small sized conductors pose a serious safety risk, the value of this risk is scored separately with help of the table below:

Table 3-20: Overhead Lines - Small Conductor Related Health Score

Condition Rating	Age
A	Absence of small sized conductors
E	Presence of small sized conductors (#4 to #6 copper)

3.2.5. Health Index Formulation for Overhead Lines

Health indexing quantifies equipment conditions relative to long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

For purposes of formulating the Health Index for overhead line sections, it is proposed to assign the following weights to various Health Index criteria described in Section 3.2.1 through 3.2.4.

Table 3-21: Overhead Lines Health Index Algorithm

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of pole line	A - E	5	3	15
2	Pole treatment	A - E	5	1	5
3	Visual inspection of poles	A - E	5	1	5
4	Pole testing	A - E	5	4	20
5	Visual inspection of insulators	A - E	5	1	5
6	Visual inspection of hardware	A - E	5	1	5
7	Small conductor risk	A - E	5	5	25
	Total				80

3.3. *Underground Distribution System*

The major assets employed on underground distribution systems can be grouped into the following categories:

- Cables, splices and terminations
- Manholes and vaults

3.3.1. Condition Assessment Criteria for Cables, Splices and Terminations

Safety, reliability, aesthetics and operating costs govern the design and construction standards for underground distribution lines. Underground cables can be constructed in a number of configurations, including direct buried cables, cables installed in direct buried conduits and cables installed in a concrete encased duct manhole system. Medium voltage underground cables have the following key components:

- Cables
- Cable Splices
- Cable Terminations

a) Cables

Medium voltage cables may employ either copper or aluminium conductors. They may be constructed in either single phase or three phase configurations. Two major types of cables are in common use in Canada: paper insulated lead covered (PILC) and cross linked polyethylene (XLPE).

Polymer insulations for cables were introduced as an economic alternative to PILC cables in 1970's. The insulation system in these cables consists of a semi-conducting sheath over the conductor, the insulation, another semi-conducting layer over the insulation, a metallic shield tape or concentric neutral and a jacket. For the early generation of these cables, manufactured in the 1970's, two unexpected factors entered into the failure mechanism: presence of impurities in the insulation system and ingress of moisture that made these cables susceptible to premature failures due to water treeing. Corrosion of concentric neutral conductors is another potential mode of failure. Water treeing is the most significant degradation process for polymeric cables. The original design of cables with polymeric sheaths allowed water to penetrate and come into contact with the insulation. In the presence of electric fields water migration can result in treeing and ultimately breakdown. The rate of growth of water trees is dependent on the quality of the polymeric insulation and the manufacturing process. Any contamination voids or discontinuities will accelerate degradation. This has been the reason for poor reliability and relatively short lifetimes of early polymeric cables.

As manufacturing processes have improved the performance and ultimate life of this type of cable has also improved. In addition to manufacturing improvements, development of tree retardant TRXLPE cables and designs to incorporate metal foil barriers and water migration control have further reduced the rate of deterioration due to treeing.

Distribution underground cables are one of the more challenging assets on electricity systems from a condition assessment and asset management viewpoint. Although a number of test techniques, such as partial discharge (PD) testing have become available over the recent years, it is still very difficult

and expensive to obtain accurate condition information for buried cables. The standard approach to managing cable systems has been monitoring of cable failure rates and the impacts of in-service failures on reliability and operating costs and when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs become higher than the annualized cost of cable replacement, the cables are replaced.

b) Cable Splices and Terminations

Cable splices and terminations are subject to the same type of insulation degradation and aging as the cables themselves. Improperly made splices may be susceptible to moisture ingress and as a result may experience higher failure rates compared to cables.

3.3.2. Ranking Condition of Cables and Splices through Multiple Criteria

Computing the Health Index for an underground cable section requires developing end-of-life criteria for its various components. The condition assessment process includes scoring based on multiple parameter criteria as described below:

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining useful life of cables, splices and terminations, it can be employed as an assessment parameter, with the following scores:

Table 3-22: Underground Cables - Age Related Score

Condition Rating	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Older than 40 years

(b) Historic Rates of Circuit Failures

Historic failure rates on a cable circuit are an excellent indicator of the cable health and condition and its useful remaining life and therefore employed in cable Health Index formulation as indicated below:

Table 3-23: Underground Cables – Failure Related Score

Condition Rating	Component Condition
A	Less than 0.5 Failures per 10 km in the last 5 years
B	0.5 to 1.0 Failures per 10 km in the last 5 years
C	1.0 to 1.5 Failures per 10 km in the last 5 years
D	1.5 to 2.5 Failures per 10 km in the last 5 years
E	2.5 or more Failures per 10 km in the last 5 years

(c) Condition of Cable Splices or Stress Cones

Physical condition of cable splices or stress cones can be employed in assessing overall condition of the cable circuit:

Table 3-24: Underground Cables - Splice or Stress Cone Related Health Score

Condition Rating	Component Condition
A	Splice or Stress Cone appears in good condition, no indication of moisture ingress
C	Normal wear, no apparent damage, no evidence of moisture ingress
E	Poor condition, potential moisture ingress or IR indicates hot spot

3.3.3. Condition Assessment Criteria for Manholes and Vaults

Manholes provide the junction point on underground ducts to facilitate cable pulling and provide access for inspection of cable splices. Vaults provide below grade space of installation of electrical equipment such as submersible transformers or switches. In the case of both manholes and vaults, steel reinforced concrete is used for walls, roofs and floors. In locations subject to flooding floor drains and sump pumps are provided. Vaults where heat generating equipment such as distribution transformers are installed are also equipped with ventilation grates. Man access is provided through the top. When vaults and manholes are located in road ways, parking lots or other areas open to vehicular traffic, the structures must be designed by a structural engineer. Since manholes and vaults are confined spaces, they must be adequately sized to rescue trapped workers during a fire or explosion inside the vault or manhole.

The common degradation mode for manholes and vaults is the deterioration of concrete structures due to concrete spalling and corrosion of rebar, sinking of the roof top surfaces allowing rain water to collect and flood the manhole and vaults. Functional obsolescence, where the size of the manhole or vault no longer meets the space requirements can also lead to end of life of a structure.

3.3.4. Ranking Condition of Manholes and Vaults through Multiple Criteria

The health and condition of manhole and vaults can be measured through visual inspections, looking for:

- Structural damage to concrete walls or roof
- Frequent flooding incidents of the vaults or manholes
- Non-functioning drains or sump pumps
- Inadequate space

(a) Structural Condition

Table 3-25: Manhole and Vaults – Structural Health Score

Condition Rating	Inspections
A	No deficiencies in the vault or manhole
C	Only minor deficiencies
E	Major deficiencies requiring immediate repairs/replacement

(b) Flooding Incidents, Drains, Sump Pumps

Table 3-26: Manhole and Vaults - Flooding Related Health Score

Condition Rating	Inspections
A	No incidents of Flooding at this location
C	Occasional Flooding, working sump pumps and drains
E	Frequent Flooding, No sump pumps or drains

(c) Vault Size and Access:

Table 3-27: Manholes and Vaults – Size Related Health Score

Condition Rating	Inspections
A	Adequate ergonomic size and safe access to vault
C	Vault size slightly smaller than ideal, but adequate for safe working and reasonable access to vault
E	Vault size or access inadequate for safe working or worker rescue during an accident immediate repairs/replacement

3.3.5. Health Index Formulation for Underground Cables, Manholes and Vaults

Health indexing quantifies equipment conditions relative to long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

For purposes of formulating the Health Index for underground cables and manholes/vaults, it is proposed to assign the following weights to various health index criteria:

Table 3-28: Cables, Splices and Terminators Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of Cable Circuit	A – E	5	3	15
4	Historic Failure rates	A – E	5	8	40
5	Visual inspection of splices or stress cones	A – E	5	1	5
	Total				60

Table 3-29: Manholes and Vaults Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Structural Integrity	A – E	5	8	40
2	Flooding and Its mitigation	A – E	5	4	20
3	Size and Access	A – E	5	8	40
	Total				100

3.4. Distribution Transformers

3.4.1. Different Types of Distribution Transformers

Four (4) main types of distribution transformers are commonly employed on distribution system:

- Pole mounted transformers
- 1-Phase Pad mounted transformers
- 3-Phase Pad mounted transformers
- Submersible transformers in vaults

Aside from the different design and construction standards employed in their manufacture and installation, each type of transformer serves the same functions and the same asset management strategy can be employed for these assets as described below:

Distribution transformers step down to the medium voltage distribution power to final utilization voltage of either 120/240V, 120/208V or 347/600 V. Both single phase and three phase transformers are in use. In pole top applications, three single phase transformers are commonly employed to create a three phase bank, however for pad mounted applications, three phase transformers are used for three phase applications.

The key components of a distribution transformer are:

- primary and secondary coils, made of copper or aluminium conductors
- magnetic core made of iron laminations
- insulation system, commonly consisting of paper and mineral oil
- sealed transformer tank
- primary and secondary bushings or bushing wells to accommodate elbows
- auxiliary devices

The most critical component in transformer aging consideration is the insulation system, consisting of mineral oil and paper. Transformer oil consists of hydrocarbon compounds that degrade with time due to oxidation, resulting in formation of moisture, organic acids and sludge. The oil oxidation rate is a function of operating temperature. Increased acidity and moisture content in insulating oil causes accelerated degradation of insulation paper. Formation of sludge adversely impacts the cooling efficiency of transformer, resulting in higher operating temperatures and further increasing the rate of oxidation of both the oil and the paper. Distribution transformers commonly fail when the age weakened insulation system is subjected to a voltage surge during lightning.

Most utilities run the distribution transformers to failure, i.e. replace them only after they fail. With the exception of rust proofing and painting of the tanks, replacing a damaged bushing or repairing a leaky gasket, very little invasive preventative maintenance or testing is carried out on distribution transformers.

3.4.2. Ranking the Condition of Distribution Transformers through Multiple Criteria

Just as in case of substation transformers multiple criteria, including service age, loading levels, results of oil testing and physical inspections can be employed for assessing the condition of distribution transformers. However, since the consequences of in-service failure of distribution transformers are relatively minor, most distribution utilities, including PUC DISTRIBUTION employ run-to-failure strategy for distribution transformers, thus avoiding costs related to oil testing or measuring load levels.

Since the service age provides a reasonably good measure of the remaining life of transformers, it is employed as an assessment parameter, with the following scores:

(a) Condition Assessment Based on Age

Table 3-30: Distribution Transformer Age Based Scoring

Condition Rating	Distribution Transformer Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Older than 40 years

(b) Visual Inspections

Visual inspections can provide a good indication of the physical condition of transformers, which can be ranked as indicated below:

Table 3-31: Distribution Transformers – Inspections Based Health Scoring

Condition Rating	Visual Inspections
A	No rust on tank/enclosure, no damage to bushings, no sign of oil leaks, padlocks in good condition on pad mounted transformers
B	Only one of the following defects: Minor rust, or minor cracks in bushings or minor oil leak
C	Two or more of the above indicated defects present but do not impact safe operation
D	Tank/radiator badly rusted or major damage to bushing or major oil leak
E	Two or more of the above indicated defects

3.4.3. Health Index Formulation for Distribution Transformers

Table 3-32: Distribution Transformers Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of transformer	A – E	5	10	50
3	Visual inspection	A – E	5	10	50
	Total				100

3.5. Disconnect Switches and Cut-outs

3.5.1. Different Types of Switching Devices

This asset class includes pad and vault mounted medium voltage switchgear, K-bars, as well as pole mounted ganged disconnect switches and single phase solid blade or cutouts. Disconnect switches and K-bars provide means of load disconnect and isolation for equipment, such as underground laterals or distribution transformers.

The key components of a distribution switch are:

- Switch blades
- Operating handle and mechanism
- Insulator bushings
- Grounding and bonding conductors

Pad mounted disconnects have the following additional components:

- Pad or vault mounted metal enclosure
- Inter-phase glass polyester barriers
- Padlocks

K-bars have the following main components

- Insulator bushings and buses
- Grounding and bonding conductors
- Pad mounted metal enclosure

The most critical components in the disconnect switch are the switch blades and operating mechanism. Misaligned or poorly surfaced contacts can result in excessive arcing during switch opening or closing, resulting in further deterioration of the blades. Corrosion may cause rusting of the links and pins in the operating mechanism reducing the blade movement speed. Broken grounds or damaged insulators are some other defects that may appear with age.

Pad or vault mounted disconnect switch enclosures are vulnerable to corrosion due to road salt spray. Non-functioning padlocks or broken inter-phase barriers are other serious defects that may develop with aging.

In case of K-bars, corrosion of steel enclosures and degradation of bushings with service age are the key degradation modes.

3.5.2. Ranking Condition of Disconnect Switches through Multiple Criteria

(a) Age Related Scoring

Since the service age provides a reasonably good measure of the remaining life of disconnect switches and K-bars, it is employed as an assessment parameter, with the following scores:

Table 3-33: K-bar, Disconnect Switches and Cutouts – Age Based Health Scoring

Condition Rating	Disconnect Switch Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Older than 40 years

(b) Visual Inspections

Visual inspections can provide a good indication of the physical condition of disconnect switches or K-bars. Infrared (IR) scan can provide indication of hot spots resulting from misaligned blades.

Table 3-34: K-bar or Disconnect Switches or Cutouts – Inspections Based Scoring

Condition Rating	Visual Inspections
A	No rust on tank/enclosure, no damage to bushings, padlocks in good condition on pad mounted switchgear, operating mechanism and blades in excellent condition
B	Only minor wear, no defects
C	No more than one of the above indicated defects present but does not impact safe operation
D	Two or more of above indicated defects, but they can be repaired
E	Two or more of the above indicated defects, but they cannot be repaired

3.5.3. Health Index Formulation for Disconnect Switches

Table 3-35: Distribution Switches and Cutouts – Health Index

	Criteria	Rankings	Highest Score	Weight Assigned	Maximum Weighted Score
1	Age of disconnect	A – E	5	10	50
2	Visual inspections and IR Scan	A – E	5	10	50
	Total				100

4 ASSET DEMOGRAPHICS AND CONDITION ASSESSMENT

The methodology described in detail in section 3 provides means of accurate and comprehensive condition assessment of all major assets employed on the distribution system. This section of the report, documents the health indices for fixed assets employed on the distribution system, determined by taking into account all available information about assets from testing, inspections, service age and other demographic information, retrieved from the GIS system. Where complete information required for condition assessment of an asset class through methodologies described in Section 3 was not available, the health index algorithm was appropriately modified to make use of the available information, to determine health indices of assets.

4.1. *Transformer Stations and Distribution Substations*

Figure 4.1 shows the location of transformer stations and distribution stations owned and operated by PUC DISTRIBUTION. There are two transformer stations TS1 and TS2, which step down power received from the transmitter at 115 kV to 34.5 kV, and 12 distribution stations, which step down power from 34.5 kV to 12.47 kV. There are also three additional distribution stations; one which steps down from 34.5kV to 4.16kV, one which step down from 12.47 kV to 4.16 kV, and one which steps down from 34.5kV to both 12.47kV and 4.16kV. The three 4.16 kV distribution stations (Sub 4, Sub 5 and Sub 14) will be retired from service, upon completion of the distribution voltage upgrade program and replaced with a single 34.5/12.47 kV station.

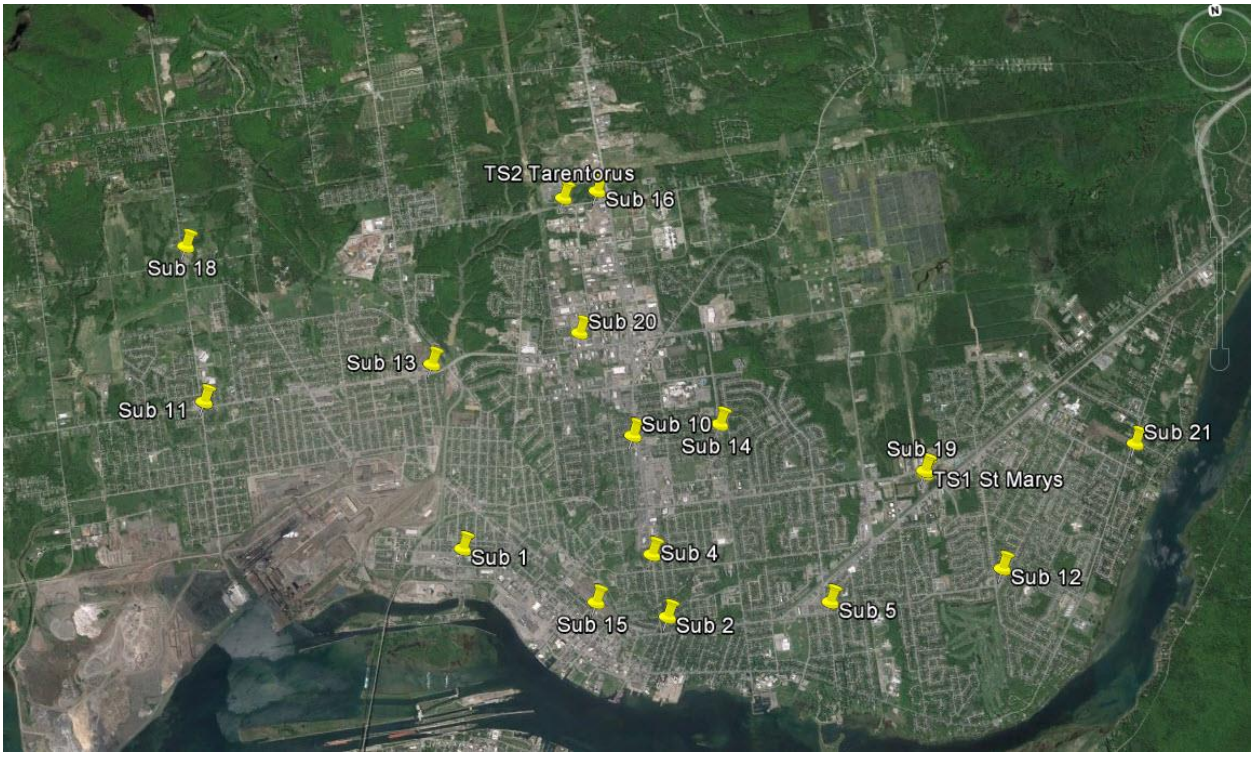
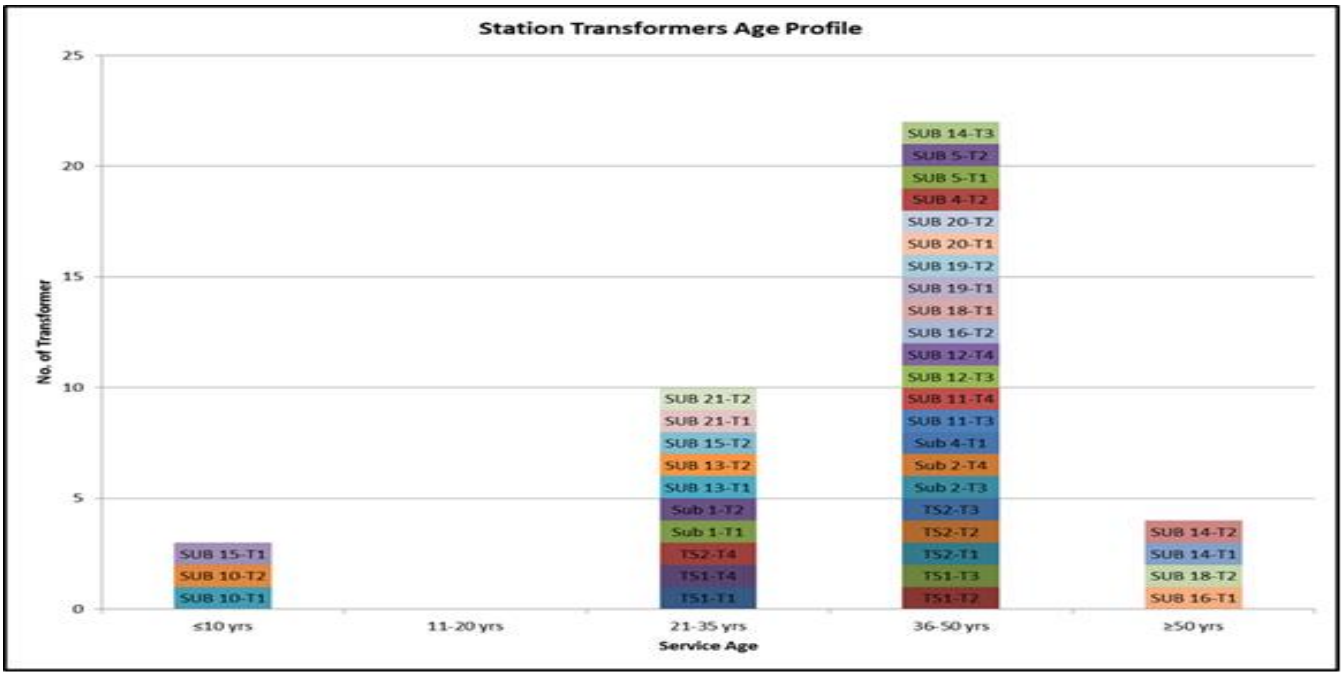


Figure 4-1: Distribution Station Locations

The results of condition assessment of major equipment employed at step-down stations are described below in detail.

4.1.1. Station Transformers

Figure 4-2 presents the age profile of power transformers employed at PUC DISTRIBUTION's step-down stations. As shown, approximately two thirds of the power transformers have reached a service age of greater than 35 years and four of the power transformers have been in service for more than 50 years. The transformer numbers in Figure 2 are not stacked in any priority order.



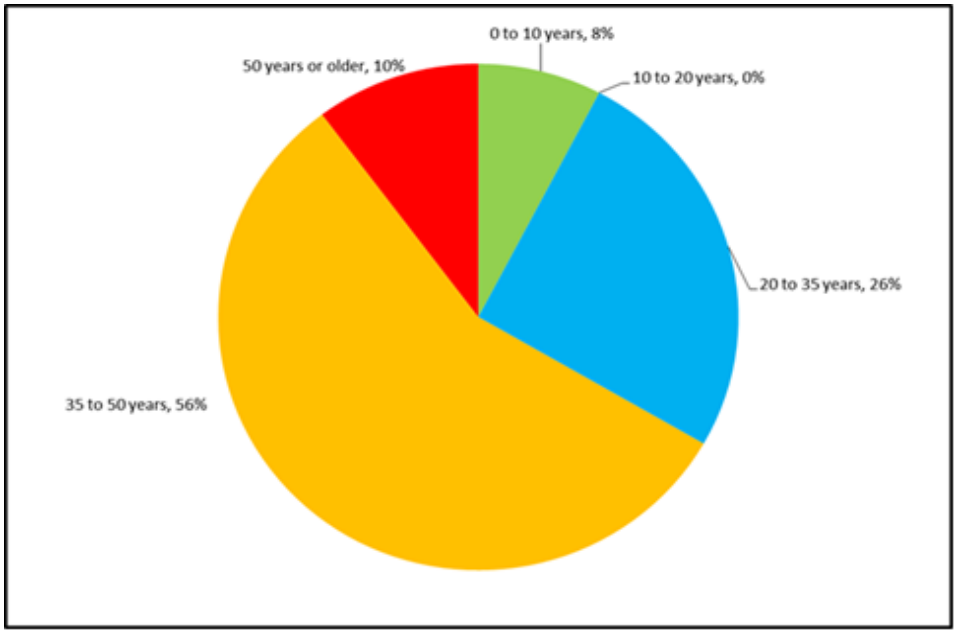


Figure 4-2: Age Profile of Station Transformers

Based on the condition assessment criteria detailed in Section 3, Health Index score has been calculated for each of the substation transformers and the results are summarized in Figure 4-3. It is noteworthy that the following transformers have undergone rehabilitation of the coil, which has been taken into account during calculation of the health index for these transformers:

- Sub 16-T1 (2013)
- Sub 13-T1 (2010)
- Sub 18-T1 (2008)
- Sub 19-T1 (2003)
- TS2 - T4 (1998)
- Sub 11-T4 (1992)

As shown, a total of 20 power transformers have determined to be in "poor" or "very poor" condition, 16 power transformers have been determined to be in fair condition and 3 transformers have been determined to be in in good or very good condition.

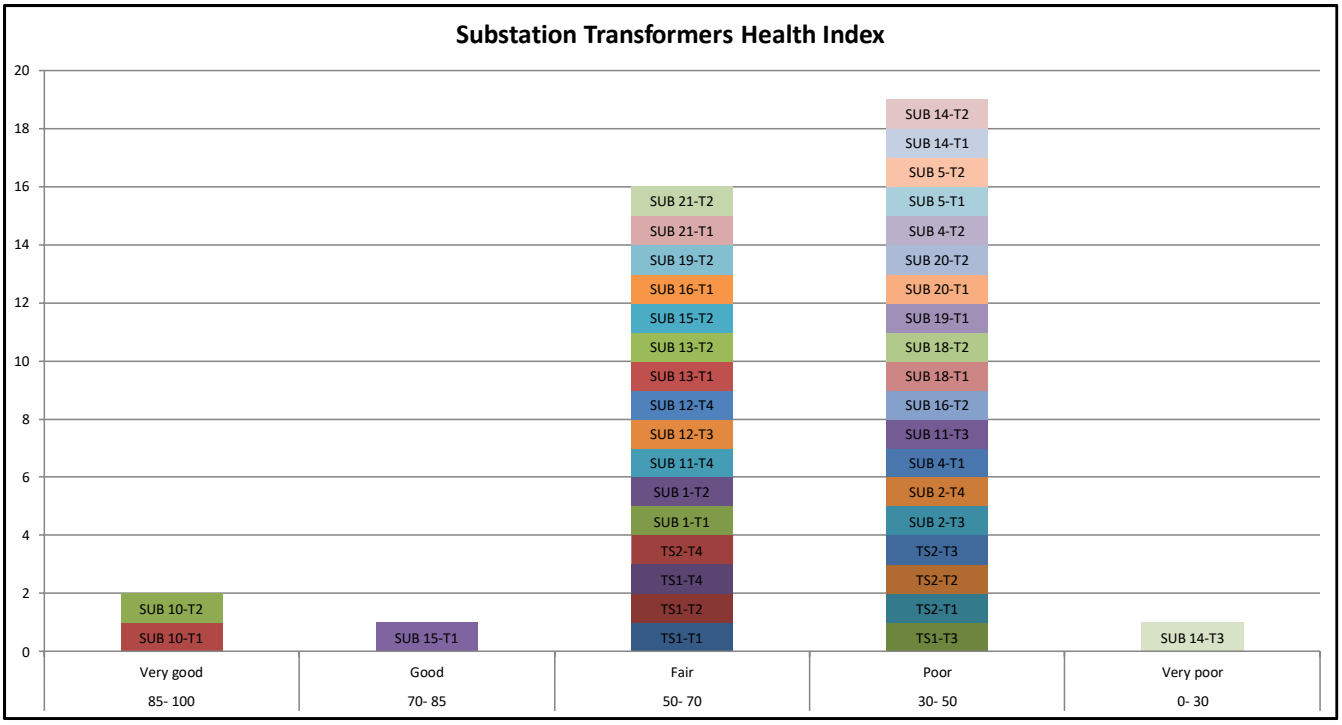


Figure 4-3: Health Index of Power Transformers Employed at Stations

4.1.2. Station Switchgear - Circuit Breakers

By taking into account the service age, the results of visual inspections and maintenance test reports (where available), Health Index score has been calculated for switchgear employed at the stations and the results are summarized in Figure 4-3. As indicated, switchgear at 14 of the stations has been determined to be in poor or very poor condition.

Although protection relays at most of the stations have been upgraded to modern solid state relays in the past, many stations employ switchgear designed and constructed using technologies, which are now considered obsolete. For example, both of the 115/34.5 kV stations employ oil circuit breakers for switching and protection on 115 kV bus. This type of circuit breaker design does not only require extensive preventative maintenance, but since the manufacture of circuit breakers using this technology has been abandoned for over 30 years, the spare parts are difficult to obtain and are costly. Similarly, a majority of the 34.5/12.47 kV stations employ magnetic air circuit breakers, which also require more frequent preventative maintenance in relation to modern technologies, employing vacuum circuit breakers and it is difficult and costly to obtain spare parts for the old vintage switchgear. Also the arc flash regulations under CSA Standard Z462 have undergone change over the years. The switchgear of older designs require complicated work methods to perform maintenance.

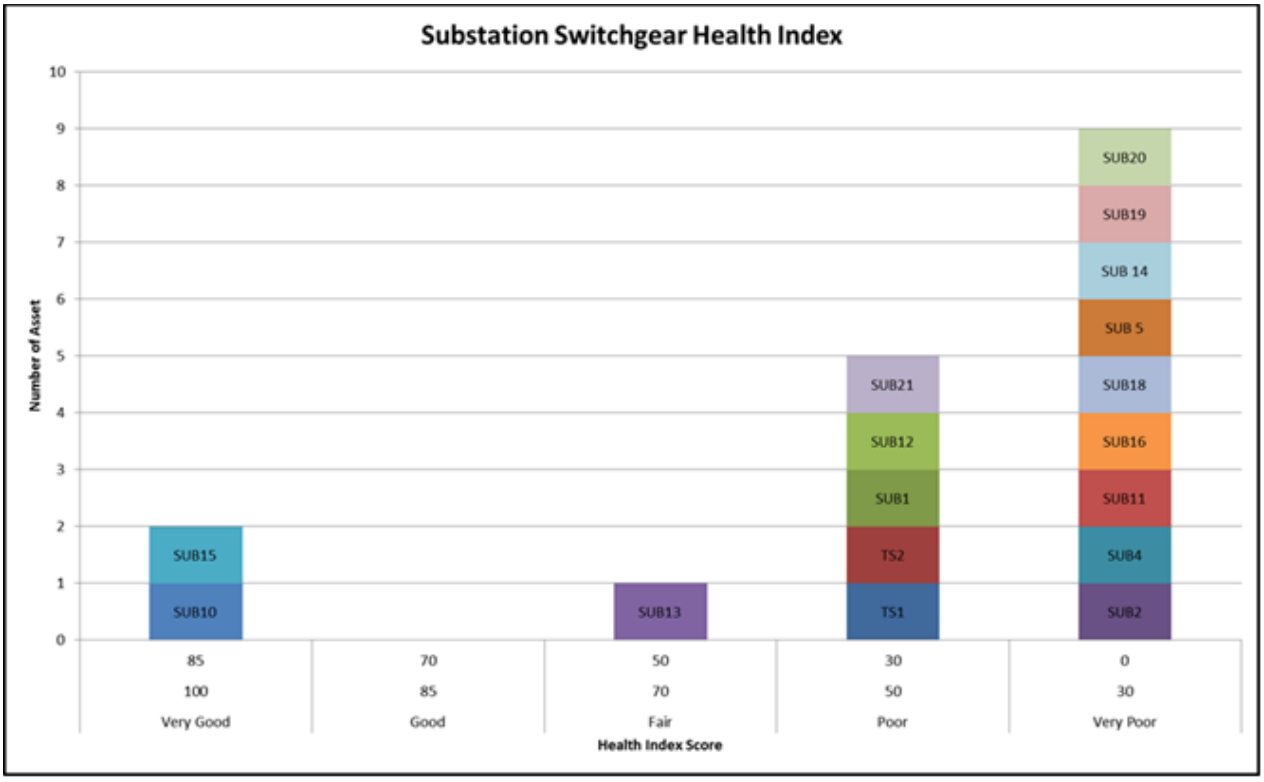


Figure 4-4: Condition Assessment of Station Switchgear

4.1.3. Stations Supervisory Control (SCADA) and Communication System

PUC DISTRIBUTION's SCADA network is comprised of 42 nodes in the form of remote terminal units (RTU's). The main SCADA server and operator's station is located at PUC's head office and a backup server and operator's station located at PUC's affiliate company's Water Treatment Plant. The interconnection between the servers, stations, and distributed devices is based on a fibre network with radio system tie-ins for sites where fibre is not cost effective. 9 of the 17 distribution and transmission stations are connected via fibre with the remaining 8 being on a MDS radio network. There are three distributed voltage regulators and three reclosures that are also on the MDS radio network. PUC also has 15 motor operated switches connected to SCADA via a Speednet radio system, which includes 3 repeaters.

Most of the network infrastructure has been upgraded since 2009 and it has expected design life of 15 years. The MDS master radio, which provides the interconnection between the remote MDS radios and fibre core, is planned to be replaced in 2016.

Each of the distribution stations is equipped with DC battery backup of adequate rating to run the station network infrastructure and RTU's for a minimum of 8 hours in the case of an AC power outage. Control battery typically provides a service life of approximately 15 years. PUC has taken the approach of replacing 1 distribution station battery bank and charger on an annual basis. The DC system chargers have a lifespan of 25 to 30 years. PUC requires redundant DC systems at each of the 2 transmission stations and has taken the approach of replacing 1 of the 4 total TS DC systems every 3 years. The cost of 115/34.5 kV station DC systems is substantially greater than 34.5/12.47 kV station DC systems due to the size required to run an entire transmission station.

4.1.4. Other Assets Employed at Stations:

Other important assets employed in stations include buildings, fences, ground grids and surface stone in station yards. Although a majority of the stations are old, the buildings are well maintained and in satisfactory condition.

The station ground grids have not been tested over the recent years to provide an accurate assessment of their condition. The condition assessment of ground grid, building and fences is based on visual inspections only.

By taking into account the service age and results of visual inspections, composite Health Index score for the buildings, yards, fences and ground grids was calculated and the condition of these assets is indicated is Figure 4.5. Two additional substations MS-5 and MS-14 are also in poor condition, but these are not included in Figure 4.5, as both of these stations are planned to be retired upon completion of the voltage conversion project and therefore these are not considered candidates for asset renewal.

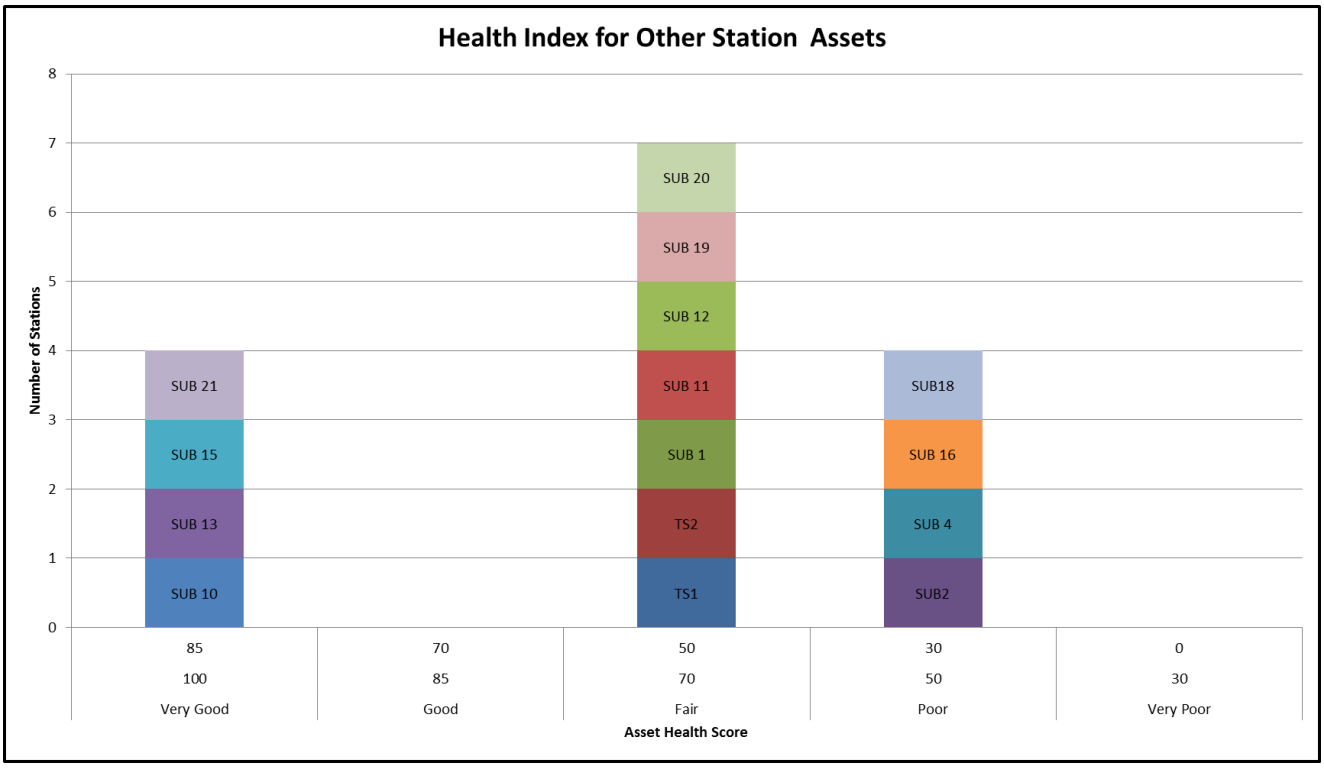


Figure 4-5: Condition Assessment of Auxiliary Assets

4.2. *Overhead Lines*

4.2.1. Distribution Line Support Poles

Based on the demographic information retrieved from the GIS system, there are approximately 12,600 wood poles and about 80 other types of poles (including steel, concrete and fiberglass) employed on PUC DISTRIBUTION's electricity distribution system. Figure 4-6 displays the age profile of line support poles employed on the distribution system. Approximately 328 poles (shown in red) have been in service for more than 60 years and an additional 857 poles (shown in yellow) have been in service for more than 50 and less than 60 years. More than 28% of the poles currently in service have a service age of 40 years more.

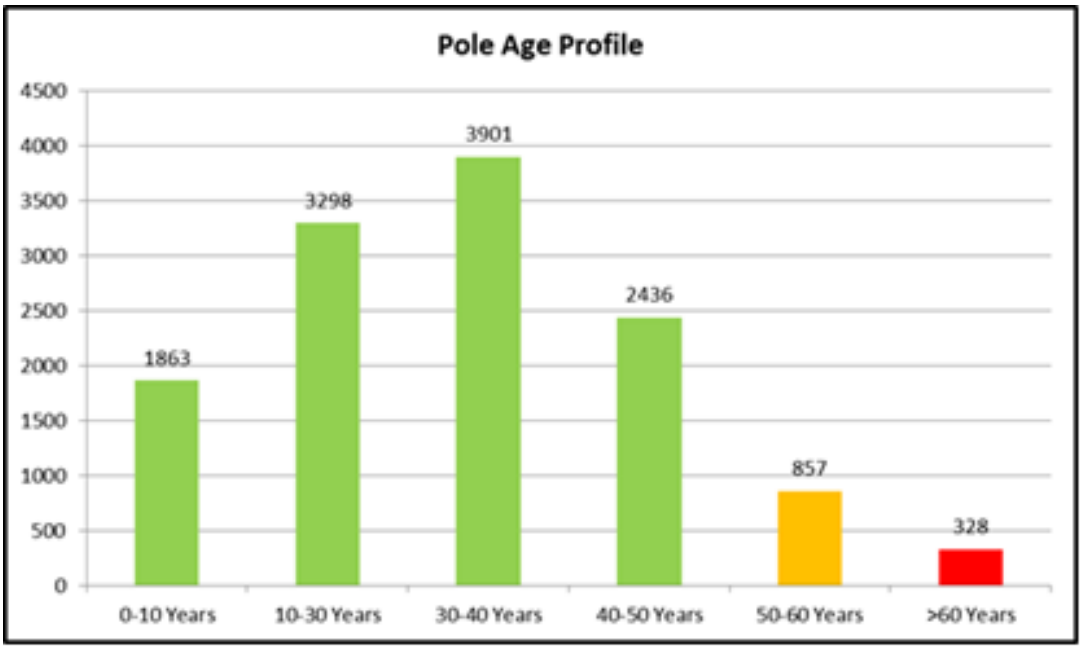


Figure 4-6: Age Demographics of Distribution Line Poles

Poles on distribution lines are employed in different configurations; some support only low voltage circuits, while others may support multiple circuits of different voltages, requiring taller poles. Figure 4-7 indicates the approximate percentage of different pole heights employed on the distribution system. As indicated, 35ft, 40ft and 45ft poles are used most commonly.

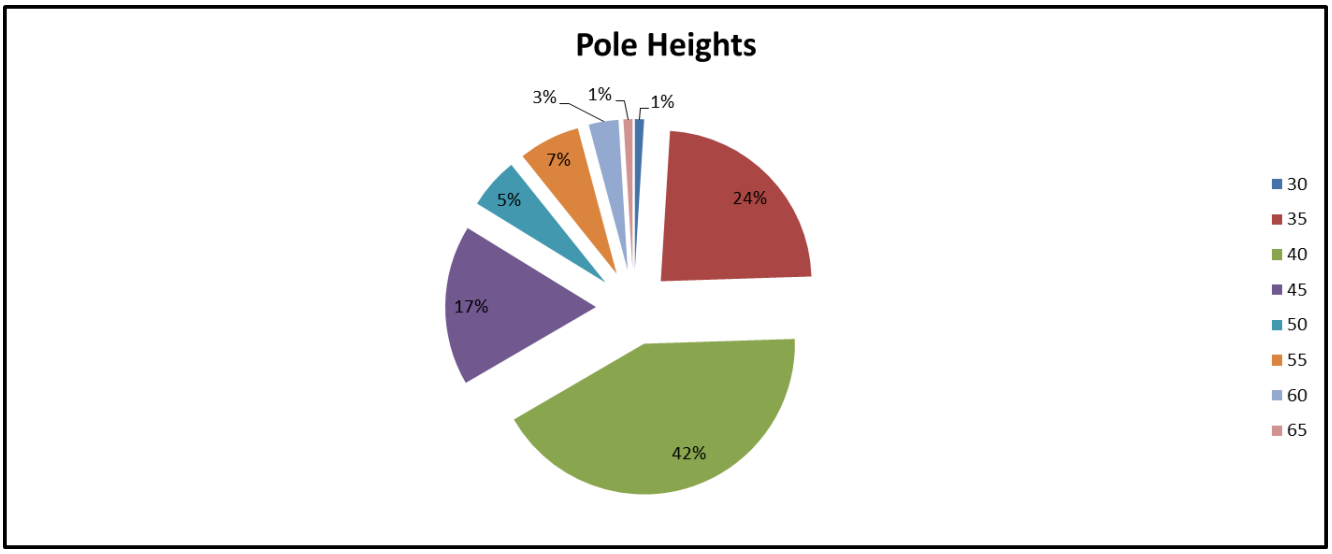


Figure 4-7: Distribution Pole Heights

Figure 4-8 displays the age profile of the poles with respect to their heights and as indicated a majority of the poles that have reached more than 50 years of service age fall within the 35', 40' and 45' height ranges.

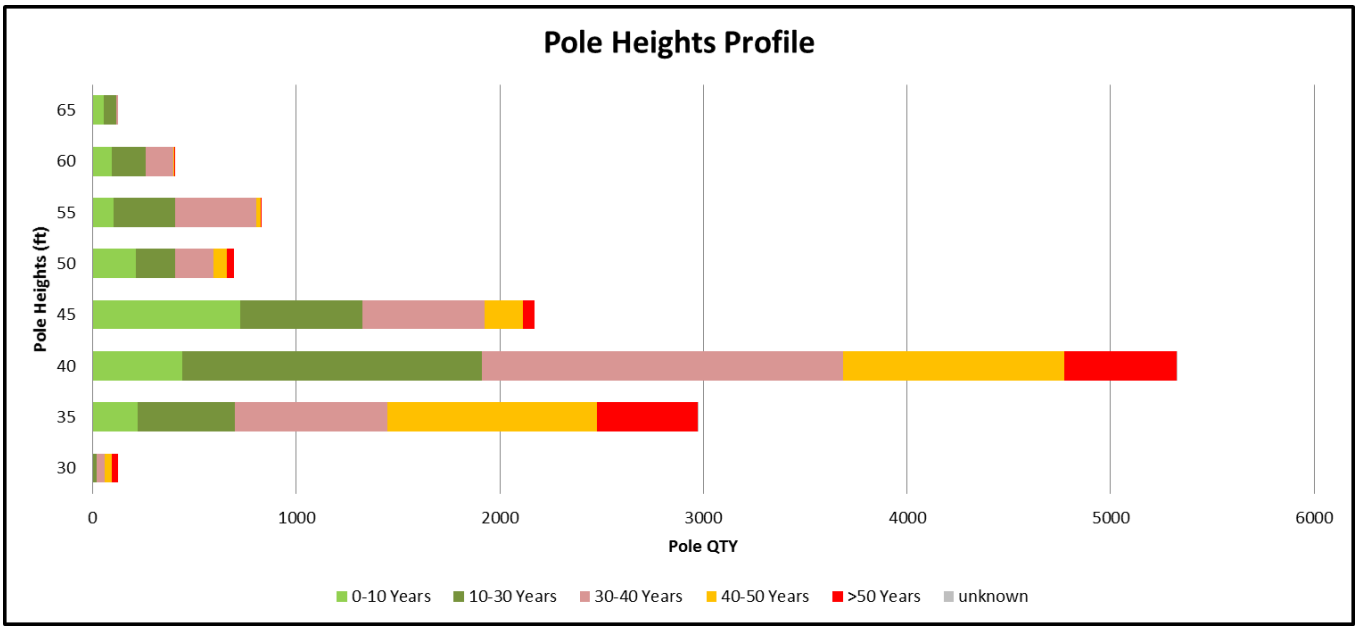


Figure 4-8: Age Profile of Poles of different Heights

PUC DISTRIBUTION has an on-going non-destructive pole testing program since 2003. Figure 4.9 shows the percentage of poles found in various conditions of strength through pole testing from 2003 to 2013. In this case, the Health Index score is calculated based on the remaining strength of the pole, where "very poor" equates to less than 3 years of remaining useful life, "poor" equates to less than 5 years of anticipated remaining useful life and "fair equates to anticipated remaining useful life of "5 to 20" years.

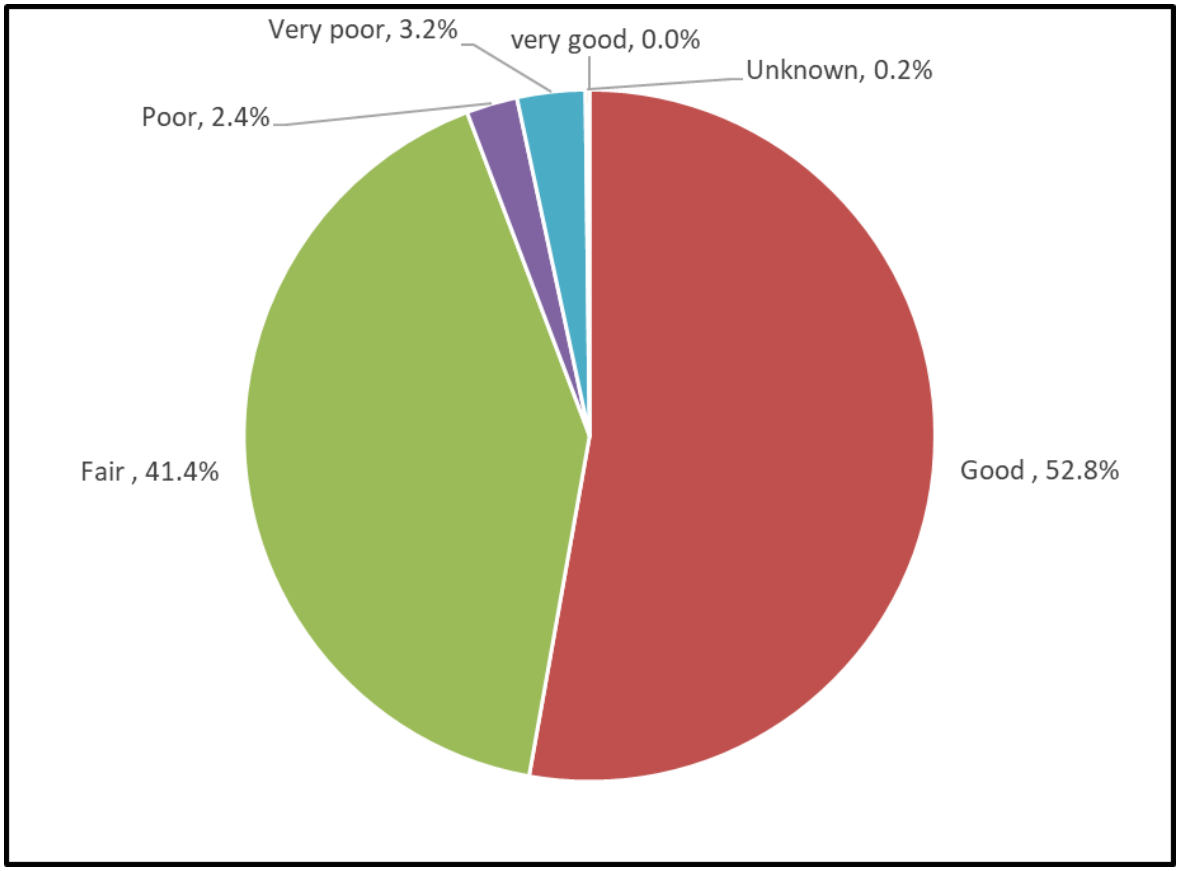


Figure 4-9: Condition Assessment of Wood Poles 2003 to 2013 Test Results

After the pole testing is completed poles found in very poor and poor condition are replaced during the following years. Pole testing has not been done during 2014 and 2015, but the tests during the previous ten years were performed on the entire population of poles. The results of this analysis are presented in Figure 4-10., indicating that approximately 700 poles were found to have reached "poor" or "very poor" condition over a period of ten years, requiring replacement of approximately 70 poles each year. Since a portion of the poles found in poor condition are employed on 4 kV lines, approximately half of the poles found in poor condition are simply retired from service during implementation of voltage upgrade program.

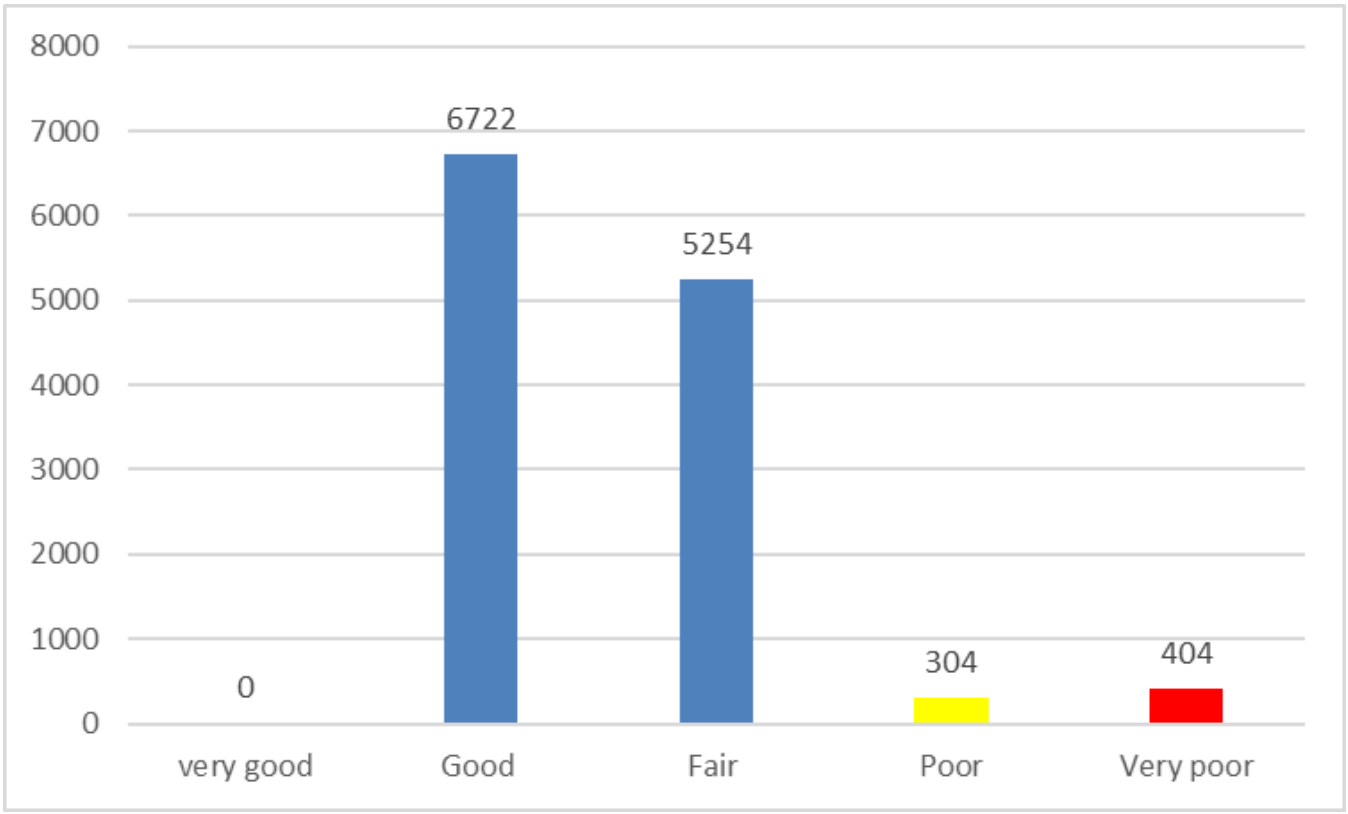


Figure 4-10: Wood Poles Health Index Score for Entire Pole Population

4.2.2. Overhead Line Conductors

PUC DISTRIBUTION's overhead distribution network employs approximately 391 km. of 3-phase and approximately 230 km of 1-ph lines, all operating at 115kV, 34.5 kV, 12.5kV, 7.2kV, 4.2kV and, 2.4 kV. Figure 4-11 and Figure 4-12, respectively, show the age profile of overhead lines and as shown, approximately 29% of the 3-ph lines and approximately 29% of the 1-ph lines will reach the end of their design service life of 45 years during the next five years. As the lines approach the end of their design life, all line components including wood poles, mounting hardware and conductors experience degradation of strength and pose a high risk of failure in service when subjected to design loading during wind and ice storms. To mitigate this risk, these lines will require rebuild with new poles and conductors.

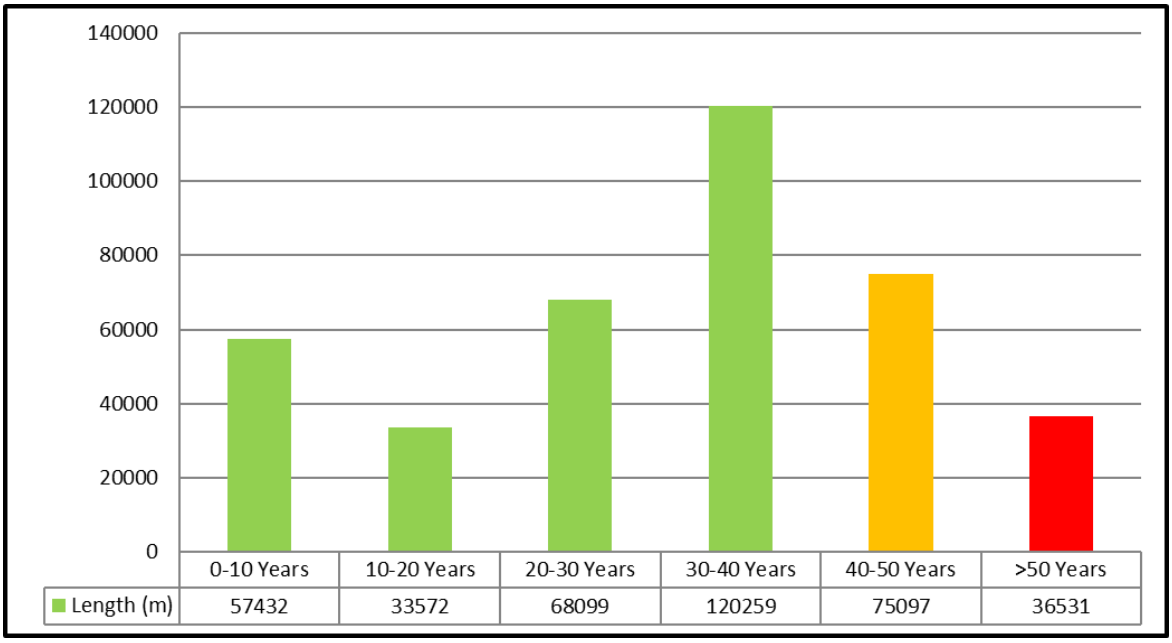


Figure 4-11: Age Profile – 3 Phase Overhead Lines

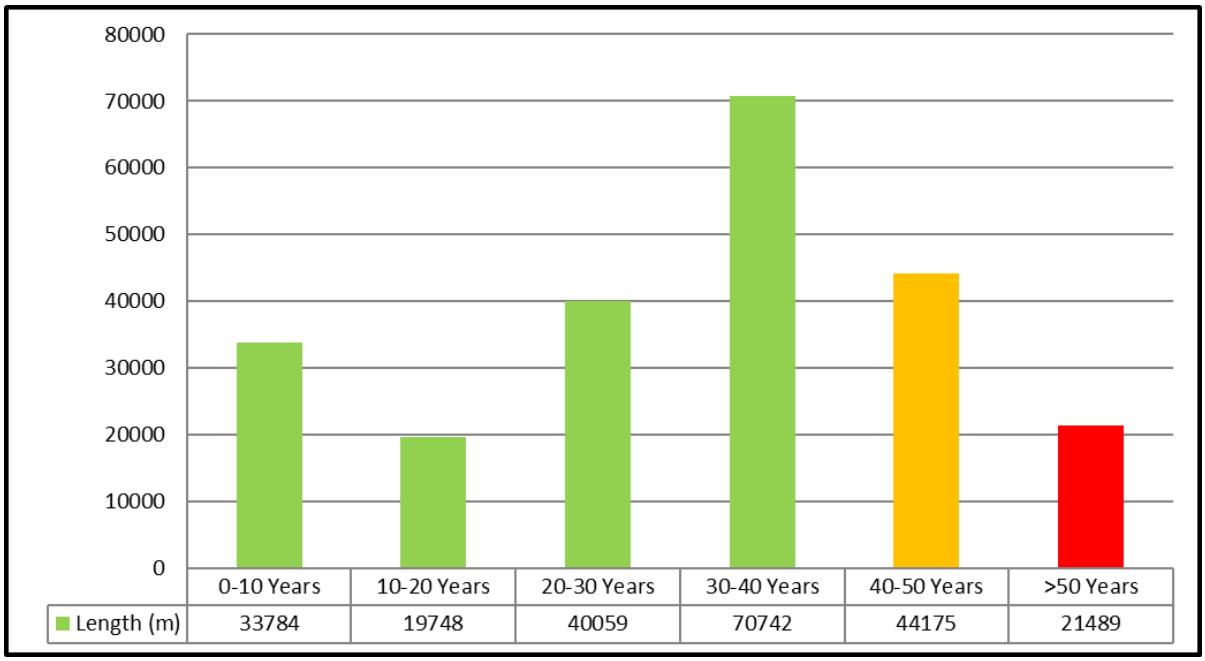


Figure 4-12: Age Profile – 1 Phase Overhead Lines

While the service age of ACSR or aluminum conductors is not generally on the critical path to determine the end of service life of overhead distribution lines, a small fraction of the PUC DISTRIBUTION's overhead lines employ copper conductors of small cross-section (#6 or smaller). These conductors are commonly referred to as "restricted conductors" and they are known to degrade in mechanical strength with service age, due to reduction in their tensile strength.

Recognizing the high risk of failure in service of restricted conductors, PUC DISTRIBUTION adopted a program for replacing the restricted conductors in 2009. Figure 4-13 and Figure 4-14 show the progress made to date in replacing the restricted conductors and the extent of lines with restricted conductors still in service as of the end of 2015. All existing overhead lines with restricted conductors are determined to be in poor condition and it is recommended the work of reconstructing these lines with aluminum conductor should continue.

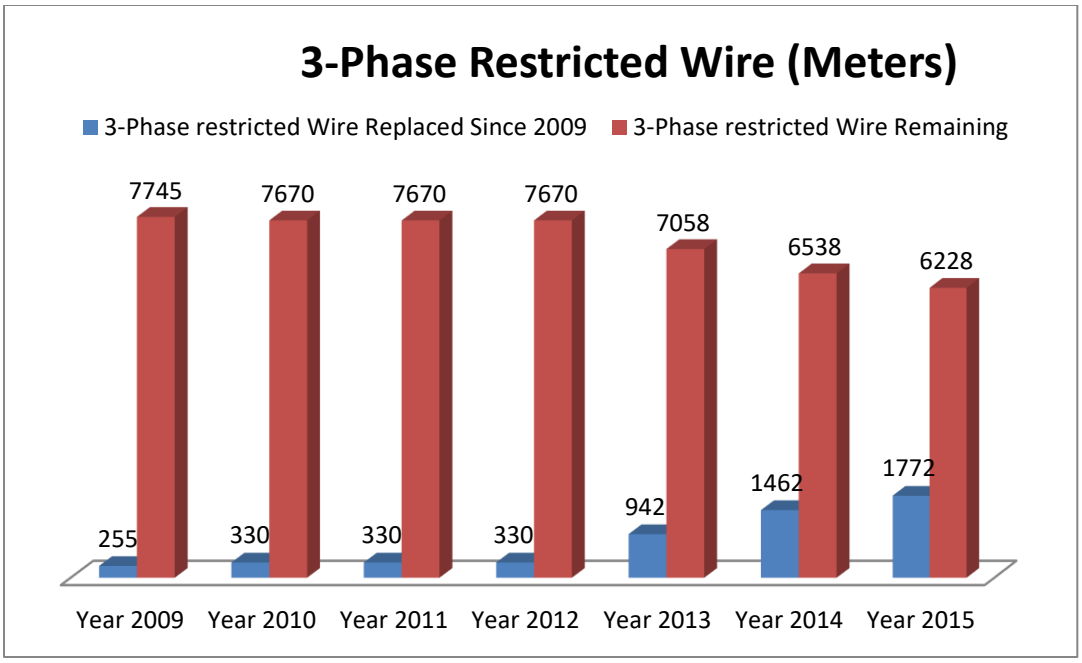


Figure 4-13: 3-Phase Overhead Line Lengths with Restricted Conductors

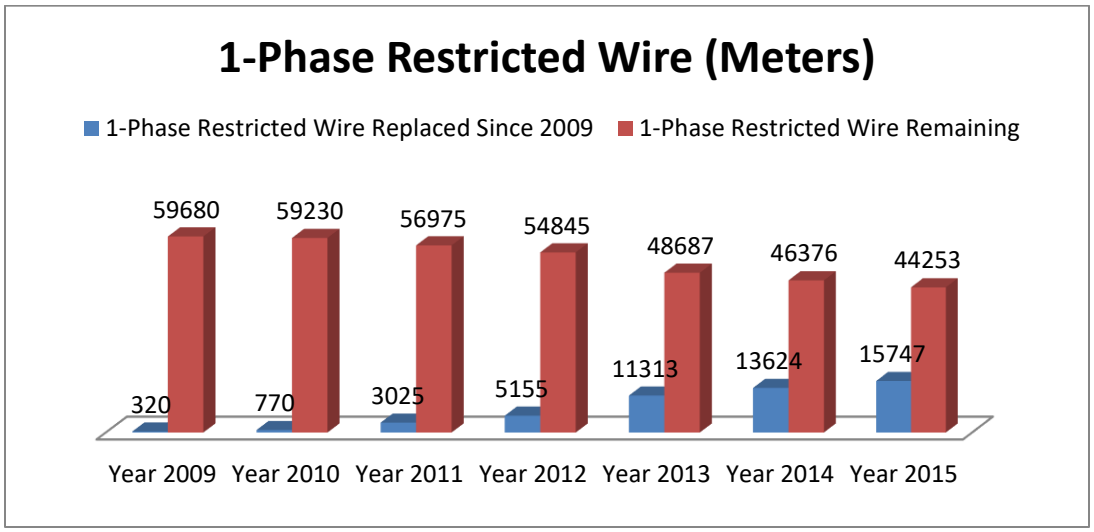


Figure 4-14: 1-Phase Overhead Line Lengths with Restricted Conductors

4.2.3. Overhead Distribution Switches and Cut-outs

PUC DISTRIBUTION's overhead lines are well equipped for disconnecting and isolating, load-breaking, and fault interrupting to provide means of isolation during power interruptions and operational functions and adequately protect the circuits during system faults. A majority of the line switches are pole type. Hook-switch operated cutouts are used for switching and isolating pole mounted transformers. The age data for the overhead switches and cutouts was unavailable, but the line switches and cutouts are typically replaced at the time of reconstruction of the line.

Porcelain insulated cut-outs have been in use in the electrical industry for many decades. Porcelain was also the material of choice for most other electrical equipment that required insulation, i.e. line insulators, arresters and bushings. In the early 1980's large numbers of porcelain insulators began failing, particularly in cold climate regions. "Cement growth" was causing insulators to crack. The expansion and contraction of the adhesive interface which joined the porcelain to the hardware (connector) caused stresses on the porcelain. These stresses caused small cracks to appear in the porcelain which eventually lead to an electrical and/or mechanical failure of the porcelain insulator.

Distribution insulators had been the focus of the industry's attention throughout the past 30 years, resulting in expenditure of millions of dollars to rectify the problem of defective porcelain. During the past several years many utilities throughout North America have seen increasing failures of their porcelain insulated cut-outs. The mode of failure is very similar to that of insulators. Small cracks in the porcelain initially appear near the interface between the porcelain and hardware. These fractures eventually lead to a mechanical failure of the cut-out. Cement growth is the likely cause of the initial cracks. The breakage of porcelain insulated cut-outs is a concern from a safety and reliability perspective. During cut-out operation the porcelain can break causing the cut-out to separate into two parts. This creates a hazard to line personnel operating the cut-out and can cause outages to customers. The common industry solution to this problem has been replacement of the porcelain insulated cut-outs with polymer insulated cut-outs, as shown in Figure 4-15.



Figure 4-15: Porcelain (Left) and Polymer (Right) Insulated Cut-outs

PUC DISTRIBUTION has also been systematically replacing the porcelain cut-outs and switches with polymer cut-outs switches since 2010. Approximately 2700 defective switches and cut-outs were identified for replacement under this program and by the end of 2015 replacement of all but about 100 of the defective switches and cut-outs had been completed. The remaining 100 defective switches and cut-outs are scheduled for replacement in 2016 and this program will be complete by the end of 2016.

4.3. *Underground Distribution System*

4.3.1. Underground Primary Conductors

The underground distribution network at PUC DISTRIBUTION employs approximately 75 km. of 3-phase cable circuits and approximately 47 km of 1-phase and 2-phase cable circuits. Figure 4-16 and Figure 4-17, respectively, show the age profile of distribution cable on 3-phase and on 1-phase and two phase 12.5 kV distribution circuits as of 2015. Approximately 25% of the cable has reached service age of greater than 40 years. There are no practical tests available which could be economically performed in field to accurately assess the remaining useful life of cables. However, XLPE insulated cables, which are typically employed on underground distribution systems, generally begin to experience an increase in failure rates when they get past 40 years of service age. It is also noteworthy that a vast majority of the cables installed prior to 1990 were installed in direct buried

configuration. Cable failures in direct buried configurations have significantly larger impact on reliability than failures that occur where cables are installed in duct. All cable circuits past 40 years of service age are considered in poor condition.

Figure 4-18 and Figure 4-19, respectively, show the age profile of distribution cables employed on 3-phase and 1-phase circuits at 4.16 kV. As indicated, a majority of these cables are past their 40 year typical useful service life. These cables are generally planned to be removed from service when these service areas are upgraded to 12.47 kV. The relatively small amount of cable, with service age of less than 20 years age, is rated for use on 12.5 kV (in anticipation of the voltage conversion) and these circuits will remain in service after voltage conversion.

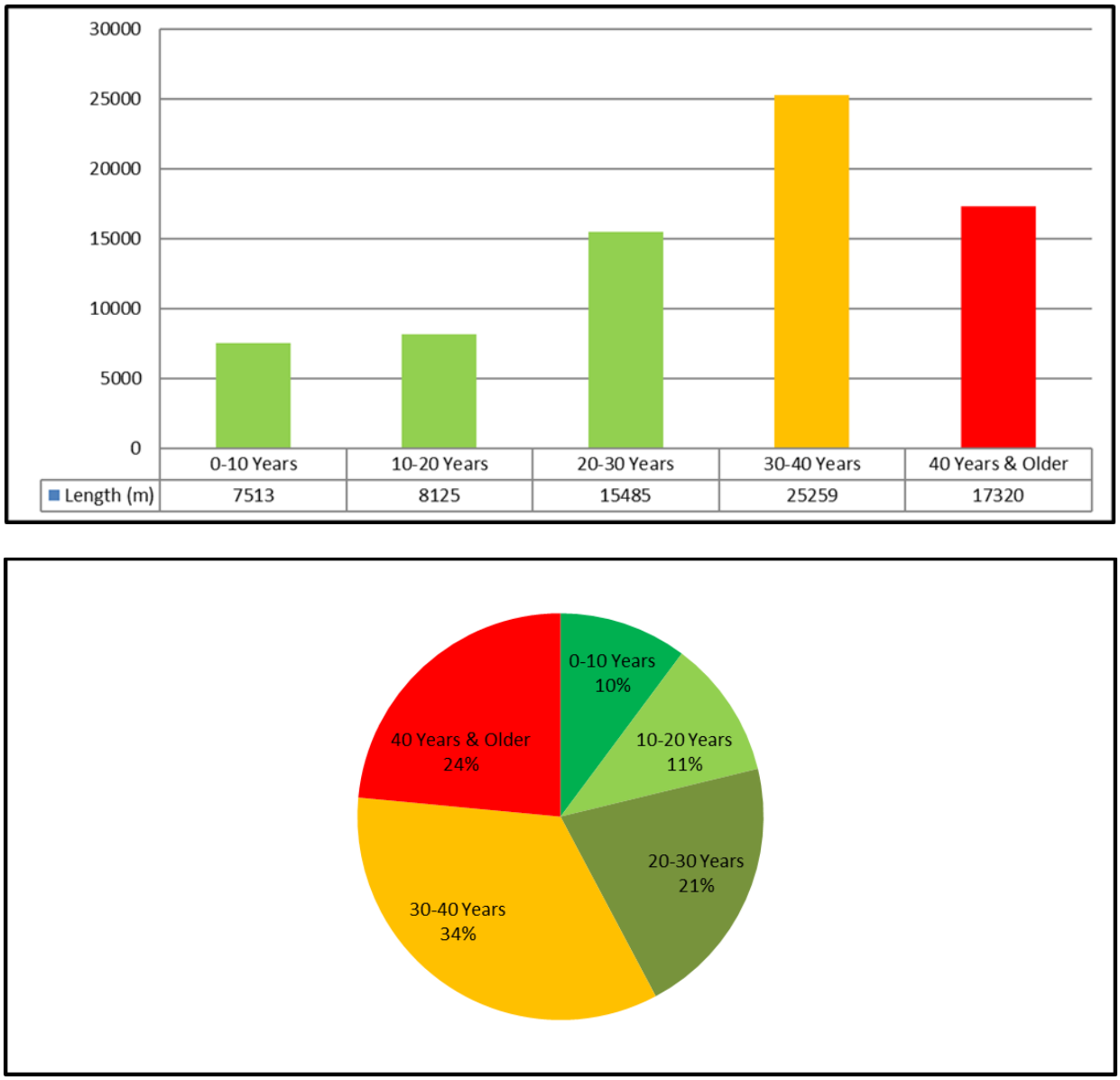
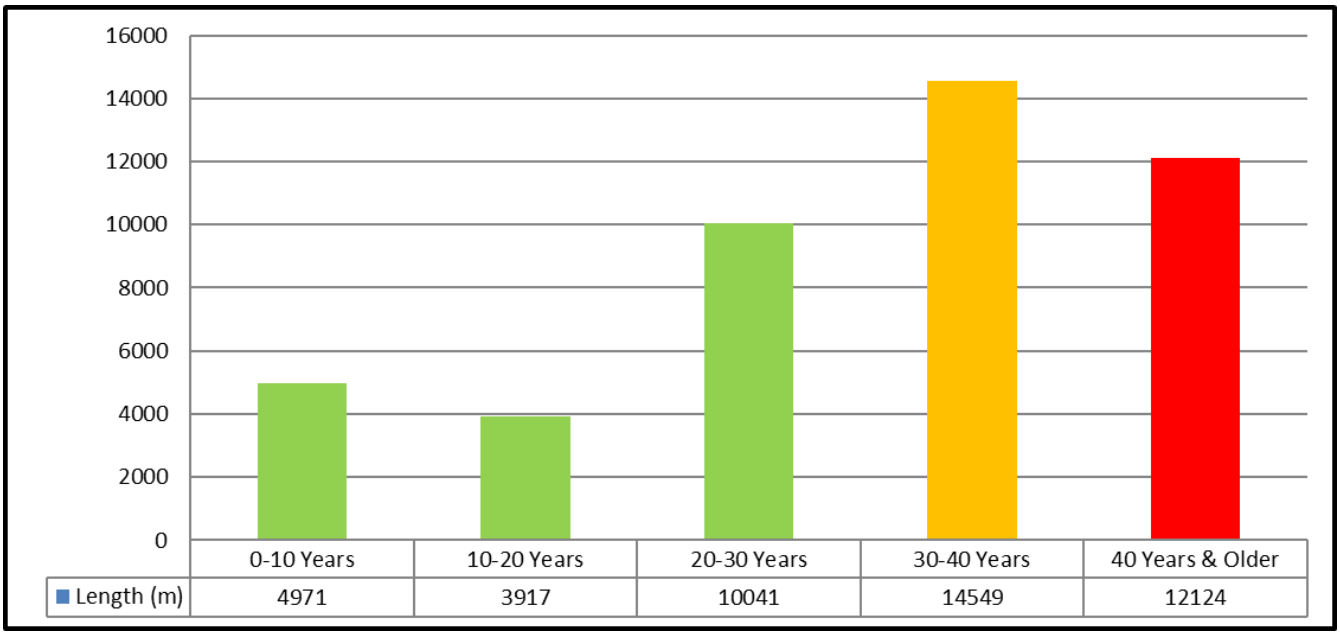


Figure 4-16: Age Profile – 34.5 kV and 12.47kV, 3-Phase Underground Cable Circuits



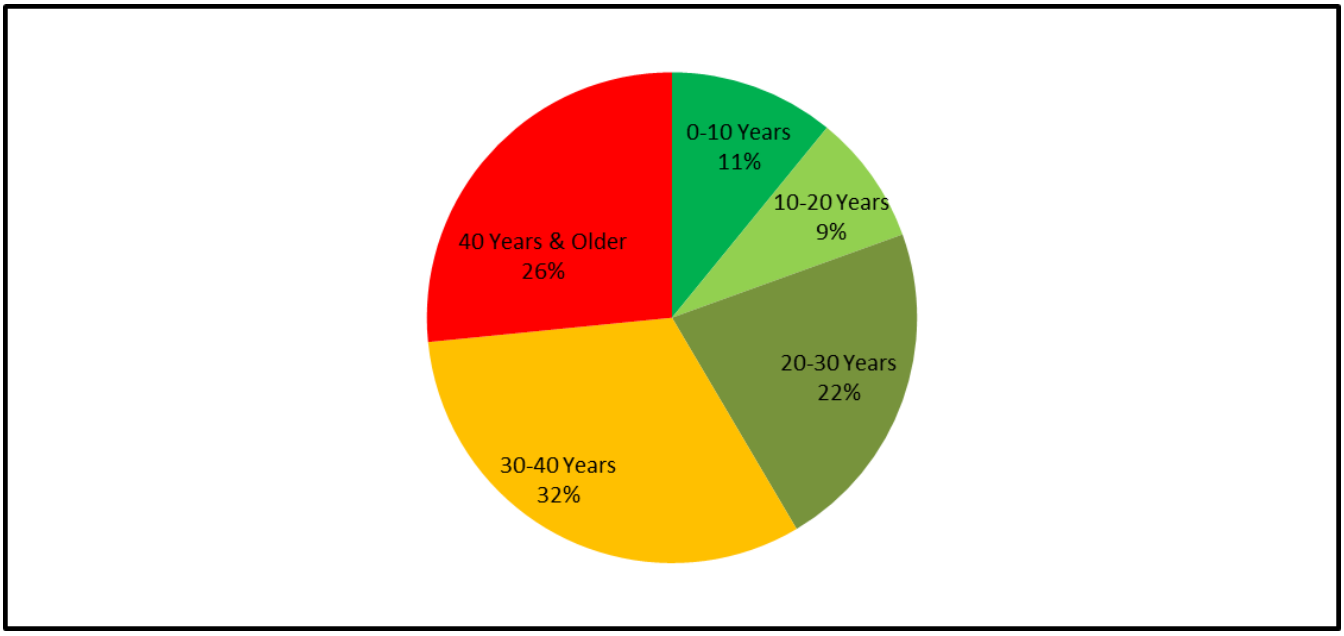


Figure 4-17: Age Profile – 12.47kV, 1-Phase Underground Cable Circuits

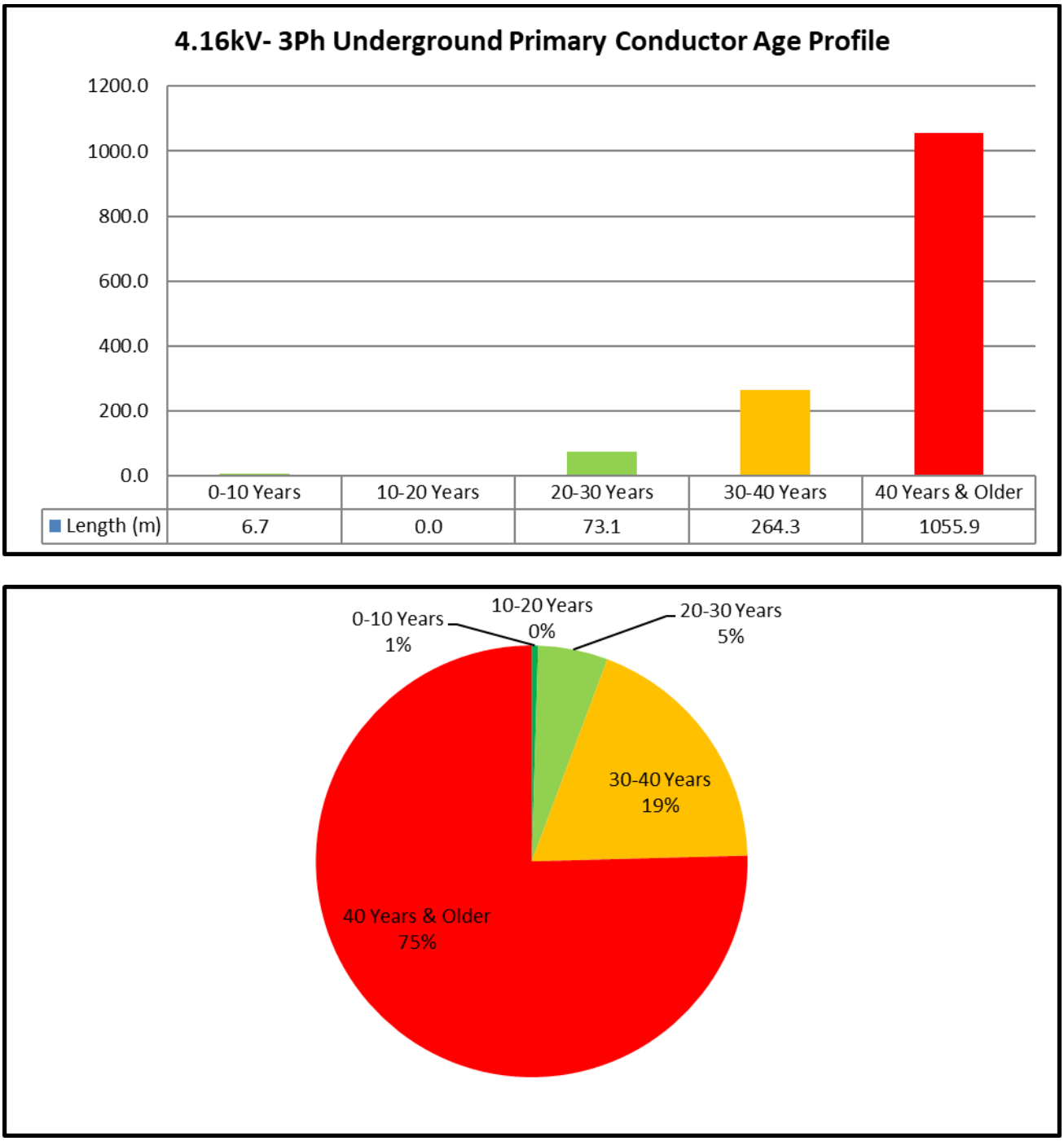


Figure 4-18: Age Profile – 4.16kV, 3-Phase Underground Cable Circuits

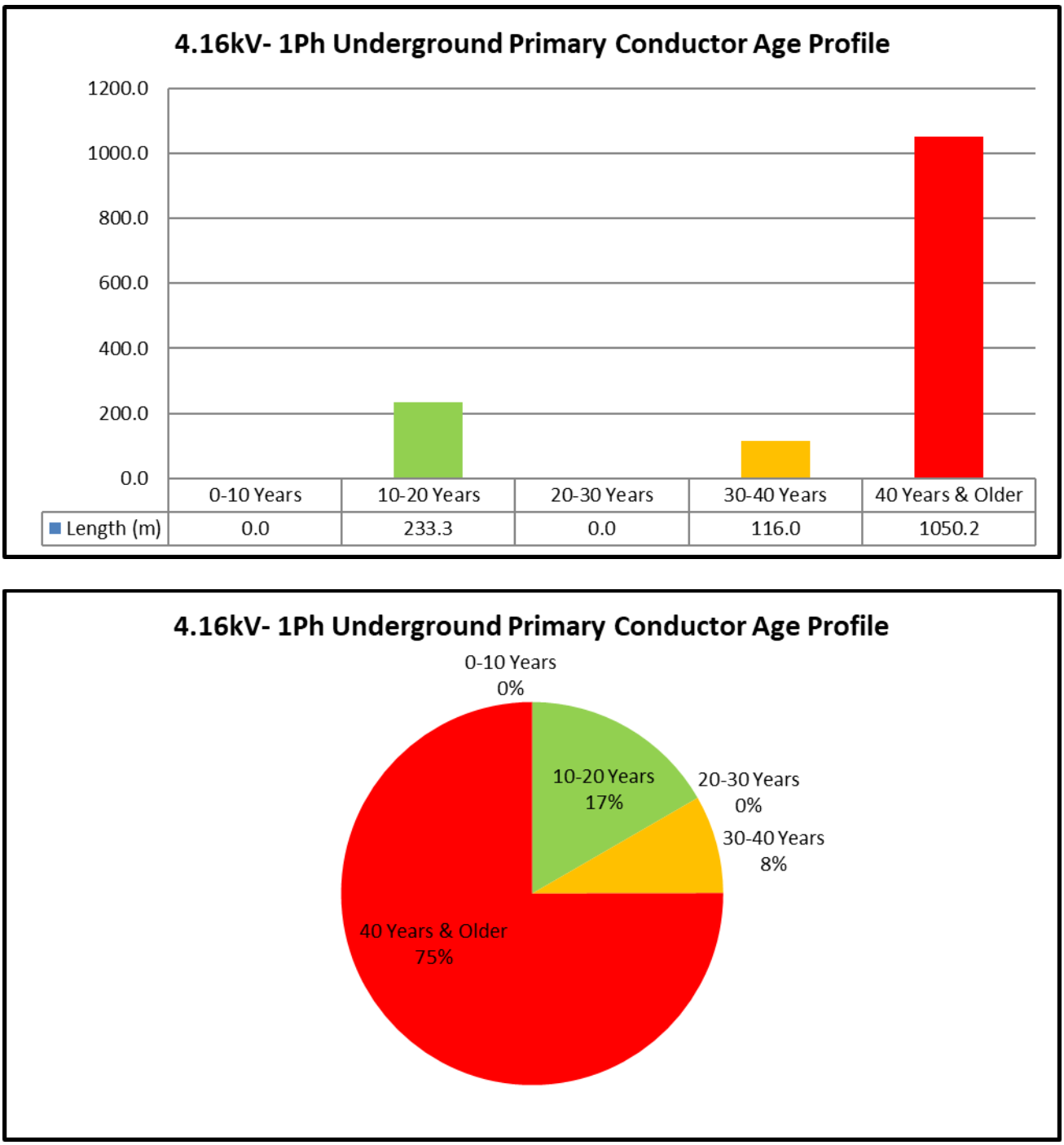


Figure 4-19: Age Profile – 4.16kV, 1-Phase Underground Cable Circuits

4.3.2. Pad-mounted Switchgear

At PUC DISTRIBUTION, live front pad-mounted switchgear, is the most commonly employed pad-mounted switchgear on underground distribution system, with a recent move towards dead front. Figure 4-20 indicates the age profile of pad-mounted switchgear. This type of switchgear

provides reliable service life of about 35 years. Based on service age and visual inspections, 5 of the pad mounted switchgear units, are determined to be in poor or very poor condition, as shown in Figure 4-21.

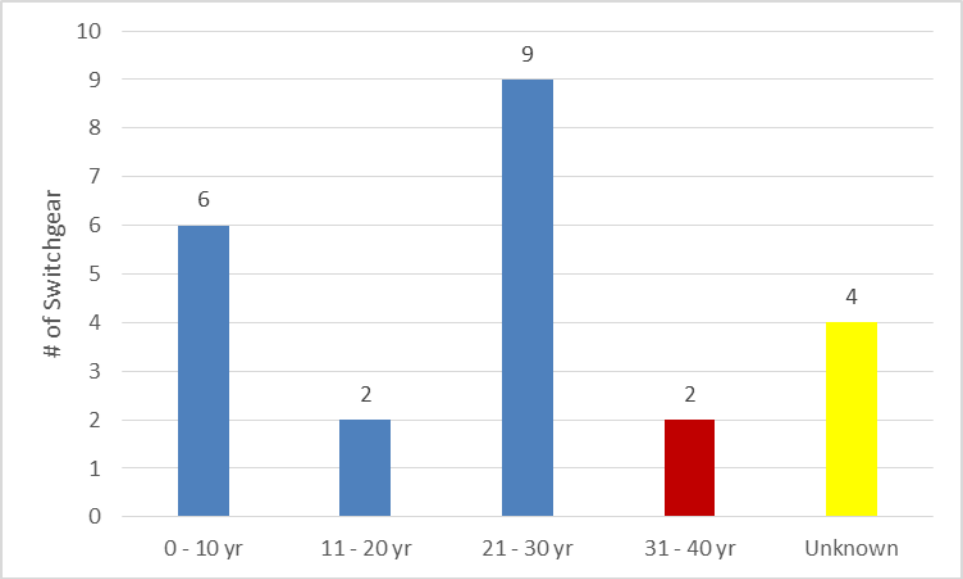


Figure 4-20: Age Profile – Pad-mounted Switchgear

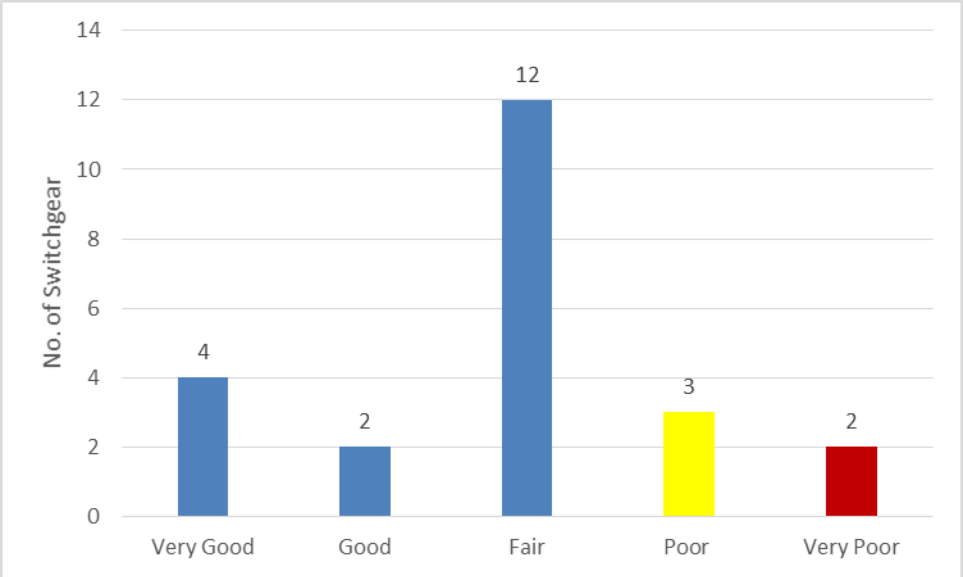


Figure 4-21: Condition Assessment of Pad-mounted Switchgear

Exact installation year for a majority of K-Bar junction boxes with service age of greater than 35 years is not known with certainty, but the estimated age profile for K-bar units is indicated in Figure

4-22. A majority of the junction boxes will reach the end of their typical service life of 40 years during the next five years.

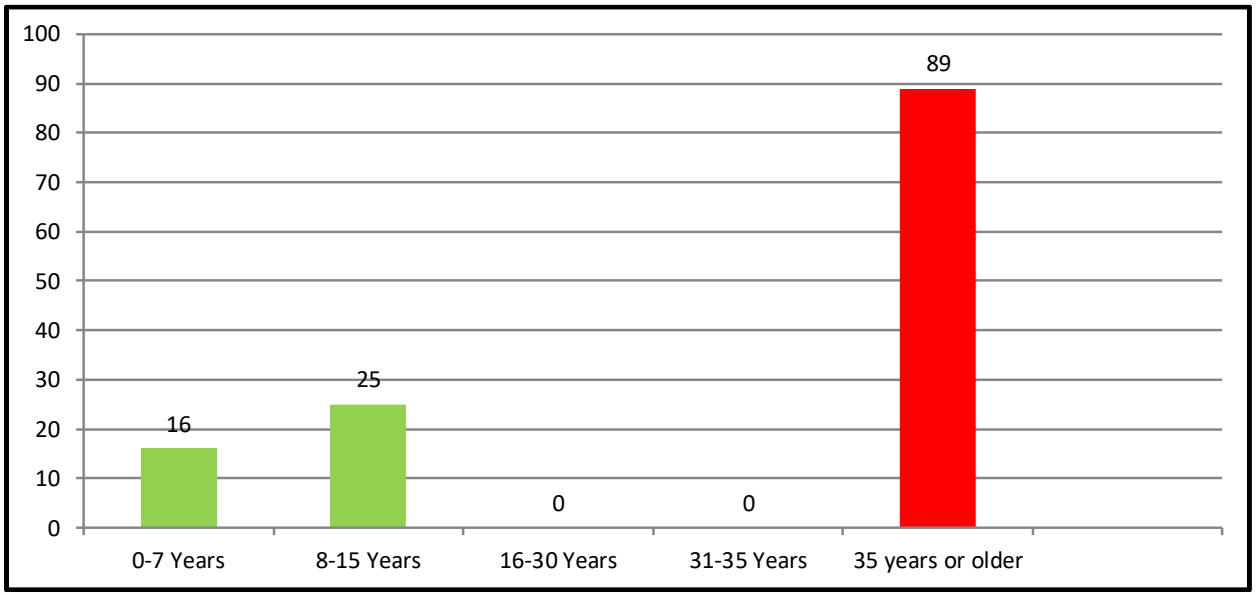


Figure 4-22: Age Profile – Pad-mounted K-Bar Units

4.3.3. Underground Concrete Chambers

PUC DISTRIBUTION's underground distribution system employs concrete chambers for various functions, including cable pull-boxes and manholes, mounting bases for switchgear and K-bar junctions, submersible transformer vaults, splice vaults and general-purpose equipment vaults. As shown in Figure 4-23, there approximately 23% of the chambers are currently more than 50 years old. Physical inspections of the concrete structures indicate, a large percentage of these old vintage chambers are functionally obsolete. From the point of view of worker safety, the submersible transformer vaults and splice vaults present a challenge in that outages are required to complete maintenance work increasing costs and inconveniencing customers.

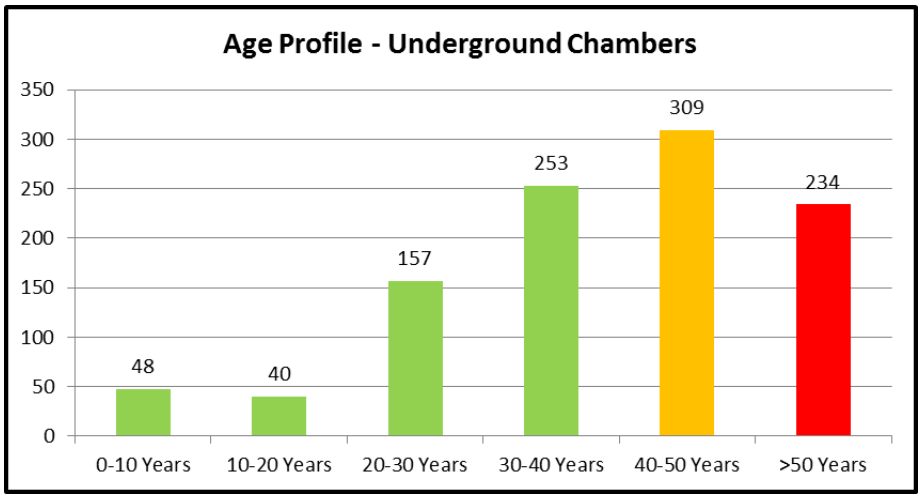


Figure 4-23: Age Profile of Underground Concrete Chambers

The submersible transformer vaults and splice vaults of inadequate size and without concrete floors, as shown in Figure 4-24, present the highest risk to workers and therefore, have been given a priority for reconstruction.

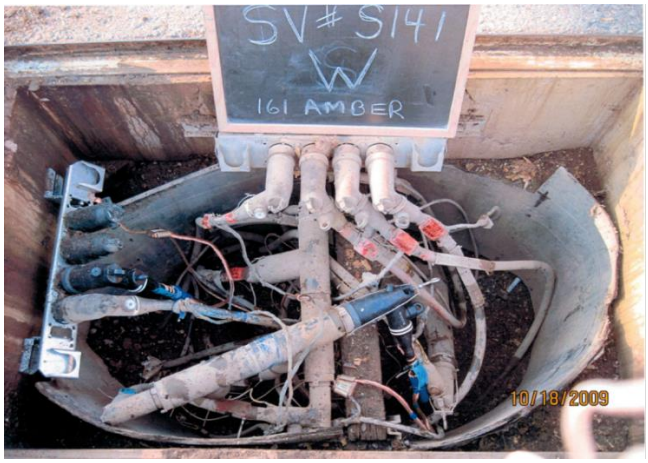


Figure 4-24: Underground Splice/Switching Vault

4.4. *Distribution Transformers*

PUC DISTRIBUTION has four different types of transformers in service: Pole-mounted, 1-phase Pad-mounted (mini-pad mount), 3-phase pad mounted and submersible vault type. Figure 4-25 through Figure 4-28 indicate the age profiles of transformers in each class.

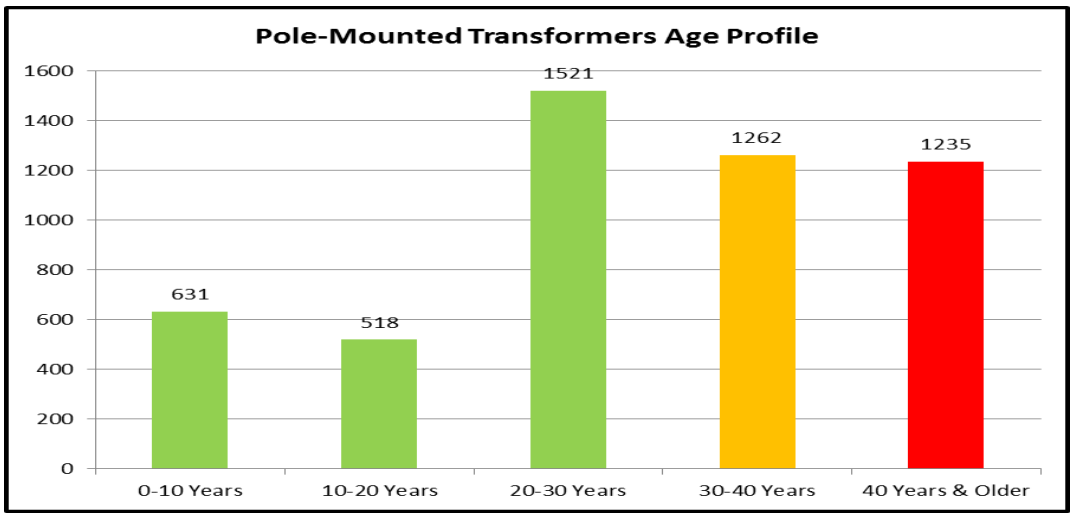


Figure 4-25: Pole Mounted Transformers – Age Profile

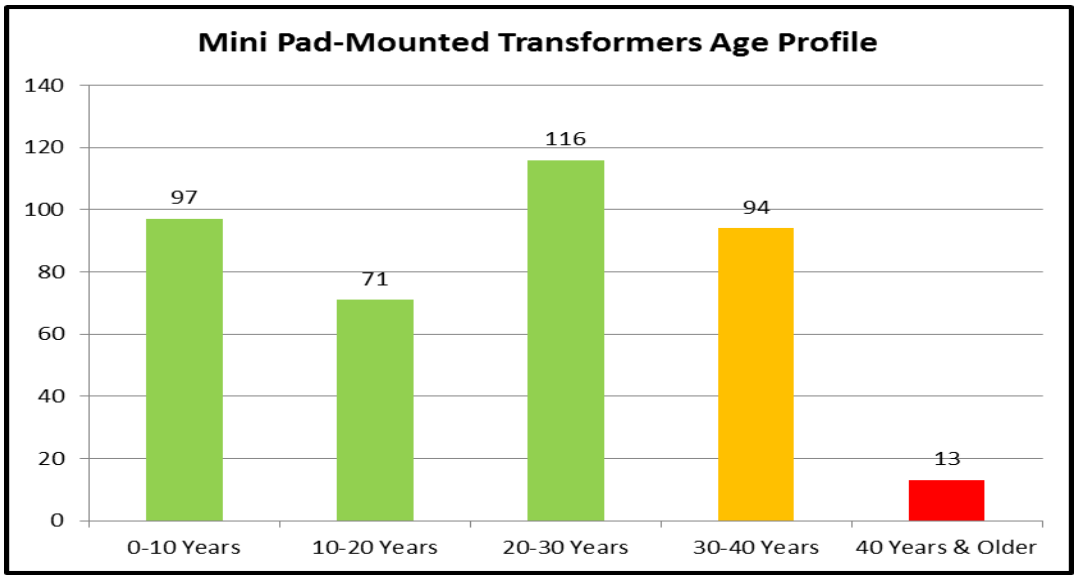


Figure 4-26: 1-Ph Pad-mounted Transformers – Age Profile

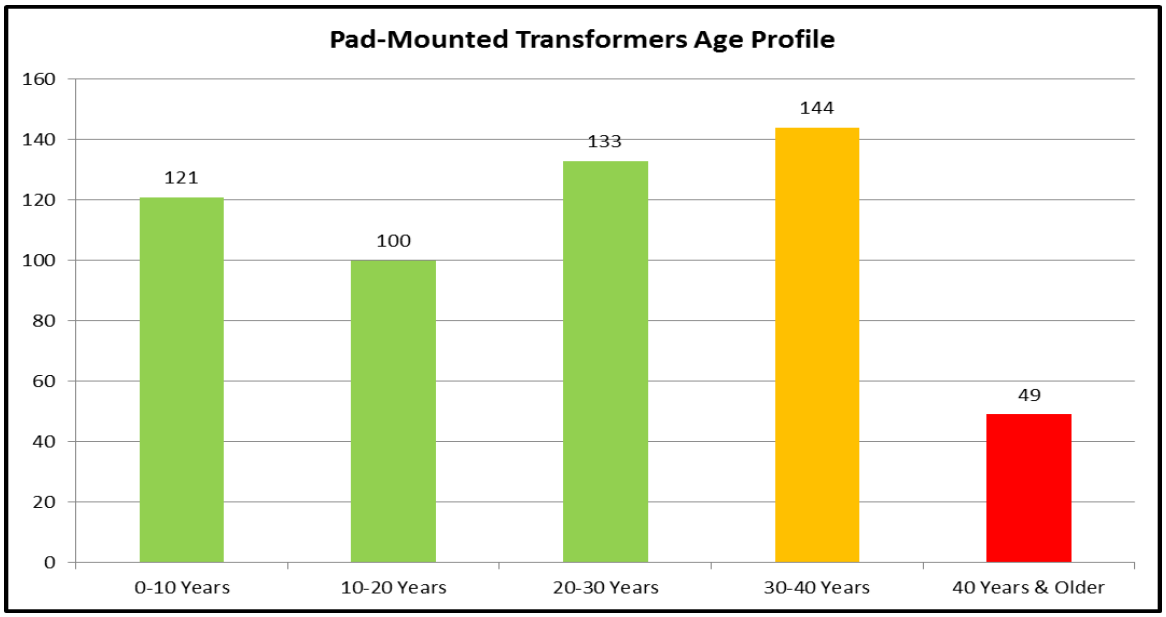


Figure 4-27: 3-Ph Pad-mounted Transformers – Age Profile

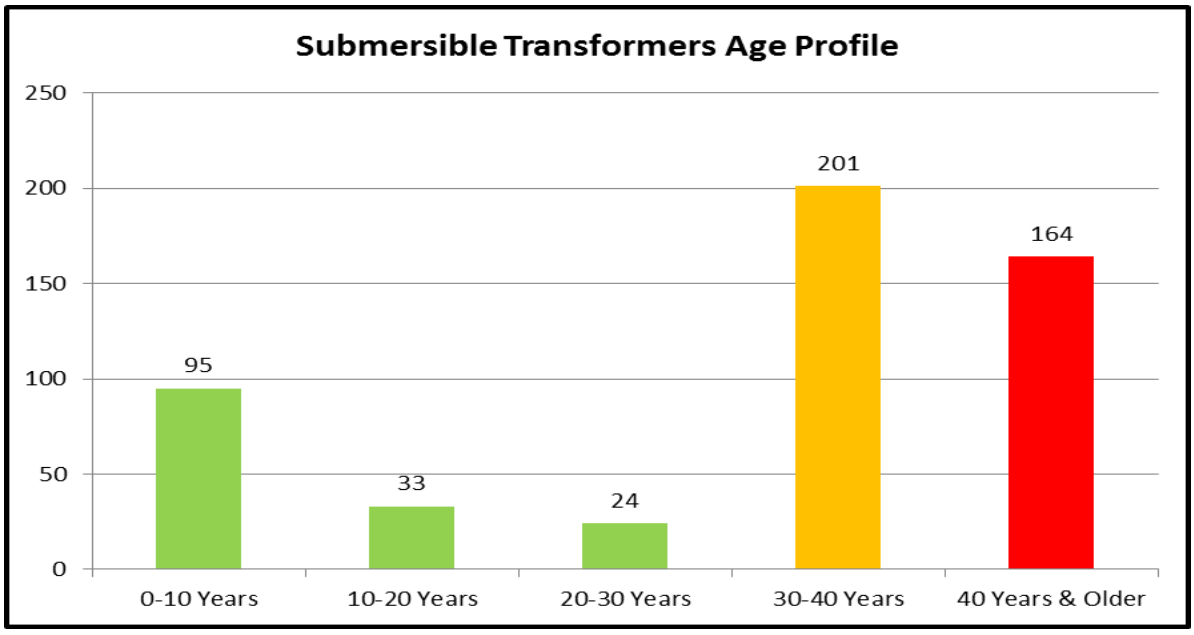


Figure 4-28: Submersible Vault Mounted Transformers – Age Profile

PUC DISTRIBUTION employs "run-to-failure" strategy for distribution transformers and due to the relatively low impact of transformer failures on reliability, this strategy serves well for the first three types of transformers and it is also in line with all other LDCs. However, because vault mounted transformers are not generally replaced with the same type of transformer upon failure, some degree of pre-planning is required to replace these with pad mounted transformers. Therefore, a proactive program is required to replace the submersible transformers with pad mounted transformers.

4.5. *Revenue Meters*

PUC DISTRIBUTION owns approximately 33,500 revenue meters, installed on its customers' premises for the purpose of measuring electric consumption, demand, and billing of connected load. The meters vary in type depending on the connection type and customer class, and are capable of measuring kWh consumption, for TOU customers, kW and KVA demand for GS >50, as well as bi-directional meters for renewable generation applications. PUC DISTRIBUTION completed the installation of all of its Residential and General Service <50kW Smart Meters by December 2010 as part of the Province of Ontario's mandated Smart Meter initiative.

Table 4-1: Revenue Meter Quantities

Customer Type	# of Customers
Residential	29708
GS<50	3419
GS>50	360
Total	33487

Table 4-1 shows the breakout of PUC DISTRIBUTION's active meters by customer/meter types. A vast majority of PUC DISTRIBUTION's electric meters were installed in 2009 and have a seal year of 2019. PUC DISTRIBUTION plans to sample 600 meters in 2019, 200 in 2020 and 80 in 2021 all in accordance with Measurement Canada's "S-S-05—Performance Requirements Applicable to Meters Granted a Conditionally Lengthened Initial Reverification Period under S-EG-01" - sample its meter population to acquire an extension of up to 8 years. It is planned on testing and recalibrating 50 three-phase meters in 2020.

PUC is also required to equip all general service customers with >50kW to <500kW demand with MIST meters

In addition, revenue meters will also be required to replace meters failed in service and the failure rate of revenue meters is expected to be approximately 0.6% per year.

In addition to the above, spare revenue meters would be required to replace meters that fail in service. Table 4-2 shows the revenue meter failures on PUC DISTRIBUTION's network during the past six years. As shown in Table 4-2, the average number of meter failures per year between 2009 and 2015 has been 216.

Table 4-2: Revenue Meter Failures

Year	Number of meter failures
2010	332
2011	332
2012	240
2013	102
2014	195
2015	92
Average number of failures per year	216

Table 4-3 summarizes the revenue meter requirements to facilitate replacement of meters failed in service as well as removal from service of the required batch size of revenue meters for calibration, prior to expiry of the meter seals. It is noteworthy that the meters purchased in 2017 to facilitate calibration check will be transferred to general inventory and will become available for replacement of failed meters in subsequent years.

Table 4-3: Revenue Meter Requirements

Year	2016	2017	2018	2019	2020	2021
1-phase meters to replace meters failed in service	220	220	220	220	220	220
1-phase meters required to facilitate recalibration				200		
3-phase meters to replace meters failed in service	5	5	5	5	5	5
3-phase meters required to facilitate recalibration					50	

5 ASSET INVESTMENT PLAN

Based on the results of condition assessment of major assets employed in step down stations, overhead lines and underground distribution system, described in detail in Section 4, this section provides the budgetary estimates of capital investment required during the next six years to replace and rebuild those assets, that present high risk of failure in service, posing a threat to supply system reliability, public and employee safety and operating efficiency.

5.1. Step-down Station Assets:

Since the in-service failure of power transformers and switchgear in step-down stations has the largest impact on power supply security and reliability, a long term proactive program is recommended to gradually reconstruct all of the stations, determined to be in poor or very poor condition.

Both of the 115/34.5 kV transformer stations (TS-1 and TS-2) will require rebuild during the next five to ten years. However to maximize the benefit/cost ratio of this major investment, significant front-end planning and engineering is required to successfully implement the rebuild of these stations. Therefore, we are recommending a planning/engineering study be commissioned to review all practical development options and identify the optimal option for implementation. For the 34.5 / 12.47 kV stations, we recommend at least two stations be included in the next five-year plan for rebuild, based on the condition of power transformers, switchgear and auxiliary equipment. Although the power transformers and switchgear at each of the three 4 kV distribution stations are also currently in poor and very poor condition, no provision is made in the investment plan for renewal of these stations, as these are recommended to be retired from service.

To minimize the risk of in-service equipment failures at the transformer stations and distribution stations, we recommend equipment condition be closely monitored through inspections and testing backed with repair and refurbishment, as required.

5.2. Overhead Distribution System:

Proposed investments into overhead distribution system, include re-construction of lines determined to be in "poor" and "very poor" condition. Because lines constructed with restricted conductors present a growing safety risk, it is recommended all 3-phase and 1-phase lines constructed with restricted conductors be rebuilt during the next eight to ten years. The five-year budget includes provision for rebuilding of 75% of all existing lines with restricted conductors. Proposed investment for line rebuilds also includes projects initiated through voltage conversion to facilitate retiring of the 4 kV stations as well as forced line rebuilds after failure of assets on existing lines. The investment plan also includes funding to replace poles found in poor and very poor condition during pole testing

5.3. Underground Distribution System:

Underground distribution cables in a number of subdivisions have reached a service age beyond their typical useful service life. Cables at the end of their useful life are expected to experience an increase in failure rates with adverse impact on reliability. Therefore, we recommend an increase in funding to replace or rejuvenate cables in this investment plan. The investment plan also includes funding for rebuilding of underground transformer vaults and splice vaults which present safety hazards to workers. Investment plan also includes funding for replacement of pad mounted switchgear and k-bar junction boxes found in poor condition.

5.4. Distribution Transformers:

For distribution transformers, a "run to failure" strategy is proposed, where a transformer is replaced only after failure. This Investment plan includes budgetary provisions to replace distribution transformers after they fail. Current PCB regulations in Canada permit the use of distribution transformers containing PCB content in oil of up to 50 parts per million and this use can continue up to December 31, 2025. All distribution transformers must be below 50 parts per million after December 31, 2025. To comply with this regulation, distribution utilities will need to either (a) test all suspect transformers (purchased prior to 1984) for PCB content and replace those containing PCBs above the threshold, or (b) replace all suspect transformers (purchased prior to 1984). The five-year investment plan includes budgetary provision for testing suspect distribution transformers for PCB content.

5.5. Miscellaneous Assets:

Investment plan includes budgetary provision for purchase of revenue meters, required to replace revenue meters failed in service as well as for calibration of meters upon expiry of meter seals. A small and reasonable amount has also been included for tools and equipment and for capital repairs to office buildings.

Table 5-1 summarizes the overall scope of capital investments proposed for the next six years. The cost estimates are based on unit-cost in 2015, and include an allowance for inflation at an annual rate of 2%.

Table 5-1: Investment Plan (2017 to 2021)

System Component	Project Description	Units of Measurement	Quantity (2017 - 2021)	Unit Cost in 2016 $	Budget in 2016 $ (2017 to 2021)	Annual Cost in 2016 $	Inflation adjusted Expenditure in Each Year				
							2017	2018	2019	2020	2021
Overhead Lines	3-Ph Line rebuild - restricted conductor	m	3,100	$ 200	620000	$ 124,000	$ 126,480	$ 129,010	$ 131,590	$ 134,222	$ 136,906
	1-Ph Line rebuild - restricted conductor	m	22,100	$ 100	2210000	$ 442,000	$ 450,840	$ 459,857	$ 469,054	$ 478,435	$ 488,004
	3-Ph Line rebuild - voltage upgrade	m	3,000	$ 200	$ 600,000	$ 120,000	$ 122,400	$ 124,848	$ 127,345	$ 129,892	$ 132,490
	1-Ph Line rebuild - voltage upgrade	m	20,000	$ 100	$ 2,000,000	$ 400,000	$ 408,000	$ 416,160	$ 424,483	$ 432,973	$ 441,632
	3-Ph Line rebuild - Lines in poor/very poor condition	m	24,000	$ 200	$ 4,800,000	$ 960,000	$ 979,200	$ 998,784	$ 1,018,760	$ 1,039,135	$ 1,059,918
	1-Ph Line rebuild - Lines in poor/very poor condition	m	6,000	$ 100	$ 600,000	$ 120,000	$ 122,400	$ 124,848	$ 127,345	$ 129,892	$ 132,490
	Replace degraded poles	#	200	$ 7,500	$ 1,500,000	$ 300,000	$ 306,000	$ 312,120	$ 318,362	$ 324,730	$ 331,224
	Forced asset replacement upon Failures (capitalized repairs)	#	5	$ 250,000	$ 1,250,000	$ 250,000	$ 255,000	$ 260,100	$ 265,302	$ 270,608	$ 276,020
	Subtotal overhead lines				**$10,750,000**	**$2,150,000**	**$2,193,000**	**$2,236,860**	**$ 2,281,597**	**$ 2,327,229**	**$ 2,373,774**
Underground Distribution System	Replacement of 3-phase cables in poor/very poor condition	m	4,980	$ 360	$ 1,792,800	$ 358,560	$ 365,731	$ 373,046	$ 380,507	$ 388,117	$ 395,879
	Replacement of 1-phase cables in poor/very poor condition	m	6,420	$ 150	$ 963,000	$ 192,600	$ 196,452	$ 200,381	$ 204,389	$ 208,476	$ 212,646
	Rejuvenation of 3-phase cables (Silicone injection)	m	3,320	$ 180	$ 597,600	$ 119,520	$ 121,910	$ 124,349	$ 126,836	$ 129,372	$ 131,960
	Rejuvenation of 1-phase cables (Silicone injection)	m	4,280	$ 75	$ 321,000	$ 64,200	$ 65,484	$ 66,794	$ 68,130	$ 69,492	$ 70,882
	Replacement of 3-phase cables for voltage upgrade	m	1,300	$ 360	$ 468,000	$ 93,600	$ 95,472	$ 97,381	$ 99,329	$ 101,316	$ 103,342
	Replacement of 1-phase cables for voltage upgrade	m	1,150	$ 150	$ 172,500	$ 34,500	$ 35,190	$ 35,894	$ 36,612	$ 37,344	$ 38,091
	Pad-mounted switchgear replacement	#	5	$ 15,000	$ 75,000	$ 15,000	$ 15,300	$ 15,606	$ 15,918	$ 16,236	$ 16,561
	k-bar replacement	#	40	$ 8,000	$ 320,000	$ 64,000	$ 65,280	$ 66,586	$ 67,917	$ 69,276	$ 70,661
	Vault rebuilds	#	60	$ 12,500	$ 750,000	$ 150,000	$ 153,000	$ 156,060	$ 159,181	$ 162,365	$ 165,612
	Forced asset replacement upon Failures (capitalized repairs)	#	5	$ 300,000	$ 1,500,000	$ 300,000	$ 306,000	$ 312,120	$ 318,362	$ 324,730	$ 331,224
	Subtotal underground system				**$ 6,959,900**	**$1,391,980**	**$1,419,820**	**$1,448,216**	**$ 1,477,180**	**$ 1,506,724**	**$ 1,536,858**
Stations	TS Rebuild - Planning and Engineering		1	$ 800,000	$ 800,000			$ 208,080	$ 212,242	$ 216,486	$ 220,816
	MS Rebuild - 2 x 10/13 MVA	#	2	$4,000,000	$ 8,000,000			$4,161,600			$ 4,416,323
	Protection Relay and SCADA miscellaneous capital upgrades	#	1	$ 400,000	$ 400,000	$ 80,000	$ 81,600	$ 83,232	$ 84,897	$ 86,595	$ 88,326
	DC Control battery and charger upgrades	#	5	$ 100,000	$ 500,000	$ 100,000	$ 102,000	$ 104,040	$ 106,121	$ 108,243	$ 110,408
	Miscellaneous building, fence, yard repairs	#	3	$ 40,000	$ 120,000		$ 41,616.00		$ 43,297.29		$ 45,046
	Subtotal station investments				**$ 9,820,000**	**$ 180,000**	**$ 225,216**	**$4,556,952**	**$ 446,556**	**$ 411,324**	**$ 4,880,920**
Distribution Transformers	Pole mounted transformers	#	48	$ 5,000	$ 240,000	$ 48,000	$ 48,960	$ 49,939	$ 50,938	$ 51,957	$ 52,996
	Pad mounted 1-ph transformers	#	24	$ 7,500	$ 180,000	$ 36,000	$ 36,720	$ 37,454	$ 38,203	$ 38,968	$ 39,747
	Pad mounted 3-ph transformers	#	6	$ 18,000	$ 108,000	$ 21,600	$ 22,032	$ 22,473	$ 22,922	$ 23,381	$ 23,848
	Testing transformers for PCB contamination	#	1,375	$ 185	$ 254,375	$ 50,875	$ 51,893	$ 52,930	$ 53,989	$ 55,069	$ 56,170
	Subtotal Distribution Transformers				**$ 782,375**	**$ 156,475**	**$ 159,605**	**$ 162,797**	**$ 166,053**	**$ 169,374**	**$ 172,761**
Miscellaneous Assets	Revenue Meters 1-ph	#	1300	$ 145	$ 188,500	$ 37,700	$ 38,454	$ 39,223	$ 40,008	$ 40,808	$ 41,624
	Revenue Meters 3-ph	#	75	$ 600	$ 45,000	$ 9,000	$ 9,180	$ 9,364	$ 9,551	$ 9,742	$ 9,937
	Miscellaneous building upgrades	#	1	$ 60,000	$ 60,000	$ 12,000	$ 12,240	$ 12,485	$ 12,734	$ 12,989	$ 13,249
	Miscellaneous tools and equipment	#	1	$ 150,000	$ 150,000	$ 30,000	$ 30,600	$ 31,212	$ 31,836	$ 32,473	$ 33,122
	Subtotal Miscellaneous investments				**$ 443,500**	**$ 88,700**	**$ 90,474**	**$ 92,283**	**$ 94,129**	**$ 96,012**	**$ 97,932**
Total Capital Investments Requirements into asset renewal					**$28,755,775**	**$3,967,155**	**$4,088,114**	**$8,497,108**	**$ 4,465,516**	**$ 4,510,663**	**$ 9,062,246**

6 PREVENTATIVE MAINTENANCE PLAN:

We have reviewed the fixed asset preventative maintenance program currently in use at PUC DISTRIBUTION and determined that it is in line with the best utility practices. However, PUC DISTRIBUTION is currently in the process of installing an under-frequency loads shedding system (UFLS) in accordance with IESO requirements. Upon placing this system in service, maintenance requirements at the 12kV distributions stations will need to be increased in accordance with regulatory requirements. The existing preventative maintenance program is briefly described below:

(a) Assets installed in transformer stations and distribution stations are inspected and maintained in accordance with the schedule shown in Table 6-1.

Table 6-1: Substation Preventative Maintenance Program

Activity	Description	Frequency	Supporting Documents
Oil Testing	Oil sample are drawn from station transformers and sent for analysis. The results are reviewed and an action plan is established	Annually	Oil test results and summaries
Infrared Scanning	Infrared scanning is performed on various stations and Line equipment annually.	Annually	Exception reports and equipment lists
Battery Maintenance	Quarterly Inspection and testing of the inter-cell connections	Quarterly	Battery test results
ESA Inspections	Inspection by ESA Inspectors of stations and equipment.	1/3 of the stations annually	Inspection results
General Inspections	Inspection by Stations staff to ensure property security, proper operation and other physical aspects.	Monthly for distribution stations, weekly for Transformer Stations	Inspection Orders
Station Maintenance	Cleaning, testing Inspection and Maintenance of relays, breakers, switchgear, transformers, buss work, motor operators, switches etc. to meet NPCC requirements	5 year rotation (3 stations annually)	Inspection and test results

Oil Breaker inspection and Maintenance	Inspection and maintenance of the oil-filled circuit breakers at our two transformer stations, includes oil testing, removal of the tank, electrical and visual inspection of contacts, bushing testing etc.	5-year cycle	Inspection and test results
115 KV Switch Inspection and Maintenance	Inspection and maintenance of the 115 KV switches including alignment of the operating mechanism, lubrication, inspection of contact surfaces etc.	5- year cycle	Inspection and test results

(b) Overhead lines and underground pads and vaults are inspected on a 3-year cycle, to comply with Distribution System Code regulations. One third of the distribution assets employed on overhead distribution system are inspected each year. Structural defects, clearance issues and electrical problems and hazards are identified through visual inspections and where problems are revealed, either repair work is scheduled or capital work is planned, as needed. Where the inspections determine an immediate hazard immediate follow up action is taken to mitigate the problem. Field inspection records are kept on file in the line department until the next cycle of inspections.

(c) On overhead distribution lines, the following deficiencies/defects are identified on various assets:

Poles/Supports:

- Bent, cracked or broken poles
- Excessive surface wear or scaling
- Loose, cracked or broken cross arms and brackets
- Woodpecker or insect damage, bird nests
- Loose or unattached guy wires or stubs
- Guy strain insulators pulled apart or broken
- Guy guards out of position or missing
- Grading changes, or washouts
- Indications of burning

Distribution Transformers:

- Paint condition and corrosion
- Phase indicators and unit numbers match operating map (where used)
- Leaking oil
- Flashed or cracked insulators
- Contamination/discolouration of bushings
- Ground lead attachments

- Damaged disconnect switches or lightning arresters
- Ground wire on arresters unattached

Switches and Protective Devices:

- Bent, broken bushings and cutouts
- Damaged lighting arresters
- Ground wire on arresters unattached

Hardware and Attachments:

- Loose or missing hardware
- Insulators unattached from pins
- Conductor unattached from insulators
- Insulators flashed over or obviously contaminated (difficult to see)
- Tie wires unraveled
- Ground wire broken or removed
- Ground wire guards removed or broken

Conductors and Cables:

- Low conductor clearance
- Broken/frayed conductors or tie wires
- Exposed broken ground conductors
- Broken strands, bird caging, and excessive or inadequate sag
- Insulation fraying on secondary

Third Party Plant:

- Attachment not secure
- Infringing on clearances
- Compromising access to electrical equipment
- Unapproved/unsafe occupation or secondary use

General Conditions & Vegetation:

- Leaning or broken "danger" trees
- Growth into line of "climbing" trees
- Accessibility compromised
- Vines or brush growth interference (line clearance)
- Bird or animal nests

(d) On underground distribution lines, the following deficiencies/defects are identified on various assets:

Pad Mounted Transformers and Switching Kiosks:

- Paint condition and corrosion
- Placement on pad or vault
- Check for lock and penta bolt in place or damage
- Grading changes
- Access changes (Shrubs, trees, etc.)
- Phase indicators and unit numbers match operating map (where used)
- Leaking oil
- Lid damage, missing bolts, cabinet damage
- Cable connections
- Ground connections
- Nomenclature
- Animal nests/damage
- General conditions

Right of Way

- Accessibility compromised
- Grade changes that could expose cable
- Excessive vegetation on right of way

(a) Tree trimming has been carried out on a 3–year cycle in the past, which we consider to be satisfactory.

(b) In accordance with the best utility practices, thermograph inspections of distribution assets are carried out with infra-red cameras and any hot spots are promptly attended. The thermograph inspections appear to be extremely effective in detecting incipient faults and we recommend these should be continued as part of the maintenance program.

PHOTOGRAPHS OF STATION ASSETS









TS1









TS2









Substation #1









Substation #2







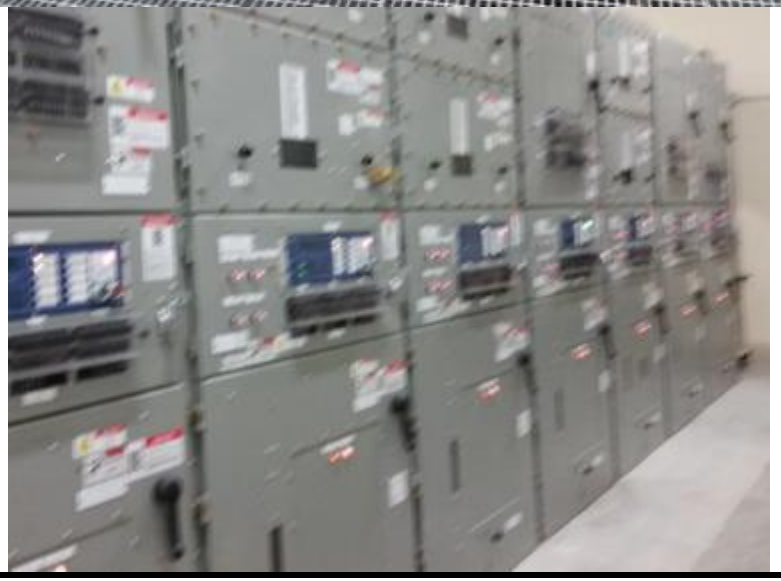


Substation #4









Substation #10









Substation #11









Substation #12









Substation #13







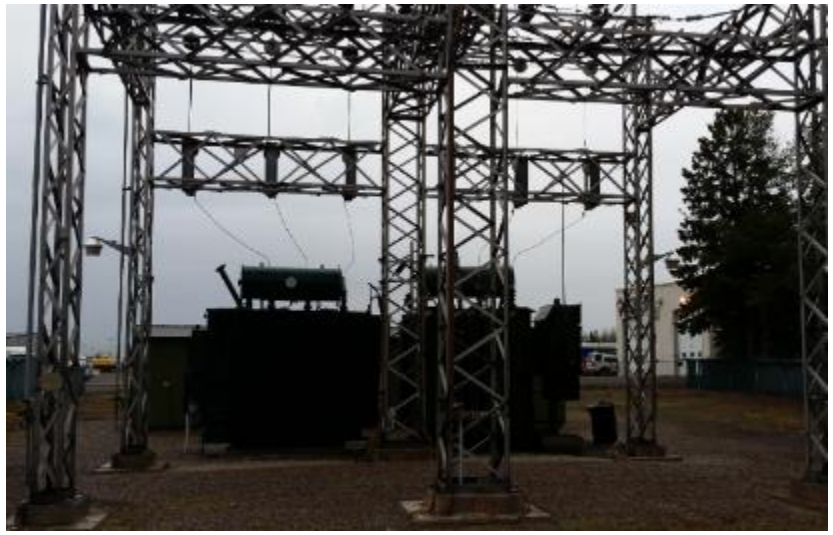


Substation #15









Substation #16









Substation #18





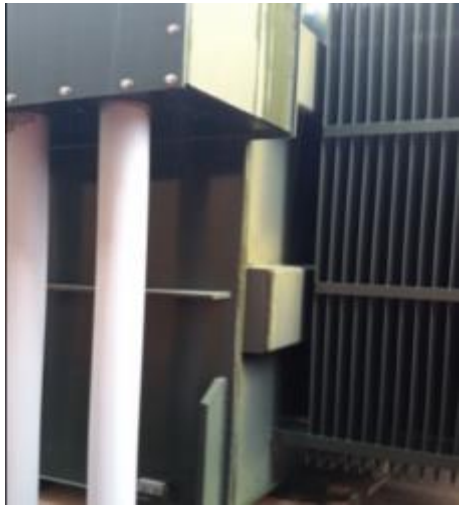




Substation #20







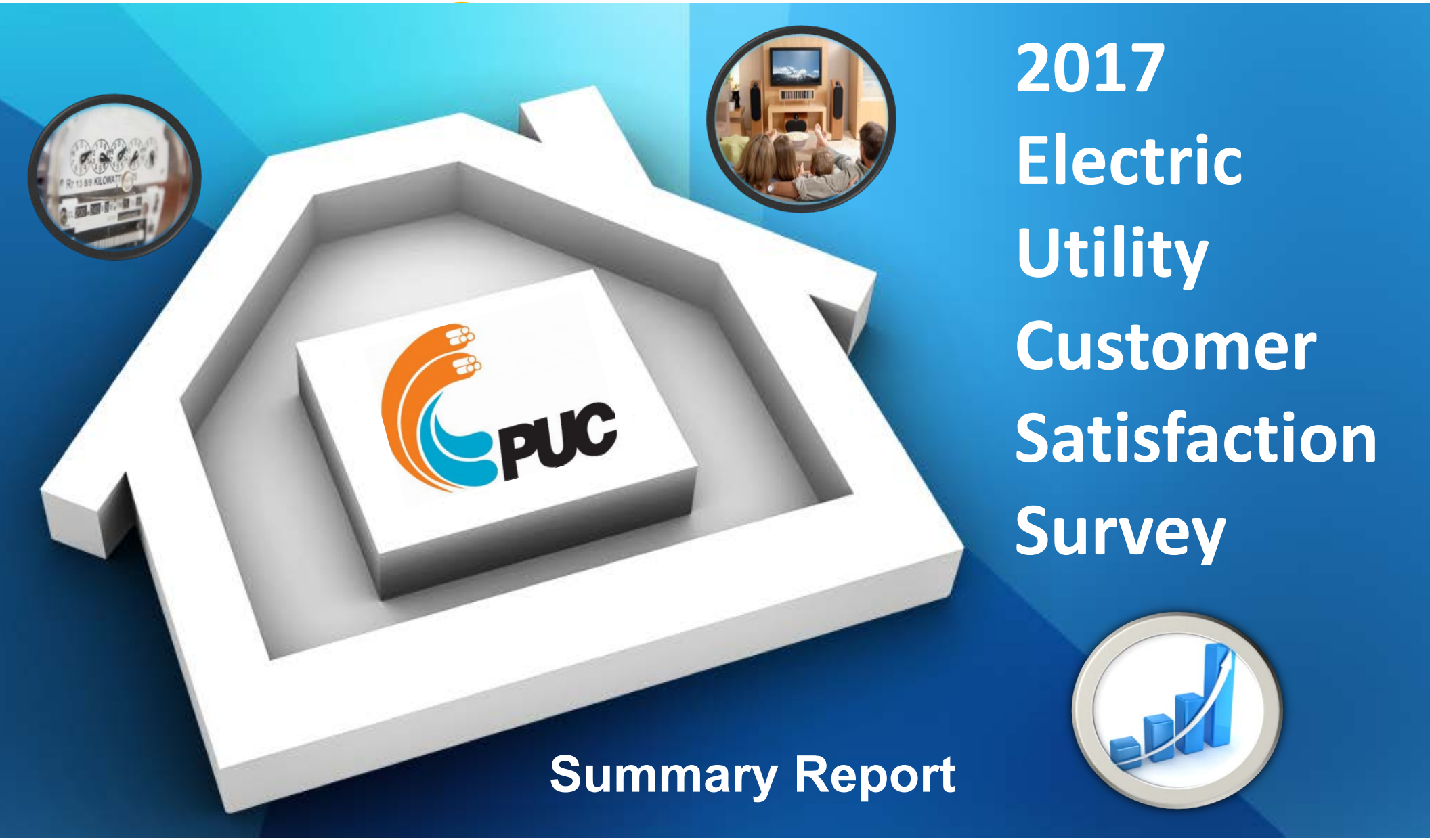


Substation #21

Appendix C

PUC Distribution Customer Satisfaction Survey

PUC Distribution Inc.



2017 Electric Utility Customer Satisfaction Survey

Summary Report

UtilityPULSE

The purpose of this report is to profile the connection between PUC Distribution Inc. (PUC Distribution) and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information to support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report do not merely capture state of mind or perceptions about your customers' needs and wants - the information contained in this survey provides actionable and measurable feedback from your customers.

This is privileged and confidential material and no part may be used outside of PUC Distribution Inc. without written permission from UtilityPULSE, the electric utility survey division of Simul Corporation.

All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

Toll free: 1-888-291-7892 or Local: 905-895-7900

Email: sidridgley@utilitypulse.com or sridgley@simulcorp.com



Survey Observations & Insights

In the 19 years UtilityPULSE has been conducting research in Ontario's LDC market, we have not seen the residential/small commercial customer base as negative – and some would say angry – as it is right now. Over the past 10 weeks UtilityPULSE has completed 6,000+ Residential and Small Commercial customer surveys – satisfaction results are ugly. Though not news to your call-centre professionals, more customers are worried about the cost of electricity and more customers are finding it difficult to pay their bill. This survey does ask respondents to pick from 3 statements the one which best describes their ability to pay. In 2015, 59% [Ontario Benchmark] and 55% [PUC Distribution] selected *"Paying for electricity is not really a worry"*, in 2017 the numbers are 53% [Ontario Benchmark] and 51% for PUC Distribution. Survey respondents are looking through the lens of costs, more specifically affordability, therefore ratings for 2017 have been impacted.

Ability to pay is a highly correlated factor to overall satisfaction, and given the steep rise in electricity costs (those costs beyond the control of your LDC), satisfaction is dropping. It is clear industry events are affecting how customers see your LDC. Customers have told us, despite spending money to assist in reducing consumption, their bill continues to go up. This double whammy is increasing the "worry" factor. We recommend everyone at PUC Distribution remain professional and demonstrate empathy and as we know about human nature, worry can easily turn into a severe erosion of trust which then leads to anger.



Though your survey is about gathering the opinions of your customers, the reality is, erosion of trust in institutions in other sectors is also contributing to the worry and angst factor your customers are experiencing – the good news is 78% of PUC Distribution's customers agree your LDC is trusted and trustworthy. Today's heroes, when customers have problems or issues, are "everyday people" whose actions show they understand and are doing everything in their power to solve the problem. We've said this to our clients many times: "where understanding stops, stress, irritation, anger and conflict begin."

Your survey was conducted from January 26 - February 24, 2017 and is based on one-on-one telephone interviews with individuals who pay or look after the electricity bill. Data for this report came from conducting a telephone interview with 401 of your residential and small commercial customers. In addition, survey findings for PUC Distribution have been enhanced with the inclusion of data from our UtilityPULSE database and the independently produced Ontario and National benchmarks.



Base: total respondents:
Top 2 Boxes: "Strongly agree + agree"

Despite an angry environment towards the electricity industry as a whole, i.e., satisfaction levels and concern over costs; survey respondents gave PUC Distribution excellent operational scores.

Operational Attributes			
	PUC Distribution	National	Ontario
Provides consistent, reliable energy	91%	89%	89%
Quickly handles outages and restores power	90%	87%	85%
Accurate billing	81%	83%	80%

Base: total respondents with an opinion

However, PUC Distribution representatives also did their part:

Representative Attributes			
	PUC Distribution	National	Ontario
Deals professionally with customers' problems	85%	83%	81%
Is 'easy to do business with'	85%	81%	77%
Customer-focused and treats customers as if they're valued	73%	75%	73%

Base: total respondents with an opinion



Attributes strongly linked to Credibility & Trust			
	PUC Distribution	National	Ontario
Keeps its promises to customers and the community	76%	77%	73%
Pro-active in communicating changes and issues affecting Customers	77%	76%	73%
Is a trusted and trustworthy company	78%	81%	74%

Base: total respondents with an opinion

We have seen a social shift in the customer base, wherein there is a high expectation they will be involved in the decisions affecting them. The higher the intensity of worry that people have about their future, the higher the likelihood they will want a say in the things which could affect them.

As such human beings will primarily act out of self-protection and self-interest which, in-turn, causes polarization of views. For LDCs it becomes much more difficult to generate a consensus view for items that are clearly in the best interest of the majority. Asking people who are very worried about paying their bill to support items which promote the "greater good" is a daunting task.

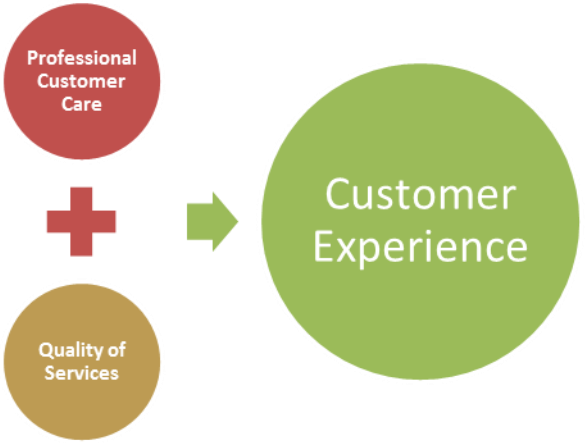
Customer engagement is not about getting agreement (though it would be nice to do so), customer engagement is about ensuring there is an understanding of customer wants and needs; particularly when the possibility of an increase in cost is involved.



Utility Customer Centric Engagement Index (CCEI)			
	PUC Distribution	National	Ontario
CCEI	78%	78%	74%

Base: total respondents

Engagement is how customers think, feel and act towards the organization. Ensuring customers respond in a positive way requires they be rationally satisfied with the services provided AND emotionally connected to the LDC and its brand.



The Customer Experience Performance rating (CEPr) score is an effectiveness rating and is affected by many dimensions of service. Every touch point with customers on the phone, website or in-person influences what customers think and feel about the organization. While an excellent transaction today creates a positive experience today, the perception created is, future transactions will be excellent too.

Of course a negative transaction creates the perception, future transactions will be negative.

Customer Experience Performance rating (CEPr)			
	PUC Distribution	**National**	**Ontario**
CEPr: all respondents	83%	82%	80%

Base: total respondents

Customer satisfaction is one dimension for measuring the effectiveness of an enterprise. But focusing on customer satisfaction as a sole measure is not enough to gain a picture about how well an operating unit/enterprise might be doing. Customer satisfaction as a measure is an effectiveness measure (not an efficiency measure) on the historical relationship or delivery of services to customers.

"Satisfaction happens when an enterprise's core services meet or exceed customer's needs, wants, or expectations."

Customer Satisfaction

SATISFACTION SCORES – Electricity customers' satisfaction			
Top 2 Boxes: 'very + fairly satisfied'	**PUC Distribution**	**National**	**Ontario**
PRE: Initial Satisfaction Scores	82%	89%	84%
POST: End of Interview	80%	86%	76%

Base: total respondents

Customer Commitment

Electricity customers' loyalty – … Is a company that you would like to continue to do business with			
	PUC Distribution	**National**	**Ontario**
Top 2 Boxes: 'Definitely + Probably' would continue	72%	78%	69%

Base: total respondents

Customer Advocacy

Electricity customers' loyalty – … is a company that you would recommend to a friend or colleague			
	PUC Distribution	**National**	**Ontario**
Top 2 boxes: 'Definitely + Probably' would recommend	67%	71%	59%

Base: total respondents

It could be said, some problems can actually anger customers. As a mnimum, a problem is an inconvenience to the customers – and they want it solved/resolved. When the problem is solved with the first interaction (often called first call resolution) overall customer satisfaction can improve.

Problems: Power Outages

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	PUC Distribution	National	Ontario
2017	32%	37%	37%
2016	-	53%	51%
2015	45%	47%	49%
2014	-	41%	35%
2013	-	44%	46%

Base: total respondents / (-) not a participant of the survey year



Problems: Billing issues

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	PUC Distribution	National	Ontario
2017	25%	15%	25%
2016	-	9%	15%
2015	13%	16%	25%
2014	-	8%	10%
2013	-	12%	13%

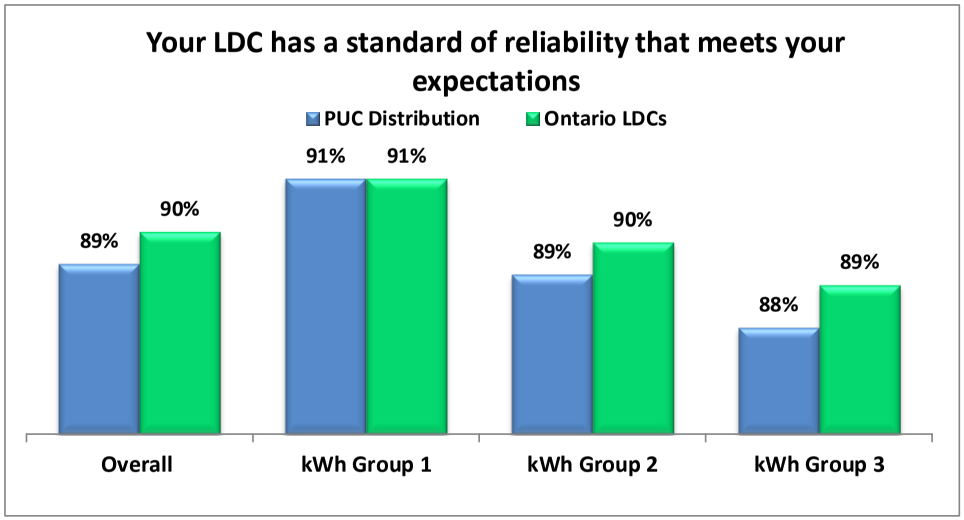
Base: total respondents / (-) not a participant of the survey year



Outage Management

The perception of competency and value of the LDC are certainly linked to the frequency and duration of power outages. Recognizing the importance of this topic to customers, a question about LDC reliability standards was asked in the survey.

Scores for PUC Distribution indicate the vast majority of customers feel the utility is consistent in meeting their expectations.



Base UtilityPulse Database / total respondents

If the utility were to improve reliability should they put more emphasis on reducing the number of unplanned outages or reducing the duration of the unplanned outage? Or both which requires an increase in costs and potentially rates. Dealing with the pain of high bills is far and away more important to customers than the pain of outages which explains the high percentage (55%) of not willing to pay more.

However, this survey was completed prior to the Ontario Government's March 2, 2017 announcement about reducing electricity bills by 25%.

Emphasis on Outage Management	
	PUC Distribution
Reduce the number of outages	4%
Reduce the duration of outages	4%
Both	32%
Neither, not willing to pay more	55%
Don't know	4%

Base: total respondents

PUC Customer respondents give PUC Distribution excellent ratings as it relates to the job/task of dealing with outages.

LDC effectiveness responding to outages: Top 2 Boxes: "Very + Somewhat effective"		
	PUC Distribution	Ontario LDCs
Responding to the power outage	92%	85%
Restoring power quickly	94%	86%
Using media channels for updates	69%	54%
Providing information about the outage	72%	61%

Base: total respondents/ 2017 UtilityPULSE Database



Customer Service

Satisfaction with Customer Service			
Top 2 Boxes: 'very + fairly satisfied'	**PUC Distribution**	**National**	**Ontario**
The time it took to contact someone	72%	67%	63%
The time it took someone to deal with your problem	64%	64%	60%
The helpfulness of the staff who dealt with you	71%	67%	64%
The knowledge of the staff who dealt with you	72%	63%	59%
The level of courtesy of the staff who dealt with you	84%	74%	69%
The quality of information provided by the staff who dealt with you	63%	65%	64%

Base: total respondents who contacted the utility

Everyone in the LDC affects a customer's perception, not just call-centre employees. Employees in other departments interact with customers and so do outside-workers. Employees, at all levels and departments of the LDC are not immune to the frustration and anger customers feel about their bills and the industry as a whole. Therefore, it is imperative everyone remain professional and focused on doing everything very well – including the little things.

Upset or angry people are critical people and they will look for behaviours which reinforce or validate their negative view. It is more important than ever to ensure every interaction with a customer is an excellent one. Demonstrating understanding through active listening is a good start.



PUC Distribution's UtilityPULSE Report Card®

Performance

	CATEGORY	PUC Distribution	National	Ontario
1	**Customer Care**	**B**	**B**	**C+**
	Price and Value	C+	B	C
	Customer Service	B+	B+	B
2	**Company Image**	**B+**	**B+**	**B**
	Company Leadership	B	B+	B
	Corporate Stewardship	B+	B+	B
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	B+
	Power Quality and Reliability	A+	A	A
	OVERALL	**B+**	**B+**	**B**

Base: total respondents

Lowest scoring attributes

Low scoring attributes			
Top 2 Boxes: 'Strongly + Somewhat agree'	**PUC Distribution**	**National**	**Ontario**
Adapts well to changes in customer expectations	68%	71%	68%
Operates a cost effective electricity system	62%	70%	56%
Provides good value for your money	57%	62%	56%
Cost of electricity is reasonable when compared to other utilities	44%	61%	48%

Base: total respondents with an opinion

Highest scoring attributes

High scoring attributes			
Top 2 Boxes: 'Strongly + Somewhat agree'	**PUC Distribution**	**National**	**Ontario**
Provides consistent, reliable electricity	91%	89%	89%
Makes electricity safety a top priority for employees and contractors	91%	87%	86%
Quickly handles outages and restores power	90%	87%	85%
Has a standard of reliability that meets expectations	89%	88%	86%

Base: total respondents with an opinion



Use of Technology

Where will technology take us in the future? What effect will technology have on people's lives?

The effect of technological changes on people's lives will lead to a future that is …	
	PUC Distribution
Mostly better	39%
Mostly worse	9%
Neither	46%
Don't know	5%

Base: total respondents

As customers increasingly demand greater empowerment, utilities seek to improve interactions and relationships in their entire operation by enhancing software capabilities for collaboration, gaining deeper customer and market insight and improving process management. Respondents were asked how important having online access to the following features was to them:

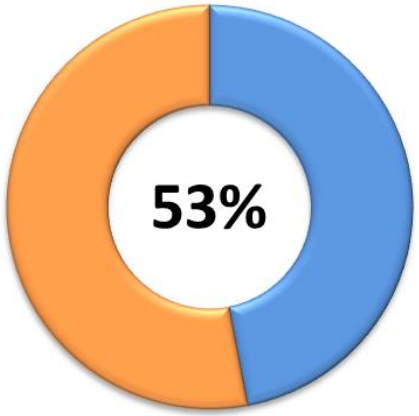
Importance of online access for the following features:		
Top 2 Boxes: 'very + somewhat important'	PUC Distribution	UtilityPULSE Database
Reporting or inquiring about an issue	53%	71%
Researching information about energy conservation	58%	79%
Having a web chat feature on the website	32%	50%
Automated alerts when electricity usage exceeds a prearranged threshold	54%	71%
Review and pay your bill online (through utility's website)	53%	68%
Power outage alerts	61%	80%
Tools and calculators to help you manage your electricity consumption	44%	67%
Comparison of your electricity consumption with your neighbours	41%	51%
Automated alert to predict your upcoming bill	40%	59%
Automated alert to remind you of your bill due date	34%	59%

Base: total respondents / total respondents from the 2017 UtilityPULSE Database

Confidence in the Industry

Respondents have a perception about the electricity industry as a whole. That image influences how people (customers) think and feel about various industry participants. Confidence represents a filter affecting customers' perception about their LDC. For example on the subject of customer satisfaction, the UtilityPULSE database shows those survey respondents who had high confidence levels scored 14% higher than those who had low confidence. This variance has little to do with the actual numbers or facts about the LDCs performance.

'Customers are well served by the electricity system in Ontario' – do you agree? Base: total respondents



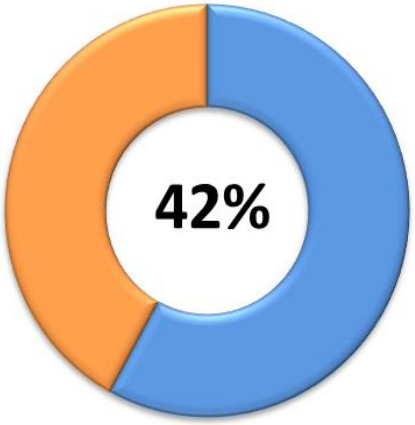
53% Agree ('strongly + somewhat') customers are well served by the electricity system in Ontario

5% neither agree nor disagree

39% Disagree ('strongly + somewhat') they are well served

1% did not render an opinion or did not know

'Customers are confident in the electricity industry's ability to meet their future expectations regarding quality, reliability and price' – do you agree? Base: total respondents



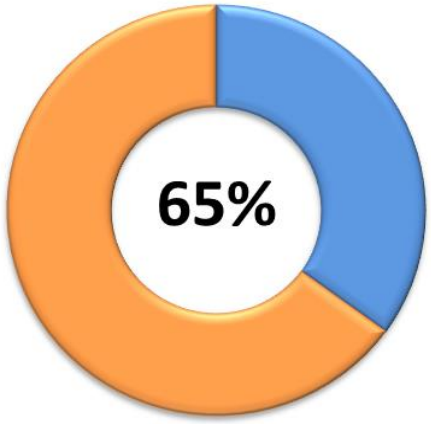
42% Agree ('strongly + somewhat') customers are confident the electricity industry has the ability to meet future expectations regarding quality, reliability and price

6% neither agree nor disagree

48% Disagree ('strongly + somewhat') the industry can deliver on future expectations

2% did not render an opinion or did not know

'Customers are confident in the electricity industry's ability to keep up with technological changes' – do you agree? Base: total respondents



65% Agree ('strongly + somewhat') customers are confident the electricity industry is able to keep up with technological changes

7% neither agree nor disagree

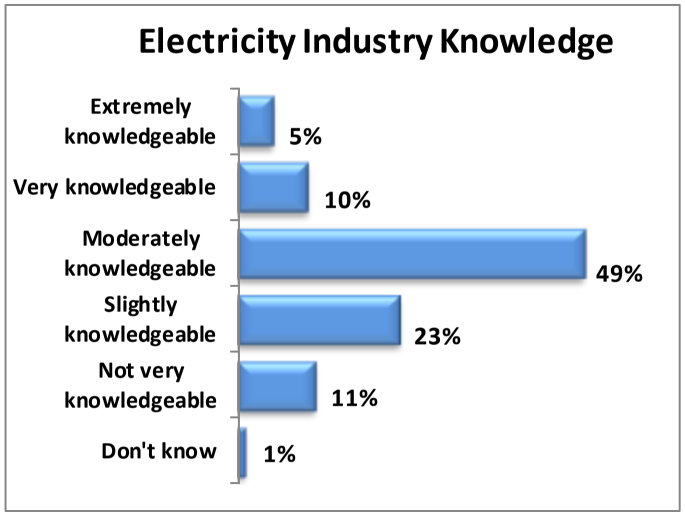
23% Disagree ('strongly + somewhat') the industry will keep up with changing technology

4% did not render an opinion or did not know

Electricity Industry Knowledge

16% of respondents for PUC Distribution described themselves as Extremely or Very knowledgeable about the electric utility industry. 49% claim they are moderately knowledgeable.

Approximately 1 in 5 (17%) survey participants in the UtilityPULSE database describe themselves as Extremely knowledgeable or Very knowledgeable. Only 50% of this knowledgeable group said they agree 'strongly + somewhat' customers were well served by the electricity system.



Base: total respondents

Approximately 1 in 3 survey respondents describe themselves in the bottom 2 categories of knowledge, and 58% of this group said they agree 'strongly + somewhat' customers are well served.

The data is clear; those who considered themselves more knowledgeable are also much less likely to say they have confidence in the industry to meet their needs and in the industry's ability to keep up with technology. Being knowledgeable is not necessarily a path to better appreciation of the electricity industry. However it does seem to be a path which creates more polarization of viewpoints thereby making it more difficult to generate support for various items/activities.

Some customers will want to understand what is going on in the industry; just like there are some customers who want to know the inner workings of an automobile. However, the vast majority of people do not want to know how their automobile or the electricity industry works. What they want to know is, when there is a problem where they can access professionals who can fix them.

Loyalty Groups

Customer Loyalty Groups				
PUC Distribution	**Secure**	**Favorable**	**Indifferent**	**At Risk**
2017	19%	18%	44%	19%
2016	-	-	-	-

Base: total respondents / (-) not a participant of the survey year

Paying for electricity

For 19 years, the highest factor correlated to satisfaction is ability to pay.

Is paying for electricity a worry or a major problem?				
	Not a worry	**Sometimes**	**Often**	**Depends**
PUC Distribution	51%	30%	17%	1%
National	65%	20%	12%	1%
Ontario	53%	25%	18%	1%

Base: total respondents

Confidence Prioritizing Investments

Survey respondents are looking through the lens of costs & affordability when providing answers to questions about investing in their LDC to ensure the reliable and safe delivery of electricity and the efficient running of operations. Understanding customer expectations, concerns, and desires does help an LDC to build their plans to ensure they remain relevant, viable, and valuable to customers, employees and other stakeholders.

85% **of Secure and Favourable respondents are confident that PUC Distribution is using good judgment to prioritize investments**



Gathering support for making capital and operational investments is going to be a challenge for items other than those linked to replacing aging equipment to improve safety and reliability. This is where customer affinity plays an important role.

Loyal customers are more likely to see the world the way management sees it. Committed customers feel their interests and those of their utility are often in common. When customers are committed, they voluntarily tell others how they feel; they are more tolerant and more supportive. Relative to 'good judgment to prioritize investments', 85% of Secure and Favourable respondents are confident ('very + somewhat') that PUC Distribution is using good judgment to prioritize investments.



Capital Expenses



It is true, customers (but not all) can tell you what they want, but they have a very difficult time telling you what they need. On the one hand many customers **"want"** lower prices, but they **"need"** reliability and responsiveness.

Hence, it is up to the professionals in the LDC to use their experience and judgment to determine what needs to be done and when it should be done. No easy task – especially with a customer base that is focused on costs. Yet, about 2 out of 3 survey respondents opted for "pro-active replacement" which is consistent with the UtilityPULSE database average of 65%.

Strategy for replacing equipment		
PUC Distribution	**2017**	**2015**
Run-to-failure when there are limited customers affected ensures full-value is received from the equipment	20%	19%
Pro-active replacement, even though it may cost more, should ensure reliable power	64%	72%
Don't Know	16%	10%

Base: total respondents



Which of the following CAPITAL items would you be willing to pay more for?

Preventive maintenance has been more popular in principle than in practice. It gets hard to argue with the idea of keeping equipment well maintained to extend its expected life and avoid future repair costs. Less clear is an understanding of the actual relationship between the cost of preventive maintenance and the returns such activities can be expected to deliver.

The following summarizes those respondents answering **'yes'** they were willing to pay more for the listed capital expenditures:

- 69% - Replacing aging equipment to improve safety and reliability
- 50% - Upgrading equipment to accommodate future growth in the community
- 45% - Adding automation and technology to reduce outage time
- 37% - Investing in technology to deal with cyber security issues

Quantifiable data from the telephone survey about paying more for capital items indicates:

- 14% respondents were willing to pay more for 1 item
- 20% willing to pay more for 2 items
- 41% willing to pay more for 3 or 4 items
- 25% were not willing to pay more for any items.



Operating Expenses

PUC Distribution has to focus on day-to-day operations while it builds, re-builds, re-furbishes and prepares the organization for a changed future. In addition, LDCs need to think in terms of decades, not just today, this week, this month, or this quarter. They need to do so in a regulated environment that is a 5 year planning environment. Respondents were asked to identify the items they were willing to pay more for and, they were asked "how much" they would be willing to pay.

Which of the following items are you willing to pay more for per month …					
PUC Distribution	**Yes**	**No**	**Not sure**	**Residential Yes**	**Small Commercial Yes**
A proactive outage management system	23%	74%	3%	23%	27%
Increased self-service options on the website	13%	85%	2%	13%	12%
Educating customers about energy conservation	23%	76%	1%	23%	22%

Base: total respondents

Quantifiable data from the telephone survey about paying more for operational items indicates:

- 18% respondents were willing to pay more for 1 item
- 12% willing to pay more for 2 items
- 6% willing to pay more for 3 items
- 64% were not willing to pay more for any items.



Elasticity in willingness to pay more per month

It is true; self-interest will drive the choices people make. If an operational or capital item directly affects the respondent, then there is a willingness to support paying more per month. This indicates there is a need to be clear about what customers get from any additional cost – especially for the 3 operational items surveyed.

PUC Distribution customers, given the responses are through the lens of costs, are worried about the impact of additional costs will have on them. It is not the amount of the investment i.e., millions of dollars that the LDC may invest, but rather the impact of that investment on the customer i.e., dollars per month. .

About 1 in 4 customer respondents indicated they do not support any increase for any capital expense which is in line with the UtilityPULSE database, however 2 out of 3 customers are not willing to support any of the 3 operational items is significantly higher than the UtilityPULSE database average of 24%.



Numbers at a Glance

	PUC Distribution	National	Ontario
Customer Satisfaction: Initial	82%	89%	84%
Customer Satisfaction: Post	80%	86%	76%
Overall Satisfaction with most recent experience	61%	72%	63%
Customer Experience Performance Rating (CEPr)	83%	82%	80%
Customer Centric Engagement Index (CCEI)	78%	78%	74%
Credibility & Trust Index	80%	80%	77%
UtilityPULSE Report Card©	B+	B+	B

While electricity industry insiders could agree there has been a tremendous amount of change in the past 10-15 years the reality is, there is no let-up in sight. Shifts in demographics and customer expectations coupled with dramatic changes in how & where electricity is generated, stored and distributed will add to the to the level of challenge everyone in the LDC face.

Marketing communications need to be comprised of simple language elements which demonstrate the LDC understands the concerns and worries of customers, and shows the LDC is doing meaningful work to address those concerns and worries. In times of disruption or uncertainty, higher levels of customer affinity are the result of a corporate culture where PUC Distribution people feel empowered to act and are focused on the results which matter to all stakeholders.

In a polarized world, LDCs must consistently communicate their values to customers. Customer affinity grows when LDCs show they understand the worries, concerns and issues customers face because of the current state of the electricity market. A communication strategy demonstrating congruency with customer values will help build the brand and reputation of the LDC.

As we look into the future, and recognizing the high degree of attention the electricity industry is getting, we recommend the LDC review its processes and standards around activities/projects – and the supporting marketing communications - which could have an impact on customer perceptions regarding



the attributes of “easy to do business with”, “keeps its promises”, “pro-active communications”, “provides information to help customers reduce electricity costs”, “adapts well to changes in customer expectations”, “credibility & trust” and, “reliability”.

We recommend having meaningful two-way dialogue with employees (and others) to leverage the results from your 2017 customer satisfaction survey derived from speaking with 401 PUC Distribution customers [January 26 - February 24, 2017]. Thoughtful discussion turns data into information and insights which lead to benefits for all parties.

UtilityPULSE
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March 2017



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Your personal contact is:

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Appendix D

OPA/IESO Comment Letter on DSP

IESO Letter of Comment

PUC Distribution Inc.

Renewable Energy Generation Plan

December 21, 2017

ieso
Independent Electricity System Operator

Introduction

On March 28, 2013, the Ontario Energy Board ("the OEB" or "Board") issued its Filing Requirements for Electricity Transmission and Distribution Applications; Chapter 5 – Consolidated Distribution System Plan Filing Requirements (EB-2010-0377). Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning', outlined in the Board's October 18, 2012 Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach.

As outlined in the Chapter 5 filing requirements, the Board expects that the Ontario Power Authority[1] ("OPA") comment letter will include:

- the applications it has received from renewable generators through the FIT program for connection in the distributor's service area;
- whether the distributor has consulted with the OPA, or participated in planning meetings with the OPA;
- the potential need for co-ordination with other distributors and/or transmitters or others on implementing elements of the Renewable Energy Generation ("REG") investments; and
- whether the REG investments proposed in the DS Plan are consistent with any Regional Infrastructure Plan.

PUC Distribution Inc. – Renewable Energy Generation Plan

On November 30, 2017, the IESO received the REG Plan ("Plan") of PUC Distribution Inc. ("PUC") as part of its 5-year (2018-2022) Distribution System Plan. The IESO has reviewed the Plan and provides the following comments.

OPA FIT/microFIT Applications Received

The Plan indicates that PUC currently has approximately 63 MW of REG connected to its distribution system, and that over the Plan period it is capable of connecting all of its anticipated REG projects forecast to be a total of 1.25 MW of additional capacity.

According to the IESO's information, as of November 30, 2017, the IESO has offered contracts to 107 microFIT projects, 9 FIT projects and 6 RESOP projects totalling approximately 62 MW of capacity, all of which have reached commercial operation. The difference in renewable energy generation connections information in PUC's Plan, compared to the IESO's information, is that PUC has an additional four Net Metering/Load Displacement projects that do not have contracts with the IESO.

[1] On January 1, 2015, the Ontario Power Authority ("OPA") merged with the Independent Electricity System Operator ("IESO") to create a new organization that will combine the OPA and IESO mandates. The new organization is called the Independent Electricity System Operator.

Independent Electricity System Operator
1600 – 120 Adelaide Street West, Toronto, ON M5H 1T1
t 416 967-7474 f 416 967-1947 toll free 1-800-797-9604 customer.relations@ieso.ca www.ieso.ca

Consultation / Participation in Planning Meetings; Coordination with Distributors / Transmitters / Others; Consistency with Regional Plans

For regional planning purposes, the IESO notes that PUC is part of the East Lake Superior Region (Group 2).

Status of Regional Planning

As part of the OEB's Regional Planning Process the transmitter Great Lakes Power Transmission LP (now Hydro One Sault Ste. Marie) led the Needs Assessment Report for the region which was completed in 2014. The final report recommended that the issues identified in the area did not require further regional coordination. As a result of this recommendation, the IESO was not required to pursue the development of an Integrated Regional Resource Plan ("IRRP").

The IESO notes that PUC participated as part of the Needs Assessment study team along with Hydro One Networks Inc. (Transmission), the former Ontario Power Authority, the former IESO, Algoma Power Inc., and Chapleau Public Utilities Corporation.

With respect to REG investments, Section 4 of the Plan outlined the analysis done to conclude that over the Plan period, PUC's system shows no concerns caused by local or regional issues that should constrain additional growth of REG as projected. As a result, PUC has not included any associated infrastructure investment for the 2018-2022 period.

While the regional planning process for this area is now complete, it is expected to commence again in 2019 based on the OEB's 5-year cycle, unless there is an event that triggers the need for the process to begin earlier.

The IESO appreciates the opportunity to comment on the REG information provided by PUC Distribution Inc. as part of its 5-year Distribution System Plan.

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Appendix E

Regional Infrastructure Planning Report

NEEDS ASSESSMENT REPORT

East Lake Superior Region

Revision: FINAL R0
Date: December 12, 2014

Prepared by: East Lake Superior Region Study Team

Great Lakes Power Transmission

ONTARIO POWER AUTHORITY

hydro one

ieso
Power to Ontario.
On Demand.

PUC DISTRIBUTION

Algoma Power Inc.
A FORTIS ONTARIO Company

CHAPLEAU PUBLIC UTILITIES CORPORATION

DISCLAIMER

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the East Lake Superior Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be re-evaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Great Lakes Power Transmission LP (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT SUMMARY REPORT

NEEDS ASSESSMENT SUMMARY REPORT			
NAME	East Lake Superior Region Study		
LEAD	Great Lakes Transmission LP (GLPT)		
REGION	East Lake Superior		
START DATE	October 12, 2014	**END DATE**	December 12, 2014

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the East Lake Superior Region (ELS-Region), determine if there are regional needs that would lead to coordinated regional planning. Where regional coordination is not required and a "wires" only solution is necessary such needs will be addressed among the relevant Local Distribution Companies (LDCs), GLPT and other parties as required.

For needs that require further regional planning and coordination, the Ontario Power Authority (OPA) will initiate the Scoping process to determine whether an OPA-led Integrated Regional Resource Planning (IRRP) process or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution) is required, or whether both are required.

2. REGIONAL ISSUES/TRIGGER

The Needs Assessment for the East Lake Superior Region was triggered in response to the Ontario Energy Board's (OEB) new Regional Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 2 Regions are to be reviewed in 2014. East Lake Superior Region belongs to Group 2 and the Needs Assessment for this Region was triggered on October 12, 2014 and was completed on December 12, 2014.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment was limited to the next 10 years because relevant data and information was collected up to the year 2023. Needs emerging over the near-term (0-5 years) and mid-term (6-10 years) should be further assessed as part of the OPA-led Scoping Assessment and/or IRRP, or in the next planning cycle to develop a 20-year plan and strategic direction for the Region.

The assessment included a review of transmission system connection facilities capacity which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and asset sustainment plans.

4. INPUTS/DATA (INFORMATION REQUIRED TO COMPLETE ASSESSMENT)

Study team participants, including representatives from Local Distribution Companies (LDC), the Ontario Power Authority (OPA), the Independent Electricity System Operator (IESO) and Hydro One Networks Inc. (Hydro One) provided information and input to GLPT for the East Lake Superior Region. The information provided includes the following:

- Actual 2013 regional coincident peak load, station non-coincident peak load and historical load provided by IESO;
- Historical net load and gross load forecast (which is the forecasted load from the historical net load) provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by OPA;
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

5. ASSESSMENT

The assessment's primary objective over the study period (2014 to 2023) is to identify the electrical infrastructure needs in the region. The study reviewed available information, load forecast and conducted single contingency analysis to confirm need, if and when required. See Section 5 for further details.

6. RESULTS

A. 230kV Connection Facilities

- Based on the demand forecast, there is sufficient capacity at the one 230kV connected load station throughout the study period. No action is required at this time and the capacity needs will be reviewed in the next planning cycle.

- Based on the demand forecast over the study period, no overload or capacity need was identified for the loss of a single 230kV circuit in the region.

- East-West Tie lines are to be upgraded within the time period of this Needs Assessment. Hydro One's Customer Impact Assessment (CIA) entitled "New East-West Tie Project' dated October 29, 2014 concludes there are no significant impact to customer in the area.

B. 230/115kV Autotransformers

- No overload or capacity issues were identified for the loss of any single 230kV/115kV autotransformer except the overload of No.3 Sault for loss of MacKay TS T2 which is mitigated by arming the MacKay TS Generation Rejection Scheme.

C. 115kV Connection Facilities

- Based on the demand forecast, there is sufficient capacity at all 115kV load stations throughout the study period except Hollingsworth (T2) /Angijami (T1) TS's. The 44 kV system supplied by Hollingsworth TS T2 and Anjigami TS T1 will become overloaded due to a new large customer connecting to the 44 kV system late 2017.

- Loading on all 115 kV circuits is within assessment criteria limits throughout the study period except for the No.1, No.2 and No.3 Algoma lines that need to be studied further due to the increased demand forecast from one large industrial customer in Sault Ste. Marie projecting an increase in peak. This could be compounded in Sault Ste. Marie with the closure of Lake Superior Power Inc.'s LSP GS in 2014.

D. System Reliability, Operation and Restoration Review

- Generally speaking, there are no significant system reliability and operating issues identified for one element out of service in this region where there are two or more parallel elements.

- There is a concern about transformer failure in the region where there are some load stations with just one transformer supplying customer load. The Ontario Resource and Transmission Assessment Criteria (ORTAC) restoration criteria of 8 hours (plus travel time) cannot always be met for single transformer stations for a transformer failure. This is being studied at this time; however, it needs to be studied further.

E. Sustainment Replacement Plans

Significant sustainment activities are scheduled within the study period at the stations listed. The new equipment ratings at these stations were considered in this need assessment. Plans to replace major equipment do not affect the needs identified based on the demand forecast.

GLPT Stations

- Anjigami TS (equipment & relaying)
- Batchawana TS (equipment)
- Clergue TS (equipment)
- D.A. Watson TS (equipment)
- Goulais Bay TS (equipment)
- Hollingsworth TS (relaying)
- HWY 101 TS (relaying)
- Magpie TS (equipment)
- Steelton TS (equipment)

PUC Stations

- St. Mary's TS (equipment & relaying)

- Tarentorus TS (equipment & relaying)

7. RECOMMENDATION

The Team Recommends:

The potential need identified for the Anjigami TS/ Hollingsworth TS does not require further regional coordination. The study team recommends that "localized" wire only solution continue to be developed in the near-term to adequately and efficiently address the above need through planning between GLPT and the impacted distributor.

The potential needs identified regarding the capacity of the Algoma lines and the Sault Ste. Marie possible issues with the shutdown of LSP GS do not require further regional coordination. The study team recommends that a "localized wire only solution be developed in the near-term to address the above need through planning between GLPT and the impacted customer.

The potential need identified for the restoration of load (ORTAC 8 hours violated) after a single supply transformer failure does not require further regional coordination. The study team recommends that a "localized" wire only solution be developed by GLPT and the impacted distributor.

PREPARED BY: East Lake Superior Region Study Team

PARTICIPANTS: LISTED BELOW

COMPANY	NAME
Great Lakes Power Transmission LP (Lead)	**Jim Tait**
Ontario Power Authority	**Bob Chow**
Independent Electricity System Operator	**Phillip Woo**
Hydro One Networks Inc. (Transmitter)	**Ajay Garg**
PUC Distribution Inc.	**Rob Harten**
Algoma Power Inc.	**Greg Beharriell**
Chapleau Public Utility Corporation	**Alan Morin**

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Table 2: Annual Load Growth for ELS-Region **13**

1. INTRODUCTION

This Needs Assessment report identifies needs in the East Lake Superior Region ("ELS-Region"). For needs that require coordinated regional planning, the OPA will initiate the Scoping process to determine the appropriate regional planning approach. The approach can either be the OPA-led Integrated Regional Resource Planning (IRRP) process or the transmitter-led Regional Infrastructure Plan (RIP), which focuses on the development of "wires" solutions. It may also be determined that the needs can be addressed more directly through localized planning between the transmitter and the specific distributor(s) or transmission connected customer(s). The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements.

This report was prepared by the ELS-Region Needs Assessment study team (Table 1) and led by the transmitter, Great Lakes Power Transmission LP (GLPT). The report captures the results of the assessment based on information provided by the Local Distribution Companies (LDCs), Ontario Power Authority (OPA), Hydro One Network Inc. and the Independent Electricity System Operator (IESO) to determine possible needs in the ELS-Region.

Table 1: Study Team Participants for ELS-Region

Company
Great Lakes Power Transmission LP (GLPT) (Lead Transmitter)
Ontario Power Authority (OPA)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Hydro One) (Transmitter)
PUC Distribution Inc. (PUC)
Algoma Power Inc. (API)
Chapleau Public Utility Corporation (CPUC)

Figure 1: East Lake Superior Region



2. REGIONAL ISSUE / TRIGGER

The Needs Assessment for the ELS-Region was triggered in response to the Ontario Energy Board's (OEB) new Regional Infrastructure Planning process approved in August 2013. To

prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 2 Regions are to be reviewed in 2014. The ELS-Region belongs to Group 2. The Needs Assessment for this ELS-Region was triggered on October 12, 2014 and was completed on December 12, 2014.

Additional information about Regional Planning can be found on the GLPT website: http://www.glp.ca/content/regional_planning_new/history-40236.html

3. SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the ELS-Region over an assessment period of 2014 to 2023. The scope of the Needs Assessment includes a review of system capability which covers transformer station loading and transmission thermal and voltage analysis based on recent detailed studies. Asset sustainment issues and other considerations were taken into account as deemed necessary.

3.1. EAST LAKE SUPERIOR REGION DESCRIPTION AND CONNECTION CONFIGURATION

Figure 2a – Wawa TS/Anjigami TS Northern Area – Hydro One 230/115 kV autotransformers at Wawa TS, Hydro One 115 kV circuit supplying CPUC load and GLPT 115 kV lines and stations connected via Anjigami TS.

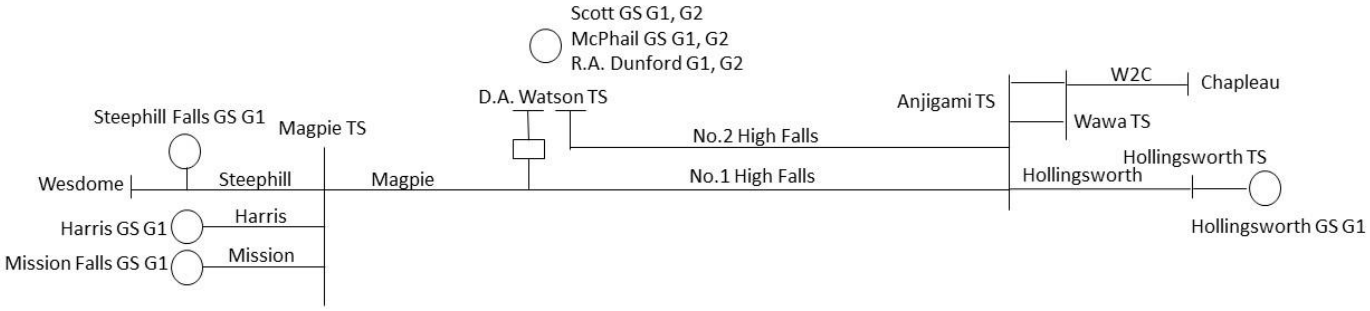


Figure 2b – MacKay TS South Central Area – GLPT 230/115 kV autotransformer at Mackay TS and 115 kV lines/stations connected via Mackay TS and two transformer stations connected to No.3 Sault.

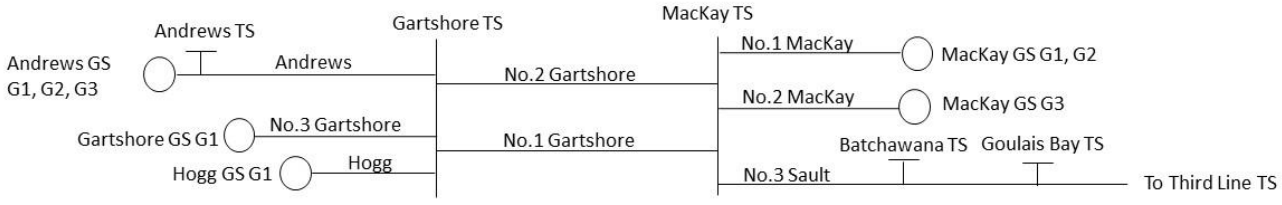


Figure 2c – Sault Ste. Marie Southern Area – GLPT 230/115 kV autotransformers at Third Line TS and 115 kV lines/stations in Sault Ste. Marie.

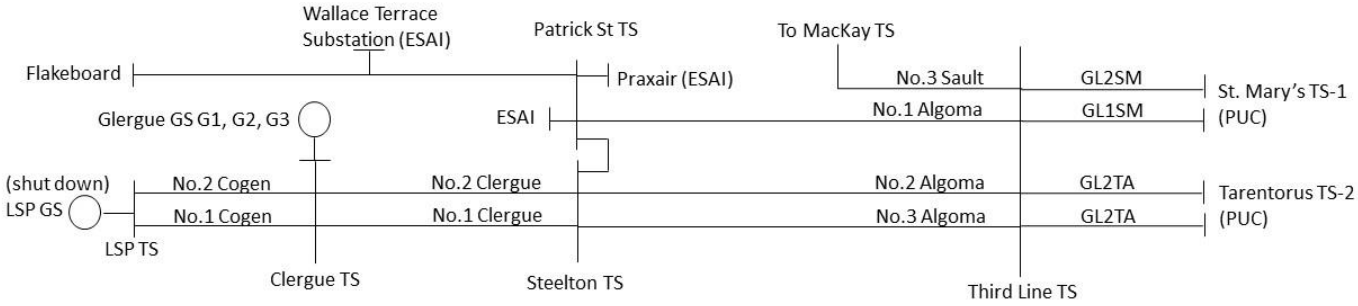
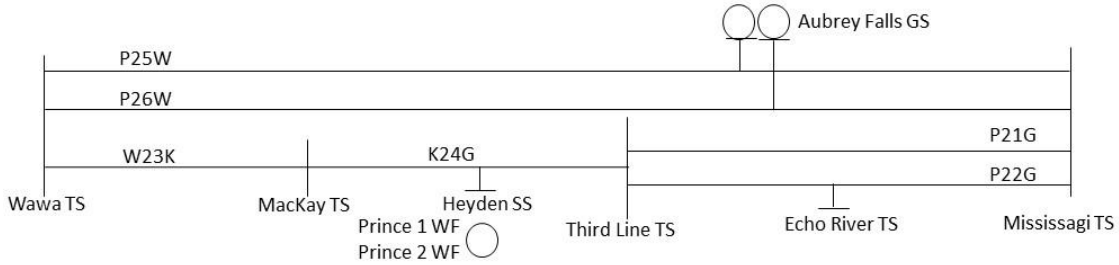


Figure 2d – GLPT and Hydro One 230 kV Eastern Area – Hydro One 230 kV lines P25W and P26W from Wawa TS to Mississagi TS, GLPT 230 kV lines W23K (Wawa TS to MacKay TS), K24G (MacKay TS to Third Line TS), P21G and P22G (Third Line TS to Mississagi TS) and one 230/34.5 kV transformer station connected to P22G.



4. INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to GLPT:

- Actual 2013 regional coincident peak load, station non-coincident peak load and historical load provided by IESO;
- Historical net load and gross load forecast (which is the forecasted load from the historical net load) provided by LDCs and other Transmission connected customers;
- Conservation and Demand Management (CDM) and Distributed Generation (DG) data provided by OPA;
- GLPT provided transformer, station and line ratings
- Hydro One provided Wawa TS autotransformer ratings
- Any known reliability and/or operating issues conditions identified by LDCs or the IESO;
- Planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1. LOAD FORECAST

As per the data provided by the LDCs, the load in the ELS-Region is expected to grow at a rate varying from -0.1% to 2.5% plus some larger customer load increases.

Table 2: Annual Load Growth for ELS-Region

LDC	Approximate % Growth Rate 2013 to 2018	Approximate % Growth Rate 2019 to 2023
PUC	Slightly Negative	Slightly Negative
API	0.0 to 2.5%	0.0 to 2.5%
CPUC	0%	0%

Large Industrial Customer Load Increases	Approximate MW Increase 2013 to 2018	Approximate MW Increase 2019 to 2023
Sault Ste. Marie Southern Area	19.4	3.2
Wawa TS/Anjigami TS Northern Area	20.85	0

The Needs Assessment considered gross loads at individual stations based on the 2013 summer or winter peak non-coincident load and the peak summer or winter load forecast for stations within the Region. The station load forecast was developed by using data provided by the LDC's load forecasts and other customer load forecasts.

5. ASSESSMENT METHODOLOGY

The following methodology and assumptions were made in this Needs Assessment:

1. The Region is winter peaking, but this assessment includes both summer and winter peak loads where one is more critical than the other due to equipment ratings.

2. Forecast loads are provided by the LDCs and other customers.

3. Stations having negative load growth over the study period are assumed to have steady load.

4. In developing a worst-case scenario, DG and CDM contributions were not considered.

5. Review and assess impact of any on-going or planned development project in the ELS-Region during the study period.

6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables and stations.

7. Station capacity adequacy is assessed assuming a 90% lagging power factor on the HV and non-coincident station loads.

8. Transmission line adequacy to be assessed using non-coincident peak station loads in the region.

9. The needs were first identified by looking at the total normal supply capacity (TNSC) of the elements that supply a specific LDC or other customer compared to the three month average peak over the last 5 years and the peak load over the last five years. This was used to identify any planning issues based on the existing peak loads. The 2023 peak load was then compared to the TNSC and if peak loads were greater than 75% of the TNSC for specific station/line(s), these station/line(s) were identified for further study. The TNSC takes into consideration one element out of service where load is not supplied via a single line/station.

10. Transmission adequacy assessment is primarily based on:

    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
    - With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their continuous ratings and transformers within their summer 10-Day limited time ratings (LTR) if there are two transformers and 10 day LTR's exist.
    - All voltages and voltage declines must be within pre- and post-contingency ranges as per ORTAC criteria.

11. The ELS-Region has a considerable amount of hydro generation connected to the 115 kV system and wind generation connected to the 230 k system. Two new wind farms are in the process of connecting to the Gartshore 115 kV lines (58.3 MW) and K24G 230 kV lines (25.3 MW). Both have had recent detailed IESO System Impact Assessments (SIA) and GLPT Customer Impact Assessments (CIA) completed which did not identify concern in the area regarding overload of facilities. Generation in the area is generally more critical to line overload than LDC and other customer load. These studies were reviewed as part of this Needs Assessment process.

12. For the Sault Ste. Marie Southern section of the ELS-Region, the 98% dependability of generation from Clergue GS was used in this assessment. Glergue GS dependable generation was assumed to be 10 MW. This is based on an IESO Feasibility Study (Confidential) undertaken to assess the Algoma lines for adequate capacity.

This Needs Assessment was conducted to identify emerging needs and determine whether or not further coordinated regional planning should be undertaken for the Region or electrical areas. It is expected that further studies in the subsequent regional planning process will undertake detailed analysis and also assess ORTAC performance requirements.

6. RESULTS

6.1. Transmission Capacity Needs

6.1.1. 230kV Connection Facilities

Based on the demand forecast, there is sufficient capacity throughout the study period at Echo River TS which is a 230kV connected load station. No action is required at this time and the capacity needs will be reviewed in the next planning cycle.

Based on the demand forecast over the study period, no overload or capacity need was identified for the loss of a single 230kV circuit in the region.

East-West Tie lines are to be upgraded in 2019. Hydro One's CIA entitled "New East-West Tie Project' dated October 29, 2014 concludes there are no significant impact to customers in the area. The Hydro One CIA assessed the Short-Circuit Impact, Voltage Impact and Supply Reliability Impact.

6.1.2. 230/115kV Autotransformers

No overload or capacity issues were identified for the loss of any single 230kV/115kV autotransformer except the overload of No.3 Sault for loss of MacKay TS T2 which is mitigated by arming the MacKay TS Generation Rejection Scheme.

6.1.3. 115kV Connection Facilities

Based on the demand forecast, there is sufficient capacity at all 115kV load stations throughout the study period except Hollingsworth (T2) /Angijami (T1) TS's. The 44 kV system supplied by Hollingsworth TS T2 and Anjigami TS T1 will become overloaded due to a new large customer connecting to the 44 kV system late 2017.

Loading on all 115 kV circuits is within assessment criteria limits throughout the study period except for the No.1, No.2 and No.3 Algoma lines that need to be studied further due to the demand forecast from one of the other customer in Sault Ste. Marie projecting an increase in peak load. This could be compounded in Sault Ste. Marie with the closure of Lake Superior Power Inc.'s LSP GS in 2014.

6.2. System Reliability, Operation and Restoration Review

Generally speaking, there are no significant system reliability and operating issues identified for one element out of service in this region where there are two or more parallel elements.

There is a concern about transformer failure in the region where there are many load stations with just one transformer supplying customer load. The ORTAC restoration criteria of 8 hours (plus travel time) cannot always be met for single transformer stations for a transformer failure. This is being studied at this time; however, it needs to be studied further.

6.3. Sustainment Replacement Plans

Significant sustainment activities are scheduled within the study period at the stations listed. The new equipment ratings at these stations were considered in this need assessment. Plans to replace major equipment do not affect the needs identified based on the demand forecast.

GLPT Stations

- Anjigami TS (equipment & relaying)
- Batchawana TS (equipment)
- Clergue TS (equipment)
- D.A. Watson TS (equipment)
- Goulais Bay TS (equipment)
- Hollingsworth TS (relaying)
- HWY 101 TS (relaying)
- Magpie TS (equipment)
- Steelton TS (equipment)

PUC Stations

- St. Mary's TS (equipment & relaying)
- Tarentorus TS (equipment & relaying)

6.4. Other Considerations

Restoration of most of the GLPT transmission system can be accomplished from a black start procedure which energizes the Sault Ste. Marie Southern Area load/generation and eventually up to MacKay TS South Central Area to load/generation and run as an island. It is expected that for the loss of Wawa TS T1 and T2 transformers and by configuration the Wawa TS/Anjigami TS Northern Area, the delay in restoration of GLPT connected load/generation can be greater than the ORTAC standard of 8 hours. There is a need to study if this area could be operated as an island until the supply from Hydro One Wawa TS can be restored.

7. RECOMMENDATIONS

The study Team Recommends:

7.1. The potential need identified for the Anjigami TS/ Hollingsworth TS does not require further regional coordination. The study team recommends that "localized" wire only solution be developed in the near-term to adequately and efficiently address the above need through planning between GLPT and the impacted distributor.

7.2. The potential needs identified for the Algoma lines and the Sault Ste. Marie possible issues with the shutdown of LSP GS does not require further regional coordination. The

study team recommends that a "localized" wire only solution be developed by GLPT and the impacted customer.

7.3. The potential need identified for the restoration of load after a single supply transformer failure which could violate the ORTAC criteria of restoring load within 8 hours does not require further regional coordination. The study team recommends that GLPT and the impacted distributor continue to work on this need.

8. NEXT STEPS

Following the Needs Assessment process, the next regional planning step, based on the results of this report, are:

8.1. GLPT and the relevant LDC's are to further assess and/or develop local wires solution as identified in the needs outlined in Section 7.1 and 7.3.

8.2. GLPT and the relevant customers will further assess and/or develop local wires solution as identified in the needs outlined in Section 7.2.

9. REFERENCES

Planning Process Working Group (PPWG) Report to the Board

IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

IESO Feasibility Study (Confidential) for Algoma Lines Redevelopment

IESO System Impact Assessment (SIA) Report and Addendum Report for Bow Lake Wind Farm (CAA ID#: 2010-392)

IESO System Impact Assessment Report and Addendum Report for Goulais Wind Farm (CAA ID#: 2010-397)

GLPT Customer Impact Assessment (CIA) Report for RTK Canada, ULC (Rentech) increased 44 kV load dated April 23, 2014.

Customer Impact Assessment (CIA) Report for Hydro One New East-West Tie Project dated October 29, 2014.

10. KEY TERMS AND DEFINITIONS

Key terms and definitions associated with this Needs Assessment are cited here.

Normal Supply Capacity (NSC): The maximum loading that electrical equipment may be subjected to continuously under nominal ambient conditions such that no accelerated loss of equipment life would be expected.
Coincident Peak Load: The electricity demand at individual facilities at the same specific point in time when the total demand of the region or system is at its maximum.

Contingency: The prevalence of abnormal conditions such that elements of the power system are not available.

Conservation and Demand Management (CDM): Programs aimed at using more of one type of energy efficiently to replace an inefficient use of another to reduce overall energy use, and influencing the amount or timing of customers' use of electricity.

Distributed Generation (DG): Electric power generation equipment that supplies energy to nearby customers with generation capacity typically ranging from a few kW to 25 MW.

Gross Load: Amount of electricity that must be generated to meet all customers' needs as well as delivery losses, not considering any generation initiatives such as CDM and DG. It is usually expressed in MW or MVA.

Limited Time Rating (LTR): A higher than nameplate rating that a transformer can tolerate for a short period of time

Load Forecast: Prediction of the load or demand customers will make on the electricity system

Net Load: Net of generation (e.g. CDM and DG) deducted from the Gross load

Non-Coincident Peak Load: The maximum electricity demand at an individual facility. Unlike the coincident peak, non-coincident peaks may occur at different times for different facilities.

Peak Load: The maximum load consumed or produced by a unit or group of units in a stated period of time. It may be the maximum instantaneous load or the maximum average load over a designated interval of time.

Total Normal Supply Capacity (TNSC): The maximum loading that electrical equipment may be subjected to post contingency (n-1) under nominal ambient conditions such that an acceptable accelerated loss of equipment life would be expected. For a single element supply system the TNSC equals the NSC.

11. ACRONYMS

CDM Conservation and Demand Management

CIA Customer Impact Assessment

DG Distributed Generation

DSC Distribution System Code

IESO Independent Electricity System Operator

IRRP Integrated Regional Resource Planning

kV Kilovolt

LDC Local Distribution Company

LTR Limited Time Rating

LV Low-voltage

MVA Mega Volt-Ampere

MW Megawatt

NA Needs Assessment

NSC Normal Supply Capacity

OEB Ontario Energy Board

OPA Ontario Power Authority

ORTAC Ontario Resource and Transmission Assessment Criteria

PF Power Factor

PPWG Planning Process Working Group

RIP Regional Infrastructure Planning

SIA System Impact Assessment

SS Switching Station

TNSC Total Normal Supply Capacity

TS Transformer Station

TSC Transmission System Code

PUC SERVICES INC.
500 SECOND LINE EAST, P.O. Box 9000
SAULT STE. MARIE, ONTARIO, P6A 6P2

September 29, 2014

Great Lakes Power Transmission LP
Transmission System Planning
Asset Management and Engineering Dept.
2 Sackville Rd., Suite B
Sault Ste. Marie, ON
P6B 6J6

Attn: Jim Tait
Technical Supervisor Engineering

Cc: Claudio Stefano, V.P Operations & Engineering (PUC)

Re: OEB Regional Infrastructure Planning (RIP) Process
Information for Needs Screening Process

Dear Mr Tait,

We are providing the following submission in response to your letter dated 2014/08/12 in which you request information to support the needs screening portion of the Regional Infrastructure Planning process. In that letter you request:

1. Gross and Net Load forecast for the next 10years, provided on the following basis:
    a. In megawatts ("MW") with power factor assumptions provided;
    b. At the supply Transformer station or delivery point
2. Regional system reliability and performance issues.
3. Any additional information considered relevant.

Historical and Forecast loading is summarized in the attached spreadsheet which was completed on the standard Load Forecast Template file provided by GLPT. Supporting information is also included to substantiate our assumptions. This information consists of:

- Conservation demand management information in form of email from CDM Officer dated 2014/09/19, entitled '2011-2013 CDM Demand Savings'
- Metering data extracted from wholesale metering points in the form of a spreadsheed, filename '0509.6 OEB RIP2014-09-25 load Forecast.xlsx'

In general terms, based on the forecast, we do not see any near term needs for a change in capacity of the 115kV transmission assets connecting our LDC to your transmission system. Loads are generally trending moderately in the negative direction in winter and moderately in the positive direction in the summer. Since the winter load is significantly larger than the summer load, the overall trend for the period of the forecast is in the negative direction.

We wish to point out that our demand forecast excludes the contribution of any distribution system connected distributed generation. As you are aware, we presently have a significant solar contribution of approximately 62MW to our distribution system. This generation results in near zero or net export conditions during their peak producing summer months when our system is near its minimum load. The generation was connected as part of the OPA RESOP and FIT programs. Because of its significant degree of penetration, distributed generation may be material to the RIP process.

Furthermore, with respect to distributed generation, there continues to be a strong interest in developing green energy in our community and this is being pursued on a number of municipal and private interests. We expect this will continue and may lead to requests to connect additional significant projects in the near to long term future (3 to 10 years).

One final topic we wish to draw your attention to is the age of our four 115kV lines and the two 115kV/34.5kV stations that connect us with GLPT. This infrastructure was installed about 40 years ago in the 1970s. Although we believe the transmission lines have several decades of serviceable life left, it is our belief that the two stations will require a major upgrade within 5 to 15 years. Although we currently do not have a specific asset management plan in place for these assets, we do intend to develop one in 2014.

We trust this submission meets all of the current requirements of the RIP process and look forward to working with you on this matter. Should you require anything further please direct your inquiries to my attention.

Best Regards,



Rob Harten, P. Eng.
Manager of Engineering

PUC DISTRIBUTION INC. • PUC SERVICES INC. • PUBLIC UTILITIES COMMISSION
Tel. (705) 759-6500 www.ssmpuc.com

Load Forecast Template

Customer Name: Sault Ste Marie PUC
Region Name: East Lake Superior

Notes:

1	Enter data for the transformer stations supplying your LDC and if there is a missing transformer station please add it to the current list
2	For LDCs directly connected to the transmission facilities, load forecasts should factor in the load forecasts of any embedded distributor. Include a list of all embedded distributors
3	For LDCs that are embedded in another distributor's system, DO NOT include your embedded load in forecasts submitted to the transmitter; instead, submit the embedded load forecasts to the host distributor for inclusion in their submission to the transmitter.
4	Provide coincident load forecast aggregated for all your feeders at the Station Level.
5	For Historical Data, LDCs are to provide the Net Load, i.e. Gross Peak Load minus any EXISTING Conservation & Demand Management (CDM) and Distributed Generation (DG), available during the time of peak demand.
6	For Forecasted Data, LDCs are to only provide the Gross Peak Load (which is the Forecasted Load from their Historical Net Load). OPA will provide Forecasted DG and CDM.
7	Provide load forecast in MWs and include power factor assumptions, if any.
8	List all assumptions made in preparing this load forecast.

		Peak Load (Net = Gross - DG - CDM)													
TS Name or DP	Customer Data (MW)	Historical Data (MW)			Near Term Forecast (MW)					Medium Term Forecast (MW)					Power Factor
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
Tarentorus T.S. (TS2)	Gross Peak Load				37.1	37.1	37.1	37.0	37.0	37.0	37.0	37.0	36.9	36.9	0.967
GL1TA(non-coincident)	Net Load	21.1	37.1	0.1											
Tarentorus T.S. (TS2)	Gross Peak Load				51.7	51.6	51.6	51.6	51.5	51.5	51.5	51.5	52.1	51.4	0.967
GL2TA(non-coincident)	Net Load	48.1	24.0	51.7											
St. Mary's T.S. (TS1)	Gross Peak Load				52.4	52.3	52.3	52.3	52.2	52.2	52.2	52.2	52.1	52.1	0.967
GL1SM(non-coincident)	Net Load	41.3	34.9	52.4											
St. Mary's T.S. (TS1)	Gross Peak Load				60.5	60.5	60.5	60.4	60.4	60.4	60.3	60.3	60.3	60.2	0.967
GL2SM(non-coincident)	Net Load	39.3	36.2	35.1											
Total PUC	Gross Peak Load				139.3	139.2	139.2	139.1	139.1	139.0	139.0	138.9	138.8	138.8	0.967
(coincident peak)	Net Load	149.9	132.2	139.2											0.967

LDC Assumptions:

1) Assumed that Generation and CDM are accounted for in Net Load Forecast of the Historical Data.
2) Assumed that the full benefit of Generation and CDM are active during peak loads.
3) Peeks for individual circuits are NOT coincident peaks with system peak; they are case by case worst case peaks for the individual feeders in a given year based on the maximum feeder load for the period 2011-2013
4) As it is unknown to PUC as to how power factor relates to load, a power factor based on the average historical value has been assumed for the forecast

From: Brooke Suurna
To: Rob Harten; Claudio Stefano
Subject: 2011-2013 CDM Demand Savings
Date: Friday, September 19, 2014 10:50:42 AM
Attachments: image003.jpg

I was originally going to provide quarterly data for 2011-2013 however upon review of the data I don't believe the quarterly numbers from the OPA are accurate because they were changed as subsequent quarterly reports were released. The only numbers I am 100% confident in are the final annual results released by the OPA.

Year	Demand Savings (MW)
2011	0.7
2012	0.8
2013	1.1

Please let me know if you require anything further

Brooke Suurna, P.Eng
Conservation & Demand Management Officer
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Forecast Calculations

System Total Peak Load

	Year	Net Peak Load	Gross Peak Load
Actual	2007 Actual	139,708	139,708
	2008 Actual	139,124	139,124
	2009 Actual	147,108	147,108
	2010 Actual	141,244	141,244
	2011 Actual	149,857	149,952
	2012 Actual	132,164	132,154
	2013 Actual	139,248	139,361
Projected	2014	139,171	139,303
	2015	139,095	139,245
	2016	139,018	139,187
	2017	138,942	139,129
	2018	138,865	139,072
	2019	138,789	139,014
	2020	138,713	138,956
	2021	138,637	138,899
	2022	138,560	138,841
	2023	138,484	138,784

Feeder Peak Loads (Non-Coincident Net)

	Year	Net Peak Load (MW) GL1TA	Net Peak Load (MW) GL2TA	Net Peak Load (MW) GL1SM	Net Peak Load (MW) GL2SM
Actual	Maximum of Calendar Years 2011 - 2013	37.12	51.68	52.39	60.57
Projected	2014	37.10	51.65	52.36	60.54
	2015	37.08	51.62	52.34	60.50
	2016	37.06	51.60	52.31	60.47
	2017	37.04	51.57	52.28	60.44
	2018	37.02	51.54	52.25	60.40
	2019	37.00	51.51	52.22	60.37
	2020	36.98	51.48	52.19	60.34
	2021	36.96	51.45	52.16	60.31
	2022	36.94	51.43	52.13	60.27
	2023	36.92	51.40	52.11	60.24

Growth Rate

Year	Rate (Net)	Rate (Gross)
2007 - 2008	0.9958	0.9958
2008 - 2009	1.0574	1.0574
2009 - 2010	0.9601	0.9601
2010 - 2011	1.0610	1.0617
2011 - 2012	0.8819	0.8813
2012 - 2013	1.0536	1.0545
Geomean	0.9995	0.9996

Notes: growth rate was used to calculate project growth

Total System Electric Loading History

										2010			2011			2012			2013			2014		
	Energy 2001 kWh	Energy 2002 kWh	Energy 2003 kWh	Energy 2004 kWh	Energy 2005 kWh	Energy 2006 kWh	Energy 2007 kWh	Energy 2008 kWh	Energy 2009 kWh	Wholesale Meter Energy 2010 kWh	Distributed Gen Energy 2010 kWh	Total System Energy 2010 kWh	Wholesale Meter Energy 2011 kWh	Distributed Gen Energy 2011 kWh	Total System Energy 2011 kWh	Wholesale Meter Energy 2012 kWh	Distributed Gen Energy 2012 kWh	Total System Energy 2012 kWh	Wholesale Meter Energy 2013 kWh	Distributed Gen Energy 2013 kWh	Total System Energy 2013 kWh	Wholesale Meter Energy 2014 kWh	Distributed Gen Energy 2014 kWh	Total System Energy 2014 kWh
YTD Totals	718,680,760	744,156,060	755,126,020	757,685,852	749,219,032	728,093,333	738,093,576	740,966,488	732,869,986	710,857,306	2,305,988	713,163,294	693,045,100	36,883,588	729,928,688	635,223,994	78,072,955	713,296,949	659,215,628	70,879,868	730,095,496	359,501,319	35,392,364	394,893,683
January	78,253,278	75,783,700	85,049,952	89,226,840	88,287,600	76,234,176	78,292,016	79,006,867	85,774,977	79,854,697	0	79,854,697	82,648,728	685,685	83,334,413	75,554,837	830,876	76,385,713	76,231,996	1,215,534	77,447,531	83,292,308	784,023	84,076,331
February	71,056,718	69,010,564	76,788,076	73,066,340	71,065,788	71,202,696	75,583,244	75,126,906	71,566,146	68,437,902	0	68,437,902	70,439,804	1,633,071	72,072,875	64,040,984	3,779,719	67,820,704	68,219,789	1,575,061	69,794,850	70,305,579	2,977,471	73,283,050
March	70,086,644	73,544,560	75,545,096	71,196,888	73,186,104	70,367,240	71,668,468	74,573,962	72,767,317	63,113,132	0	63,113,132	68,440,898	3,244,798	71,685,695	58,334,633	5,542,828	63,877,461	62,222,455	7,041,704	69,264,159	69,150,658	6,785,778	75,936,435
April	58,715,640	61,508,916	63,274,204	61,357,220	56,446,820	56,652,640	60,506,916	58,751,936	59,966,274	53,088,771	0	53,088,771	57,001,677	3,031,773	60,033,450	47,033,398	9,901,424	56,934,822	56,115,257	6,375,267	62,490,524	54,009,639	6,936,289	60,945,928
May	50,799,464	56,801,704	52,784,032	55,571,152	53,664,344	52,446,572	51,273,936	53,931,566	52,676,063	51,130,272	0	51,130,272	48,309,149	3,345,715	51,654,863	41,538,463	10,563,057	52,101,520	42,336,726	8,924,016	51,260,742	45,055,529	8,072,055	53,127,584
June	49,362,308	50,055,824	49,325,848	49,366,380	51,111,168	49,917,449	50,644,216	48,466,639	49,196,439	47,896,130	0	47,896,130	44,474,216	3,325,220	47,799,435	40,321,370	10,262,554	50,583,924	38,741,499	9,504,552	48,246,051	37,687,605	9,836,750	47,524,355
July	49,714,844	53,526,780	51,148,508	51,210,208	53,387,012	53,606,640	51,622,068	50,725,083	48,238,905	53,062,397	0	53,062,397	49,476,613	4,002,802	53,479,415	44,339,537	11,305,974	55,645,511	42,744,917	9,501,815	52,246,732			0
August	51,535,500	51,335,848	50,113,412	50,192,756	52,102,684	51,038,392	51,764,316	50,225,177	49,652,791	53,165,646	0	53,165,646	48,089,241	4,651,619	52,740,860	41,430,538	9,785,385	51,215,923	40,863,333	10,239,998	51,103,331			0
September	48,974,448	50,111,652	49,728,476	50,272,804	49,504,120	49,455,772	48,836,864	48,690,797	48,812,970	48,475,869	0	48,475,869	44,365,173	6,150,436	50,515,609	40,740,588	7,746,529	48,487,116	39,805,113	8,252,743	48,057,856			0
October	56,653,116	57,639,776	58,883,124	57,641,764	55,381,484	58,920,568	54,192,940	56,073,866	57,724,020	53,271,933	806,084	54,078,017	50,577,506	2,624,178	53,201,684	50,702,525	4,734,240	55,436,765	49,039,469	5,154,603	54,194,072			0
November	61,414,444	67,404,840	66,040,876	64,887,008	65,851,664	63,979,576	65,729,492	63,785,625	59,532,749	61,524,030	1,105,052	62,629,082	58,264,120	2,342,368	60,606,488	59,933,496	2,488,914	62,422,410	62,214,471	2,461,092	64,675,563			0
December	72,114,356	77,431,896	76,444,416	83,696,492	79,230,244	74,271,612	77,979,100	81,608,064	76,961,335	77,836,527	394,852	78,231,379	70,957,977	1,845,923	72,803,900	71,253,625	1,131,456	72,385,081	80,680,603	633,483	81,314,086			0
3-month total	150,612,652	154,918,452	150,587,768	150,769,344	156,600,864	154,562,481	154,030,600	149,416,898	147,088,135	154,124,173	0	154,124,173	142,040,069	11,979,641	154,019,710	126,091,445	31,353,913	157,445,358	122,349,749	29,246,365	151,596,114	37,687,605	9,836,750	47,524,355
Summer Average	50,204,217	51,639,484	50,195,923	50,256,448	52,200,288	51,520,827	51,343,533	49,805,633	49,029,378	51,374,724	0	51,374,724	47,346,690	3,993,214	51,339,903	42,030,482	10,451,304	52,481,786	40,783,250	9,748,788	50,532,038	12,562,535	3,278,917	15,841,452

	Demand 2001 kW	Demand 2002 kW	Demand 2003 kW	Demand 2004 kW	Demand 2005 kW	Demand 2006 kW	Demand 2007 kW	Demand 2008 kW	Demand 2009 kW	Wholesale Meter Demand 2010 kW	Adjusted for DG Demand 2010 kW		Wholesale Meter Demand 2011 kW	Adjusted for DG Demand 2011 kW		Wholesale Meter Demand 2012 kW	Adjusted for DG Demand 2012 kW		Wholesale Meter Demand 2013 kW	Adjusted for DG Demand 2013 kW		Wholesale Meter Demand 2014 kW	Adjusted for DG Demand 2014 kW	
January	136,152	133,624	147,064	150,828	156,336	137,316	137,364	139,124	147,108	141,244			149,857	149,857		132,090	132,154		138,936	138,936		143,061	143,172	
February	128,524	132,204	142,840	133,168	132,028	131,504	139,708	137,099	140,994	129,450			136,294	136,294		115,178	126,117		129,404	129,440		139,986	140,075	
March	122,084	129,004	143,188	121,748	132,728	121,328	138,956	126,361	134,710	109,694			124,344	124,344		117,881	118,115		115,636	115,710		135,918	135,983	
April	104,040	110,624	118,652	108,156	99,876	110,744	120,464	113,370	109,073	97,996			104,965	107,493		49,908	98,975	49.6%	111,773	111,959	0.2%	106,629	106,738	0.1%
May	88,452	102,020	89,152	103,988	98,032	95,184	90,156	93,108	91,475	97,193			90,361	92,646		36,736	94,353	61.1%	90,856	93,804		88,990	89,101	
June	91,560	91,424	97,240	90,496	96,532	88,948	100,876	86,634	97,507	87,013			94,306	94,306		52,482	104,308	49.7%	59,677	95,568	38%	59,003	87,494	33%
July	95,032	98,244	91,376	90,784	100,440	99,704	100,184	91,419	82,098	96,868			95,135	100,702		50,311	104,552		78,335	104,736				
August	96,272	91,912	89,224	89,708	98,928	94,792	101,464	92,154	92,161	101,492			88,991	97,338		69,686	92,694		64,298	99,844				
September	94,488	97,104	91,968	92,732	96,484	87,132	94,760	95,412	90,184	93,047			89,277	97,824		66,742	92,013		89,768	90,949				
October	101,716	106,588	107,616	100,520	95,520	104,856	93,000	101,744	102,250	96,934	96,934		94,283	94,370		102,667	102,702		98,465	98,465				
November	125,460	126,200	120,924	120,900	136,364	119,060	133,912	119,819	111,244	123,865	123,865		112,491	112,491		118,381	118,527		124,726	124,838				
December	130,692	137,444	134,140	159,136	141,964	134,212	135,708	144,796	134,470	141,147	141,147		128,372	128,372		122,761	122,935		139,248	139,361				
System Winter Peak	147,690	133,624	147,064	150,828	159,136	141,964	139,708	139,124	147,108	141,244				149,857			132,154							
Peak Month	December' 2000	January' 2002	January' 2003	January' 2004	December' 2004	December' 2005	February' 2007	January'2008	January'2009	January'2010				January'2011			January'2012							

Note: Winter is defined as December of the previous year to February of the current year

	LF 2001	LF 2002	LF 2003	LF 2004	LF 2005	LF 2006	LF 2007	LF 2008	LF 2009	LF 2010	LF 2011
January	77.3%	76.2%	77.7%	79.5%	75.9%	74.6%	76.6%	76.3%	78.4%	76.0%	74.1%
February	82.3%	77.7%	80.0%	78.8%	80.1%	80.6%	80.5%	78.7%	72.9%	76.0%	74.3%
March	77.2%	76.6%	70.9%	78.6%	74.1%	78.0%	69.3%	79.3%	72.6%	77.3%	74.0%
April	78.4%	77.2%	74.1%	78.8%	78.5%	71.1%	69.8%	72.0%	76.4%	75.2%	75.4%
May	77.2%	74.8%	79.6%	71.8%	73.6%	74.1%	76.4%	77.9%	77.4%	70.7%	71.9%
June	74.9%	76.0%	70.5%	75.8%	73.5%	77.9%	69.7%	77.7%	70.1%	76.5%	65.5%
July	70.3%	73.2%	75.2%	75.8%	71.4%	72.3%	69.3%	74.6%	79.0%	73.6%	69.9%
August	72.0%	75.1%	75.5%	75.2%	70.8%	72.4%	68.6%	73.3%	72.4%	70.4%	72.6%
September	72.0%	71.7%	75.1%	75.3%	71.3%	78.8%	71.6%	70.9%	75.2%	72.4%	69.0%
October	74.9%	72.7%	73.5%	77.1%	77.9%	75.5%	78.3%	74.1%	75.9%	73.9%	72.1%
November	68.0%	74.2%	75.9%	74.5%	67.1%	74.6%	68.2%	73.9%	74.3%	69.0%	71.9%
December	74.2%	75.7%	76.6%	70.7%	75.0%	74.4%	77.2%	75.8%	76.9%	74.1%	74.3%

Total System Electric Loading

	2011			2012			2013		
	Wholesale Meter Energy 2011 kWh	Distributed Gen Energy 2011 kWh	Total System Energy 2011 kWh	Wholesale Meter Energy 2012 kWh	Distributed Gen Energy 2012 kWh	Total System Energy 2012 kWh	Wholesale Meter Energy 2013 kWh	Distributed Gen Energy 2013 kWh	Total System Energy 2013 kWh
YTD Totals	693,045,100	36,883,588	729,928,688	635,223,994	78,072,955	713,296,949	659,215,628	70,879,868	730,095,496
January	82,648,728	685,685	83,334,413	75,554,837	830,876	76,385,713	76,231,996	1,215,534	77,447,531
February	70,439,804	1,633,071	72,072,875	64,040,984	3,779,719	67,820,704	68,219,789	1,575,061	69,794,850
March	68,440,898	3,244,798	71,685,695	58,334,633	5,542,828	63,877,461	62,222,455	7,041,704	69,264,159
April	57,001,677	3,031,773	60,033,450	47,033,398	9,901,424	56,934,822	56,115,257	6,375,267	62,490,524
May	48,309,149	3,345,715	51,654,863	41,538,463	10,563,057	52,101,520	42,336,726	8,924,016	51,260,742
June	44,474,216	3,325,220	47,799,435	40,321,370	10,262,554	50,583,924	38,741,499	9,504,552	48,246,051
July	49,476,613	4,002,802	53,479,415	44,339,537	11,305,974	55,645,511	42,744,917	9,501,815	52,246,732
August	48,089,241	4,651,619	52,740,860	41,430,538	9,785,385	51,215,923	40,863,333	10,239,998	51,103,331
September	44,365,173	6,150,436	50,515,609	40,740,588	7,746,529	48,487,116	39,805,113	8,252,743	48,057,856
October	50,577,506	2,624,178	53,201,684	50,702,525	4,734,240	55,436,765	49,039,469	5,154,603	54,194,072
November	58,264,120	2,342,368	60,606,488	59,933,496	2,488,914	62,422,410	62,214,471	2,461,092	64,675,563
December	70,957,977	1,845,923	72,803,900	71,253,625	1,131,456	72,385,081	80,680,603	633,483	81,314,086
3-month total	142,040,069	11,979,641	154,019,710	126,091,445	31,353,913	157,445,358	122,349,749	29,246,365	151,596,114
Summer Average	47,346,690	3,993,214	51,339,903	42,030,482	10,451,304	52,481,786	40,783,250	9,748,788	50,532,038

	Wholesale Meter Demand 2011 kW	Adjusted for DG Demand 2011 kW		Wholesale Meter Demand 2012 kW	Adjusted for DG Demand 2012 kW		Wholesale Meter Demand 2013 kW	Adjusted for DG Demand 2013 kW	
January	149,857	149,857		132,090	132,154		138,936	138,936	
February	136,294	136,294		115,178	126,117		129,404	129,440	
March	124,344	124,344		117,881	118,115		115,636	115,710	
April	104,965	107,493		49,908	98,975	49.6%	111,773	111,959	0.2%
May	90,361	92,646		36,736	94,353	61.1%	90,856	93,804	
June	94,306	94,306		52,482	104,308	49.7%	59,677	95,568	38%
July	95,135	100,702		50,311	104,552		78,335	104,736	
August	88,991	97,338		69,686	92,694		64,298	99,844	
September	89,277	97,824		66,742	92,013		89,768	90,949	
October	94,283	94,370		102,667	102,702		98,465	98,465	
November	112,491	112,491		118,381	118,527		124,726	124,838	
December	128,372	128,372		122,761	122,935		139,248	139,361	

System Winter Peak
Peak Month

2011	Date	Interval	Gross Load	Power factor	GL1TA	GL2TA	GL1SM	GL2SM	DG Contribution	GLPT Contribution
January	23-Jan-11	19	149,952	0.966	21079.1	48127.5	41337.4	39313.2	95	149857.2
February	9-Feb-11	19	136,345	0.996	15227.3	43511.1	38978.6	38577.2	51	136294.2
March	2-Mar-11	20	124,406	0.968	15474	39853.4	33384.8	35631.3	63	124343.5
April	17-Apr-11	16	107,694	0.968	13923.5	31958.1	31615.5	27467.5	2,730	104964.6
May	3-May-11	17	92,850	0.966	35558.2	26713.2	0	27540	3,039	89811.4
June	7-Jun-11	21	94,493	0.938	33735.2	0	0	60571.1	187	94306.3
July	18-Jul-11	17	100,702	0.945	23159.7	18832.3	0	47599.5	11,111	89591.5
August	5-Aug-11	16	97,338	0.899	0	15454.6	16255.1	47806.3	17,822	79516
September	12-Sep-11	16	97,824	0.908	0	18184.1	25314.4	26833.1	27,492	70331.6
October	17-Oct-11	19	94,480	0.965	10996.5	32506.1	25727	25053	197	94282.6
November	21-Nov-11	18	112,692	0.973	23848.1	35231.3	19989	33422.9	201	112491.3
December	28-Dec-11	19	128,565	0.973	24425.1	40660.8	23866.2	39420.3	192	128372.4

2012	Date	Interval	Gross Load	Power factor	GL1TA	GL2TA	GL1SM	GL2SM	DG Contribution	GLPT Contribution
January	19-Jan-12	20	132,154	0.968	37119.5	23950.6	34856.7	36237.6	(10)	132164.4
February	11-Feb-12	11	126,117	0.969	9823.6	34053.6	39068.5	32232.5	10,939	115178.2
March	5-Mar-12	9	118,115	0.973	12352	34383.2	40389.2	30756.8	234	117881.2
April	17-Apr-12	12	98,975	0.877	0	7267.6	17853	24787.8	49,066	49908.4
May	10-May-12	14	94,353	0.571	0	0	5547.3	31188.5	57,617	36735.8
June	11-Jun-12	13	104,308	0.76	0	13435.1	11544.8	27501.8	51,826	52481.7
July	4-Jul-12	13	104,552	0.757	0	7427	13106.8	29777.6	54,241	50311.4
August	30-Aug-12	16	92,694	0.899	3566.8	19500.8	6814.5	40207.8	22,604	70089.9
September	4-Sep-12	17	92,013	0.902	3146.9	28714.4	34798.8	81.5	25,271	66741.6
October	30-Oct-12	19	102,702	0.969	10245.5	29446.6	35513.3	27461.1	35	102666.5
November	30-Nov-12	18	118,527	0.969	20618.6	37103.4	31972.7	28686.5	145	118381.2
December	11-Dec-12	18	122,935	0.97	21169.4	38407	33611.1	29573.1	174	122760.6

2013	Date	Interval	Gross Load	Power factor	GL1TA	GL2TA	GL1SM	GL2SM	DG Contribution	GLPT Contribution
January	22-Jan-13	20	138,936	0.971	13846.8	41386.6	48307	35395.9	-	138936.3
February	6-Feb-13	20	129,440	0.972	13212.6	41578.7	36942.7	37669.7	37	129403.7
March	3-Mar-13	20	115,710	0.97	9391.7	39529.5	36944.1	29770.2	75	115635.5
April	2-Apr-13	20	111,959	0.973	11613	29754.6	38519.7	31885.6	186	111772.9
May	12-May-13	11	93,804	0.971	24895	7788.3	30606.5	27566.1	2,948	90855.9
June	26-Jun-13	16	95,568	0.865	43	21043.1	19149.9	20658.4	34,673	60894.4
July	17-Jul-13	16	105,070	0.89	0	23950.5	22783.8	31601	26,735	78335.3
August	29-Aug-13	16	100,086	0.869	1064.9	19540.3	24308.3	19729.4	35,443	64642.9
September	10-Sep-13	17	91,012	0.945	19524.1	18962.7	31934.2	19346.9	1,244	89767.9
October	29-Oct-13	19	98,633	0.998	71.8	35553.7	37925.5	24913.7	168	98464.7
November	24-Nov-13	18	124,838	0.972	13351.1	35814.5	44595.7	30964.4	112	124725.7
December	14-Dec-13	18	139,361	0.967	69.7	51681.6	52393.5	35103	113	139247.8

	GL1TA	GL2TA	GL1SM	GL2SM	DG Contribution	GLPT Contribution
Maximum Value over three year period 2011-2013	37119.5	51681.6	52393.5	60571.1	57616.74	149857.2

Appendix F

OEB Score Card Performance Measures

Scorecard - PUC Distribution Inc.

9/24/2014

Performance Outcomes	Performance Categories	Measures	2009	2010	2011	2012	2013	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time	98.20%	96.70%	97.80%	95.80%	96.50%	down	90.00%	
		Scheduled Appointments Met On Time	96.10%	92.40%	97.20%	98.40%	97.10%	up	90.00%	
		Telephone Calls Answered On Time	65.10%	70.10%	76.70%	74.60%	80.90%	up	65.00%	
	Customer Satisfaction	First Contact Resolution								
		Billing Accuracy								
		Customer Satisfaction Survey Results								
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Public Safety [measure to be determined]								
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted	2.14	2.11	2.92	1.65	2.48	up		at least within 1.65 - 2.92
		Average Number of Times that Power to a Customer is Interrupted	2.97	2.83	3.61	2.17	2.67	down		at least within 2.17 - 3.61
	Asset Management	Distribution System Plan Implementation Progress								
	Cost Control	Efficiency Assessment				3	4			
		Total Cost per Customer [1]	$456	$485	$513	$615	$687			
		Total Cost per Km of Line [1]	$20,445	$21,729	$22,981	$27,523	$30,950			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) [2]			12.00%	14.00%	19.20%			5.58MW
		Net Cumulative Energy Savings (Percent of target achieved)			35.00%	61.00%	87.20%			30.83GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	66.67%					
		New Micro-embedded Generation Facilities Connected On Time					100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)	1.38	1.39	1.43	1.19	1.06			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.52	1.53	1.44	2.01	1.99			
		Profitability: Regulatory Return on Equity — Deemed (included in rates)			8.57%	8.57%	8.98%			
		Profitability: Regulatory Return on Equity — Achieved			8.16%	4.99%	7.00%			

Legend: up, down, flat, target met, target not met

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings do not include any persisting peak demand savings from the previous years.

Scorecard - PUC Distribution Inc.

9/28/2015

Performance Outcomes	Performance Categories	Measures		2010	2011	2012	2013	2014	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		96.70%	97.80%	95.80%	96.50%	93.00%	down	90.00%	
		Scheduled Appointments Met On Time		92.40%	97.20%	98.40%	97.10%	95.40%	up	90.00%	
		Telephone Calls Answered On Time		70.10%	76.70%	74.60%	80.90%	81.90%	up	65.00%	
	Customer Satisfaction	First Contact Resolution						99.89%			
		Billing Accuracy						99.83%	flat	98.00%	
		Customer Satisfaction Survey Results						In progess			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public awareness [measure to be determined]									
		Level of Compliance with Ontario Regulation 22/04		NI	NI	NI	C	C	up		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	3	1	3	up		1
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.407	0.135	0.405	up		0.132
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		2.11	2.92	1.65	2.48	1.19	down		at least within 1.65 - 2.92
		Average Number of Times that Power to a Customer is Interrupted		2.83	3.61	2.17	2.67	1.21	down		at least within 2.17 - 3.61
	Asset Management	Distribution System Plan Implementation Progress						In progress			
	Cost Control	Efficiency Assessment				3	4	4			
		Total Cost per Customer [1]		$485	$513	$615	$687	$664			
		Total Cost per Km of Line [1]		$21,729	$22,981	$27,523	$30,950	$29,886			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Annual Peak Demand Savings (Percent of target achieved) [2]			11.19%	24.67%	43.55%	59.52%	target not met		5.58MW
		Net Cumulative Energy Savings (Percent of target achieved)			35.22%	60.88%	87.17%	99.06%	target not met		30.83GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		100.00%	66.67%						
		New Micro-embedded Generation Facilities Connected On Time					100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.39	1.43	1.19	1.06	1.68			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.53	1.44	2.01	1.99	2.42			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)		8.57%	8.57%	8.98%	8.98%			
			Achieved		8.16%	4.99%	7.00%	5.47%			

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings include any persisting peak demand savings from the previous years.

Legend: up, down, flat, target met, target not met

Appendix A – 2014 Scorecard Management Discussion and Analysis ("2014 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2014 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

For the year 2014, PUC Distribution exceeded prescribed targets for most scorecard measures. In particular, system reliability performance for the year 2014 was the best achieved since 1999. This notable improvement in reliability is primarily the result of ongoing efforts related to replacing aging or defective infrastructure and improved vegetation management.

For 2014, average interruption duration (SAIDI) decreased 52% compared to 2013, while average interruption frequency (SAIFI) decreased 55%. Moving forward, PUC Distribution plans to continue efforts aimed at improving reliability for its customers thereby delivering greater value for the service provided to them.

Service Quality

- **New Residential/Small Business Services Connected on Time**

  In 2014, PUC Distribution connected 213 eligible low-voltage residential and small business customers (connections under 750 volts) to its system, 93% of which were connected within the five-day timeline prescribed by the Ontario Energy Board (OEB). This is a 3.5% decrease from the previous year but still above the OEB-mandated target of 90%. PUC Distribution is undergoing process reviews for the purpose of identifying any potential areas of improvement and to continue to ensure that the New Service performance measures are exceeded.

- **Scheduled Appointments Met On Time**

  In 2014, PUC Distribution scheduled 1,466 appointments with customers to complete customer requested work (e.g. meter re-reads, reconnections, meter locates, etc.). Although a slight decrease from 2013, PUC Distribution met 95.4% of these appointments on time, which exceeds the OEB-mandated target of 90%.

- **Telephone Calls Answered On Time**

In 2014, PUC Distribution's Customer Care Department received 39,681 calls from its customers – that's over 159 calls per working day. Of those calls, a Customer Care Representative answered the call in 30 seconds or less, 81.90% of the time. This result significantly exceeds the OEB-mandated 65% target for timely call response. The 2014 result amounts to a 1% improvement over 2013, driven primarily by a reduction in the number of calls, due primarily to fewer outages in 2014. Also, the reduction in call volume can, in part, be attributed to the introduction of automated emergency messaging employed during large scale power outages. Additionally, the shift towards email as the communication medium of choice for customers has also contributed to the reduction.

Customer Satisfaction

Specific customer satisfaction measurements have not been previously defined across the industry. The OEB has instructed all electricity distributors to review and develop measurements in these areas and begin tracking by July 1, 2014 so that information can be reported in 2015. The OEB plans to review information provided by electricity distributors over the next few years and implement a commonly defined measure for these areas in the future. As a result, each distributor may have different measurements of performance until such time as the OEB provides specific direction regarding a commonly defined measure.

- **First Contact Resolution**

  First Contact Resolution can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors.

  PUC Distribution's First Contact Resolution was measured by tracking the number of electric related calls which were escalated to a Supervisor/Manager and a Senior Customer Care Representative. This was done by creating two specific call types in our Customer Information System (CIS) which could then be queried to provide the number of customer concerns which were escalated.

  To establish the number of calls which were handled without escalation, the CIS was queried based on the associated call types to arrive at the number of customer calls handled by the Customer Care Team.

  To determine the number of repeat calls for the same issue, a review of the escalated calls was conducted on the premise that if the call reached the Senior Customer Care level the concern would not have been satisfactorily resolved at the time of first contact.

- **Billing Accuracy**

  Until July 2014 a specific measurement of billing accuracy had not been previously defined across the industry. After consultation with some electricity distributors, the OEB has prescribed a measurement of billing accuracy which must be used by all distributors effective October 1, 2014. For the period from October 1, 2014 – December 31, 2014 PUC Distribution issued more than 100,000 bills and

achieved a billing accuracy of 99.83%. This compares favorably to the prescribed OEB target of 98%.

PUC Distribution continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

  The OEB introduced the Customer Satisfaction Survey Results measure beginning in 2013. At a minimum, electricity distributors are required to measure and report a customer satisfaction result at least every other year. At this time the OEB is allowing distributors discretion as to how they implement this measure.

  PUC engaged a third party to conduct the customer satisfaction survey. The survey was conducted in April 2015 and completed in June 2015, therefore, survey results along with the mangement discussion will published on the 2015 Scorecard.

Safety

- **Public Safety**

  The OEB introduced the Safety Measure in 2015. This measure looks at safety from a customer's point of view as safety of the distribution system is a high priority. The Safety measure is generated by the Electrical Safety Authority (ESA) and includes three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04 and the Serious Electrical Incident Index.

  - **Component A – Public Awareness of Electrical Safety**

    This Component of the public safety measure does not have performance data for the 2014 scorecard as the public awareness of electrical safety survey was not required to be conducted in the subject year. 2016 will be the first year that data for this measure will

be reported on the scorecard for the 2015 results.

- **Component B – Compliance with Ontario Regulation 22/04**

  Component B is comprised of: the External Audit, the Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. All these elements are evaluated as a whole and determine the status of compliance. Over the past two years, PUC Distribution was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety and adherence to company policies and procedures. Ontario Regulation 22/04 establishes objective based electrical safety requirements for the design, construction and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans, and specifications and the inspection of construction to ensure there are no undue hazards before they are put in service.

- **Component C – Serious Electrical Incident Index**

  PUC Distribution reported three (3) serious electrical incidents involving members of the public in 2014. There were no injuries associated with these incidents. A detailed analysis of the data and root cause evidence has helped steer PUC Distribution's efforts to increase public awareness in an effort to eliminate future incidents. PUC Distribution offers electrical safety awareness outreach via newspaper and radio ads, presentations to elementary school students, and detailed hazard awareness presentations to contractors.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  Average duration of outages for the year 2014 demonstrated a marked improvement compared to 2013. In fact, 2014 system reliability was the best achieved since 1999. The notable improvement in reliability is due primarily to ongoing efforts related to replacing aging or defective infrastructure and improved vegetation management. Continued improvement is anticipated moving forward.

  Average interruption duration for 2014 decreased 52% compared to 2013.

- **Average Number of Times that Power to a Customer is Interrupted**

  Average frequency of outages for the year 2014 also demonstrated a marked improvement compared to 2013. Average interruption frequency for 2014 decreased 55% compared to 2013.

Asset Management

- **Distribution System Plan Implementation Progress**

  All distributors are required to file a Distribution System Plan (DSP) when filing a cost of service application for the rebasing of their rates. Accordingly, PUC Distribution plans to file an application with the OEB for a full review of its rates effective May 1, 2017, which will include a complete DSP.

Cost Control

- **Efficiency Assessment**

  The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs. The following table summarizes the distribution of all distributors across the 5 groupings.

Group	Demarcation Points for Relative Cost Performance	% of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	8
2	Actual costs are 10% to 25% below predicted costs	20
3	Actual costs are within +/-10% of predicted costs	47
4	Actual costs are 10% to 25% above predicted costs	18
5	Actual costs are 25% or more above predicted costs	7

In 2014, as in 2013, PUC Distribution was placed in Group 4, where a Group 4 distributor is defined as having actual costs between 10% and 25% of predicted costs under the PEG model. Group 3 is considered "average efficiency".

PUC Distribution's efficiency performance improved from 22.7% in 2013 to 14.6% in 2014.

- **Total Cost per Customer**

  Total cost per customer is calculated as the sum of PUC Distribution's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC Distribution serves. The cost performance result for 2014 is $664/customer which is a 3.4 % decrease over 2013.

  Overall, the company's Total Cost per Customer has increased on average by 7.3% per annum over the period 2010 through 2014. Similar to most distributors in the province, PUC Distribution has experienced increases in its total costs required to deliver quality and reliable services to customers. Province-wide programs such as Time of Use pricing, growth in wage and benefits costs for employees, as well as investments in new information systems technology and the renewal of the distribution system, have all contributed to increased operating and capital costs.

  PUC Distribution will continue to replace distribution assets proactively in a manner that balances system risks and customer rate impacts. PUC Distribution's capital and operating programs will be further defined in its 2017 rate application to be filed in 2016. The company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2015 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC Distribution's capital spending plans.

- **Total Cost per Km of Line**

  This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometers of line that the company operates to serve its customers. PUC Distribution's 2014 rate is $29,886 per Km of line, a 3.4% decrease over 2013.

  PUC Distribution has experienced a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per Km of line has increased since 2010 with the increase in capital and operating costs.

Conservation & Demand Management

- **Net Annual Peak Demand Savings (Percent of target achieved)**

  PUC Distribution achieved 59.52% of its 2011-2014 Peak Demand target of 5.58 MW. It was a challenge to meet the peak demand

target due to the fact PUC Distribution is a winter peaking utility. PUC Distribution was pleased with its efforts as peak demand savings results aligned fairly well with the provincial average.

- **Net Cumulative Energy Savings (Percent of target achieved)**

  PUC Distribution achieved 99.06% of its 2011-2014 net cumulative energy savings target of 30.83 GWh. Much of this success can be attributed to the successful promotion of energy efficiency programs and strong participation by commercial customers in the Retrofit and Small Business Lighting Programs. PUC Distribution looks forward to promoting energy efficiency programs and assisting its customers in saving money and conserving energy throughout the new 2015-2020 Conservation First Framework.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority. For the year 2010 one CIA request was received and processed within the prescribed timelines.

  In 2011 three requests were received. Two were processed within the prescribed timelines and the progress of the third was not adequately documented so it could not be determined whether it was or was not completed on time. To minimize the likelihood of similar future reporting anomalies, refinements have been made to our CIA application processes and process documents.

  No requests for CIAs were received for the years 2012 through 2014.

- **New Micro-embedded Generation Facilities Connected On Time**

  In 2014, PUC Distribution connected seven new micro-embedded generation facilities (microFIT projects of less than 10 kW) 100% of time within the prescribed time frame of five business days. The minimum acceptable performance level for this measure is 90% of the time.

  Our process to connect these projects is very streamlined and transparent for our customers. PUC Distribution works closely with its customers and their contractors to address any connection issues and ensure projects are connected in a timely manner.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

  PUC Distribution's current ratio increased from 1.06 in 2013 to 1.68 in 2014 as a result of long term borrowing that was completed late in 2014. PUC Distribution's current ratio in subsequent years is expected to be in line with 2014 results.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

  The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

  PUC Distribution has a debt to equity structure of 71% to 29% that approximates the deemed 60% to 40% capital mix as set out by the OEB – this translates to a 2014 debt to equity ratio of 2.42. PUC Distribution's long range plan is to push the debt to equity towards the deemed 60% to 40%.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

  PUC Distribution's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 8.98%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review by the OEB of the distributor's revenues and costs structure.

- **Profitability: Regulatory Return on Equity – Achieved**

  PUC Distribution's return on equity in 2014 at 5.47% was more than 3% lower than the expected return of 8.98%. The variance in return on equity is the result of the company's OM&A expenses in 2014 being approximately $1.1 million higher than included in the approved 2013 cost of service rate application.

Note to Readers of 2014 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Scorecard - PUC Distribution Inc.

9/29/2016

Performance Outcomes	Performance Categories	Measures		2011	2012	2013	2014	2015	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		97.80%	95.80%	96.50%	93.00%	97.20%	↓	90.00%	
		Scheduled Appointments Met On Time		97.20%	98.40%	97.10%	95.40%	97.40%	↓	90.00%	
		Telephone Calls Answered On Time		76.70%	74.60%	80.90%	81.90%	82.30%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution					99.89%	99.92%			
		Billing Accuracy					99.83%	99.36%	↓	98.00%	
		Customer Satisfaction Survey Results					In progess	79%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness						86.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	NI	C	C	C	↑		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	3	1	3	1	→		1
			Rate per 10, 100, 1000 km of line	0.000	0.407	0.135	0.405	0.134	→		0.151
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		2.92	1.65	2.48	1.19	3.35	↑		2.07
		Average Number of Times that Power to a Customer is Interrupted [2]		3.61	2.17	2.67	1.21	1.84	↓		2.50
	Asset Management	Distribution System Plan Implementation Progress					In progress	In Progress			
	Cost Control	Efficiency Assessment			3	4	4	4			
		Total Cost per Customer [3]		$513	$615	$687	$664	$699			
		Total Cost per Km of Line [3]		$22,981	$27,523	$30,950	$29,886	$31,377			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]						17.18%			26.41 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		66.67%				0.00%			
		New Micro-embedded Generation Facilities Connected On Time				100.00%	100.00%	100.00%	→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.43	1.19	1.06	1.68	0.90			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.44	2.01	1.99	2.42	2.31			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.57%	8.57%	8.98%	8.98%	8.98%			
			Achieved	8.16%	4.99%	7.00%	5.47%	4.46%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework. This measure is under review and subject to change in the future.

Legend:

5-year trend
↑ up ↓ down → flat

Current year
target met target not met

Appendix A – 2015 Scorecard Management Discussion and Analysis ("2015 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2015 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

For the year 2015, PUC Distribution met or exceeded all prescribed targets for scorecard measures except one, the outage duration index, SAIDI. This metric was significantly impacted by a late-year winter storm that hit Sault Ste. Marie and surrounding area in the early morning hours of December 24th. With wind gusts up to 90 kph, many trees came down onto PUC distribution lines interrupting power to approximately 10,000 customers for varying time durations. PUC Distribution crews worked extensive hours late into the day on Christmas Eve to restore all affected customers in time for their Christmas Eve dinners. We are very grateful to our staff for their extensive efforts in responding to this demanding weather event and we extend our praise for the excellent work they did in restoring service to all our customers as quickly as possible.

One particular area of performance where PUC Distribution is especially proud of is in the area of safety, both in regards to the general public and in the area of our workers. Of the 36 LDC's that participated in the 2015 electrical safety awareness survey, PUC Distribution scored the highest with an awareness score of 86%. Our efforts in awareness education for elementary school students and the use of general safety promotions through the various media venues play an important part in this achievement.

Service Quality

- **New Residential/Small Business Services Connected on Time**

  In 2015, PUC Distribution connected 144 eligible low-voltage residential and small business customers (connections under 750 volts) to its distribution system, 97.20% of which were connected within the five-day timeline prescribed by the Ontario Energy Board (OEB). This is an improvement of 4.2 percentage points over 2014 and exceeds the OEB mandated target of 90%. PUC Distribution remains committed to a process of continuous improvement to ensure performance targets are not only met, but exceeded.

- **Scheduled Appointments Met On Time**

  In 2015, PUC Distribution scheduled 1,240 appointments with customers to complete customer requested work (e.g. meter installs or

removals, service disconnects or reconnects, and meter locates). As a result of our continuous improvement efforts, PUC Distribution met 97.40% of scheduled appointments, an improvement over 2014 by 2 percentage points, and exceeded the OEB target of 90%.

- **Telephone Calls Answered On Time**

  In 2015, PUC Distribution's Customer Care Department received 38,874 calls from customers. Our Customer Care Representatives answered those calls in 30 seconds or less, 82.30% of the time. This result significantly exceeds the OEB mandated target of 65%. The five year trend has shown continuous improvement for this performance measure in part due to a concerted effort to proactively communicate with our customers. Additionally, the PUC Distribution website is being used more effectively.

Customer Satisfaction

- **First Contact Resolution**

  For 2015, PUC Distribution handled 99.92% of calls without escalating the calls to a; Senior Customer Care Representative, Supervisor, or Manager. However, it's important to note that First Contact Resolution can be measured in a variety of ways, and further regulatory guidance is necessary in order to achieve a meaningful statistic that is comparable across electricity distributors.

  First Contact Resolution was determined by creating two specific call types in our Customer Information System (CIS) which could then be queried to provide the number of customer concerns which were escalated. To establish the number of calls which were handled without escalation, the CIS was queried based on the associated call types to arrive at the total number of customer calls handled by the Customer Care Team.

  To determine the number of repeat calls for the same issue, a review of the escalated calls was conducted on the premise that if the call reached the Senior Customer Care level the concern would not have been satisfactorily resolved at the time of first contact.

- **Billing Accuracy**

  PUC Distribution issued approximately 400,000 bills for the period from January 1, 2015 – December 31, 2015 and achieved an accuracy of 99.36%. This exceeds the prescribed OEB target of 98%. PUC Distribution continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

  PUC Distribution engaged the UtilityPulse Division of Simul Corporation to conduct our 2015 customer satisfaction survey. The UtilityPulse Electric Utility Survey is in its 17th year of annual surveys and is used by a significant number of Ontario distributors. The final report on our customer satisfaction survey was received in June and PUC Distribution received a customer satisfaction score of

79% (post survey result). The survey asked customers questions on a wide range of topics, including: overall satisfaction with reliability, customer service, outages, billing and corporate image. These customer satisfaction surveys provide information that supports discussions surrounding improving customer service at all levels and departments within PUC Distribution.

Safety

- **Public Safety**

  The OEB introduced the Safety Measure in 2015. This measure looks at safety from a customer's point of view as safety of the distribution system is a high priority. The Safety Measure is generated by the Electrical Safety Authority (ESA) and includes three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04 and the Serious Electrical Incident Index.

  - **Component A – Public Awareness of Electrical Safety**

    In 2015, PUC Distribution participated in a public electrical safety awareness survey. A representative sample of PUC Distribution's service territory population was surveyed to gauge the public's awareness level of key electrical safety concepts related to distribution assets (the survey was based on a template provided by the Electrical Safety Authority). Of the 36 LDC's that participated in the electrical safety awareness survey, PUC Distribution scored the highest with an awareness score of 86%. The purpose of the survey was to provide a benchmark level concerning the public's electrical safety awareness, and identify opportunities where additional education and outreach may be required.

    With several major public safety awareness events held in 2015, PUC Distribution's commitment to education and public safety was highlighted once again. Below are the electrical safety initiatives PUC Distribution participated in over the last year:

    - Elementary School Electrical Safety Program for Grade 3 – 5 within our geographic service territory (24 schools involving 1,863 students and their teachers participated)
    - Advanced Research & Technology Innovation Expo (ARTIE) (approx. 360 students and their teachers participated)
    - Sault Ste. Marie Science Festival (approx. 500 adults and children participated)
    - Sault Ste. Marie PUC website – Safety tab
    - Advertisements in the geographic service territory consists of: newspaper and radio ads

  - **Component B – Compliance with Ontario Regulation 22/04**

    Component B is comprised of; an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns, and

Compliance Investigations. All these elements are evaluated as a whole to determine the status of compliance. Over the past three years, PUC Distribution was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety and continued adherence to company policies and procedures.

Ontario Regulation 22/04 establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of; equipment, plans, and specifications, and the inspection of construction to ensure there are no undue hazards before installations are put in service.

- **Component C – Serious Electrical Incident Index**

  For 2015, PUC Distribution was below the serious electrical incident target rate of 0.151 incidents per kilometer. PUC Distribution reported one (1) serious electrical incident involving members of the public last year, which is a decrease in the quantity (3) of incidents reported during the previous year. Fortunately, there were no injuries associated with this incident. In following up on this incident, PUC Distribution reached out to the ESA to offer assistance in educating first responders with respect to electrical safety. Additionally, PUC Distribution continues to increase public awareness in an effort to eliminate future incidents. PUC Distribution offers electrical safety awareness outreach via; newspaper and radio, presentations to elementary school students, and detailed hazard awareness presentations to contractors.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  The System Average Interruption Duration Index (SAIDI) of 3.35 in 2015 was higher than the target of 2.07. Outage performance for 2015 was significantly impacted by a severe windstorm that hit the Sault Ste. Marie area early on December 24, 2015. The events of that one day accounted for 42% of the outage duration performance for the entire year.

  Excluding the windstorm, SAIDI would have been 1.94. There are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

- **Average Number of Times that Power to a Customer is Interrupted**

  The System Average Interruption Frequency Index (SAIFI) of 1.84 in 2015 was lower than the target of 2.50. Consistent with SAIDI, outage performance for the year was significantly impacted by a severe windstorm that hit the Sault Ste. Marie area on December 24, 2015. The events of that one day accounted for 31% of the outage frequency performance for the entire year. Excluding the windstorm, SAIFI would have been 1.27.

Asset Management

- **Distribution System Plan Implementation Progress**

  All Distributors are required to file a Distribution System Plan (DSP) when filing a cost of service application for the rebasing of their rates. We expect that implementation of this standardized approach will re-inforce our existing commitment to long term planning and sustainable asset management. PUC Distribution is presently engaged in reviewing, updating, and migrating its Asset Management Plan into the creation of an integrated DSP which will meet all OEB requirements. Accordingly, PUC Distribution plans to file an application with the OEB in 2017 which will include a complete DSP.

Cost Control

- **Efficiency Assessment**

  The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs. The following table summarizes the distribution of all distributors across the 5 groupings for 2015.

Group	Demarcation Points for Relative Cost Performance	% of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	8
2	Actual costs are 10% to 25% below predicted costs	20
3	Actual costs are within +/-10% of predicted costs	51
4	Actual costs are 10% to 25% above predicted costs	15
5	Actual costs are 25% or more above predicted costs	6

In 2015, for the third year in a row, PUC Distribution was placed in Group 4. Group 3 is considered "average efficiency".

PUC Distribution's efficiency performance based on the PEG model was over the predicted costs by 16.2% in 2015 compared to 14.6% in 2014.

- **Total Cost per Customer**

  Total cost per customer is calculated as the sum of PUC Distribution's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC Distribution serves. The cost performance result for 2015 is $699 per customer which is a 5.3 % increase over 2014.

  Overall, the company's Total Cost per Customer has increased on average by 7.3% per annum over the period 2011 through 2015. Similar to most distributors in the province, PUC Distribution has experienced increases in its total costs required to deliver quality and reliable services to customers. Province-wide programs such as Time of Use pricing, growth in wage and benefits costs for employees, as well as investments in new information systems technology and the renewal of the distribution system, have all contributed to increased operating and capital costs.

  PUC Distribution will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. PUC Distribution's capital and operating programs will be further defined in its 2018 rate application to be filed in 2017 The company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2015 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC Distribution's capital spending plans.

- **Total Cost per Km of Line**

  This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometers of line that the company operates to serve its customers. PUC Distribution's 2015 rate is $31,377 per Km of line, a 5.0% increase over 2014.

  PUC Distribution continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per Km of line has increased since 2011 with the increase in capital and operating costs.

Conservation & Demand Management

- **Net Cumulative Energy Savings**

  2015 was a transition year from the previous framework to the new Conservation First Framework. This framework will continue until 2020 with a new MWh target. This transition year allowed LDC's to close out projects from the previous framework and submit new projects under the new framework.

PUC Distribution worked diligently with businesses and channel partners to complete all outstanding projects in addition to updating the changes in rules and submission process for the new framework. As a result of this work, the final net savings for 2015 was 4,538 MWh, slightly better than double our target for the year, and giving us a head start going forward to 2020.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for the project from the Electrical Safety Authority. For the year 2015, one CIA request was received and processed, however, not within the prescribed timelines. PUC Distribution has adjusted its established process for Generator CIAs to address this issue going forward. .

- **New Micro-embedded Generation Facilities Connected On Time**

  In 2015, PUC Distribution connected six new micro-embedded generation facilities (microFIT projects of less than 10 kW). For those projects, 100% were connected within the prescribed timeframe of five business days. The minimum acceptable performance level for this measure is 90%. PUC Distribution achieved this metric by working closely with our customers and their contractors to ensure the connection process for these types of projects are as streamlined and transparent as possible.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

  PUC Distribution's current ratio decreased from 1.68 in 2014 to 0.90 in 2015. A construction loan of $15M which was in current liabilities was converted to a long term loan in 2016 as planned. The result of this is a reduction of current liabilities of $15M which would increase the current ratio to 2.19.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

  The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have

difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

PUC Distribution has a debt to equity structure of 70% to 30% that approximates the deemed 60% to 40% capital mix as set out by the OEB – this translates to a 2015 debt to equity ratio of 2.31. PUC Distribution's long range plan is to push the debt to equity towards the 60/40 level.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

  PUC Distribution's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 8.98%. The OEB allows a distributor to earn within +/- 3 percentage points of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**

  PUC Distribution's return on equity in 2015 at 4.46% was more than 3 percentage points lower than the expected return of 8.98%. The variance in return on equity is the result of PUC Distribution's OM&A expenses in 2015 being approximately $1.3 million higher than included in the approved 2013 cost of service rate application.

Note to Readers of 2015 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Scorecard - PUC Distribution Inc.

9/11/2017

Performance Outcomes	Performance Categories	Measures		2012	2013	2014	2015	2016	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		95.80%	96.50%	93.00%	97.20%	98.90%	↑	90.00%	
		Scheduled Appointments Met On Time		98.40%	97.10%	95.40%	97.40%	98.30%	↑	90.00%	
		Telephone Calls Answered On Time		74.60%	80.90%	81.90%	82.30%	81.30%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution				99.89%	99.92%	99.58%			
		Billing Accuracy				99.83%	99.36%	99.97%	↑	98.00%	
		Customer Satisfaction Survey Results				In progess	79%	80%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness					86.00%	86.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	3	1	3	1	0	↓		1
			Rate per 10, 100, 1000 km of line	0.407	0.135	0.405	0.134	0.000	→		0.151
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.65	1.42	1.19	1.37	1.49	↓		1.86
		Average Number of Times that Power to a Customer is Interrupted [2]		2.17	1.78	1.21	1.03	1.41	↓		2.32
	Asset Management	Distribution System Plan Implementation Progress				In progress	In Progress	In progress			
	Cost Control	Efficiency Assessment		3	4	4	4	4			
		Total Cost per Customer [3]		$615	$687	$664	$699	$695			
		Total Cost per Km of Line [3]		$27,523	$30,950	$29,886	$31,377	$31,314			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]					17.18%	52.97%			26.41 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time					0.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time			100.00%	100.00%	100.00%		→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.19	1.06	1.68	0.90	1.52			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		2.01	1.99	2.42	2.31	2.34			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.57%	8.98%	8.98%	8.98%	8.98%			
			Achieved	4.99%	7.00%	5.47%	4.46%	0.98%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework.

Legend:

5-year trend: ↑ up ↓ down → flat

Current year: target met; target not met

Appendix A – 2016 Scorecard Management Discussion and Analysis ("2016 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2016 Scorecard MD&A:
http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

In 2016 PUC Distribution Inc. (PUC) met or exceeded all prescribed targets for scorecard measures. PUC continued with strong performance in the Customer Focus, Operational Effectiveness and Public Policy Responsiveness areas of our scorecard. This has generally been reflected in good customer satisfaction survey measure results.

Service Quality

- **New Residential/Small Business Services Connected on Time**
  In 2016, PUC Distribution connected 349 eligible low-voltage residential and small business customers (connections under 750 volts) to its distribution system, 98.90% of which were connected within the five-day timeline prescribed by the Ontario Energy Board (OEB). This is a 1.7% increase from the previous year and exceeds the OEB mandated target of 90%. The improved performance over 2015 can be partly attributed to a reduction in capital works projects which allowed additional resources to focus on low volume connections. PUC Distribution has demonstrated our commitment to continuous improvement through staff education to ensure customer satisfaction is a top priority.

- **Scheduled Appointments Met On Time**
  In 2016, PUC Distribution scheduled 1,468 appointments with customers to complete customer requested work (e.g. meter installs/removals, service disconnects/reconnects, and meter locates). As a result of our emphasis on customer satisfaction, PUC was able to meet 98.30% of scheduled appointments on time, which exceeds the OEB target of 90%.

- **Telephone Calls Answered On Time**
  In 2016, PUC Distribution's Customer Care Department received 40,787 calls from its customers. This represents an increase in call volume of approximately 1,900 calls from 2015, due in part, to the utility switching to automated reminder calls for past due accounts.

Of the 40,787 calls, a Customer Care Representative answered the call within 30 seconds or less, 81.30% of the time. This result significantly exceeds the OEB mandated 65% target for timely call response.

Customer Satisfaction

- **First Contact Resolution**

  PUC Distribution's First Contact Resolution was measured by tracking the number of electric related calls which were escalated to a Senior Customer Care Representative or Supervisor/Manager. This was accomplished by creating two specific call types in our Customer Information System (CIS) which would then be queried to provide the number of customer concerns which were escalated.

  In 2016, PUC had 40,787 calls, of which, 171 contacts were escalated to a higher level of management. This resulted in a First Contact Resolution percentage of 99.58%.

  To establish the number of calls which were handled without escalation, the total number of calls which were escalated to a higher level of management was subtracted from the total number of calls received. However, it should be noted that First Contact Resolution can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors.

- **Billing Accuracy**

  PUC issued approximately 395,000 bills for the period from January 1, 2016 – December 31, 2016, and achieved an accuracy of 99.97%. This score compares favourably to the prescribed OEB target of 98%. PUC continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

  PUC Distribution engaged the UtilityPulse Division of Simul Corporation to conduct our 2016 customer satisfaction survey. The UtilityPulse Electric Utility Survey is in its 19th year of annual surveys and is used by a significant number of Ontario distributors. The final report on our customer satisfaction survey was received in March 2017, and PUC Distribution received a B+ customer satisfaction score of 80% (post survey result) which is above the Ontario benchmark survey that had a grade of "B".

  The raw score had a slight increase from our last survey of 79%. The survey asked customers questions on a broad range of topics, including overall satisfaction with reliability, customer service, outages, billing and corporate image. These customer satisfaction surveys

are an important element in our overall customer engagement strategy providing further insight towards planning and supporting customer service improvement at all levels within PUC Distribution.

Public Safety

The Public Safety measure was introduced by the OEB in 2015 and focuses on the safety of the distribution system from a customer's point of view. The Electrical Safety Authority (ESA) provides an assessment as it pertains to Component B – Compliance with Ontario Regulation 22/04 and Component C – Serious Electrical Incident Index.

- **Component A – Public Awareness of Electrical Safety.**

  A representative sample of PUC Distribution's service territory population was surveyed in late 2015 to gauge the public's awareness level of key electrical safety concepts related to distribution assets. The purpose of the survey was to provide a benchmark level concerning the public's electrical safety awareness, and identify opportunities where additional education and outreach may be required. The results of the survey were analyzed in 2016, a number of opportunities to improve our existing outreach programs were identified and an action plan was developed.

  One item of note from the survey results indicated that more emphasis was required to ensure public awareness of Ontario One Call. In an effort to improve this metric, PUC approved a budget in 2016 (for 2017) to purchase promotional Dig Safe decals for the entire operations fleet, and through participation with the Association of Electrical Utility Professionals (AEUSP) has contributed to the production of a series of Electricity Safety videos for television broadcast in our service area. (Expected for 2017)

  PUC Distribution continues to look for every opportunity to communicate and engage with the public to promote electrical safety awareness in our service area. Below are examples of PUC Distribution's public safety communication initiatives in 2016:

  - Elementary School Electrical Safety Program for Grade 3 – 5 within our geographic service territory. Participation included 24 schools. (73 classes, and 1,874 students)
  - Advanced Research & Technology Innovation Expo (ARTIE) (approx. 360 students and their teachers participated)
  - Sault Ste. Marie Science Festival (approx. 500 adults and children attended)
  - Sault Ste. Marie PUC website – Safety tab with particular activities aimed at educating young people on electrical safety
  - Advertisements in the geographic service territory consists of newspaper and radio ads

- **Component B – Compliance with Ontario Regulation 22/04**

  Ontario Regulation 22/04 establishes objective based electrical safety requirements for the design, construction and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the Regulation requires the approval of equipment, plans, and specifications and the inspection of construction to ensure there are no undue hazards before they are put in service.

  Component B is comprised of an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns, and Compliance Investigations. ESA evaluates all these elements as a whole to determine the status of compliance. In each of the past four years, PUC Distribution was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). PUC attributes this continued success to our strong commitment to safety, and adherence to company policies and procedures.

- **Component C – Serious Electrical Incident Index**

  Section 12 of Ontario Regulation 22/04 specifies the requirement to report to ESA any serious electrical incident of which they become aware within 48 hours after the occurrence. For the 2016 reporting period, PUC Distribution did not experience any serious electrical incidents.

  To increase public safety awareness, PUC Distribution offers electrical safety awareness outreach via; newspapers, radio, public events, presentations to elementary school students, and detailed hazard awareness presentations to contractors.

System Reliability

A key change for 2016, as required by the OEB, is the revised reporting of reliability data with respect to Major Events. Specifically the change serves to adjust the reliability data to remove the impact of Major Events. Additionally, distributors are required to report criteria to monitor the distributor's performance related to the Major Event.

The 2016 Scorecard system reliability data, excludes both Loss of Supply and Major Events. The adjusted reliability measures capture interruptions caused by circumstances within the distributor's control and are published in the 2016 scorecard.

A "Major Event" is defined as an event that is beyond the control of the distributor and is; unforeseeable, unpredictable, unpreventable, or unavoidable. Such events disrupt normal business operations and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets,

take significantly longer than usual to repair, and affect a substantial number of customers.

In 2016 there were two major event days. The first happened on March 6 (foreign interference) and the second on June 20 (adverse weather).

- **Average Number of Hours that Power to a Customer is Interrupted**
  The System Average Interruption Duration Index (SAIDI) of 1.49 in 2016 was below the target of 1.86. There are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

- **Average Number of Times that Power to a Customer is Interrupted**
  The System Average Interruption Frequency Index (SAIFI) of 1.41 in 2016 was substantially below the target of 2.32. Consistent with SAIDI, there are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management.

Asset Management

- **Distribution System Plan Implementation Progress**
  Although PUC has employed distribution system planning for several years, the OEB instituted a mandatory requirement for this activity to be practised provincially, along with associated performance measures, beginning in 2013. We expect that implementation of this standardised approach will allow us to strengthen our commitment to responsible long term planning and sustainable asset management and to align our objectives with those of the of the OEB ultimately maximising benefit to our ratepayers.

  All distributors are required to file a Distribution System Plan (DSP) when filing a cost of service application for the rebasing of their rates. PUC is presently engaged in migrating and expanding upon its existing distribution system planning to create a formal DSP that meets all OEB requirements. The new DSP will be accompanied by performance measures and once completed will be filed with PUC's next OEB rate application to be filed in 2017.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (PEG) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs. The following table summarizes the distribution of all distributors across the 5 groupings for 2016:

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	6
2	Actual costs are 10% to 25% below predicted costs	More Efficient	14
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	32
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	13
5	Actual costs are 25% or more above predicted costs	Least Efficient	3

In 2016, for the fourth year in a row, PUC Distribution was placed in Group 4. PUC Distribution's efficiency performance based on the PEG model was over the predicted costs by 14% in 2016 compared to 16.2% in 2015.

- **Total Cost per Customer**

Total cost per customer is calculated as the sum of PUC Distribution's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e. under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC Distribution serves.

The cost performance result for 2016 is $695 per customer which is a 0.57 % decrease over 2015. Overall, the company's Total Cost per Customer has increased on average by 3.26% per annum over the period 2012 through 2016. For the period of 2013 to 2016, the Total Cost per Customer has increased by approximately 0.40% per year.

PUC Distribution will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. PUC Distribution's capital and operating programs will be further defined in its 2018 rate application to be filed in 2017. The

company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2016 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC Distribution's capital spending plans.

- **Total Cost per Km of Line**
  This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometers of line that the company operates to serve its customers. PUC Distribution's 2016 rate is $31,314 per Km of line, a 0.20% decrease over 2015.

  PUC Distribution continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per Km of line has increased an average of 3.45% since 2012 with the increase in capital and operating costs. For the period of 2013 to 2016, the Total Cost per Km of Line has increased by approximately 0.40% per year.

Conservation & Demand Management

- **Net Cumulative Energy Savings**
  PUC is committed to helping its customers understand their energy usage by offering programs that enable them to become more energy efficient. PUC has a conservation target of 26.4 Gigawatt hours by the end of 2020. Results for 2016 show progress of 52.97% towards that target. This achievement was made possible by the strong participation by local commercial/industrial customers in retrofit and auditing programs. Residential customers also participated in saveONenergy coupon events opting to replace lights in their homes to more energy efficient ones, as well as purchasing other energy efficient equipment. The combined efforts of participants from both the residential and business sectors made the achievement of substantial energy savings possible.

  Notable projects where city wide street lighting, not only in Sault Ste. Marie but Prince Township and Batchewana First Nations. Municipal parking lots followed suit with upgrading their parking lot lighting to LED, while small businesses began changing their florescent lamps and incandescent bulbs to efficient LED tubes and lamps.

  PUC remains committed to providing its customers with cost effective conservation programs to help them save electricity and lower their electricity bills. PUC will continue to innovate new ways to promote and support customers in reducing their consumption today

and for the future.

As a member of CustomerFirst, PUC is part of a joint Conservation (CDM) Plan that has been approved by the IESO. The joint plan will achieve 141,877 MWh of savings which is equal to the combined targets that were allocated to each CustomerFirst member under the new framework. Through the CustomerFirst joint CDM Plan, PUC will continue to work collaboratively with the other CustomerFirst utilities to find efficiencies and reduce costs. The group will be sharing resources and working together in all areas of CDM including sales, marketing, customer and project support to provide value to ratepayers.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**
  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority. For the year 2016 four CIA requests were received for a total of 820kW of FIT generation, and all applications were processed within the prescribed timelines.

- **New Micro-embedded Generation Facilities Connected On Time**
  In 2016, interest in the micoFIT program was much lower than in previous years. PUC Distribution Inc. received only one application and provided an offer to connect, but no follow-up request for connection was received. Outside of the micoFIT program, one application for a net metering load displacement installation was made.

  PUC's process to connect these projects is very streamlined and transparent for its customers. PUC works closely with customers and contractors to address any connection issues and ensure projects are connected in a timely manner.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**
  As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

  PUC Distribution's current ratio has increased from 0.90 in 2015 to 1.52 in 2016. By increasing over 1, PUC Distribution is in a good

position to cover the company's short-term debts and financial obligations.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**
  The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt to equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

  PUC Distribution has a debt to equity structure of 70% to 30% that approximates the deemed 60% to 40% capital mix as set out by the OEB – this translates to a 2016 debt to equity ratio of 2.34. PUC Distribution's long range plan is to push the debt to equity towards the 60/40 level.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**
  PUC Distribution's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 8.98%. The OEB allows a distributor to earn within +/- 3 percentage points of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**
  PUC Distribution's return on equity in 2016 at 0.98% was more than 3 percentage points lower than the expected return of 8.98%. The variance in return on equity is the result of PUC Distribution's OM&A expenses in 2016 being approximately $1.4 million higher than included in the approved 2013 cost of service rate application. PUC plans on filing a 2018 Cost of Service Rate Application for rates effective in 2018.

Note to Readers

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard, and could be markedly different in the future.

Appendix G

Project Descriptions for Specific Projects Exceeding Materiality Threshold

A. General Information					
Project/Activity	#1 - Customer Demand - Services				
Project Number	1C100-1				
Investment Category	System Access				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 1,165,797				
Capital Contribution	$ 253,750				
Net Cost	$ 912,047				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent upon quantity and location of customer requests.

Start Date (5.4.5.2 A.3)	Dependent on request			**In Service Date (5.4.5.2 A.3)**	Dependent on request
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**	
	$ 174,870	$ 408,029	$ 408,029	$ 174,870	

Project Summary

In an effort to comply with Distribution System Code (DSC) requirements and to support ongoing customer demand, the above values have been budgeted for using historical expenditures and predictions from the City of Sault Ste. Marie regarding projected development. Budgeted expenditures include installations of new/upgraded residential services, commercial services, new transformers to support services, replacement/relocation of infrastructure due to customer requests and other miscellaneous requests from customers. All requests are reviewed against the DSC and reasonableness to determine PUC's contribution level.

Risk Identification & Mitigation (5.4.5.2 A.4)

Tasks occur throughout the year as requested by customers. Risks include internal and contractor resource constraints due to fluctuation of customer requests. PUC is regulated to connect customers who lie along the line within a specified timeframe. In an effort to mitigate the risk of not complying with timelines, PUC reallocates resources from planned capital projects to customer demand as required.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Compared to the previous 5 years, PUC's investment to customer demand, specific to services and accommodating relocation requests is estimated to be low for the next five years. The city has been impacted by uncertainty of local steel industry which, in turn, has impacted the economy. Due to the impact, the housing industry, commercial development and overall spending in the economy has been impacted, reducing the anticipated expenditures in the immediate future to support customer demand. Due to the nature of the economy, this is a prediction and is subject to change.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific requests whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Services will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

PUC is regulated by the OEB Distribution System Code (DSC). The DSC states that all customer that lie along the line of the existing electrical distribution line shall be provided the ability to connect. PUC considers and complies with this requirement to connect new customers as required. PUC provides new connections with the basic connection allowance as specified in the DSC.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

New customer connections, increased revenue and customer relations are the secondary driver for the project. This project will increase quantity of customers supplied by PUC and revise service sizes affecting revenue stream. Replacing/relocating assets to accommodate customers provides PUC with an opportunity to increase customer relations and replace assets at a reduced cost through customer contributions.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

Investment objectives are to comply with all regulations, secure more customers and improve customer relations.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The City of Sault Ste. Marie is currently preparing a revised population projection for their Official Plan. A preliminary review of the population projection predicts that the population of Sault Ste. Marie will plateau at approximately 75,000 causing a negligible change from today's population. PUC has also referenced the Regional Infrastructure Plan. These documents were referenced when estimating expenditures for the period identified within this cost of service.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a very high priority, immediately behind emergency replacements. This is due to regulatory compliance and customer satisfaction.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

PUC reviews options for new/revised services on a case by case basis to ensure the solution is implemented is safe, low maintenance and economical for all parties.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Net benefits accruing to customers have been qualitatively identified but are unable to quantitatively calculate at this stage.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

There will be no negligible impact to reliability performance resulting from this project. Very minor upgrades to individual services should result in less long term outages for the individual customer.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)
Alternatives are considered on a case by case basis. The most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.
Safety (5.4.5.2 B2)
New/upgraded services are installed to the most current safety standards available ensuring safety for all.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
This project has no adverse impact on cyber security or privacy issues.
Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers
Services will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.
Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements
Services and supporting infrastructure are designed to be constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.
Economic Development (5.4.5.2 B.5)
By assuring sustainable, reliable, cost effective electrical services to customers in PUC's service territory, this project contributes towards economic development in the region.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
PUC considers different technologies when installing services and supporting infrastructure inclusive of vacuum trucks and directional drilling. These technologies cause less disturbance to the area and in turn less environmental impacts. Additionally, PUC considers environmental impacts when specifying material to be installed.

C. Category-Specific Requirements - System Access
Factors Affecting Timing/Priority (5.4.5.2 SA-C1)
This project receives a very high priority in order for PUC to comply with regulations. Scheduling tasks is dependent on complying with regulations and accommodating customers.
Factors Related to Customer/ Third Party Preferences (5.4.5.2 SA-C2)
PUC informs customers that it is their responsibility to coordinate third party services to be installed. PUC provides contractor information to customer for the customer to obtain benefits of installing multiple utilities in the same excavation. PUC installs services as per USF and/or PUC standards which are in line with industry standards allowing third parties reasonable access.
Factors Affecting the Final Cost (5.4.5.2 SA-C3)
There are many factors that affect the final cost of the project. Costs are affected by how the economy responds, customer requests, regulatory compliance, existing asset life and customer contributions. These costs are vairable and fluctuate annually.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA-C4)
PUC considers all options when services are installed/revised in an effort to provide the most practical solution for all parties. PUC has recently began purchasing large, pad mount transformers with integral group operated switches to minimize costs of pole mounted group operated switches and pole changes to obtain the increased space required on the pole. This is one example considered when new/revised services are installed.
Other Planning Objectives (5.4.5.2 SA-C5) (where applicable)
PUC considers other projects when installing new services. If the service is within the area of an upcoming project, it is considered to revise timing of projects to gain overall economic efficiencies. Additionally, adjacent services are grouped together in an attempt to improve efficiency.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA-C6)
Technical options are considered during development of standards and specific designs. Specific products are reviewed in an attempt to improve system safety, reliability and redundancy while managing costs.
Summary of Results Analysis - "Least Cost", "Cost Efficient" options (5.4.5.2 SA-C7)
Options are considered on a case by case basis.
Results of a final Economic Evaluation (5.4.5.2 SA-C8) (where applicable)
If an expansion is identified, PUC will perform an economic evaluation as per section 3.2 of the Distribution System Code. Results of economic evaluation are made available to the customer requesting the expansion.
System impacts costs & cost recovery method (5.4.5.2 SA-C9) (where applicable)
Impacts to the system when connecting a new/revised customer are considered on a case by case basis ensuring the capacity of the system is adequate and impacts to adjacent customers is minimal or positive. Costs and cost recovery is considered on a case by case basis, affected by regulations and corporate practices.

A. General Information						
Project/Activity	#2 - Customer Demand - Subdivisions					
Project Number	1C100-2					
Investment Category	System Access					
	2018	**2019**	**2020**	**2021**	**2022**	
Capital Cost (5.4.5.2 A.1)	$ 137,153					
Capital Contribution	$ 30,000					
Net Cost	$ 107,153					
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**	
	NA	NA	NA	NA	NA	

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on quantity and location of customer requests.

Start Date (5.4.5.2 A.3)	Dependent on request			**In Service Date (5.4.5.2 A.3)**	Dependent on request
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**	
	$ 20,573	$ 48,004	$ 48,004	$ 20,573	

Project Summary

In an effort to comply with Distribution System Code (DSC) requirements and support ongoing customer demand, the above values have been budgeted for using historical expenditures and predictions from the City of Sault Ste. Marie on development. Budgeted values include installations of new subdivisions inclusive of the expansion of our distribution system and transformation up to property lines for projected residential customers. All requests are reviewed against the DSC and reasonableness to determine PUC's contribution level.

Risk Identification & Mitigation (5.4.5.2 A.4)

Tasks occur throughout the year as requested by customers. Risks include internal and contractor resource constraints due to fluctuation of customer requests. PUC provides commitments to subdivision developer's in ways of formal agreements. In an effort to mitigate the risk of not complying with timelines, PUC reallocates resources from planned capital projects to customer demand as required.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Compared to the previous 5 years, PUC's investment to customer demand, specific to subdivisions is estimated to be low/moderate for the next five years. The city has been impacted by uncertainty of local steel industry which, in turn, has impacted the economy. Due to the impact, the housing industry, commercial development and overall spending in the economy has been impacted, reducing the anticipated expenditures in the immediate future to support customer demand. Due to the nature of the economy, this is a prediction and is subject to change.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific requests whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Services will be constructed using USF standards, PUC standards, in coordination with municipal road allowance standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

PUC is regulated by the OEB DSC. The DSC regulates PUC to provide offers for expansions inclusive of contestable work offered to the developer. PUC considers and complies with all requirements while ensuring all installations add to a safe, efficient, reliable system.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

New customer connections, increased revenue and customer relations are the secondary driver for the project. This project will increase quantity of customers supplied by PUC affecting revenue stream. Expanding the distribution system to connect new subdivisions and in turn, individual customers, provide PUC with an opportunity to improve customer relations.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

Investment objectives are to comply with all regulations, secure more customers and improve customer relations.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The City of Sault Ste. Marie is currently preparing a revised population projection for their Official Plan. A preliminary review of the population projection predicts that the population of Sault Ste. Marie will plateau at approximately 75,000 causing a negligible change from today's population. PUC has also referenced the Regional Infrastructure Plan. These documents were referenced when estimating expenditures for the period identified within this cost of service. Additionally, PUC communicates frequently with primary subdivision developers inquiring about upcoming plans to ensure PUC is prepared.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a very high priority, immediately behind emergency replacements. This is due to regulatory compliance and customer satisfaction.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

PUC reviews options for system expansions on a case by case basis to ensure the solution is designed and constructed in a safe, low maintenance and economical manner for all parties.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Net benefits accruing to customers have been qualitatively identified but are unable to quantitatively calculate at this stage.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

There will be no negligible impact to reliability performance resulting from typical subdivision developments. Some expansions caused by subdivision developments provide PUC with an opportunity to further loop our system providing additional system redundancy allowing PUC to more effectively reduce outage areas as they occur. Expansions also allow PUC to review circuit and system imbalances and further balance the electrical system through connection of additional demand.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)
Alternatives are considered on a case by case basis. The most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.
Safety (5.4.5.2 B2)
System expansions consider safety as paramount by designing and installing to USF standards, PUC standards, in coordination with municipal road allowance standards and/or specifics approved by a Professional Engineer.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
This project has no adverse impact on cyber security or privacy issues.
Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers
System expansions will be designed and constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.
Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements
System expansions are designed and constructed using USF standards and/or PUC specific standards, which are based on meeting the current and future customer needs and distributing electricity safely, reliably and cost effectively.
Economic Development (5.4.5.2 B.5)
By assuring sustainable, reliable, cost effective electrical services to customers in PUC's service territory, this project contributes towards economic development in the region.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
PUC considers different technologies when installing services and supporting infrastructure inclusive of vacuum trucks and directional drilling. These technologies cause less disturbance to the area and in turn less environmental impacts. Additionally, PUC considers environmental impacts when specifying material to be installed.

C. Category-Specific Requirements - System Access
Factors Affecting Timing/Priority (5.4.5.2 SA-C1)
This project receives a very high priority in order for PUC to comply with regulations. Scheduling tasks is dependent on complying with regulations and accommodating customers.
Factors Related to Customer/ Third Party Preferences (5.4.5.2 SA-C2)
PUC informs developers that it is their responsibility to coordinate third party services to be installed. PUC provides contractor information to developer for the developer to obtain benefits of installing multiple utilities in the same excavation. PUC designs and installs as per USF and/or PUC standards which are in line with industry standards allowing third parties reasonable access.
Factors Affecting the Final Cost (5.4.5.2 SA-C3)
There are uncontrollable factors that affect the final cost of the project. Costs are affected by how the economy responds, customer requests for new developments, regulatory compliance and increased costs in material.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA-C4)
PUC strives to manage controllable costs such as labour, equipment and optimizing designs. PUC has started eliminating underground hand boxes from our designs by identifying increased long term O&M costs.
Other Planning Objectives (5.4.5.2 SA-C5) (where applicable)
When designing new system expansions to accommodate subdivisions, PUC considers our system as a whole identifying opportunities to improve safety, reliability and system redundancy.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA-C6)
Technical options are considered during development of standards and specific designs. Specific products are reviewed in an attempt to improve system safety, reliability and redundancy while managing costs.
Summary of Results Analysis - "Least Cost", "Cost Efficient" options (5.4.5.2 SA-C7)
Options are considered on a case by case basis.
Results of a final Economic Evaluation (5.4.5.2 SA-C8) (where applicable)
Values for the OEB regulated Economical Evaluation are completed on a project by project basis. The final values are made available and reviewed with the developer. The costs for the majority of most new expansions to accommodate subdivisions are primarily absorbed by PUC due to quantity of projected future consumption and revenue.
System impacts costs & cost recovery method (5.4.5.2 SA-C9) (where applicable)
Impacts to the system when expanding to accommodate new subdivision developments are considered on a case by case basis ensuring the capacity of the system is adequate and impacts to adjacent neighborhoods are minimal or positive. Cost and cost recovery is considered on a case by case basis, affected by regulations and corporate practices.

A. General Information					
Project/Activity	#3 - Customer Demand - Joint Use				
Project Number	1C100-3				
Investment Category	System Access				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 137,153				
Capital Contribution	$ 40,000				
Net Cost	$ 97,153				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on quantity and location of customer requests.

Start Date (5.4.5.2 A.3)	Dependent on request			**In Service Date (5.4.5.2 A.3)**	Dependent on request
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**	
	$ 34,288	$ 34,288	$ 34,288	$ 34,288	

Project Summary

PUC is a partner with multiple third party communication companies in Sault Ste. Marie. Third party communication companies request to attach to PUC poles in an effort to minimize infrastructure. In doing so, PUC charges a monthly rental fee established in agreements between each company. On a regular basis third party companies will apply for revisions to their existing attachments or for new attachments to be added to coordinate with their business's objectives and customer demand. When applications are received, it is identified whether or not the existing PUC infrastructure is adequate to support the new/revised infrastructure in a safe manner. If PUC's infrastructure requires revisions (make ready work), the work is performed by PUC on a time and material basis.

Risk Identification & Mitigation (5.4.5.2 A.4)

Tasks occur throughout the year as requested by third party companies. Risks include internal and contractor resource constraints due to quantity of requests and other projects occurring. PUC discusses preferred completion dates with the third party companies in an effort to more effectively schedule work. In an effort to mitigate the risk of not achieving discussed timelines, PUC reallocates resources from planned capital projects to customer demand as required.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Historical values for this project vary substantially over the past five years. In 2013 and 2014, Bell Aliant had a business plan to attach fibre optic cable throughout the city to attach to all residential and most commercial customers offering a more advanced service. This project was terminated at approximately 50% completion due to cost. This affected PUC immensely and cause a significant fluctuation in our costs. As these special projects are typically unknown to PUC until last minute, it is near impossible to adjust long term budgets, but react when it occurs. Slight fluctuation is projected from high level discussions with one company.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific requests whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

New/Revised attachments will be reviewed against CSA, USF and PUC specific standards. Infrastructure revisions to accommodate third party requests will be completed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

PUC is a partner with multiple third party communication companies in Sault Ste. Marie. All attachment points from third party companies result in revenue for PUC. It is important to work collectively to find the optimal solution for all parties. PUC does increase revenue with new third party attachments.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

In being partners with third party communication companies, it is important to minimize infrastructure required to support our systems. This may require shared conduit structures and shared poles in lieu of standalone systems. This provide less conflict in the field and improved customer relations.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

Investment objectives are to comply with contractual requirements and obtain additional revenue through increased quantity of third party attachments.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

Historical averages on expenditures are referenced while eliminating the unique large projects (i.e. Bell Aliant Fibre to the Home) in addition to ongoing conversations with third party communications companies. As majority of their business plans are confidential, PUC is primarily unaware of large projects prior to projects commencing.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a relatively high priority, behind emergency replacements and balanced with general customer demand. This priority is based on continuing good working relationships with third party partners.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

PUC reviews each application for new/revised attachments on a case by case basis to maximize system operation efficiency and cost effectiveness. Make ready work is reviewed and analyzed to maximize benefit for both parties while ensuring cost effectiveness.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

While ensuring safety and reliability of the system are not negatively affected, PUC is able to offset costs with revenue received from third party companies, reducing the impact to customer rates.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

There will be no negligible impact to reliability performance resulting from third party attachment requests. On a case by case review, if PUC observes an opportunity to improve the system for minimal cost in conjunction with the make ready work ready to support the request, the improvement will generally be completed improving system performance.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)
Alternatives are considered on a case by case basis. The most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.
Safety (5.4.5.2 B2)
Make ready work to allow new/revised third party attachments on PUC's infrastructure consider safety as paramount by designing and installing to USF standards, PUC standards and/or specifics approved by a Professional Engineer.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
This project has no adverse impact on cyber security or privacy issues.
Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers
Infrastructure revisions will be designed and constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.
Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements
All make ready work to support new/revised third party attachments is designed and constructed using USF standards and/or PUC specific standards, which are based on meeting the current and future customer needs and distributing electricity safely, reliably and cost effectively.
Economic Development (5.4.5.2 B.5)
By permitting third party companies to attach to PUC's infrastructure in a safe, economical manner this project allows third party communication companies to supply communications throughout PUC's area and beyond, contributing towards economic development in the region.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
PUC considers environmental benefits with each design and installation to minimize environmental impacts.

C. Category-Specific Requirements - System Access
Factors Affecting Timing/Priority (5.4.5.2 SA-C1)
This project receives a relatively high priority, behind emergency replacements and balanced with general customer demand. Scheduling tasks is dependent on complying with contractual requirements, while balancing other projects.
Factors Related to Customer/ Third Party Preferences (5.4.5.2 SA-C2)
PUC currently limits quantity of attachments on a PUC pole to three. Ensuring a single attachment company resides on a maximum of one attachment position allows other third party companies the same potential benefit.
Factors Affecting the Final Cost (5.4.5.2 SA-C3)
There are uncontrollable factors that affect the final cost of the project. Costs are affected by partnering companies and their confidential business plans. Additionally, current state and orientation of PUC's infrastructure in the area of the attachments contributes to the fluctuation of costs.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA-C4)
PUC strives to manage controllable costs such as labour, equipment and optimizing designs. PUC continues to review techniques for design (ex. in house vs. external), excavation (ex. vacuum truck), installation (ex. crane use in rear lot) to minimize controllable costs.
Other Planning Objectives (5.4.5.2 SA-C5) (where applicable)
When receiving make ready suggestions during the permit application process, PUC reviews and considers other programs, age of existing infrastructure and customer impacts. PUC ensures that the solution provides benefit to the system to all parties.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA-C6)
Technical options are considered during development of standards and specific designs. Specific products are reviewed in an attempt to improve system safety, reliability and redundancy while managing costs.
Summary of Results Analysis - "Least Cost", "Cost Efficient" options (5.4.5.2 SA-C7)
Options are considered on a case by case basis. Least cost option is not always selected as it is not the most practical.
Results of a final Economic Evaluation (5.4.5.2 SA-C8) (where applicable)
Not applicable
System impacts costs & cost recovery method (5.4.5.2 SA-C9) (where applicable)
Impacts to the system when make ready work is completed for a new/revised third party attachment are considered on a case by case basis ensuring the safety and reliability of the system are not negatively impacted. Costs and cost recovery is as per existing agreements between PUC and third party company.

A. General Information					
Project/Activity	#4 - Customer Demand - City Projects				
Project Number	1C100-4				
Investment Category	System Access				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 274,305				
Capital Contribution	$ 50,000				
Net Cost	$ 224,305				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on specific projects.

Start Date (5.4.5.2 A.3)	April 1, 2018 (typical)			**In Service Date (5.4.5.2 A.3)**	October 31, 2018 (typical)
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**	
	$ 27,431	$ 137,153	$ 82,292	$ 27,431	

Project Summary

Much of PUC's infrastructure is located within the municipal right of way in Sault Ste. Marie and some on right of way owned by the Ministry of Transportation. The City of Sault Ste. Marie conducts complete road reconstructions, storm sewer replacement, curb and asphalt work annually. During these projects, PUC's infrastructure may require relocation/replacement to support the excavation. Due to the "Municipal Act" and specifically the "Public Service Works on Highways Act", PUC is required to relocate/replace infrastructure to support these projects upon request. A cost apportionment is identified in the "Public Service Works on Highways Act" as 100% material and 50% labour to be absorbed by the utility. Extent of the project areas vary from year to year depending on the City's overall plan and dependent on the nature of PUC's infrastructure in the area being addressed.

Risk Identification & Mitigation (5.4.5.2 A.4)

Tasks typically occur between Spring and Fall with majority of the work occurring in early summer in preparation for the road excavations. PUC is regulated to complete the work stated and not completing the work in a reasonable time places PUC at risk of delay charges from the City's contractor. In order to mitigate risks, PUC discusses scope and schedule early in the process to anticipate when work will be required. Placing the project in priority and schedule as well as reallocating resources as required mitigates risk of not completing the work within required timelines.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Historical values are used in conjunction with the City's five year plan. Within the five year plan, specific jobs are identified as large impacts to PUC. Expenditures can significantly vary annually dependent on the areas being addressed, whether PUC's infrastructure will be affected, if PUC's infrastructure is underground or overhead, etc.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific requests whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

PUC coordinates and references the City of Sault Ste. Marie's five year capital works program to identify approximate scope of work and requirements for upcoming years. As this plan is subject to change without PUC's approval, PUC's projected expenditures are variable. When revisions occur to PUC's infrastructure to accommodate the above project, all areas revised are reviewed and constructed in compliance with CSA, USF and/or PUC specific standards.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

PUC is required to relocate infrastructure to support highway improvements as defined by the Public Service Works on Highways Act. Scope of work is dependent on the City of Sault Ste. Marie's long term plan.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

During the relocation, it is a possibility for PUC to update infrastructure and gain increased life and increased asset value at a reduced cost due to cost apportionment.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

Investment objectives are to relocate/revise PUC's infrastructure to support City/MTO projects. This allows the projects to progress smoothly while minimizing or eliminating potential safety hazards relating to PUC's infrastructure.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

PUC is required to relocate infrastructure to support highway improvements as defined by the Public Service Works on Highways Act. Scope of work is dependent on the City of Sault Ste. Marie's long term plan. Cost apportionment is generally as per Public Service Works on Highways Act. Historical expenditures have been reviewed in conjunction with the City's five year plan to estimate the required investment.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a relatively high priority, behind emergency replacements and balanced with general customer demand. This priority is based on continuing good working relationships with the City and mitigating risks of delay costs.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Project has negligible effects on system operation efficiency as the infrastructure is typically replaced in kind after the contractor work has been completed. PUC attempts to coordinate projects to optimize cost effectiveness is feasible.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers continue to benefit from PUC infrastructure located on municipal road allowances, minimizing cost for PUC to install electrical services.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Frequency of outages once the project has been completed may reduce due to new assets installed.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)
Alternatives are considered on a case by case basis. The most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.
Safety (5.4.5.2 B2)
All relocation/replacement work to accommodate City projects consider safety as paramount by designing and installing to USF standards, PUC standards and/or specifics approved by a Professional Engineer.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
This project has no adverse impact on cyber security or privacy issues.
Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers
The project is specific to coordination with the municipality and other utilities to relocate PUC infrastructure to accommodate conflicts. The relocation(s) is designed and constructed to USF standards and/or PUC specific standards, which are in line with industry standards allowing other utilities and third parties reasonable separation and access.
Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements
All relocations to support City projects are designed and constructed using USF standards and/or PUC specific standards, which are based on meeting the current and future customer needs and distributing electricity safely, reliably and cost effectively.
Economic Development (5.4.5.2 B.5)
In coordination with the City, relocating PUC's infrastructure to accommodate road work assist the City to construct municipal infrastructure that will support economic development.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
PUC considers environmental benefits with each design and installation to minimize environmental impacts.

C. Category-Specific Requirements - System Access
Factors Affecting Timing/Priority (5.4.5.2 SA-C1)
This project receives a high priority, behind emergency replacement and balanced within general customer demand and subdivisions. As PUC is not regulated to have this work completed in a defined time, scheduling and coordination is essential to mitigate financial risks to PUC and potential safety risks to contractors.
Factors Related to Customer/ Third Party Preferences (5.4.5.2 SA-C2)
Third party companies are invited to planning, design and construction meetings to ensure they are aware of the relocations. Third party companies are able to discuss specifics with PUC at all stages in an effort to minimize costs for all parties.
Factors Affecting the Final Cost (5.4.5.2 SA-C3)
Final cost of this project are extremely variable. The costs depend on the impacts each project area has on PUC infrastructure, whether it is approved by City Council to proceed and/or the Contractor's requirements during the project.
Methods Utilized to Minimize Controllable Costs (5.4.5.2 SA-C4)
PUC reminds the City of the importance to have PUC in the planning and design meetings to ensure everyone is aware of the impacts and potential costs to relocate the infrastructure. This allows the design team to revise the design to minimize impacts to PUC's infrastructure if feasible. If relocation requirements remain, coordination and scheduling are essential to minimize delays, and in turn, costs.
Other Planning Objectives (5.4.5.2 SA-C5) (where applicable)
PUC always considers adjacent projects and programs when relocating infrastructure to maximize benefits. Adjusting priority of projects may be a possibility to maximize benefits for all parties.
Technically feasible project design and/or implementation options exist (5.4.5.2 SA-C6)
Technical options are considered during development of standards and specific designs. Specific products are reviewed in an attempt to improve system safety, reliability and redundancy while managing costs.
Summary of Results Analysis - "Least Cost", "Cost Efficient" options (5.4.5.2 SA-C7)
Options are considered on an area by area basis to ensure the most practical option is chosen.
Results of a final Economic Evaluation (5.4.5.2 SA-C8) (where applicable)
Not applicable
System impacts costs & cost recovery method (5.4.5.2 SA-C9) (where applicable)
Impacts to the system when relocating PUC infrastructure to accommodate City projects is minimal. Cost recovery is typically based upon the cost apportionment set out in the Public Service Works on Highways Act.

A. General Information					
Project/Activity	#5 - Forced Overhead Renewal				
Project Number	1C200-1-1				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 308,593				
Capital Contribution	$ 56,250				
Net Cost	$ 252,343				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on outage areas.

Start Date (5.4.5.2 A.3)	1-Jan-18			**In Service Date (5.4.5.2 A.3)**	31-Dec-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**	
	$ 77,148	$ 77,148	$ 77,148	$ 77,148	

Project Summary

Overhead forced renewal project is intended to cover costs associated with capital asset renewal from unplanned occurrences, typically resulting from weather related occurrences and/or vehicle accidents. When an occurrence occurs, PUC reviews the situation and determines whether a repair (maintenance budget) is adequate or if a complete replacement of the asset is warranted. When a complete replacement is warranted, PUC will replace the asset to today's standards, where feasible.

Risk Identification & Mitigation (5.4.5.2 A.4)

PUC identifies and mitigates risk of outages whenever possible. Through system inspection and asset testing, PUC understands where the majority of our concerning assets are located and place the replacement of those assets in priority. As it is not practical to have a system so robust that no outages occur, complete elimination of outages is not feasible.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC compares historical values for each category to budget for a recent average. As this budget is dependent on externally driven aspects such as weather and traffic accidents, the expenditures are considered on an annual basis and become difficult to predict.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Safety to the public and workers when a fault occurs in the system is the investment main driver. Although the system is protected via fusing, reclosers, relays and breakers, it is imperative that PUC attend site to ensure the site is safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

System reliability is a secondary driver. When a fault occurs, it typically causes an outage for a number of customers. PUC strives to provide a reliable system for all of our customers. Minimizing the outage duration contributes to a reliable system improving our CAIDI and SAIDI statistics.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to continue a safe electrical system and mitigate the risk of PUC's reliability statistics from decreasing by limiting the duration of outages, providing a safe and reliable electrical system to consumers.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

Historical expenditures have been analyzed in conjunction with age and condition of existing infrastructure. As the infrastructure ages increased forced renewal expenditures should be expected to increase.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives the highest priority as it is primarily caused by system outages and safety concerns. Tasks are typically considered emergency in nature.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Investment to replace assets in an emergency nature will provide increased system reliability as the asset has now been replaced. The investment is not typically performed in a cost effective manner as it is due to emergency. PUC does attempt to make it as cost effective as possible by performing minimal repairs during after hours in an effort to complete full replacement during regular hours at regular rates. Additionally, transformers are set at a run to failure scheme, which is predicted to be the most cost effective method for transformer failure.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from this project in having outage times reduced and safety concerns managed in a timely fashion. Benefits have not been quantitatively calculated.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project has a significant impact on reliability performance. Although this project does not impact the frequency of outages (SAIFI) it does limit the size of the extended outage and reduce the duration of outages (SAIDI, CAIDI).

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no other practical and cost effective alternatives to this project. This project is a reactive based project that receives a very high priority when tasks arise.

Safety (5.4.5.2 B2)

Public and worker safety is a primary driver in this project. By attending the site, making it safe and replacing the failed infrastructure, reduces hazards for both the public and workers. Final installation will be completed as per CSA, USF and/or PUC specific standards which adhere to a high level of safety standards.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
This project has no adverse impact on cyber security or privacy issues.
Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)
Emergency replacement of assets will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.
Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)
Emergency replacements are typically constructed like-for-like, but when practical, they are constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.
Economic Development (5.4.5.2 B.5) (where applicable)
By minimizing system outage durations to customers in PUC's service territory, this project contributes towards economic development in the region.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
PUC considers environmental impacts when performing emergency repairs/replacements. These benefits/impacts are balanced with safety and reliability to come to the most practical solution.

C. Category-Specific Requirements - System Renewal
Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)
This project is non-discretionary and has been allocated a very high priority due to safety and system reliability concerns once a failure has arisen.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)
Information is not proactively available regarding assets that will be replaced due to the nature of the project. Typically, assets that fail on their own are older in nature, with some exceptions. Assets that fail due to external impacts may be any age.
The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)
The number of customers affected by each failure is dependent on the location of the failure and the assets affected. If a single distribution transformer fails, the customers affected should be limited to approximately 15. If the asset failed is a distribution pole supporting the sub transmission line (34.5kV), the customers affected could be up to 50% of the City. Number of customers immediately affected is not within PUC's control. PUC attempts to limit the quantity of customers that experience extended outages by switching, repairing and/or replacing assets.
Quantitative customer impacts (5.4.5.2 SR-C1.4)
It is not feasible to determine quantitative customer impacts for this project ahead of time.
Qualitative customer impacts (5.4.5.2 SR-C1.5)
Customers located in the area of the failure up to the complete distribution and/or sub transmission circuit will be affected by potential power outages caused by failed assets. PUC will strive to minimize duration of all outages by responding and repairing safe and effectively.
Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)
Impacts to customers vary on a case to case basis. Some examples are extended outages on residential homes heated using electrical heat, commercial properties with extended outages during regular business hours and critical customers who rely on electricity for emergency services. Due to the unknowns and the possibility for loss of electricity being detrimental, PUC responds to each case effectively with the goal to minimize the duration of outages for all customers.
Timing and Priority of Project (5.4.5.2 SR-C2)
This project has been given the highest priority as the failure may cause a safety concern or a system outage.
Consequences for system O&M costs (5.4.5.2 SR-C3)
This project has minimal long term effects on O&M costs. Asset replacements due to failure should not require significant O&M attention in the future. In retrospect, when a rebuild is required, the pole replaced may require additional work which would not be required if the pole was replaced at the same time.
Impact on reliability performance and/or safety (5.4.5.2 SR-C4)
Reliability performance statistics are immediately impacted by this project as it is a project initiated by failures. Safety is also impacted by this project as failures usually may create safety concerns until our staff arrive to fix the problem.
Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)
Project timing is generally considered emergency as the majority of the tasks are based upon system outages or safety concerns. This ranks highest on all of PUC's projects. This project does have a benefit of reacting to outages versus planned replacement for some assets. Transformers are an asset where PUC has chosen to apply a "run to failure" approach. This maximizes the life of the transformer, obtains additional value from the transformer while paying only a slight premium for reactive replacement.
Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)
Like for like replacements are typical for majority of tasks that arise from outages or safety concerns due to typical timing of tasks. To have the asset designed on the spot after the failure has occurred is not a practical alternative. Proactively designing all potential failure assets is another alternative that is not practical.

A. General Information					
Project/Activity	#6 - Forced Underground Renewal				
Project Number	1C200-1-2				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 308,593				
Capital Contribution	$ -				
Net Cost	$ 308,593				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on outage areas.

Start Date (5.4.5.2 A.3)	1-Jan-18			**In Service Date (5.4.5.2 A.3)**	31-Dec-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**	
	$ 77,148	$ 77,148	$ 77,148	$ 77,148	

Project Summary

Underground forced renewal project is intended to cover costs associated with capital asset renewal from unplanned occurrences, typically resulting from failed underground and/or pad mounted assets and/or vehicle accidents. When an occurrence occurs, PUC reviews the situation and determines whether a repair (maintenance budget) is adequate or if a complete replacement of the asset is warranted. When a complete replacement is warranted, PUC will replace the asset to today's standards, where feasible.

Risk Identification & Mitigation (5.4.5.2 A.4)

PUC identifies and mitigates risk of outages whenever possible. Through system inspection and asset testing, PUC understands where the majority of our concerning assets are located and place the replacement of those assets in priority. As it is not practical to have a system so robust that no outages occur, complete elimination of outages is not feasible.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC compares historical values for each category to budget for a recent average. As this budget is dependent on externally driven aspects such as traffic accidents, the expenditures are considered on an annual basis and become difficult to predict. Limited investment into aging underground infrastructure should result in increased forced replacement and maintenance costs.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Safety to the public and workers when an asset failure occurs in the system is the investment main driver. Although the system is protected via fusing, reclosers, relays and breakers, it is imperative that PUC attend site to ensure the site is safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

System reliability is a secondary driver. When an asset failure occurs, it typically causes an outage for a number of customers. PUC strives to provide a reliable system for all of our customers. Minimizing the outage duration contributes to a reliable system improving our CAIDI and SAIDI statistics.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to continue a safe electrical system and mitigate the risk of PUC's reliability statistics from decreasing by limiting the duration of outages, providing a safe and reliable electrical system to consumers.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

Historical expenditures have been analyzed in conjunction with age and condition of existing infrastructure. As the infrastructure ages increased forced renewal expenditures should be expected.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives the highest priority as it is primarily caused by system outages and safety concerns. Tasks are typically considered emergency in nature.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Investment to replace assets in an emergency nature will provide increased system reliability as the asset has now been replaced. The investment is not typically performed in a cost effective manner as it is due to emergency. PUC does attempt to make it as cost effective as possible by performing minimal repairs during after hours in an effort to complete full replacement during regular hours at regular rates. Additionally, transformers are set at a run to failure scheme, which is predicted to be the most cost effective method for transformer failure.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from this project in having outage times reduced and safety concerns managed in a timely fashion. Benefits have not been quantitatively calculated.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project has a significant impact on reliability performance. Although this project does not impact the frequency of outages (SAIFI) it does limit the size of the extended outage and reduce the duration of outages (SAIDI, CAIDI).

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no other practical and cost effective alternatives to this project. This project is a reactive based project that receives a very high priority when tasks arise.

Safety (5.4.5.2 B2)

Public and worker safety is a primary driver in this project. By attending the site, making it safe and replacing the failed infrastructure, reduces hazards for both the public and workers. Final installation will be completed as per CSA, USF and/or PUC specific standards which adhere to a high level of safety standards.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
This project has no adverse impact on cyber security or privacy issues.
Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)
Emergency replacement of assets will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.
Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)
Emergency replacements are typically constructed like-for-like, but when practical, they are constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.
Economic Development (5.4.5.2 B.5) (where applicable)
By minimizing system outage durations to customers in PUC's service territory, this project contributes towards economic development in the region.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
PUC considers environmental impacts when performing emergency repairs/replacements. These benefits/impacts are balanced with safety and reliability to come to the most practical solution.

C. Category-Specific Requirements - System Renewal
Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)
This project is non-discretionary and has been allocated a very high priority due to safety and system reliability concerns once a failure has arisen.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)
Information is not proactively available regarding assets that will be replaced due to the nature of the project. Typically, assets that fail on their own are older in nature, with some exceptions. Assets that fail due to external impacts may be any age.
The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)
The number of customers affected by each failure is dependent on the location of the failure and the assets affected. If a single distribution transformer fails, the customers affected should be limited to approximately 15. If the asset failed is a pad mounted sub transmission switch, the customers affected could be up to 50% of the City. Number of customers immediately affected is not within PUC's control. PUC attempts to limit the quantity of customers that experience extended outages by switching, repairing and/or replacing assets.
Quantitative customer impacts (5.4.5.2 SR-C1.4)
It is not feasible to determine quantitative customer impacts for this project ahead of time.
Qualitative customer impacts (5.4.5.2 SR-C1.5)
Customers located in the area of the failure up to the complete distribution and/or sub transmission circuit will be affected by potential power outages caused by failed assets. PUC will strive to minimize duration of all outages by responding and repairing safe and effectively.
Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)
Impacts to customer vary on a case to case basis. Some examples are extended outages on residential homes heated using electrical heat, commercial properties with extended outages during regular business hours and critical customers who rely on electricity for emergency services. Due to the unknowns and the possibility for loss of electricity being detrimental, PUC responds to each case effectively with the goal to minimize the duration of outages for all customers.
Timing and Priority of Project (5.4.5.2 SR-C2)
This project has been given the highest priority as the failure may cause a safety concern or a system outage.
Consequences for system O&M costs (5.4.5.2 SR-C3)
This project has minimal long term effects on O&M costs. Asset replacements due to failure should not require significant O&M attention in the future. In retrospect, when a rebuild is required, the underground asset replaced may require additional work which would not be required if the entire area was rejuvenated at the same time.
Impact on reliability performance and/or safety (5.4.5.2 SR-C4)
Reliability performance statistics are immediately impacted by this project as it is a project initiated by failures. Safety is also impacted by this project as failures usually may create safety concerns until our staff arrive to fix the problem.
Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)
Project timing is generally considered emergency as the majority of the tasks are based upon system outages or safety concerns. This ranks highest on all of PUC's projects. This project does have a benefit of reacting to outages versus planned replacement for some assets. Transformers are an asset where PUC has chosen to apply a "run to failure" approach. This maximizes the life of the transformer, obtains additional value from the transformer while paying only a slight premium for reactive replacement.
Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)
Like for like replacements are typical for majority of tasks that arise from outages or safety concerns due to typical timing of tasks. To have the asset designed on the spot after the failure has occurred is not a practical alternative. Proactively designing all potential failure assets is another alternative that is not practical.

A. General Information					
Project/Activity	#7 - Substation 16 Rebuild				
Project Number	1C300-3-7 - A				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 419,687				
Capital Contribution	$ -				
Net Cost	$ 419,687				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**

Customer Attachments and Load (5.4.5.2 A.2)

Number of Customers fed from Sub 16 Feeders: Approximately 2417
Load Impacted: Approximately 10MW annual average

Start Date (5.4.5.2 A.3)	1/7/2016			**In Service Date (5.4.5.2 A.3)**	12/20/2019
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**	
	$ 104,922		$ 209,844	$ 104,922	

Project Summary

As detailed in the Asset Management Plan, this substation has been in service for just under 50 years, is in very poor condition and has reached end of life. The planned Sub 16 rebuild is an upgrage from a 34.5k -12.47/7.2kV, 15MVA station to a 34.5kV - 12.47/7.2kV, 26.6MVA substation that will have two incoming 34.5kV supplies, two 10/13.3 MVA power transformers, and four outgoing 12.47kV feeders supplied by arc resistant metalclad switchgear. Due to the state of the existing station infrastructure, the switchgear is deemed to be unsafe to operate while energized and must be isolated and de-energized prior to operation. This results in isolation out on the 34.5kV distribution lines, which significantly reduces reliability and contigency buffers for connected customers.

Risk Identification & Mitigation (5.4.5.2 A.4)

PUC does not have the resource requirements to design and construct substations. The work of the detailed design and construction will be outsourced to an experienced and reputable consultant and contractor to mitigate risks during the project implementation. No risks are anticipated with the proposed outsourcing plan. PUC plans to bypass the Sub 16 34.5kV feeds during the construction phase in order to keep the dual feed supplying affected customers, as referenced above in the Project Summary section.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC's Substation 10 rebuild was completed in 2015 for a total of $4,483,000 and the total estimated cost of the Sub 16 rebuild is $3,910,244.00. Sub 16 is estimated to be less than Sub 10 due to a different switchgear type being used which will allow the building sfootprint to be reduce by about 40%.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

The protection relays are modern micro-processor and IP based relays that are capable of reverse power flow to accommodate REG applications.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

This project does not fall in the category requiring leave to construct.

Attach other project reference material i.e. images, drawings and or reference material

"1C300-3-7 - EST 3707 - DSP Material Capital Asset Justification - Sub 16 Rebuild Attachment 1"

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Power supply reliability is the key driver for this project. This project will reduce the risk of prolonged power interruptions and reduce the frequency of power interruptions due to equipment failure at Sub 16.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Operating efficiency is the secondary driver to this project. New switchgear and protection and control equipment will improve operating abilities, and reduce operating costs.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to mitigate the risk of power outage duration and frequency falling below PUC's performance targets as outlined on it's OEB annual LDC scorecard.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

The source for information for justification of this project is the Asset Management Plan, which was prepared by taking into account all relevant information pertaining to the condition of station and and lines assets.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project has been determined as a high priority due to the old age and very poor condition of power transformers and switchgear at the existing Sub 16.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

There are no economical alternatives to this project.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Net benefits accruing to customers have been qualitatively described above but have not been quantitatively calculated because accurate information on customer interruption costs is not readily available.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project, by reducing the risk of in-service equipment failures, will reduce the risk of prolonged or highly frequent outages. It mitigates the risk of reliability performance falling below PUC's targets as outlined on its OEB annual scorecard.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no other practical and cost effective design or funding alternatives, or co-ownership options available. This project received a high priority based on the criteria presented in the Asset Management Plan.

Safety (5.4.5.2 B2)

Modern protection and controls, capable of automatically responding to mitigate unsafe conditions on the distribution system will be implemented, thus mainting public safety in PUC's service territory.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

The SCADA and protection and control systems will be connected to PUC's fibre network connecting most of PUC owned facilities. This fibre network is protected by PUC's corporate IT managed services which utilizes NIST cybersecurity standards and regulations.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

The protection and controls meeting interoperability standards will be specified and implemented for this project. Power transformers and switchgear conforming to ESA, CSA, and IEEE standards will be utilized.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

The protection relays are modern micro-processor and IP based relays that are capable of reverse power flow to accommodate REG applications. The relays are also capable of being incorporated into PUC's IESO mandated Under-Frequency Load Shedding scheme.

Economic Development (5.4.5.2 B.5) (where applicable)

The substation will be sized with consideration for future load growth within its service territory. By assuring a sustainable reliability of the power system in PUC's service territory, this project contributes towards economic development in the region. Also, the protection and control system will be able to support large REG applications. Lastly, residents or businesses will not have an issue developing near the substation as the layout and design is non obtrusivecally with landscaping and brick type exterior matched to the surrounding land uses. The transformer bays will also have barrier walls to limit transformer hum to below MOE limits.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

Transformer Oil Containment systems will be built into the design to mitigate the environmental risks caused by a transformer failure and oil spill.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project was prioritized through asset life cycle optimization techniques as detailed in the PUC's Asset Management Plan.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

As seen in the Asset Management Plan, the condition of the existing assets at Sub 16 has been determined as poor or very poor, presenting a high risk of failure. Sub 16's SCADA RTU has been failed since the winter of 2017 which results in all troubleshooting and operations being performed through site visits and there is a lack of real time knowledge when equipment fails. Also, 24VDC protection relays are no longer available and a workaround power supply conversion was required aroud 2013 to allow newer 125VDC relays to be installed where several 1980s vintage relays were failing timing tests. Lastly, one of the two 7.5MVA transformers failed and wos repaired approximately 7 years ago at considerable expense.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 1975
Number of General Service <50kW: 396
Number of General Service >50kW: 46

Quantitative customer impacts (5.4.5.2 SR-C1.4)

The main impact of this project on customers served from Sub 16 are mitigating the risk of SAIFI and SAIDI worsening due to the anticipated failures of the equipment determined to be in poor or very poor condition.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customer satisfaction will improve with the rebuild of Sub 16 as the risk of failure and the potential for reduced outage impacts.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

The station currently supports one of the fasted growing areas of development in the city along the north Highway 17 corridor and this growth is expected to continue for the foreseeable future. A new hospital was added in the area about 7 years ago and both C&I and subdivision developments continue to spring up. With the poor condition of assets in the existing Sub 16 and the growing customer base, impacts of reliability are affecting more and more customers as time goes on.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project is given a high priority when compared to other projects. Substation 16 is on the edge of town with some long distance feeders and PUC will be pushing other stations, that are picking up the load during the construction, to their limits if the rebuild extends into the winter (high loading) months.

Consequences for system O&M costs (5.4.5.2 SR-C3)

The new Sub 16 will reduce O&M when compared to the existing Sub 16 O&M requirements. The existing station contains open bus and switches on lattice structures with equipment exposed to the harsh northern Ontario environment. The new station will have all equipment except transformers fully enclosed and the type of switchgear to be utilized has monitoring capabilities and minimal maintenance requirements.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

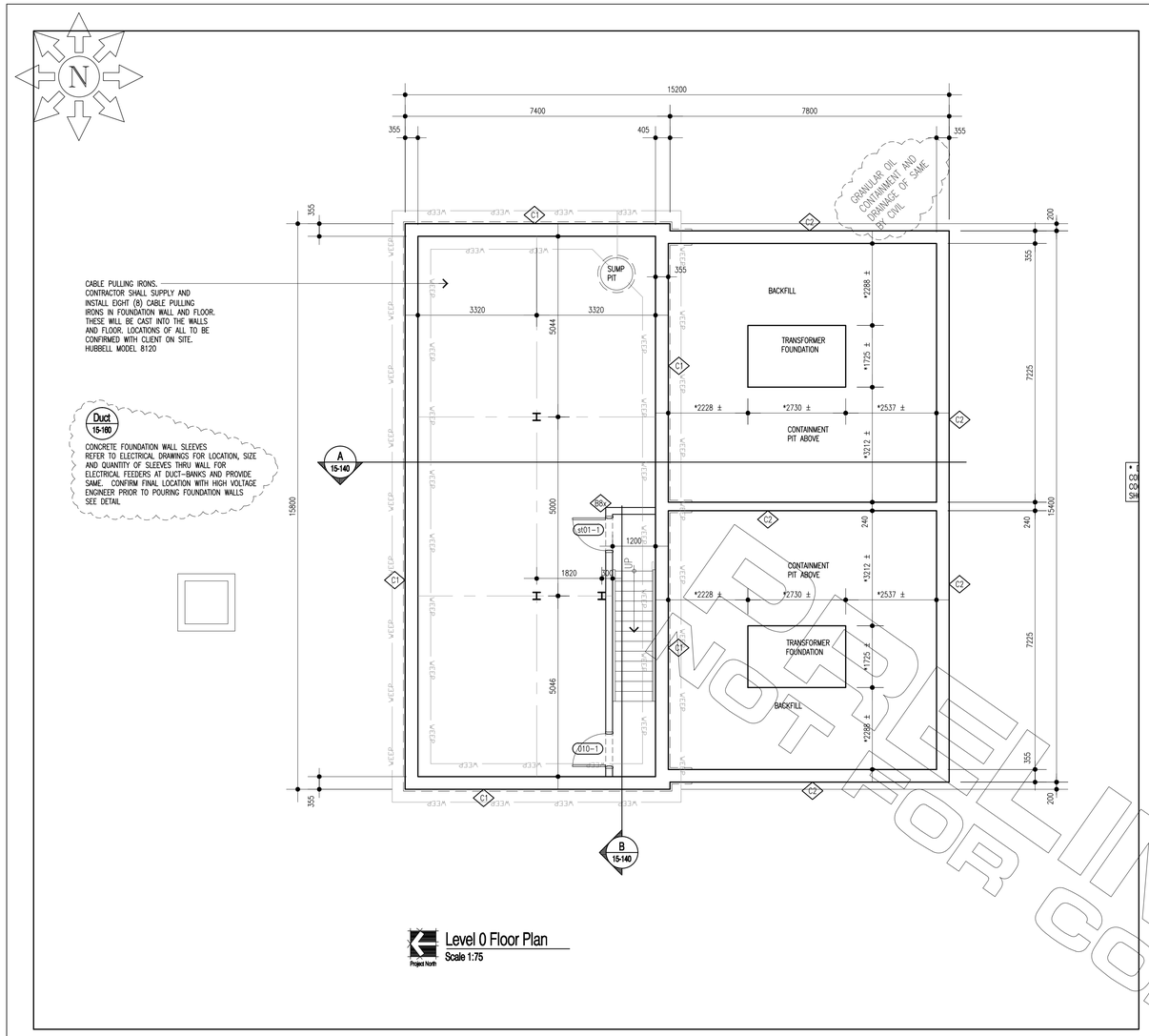
As mentioned above the modern micro-processor based protection relays and new switchgear will offer major benefits for operating safety and public safety by reacting to faults on the system. Also, the transformers will be separated by a firewall, have oil containment, and be surrounded by noise reducing exterior walls. The rebuild of Sub 16 will increase system reliability and safety.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

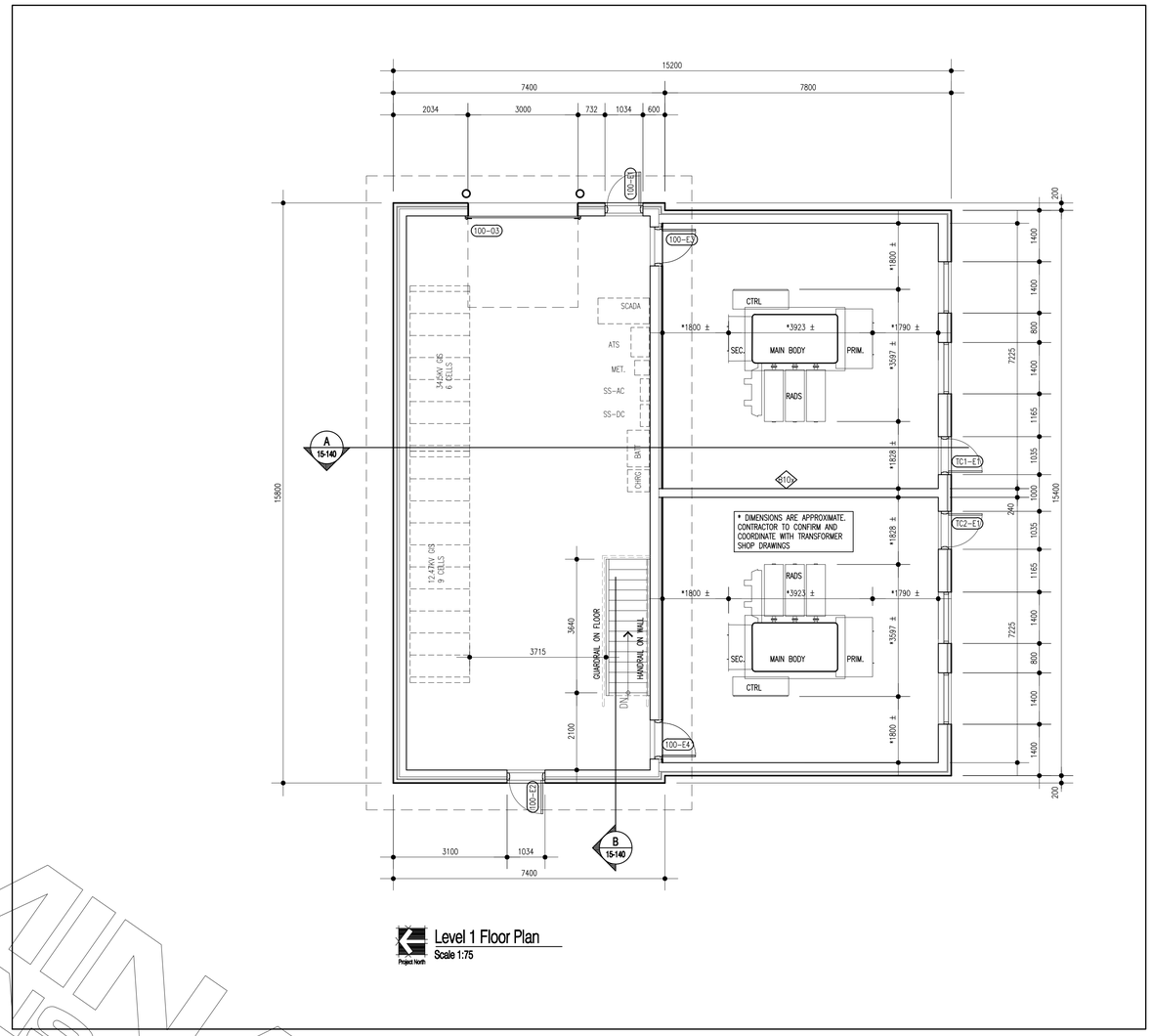
This project has been given a high priority because it offers a high benefit for risk mitigation and the health its existing equipment was ranked as poor and very poor.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

The station rebuild will not be like for like as new technology and designs are available to increase operating and maintenance efficiencies. All of the equipment and designs will be specified to meet the current version of applicable standards and to fully meet the current and future needs of customers.



Level 0 Floor Plan
Scale 1:75



Level 1 Floor Plan
Scale 1:75

PRELIMINARY NOT FOR CONSTRUCTION

SCALE: 1:75

NO.	REVISION	DATE	INITIAL

ePOH
architects + engineers + interior design
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Professional Seal

This drawing has been prepared solely for the use of PUC and there are no representations of any kind made by IBI Group to any party with whom IBI Group has not entered into a contract

Check Scale (may be photo-reduced)
0 1 inch 0 10mm

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IBI Project No.: 24RX12.0195

PUC

SUBSTATION 16
ARCHITECTURAL FLOOR PLANS

DRAWN BY: K.OLIVER	DATE DRAWN:
CHECKED BY: K.OLIVER	DATE CHECKED:
APPROVED BY:	DATE APPROVED:
DWG. NO.: D-ES16-15-120	REV.: A.B.

A. General Information						
Project/Activity	#8 - Overhead Renewal - Poles					
Project Number	1C300-1-2					
Investment Category	System Renewal					
	2018	**2019**	**2020**	**2021**	**2022**	
Capital Cost (5.4.5.2 A.1)	$ 314,765					
Capital Contribution	$ -					
Net Cost	$ 314,765					
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**	
	NA	NA	NA	NA	NA	

Customer Attachments and Load (5.4.5.2 A.2)

Customer attachments and load vary year to year dependent on identified deteriorated poles, pole locations and which circuit poles are located on.

Start Date (5.4.5.2 A.3)	1-Jan-18			**In Service Date (5.4.5.2 A.3)**	31-Dec-18	
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**		
	$ 125,906	$ 31,477	$ 31,477	$ 125,906		

Project Summary

PUC has s significant amount of overhead electrical infrastructure. Within that overhead infrastructure, PUC owns approximately 12,500 poles and are currently joint use on another 3350 Bell Poles. As of 2016 approximately 6% of PUCs poles were either in poor or very poor condition. PUC obtains a third party to perform pole testing on 1/7 of our poles annually that are 10 years or older to determine poles that require immediate attention, short term attention and poles to continue to monitor. Through third party testing and field identification by staff and the public, poles are identified as requiring replacement. This results in the scope of work for the deteriorated pole project for the year. It is estimated that 30 poles will be identified annually for replacement.

Risk Identification & Mitigation (5.4.5.2 A.4)

This project is based on deteriorated pole identification and level of risk identified in the field. Dependent on the level of risk for the poles identified, they may be considered emergency replacements, short term replacements (<1year) or long term replacements (<5years). Dependent on the risk identified, each task will be given a relative priority in an effort to mitigate risks. Resources play a factor in designing and replacing the identified poles. Reallocating resources may be required to mitigate risks.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

Historical information is used to average out the cost of a single pole replacement as well as averaging out the quantity of poles that are anticipated to be identified as deteriorated. Estimated expenditure may require revision due to a higher level of identified poles caused by our system aging faster than replacements occurring. Ensuring pole testing is included in O&M budget to effectively retrieve pole strength results should minimize risks of quantity of poles significantly increasing.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Power supply reliability is the primary driver for this project. Proactively identifying poles that are close to failure and proactively replacing them minimizes the risk of a failure occurring. This reduces the risk of prolonged, uncontrolled power outages. Without this project PUC's reliability statistics would be negatively affected.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Public safety is the secondary driver for this project. Proactively replacing identified poles mitigates the risk of the pole failing in service and controls the hazards to a reasonable level.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to continue a safe electrical system and mitigate the risk of PUC's reliability statistics from decreasing by controlling hazards and outages through proactively replacing poles nearing the end of their life.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

Using the age distribution of PUC's poles in conjunction with previous pole testing data and historical quantities of deteriorated poles identified in the field, PUC attempts to accurately predict the quantity of poles that will require replacement. Using historical average costs per pole replacement with the estimated quantity of poles, PUC estimates the expenditures required. Cost vary depending on the quantity of the poles identified and the nature of the poles (ex. 35ft pole vs 65 ft. pole).

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project generally receives the highest priority in relation to PUC's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a pole failing in service. The risk level is based upon the nature of the pole and the potential reliability and safety concerns that would arise if the pole fails. PUC reviews identified deteriorated poles and prioritizes each pole within the project.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

The project has minimal effect on system operation efficiency. The project is considered with other projects in an attempt to coordinate projects for cost effectiveness. If this is not practical, the single pole replacements occur. There are no practical alternatives to this project as not replacing the poles will result in asset failures, system reliability concerns and potential public safety concerns.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Proactive pole replacements provide system reliability benefits to customers. Additionally, proactive pole replacements reduce the cost in comparison to reactive replacements upon failure, reducing PUC's overall costs and minimizing impacts to customer's monthly bill.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Proactive replacement of poles identified as deteriorated reduces the unplanned frequency of outages and significantly reduces the duration of outages. Proactive replacements allow for limited, planned outages to transfer infrastructure in lieu of the unplanned outage. This allows PUC to advise effected customers to allow them to plan for the outage versus react to an outage. Proactive replacements positively impacts reliability statistics.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)
Each pole replacement is reviewed on a case by case basis to identify any available alternatives. Some alternatives may include the replacement of two poles with one, additional coordination with adjacent pole owners, etc. Generally, there are no practical alternatives to pole replacements.
Safety (5.4.5.2 B2)
Public safety is a secondary driver for this project. Proactively replacing deteriorated poles reduces the risk of in service failures and the risk of poles and/or live conductors falling to the ground.
Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)
This project has no adverse impact on cyber security or privacy issues.
Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)
Pole replacements will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access.
Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)
Pole replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.
Economic Development (5.4.5.2 B.5) (where applicable)
By minimizing system outages to customers in PUC's service territory, this project contributes towards economic development in the region.
Environmental Benefits (5.4.5.2 B.6) (where applicable)
PUC considers environmental impacts when replacing poles. This is one of the considerations during the planning stage, selecting installation methods. As much as practical, PUC attempts to minimize environmental impacts.

C. Category-Specific Requirements - System Renewal
Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)
This project generally receives the highest priority in relation to PUC's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a pole failing in service. The risk level is based upon the nature of the pole and the potential reliability and safety concerns that would arise if the pole fails. PUC reviews identified deteriorated poles and prioritizes each pole within the project.
Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)
Conditions of pole to be replaced are all below acceptable, sustainable condition. The condition is based on visual inspections and third party pole testing. Asset life relative to the typical life cycle is on a case by case basis. Generally, deteriorated poles are beyond the 45 years old, but some poles are identified as deteriorated prior to this due to ground line rot, infestation, woodpecker damage, etc.
The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)
The quantity and class of customers is unknown at this time and is dependent on the poles that are identified as requiring replacement. The quantity and class is variable if the poles are secondary cross over poles versus supporting sub transmission lines (34.5kV)
Quantitative customer impacts (5.4.5.2 SR-C1.4)
It is not feasible to determine quantitative customer impacts for this project ahead of time.
Qualitative customer impacts (5.4.5.2 SR-C1.5)
Customers located in the area of the deteriorated poles identified will benefit from increased system reliability dependent on the nature of the pole.
Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)
Impacts to customers vary on a case to case basis. Some examples reducing the extended outages on residential homes heated using electrical heat, commercial properties with extended outages during regular business hours and critical customers who rely on electricity for emergency services. Due to the unknowns and the possibility for loss of electricity being detrimental, PUC reviews each identified pole on a case by case basis relating to reliability and safety risks and place poles within replacement schedule.
Timing and Priority of Project (5.4.5.2 SR-C2)
This project generally receives the highest priority in relation to PUC's system renewal project, after emergency forced renewal.
Consequences for system O&M costs (5.4.5.2 SR-C3)
Replacement of deteriorated poles that are beyond 10 years old, reduces O&M costs as PUC tests poles only that are over 10 years old. Treatment of poles has an increased O&M cost which extends the life of certain poles minimizing the required cost within this project.
Impact on reliability performance and/or safety (5.4.5.2 SR-C4)
Reliability performance is directly benefited from replacement of deteriorated poles. This reduces the quantity of unplanned outages which typically result in longer duration outages. This project increases safety by minimizing the risk of pole failures causing potential maintenance and electrical hazards.
Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)
Project timing is generally immediately after emergency replacements and customer demand. System benefits from reducing the quantity of unplanned outages resulting from pole failures.
Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)
PUC attempts to have all poles replaced within this project designed to USF and/or PUC specific standards. Alternatives are reviewed on a case by case basis to maximize benefits and minimize costs.

A. General Information					
Project/Activity	#9 - Overhead Renewal - Restricted Wire (Wallace Terr., 2nd Ave., 5th Ave., 6th Ave., Devon Rd. & Woodcroft Ave.)				
Project Number	(2018) 1C300-1-4C				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 433,676				
Capital Contribution	$ -				
Net Cost	$ 433,676				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 240
Number of General Service Customers (<50kW): 14
Load Impacted (Tx Ratings): 1007.5kVA

Start Date (5.4.5.2 A.3)	1-Mar-18			**In Service Date (5.4.5.2 A.3)**	31-Dec-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**	
	$ 173,470	$ 43,368	$ 43,368	$ 173,470	

Project Summary

PUC has identified #6 copper overhead primary conductor as "restricted wire". Due to the nature of the conductor, being small and constructed of copper, it is known to become elongated and brittle over years of use. Due to this, the conductor is prone to failure through breaking. One of the consequences is an increase in the frequency and duration of outages. Additionaly, because conductors present the potential to breaking with minimal disturbances, line workers are 'restricted' to only work on these circuits in a deenrgized state only. This time required to make the worksite safe comes at the cost of more frequent planned outages and higher associated operational costs. When #6 is replaced, it is upgrades to #2ACSR. Usually insulators and any end of live cross arms or poles are addressed at the same time to gain economies of scale. The project is described in more detail within the asset management plan. This area has been identified as a high priority of those remaining in the project.

Risk Identification & Mitigation (5.4.5.2 A.4)

This restricted wire project area is a typical replacement project including replacement of conductor, insulation and other assets such as poles and/or transformers as required. PUC has extensive experience with projects of this nature and through usage of standardized framings, the design and construction should be efficient and straight forward. Project construction may be delayed if unanticipated higher priority unplanned emrgency or customer demand work arises. However, no risks are anticipated which would delay the design or construction of this project significantly.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has fairly extensive historical information on restricted wire projects and projects of similar nature. Using this information, the length of restricted conductor to be replaced, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC is able to reasonably estimate each project without a detailed design being completed beforehand. Variances within project areas may occur that will affect budget, but anticipate that cost variances will even out over the project.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no new REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-1-4C for an understanding of the area to be replaced.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Worker safety is the primary investment driver for this project. As stated in the project summary, the restricted wire can become brittle and break with minimal disturbances. This becomes even more of a concern when PUC and/or third party contractors are working on infrastructure attached to PUC's poles with restricted wire present. Eliminating the restricted wire will eliminate the planned outage times an delay costs associted with making the worksafe safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Economical efficiencies is the secondary driver for this project. PUC's current practice for work on poles containing restricted wire is to take an outage if staff, contractors or joint use telecom parties are working on or below the conductor. By eliminating restricted conductors, PUC reduces the requirements to take outages.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to eliminate safety hazards within PUC's electrical distribution system.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

It is common knowledge and well documented across the utility sector that small copper conductors, over time, become brittle and present a safey risk if not adequately manged through costly customer impactive work methods. Most utilities have already eliminated or are in the process of eliminating restricted conductor where it still exists.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the nature of the hazard, it is important to continue to remove restricted conductor from service, but working around restricted conductor can be handled through work procedures until all restricted conductor is removed. Not completing this project area in the budget year will cause the project to be extended, resulting in the associated operation and repair costs both stretching out and icreasing over time.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and removing the restricted conductor will have a positive effect on system operation efficiency. Removal of restricted conductor will minimize failures leading to a more efficient, higher reliability system. During the removal of restricted conductors, associated infrastructure (insulators, poles, transformers, etc.) are reviewed and addressed if required.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a safer, more reliable system and more cost effective electrical distribution system.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Through the removal of restricted conductor and replacement associated infrastructure beyond it's useful life will provide a more reliable system, reducing the frequency of outages.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no practical alternatives available for this project area and project as a whole.

Safety (5.4.5.2 B2)

Safety is a primary driver of this project. Removal of restricted conductor eliminates the costs and customer inconveniences associate with routinely isolating circuits to provide adequte worker safety.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access. Where third party providers are currently attached to poles, coordination will occur during design phase.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

Reducing downtime of PUC's system contributes positively towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when replacing infrastructure. Construction techniques are considered to minimize effects on the environment.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal projects, after emergency forced renewal. This prioritization is based upon the safety aspect in conjunction with the reliability concern compared to other projects. Additionally, each project area within the project is reviewed and prioritized compared to one another. Aspects considered are, but not limited to, residential versus rural, vegetation, pedestrian traffic, nearby protective devices. The higher the risk, the higher the priority of the project becomes.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

The typical age of installation in areas where restricted wire is present is typically mid 1970's or earlier. This results in assets being a minimum 40 years or older. This is generally why restricted wire projects involve more than simply replacing the conductor. Replacing the conductor only, would not be an efficient long term solution and would not bring the value of economies of scale.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 240
Number of General Service Customers (<50kW): 14
Load Impacted (Tx Ratings): 1007.5kVA

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers in the area of this project will benefit from an improved system, higher level of safety and a more reliable electrical distribution system.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives a moderate priority in relation to PUC's system renewal projects. The project is a front lot project fully accessible from the road. Due to the nature of this project in coordination with other projects, this project is scheduled to be constructed early in 2018 and then again late in 2018 with resources shifted to more difficult access projects in the summer.

Consequences for system O&M costs (5.4.5.2 SR-C3)

The project will remove restricted wire and generally replace it with new primary conductor causing a negligible difference in overall system length. Investment in capital through the replacement of aged poles and associated infrastructure is a positive factor with respect to long term operating costs.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

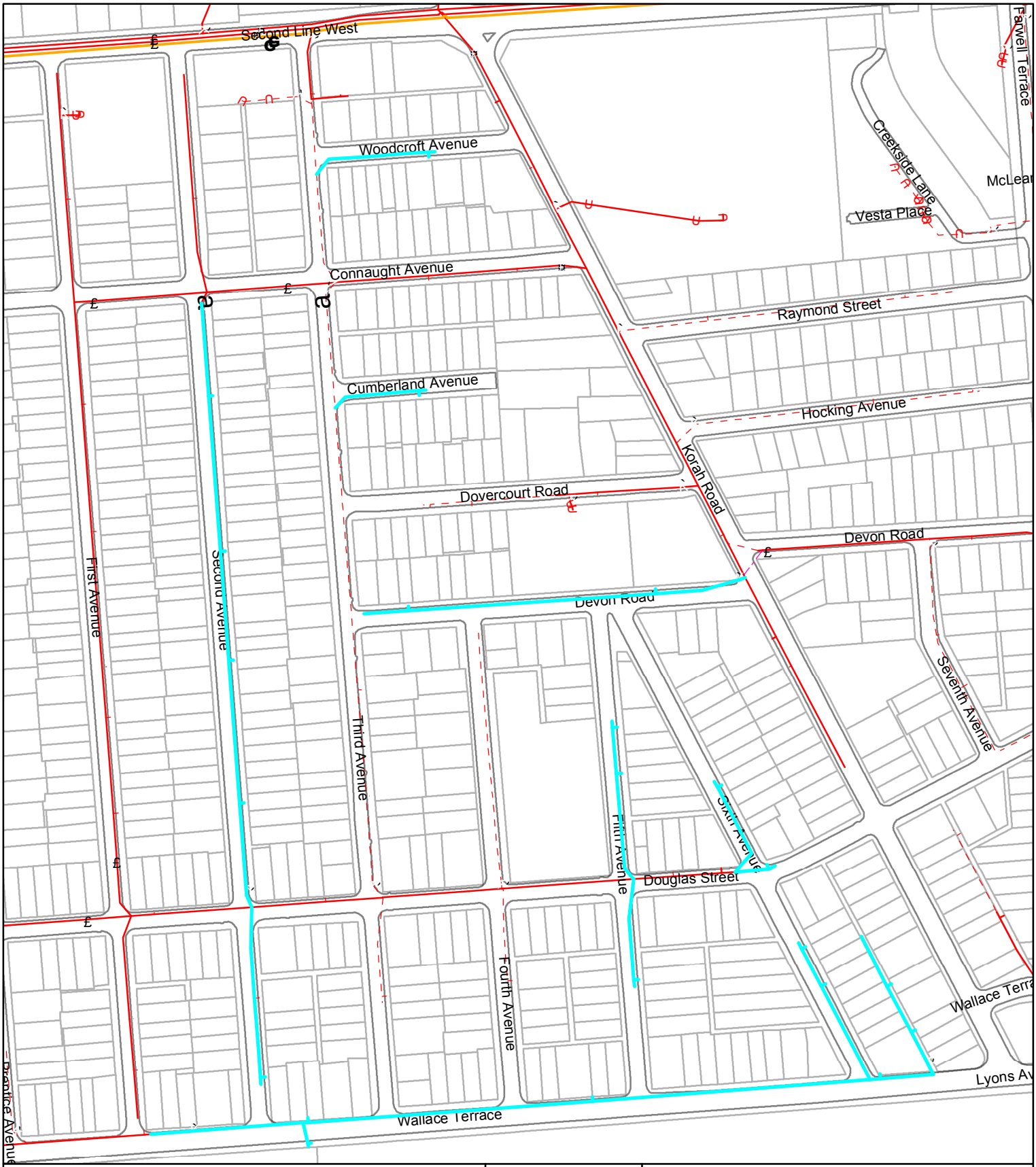
As described above, this project will have a positive impact on worker safety, eliminating the need to put barriers in place and inconvenience customers through outages when working on the distribution system.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project generally receives a moderate priority in relation to PUC's system renewal projects. Project timing is considered to optimize all project construction schedules considering access, seasons and customer impacts.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

While like-for-like replacements may be a possibility, reviewing the distribution system as a whole, replacing and reframing infrastructure will provide the most long term benefit to the system and in turn, the customers. Alternatives to replacing restricted conductor are not available.



Notes:

All locations are approximate as final design has yet to be completed.

N
W E
S

SCALE: NTS

SYSTEM PLANNING
2018 - RESTRICTED WIRE
WALLACE TERR, SECOND AVE, FIFTH AVE, SIXTH AVE, DEVON RD AND WOODCROFT AVE

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 12/17	JT

DRAWN BY: J. TEVC	DATE: SEP. 12/17
CHECKED BY:	DATE:
APPROVED BY:	DATE:

DRAWING No.: (2018)-1C300-1-4C

REV A

A. General Information						
Project/Activity	#10 - Underground Renewal - Voltage Conversion (Laronde Ave., Koprash Crt.)					
Project Number	(2018) 1C300-2-4					
Investment Category	System Renewal					
	2018	**2019**	**2020**	**2021**	**2022**	
Capital Cost (5.4.5.2 A.1)	$ 531,603					
Capital Contribution	$ -					
Net Cost	$ 531,603					
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**	
	NA	NA	NA	NA	NA	

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 79
Load Impacted (Tx Ratings): 825kVA

Start Date (5.4.5.2 A.3)	1-Jun-18			**In Service Date (5.4.5.2 A.3)**	31-Aug-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**	
		$ 132,901	$ 398,702		

Project Summary

As shown in PUC's asset management plan, PUC has near 3km of 4.16/2.4kV underground circuits and two 4.16kV distribution stations in service. As the two stations are beyond their anticipated lifespan, replacement will be required. In an effort to bring stations to industry standard, the stations will be replaced with stations producing 12.47/7.2kV distribution voltage. In order to accommodate these station rebuilds all of 4.16/2.4kV underground lines will be required to be converted. Additional to the reliability concerns related to the stations, there are other benefits to convert voltages to a standard 12.47kV including less power losses and standardized equipment allowing for purchasing efficiencies. Coordinating the voltage conversion program with replacing aged, direct buried cables and deteriorated underground vaults provides opportunities through synergies.

Risk Identification & Mitigation (5.4.5.2 A.4)

The underground voltage conversion project inclusive of direct buried cable replacement is fairly new to PUC. PUC has completed two similar projects in the past and have experienced significant variables during the projects. As PUC continues to learn from the variables as they arise and communicate with similar utilities, there are risks of unknowns that may arise. In an effort to mitigate these risks, PUC attempts to include all parties that will be affected early in the planning stage and obtain all information for consideration in designs and planning stages. This project will require construction during the summer months when resources and minimal and resource demands are highest. Reallocating resources to ensure construction is accomplished may be required to mitigate risks of delays.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has minimal history on similar projects and therefore rely on contractor rates and discussions with other utilities. Customer impacts, restoration, conflicts with adjacent utilities and municipal consent are large factors that can affect expenditures. During design, estimated expenditures are revised to more accurate values. After design, prior to construction, scope of project will be adjusted within or expenditures reassigned as required.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

As customer meters will not be replaced, existing REG customers will not be affected. Transformers will be sized accordingly to accommodate all existing REG customers.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-2-4 for an understanding of the area to be replaced.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Power supply reliability is the primary investment driver of this project. As stated in the project summary, the supplying stations are beyond their rated life, causing significant reliability concerns. In order to replace the stations to industry standard stations, they will be replaced with a higher distribution voltage. To support these station replacements, the existing 4.16kV lines will require conversion. Additionally, replacement of aged direct buried underground distribution cables, vaults and transformers significantly increase the reliability of the distribution system within the area.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Cost effectiveness is the secondary investment driver. As the conductors are operating at a lower voltage (4.16kV vs 12.47kV), it is required to feed a larger amount of current through conductors to supply the same amount of power. Voltage conversion will result in a reduction in losses. Additionally, standardizing material allows PUC to store less material, requiring less inventory.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to mitigate risk of power supply reliability from degrading below PUC's targets by allowing for end of life distribution stations to be replaced as well as replacing underground cables, vaults and transformers.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

As shown in PUC's asset management plan, distribution stations 4 and 5, currently operating at 4.16kV distribution voltage are nearing end of life. As stated above, this project is to support the replacement of said distribution stations. Additionally, as shown in the asset management plan, PUC has a significant length of underground direct buried cables approaching, if not beyond their rated life. Replacing these cables will mitigate the risk of cable failures occurring.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the condition of the distribution systems, it is important to ensure that this project be completed in the budgeted year. Not completing this project in the budgeted year will delay the voltage conversion program, delay the replacement of the 4.16kV distribution stations, continue to operate cables beyond their rated life and, in turn, increase risk of system reliability decreasing.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and in turn the distribution station replacements will have a significant positive effect on system operational efficiency, decreasing power loss costs, improving reliability and decreasing stations maintenance costs. Alternatives are observed on a case by case basis. Installing step down transformers is an alternative reviewed for each area. This is used more for scheduling purpose versus a final solution as it is expenditures that would be lost.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a more reliable distribution system with additional supply points and new assets in their immediate subdivision. This should result in less outages, and when an outage occurs, the duration will be limited. Benefits have not been quantitatively calculated for this project.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project will positively impact system reliability performance. The project will result in the ability to replace existing, aged distribution stations with new. Additionally, this project will replace all underground cables, vaults and transformers currently installed. Upon completion of the project, the area will be supplied from the 12.47kV system, which has many distribution stations available, resulting in shorter duration outages, if they occur. Additionally, as submersible transformers will be replaced with above ground, minipad transformers, time to complete switching operations and transformer replacements will be reduced.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are many project alternatives available for this project, including the installation of step down transformers, cable injection versus replacement, directional drilling verses trenching and replacing submersible transformers in kind verses above ground, minipad transformers. All options are reviewed to ensure the most practical, long term solution is selected.

Safety (5.4.5.2 B2)

In replacement of underground cables, vaults and transformers with new, accommodating a voltage upgrade, the transformers are replaced with above grade, minipad transformers. This provides an increased level of safety around multiple areas. PUC staff are able to operate the minipad transformers in a more ergonomic fashion and less risk to City sidewalk plows from damaging submersible vault lids leaving energized transformers exposed.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards. PUC coordinates early with third party utilities including communication companies, gas, water and municipality to ensure all parties are both aware of the construction that will be occurring and allow them to coordinate work to provide the maximum benefit to all parties.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively. Future operational requirements are projected to decrease as maintaining above ground, minipad transformers require significantly less effort than below grade submersible transformers.

Economic Development (5.4.5.2 B.5) (where applicable)

By minimizing system outages to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

Replacing underground direct buried cables with new, replacing underground submersible transformers in vaults with above ground, minipad transformers has environmental benefits as a potential leaking below grade transformer may go unnoticed for a long time versus an above grade transformer. Additionally, environmental impacts will be considered when installation options are reviewed.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a distribution system infrastructure failure and the immediate reliability impact. Additionally, each area is reviewed in relation to the age of underground infrastructure, history of cable failures, whether cables are direct buried or not and immediate customer impacts. If below grade vaults are causing safety concerns in the area, the project priority is increased within the program.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

Assets within this area are generally approach or beyond their rated life-cycle. This is based on the age of installation of 4.16kV systems and when cables were direct buried versus installed in conduit. Due to the age of the assets in conjunction with the requirement to increase voltage, most infrastructure is due for replacement.

The number of customers in each class potentially affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 79
Load Impacted (Tx Ratings): 825kVA

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers located in the area of this project will benefit from a more reliable distribution system from new substation builds as well as new cables and transformers in the immediate subdivision.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives a moderate priority in relation to PUC's system renewal projects. The project requires a significant amount of excavation and therefore is most efficient to complete the replacement during summer months.

Consequences for system O&M costs (5.4.5.2 SR-C3)

Replacement of direct buried cables and aged transformers and vaults with new infrastructure including above ground, minipad transformers should reduce system O&M costs. It is expected that anticipated upcoming cable failures will not occur minimize reactive O&M costs.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

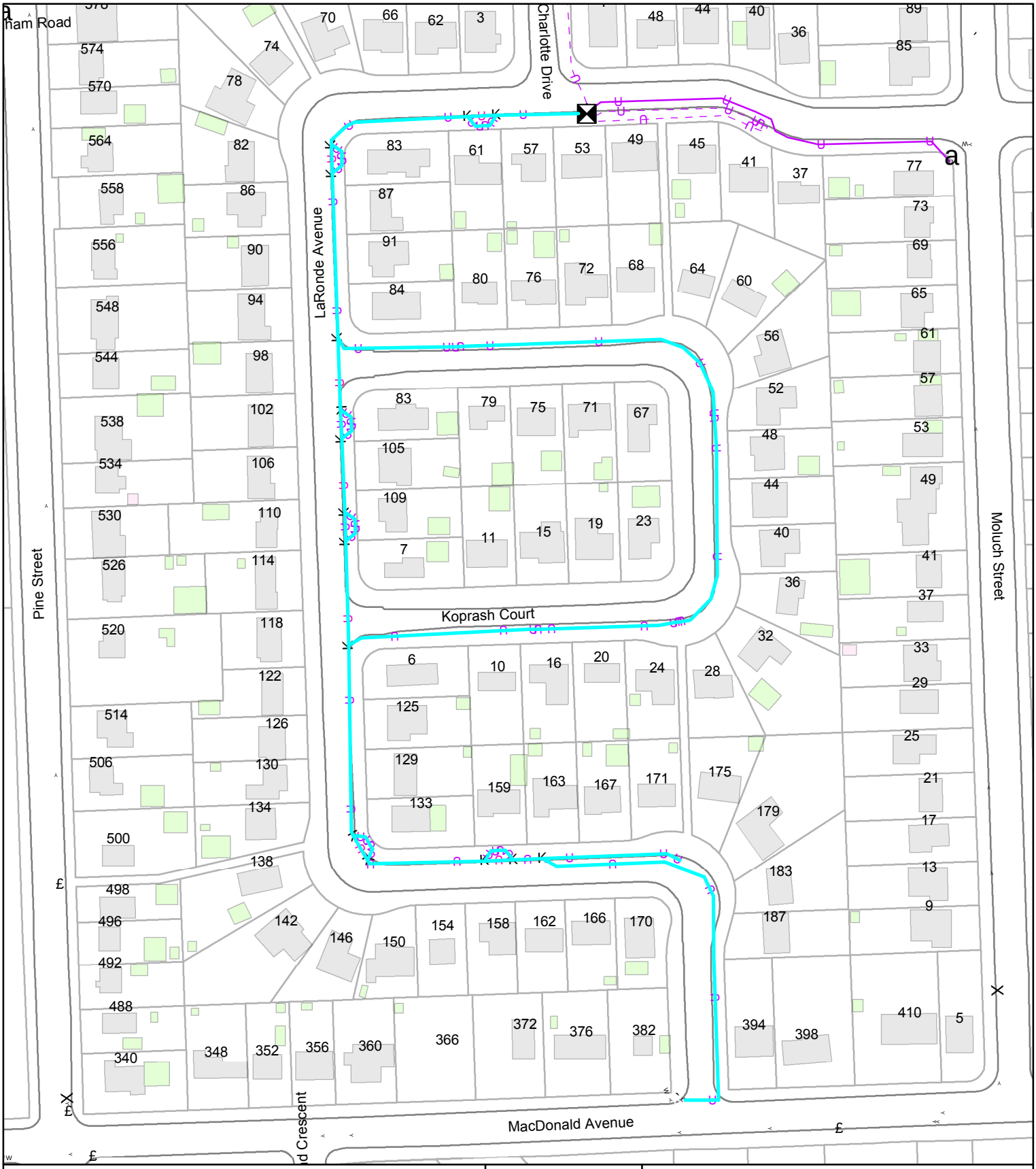
As described above, this project, incoordination with distribution station replacements, should result in improved system reliability and safety.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project generally receives a moderate priority in relation to PUC's system renewal projects. Project should be completed in summer months to ensure cost effectiveness. Project will allow aged distribution substations to be replaced and will replace aged distribution cables and transformers resulting in a higher level of reliability.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

Like-for-like renewal is not an option. Many alternative designs will be considered prior to detailed design including step down transformers, cable injection and directional drilling. After review, PUC will select the most practical solution for the specific project. It is essential to complete this project in the budgeted year as the projects to accommodate the complete voltage conversion have been prioritized and scheduled in conjunction with substation renewals.



Notes:
All locations are approximate as final design has yet to be completed.

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SCALE: NTS

SYSTEM PLANNING
2018 - UG RENEWAL - VOLTAGE CONVERSION
LaRONDE AVE AND KOPRASH CRT

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 13/17	JT

DRAWN BY: J. TEVC	DATE: SEP. 13/17
CHECKED BY:	DATE:
APPROVED BY:	DATE:

DRAWING No.: (2018)-1C300-2-4

REV A

A. General Information					
Project/Activity	#11 - Overhead Renewal - Restricted Wire (Red Pine Drive - North of Pnt. Of Pins)				
Project Number	(2018) 1C300-1-4B				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 349,739				
Capital Contribution	$ -				
Net Cost	$ 349,739				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 32
Load Impacted (Tx Ratings): 212.5kVA

Start Date (5.4.5.2 A.3)	1-May-18			**In Service Date (5.4.5.2 A.3)**	31-Aug-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**	
	$ -	$ 174,870	$ 174,870	$ -	

Project Summary

PUC has identified #6 copper overhead primary conductor as "restricted wire". Due to the nature of the conductor, being small and constructed of copper, it is known to become elongated and brittle over years of use. Due to this, the conductor is prone to failure through breaking. One of the consequences is an increase in the frequency and duration of outages. Additionaly, because conductors present the potential to breaking with minimal disturbances, line workers are 'restricted' to only work on these circuits in a deenrgized state only. This time required to make the worksite safe comes at the cost of more frequent planned outages and higher associated operational costs. When #6 is replaced, it is upgrades to #2ACSR. Usually insulators and any end of live cross arms or poles are addressed at the same time to gain economies of scale. The project is described in more detail within the asset management plan. This area has been identified as a high priority of those remaining in the project.

Risk Identification & Mitigation (5.4.5.2 A.4)

This restricted wire project area is a typical replacement project including replacement of conductor, insulation and other assets such as poles and/or transformers as required. PUC has extensive experience with projects of this nature and through usage of standardized framings, the design and construction should be efficient and straight forward. Project construction may be delayed if unanticipated higher priority unplanned emrgency or customer demand work arises. However, no risks are anticipated which would delay the design or construction of this project significantly.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has fairly extensive historical information on restricted wire projects and projects of similar nature. Using this information, the length of restricted conductor to be replaced, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC is able to reasonably estimate each project without a detailed design being completed beforehand. Variances within project areas may occur that will affect budget, but anticipate that cost variances will even out over the project.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no new REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-1-4B for an understanding of the area to be replaced.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Worker safety is the primary investment driver for this project. As stated in the project summary, the restricted wire can become brittle and break with minimal disturbances. This becomes even more of a concern when PUC and/or third party contractors are working on infrastructure attached to PUC's poles with restricted wire present. Eliminating the restricted wire will eliminate the planned outage times an delay costs associted with making the worksafe safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Economical efficiencies is the secondary driver for this project. PUC's current practice for work on poles containing restricted wire is to take an outage if staff, contractors or joint use telecom parties are working on or below the conductor. By eliminating restricted conductors, PUC reduces the requirements to take outages.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to eliminate safety hazards within PUC's electrical distribution system.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

It is common knowledge and well documented across the utility sector that small copper conductors, over time, become brittle and present a safey risk if not adequately manged through costly customer impactive work methods. Most utilities have already eliminated or are in the process of eliminating restricted conductor where it still exists.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the nature of the hazard, it is important to continue to remove restricted conductor from service, but working around restricted conductor can be handled through work procedures until all restricted conductor is removed. Not completing this project area in the budget year will cause the project to be extended, resulting in the associated operation and repair costs both stretching out and icreasing over time.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and removing the restricted conductor will have a positive effect on system operation efficiency. Removal of restricted conductor will minimize failures leading to a more efficient, higher reliability system. During the removal of restricted conductors, associated infrastructure (insulators, poles, transformers, etc.) are reviewed and addressed if required.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a safer, more reliable system and more cost effective electrical distribution system.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Through the removal of restricted conductor and replacement associated infrastructure beyond it's useful life will provide a more reliable system, reducing the frequency of outages.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no practical alternatives available for this project area and project as a whole.

Safety (5.4.5.2 B2)

Safety is a primary driver of this project. Removal of restricted conductor eliminates the costs and customer inconveniences associate with routinely isolating circuits to provide adequte worker safety.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access. Where third party providers are currently attached to poles, coordination will occur during design phase.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

Reducing downtime of PUC's system contributes positively towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when replacing infrastructure. Construction techniques are considered to minimize effects on the environment.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal projects, after emergency forced renewal. This prioritization is based upon the safety aspect in conjunction with the reliability concern compared to other projects. Additionally, each project area within the project is reviewed and prioritized compared to one another. Aspects considered are, but not limited to, residential versus rural, vegetation, pedestrian traffic, nearby protective devices. The higher the risk, the higher the priority of the project becomes.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

The typical age of installation in areas where restricted wire is present is typically mid 1970's or earlier. This results in assets being a minimum 40 years or older. This is generally why restricted wire projects involve more than simply replacing the conductor. Replacing the conductor only, would not be an efficient long term solution and would not bring the value of economies of scale.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 32
Load Impacted (Tx Ratings): 212.5kVA

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers in the area of this project will benefit from an improved system, higher level of safety and a more reliable electrical distribution system.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives a moderate priority in relation to PUC's system renewal projects. The project is a complex project due to currently being constructed across private property near the shore of Lake Superior. Due to access constraints, it will be optimal to complete project during summer months.

Consequences for system O&M costs (5.4.5.2 SR-C3)

The project will remove restricted wire and generally replace it with new primary conductor causing a negligible difference in overall system length. Investment in capital through the replacement of aged poles and associated infrastructure is a positive factor with respect to long term operating costs.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

As described above, this project will have a positive impact on worker safety, eliminating the need to put barriers in place and inconvenience customers through outages when working on the distribution system.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project generally receives a moderate priority in relation to PUC's system renewal projects. Project timing is considered to optimize all project construction schedules considering access, seasons and customer impacts.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

While like-for-like replacements may be a possibility, reviewing the distribution system as a whole, replacing and reframing infrastructure will provide the most long term benefit to the system and in turn, the customers. Alternatives to replacing restricted conductor are not available.



Notes:
All locations are approximate as final design has yet to be completed.

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SCALE: NTS

SYSTEM PLANNING
2018 - RESTRICTED WIRE
RED PINE DR
NORTH OF POINTE AUX PINS DRIVE

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 12/17	JT

DRAWN BY: J. TEVC	DATE: SEP. 12/17
CHECKED BY:	DATE:
APPROVED BY:	DATE:

DRAWING No.: (2018)-1C300-1-4B

REV A

A. General Information						
Project/Activity	#12 - Overhead Renewal - Voltage Conversion (MacDonald Ave - Lake St. to Moluch St.)					
Project Number	(2018) 1C300-1-3A					
Investment Category	System Renewal					
	2018	**2019**	**2020**	**2021**	**2022**	
Capital Cost (5.4.5.2 A.1)	$ 288,020					
Capital Contribution	$ -					
Net Cost	$ 288,020					
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**	
	NA	NA	NA	NA	NA	

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 25
Number of MicroFit Customers: 1
Load Impacted (Tx Ratings): 187.5kVA

Start Date (5.4.5.2 A.3)	1-Jan-18			**In Service Date (5.4.5.2 A.3)**	30-Apr-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**	
	$ 216,015	$ 72,005	$ -		

Project Summary

As shown in PUC's asset management plan, PUC has over 30km of overhead 4.16/2.4kV circuits and two 4.16kV distribution stations in service. As the two stations are beyond their anticipated lifespan, replacement of the stations will be required. In an effort to bring stations to industry standard, the stations will be replaced with stations producing 12.47/7.2kV distribution voltage. In order to accommodate these station rebuilds, all 30km of line will be required to be converted. Additional to the reliability concerns related to the stations, there are other significant benefits to convert voltages to a standard 12.47kV including less power losses and standardized equipment allowing for purchasing efficiencies.

Risk Identification & Mitigation (5.4.5.2 A.4)

This voltage conversion project should be a typical PUC line rebuild, in which PUC has extensive experience designing and constructing. In using standardized framing standards, the design should be efficient and completed as required. Project implementation may be delayed dependent on unplanned, higher priority work arising. No risks are anticipated which would delay the design or construction of this project significantly.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has fairly extensive historical information on voltage conversion projects and projects of similar nature. Using this information, the length of conductor to be converted/removed, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC is able to reasonably estimate each project without a detailed design being completed beforehand. Variances within projects may occur that will affect budget, but anticipate that program cost variances will even out between projects.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no new REG investments associated with this project. If existing REG customers are attached to the 4.16kV system, they will be transferred over to the 12.47kV system. As they will all be connected on the low voltage side, this will have negligible impacts to the project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-1-3A for an understanding of the area to be converted.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Power supply reliability is the primary investment driver of this project. As stated in the project summary, the supplying stations are beyond their rated life, causing reliability concerns. In order to replace the stations to industry standard, they will be replaced with a higher distribution voltage. To support these station replacements, the existing 4.16kV lines will require conversion.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Cost effectiveness is the secondary investment driver. As the conductors are operating at a lower voltage (4.16kV vs 12.47kV), it is required to feed a larger amount of current through conductors to supply the same amount of power. Voltage conversion will result in a reduction in losses. Additionally, standardizing material allows PUC to store less material, requiring less inventory.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to mitigate risk of power supply reliability from degrading below PUC's targets by allowing for end of life distribution stations to be replaced.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

As shown in PUC's asset management plan, distribution stations 4 and 5, currently operating at 4.16kV distribution voltage are nearing end of life. As stated above, this project is to support the replacement of said distribution stations.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the condition of the distribution systems, it is important to ensure that this project area be

completed in the budgeted year. Not completing this project area in the budgeted year will delay the voltage conversion project, delay the replacement of the 4.16kV distribution stations and increase risk of system reliability decreasing.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and in turn the distribution station replacements will have a significant positive effect on system operational efficiency, improving reliability and decreasing stations maintenance costs. Alternatives are observed on a case by case basis. Installing a step down transformer is an alternative reviewed for each area. This is used more for scheduling purpose versus a final solution as expenditures would be lost once final conversion occurs.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a more reliable distribution system with additional supply points. This should result in less outages, and when an outage occurs, the duration will be limited. Benefits have not be quantitatively calculated for this project.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

This project will positively impact system reliability performance. The project will result in the ability to replace existing, aged distribution stations with new. Additionally, this project will replace each distribution transformer and insulator used within the 4.16kV system to support the higher voltage resulting in new assets with lower risk of failures. Upon completion of the project area, the area will be supplied from the 12.47kV system, which has many distribution stations available, resulting in shorter duration outages, if they occur.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no practical and cost effective alternative designs for this project that provide the same level of benefits to customers.

Safety (5.4.5.2 B2)

In order to convert voltages within this project, many transformers will require replacement. Framing, inclusive of separations on existing poles may be well below current standards. In order to ensure separations are achieved and working space is considered, many poles beyond their useful life will require replacement. In replacing poles, safety is increased for both the work (working space) and the public (new asset).

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access. Where third party providers are currently attached to poles, coordination will occur during design phase.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

By minimizing system outages to customers in PUC's service territory, this project contributes towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when replacing infrastructure. Many existing 4.16/2.4kV, pole mounted transformers are well aged transformers, typically manufactured prior to the 1980's, resulting in a posibility of containing PCB levels exceeding the acceptable 50ppm. During this project, all 4.16kV transformers will be removed, mitigating environmental risks in an occurance of transformer oil leaking.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal project, after emergency forced renewal. This prioritization is based upon the risk level of a distribution system infrastructure failure and the immediate reliability impact. Additionally, each area is reviewed in relation to the age of infrastructure, deteriorated poles, restricted wire, etc. to ensure all aspects are considered during prioritization. Increased safety concern would increase project prioritization.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

Assets within this projects are generally beyond their typical life-cycle. This is based on the age of installation of 4.16kV systems, specific to these areas. Due to this, in conjunction with pole testing records, most of the infrastructure is due for replacement. This is considered during conversion for efficiencies.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 25
Number of MicroFit Customers: 1
Load Impacted (Tx Ratings): 187.5kVA

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers located in the area of this project will benefit from a more reliable distribution system as well as new infrastructure providing for a higher level of safety.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR-C1.6)

Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives a moderate priority in relation to PUC's system renewal projects. The project is a front lot project fully accessible from the road. Due to the nature of this project in coordination with other projects, this project is scheduled to be constructed during Q1 of 2018.

Consequences for system O&M costs (5.4.5.2 SR-C3)

This project will convert an existing line with similar length of a new line causing negligible O&M impacts. Replacement of poles and infrastructure during the project should be a positive contributing factor pertaining to outages and repairs, reducing potential O&M costs.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

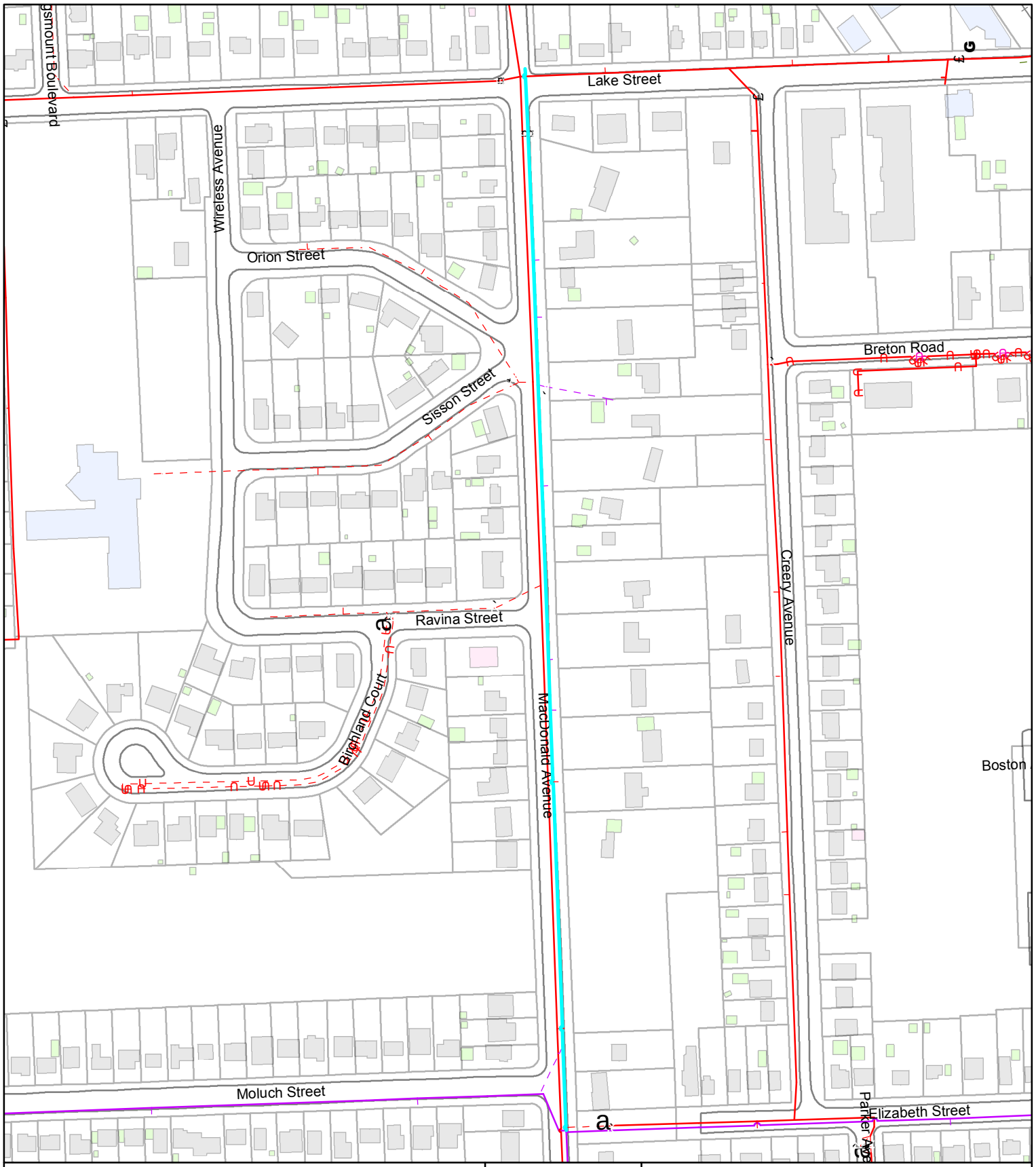
As described above, this project, in coordination with distribution station replacements, should result in improved system reliability and safety.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project generally receives a moderate priority in relation to PUC's system renewal projects. Project timing is considered to optimize all project construction schedules considering access, seasons and customer impacts.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

While like-for-like replacements may be a possibility, reviewing the distribution system as a whole, replacing and reframing infrastructure will provide the most long term benefit to the system and in turn, the customers. Alternatives are reviewed on a case by case basis to maximize benefits and minimize costs.



Notes:
All locations are approximate as final design has yet to be completed.

SCALE: NTS

SYSTEM PLANNING
2018 - VOLTAGE CONVERSION
MacDONALD AVE.
LAKE ST. TO MOLUCH ST.

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 08/17	JT

DRAWN BY: J. TEVC	DATE: SEP. 08/17
CHECKED BY:	DATE:
APPROVED BY:	DATE:

DRAWING No.: (2018)-1C300-1-3A

REV A

A. General Information					
Project/Activity	#13 - Overhead Renewal - Restricted Wire (Carpin Beach Road - Base Line to Herkimer, Phase 1 of 2)				
Project Number	(2018) 1C300-1-4A				
Investment Category	System Renewal				
	2018	**2019**	**2020**	**2021**	**2022**
Capital Cost (5.4.5.2 A.1)	$ 185,155.00				
Capital Contribution	$ -				
Net Cost	$ 185,155.00				
O&M Cost (5.4.5.2 A.1)	**2018**	**2019**	**2020**	**2021**	**2022**
	NA	NA	NA	NA	NA

Customer Attachments and Load (5.4.5.2 A.2)

Number of Residential Customers: 12
Load Impacted (Tx Ratings): 137.5kVA

Start Date (5.4.5.2 A.3)	1-Sep-18			**In Service Date (5.4.5.2 A.3)**	31-Oct-18
Expenditure Timing for the Test Year	**2018 Q1**	**2018 Q2**	**2018 Q3**	**2018 Q4**	
	$ -	$ -	$ 92,577.50	$ 92,577.50	

Project Summary

PUC has identified #6 copper overhead primary conductor as "restricted wire". Due to the nature of the conductor, being small and constructed of copper, it is known to become elongated and brittle over years of use. Due to this, the conductor is prone to failure through breaking. One of the consequences is an increase in the frequency and duration of outages. Additionaly, because conductors present the potential to breaking with minimal disturbances, line workers are 'restricted' to only work on these circuits in a deenrgized state only. This time required to make the worksite safe comes at the cost of more frequent planned outages and higher associated operational costs. When #6 is replaced, it is upgrades to #2ACSR. Usually insulators and any end of live cross arms or poles are addressed at the same time to gain economies of scale. The project is described in more detail within the asset management plan. This area has been identified as a high priority of those remaining in the project.

Risk Identification & Mitigation (5.4.5.2 A.4)

This restricted wire project area is a typical replacement project including replacement of conductor, insulation and other assets such as poles and/or transformers as required. PUC has extensive experience with projects of this nature and through usage of standardized framings, the design and construction should be efficient and straight forward. Project construction may be delayed if unanticipated higher priority unplanned emrgency or customer demand work arises. However, no risks are anticipated which would delay the design or construction of this project significantly.

Comparative information on expenditures for equivalent projects/activities (5.4.5.2 A.5)

PUC has fairly extensive historical information on restricted wire projects and projects of similar nature. Using this information, the length of restricted conductor to be replaced, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC is able to reasonably estimate each project without a detailed design being completed beforehand. Variances within project areas may occur that will affect budget, but anticipate that cost variances will even out over the project.

REG Investment Details including Capital and OM&A costs (5.4.5.2 A.6)

There are no new REG investments associated with this project.

Leave to Construct approval under Section 92 of the OEB Act (5.4.5.2 A.7)

It is dependent on specific locations whether this project requires leave to construct as defined under Section 92 of the OEB Act. If tasks arise that require Leave to Construct approval, PUC will follow required protocol.

Attach other project reference material i.e. images, drawings and or reference material

Replacements will be constructed using USF standards, PUC standards and/or specifics approved by a Professional Engineer.

Refer to sketch (2018) 1C300-1-4A for an understanding of the area to be replaced.

B. Evaluation criteria and information requirements for each project/activity

Efficiency, Customer Value & Reliability - Investment Main Driver (5.4.5.2 B.1.a)

Worker safety is the primary investment driver for this project. As stated in the project summary, the restricted wire can become brittle and break with minimal disturbances. This becomes even more of a concern when PUC and/or third party contractors are working on infrastructure attached to PUC's poles with restricted wire present. Eliminating the restricted wire will eliminate the planned outage times an delay costs associted with making the worksafe safe.

Efficiency, Customer Value & Reliability - Investment Secondary Driver (5.4.5.2 B.1.a)

Economical efficiencies is the secondary driver for this project. PUC's current practice for work on poles containing restricted wire is to take an outage if staff, contractors or joint use telecom parties are working on or below the conductor. By eliminating restricted conductors, PUC reduces the requirements to take outages.

Efficiency, Customer Value & Reliability - Investment Objectives and/or Performance Targets (5.4.5.2 B.1.a)

The investment objectives are to eliminate safety hazards within PUC's electrical distribution system.

Efficiency, Customer Value & Reliability - Source and nature of the information used to justify the investment (5.4.5.2 B.1.a)

It is common knowledge and well documented across the utility sector that small copper conductors, over time, become brittle and present a safey risk if not adequately manged through costly customer impactive work methods. Most utilities have already eliminated or are in the process of eliminating restricted conductor where it still exists.

Efficiency, Customer Value & Reliability - Priority Level/Project Prioritization and Reasoning (5.4.5.2 B.1.b) Priority relative to other investments

This project receives a moderate priority, below emergency and system access demands. Due to the nature of the hazard, it is important to continue to remove restricted conductor from service, but working around restricted conductor can be handled through work procedures until all restricted conductor is removed. Not completing this project area in the budget year will cause the project to be extended, resulting in the associated operation and repair costs both stretching out and icreasing over time.

Analysis of Project & Alternatives - Effect of the investment on system operation efficiency and cost -effectiveness (5.4.5.2 B.1.c)

Completing this project and removing the restricted conductor will have a positive effect on system operation efficiency. Removal of restricted conductor will minimize failures leading to a more efficient, higher reliability system. During the removal of restricted conductors, associated infrastructure (insulators, poles, transformers, etc.) are reviewed and addressed if required.

Analysis of Project & Alternatives - Net benefits accruing to customers (5.4.5.2 B.1.ci)

Customers benefit from a safer, more reliable system and more cost effective electrical distribution system.

Analysis of Project & Alternatives - Impact of the investment on reliability performance including frequency and duration of outages (5.4.5.2 B.1.cii)

Through the removal of restricted conductor and replacement associated infrastructure beyond it's useful life will provide a more reliable system, reducing the frequency of outages.

Project Alternatives (Design, Scheduling, Funding/Ownership) (5.4.5.2 B.1.ciii)

There are no practical alternatives available for this project area and project as a whole.

Safety (5.4.5.2 B2)

Safety is a primary driver of this project. Removal of restricted conductor eliminates the costs and customer inconveniences associate with routinely isolating circuits to provide adequte worker safety.

Cyber-Security, privacy (5.4.5.2 B.3) (where applicable)

This project has no adverse impact on cyber security or privacy issues.

Co-Ordination, Interoperability (5.4.5.2 B.4i) Recognized Standards, co-ordination with utilities, regional planning, and/or 3rd party providers (where applicable)

Project will be constructed to USF and/or PUC specific standards which are in line with industry standards allowing third parties reasonable access. Where third party providers are currently attached to poles, coordination will occur during design phase.

Co-Ordination, Interoperability (5.4.5.2 B.4ii) Future technological functionality and/or future operational requirements (where applicable)

Infrastructure replacements are typically constructed to USF and/or PUC standards, which are based on meeting the current and future customer needs and distributing electricity reliably, safely and cost effectively.

Economic Development (5.4.5.2 B.5) (where applicable)

Reducing downtime of PUC's system contributes positively towards economic development in the region.

Environmental Benefits (5.4.5.2 B.6) (where applicable)

PUC considers environmental impacts when replacing infrastructure. Construction techniques are considered to minimize effects on the environment.

C. Category-Specific Requirements - System Renewal

Asset Performance-related operational targets & asset lifecycle optimization policies and practices (refer to 5.2.3 & 5.3.3) (5.4.5.2 SR-C1.1)

This project receives a moderate priority in relation to PUC's system renewal projects, after emergency forced renewal. This prioritization is based upon the safety aspect in conjunction with the reliability concern compared to other projects. Additionally, each project area within the project is reviewed and prioritized compared to one another. Aspects considered are, but not limited to, residential versus rural, vegetation, pedestrian traffic, nearby protective devices. The higher the risk, the higher the priority of the project becomes.

Information on the condition of the assets relative to their typical life-cycle and performance record (5.4.5.2 SR-C1.2)

The typical age of installation in areas where restricted wire is present is typically mid 1970's or earlier. This results in assets being a minimum 40 years or older. This is generally why restricted wire projects involve more than simply replacing the conductor. Replacing the conductor only, would not be an efficient long term solution

and would not bring the value of economies of scale.

The number of customers in each class potential affected by failure of the assets (5.4.5.2 SR-C1.3)

Number of Residential Customers: 12
Load Impacted (Tx Ratings): 137.5kVA

Quantitative customer impacts (5.4.5.2 SR-C1.4)

It is not feasible to determine quantitative customer impacts for this project ahead of time.

Qualitative customer impacts (5.4.5.2 SR-C1.5)

Customers in the area of this project will benefit from an improved system, higher level of safety and a more reliable electrical distribution system.

Value of customer impact in terms of characteristics of customers potentially affected by failure that have bearing on the criticality and/or cost of failure (5.4.5.2 SR

Impacts to customers can vary on a customer by customer basis. Failure of system to a residential customer will have different impacts depending on the season and if the customer's residence is heated via electric heat or not. If the customer is a commercial customer, outages during regular business hours can impact revenue and therefore an increased cost to the customer. This project will improve system reliability, reduce outage durations and in turn be less impactive to customers.

Timing and Priority of Project (5.4.5.2 SR-C2)

This project generally receives a moderate priority in relation to PUC's system renewal projects. The project is a front lot project fully accessible from the road. Due to the extensive ditches in the rural areas well as the lack of snow storage in the area, this project is preferred to be completed in the non-winter months.

Consequences for system O&M costs (5.4.5.2 SR-C3)

The project will remove restricted wire and generally replace it with new primary conductor causing a negligible difference in overall system length. Investment in capital through the replacement of aged poles and associated infrastructure is a positive factor with respect to long term operating costs.

Impact on reliability performance and/or safety (5.4.5.2 SR-C4)

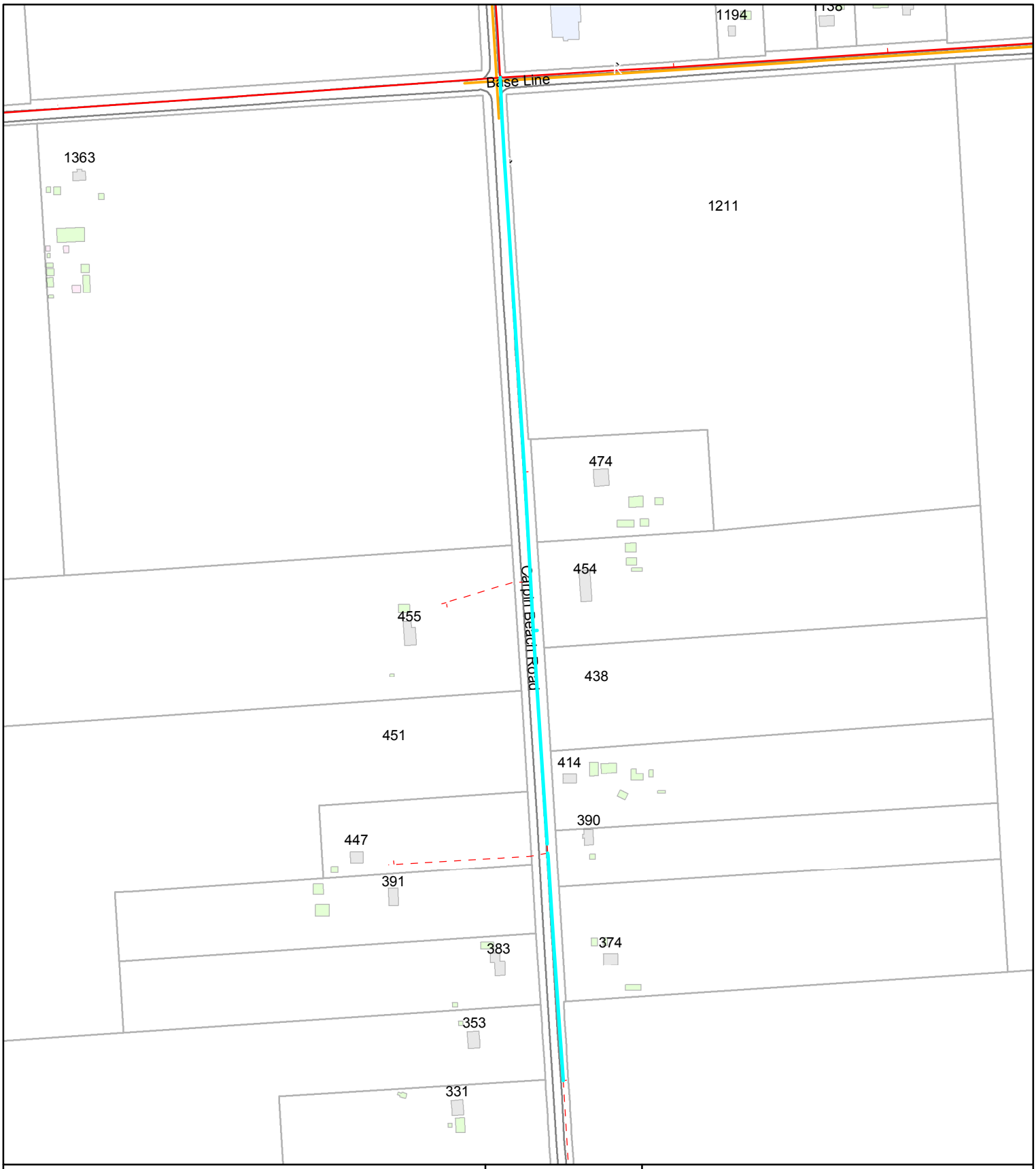
As described above, this project will have a positive impact on worker safety, eliminating the need to put barriers in place and inconvenience customers through outages when working on the distribution system.

Analysis of Project Benefits and Timing (5.4.5.2 SR-C5)

This project generally receives a moderate priority in relation to PUC's system renewal projects. Project timing is considered to optimize all project construction schedules considering access, seasons and customer impacts.

Like for Like Renewal Analysis, Alternatives Comparison (like for like vs. not like for like, timing, rate of replacements, etc.) (5.4.5.2 SR-C6)

While like-for-like replacements may be a possibility, reviewing the distribution system as a whole, replacing and reframing infrastructure will provide the most long term benefit to the system and in turn, the customers. Alternatives to replacing restricted conductor are not available.



Notes:
All locations are approximate as final design has yet to be completed.

N
W E
S
SCALE: NTS

SYSTEM PLANNING
2018 - RESTRICTED WIRE
CARPIN BEACH RD
BASE LINE TO HERKIMER ST.
PHASE 1 OF 2

REV #	REVISION	DATE	INITIAL
A	FOR INFORMATION ONLY	SEP 08/17	JT

DRAWN BY: J. TEVC	DATE: SEP. 08/17
CHECKED BY:	DATE:
APPROVED BY:	DATE:

DRAWING No.: **(2018)-1C300-1-4A**

REV **A**

Appendix H

Customer Engagement

Customer Engagement Overview

OVERVIEW

PUC Distribution Inc. (PUC) believes that customer engagement is the backbone of its community-driven operations. PUC recognizes that providing opportunities for customers to share their feedback will not only strengthen their relationship with them but also, improve the overall customer experience.

As a Local Distribution Company (LDC), PUC understands that its role in planning for the future of the electrical distribution system involves more than just measuring equipment service life. It requires including customers in the planning process to ensure that they have considered their needs and preferences when it comes to developing long-term plans. To that end, PUC is committed to growing and expanding on the success of its existing community service and customer engagement initiatives.

PUC has increased formal and informal community engagement activities with its customers over the last five (5) years. Those engagement opportunities identified a number of customer needs and preferences, along with room for improvements to be made. The areas identified that needed the most attention were improving customer communications, increasing customer consultations, and growing energy literacy in the community. Although many new ideas continue to be explored, we have successfully implemented a number of improvement initiatives over the past five years that have been directly related to customer feedback and expectations.

For the purposes of this summary, formal engagement is described as a direct, focused method to obtain detailed customer feedback pertaining to specific issues. For example, surveys, focus groups, and information sessions.

Informal engagement is described as an indirect method of engagement that supports two-way communications with customers. Customers are encouraged to share their opinions, feedback, and anecdotal experiences in an informal environment, such as a trade show, community festival, or retail consultation event.

CUSTOMER ENGAGEMENT (Formal)

The customer engagement program at PUC has gradually become more integrated into the operations of the company. It has evolved from a basic business-to-consumer relationship to a more strategic and informed partnership. This has been accomplished by the increased communications and outreach through surveys, media releases, and community speaking engagements, such as community information sessions. The formal customer engagement methodology is derived from the need to improve our community's overall energy literacy, especially pertaining to the electrical distribution system, its assets, and PUC's operations. We utilize the following to gain feedback from our customers, and to promote open discussion of customer issues, so that we may ensure we are continuously adapting to a customer-driven environment.

a. Customer Surveys

Additional efforts to inform, educate and engage with customers have been conducted through public surveys. The surveys gauge the understanding of the electricity bill, the electrical distribution system, PUC operations, well as the overall public perception and customer satisfaction.

i. Customer Engagement Survey (COS Application)

Purpose: This survey was developed to inform customers of the proposed rate increase associated with the 2018 Cost of Service application. It provided a short overview of PUC operations, cost drivers, bill breakdown, and a variety of capital projects needed to be completed. It allowed customers to comment, and open two-way communication between PUC and its customer base, in order to move forward with efficient customer engagement strategies.

Initiated By: PUC, third party consulting company

Participants: 2,004 (1,321 completed surveys)

Nature and Timing of Deliverables: PUC wanted to target 1,000 respondents regarding service reliability, COS application and most importantly, the proposed rate increase. The customer engagement survey was meant to open discussion about operations, and capital projects needed for system reliability. The survey results will be used as a benchmark to address customer concerns, and measure/track improvements.

DSP-related: Customers agreed that keeping rates as low as practical while maintaining good quality electrical service was the most important priority for PUC. The DSP was revised several times to ensure that the proposed rate increase was as low as possible, while taking the Asset Management Plan into consideration for necessary system renewal projects.

- The survey detailed the Operations, Maintenance and Administrative cost drivers, including new Regulatory Requirements, utility costs, bad debt, industry regulations, and inflationary increases which have all increased since 2012/2013. For that reason specifically, the DSP includes an additional staff member to assist with Rates and Regulatory needs. Currently, there is one person tasked with the R&R responsibilities.

- 48% of respondents agreed that they had a better understanding of the proposed rate increase to cover the OM&A costs, and another 12% that were interested in obtaining more information. The 5th project in the DSP complies with the OEB mandate requiring general service customers >50kW to be equipped with MIST revenue meters.
- Customers were informed of capital projects such as the overhead/underground system renewal, pole replacements, substation builds, and the voltage conversion replacement plan. One of the capital projects included in the DSP is the building of a new 12kV distribution station to replace two 4kV existing distribution stations that are currently in very poor condition and at the end of their useful service life. This will help reduce operating costs when the two 4kV stations are retired from service.

Future Considerations: PUC will expand on the DSP-related customer engagement through information sessions regarding projects listed in the DSP, including a Q&A discussion for customer input and concerns to be addressed. Furthermore, customer engagement related to the DSP framework and ongoing implementation will be conducted with timely, effective discussion.

Customer Engagement Survey - KEY FINDINGS

PUC, along with the assistance of a third party consultant, developed the Cost of Service, Customer Engagement survey to distribute to its customers. The survey provided PUC an opportunity to expand on its customer engagement, and provide customers with information on the proposed rate increase. The survey provided a short overview of PUC operations, cost drivers, the breakdown of a customer's electricity bill, and a variety of capital projects to be completed.

The survey had informational videos embedded within it. The videos included pertinent information related to the COS application, such as the cost drivers associated with operations, and planned capital projects. The survey was designed to provide two-way engagement between the PUC and its customer base. It allowed customers to provide feedback about existing services, and to share their thoughts about a proposed increase.

Some of the recurring themes in the survey analysis were:

- The cost of electricity
- Seniors on fixed incomes
- Dislike Smart Meter System (inefficient, costly)
- TOU discrimination (seniors, families, shift workers)
- High electric heating costs in Northern Ontario winters
- Government Assistance (should assist more with infrastructure renewal)
- PUC should be advocating/lobbying for customers with the Government
- Internal spending; cut costs before requesting an increase (provide evidence of doing so)
- Operation transparency (customers want more details and information on where money will be used)

The cost of electricity is a large concern for customers, and ensuring that good service is provided in the most cost-effective way needs to be a priority for PUC. The survey data indicates a large percentage of customers are on fixed incomes and are struggling to afford their electricity bills.

As a follow-up to the survey, and as an enhancement to the customer engagement element of PUC's operations, there are plans to host public information sessions. These will open discussion about the COS application, proposed increase, and most importantly address some of the customer comments received in the survey. PUC wants to ensure that their customers know they are listening to them, and care about their opinions. There will be specific sessions to ensure PUC engages larger business customers as well.

The following is a breakdown of the survey data, as well as the analysis of over 3,500 customer comments.

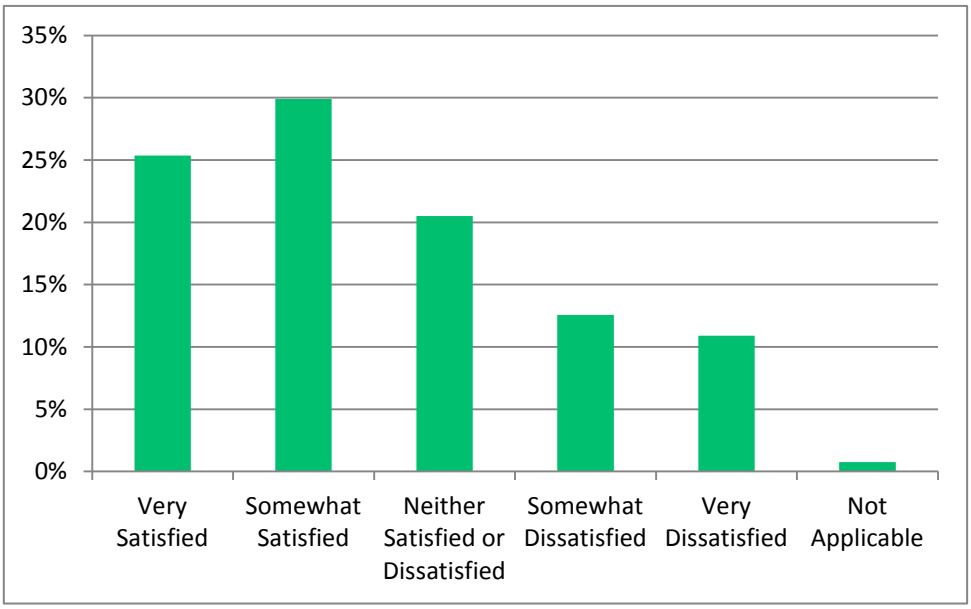
Customer Engagement Survey - DEMOGRAPHICS & SEGMENTATION

As of January 24, 2018, PUC Distribution's Customer Engagement survey had a combined total of 1,962 participants with 1,321 completed responses. The majority of respondents were aged 55-74, and based on the comments received in the survey, most are retired and living on a set income. The second largest contributors are ages 35-54. There was an equal amount of male and female participants.

The largest group of participants were homeowners at 85%, with the second largest being tenants at 12%. Unfortunately, the response from PUC business customers was low, so with that in mind, PUC plans on coordinating information sessions, specifically targeted to inform business customers on how the increase may affect them.

97% of survey participants were located in the City of Sault Ste. Marie, while another 3% of respondents were PUC customers in surrounding areas. PUC Distribution's customers are serviced by a multi-utility service provider, including electricity, water and the sewer charge for the City of Sault Ste. Marie, all included on a common bill. 85% of participants receive both electricity and water services. This is evident through the survey comments received, as many mention both electrical and water services.

Customer Engagement Survey - OVERALL SATISFACTION



Question 8

When asked about the overall customer satisfaction, results showed that 56% of respondents said that they were "very" or "somewhat satisfied" with the overall service(s) they received from PUC, while 24% were somewhat or very dissatisfied.

Out of the 342 comments received, participants elaborated on the factors they were unhappy with, or what they wanted more information about.

With the main concern identified in the comments as the 'High Cost of Electricity', PUC has worked hard to ensure that the proposed rate increase in the COS application, is as low as possible while still balancing infrastructure needs with customer affordability.

Additionally, many comments were received requesting more information about PUC's operations and transparency with internal spending. The Customer Engagement team will be delivering public information sessions to answer some of these and other questions that were raised in the survey comments.

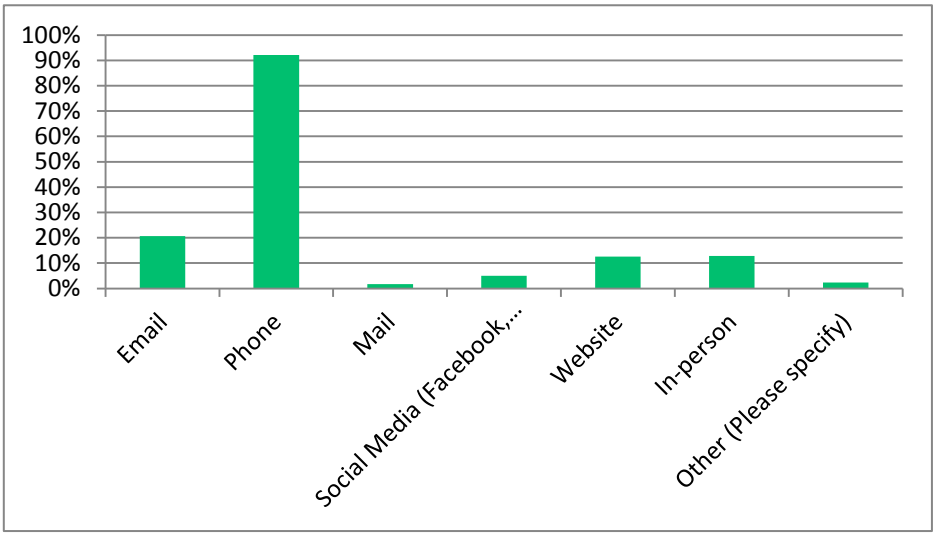
Customer Engagement Survey - PUC PRIORITIES

The OEB requires LDC's to understand customers' preferences so customers were asked to place PUC priorities in order of importance to them. The results support the importance of keeping costs as low as possible without sacrificing system reliability.

Out of the 1,321 respondents, these are the top three customer priorities:

1. 58% of respondents selected; "**Keep rates as low was practical while maintaining good quality electrical service**" as their number one priority. This supports the belief that customers want reliability, but want to ensure that it is done in a cost-effective way.
2. 34% of respondents selected; "**Maintaining reliable electrical service (e.g. prevent/reduce power outages)**" as their number two priority.
3. 34% of respondents selected; "**Helping customers reduce/manage consumption and by doing so reducing costs**" as their number three priority.

Customer Engagement Survey - COMMUNICATION

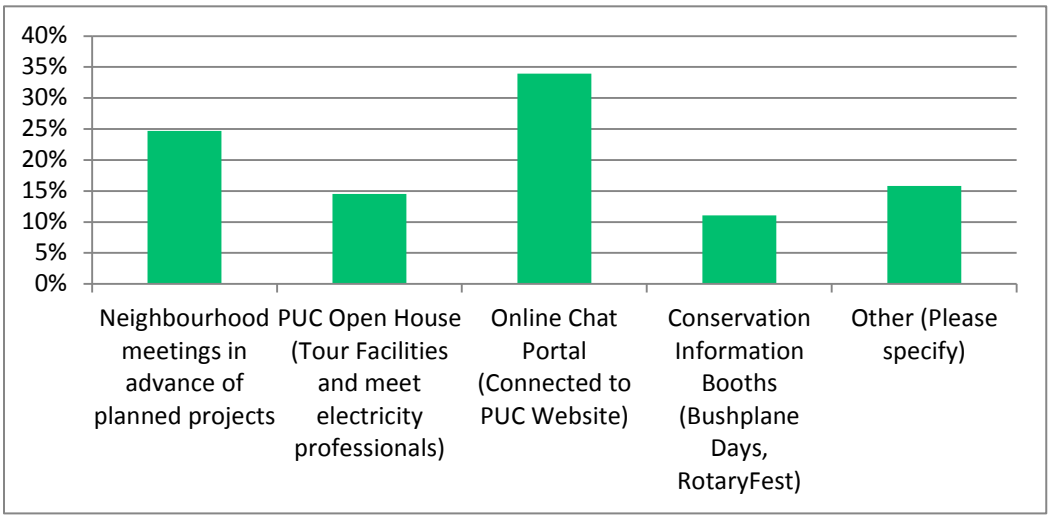


Question 14

Customers indicated overwhelmingly that their preferred method for contacting PUC for service issues was via the phone. However, some customers mentioned in the comments that they would appreciate the opportunity to speak with a PUC employee face-to-face, at their home.

In 2017, in an effort to improve customer service, PUC introduced a new stage in the planning process. Engineering technicians are now required to include customers whose property will be impacted by infrastructure renewal in the design phase of the project. Customer input will now be included directly into the design phase. The first example of this new engagement process occurred in 2017, with a number of submersible transformer being converted to a pad-mounted transformers in a neighborhood.

Improved customer communications is needed; this is evident through comments received and the overall perception customers have about PUC. However, while customers indicated that they would like PUC to improve communications and engagement, they do not want it at a significant cost to their bills.



Question 27

34% of customers responded in favour of an online chat portal as an improvement in communications, wanting to be connected to a live representative when they do have an issue. In response to this feedback, PUC is actively exploring options for integrating an online chat portal into its website by the end of 2018.

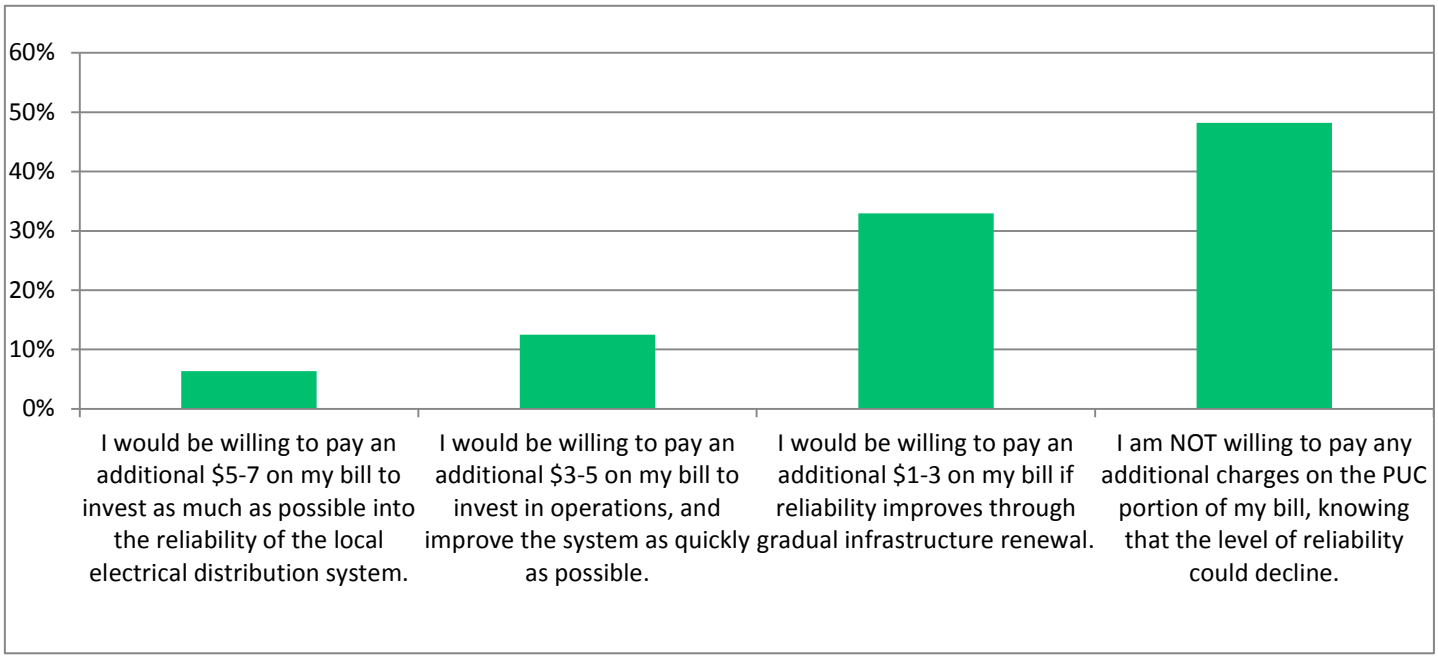
Customer Engagement Survey - OPERATIONS, MAINTENANCE & ADMINISTRATION

Participants were provided information on the cost drivers behind the PUC's proposed rate increase in the OM&A video. The goal was to provide customers with a better understanding of the reasons behind the proposed rate increase. After reviewing comments, it was evident that customers want more information, some questioning the validity of each cost increase, others not understanding regulations pertaining to the LDC. The survey results show that the majority of customers have a better understanding of the reasons behind the rate increase. However, there are still a large amount of customers that need more information, before they can support it.

This is another reason why PUC plans to host information sessions, release the survey results, address comments received, and provide clarification about operations. It will ensure customers have adequate knowledge of how PUC is regulated, what measures are in place to reduce spending, and how costs were reduced internally before requesting a rate increase.

Customer Engagement Survey - CAPITAL INVESTMENT PROJECTS

The participants were provided information on cost drivers related to infrastructure renewal, including voltage conversion, and sub-station rebuilds. After which, they were asked if they would be willing to pay any additional amount to assist with maintaining reliability, improving reliability, or not paying anything knowing that reliability of the system could decline.



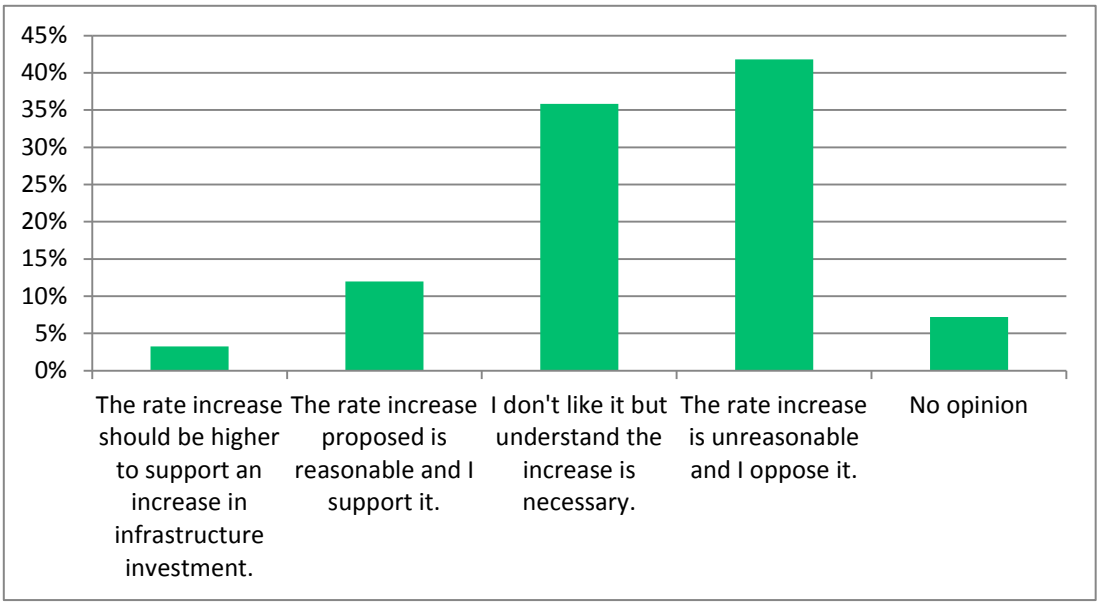
Question 22

The results represent an almost evenly divided group of customers 52% willing to pay something to improve reliability, and 48% unwilling to pay any additional amount for an increase in reliability.

While there were positive comments received from customers indicating that they understand the necessity of upgrading, along with maintaining equipment to ensure reliable service. There were also customers who stated that they need more information to support an increase of any kind; not that they oppose it.

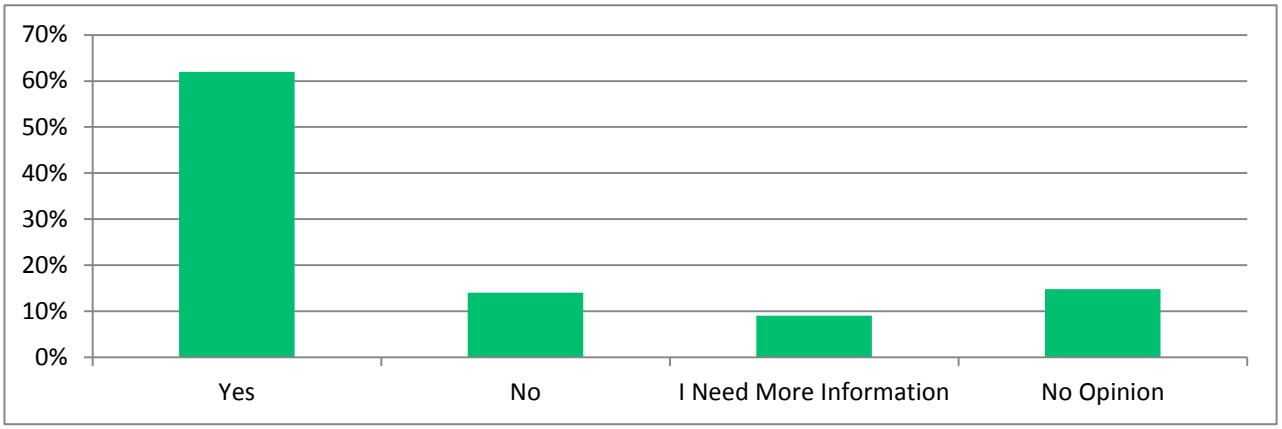
Customer Engagement Survey - PROPOSED INCREASE

When asked, ***Now that you're familiar with some of the planned projects, what do you think of the proposed rate increase to support infrastructure investment?*** A large segment of customers believe it to be unreasonable and do not support it. After reviewing comments, there were participants who once again mentioned needing clarification to make an informed decision to support or oppose the increase.



While a majority of customers either support the increase, or understand the necessity behind it – PUC recognizes that more needs to be done to engage with customers.

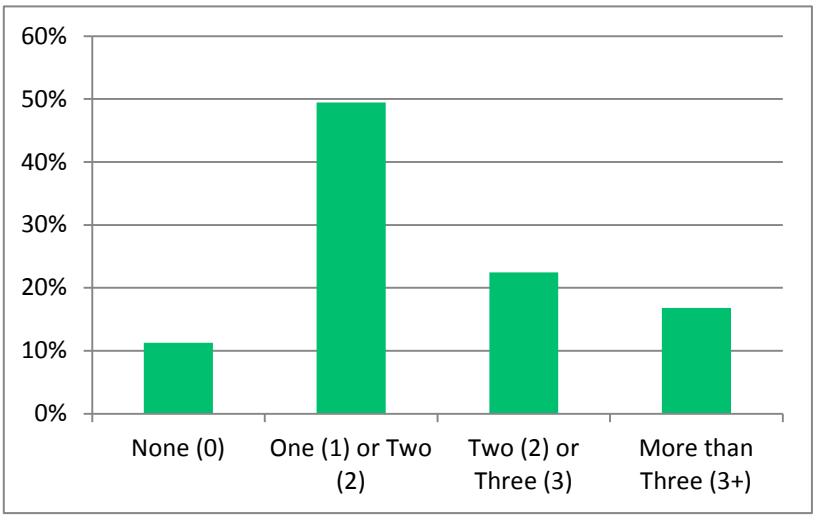
Most participants did state that they were provided with enough information in the survey to understand the reasons behind the proposed rate increase. This supports the previous question of customers understanding the rate increase is necessary, but not liking it or supporting it, based on the information provided to them. PUC will continue to provide information and address comments received in the survey to ensure customer concerns are addressed.



Question 24

Customer Engagement Survey - RELIABILITY

Customers chose "maintaining reliable electrical service" as the second priority for PUC. When customers were asked; ***In the Past Year, How Many Power Outages Have You Experienced?*** The results show that the majority of customers do not experience many outages.



Question 25

Customers rarely experience outages more than 3 times in a year. These statistics correspond with PUC's the reliability data for SAIDI and SAIFI. When asked; ***What was the longest power outage they had in the past year?*** 72% of participants indicated that they had only experienced short outages, up to 90 minutes.

When asked if they contacted PUC about the power outage, 71% of customers commented that they did not, stating that they trust the organization knowing that the problem will be reported, acknowledged, and fixed as soon as possible. 79% of customers agree that the reliability is "very good" or "good" when it comes to PUC response times for outages.

Reliability means more than maintaining quality electrical service; it also relates to PUC's responsiveness to customer needs and preferences. PUC has increased the amount of calls it can handle through software upgrades, provided an updated outage notification system, and improved services such as service orders for real-time metering.

Customer Engagement Survey - Exhibits

- Cost of Service Survey Master Script See: EXHIBIT 1
- Cost Of Service Survey Storyboard: EXHIBIT 2

ii. Customer Satisfaction Surveys (2015 and 2017)

Purpose: Gauge overall customer satisfaction, the utility's performance, public perception, and utilize as an engagement tool to collect quantitative data. Customers were also consulted about the willingness to pay an increase for expenses such as capital, and operational items.

Initiated By: PUC, through the Utility Pulse Division of Simul Corporation

Participants: **2017** - 1,553 Households (401 Completed Interviews) – Residential (85%) Commercial (15%)
2015 – 1,600 Households (403 Completed Interviews) – Residential (85%) Commercial (15%)

Nature and Timing of Deliverables: The survey allowed PUC to gain valuable insight from the results, including customer preferences about system reliability, infrastructure replacement, and PUC priorities. Unless otherwise stated, the results listed below are based on the most recent (2017) Electric Utility Customer Satisfaction Survey data.

DSP-related: 91% *(pg. 25 – 2017 UtilityPULSE CS Survey)* of ALL respondents with an opinion agree that PUC provides consistent, reliable electricity, and continues to meet customer expectations. Over the last 5 years, PUC has improved reliability for customers through voltage conversion projects, substation rebuilds, outage management system improvements and upgrades to the overhead/underground distribution system.

The amount of customers that believe a pro-active replacement of equipment to ensure reliable power (even though it may cost more) has declined by 8% from 72% in 2015 *(pg. 93 – 2015 UtilityPULSE CS Survey)* to 64% in 2017*(pg. 38 – 2017 UtilityPULSE CS Survey)*, based on **ALL** respondents. Although 89% of PUC customers *(pg. 16 – 2017 UtilityPULSE CS Survey)* agree that reliability is consistent with their expectations, 69% of all respondents *(pg. 41 – 2017 UtilityPULSE CS Survey)* (69% Residential and 70% Small Commercial) are willing to pay more to replace aging equipment to improve safety and reliability. As a result of customer input, this DSP focuses on equipment in poor or very poor condition, or near the end of its service life, in alignment with the Asset Management Plan.

The DSP includes a variety of projects that are driven in part by safety. For example, one of these projects is the rebuild of a substation (16), in very poor condition, and at the end of its service life. Due to the state of the existing station infrastructure, the switchgear is deemed to be unsafe to operate while energized and must be isolated and de-energized prior to operation. This results in isolation out on the 34.5kV sub-transmission lines, the path for one of two circuits feeding the local hospital.

Future Considerations: We have identified future opportunities to include more specific questions related to projects in the DSP. The biggest challenge is ensuring that the electrical engineering terms are communicated clearly enough for customers to understand equipment, processes and how the system works, which will be part of our customer education efforts.

Here are some of the results that compare 2015 and 2017 survey data (residential and businesses):

2015 *UtilityPULSE Customer Satisfaction Survey*	**2017** *UtilityPULSE Customer Satisfaction Survey*	**Variance**
* 89% agree PUC provides consistent, reliable electricity (pg. 14)	* 91% agree PUC provides consistent, reliable electricity (pg. 25)	+2% increase in reliability
* 89% agree PUC quickly handles outages and restores power (pg. 14)	* 90% agree PUC quickly handles outages and restores power (pg. 25)	+1% increase in outage management
* 89% agree electricity safety is a top priority for employees and contractors (pg. 14)	* 91% agree PUC ensures electricity safety is a top priority (pg. 25)	+2% increase in safety as a top priority
** 45% indicated they had a blackout or outage problem in the last year (pg. 9)	** 32% indicated they had a blackout or outage problem in the last year (pg. 12)	-13% decrease in blackout or outage issues; coincides with outage management and less occurrences
* 81% agree PUC is "easy to do business with" (pg. 15)	* 85% agree PUC is "easy to do business with" (pg. 5)	+4% increase in ease of doing business
* 75% agree PUC is customer-focused and treats customers as if they're valued (pg. 15)	* 73% agree PUC is customer-focused and treats customers as if they're valued (pg. 5)	- 2% decrease in being customer focused and treat customers as if they're valued
* 50% agree that the cost of electricity is reasonable when compared to other utilities (pg. 15)	* 44% agree that the cost of electricity is reasonable when compared to other utilities (pg. 25)	-6% decrease One of the lowest LDC rates in Ontario; customer perception remains a challenge.
** 13% had a billing problem in the last year; with majority stating the amount owing was too high (pg. 8)	** 25% had a billing problem in the last year; with majority stating the amount owing was too high (pg. 13)	+12% increase Generally, our analysis suggests the "problem" is high cost rather than billing errors.

Based on* **ALL *respondents with an opinion*

***Based on* **ALL** *respondents*

Reliability

- 89% of **ALL** respondents agree PUC has a standard of reliability that meets their expectations *(pg. 16 – 2017 UtilityPULSE CS Survey)*
- 92% of **ALL** respondents agree that PUC is effective in responding to outages *(pg. 19 – 2017 UtilityPULSE CS Survey)*
- 94% of **ALL** respondents agree PUC restores power quickly *(pg. 19 – 2017 UtilityPULSE CS Survey)*
- 57% of **ALL** respondents with an opinion agree PUC provides good value for money *(pg. 25 – 2017 UtilityPULSE CS Survey)*

We have identified this as an opportunity to educate customers about operations and what is done with the amount that PUC retains on their bill. This is evident through CDM initiatives such as funded programs, in-store retail product consultations, and information sessions for understanding the electricity bill. It is our responsibility, in the position of trust and public interest that we communicate what PUC is doing to improve the electric system, ways we are trying to keep the rates at reasonable levels and improvements to expect with capital investments.

PUC is increasing customer engagement and improving the methodology used to do so, including an interactive customer survey that provides a detailed overview of operational and capital costs for customers to understand. Based on the results of our formal engagement, PUC has implemented several customer-driven changes which are as follows:

Better prices/lower rates

PUC customers are increasingly focused on their electricity costs, with emphasis on receiving better prices and lower rates. There has been a dramatic increase, from 36% of total respondents with suggestions in 2015 *(pg. 75 – 2017 UtilityPULSE CS Survey),* and now 67% of **ALL** respondents in 2017 *(pg. 46 – 2017 UtilityPULSE CS Survey)*. PUC does not believe our customers want to see us sacrificing their electrical distribution system's reliability and service levels for the lowest rate. PUC believes its obligation to the public is to provide a safe, reliable, and efficient service as well as meeting regulatory requirements as an LDC.

During 2015/2016 operations, PUC declined a potential rate increase, recognizing in part severe concerns on the state of the local economy. Our largest employer, a steel manufacturer experienced a time of financial hardship. Knowing that a vast majority of customers rely on income from the steel manufacturer, we understood that it was not a good time for the suggested rate increase, even though it was needed.

Most customers are unaware of the ageing of the electrical distribution system infrastructure, operational costs, and asset renewal. With that in mind, we have introduced engagement opportunities to provide energy literacy. The price of electricity has also risen provincially in the last few years, and customers are feeling the effects on their bills. Although the Provincial 25% cost reduction has been of great assistance to residential customers, small business has not seen the same reduction and have been hit hard by local economic conditions.

Although a large percentage of our assets are part of an aging electrical distribution system, we have held off on capital investments for large-scale infrastructure such as the transformer stations, based on customer concern for increasing costs. PUC has developed its DSP to include asset renewal at a steady pace, rather than a significant increase that would affect the customers more advertently. Especially being in the North, where heating costs can be highly impacted during the winter months, and the local economy is still reeling from the effect of the steel industry.

Customer Communication = Online Access *(2017 UtilityPULSE CS Survey Results)*

- 83% of total respondents access the internet for information; 71 % use online banking *(pg. 27)*
- 72% of **ALL** respondents agree PUC effectively provides information about the outage *(pg. 19)*
- 75% of **ALL** respondents agree PUC provides information to help customers reduce their costs *(pg. 47)*
- 69% of **ALL** respondents agree PUC is using media channels for updates *(pg. 19)*
- 58 % of **ALL** respondents agree researching information about energy conservation *(pg. 28)*
- 53% of **ALL** respondents agree that it was important to review their bill online *(pg. 28)*
- 44% of **ALL** respondents agree that tools and calculators are important to help manage consumption *(pg. 28)*
- 34% of **ALL** respondents agree automated alerts to remind you of your bill date *(pg. 28)*

We have increased our online presence for power outage notification and conservation on our website and local media outlets. The introduction of the customer portal, Customer Connect, was implemented to aid customers in understanding usage, utilized as a tool to change consumption habits based off TOU data, and to ensure customers had the information to make choices about usage.

Trust

Overall, 85% of Secure and Favourable respondents are confident that PUC Distribution is using good judgment to prioritize investments *(pg. 37 – 2017 UtilityPULSE CS Survey Results)*

Willing to Pay For

In 2015, customers (*based on 90% of **ALL** respondents from the PUC), top **operational** items they were willing to pay more for *(pg. 96 – 2017 UtilityPULSE CS Survey Results)*

- 54% increased tree trimming
- 46% a proactive outage management system
- 46% educating customers and the public about electricity safety
- 45% educating customers about energy conservation

In 2017, customers (based off **ALL** respondents), top **operational** items they were willing to pay more for: *(pg. 44 – 2017 UtilityPULSE CS Survey Results)*

- 23% a proactive outage management system
- 23% educating customers about energy conservation
- 13% increased self-service options on the website

In 2017, customers (based off **ALL** respondents), top **capital** items they were willing to pay more for: *(pg. 41 - 2017 UtilityPULSE CS Survey Results*)

- 69% replacing aging equipment to improve safety and reliability
  - Of those who answered YES = Residential 69% / Small Commercial 70%
- 50% upgrading equipment to accommodate future growth in the community
  - Of those who answered YES = Residential 47% / Small Commercial 63%

Which of the following OPERATIONAL items would you be willing to pay more for?					
PUC Distribution	Yes	No	Not sure	Residential Yes	Small Commercial Yes
A proactive outage management system	23%	74%	3%	23%	27%
Increased self-service options on the website	13%	85%	2%	13%	12%
Educating customers about energy conservation	23%	76%	1%	23%	22%

(pg. 44 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)

Which of the following CAPITAL items would you be willing to pay more for?					
PUC Distribution	Yes	No	Not sure	Residential Yes	Small Commercial Yes
Replacing aging equipment to improve safety and reliability	69%	29%	2%	69%	70%
Upgrading equipment to accommodate future growth in the community	50%	48%	2%	47%	63%
Adding automation and technology to reduce outage time	45%	52%	2%	43%	55%
Investing in technology to deal with cyber security issues	37%	58%	5%	37%	33%

(pg. 41 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)

Strategy for replacing equipment

PUC Distribution	Residential	Small Commercial
Run-to-failure when there are limited customers affected ensures full-value is received from the equipment	21%	13%
Pro-active replacement, even though it may cost more, should ensure reliable power	63%	68%
Don't Know	16%	18%

(pg. 39 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)

Strategy for replacing equipment

PUC Distribution	2017	2015
Run-to-failure when there are limited customers affected ensures full-value is received from the equipment	20%	19%
Pro-active replacement, even though it may cost more, should ensure reliable power	64%	72%
Don't Know	16%	10%

Base: total respondents

(pg. 38 – PUC Distribution Inc. 2017 UtilityPULSE Customer Satisfaction Survey)

iii. Strategic Direction Plan Survey (2016)

Purpose: PUC started the process of developing a new Corporate Strategic Plan to set direction and priorities for the utility over the coming years. Customers were asked their opinions on the organization's strategic direction, and what they believed were key challenges for the utility. PUC wanted to gain feedback to support the development of the strategic plan.

Initiated By: PUC, through Ironside Consulting Services Inc.

Participants: 194 Respondents (Customers and other Stakeholders)

Nature and Timing of Deliverables: The survey allowed PUC to gain valuable insight from the results, including input to align the utility's vision, values and PUC priorities.

DSP-related: 83% of survey participants agree that PUC's key challenges include rate increases, 67% agree aging electric infrastructure, and 55% state the uncertain local economy. 92% of customers are aware that PUC does not set the price of electricity, although 76% believe the cost for electricity is not reasonable.

65% of respondents determined that in order to meet these challenges, PUC must ensure that rates are kept fair and competitive. PUC elected to defer a rate increase in 2016 based on the state of the local economy.

52% of respondents believe that rate increases must be reasonable in order to address aging infrastructure. The DSP includes necessary system improvements that will occur gradually, and not at a substantial cost increase to PUC customers, due to their concerns about affordability. PUC has worked to balance the infrastructure and affordability drivers with a proposed rate increase that will affect the total average (using 750kWh) residential electricity bill, by less than $3.00/month.

Customers spoke about the importance of including Customer Service Sensitivity Training, which PUC implemented in 2017 as part of the entire organization's participation in C.A.R.E. Training. Customers wanted more information on bills, residential, commercial and industrial electricity rates in Ontario which PUC introduced at the Public Library information sessions, as well as the Innovation Centre presentations. Comments were received about the importance of affordability as well as money allocation going towards infrastructure improvements.

Customers mentioned online services for moving of service, rather than having to come into the office to initiate service change. They would like to see more incentive programs to get rid of older, inefficient appliances, and more conservation awareness to improve public education and customer outreach. There were also customers who spoke of accountability as an organization; striving to decrease spending internally with overtime, fleet vehicles, and purchasing. The PUC underwent Accountability and Leadership training in 2017 to improve management and employee responsibility. An internal Business Improvement Committee was struck with a mandate to review internal business and process efficiencies. Lastly, customers wanted to eliminate TOU based on discrimination with stay at home parents, large families, aged, ill and unemployed demographics.

iv. Public Awareness of Electrical Safety Survey (2015 and 2016)

Purpose: PUC Distribution participated in a public electrical safety awareness survey to provide a benchmark level concerning the public's electrical safety awareness and identify opportunities where additional education and outreach may be required.

Initiated By: PUC, through the Utility Pulse Division of Simul Corporation

Participants: A representative sample of PUC Distribution's service territory population was surveyed to gauge the public's awareness level of key electrical safety concepts related to distribution assets (the survey was based on a template provided by the Electrical Safety Authority).

Nature and Timing of Deliverables: In 2016 the results of the survey were further analyzed, and a number of opportunities to improve our existing outreach programs were identified. One item of note from the survey results indicated that more emphasis was required to ensure public awareness of Ontario One Call. Of the 36 LDC's that utilized Utility Pulse for the electrical safety awareness survey, PUC Distribution scored the highest with an awareness score of 86%.

In an effort to improve the Ontario One Call awareness, PUC approved a budget in 2016 (for 2017) to purchase promotional Dig Safe decals for the entire operations fleet. Additionally, in partnership with the Association of Electrical Utility Professionals (AEUSP), PUC contributed to the production of a series of Electricity Safety videos for television broadcast in our service area.

PUC Distribution continues to look for every opportunity to communicate and engage with the public to promote electrical safety awareness in our service area. Below are examples of PUC Distribution's public safety communication initiatives:

- Elementary School Electrical Safety Program (Caution and Chance) for Grade 3 – 5 within our geographic service territory. Participation included 24 schools. (73 classes, and 1,874 students)
- Advanced Research & Technology Innovation Expo (ARTIE) (approx. 360 students and their teachers participated)
- Sault Ste. Marie Science Festival (approx. 500 adults and children attended)
- Sault Ste. Marie PUC website – Safety tab with particular activities aimed at educating young people on electrical safety

DSP-related: The DSP includes a variety of system renewal projects that are driven by system reliability, public and worker safety. In addition, the DSP includes ongoing operating costs to support community and public safety engagement.

Future Considerations: PUC has identified the importance of continuing the Caution and Chance Electrical Safety Program and ensuring that Public Service Announcements along with other advertising are utilized to promote safety as a top priority. PUC will also ensure that customers understand the validity of safety behind projects, such as those included in the DSP, by providing more detail and clarification of projects driven by safety.

b. **INFORMATION SESSIONS**

i. Sault Ste. Marie Public Library (April 2017)

Purpose: PUC has received a variety of customer comments regarding issues with bills being too high, and requests to help with lowering utility costs, through customer care calls, surveys, and event interactions. PUC advertised and held a free informational workshop hosted at the Centennial Library. This was timed in accordance with the recent news from the OEB about disconnection bans. The workshop was divided into two parts; the first part focused on breaking down an average PUC bill and explaining how the charges are set. The second part of the workshop provided customers information and ideas to control their energy usage, which included Save on Energy tips and tools.

Initiated By: PUC, (Community Engagement and CDM teams) in partnership with the Sault Ste. Marie Public Library

Participants: There were approximately 40 attendees. Both the Communications and Conservation teams were on-site to speak with customers and answer any questions they had regarding the industry, and PUC's electrical distribution services. The Q&A period allowed customers to share concerns about rates, rising electricity costs, and overall customers mentioned they were pleased with the amount of information supplied.

Nature and Timing of Deliverables: PUC's objective to inform and engage customers was delivered precisely after the media release of the disconnection ban. It is the organization's responsibility to act as a key ambassador for the public, when delivering information that will affect them or their bills.

DSP-related: The DSP was not directly affected by this engagement opportunity, it does take into account the overall concern from customers about affordability by keeping the proposed rate increase as low as practical while focusing on necessary system renewal.

Future Considerations: We have identified future opportunities to increase the number of sessions held and plan to target different groups and organizations like service clubs and the local Chamber of Commerce (business customers).

ii. Community Energy Learning Series Presentations (February 2017)

Purpose: PUC identified a need through customer interactions, to address assistance needed to lower bills, understand bill charges, and the electricity industry and its operations. The PUC was involved with the SSM Innovation Centre, as its Energy Innovation Hub conducted by the Smart Energy Business Strategist who provided public presentations to increase "energy education" using industry facts/trends to reduce energy consumption through energy efficiency and conservation. The overall goal was to improve understanding of consumption habits, tips on lighting, air sealing, appliances, insulating, water heating, heating and cooling, windows and alternative energy technologies available such as solar panels. One presentation focused on understanding what goes into the cost of electricity**,** geared toward the general public and people who desire a greater understanding of what goes into their electricity bill while discussing both government and consumer forces impacting the cost of electricity. The other presentation focused on how to use less energy and save money since the residential cost of electricity has risen significantly in the past decade. Its goal was to teach homeowners and businesses how to save energy and money.

Initiated By: Sault Ste. Marie Innovation Centre, in association with the PUC

Participants: There were approximately 15 attendees.

Nature and Timing of Deliverables: The SSM Innovation Centre recognized that there was a need during the winter months to educate the public about conservation, alternative energy sources, and the electricity industry.

DSP-related: The DSP was not directly affected by this engagement opportunity, it does take into account the overall concern from customers about affordability by keeping the proposed rate increase as low as practical while focusing on necessary system renewal.

Future Considerations: We will continue to develop new partnership opportunities where these types of presentations can be delivered to the community. PUC will utilize advertising and promotions to assist with future events, as the sessions had low attendance.

iii. Neighbourhood Project Meetings

Purpose: In 2017, PUC held customer consultations in neighbourhoods affected by the system renewal projects. PUC engaged customers to discuss the overall program objectives, as well as logistics and possible impact to their property. The consultations were aimed to speak with customers about rear-lot pole replacement and underground conversion for pad-mount equipment location placement.

Initiated By: PUC

Participants: There were approximately 20 of customers spoken to.

Nature and Timing of Deliverables: PUC's objective was to inform and engage with customers through individual consultations before work began. The feedback was positive; the project was completed successfully and with customer involvement in the decision-making process.

DSP-related: The neighbourhood consultations confirm that the execution of projects was enhanced by including this form of customer engagement, and will be included in all future projects.

Future Considerations: PUC found that the one-on-one engagement not only led to a successful project but also improved the level of customer satisfaction from those impacted. We have identified future opportunities to incorporate these interactions on upcoming infrastructure renewal projects, like those mentioned in the DSP. PUC will need to restructure its engagement, and ensure that consultations occur with work planners, engineers, and eventually filter through a standardized engagement process involving customers.

iv. Focus Groups (2016 and 2017)

Purpose: Focus groups were conducted to promote the HEAR (Home Energy Assessment and Retrofit), CDM pilot program and obtain qualitative research data about the current perception of PUC and the Save on Energy program. The first focus group was geared to addressing the substantial amount of homes in Northern Ontario that utilize electric heat. The second focus group was conducted to help improve marketing communications for both residential and small business customers.

Initiated By: PUC, in partnership with the Customer First (group of LDC's)

Participants: 16 respondents, the group was mixed with residential and small business individuals. The customers involved in the focus groups use mostly electric heat in their homes and identified that as their main source of heating.

Nature and Timing of Deliverables: Customers state that utilizing electric heat as their main source of heating in Northern Ontario is costly, ranging anywhere from $100 to $500/per month. This pilot program offered residential home assessments and the installation of programmable thermostats, low flow shower heads, pipe wrap, and block timers.

DSP-related: The DSP was not directly affected by the focus groups.

Future Considerations: PUC has been approached by the local college to partner with their Public Relations and Event Management program to conduct future focus groups on a wide range of energy-related issues.

Focus Group Findings/Results:
The focus group results show that some PUC customers believe they are doing as much as possible to save energy; most commonly by switching light bulbs, using Time-Of-Use savings, and turning off or unplugging unused equipment/machinery. Some are utilizing technology, and interest in capabilities to do so is high with participants. Most thought that some of the large-scale efforts, such as renovations, may not be worth up-front costs vs. the length of time it would take to recoup as an investment.

The participant's overall impression is favourable towards the LDC being the preferred face of energy saving programs in comparison to the Government, whom they associate larger negative issues with Ontario's electrical system. Customers wanted to see relevant comparisons between older vs. newer high-efficiency appliances, before/after cost-savings, detailed usage based on specific electronic/appliance, testimonials from home/businesses that have utilized the program, technology that provides warnings for excessive usage and specific targets for each customer (E.g. Restaurant owners with fridges, coolers, stoves and apartments with refrigerators, air conditioners, etc.).

The CDM department at PUC provided a testimonial from a local automotive dealership that utilized an energy efficiency program to capitalize on lighting savings for its business. We have identified future opportunities that include a customer-focused survey in our COS Application to present opinions and feedback to the Ontario Energy Board; acting as a voice for the customer to the Government. Customers stated that PUC priorities should be: ensuring fair and competitive rates, enhancing quality and reliability of electricity services and ensuring the electrical infrastructure is maintained for future generations.

CUSTOMER ENGAGEMENT (Informal)

PUC's informal customer engagement program includes; industry-related events, community event partnerships, and awareness programs that allow PUC to connect with its customers. PUC utilizes these engagement opportunities to interact with customers, listening to their concerns, and maintaining a presence in the community it serves.

a. COMMUNITY EVENT PARTICIPATION

i. Retail Product Consultation Coupon Campaigns

Through the focus group, PUC customers mentioned that they are unsure what to change or upgrade in their home/business to increase energy efficiency. PUC's CDM team supports the retail product coupon and consultation campaign, where it works alongside local hardware and home supply stores, to promote energy efficient products, provide coupons to purchase those items and provide conservation tips. The customers were pleased with the amount of conservation knowledge received and small improvements such as changing their light bulbs that they could do.

ii. Bush plane Days Festival

This engagement opportunity supports the community's need for social responsibility and is scheduled in September, so we can allocate this time to speak with families about back-to-school consumption habits, new assistance programs available, and provide electrical safety tips to children. The Canadian Bushplane Heritage Centre draws thousands for its Annual Bushplane Days Festival. We provide information about power outages, line work, energy awareness, Caution and Chance for children, and offer giveaways such as TOU stickers.

iii. Rotary Fest Summer Festival

This customer outreach supports the community's need for corporate social responsibility, community sponsorship, and fostering the growth of community festivals. This event is scheduled in the summer with the Rotary Service Club, and we utilize this opportunity to promote children's electrical safety, program assistance for families, and sign-up people for available programs.

iv. Home and Trade Shows

The customer engagement during the Annual Home and Trade Show in our community promotes maintenance and sustainability for home and businesses. During this event, we are able to communicate with customers that may not visit or call PUC offices. This opportunity enables face-to-face communications in an intimate setting for people to ask questions and feel comfortable doing so. Most customers wanted information about rates, the cost of electricity, and how to save. PUC staff offer information about the Save on Energy/HEAR program, CDM initiatives, and explain the time-of-use, smart meter operations, online services such as Customer Connect, capital projects, and sign-up customers for save-on-energy programs when eligible.

v. Caution and Chance Electrical Safety Awareness Program



Safety is a top priority for PUC operations. Internally, PUC fosters a culture of safety across the entire organization and continues to support community awareness through safety campaigns such as "Give Our Workers a Brake" and "Call Before You Dig.". Since 1995, PUC has invested in the Caution and Chance Electrical Safety program. This educational program supports our organization's priority of safety, starting with children in elementary schools. These safety awareness presentations are conducted at local schools by our employees. We attribute, in part, our high score in the public safety awareness survey, (86%), to this investment and commitment to safety education and awareness.

vi. Chamber of Commerce Business Networking Events

The survey and focus group responses from business customers wanted more information to assist in lower costs and increasing energy efficiency. The CDM team provided business customer support, awareness and program eligibility to minimize costs. There was a breakfast event and presentations for small business incentive information, such as lighting, retro-fit programs and save on energy promotions. We have identified future opportunities that include increased involvement with Chamber of Commerce events to reach a broader business network, open discussion about business issues, and promote the Save on Energy brand.

COMMUNITY SUPPORT

PUC believes in sustaining a positive relationship with the community it serves, and social responsibility as an organization. The following engagement activities relate to PUC's charitable involvement in the community, as we take into account how important our customers feel about giving back to the community. Along with various event sponsorships, these are some of the charitable events that PUC is involved in:

a. The Sault Ste. Marie Downtown Association

PUC employees install banners year round on streetlights in the downtown sector. PUC is also a proud sponsor of the DTA outdoor street party festival event that includes live bands, music, food and beverage, and activities.

b. SSM Community Tree Lighting sponsorship

PUC employees attend the lighting of the community Christmas tree and sponsor the star in recognition of the energy savings, especially during the holidays

c. Sault Ste. Marie Christmas Lighting Awards Program

PUC co-sponsors this event that encourages community pride and recognizes the efforts of residents who light up their home/business for the Christmas season. Winners are awarded a plaque and a credit on their PUC bill.

d. The Lung Association Festival of Trees

PUC employees submit a decorated holiday tree with energy efficient products (thermostats, power bars, lighting, and a PUC electricity credit) in support of the Lung Association

e. SSM Santa Claus Parade

PUC employees decorate a line truck and volunteer for the annual local holiday tradition

f. Bon Soo Festival (event sponsorship)

PUC sponsors the area's largest winter carnival tradition, which has been around since 1964.

g. ARCH Hospice

The PUC Employee Association fundraised over $7,500 for ARCH through an annual golf tournament. The Association was formed in 1976 to look after the welfare of its colleagues, consists of 9 representatives from various departments across the utility, and has a current membership total of 148, out of 178 employees.

h. Christmas Safety Breakfast

This PUC employee event includes a donation of canned goods for the Local Sault Ste. Marie Food Bank.

i. United Way

From 2008 to 2016, **$301,222** has been raised by PUC employees, and Corporate has matched contributions.

j. LEAP program

PUC Distribution participates in the LEAP Emergency Financial Assistance Program, delivered by United Way - Community Assistance Trust. The funds provided by PUC to the United Way are used locally to provide grants to eligible low-income customers of PUC Distribution that qualify. Since 2012, we have donated over $130,000 to the program, supporting customers who have difficulty paying their electricity bills.

COMMUNICATION

Through customer interactions, engagement activities and community support initiatives, we have identified one of the most important customer needs is to keep our customers informed. Information about operational transparency, capital projects, bill changes, regulations, service improvements and what our company is doing to ensure we can provide safe, reliable, and efficient electrical service to the community. Community refers to those affected by decisions made by our organization, and also our stakeholders in a community-owned asset. PUC considers "Engagement" as a continuum of community involvement, moving towards greater community collaboration and evolving as a partnership.

As a proud community partner for the last 100 years, we maintain that we provide a safe, reliable, and efficient electrical distribution system to our service territory. It is our responsibility as a community-owned asset to deliver service, provide information, and continue to communicate with those affected by our

operations. Communication is a key element to share knowledge, inform of any changes, and develop a trusting relationship with our customers.

a. Communications and Community Engagement FTE (Full-time Employee)

PUC understands the need for improved communications with customers to ensure we are encouraging their feedback and growing as a customer-driven utility. PUC has established the role of a full-time, community engagement and communications employee, who was hired to focus on outreach in daily operations, both internal and external. The Supervisor of Customer Engagement was trained in public relations and has shown advocacy for customers when speaking to the media about concerns, and providing clarification on PUC operations that the public can understand. This pro-active and dedicated voice works alongside the management team, engineering, customer care and CDM to promote energy literacy, industry changes and transparency in PUC operations for customers.

This ensures that communication flows from PUC, to inform and educate customers through the various channels. The role encompasses community engagement through public speaking events, media releases, and escalated customer care issues. Most importantly, the position represents the centralized source for information and knowledge of operations to relay to media and the public. We have released information that speaks to a variety of operational issues, as well as industry changes. For example, Public Service Announcements about electrical safety, and media releases that provide knowledge about the Ontario Energy Board disconnect legislative changes.

b. Power Outages

Through customer interactions, PUC has recognized that our customers are concerned about response times, waiting for assistance during outages, and reliability.

i. The implementation and utilization of smart meter data provided an opportunity to leverage these assets for improvement. Today, we are able to utilize the AMI data to provide Outage and Restoration alerts to the Operations and Customer Care staff to efficiently dispatch crews in advance of the “wait until they call” approach. This helps to ensure that PUC is pro-active in delivering service. This also provides System Operators with a mapping view to help identify the precise area and feeders that are impacted for a direct response. We have identified future opportunities to enhance these systems that include the development of a mapping view for customer access.

ii. During an outage, customers would call in and become upset when they received a busy signal or long wait times, during an already stressful time. In response to these concerns, PUC upgraded the phone system to increase capabilities of handling more customer calls. This meant that customers would not have to hear a busy signal, and could be connected to a representative. Upgrading the system allowed for more calls to be handled with an expanded call sorting and queue capability to assist with managing customer calls. It also introduced an automated messaging service that can be customized to detail the current situation. “We are aware of the current power outage in the Queen Street area, and crews are currently on site working to restore power.”

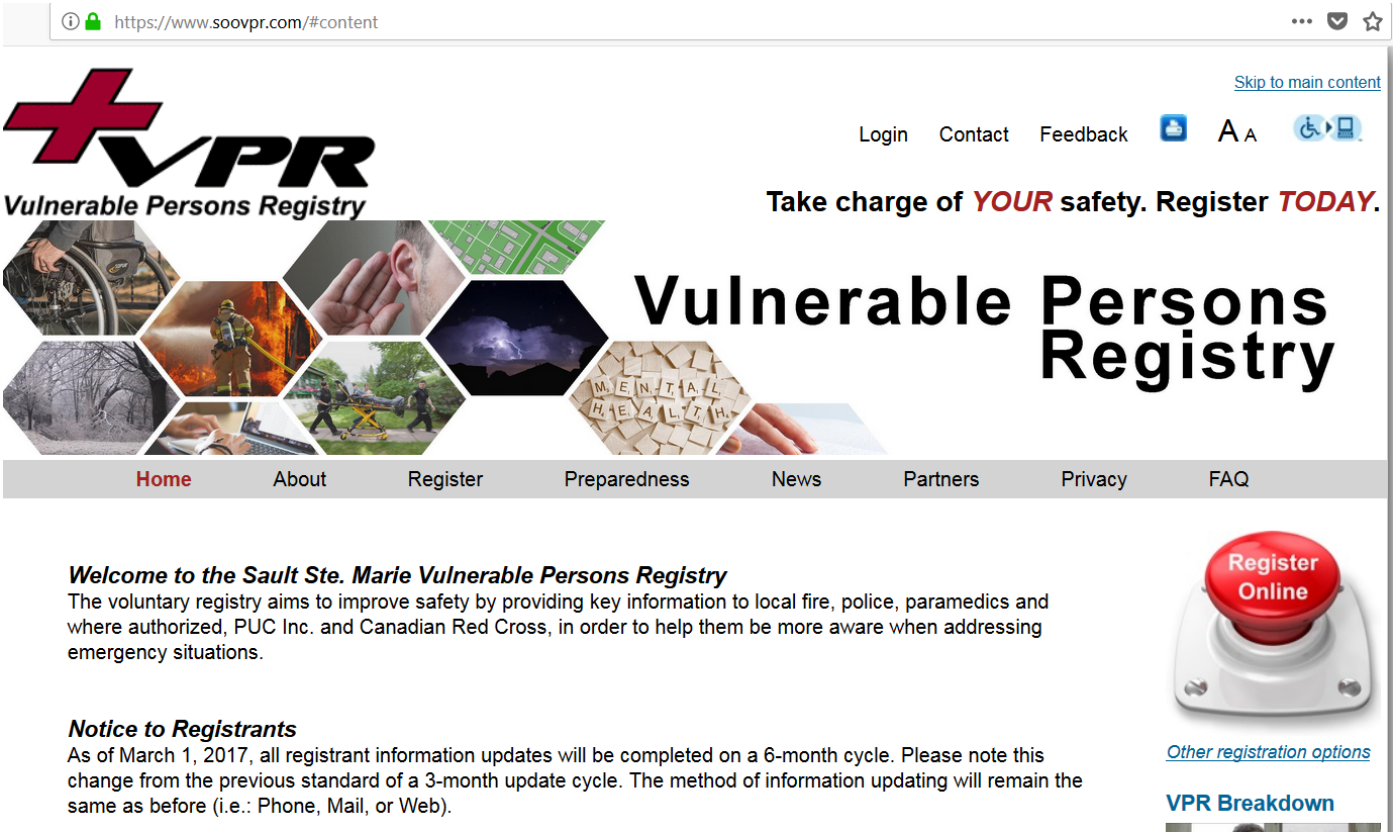
iii. While improvements were made to the emergency, unplanned outage notification system, customers expressed the desire for improvements to be made in PUC's planned outage notification process. PUC addressed these concerns by developing the Atlas Notification System. Implementing this new system required the planning and incorporation of three different components including a geographic mapping system, PUC's customer information database and an automated dialing system. The Atlas Notification System is three separate systems; a geographic information system (GIS), PUC's customer information database and an Interactive Voice Response system (auto-dialer). When work involving service interruption to customers is being planned, PUC staff will identify which area will be affected by the disruption. The electric meters in the identified area will be cross-referenced with the PUC customer database, and a call list will be compiled. That list will be used by the auto-dialer to notify affected customers

We have identified future opportunities that include the ability to increase notification through various devices, for example, text messages, or emails to alert customers of a power outage in their area. We would also like to include an option for communication with renters/multi-renters/apartment buildings with single meter so that those directly affected are contacted, and the onus does not fall directly on the landlord or building owner.

c. Vulnerable Person's Registry (VPR)

PUC services a community with an ageing mature demographic. With this in mind, PUC partnered with the Canadian Red Cross and the SSM Community Geomatics Centre for an innovative service for vulnerable persons. This significant customer-focused initiative utilizes the AMI outage information system to provide vital information to emergency responders. The cooperation of all three entities created a confidential database for "Vulnerable Person Registration" that links to PUC's GIS, providing an email alert to Operations and Customer Care staff whenever an outage impacts a VPR customer. If a VPR customer registers with this service, their status becomes a part of PUC's operational planning and response. This has proven to be of immense value during planned outages to look for additional options when practical for these customers and especially vital during emergency restoration. A standard operating procedure has been developed in cooperation with local emergency services that includes escalation criteria for weather conditions and duration, which allows PUC operations to contact first responders to provide VPR check-ins and support when required. This program can be used by first responders in localized emergency situations including but not limited to; extended power outages, Fire and 911 response, and boil water advisories. It sets a new standard of care, concern, and responsiveness for persons with disabilities who may experience emergencies in our community.

www.soovpr.com



d. Website

Through our community engagement activities, Customer Care department interactions, as well as the 2017 Utility Pulse survey results noting that "83% of customers access the internet for information," PUC has recognized the need for online services. Over the last few years, PUC has invested in a variety of online initiatives to improve communication with customers, based on an increase in online usage and the advantages of self-serve options, like reviewing usage online. Our commitment to serving customers includes providing access to information, 24/7/365.

We strive to improve our online presence through website enhancements that improve the overall customer experience, making it user-friendly, visually stimulating and encouraging customers to monitor usage. In 2013, comments received through customer interactions suggested a user-friendly website experience was needed. There was a need for improvement in the communication of outages and duration information. PUC updated the website with a refresh project which also included a customer-focused portal; Customer Connect. This refresh included improved outage notification, project awareness, tree trimming work areas, conservation awareness, and program initiatives for homes and businesses that were easily accessible.

We have identified future opportunities that include the development of an outage map/grid, specific page for system renewal projects (as included in capital investment projects detailed in DSP), social media links for conservation awareness promotions, and self-serve options such as opening, closing and relocating an account.

e. Social Media

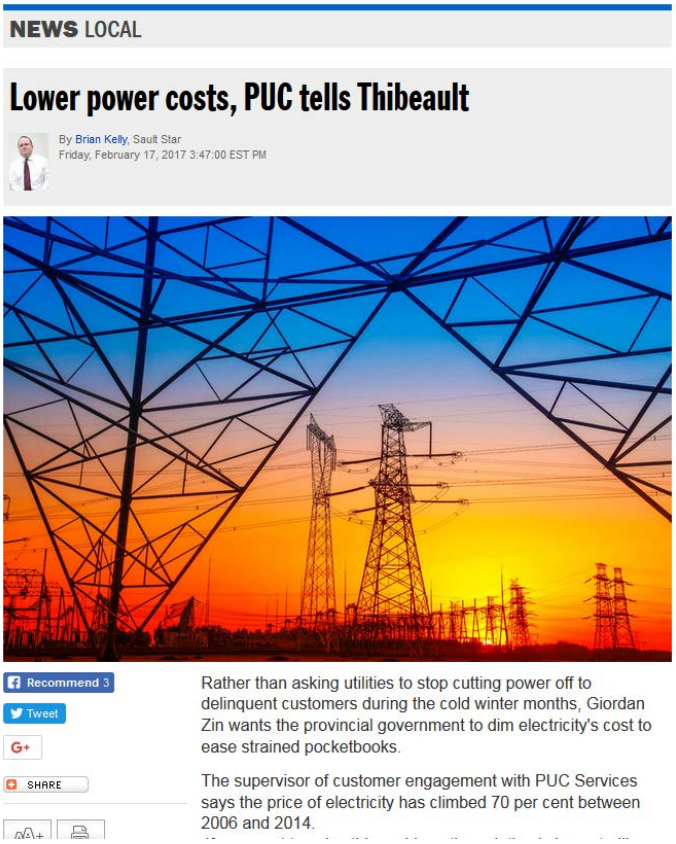
The introduction of Social Media accounts such as Facebook, in 2013 and Twitter in 2012 allowed PUC to communicate with a larger online audience and reach different target markets with messages about; worker safety, electrical shock and safety, home renovation/upgrades, energy-efficient products, electricity industry information, conservation tips, community engagement events such as retail product consults/coupon giveaways, and charitable fundraising.

f. Public Notices

Customers want a reliable electrical service, and through interactions have spoken to the inconvenience of outages. PUC ensures that any changes in service are communicated so that our customers are able to pre-plan beforehand. We provide advanced notification of planned projects and service modifications. These include, but are not limited to hand-delivered notices in the affected neighbourhood. We have identified future opportunities that include possible email notifications and text messages to serve as a convenient method for PUC to communicate any project information or service changes that may affect them.

g. Media Interviews/Press Releases

Our PUC Communications is tasked with continuously providing customers with information about changes that may affect their bill, projects, consumption rates, operations, regulations/legislation and current energy industry events. In order to ensure that information reaches all of our audiences, we utilize multiple media channels. This communication is supported through media relations within our community, such as media interviews and press releases. These interviews are arranged through the Department and include the CEO and the Supervisor of Communications/Community Engagement. Each interview is an opportunity for PUC to address and speak to issues affecting customers.



NEWS LOCAL

Lower power costs, PUC tells Thibeault

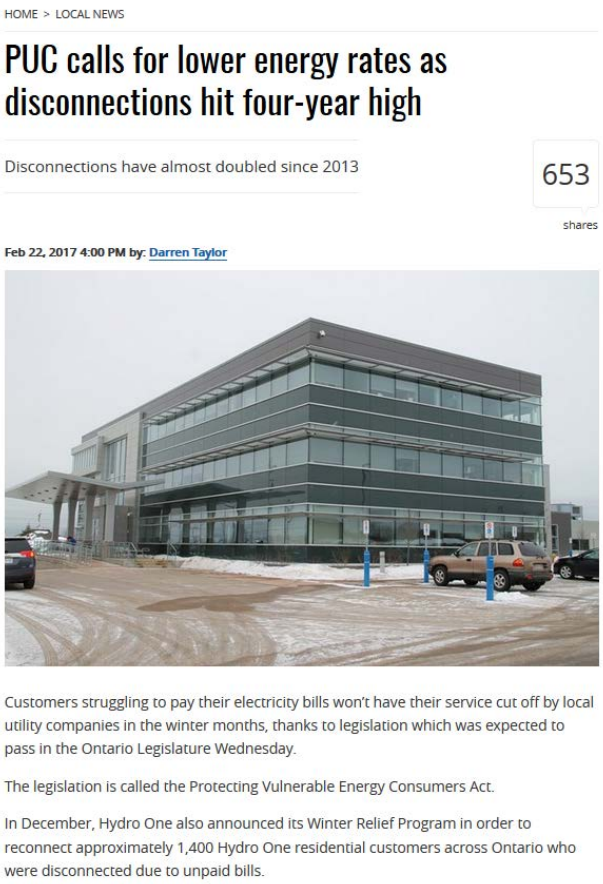
By Brian Kelly, Sault Star
Friday, February 17, 2017 3:47:00 EST PM

Recommend 3 Tweet G+ SHARE

Rather than asking utilities to stop cutting power off to delinquent customers during the cold winter months, Giordan Zin wants the provincial government to dim electricity's cost to ease strained pocketbooks.

The supervisor of customer engagement with PUC Services says the price of electricity has climbed 70 per cent between 2006 and 2014.

http://www.saultstar.com/2017/02/17/lower-power-costs-puc-tells-thibeault



HOME > LOCAL NEWS

PUC calls for lower energy rates as disconnections hit four-year high

Disconnections have almost doubled since 2013

653 shares

Feb 22, 2017 4:00 PM by: Darren Taylor

Customers struggling to pay their electricity bills won't have their service cut off by local utility companies in the winter months, thanks to legislation which was expected to pass in the Ontario Legislature Wednesday.

The legislation is called the Protecting Vulnerable Energy Consumers Act.

In December, Hydro One also announced its Winter Relief Program in order to reconnect approximately 1,400 Hydro One residential customers across Ontario who were disconnected due to unpaid bills.

https://www.sootoday.com/local-news/puc-calls-for-lower-energy-rates-as-disconnections-hit-four-year-high-543044

h. Advertising

To ensure we provide our customers with the most updated information, we support local advertising through a variety of outlets such as print, online, radio and television. The advertising campaigns promote our community brand as well as building awareness with conservation tips, PSA's (Public Service Announcements), Time-of-Use, tree trimming and worker safety to name a few. We ensure that there is a strategic alignment with our advertising campaigns that promote significant issues to our customers. For example, during December, we advise of high costs due to entertaining during the holidays, holiday lighting and TOU changes. We have identified future opportunities that include obtaining specific feedback from customers for communication outlet preference.

i. Bill Inserts

We include inserts for increased communication about provincial legislation, regulations, the Atlas program, services, changes, conservation program initiatives, etc. and it is a direct line of communication to the customers, as well as a record of information provided through paperwork. We have identified future opportunities that include adding this as a focus group initiative. This would allow us to understand how many customers find this method of communication efficient as well as the overall retention of information.

j. Paperless Billing (E-Billing)

This initiative was introduced based on customer feedback and the importance of reducing the environmental footprint and improving accessibility. Those registered will receive their monthly bill via email. Some customers have made comments about the availability of credit card payment. Based on the cost analysis in comparison to the number of customer requests received, covering those costs would be at a loss for the organization at this time. However, in the event of a collection situation where they need to pay with credit card, there is a fee that accompanies using that payment method and a third party that provides the availability of the credit card service. We have identified future opportunities that include a paperless billing campaign, introducing bill email reminders which have the customers' bill in a short breakdown so they can pay or log on to Customer Connect and review.

CUSTOMER CARE/CONTROL

Over the years, electricity costs have risen, and customer concerns have escalated as a result. Our challenge as a local utility is to encourage customers to curb their consumption habits and help them manage their electricity usage. PUC understands that each touchpoint with customers on the phone, website, social media, or in-person influences what customers think and feel about our organization. It is our responsibility to provide information to help customers understand how the system works, what costs are associated with operations, as well as lowering their electricity bill.

Over the last 3 years, PUC's Customer Service department has rebranded itself to Customer Care, with more focus on caring for the customer rather than just serving the customer. The website, inbound/outbound scripts, and templates have shifted to represent this value. PUC will continue to encourage its employees to see the value in every customer interaction, in order to enhance customer experiences, and overall public perception of the PUC.

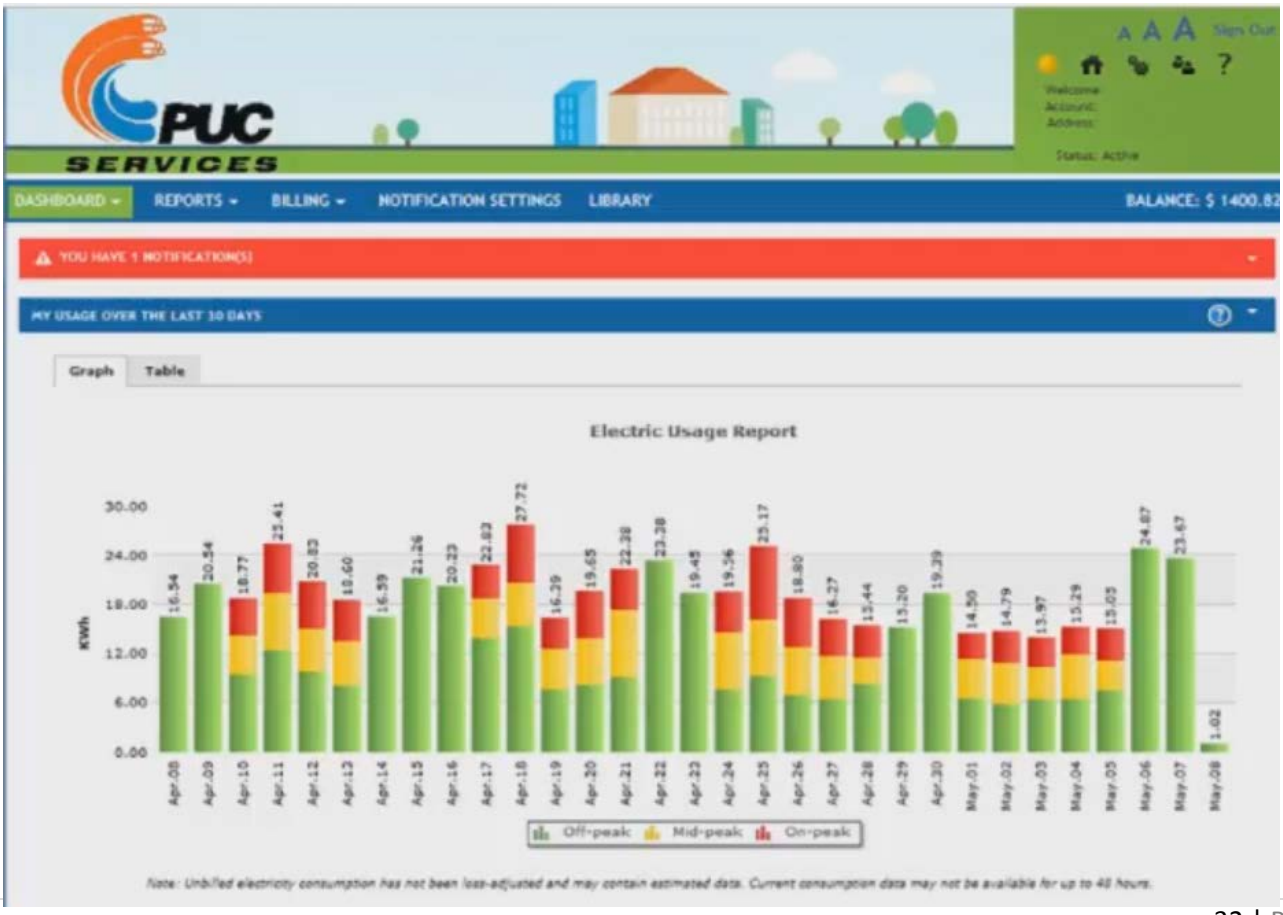
Our commitment to customer care goes beyond the Customer Care department; it involves the entire organization and includes our core value of responsiveness to our community. We are fortunate enough to have a local office where a customer can speak to an engineer about a technical question, a billing representative for their statement, a planner about upcoming neighbourhood projects, and even a forestry technician about tree trimming near their home or business, all in one place of business.

The top 3 customer issues we receive are; high bills, billing inquiries and moving of services. We often get questions about government initiatives as well, such as the 25% rebate. PUC recognizes that there is room for improvement. According to the 2017 Utility Pulse survey, “68% believe we adapt well to changes in customer expectations.” Customers want “their problem solved quickly, to have a personal interaction with a customer care representative and to speak with a knowledgeable and courteous customer care representative.” “73% said that PUC is customer-focused and treats customers as if they’re valued.” To improve our operations to support a customer-driven culture, we have invested in the following elements so customers can be reassured that we are here to serve them.

a. Customer Connect

PUC receives the most calls concerning the cost of electricity during the winter months when the weather is the coldest. The Customer Connect platform was designed to help those customers monitor their consumption, bill, and review historical data to stay informed about their energy usage. As of November 2017, 8,596 or 26% of customers are signed up for Customer Connect.

The Customer Care department also uses this tool directly with customers as a walk-through for understanding the bill, and specific charges on dates or times of high utilization. It allows for real-time access, to advise people of various spikes, TOU, and in-person, to add a visual representation of consumption, when a customer comes to the office. The customers can better understand once provided with the knowledge, and possibly change consumption habits if necessary, or realize why their bill charges were at the amounts listed. This element is critical to operations during the winter months in the North when the weather is coldest, and costs are highest.



b. Front Desk Support

PUC ensures that customer care is offered through face-to-face interaction, based on our population and ageing demographics. Customers are able to come to the administrative offices and go through their bill step-by-step with a Customer Care Representative. In a city with a mature demographic, this asset is becoming more vital to our operations as each day passes. PUC has the advantage of having local representatives that can speak to the same environment, especially during the cold winter months when everyone is trying to keep warm. When customers are experiencing difficulty, we offer a walk-in service. This helps us to ensure we take the extra time to better serve our customers' needs and help them with understanding industry and operational information. This element has worked efficiently with the Customer Connect online tool so that our representatives can provide a visual representation of what the electrical usage looks like with hourly, daily and weekly viewpoints. Although we offer this walk-in service, many customers would prefer online and self-serve options. We have identified future opportunities that include more online forms and email correspondence such as contracts, as currently, we request customers come into the office to sign a paper contract that is kept on file.

c. Customer Service Training

PUC decided to invest in customer care training for the entire organization in 2017 after a variety of customer interactions, and engagement opportunities reflected customers' negative perception of the utility. Our entire organization underwent CARE Training (Customers Are the Reason we Exist). This interactive training program encouraged customer-centred operations, customer loyalty, communication skills, resolving customer disputes and concerns as well as changing the overall attitude towards customers, understanding the vital role they have in our operations. This training was provided by the Simul Corporation, in mixed department group sessions and was well-received by staff. The training provided staff with up-to-date insights into customer satisfaction and what customers were saying about the utility. We have identified future opportunities which include annual investment in company-wide refresh training with the C.A.R.E. model to improve customer satisfaction and support the commitment to customer care being one of our top priorities.

d. Internal Training

Customers want to have knowledgeable, professional staff that can provide the most up-to-date information about the industry and changes that may affect them. PUC holds monthly staff meetings that include the latest industry and company information such as the winter disconnects, OEB backgrounders and any rate changes that may affect a customer's bill. Our Conservation (CDM) and Line departments provide the Customer Care, Billing and Metering departments with presentations to review upcoming program initiatives offered. The Line department provides the Customer Care department with presentations to help with terminology and understanding of the electrical distribution system. Additionally, our Customer Care department representatives shadow the Metering and Line departments in field operations so that they can experience firsthand, the exact equipment and processes that are used. This enables representatives to speak with customers if they are having trouble with affordability, understanding the electrical system, and any other technical questions that may require a broader field of experience to answer. Throughout the organization, our employees, from frontline to management, are encouraged to respond to escalated customer concerns and to assist with finding solutions. This reassures our customers that they are a priority.

e. Customer Information System (CIS) and MCare (Electronic Service Orders)

PUC received customer complaints that the metering service process did not work efficiently with the Customer Service Order paperwork, and ensuring reliability with meter reading times. Customer Care, Billing and Metering departments were receiving complaints about the meters being wrong, incorrect readings, billing issues, and overall dissatisfaction with the meter service. In conjunction with the Customer Connect upgrade, PUC decided to upgrade the Customer Information System from its existing "Harris" system to the "Northstar" system. This provided electronic metering service orders and real-time electronic communication with Meter department staff to improve services. This has improved communication and response times between the customer, Customer Care department, and the meter reading technicians.

CONCLUSION

PUC Distribution believes that its customers trust in its ability to make decisions to ensure a safe, reliable and efficient electrical service is delivered to their homes and businesses. Through various customer engagement opportunities, PUC has been able to implement customer-driven initiatives into our operations.

These activities include customer satisfaction and strategic planning surveys, focus groups, information sessions, residential and business awareness events, and innovative community partnerships to drive sustainable growth. We have supported customer-driven initiatives such as Customer Connect, the online usage platform, Atlas, the outage notification system,

As a local distribution company, PUC has developed and enhanced its customer engagement over the last five years. We understand that customers would rather not pay more for their electricity bills; however, the reality is that the ageing infrastructure in our community needs to be revitalized, in order to provide that reliability.

Each interaction with customers allows us to grow as a community-owned asset, and better align our operations with our customers' needs. As such, PUC will continue to search for new opportunities to engage customers and provide them access to more information about our activities, which will allow for an improved flow of communication.

EXHIBIT 1 – Cost of Service Survey Master Script

Introduction Page (text for screen, not verbally – LANDING PAGE)

Welcome,
Thank you for participating in PUC Distribution's Customer Engagement Survey.

We are applying to the Ontario Energy Board (OEB) for approval to increase PUC's portion of the electricity bill, also known as the delivery rate. If approved, a (750kWh) residential electricity bill would increase by approximately $2.17 per month.

The purpose of this survey is to give you a better understanding of the details behind our proposed rate increase, and to provide you with an opportunity to share your feedback.

The survey is broken down into a few sections. Most sections have a short video that provides a quick summary and are followed by a "YOUR SAY" segment. These segments provide you with the opportunity to share your thoughts.

Please keep in mind that all numbers are preliminary and may change prior to final submission as we consider customer feedback.

Your feedback will also be shared with the OEB, the independent energy regulator that ultimately approves the rate that PUC can charge on the bill.

Help us get to know you a little better!

1) What are the first three digits of your postal code?
   a. P6A
   b. P6B
   c. P6C
   d. Other (please specify)

2) What is your age?
   a. 18 to 34
   b. 35 to 54
   c. 55 to 74
   d. 75 +
   e. Prefer not to answer

3) Are you?
   a. Male
   b. Female
   c. Other
   d. Prefer not to answer

4) Which of the following best describes you?
   a. Homeowner
   b. Tenant (Renter)
   c. Landlord
   d. Business
   e. Other (Please specify)

5) Including yourself, how many people live in your household?
   a. 1
   b. 2
   c. 3
   d. 4
   e. 5+

6) Where do you live within PUC Distribution's service area?
   a. City of Sault Ste. Marie
   b. Prince Township
   c. Dennis Township
   d. Batchewana First Nation Rankin Reserve
   e. I reside outside of PUC's service territory
      (Please specify your location below)

7) If you are a PUC customer, what services do you currently receive from PUC?
   a. Electricity
   b. Electricity and Water
   c. I am not a PUC customer.

8) How satisfied are you with the overall service(s) you receive?
   a. Very satisfied
   b. Somewhat satisfied
   c. Neither satisfied or dissatisfied
   d. Somewhat dissatisfied
   e. Very dissatisfied
   f. Not applicable

   Please explain why you feel that way.

9) Which of the following is your **primary** source of heating?
   a. Electricity
   b. Natural Gas
   c. Propane
   d. Oil
   e. Wood
   f. I'm not sure
   g. Other (Please specify)

Please watch the following video before completing the questions below. Ensure your volume is on and turned up, so you can hear the information. Closed Captioning is available for those that need it.

INTRODUCTION - VIDEO 1

Hi, I'm Jordan and I'd like to thank you for participating in PUC Distribution's customer engagement survey. This survey is part of our Cost of Service application to the Ontario Energy Board. The Ontario Energy Board (or OEB) regulates the electricity industry in the province. This includes local distribution companies, or LDC's, like PUC.

The OEB's Cost of Service application occurs every five years and determines what each LDC can charge for its distribution rate. PUC is currently applying to the OEB for approval to increase the average residential electricity bill, by approximately $2.17 per month.

This short survey will guide you through our Cost of Service Application, and more importantly, get your feedback on it. We are looking for valuable information from you, our customer, to better understand your needs and how we can provide you with the best possible service.

YOUR SAY

10) Among the following PUC priorities, place what you think each is in order of importance. Using the scale 1 = Most Important and 5 = Least Important
    - Community Engagement/Communication
    - Providing more information during power outages
    - Maintaining reliable electrical service (e.g. prevent/reduce power outages)
    - Keep rates as low as practical while maintaining good quality electrical service
    - Helping customers reduce/manage consumption and by doing so reducing costs

11) Where do you currently find information on topics such as electricity rates, conservation tips, and consumption/usage information? Please select **ALL** that apply.
    a. Local Media
    b. Call, Email or In-person at the PUC Office
    c. PUC Website
    d. PUC Information Booths (Home/Trade Shows)
    e. Open Houses/Information Sessions
    f. Government of Ontario Website
    g. Ontario Energy Board Website
    h. Other (Please specify)

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

YOUR ELECTRICITY BILL – VIDEO 2

Let's start by taking a look at your electricity bill.
Did you know that every charge on your hydro bill is either mandated by the provincial government or regulated by the Ontario Energy Board?
Here is a breakdown of a PUC customer's 2017 electricity bill, using the Provincial average of 750kwh per month. The bill is made up of 5 components:

- Energy, which = 53% of the bill - this is the cost of the actual electricity you use. PUC does not keep this amount; instead, it's paid to provincial agencies.
- Distribution = 27% of the bill. This is PUC's portion; it covers the costs of the poles, wires and transformers that are used to deliver electricity.
- Transmission, which = 4%. This covers the cost of transmitting high voltage electricity from generation sites across the province, to our community. PUC does not keep this charge as it is paid to the transmission companies.
- Regulatory fees, which = 4% PUC does not keep this, as this fee must be paid to regulators
- and Taxes, which = 12%

You'll notice that the delivery line from your bill isn't on this chart, that's because the delivery charge is made up of both the distribution and transmission fees. As you can see, PUC's portion (or the distribution charge) is only about 27% of the total bill. This charge is the ONLY fee that PUC has any control over and the ONLY charge we keep - the remaining 73% of the bill is passed on to power generation companies, transmission companies, the provincial government and regulatory agencies.

This means, 27% of the electricity bill covers the total cost of operating our community's utility. Everything from financing capital projects, day-to-day operations, infrastructure replacement, and employee wages. To help put this in perspective; 27¢ from every dollar on the electricity bill covers the entire cost of operating PUC's electric utility.

YOUR SAY

12) Do you think the amount ($0.27 cents from each dollar on an average 750kWh residential bill), that PUC Distribution keeps for operating and maintaining safe, local electricity service is reasonable?
    a. Very Reasonable
    b. Somewhat Reasonable
    c. Neither Reasonable or Unreasonable
    d. Somewhat Unreasonable
    e. Very Unreasonable

    Please explain why you feel that way.

13) How familiar are you with the Time-Of-Use information about off-peak, on-peak and mid-peak usage rates?
    For example, holidays are off-peak and if the holiday is on a weekend then the following weekday is off-peak in lieu of.
    a. Very familiar
    b. Somewhat familiar
    c. Not very familiar
    d. Not at all familiar

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

ELECTRICAL DISTRIBUTION OVERVIEW – VIDEO 3

Did you know that PUC Distribution's service territory includes more than just the City of Sault Ste. Marie? It actually extends to parts of Prince and Dennis Townships and the Batchewana First Nation Rankin Reserve.

Before we get into what we need the rate increase for, let's talk about how electricity is delivered across PUC's service territory to your home or business.

We receive power from the provincial transmission grid at 115 thousand volts which supply our two transformer stations. Here we step-down the voltage to 34 thousand volts and transmit it to 14 neighbourhood distribution stations or substations. These substations further reduce power to 12 thousand volts or in some cases, 4 thousand volts. Power is then delivered to neighbourhoods through overhead or underground wires along the streets and roadways. The last step in the journey is the individual distribution transformers that lower the voltage one more time, before the electricity is used by you, the customer.

YOUR SAY

14) When you have an electrical service issue, what is your preferred method to contact PUC for assistance?
Please select **ALL** that apply.
    a. Email
    b. Phone
    c. Mail
    d. Social Media (e.g. Facebook, Twitter)
    e. Website
    f. In-Person
    g. Other (Please specify)

15) If you've ever contacted PUC about an electrical service issue, how satisfied were you with the customer care you received?
    a. Very satisfied
    b. Somewhat satisfied
    c. Neither satisfied nor dissatisfied
    d. Somewhat dissatisfied
    e. Very dissatisfied
    f. Not Applicable
    Please explain why you feel that way.

16) If you've ever had a PUC Field Representative visit your home or business concerning an electrical service issue (e.g. power outage, overhead or underground system work), how satisfied were you with the service level provided?
    a. Very satisfied
    b. Somewhat satisfied
    c. Neither satisfied nor dissatisfied
    d. Somewhat dissatisfied
    e. Very dissatisfied
    f. Not Applicable
    Please explain why you feel that way.

17) As we move forward, PUC Distribution would like to improve communications and engagement with our community. Of the following ideas, what would you prefer to see?
    a. Neighbourhood meetings in advance of planned projects
    b. PUC Open House (e.g. Tour PUC facilities and meet electricity professionals)
    c. Online Chat Portal (Connected to PUC website)
    d. Conservation Information Booths (e.g. Bushplane Days, RotaryFest)
    e. Other (Please specify)

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

PROPOSED RATE INCREASE – VIDEO 4

Now that we've reviewed the bill breakdown, let's take a look at our proposed rate increase.
Since 2013's application, our service revenue requirements have increased, by approximately $3.3 million, up from $18.8 million to $22.1 million. This is largely driven by increases in operation, maintenance, and administrative costs, as well as a number of infrastructure renewal projects.

While we understand the concerns around rising electricity costs, the unfortunate reality is, additional financial resources are needed for us to continue addressing our community's electrical distribution needs.

If the rate increase is approved, an average residential customer, using the Provincial average of 750 kWh a month, will see an approximate two dollar and seventeen cent increase on their monthly electricity bill. This represents a sixteen point five percent increase on the PUC portion of the bill or a two point one percent increase on the total electricity bill. And, for the duration of the following five-years – distribution rate increases would be held to less than the rate of inflation.

As mentioned earlier, this rate increase is largely driven by increased costs which we will be breaking down in the upcoming videos.

YOUR SAY

18) In order to improve our customer communication, please choose your **preferred** method for PUC to communicate with you.
    a. TV (e.g. CTV)
    b. Online (e.g. Sootoday)
    c. Print (e.g. Sault Star)
    d. Radio
    e. PUC Website
    f. Social Media
    g. Information Sessions
    h. Bill Inserts
    i. Email Blasts
    j. Other (Please specify)

19) To increase awareness of electricity usage, PUC offers an online energy usage tool called, Customer Connect. Have you ever used it to monitor your hourly, daily and weekly electrical usage?

    (If you would like more information about Customer Connect, please contact Customer Care at 705-759-6522)
    a. Yes, I find it useful to visually track usage.
    b. Yes, I've used it a few times.
    c. I don't have access to a computer.
    d. No, I'm not interested in online services.

20) Have you visited the PUC website for any of the following in the last 6 months? Please select **ALL** that apply.
    If not, please choose Not Applicable.
    a. Customer Connect
    b. Paperless Billing (E-Billing)
    c. Conservation Programs and Information
    d. Power Outage Inquiry
    e. Project Information Search (e.g. Overhead line work in your neighbourhood)
    f. Not Applicable
    g. Other (Please specify)

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

OPERATIONS, MAINTENANCE & ADMINISTRATION – VIDEO 5

In previous videos, we've talked about the 3.3 million dollar increase in our service revenue requirements. Approximately, 61% or 2 million dollars of this increase is driven by operational, maintenance and administrative costs. Here's a breakdown of those costs:

21 percent of the 2 million dollar increase is made up of new Regulatory Requirements.
These include things like:

- PCB chemical testing for overhead transformers, to ensure they are all PCB-free by 2025.
- New meter reading requirements for large general service customers.
- Newly mandated initiatives, like the Under Frequency Load Shedding program – which is designed to improve the reliability of the Provincial electricity grid.
- And finally, the hiring of an additional staff member to assist with growing OEB requirements – all contribute to the increased costs in Regulatory Requirements

10 percent of the increase covers the rising cost of utilities since our last application. This accounts for basic utilities for the transmission and distribution stations, and the administrative building and service center.

5 percent of the increase is a result of the growing cost of utilizing the Smart Meter Network, which include things like the automated meter-reading software fees.

Another 7 percent of the increase is needed to cover Bad Debt, which has grown, due to the rising number of customers unable to pay their electricity bill. This can be attributed to the combination of; the rising cost of electricity, the moratorium on winter disconnections, and the state of our local economy.

9 percent of the increase accounts for the growing costs of meeting Industry Regulations. For example, costs for things like; OEB Annual Assessments, Cost of Service Applications, and mandated Customer Engagement Programs have all grown since 2012.

7 percent of the increase covers the cost to operate our Vegetation Management or Tree Trimming program. While, PUC has extended this program to a four-year cycle to reduce costs annually, costs fluctuate based on the total area needing to be cleared, and the number of contractors bidding on that year's cycle.

The remaining 41% of the increase in service revenue requirements is driven largely by inflationary growth in things like; employee wages, benefits, contracted services, insurance costs, and fuel expenses.

YOUR SAY

21) Now that you're familiar with the rising costs associated with our operational, maintenance, and administrative needs. Do you feel you have a better understanding of the proposed rate increase, to cover those costs?
    a. Yes
    b. No
    c. I Need More Information
    d. No Opinion
    Please explain why you feel that way.

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

CAPITAL INVESTMENT PROJECTS – VIDEO 6

As mentioned, operations, maintenance and administrative expenses account for two-thirds of the total service revenue requirement increase. The remainder is driven by Capital Investments in infrastructure renewal. Let's explore some of the infrastructure renewal projects PUC has planned for the next few years.

Probably, the most visible components of the electrical distribution system are the overhead lines and poles. PUC has about 621 km of overhead lines using about twelve thousand, seven hundred poles. Of those, approximately 102 poles have been in service for more than 60 years. Over the next five years, our plan is to replace approximately 150 poles, identified as being in poor or very poor condition.

Additionally, some of the older overhead lines in our system were constructed with a type of copper wire, which no longer meets reliability and safety standards. Our proposed plan would see those lines replaced within the next ten years.

The underground electrical distribution system is comprised of approximately 122 kms of cable, 30 kms of which are approaching the end of their service life. Additionally, underground infrastructure like switches, concrete vaults, and submersible transformers are also a priority for replacement based on their condition. Our plan will continue addressing this aging infrastructure, and focus on neighbourhoods with high equipment failure rates.

Substations are a critical part of any electrical system, as they supply entire neighbourhoods with power. A single substation can provide enough power for 2,000 homes. Replacing a sub-station costs approximately three point five million dollars and takes about two years to complete.

It's important to note that the average service life for a transformer is 40 years so special attention needs to be paid to those located within our substations, as 66% of station transformers have been in service longer than 35 years. With that in mind, we plan on replacing two substations by 2022.

Locally, our substations transform electricity from 34 thousand volts to twelve or four thousand volts. Over the last few years, PUC has been converting the four thousand volt system to a twelve thousand volt system. This is because the four thousand volt system is at, or very near, the end of its service life.

PUC is proposing a replacement plan that will completely retire the 4 thousand volt system by 2022; including poles, wires and transformers and replace it with the more efficient and reliable 12 thousand volt system.

YOUR SAY

22) The long-term plan that includes operational and maintenance costs, asset renewal and replacements to ensure reliability and system performance will include a monthly bill price increase.

Which statement best represents your point of view?

a. I would be willing to pay an additional $5-7 on my bill to invest as much as possible into the reliability of the system.
b. I would be willing to pay an additional $3-5 on my bill to invest in operations, and improve the system as quickly as possible.
c. I would be willing to pay an additional $1-3 on my bill if reliability improves through gradual infrastructure renewal.
d. I am NOT willing to pay any additional charges on the PUC portion of my bill knowing that the level of reliability could decline.

Please explain why you feel that way.

23) Now that you're familiar with some of the planned projects, what do you think of the proposed rate increase to support infrastructure investment?
    a. The rate increase should be higher to support an increase in infrastructure investment.
    b. The rate increase proposed is reasonable and I support it.
    c. I don't like it but understand the increase is necessary.
    d. The rate increase is unreasonable and I oppose it.
    e. No opinion

    Please explain why you feel that way.

24) Are you satisfied with the amount of information we provided you in this survey to understand the reasons behind the proposed rate increase?
    a. Yes
    b. No
    c. I Need More Information

    Please explain why you feel that way.

Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate.

POWER OUTAGES AND SYSTEM RELIABILITY – VIDEO 7

Power outages are an unfortunate reality in the electricity industry. That said, at PUC we work very hard to keep outages to a minimum and if required, as short as possible.

One of the annual industry measurements for system reliability is the System Average Interruption Duration Index, or SAIDI. This is measured by the average number of hours the power to a customer is interrupted. In 2016, the total time the average customer was without power was 90 minutes. This is below our target of 112 minutes, per year.

The other annual industry measurement is the System Average Interruption Frequency Index, or SAIFI. This is measured by the average number of times the power to a customer is interrupted.
In 2016, the total number of times the average customer experienced an interruption was 1.4 times. This is well below the target of 2.3 interruptions per year.

As you can see, PUC's reliability metrics are trending in a positive direction. We attribute these results to our ongoing commitment to improving system reliability through infrastructure renewal and a successful vegetation management program, better known as tree trimming.

PUC knows that reliability is important to customers, and that's why we plan to increase our investment in infrastructure renewal to improve system reliability. This will ensure we continue to provide a safe, reliable and efficient electrical system for the community we serve.

YOUR SAY

25) In the past year, how many power outages have you experienced?
    a. None (0)
    b. One or Two (1 or 2)
    c. Two or Three (2 or 3)
    d. More than Three (3 +)

26) What was the longest power outage you had in the past year?
    a. Less than 30 minutes
    b. 30 – 60 minutes
    c. 1 – 1.5 hours
    d. More than 1.5 hours

27) Did you contact PUC about the power outage?
    a. Yes
    b. No
    c. I can't remember

28) If you contacted PUC about a power outage, how satisfied were you with the way PUC responded to the outage?
    a. Very satisfied
    b. Somewhat satisfied
    c. Neither satisfied or dissatisfied
    d. Somewhat dissatisfied
    e. Very dissatisfied
    f. Not Applicable

    Please explain why you feel that way.

29) On average a PUC customer loses power due to outages for less than 90 minutes over the year. Do you feel this level of reliability is?
    a. Very good
    b. Good
    c. Poor
    d. Very poor
    e. No opinion

    Please explain why you feel that way.

Final Thoughts (text for screen, not verbally)

YOUR SAY

30) Is there anything in particular that PUC Distribution can do to improve its electricity service for you?

31) Outstanding Questions – Do you have any further **questions, concerns you would like to share?**

Thank you for your time, we know how valuable it is and we appreciate your feedback and input.

Click on the link below to enter for a chance to win one (1) of five (5) credits of $100.00 (One hundred Canadian dollars), towards your PUC bill.

MUST be a PUC customer (residential or business) at the time of the draw.

Limit one (1) entry per household.

Please note that survey responses are NOT associated with your draw entry information.

https://www.surveymonkey.com/r/WIN100PUCCREDIT

Thank you!

PUC Distribution Inc. Customer Engagement Survey Contest

Official Contest Rules

The Customer Engagement Survey contest is sponsored and administered by PUC Services Inc. ("PUC") on behalf of PUC Distribution Inc. The contest begins on January, 9, 2018 at 11:00 a.m. E.S.T. and ends on February 11, 2018 at 11:59 E.S.T. By participating, entrants agree to be bound by these contest rules and the decisions of PUC, which are binding and final, without right of appeal, on all matters relating to this Contest. Contest is subject to all applicable federal, provincial and local laws. Void where prohibited by law. **NO PURCHASE IS NECESSARY**.

Eligibility

- Must be a PUC customer (residential or business) at the time of the draw.
- Must be 18 years of age or older.
- Limit one (1) entry per household.
- All Contest entries must be submitted by February 11, 2018 at 11:59 E.S.T. to be eligible to win.
- By entering this contest, all participants are deemed to have accepted the Contest Rules.
- Must not be an employee, representative, agent or Board member of PUC Services Inc., PUC Distribution Inc., or any of its affiliates.
- Must correctly answer a skill-testing question on the contest entry page.
  (2x4) + (100/5)

How to Enter

During the contest period, participants may enter the contest once by completing the PUC Distribution Customer Engagement Survey. Once participants have completed the survey, there will be a Survey Draw Link to click on that will redirect participants to the contest entry page where participants will fill in and complete the requested information. Participants must also correctly answer a skill-testing question on the contest entry page in order to be eligible to win. Participants are allowed only one entry to the contest. Multiple entries from the same participant or from the same household will void all of such participant's or participants' entries.

Prizes

There are five (5), $100 bill credit grand prizes, to be randomly drawn on February 12, 2018 at 9:00 a.m. E.S.T., after the Contest Period has ended. The total approximate value of all prizes is $500.00. The Prize will be applied directly to the winner's next PUC electricity bill and will appear as a line item on their bill. PUC will notify the winner when the credit has been applied. The prize must be accepted as is, has no cash value and is non-transferable. Winners must attend PUC head office located at 500 Second Line East, Sault Ste. Marie, Ontario and show proof of identification, along with their account number, to claim their prize. The $100 credit will be applied to the winner's next PUC bill.

Odds of Winning

The odds of winning a prize depends on the total number of eligible entries received during the contest period.

How to Win

There will be a random drawing for each of the five (5) grand prizes conducted by PUC at the following date, time and location: February 12, 2018 at 9:00 a.m. EST at PUC Head Office located at 500 Second Line East, Sault Ste. Marie, Ontario. Five Entrants will be selected from all eligible entries received. The selected Entrants must also provide proof of identity (driver's license or other government issued photo identification). Failure to provide such proof of identity shall disqualify the selected Entrant.

Notification

Selected Entrants will be notified by telephone using the phone number provided in the Contest entry form. If a participant is identified as a selected Entrant then such selected Entrant must respond to claim the prize within ten (10) business days. A prize will be forfeited if it goes unclaimed for ten (10) business days, from the date a phone call is made. In the event the prize is not claimed within the allotted time period or the selected Entrant is disqualified or the prize is otherwise forfeited, PUC will re-draw and choose a new selected Entrant randomly from all remaining entries until a winner is declared. PUC shall have no liability if the winner notification is lost, intercepted or not received by a selected Entrant

Use of Information

All personal information collected herein will be used only for the administration of determining the eligibility for the contest draw in accordance with the requirements of Municipal Freedom of Information and Protection of Privacy Act (MFIPPA). By participating in this Contest, Contest winners are deemed to have consented to the disclosure of their names and photos, without compensation, being included in any publicity carried out by PUC. Each participant consents to the collection, use and disclosure of his/her personal information for the purposes of this Contest and grants permission for PUC to disclose personal information to its related and affiliated companies, contractors and agents to assist in the Contest.

Limitation of Liability

PUC assumes no responsibility for late, lost, incomplete, incorrect, delayed or misdirected entries or for any failure of any website, for any problems or technical malfunction of any computer online systems, servers, access providers, computer equipment, software, failure of any e-mail or entry to be received by PUC on account of technical problems or traffic congestion on the Internet or at any website, or any combination thereof, including any injury or damage to a participant's or any other person's computer, mobile device or other electronic device related to or resulting from this Contest. In the event the Contest is compromised by a virus, non-authorized human intervention, tampering or other causes beyond reasonable control of PUC which corrupts or impairs the administration, security, fairness or proper operation of the Contest, PUC reserves the right in its sole discretion to suspend, modify or terminate the Contest.

General Conditions

Participants agree, by participating, (I) to be bound by the terms of these Contest Rules and the decisions of PUC, which are final and binding, without right of appeal, on all matters relating to this Contest; and (ii) to indemnify, release and hold harmless PUC and its parent companies, affiliates, subsidiaries, officers, directors, agents, representatives and employees from any liability, for any injuries, losses or damages of any kind, including death, to persons, or property resulting in whole or in part, directly or indirectly, from participation in this Contest or acceptance, misuse, non-use or use of any Prize. By accepting a Prize, winners release PUC from any and all liability, loss or damage incurred with respect to the awarding, receipt, or possession of any prize, and acknowledge that PUC is not responsible in any way for any issues in connection with the prizes awarded or any losses, damages, or claims relating to the Contest. Any and all issues, questions, disputes, claims and causes of action arising out of this contest or any prize award shall be resolved in accordance with the laws of the Province of Ontario.

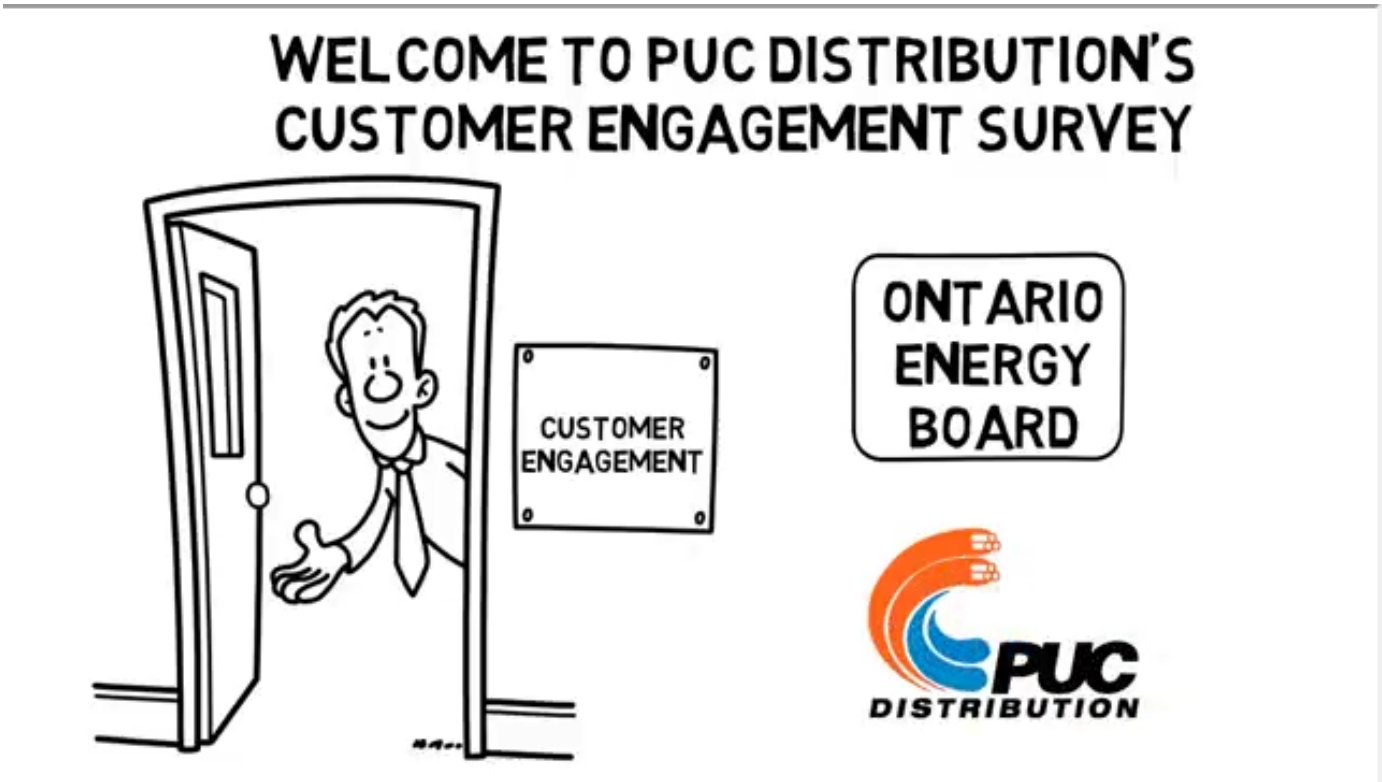
If there are any questions or concerns about the contest rules and regulations, please contact: customer.care@ssmpuc.com or 705-759-6522, Monday – Friday, 9:00 a.m. E.S.T. to 4:30 p.m. E.S.T.

EXHIBIT 2 – COST OF SERVICE SURVEY STORYBOARD

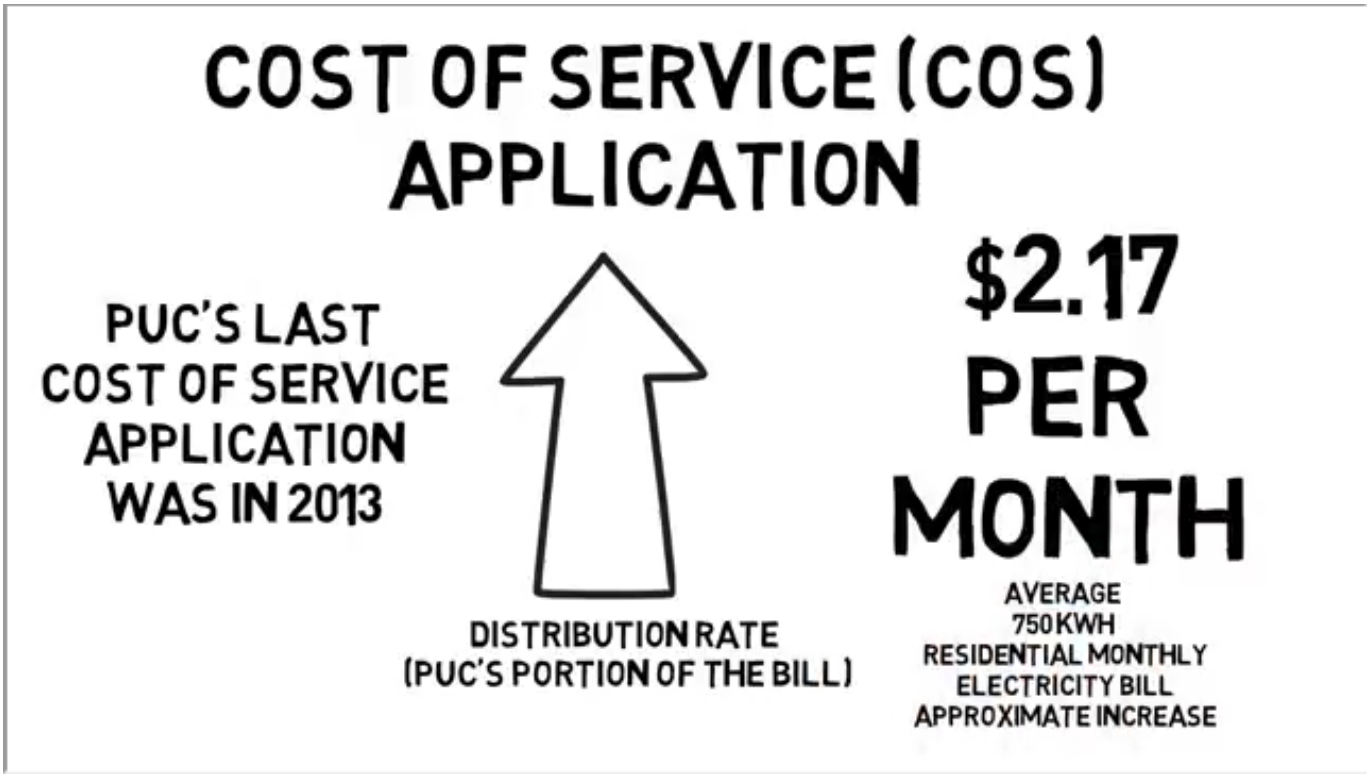
EXHIBIT 2 – COST OF SERVICE SURVEY STORYBOARD

INTRODUCTION - VIDEO 1

Hi, I'm Jordan and I'd like to thank you for participating in PUC Distribution's customer engagement survey. This survey is part of our Cost of Service application to the Ontario Energy Board. The Ontario Energy Board (or OEB) regulates the electricity industry in the province. This includes local distribution companies, or LDC's, like PUC.



The OEB's Cost of Service application occurs every five years and determines what each LDC can charge for its distribution rate. PUC is currently applying to the OEB for approval to increase the average residential electricity bill, by approximately $2.17 per month.



This short survey will guide you through our Cost of Service Application, and more importantly, get your feedback on it.

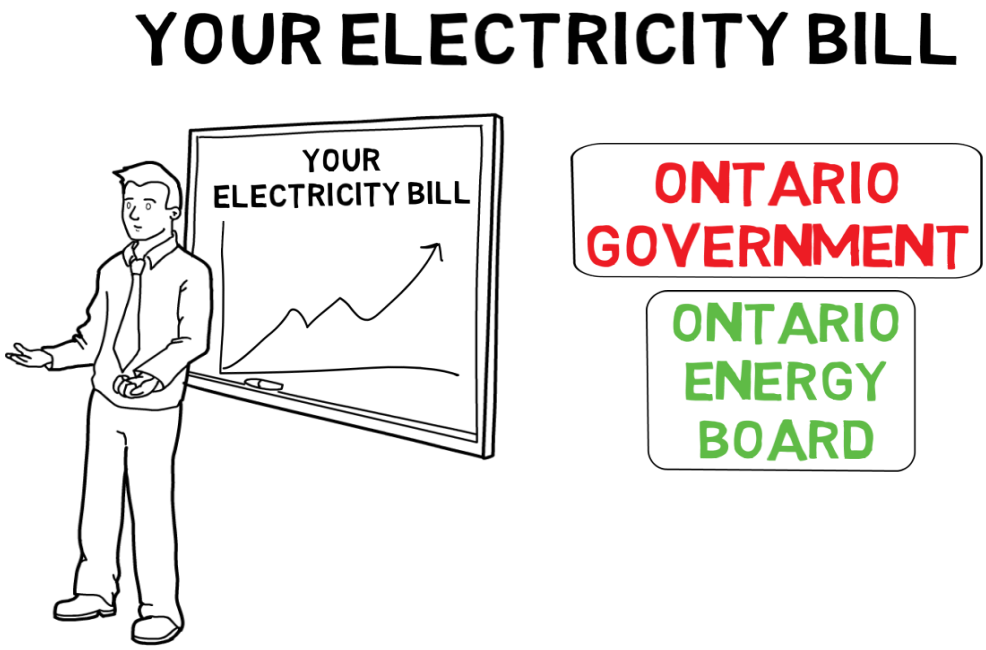


We are looking for valuable information from you, our customer, to better understand your needs and how we can provide you with the best possible service.



YOUR ELECTRICITY BILL - VIDEO 2

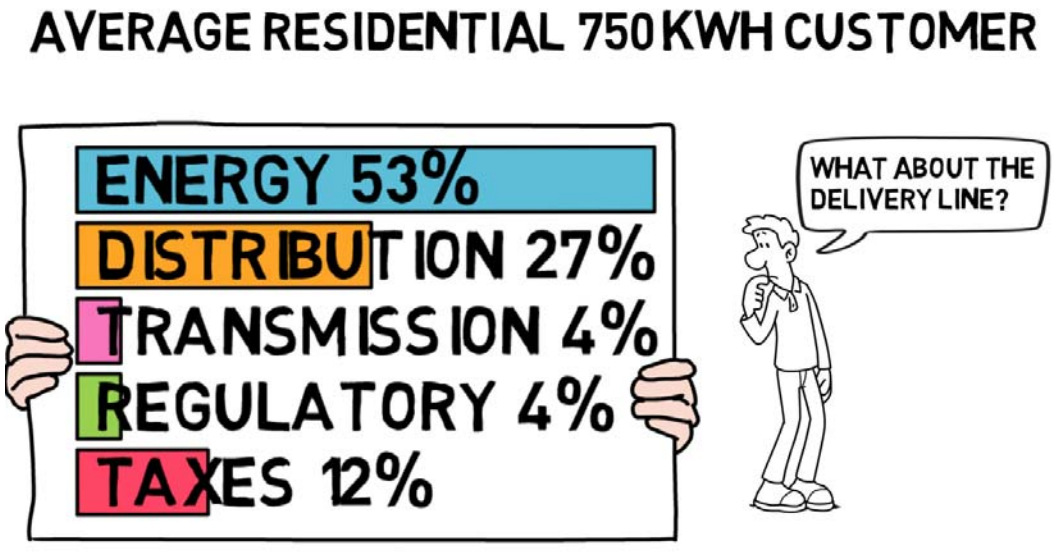
Let's start by taking a look at your electricity bill.
Did you know that every charge on your hydro bill is either mandated by the provincial government or regulated by the Ontario Energy Board?



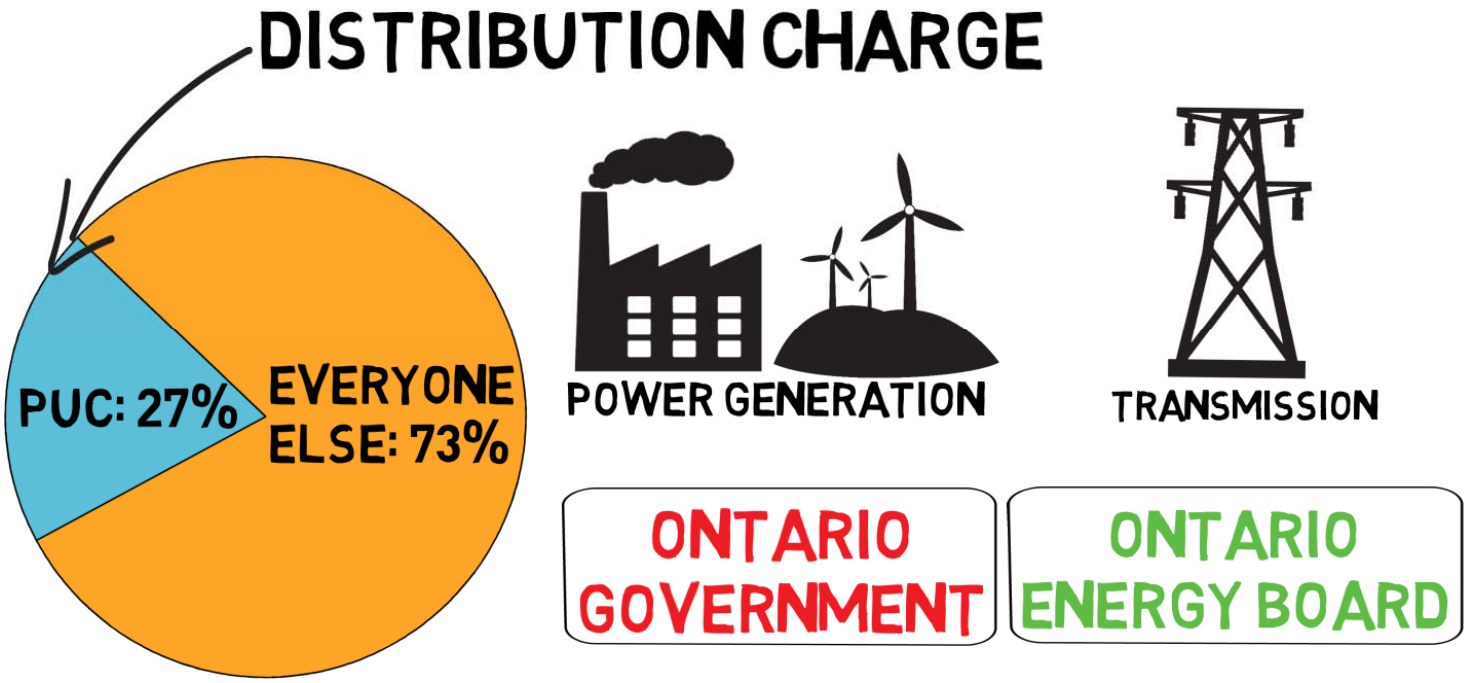
Here is a breakdown of a PUC customer's 2017 electricity bill, using the Provincial average of 750kwh per month. The bill is made up of 5 components: Energy, which = 53% of the bill - this is the cost of the actual electricity you use. PUC does not keep this amount; instead, it's paid to provincial agencies.

Distribution = 27% of the bill. This is PUC's portion; it covers the costs of the poles, wires and transformers that are used to deliver electricity. Transmission, which = 4%. This covers the cost of transmitting high voltage electricity from generation sites across the province, to our community. PUC does not keep this charge as it is paid to the transmission companies. Regulatory fees, which = 4% PUC does not keep this, as this fee must be paid to regulators. and Taxes, which = 12%.

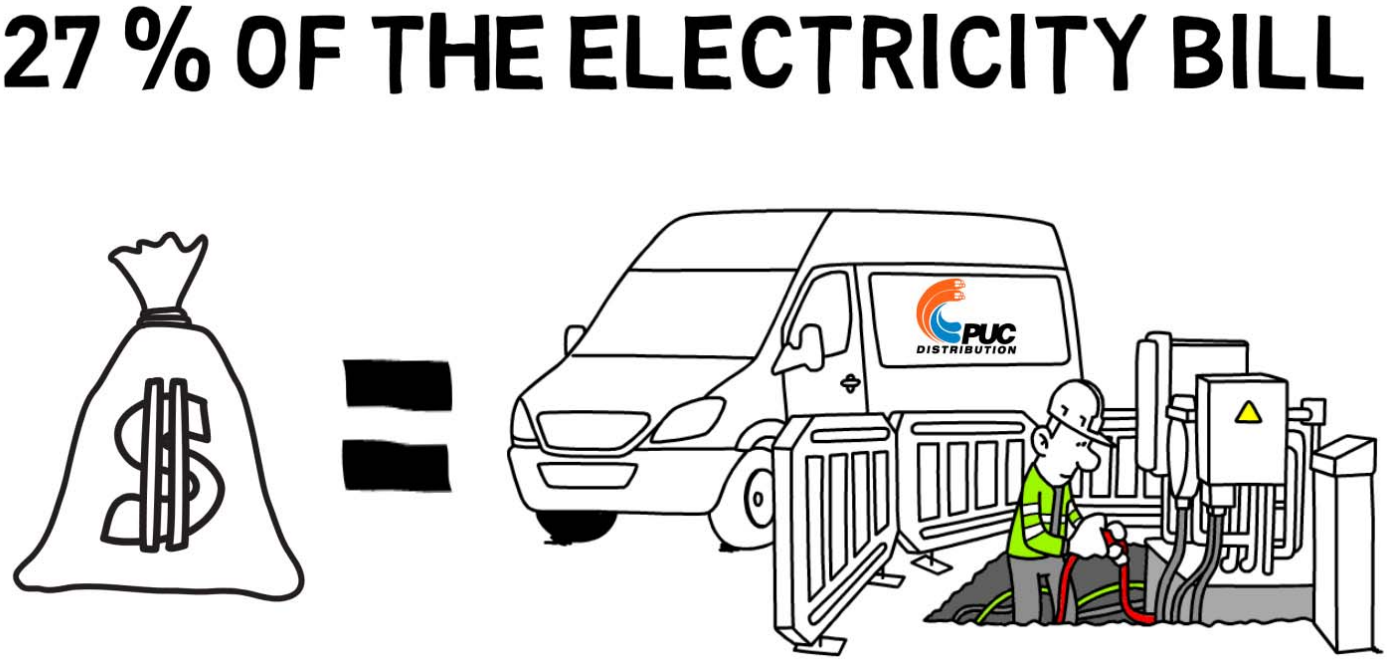
You'll notice that the delivery line from your bill isn't on this chart, that's because the delivery charge is made up of both the distribution and transmission fees .



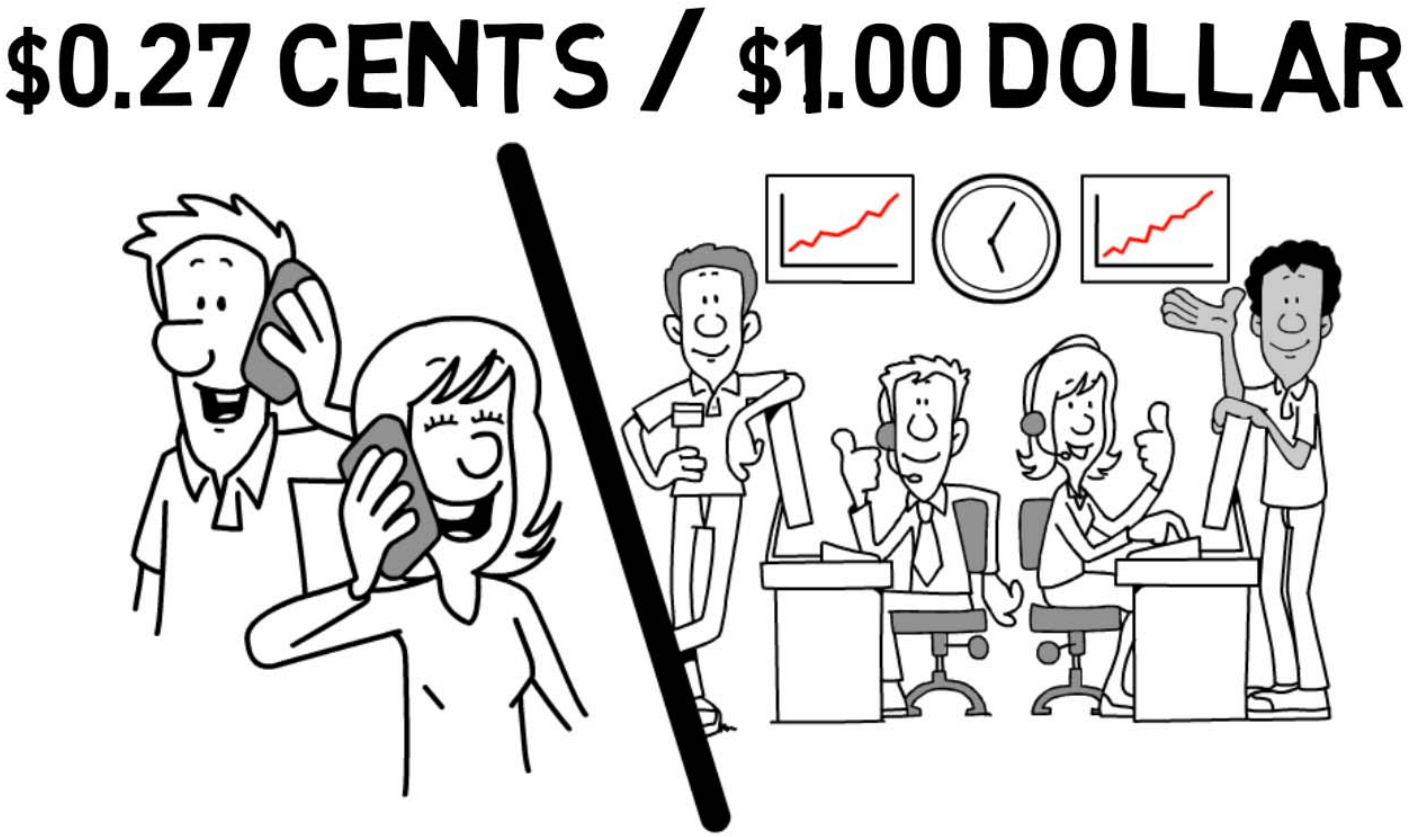
As you can see, PUC's portion (or the distribution charge) is only about 27% of the total bill. This charge is the ONLY fee that PUC has any control over and the ONLY charge we keep - the remaining 73% of the bill is passed on to power generation companies, transmission companies, the provincial government and regulatory agencies.



This means, 27% of the electricity bill covers the total cost of operating our community's utility. Everything from financing capital projects, day-to-day operations, infrastructure replacement, and employee wages.

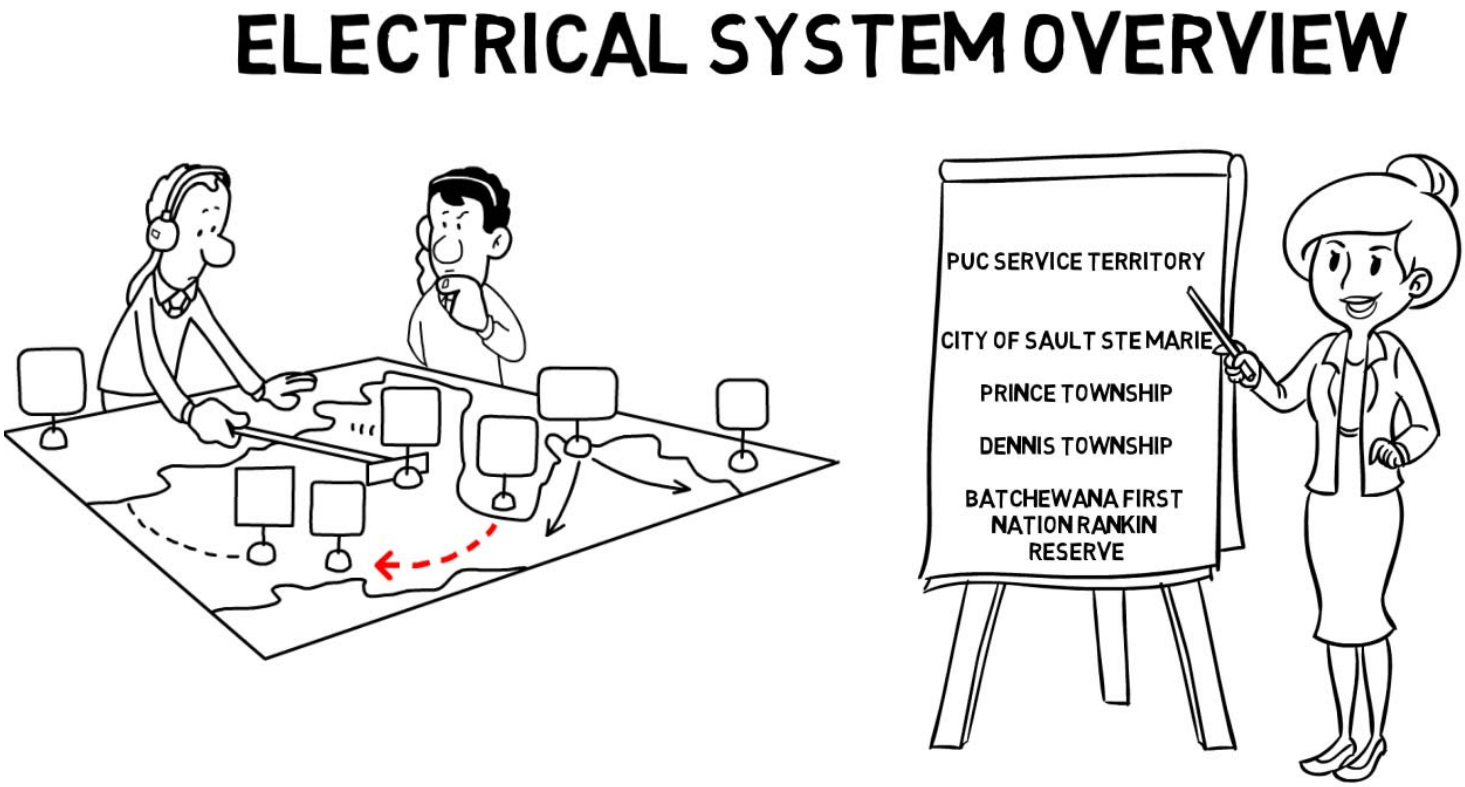


To help put this in perspective; 27¢ from every dollar on the electricity bill covers the entire cost of operating PUC's electric utility.



ELECTRICAL DISTRIBUTION OVERVIEW - VIDEO 3

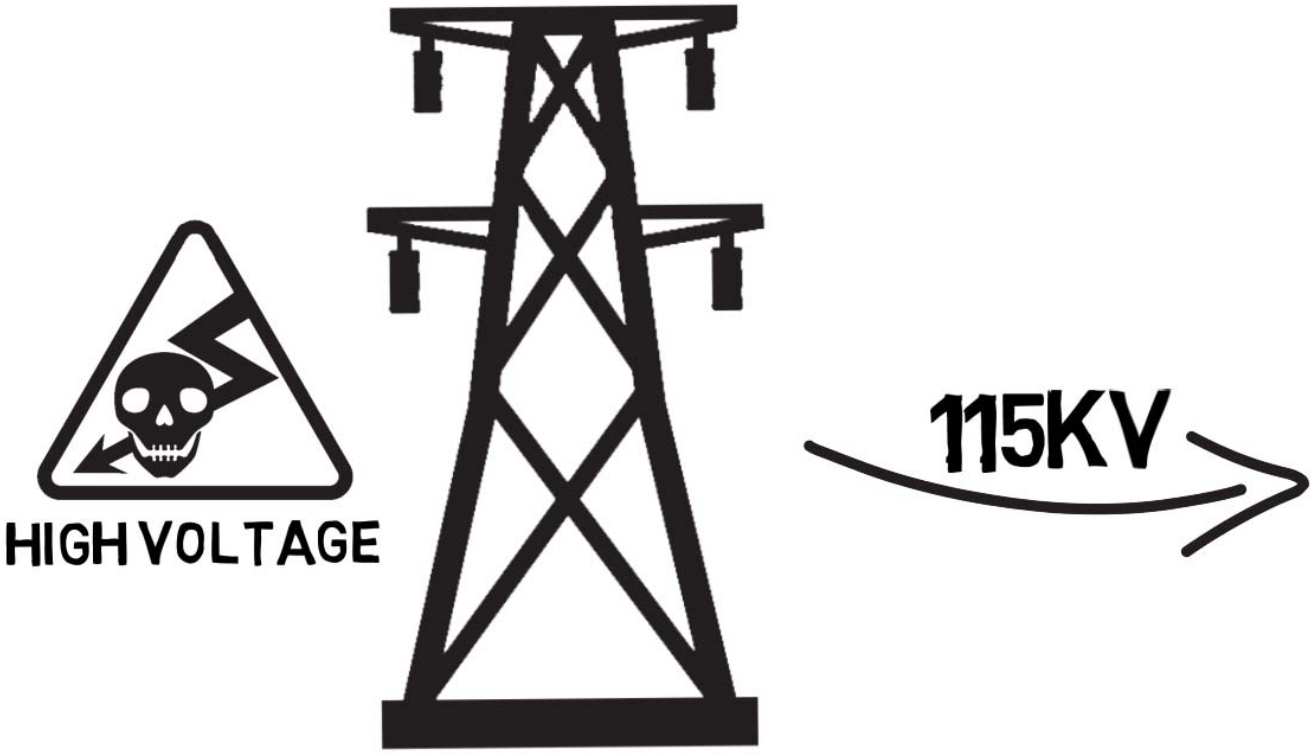
Did you know that PUC Distribution's service territory includes more than just the City of Sault Ste. Marie? It actually extends to parts of Prince and Dennis Townships and the Batchewana First Nation Rankin Reserve.

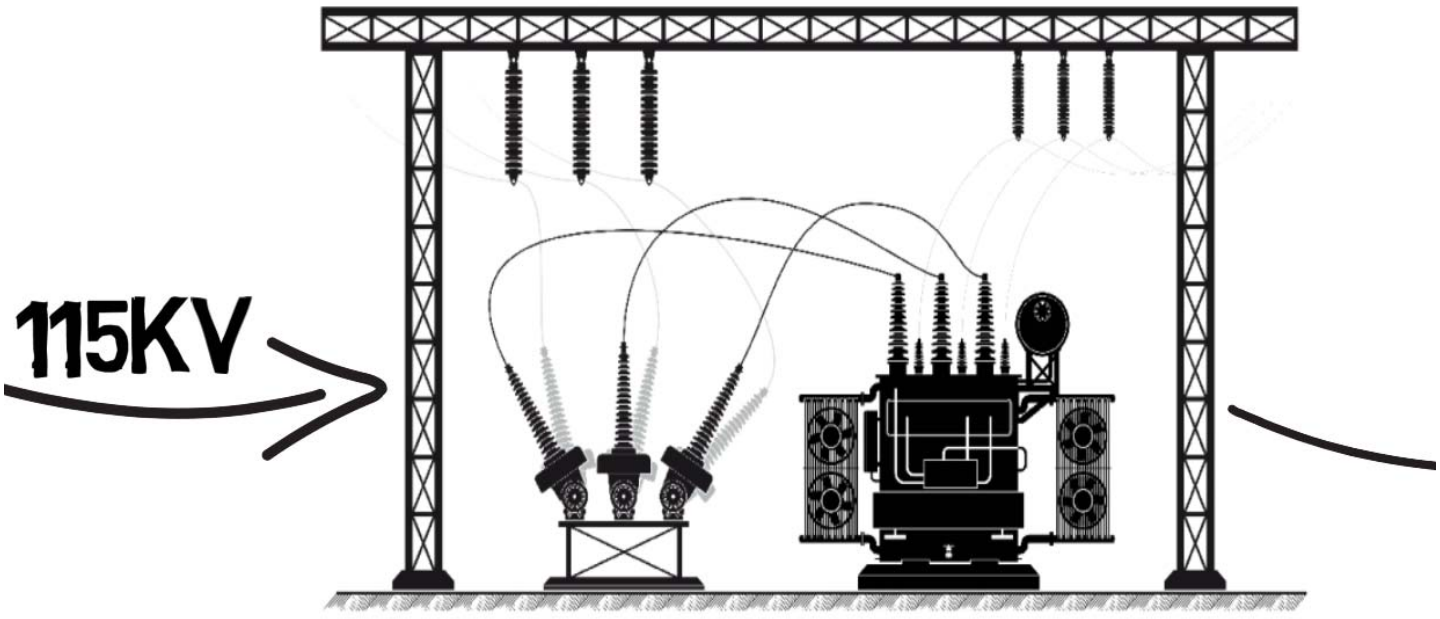


Before we get into what we need the rate increase for, let's talk about how electricity is delivered across PUC's service territory to your home or business.



We receive power from the provincial transmission grid at 115 thousand volts, which supply our two transformer stations.





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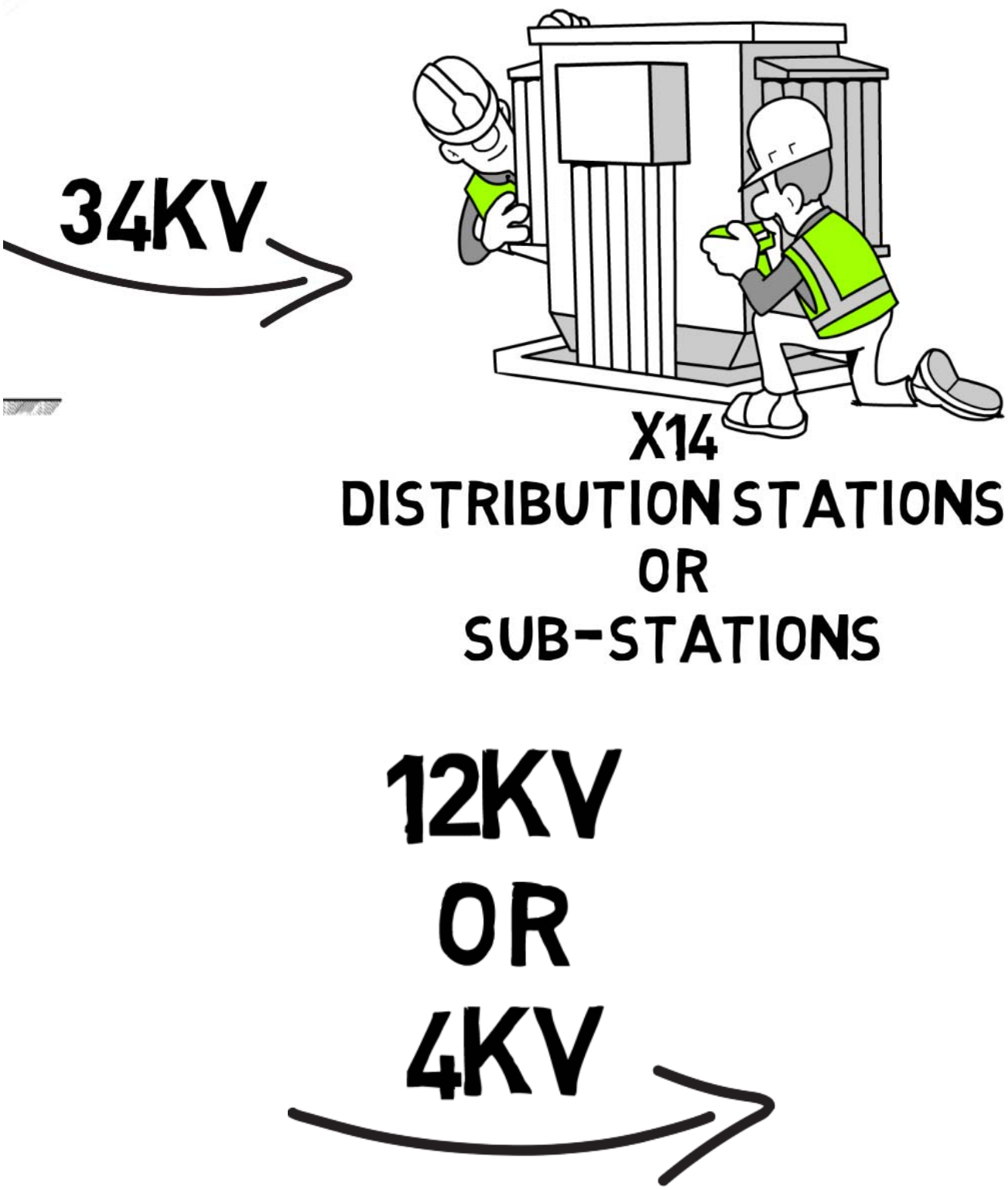
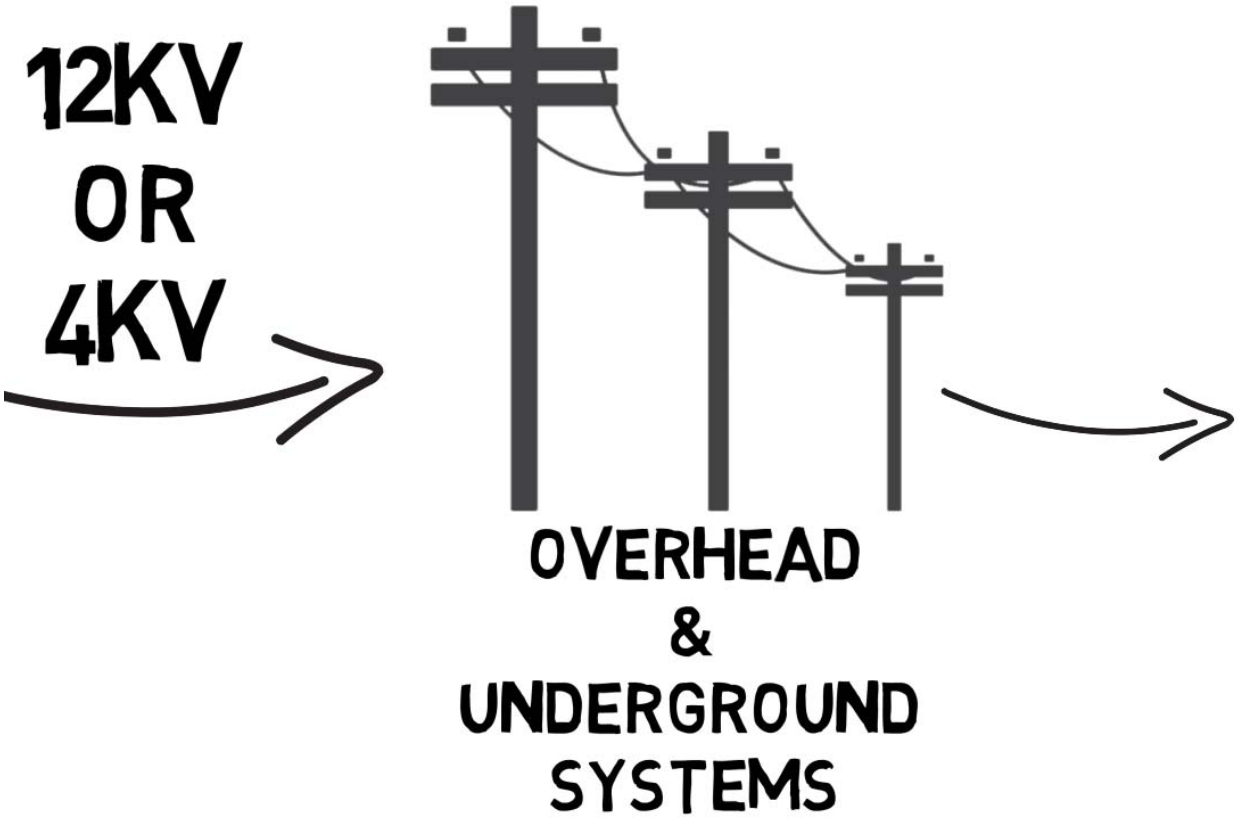
TRANSFORMER STATIONS

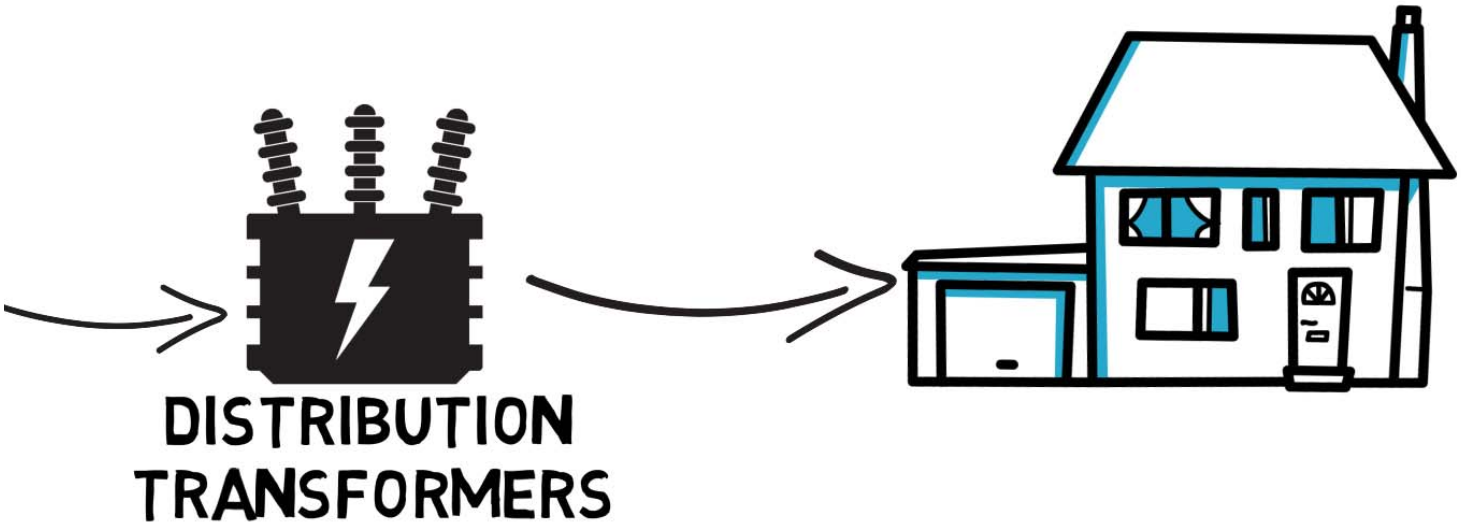
Here we step-down the voltage to 34 thousand volts and transmit it to 14 neighbourhood distribution stations or substations. These substations further reduce power to 12 thousand volts or in some cases, 4 thousand volts.



Power is then delivered to neighbourhoods through overhead or underground wires along the streets and roadways.

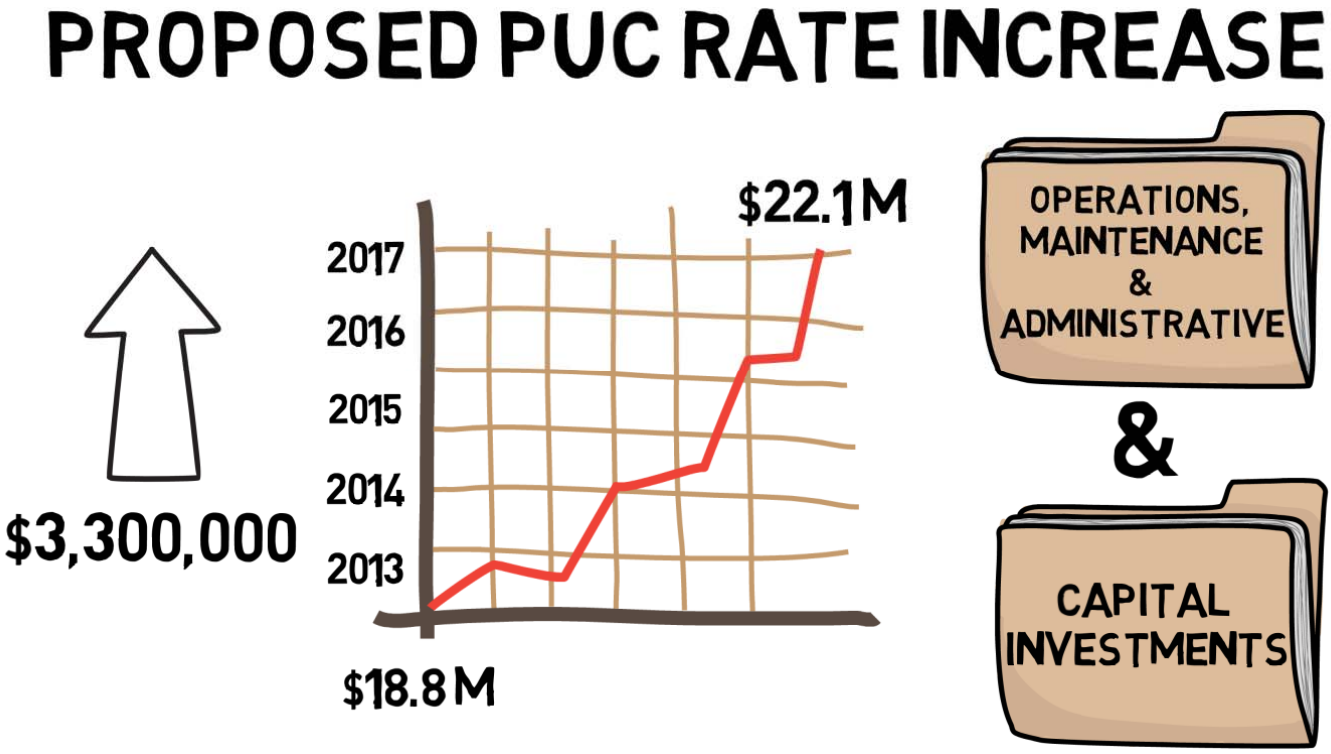


The last step in the journey is the individual distribution transformers that lower the voltage one more time, before the electricity is used by you, the customer.

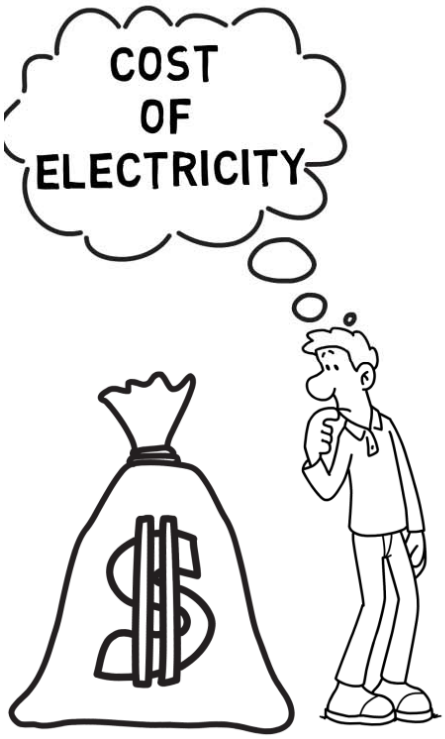


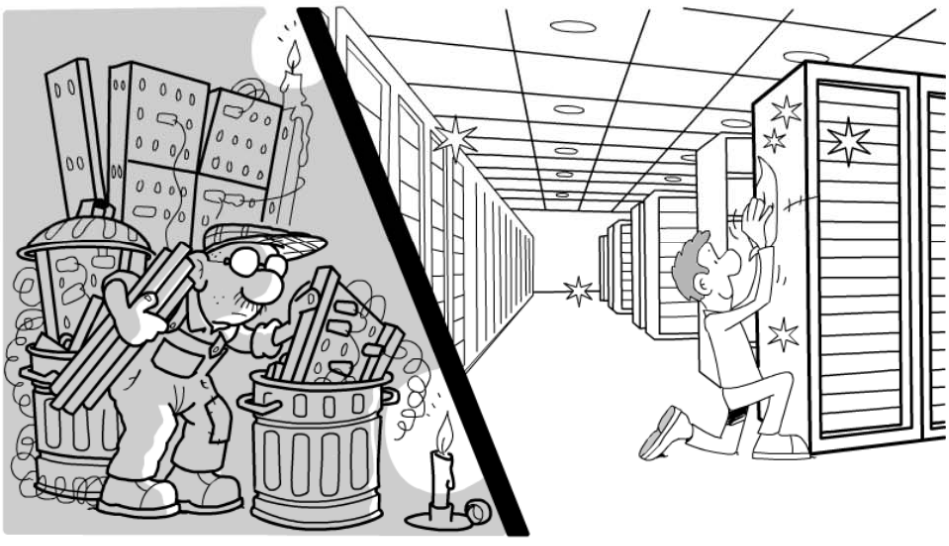
PROPOSED RATE INCREASE - VIDEO 4

Now that we've reviewed the bill breakdown, let's take a look at our proposed rate increase. Since 2013's application, our service revenue requirements have increased, by approximately $3.3 million, up from $18.8 million to $22.1 million. This is largely driven by increases in operation, maintenance, and administrative costs, as well as a number of infrastructure renewal projects.



While we understand the concerns around rising electricity costs, the unfortunate reality is, additional financial resources are needed for us to continue addressing our community's electrical distribution needs.





If the rate increase is approved, an average residential customer, using the Provincial average of 750 kWh a month, will see an approximate two dollar and seventeen cent increase on their monthly electricity bill.



This represents a sixteen point five percent increase on the PUC portion of the bill or a two point one percent increase on the total electricity bill.

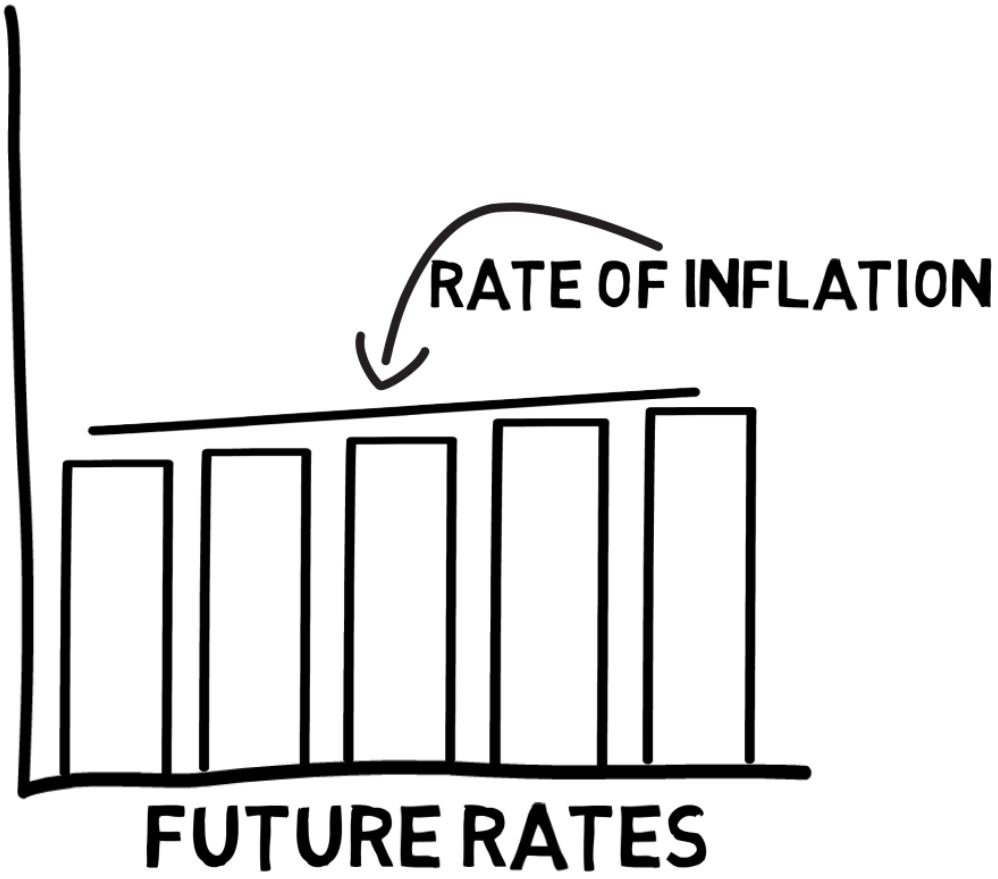
16.5%

PUC PORTION OF THE ELECTRICITY BILL

2.1%

TOTAL ELECTRICITY BILL

And, for the duration of the following five-years – distribution rate increases would be held to less than the rate of inflation.

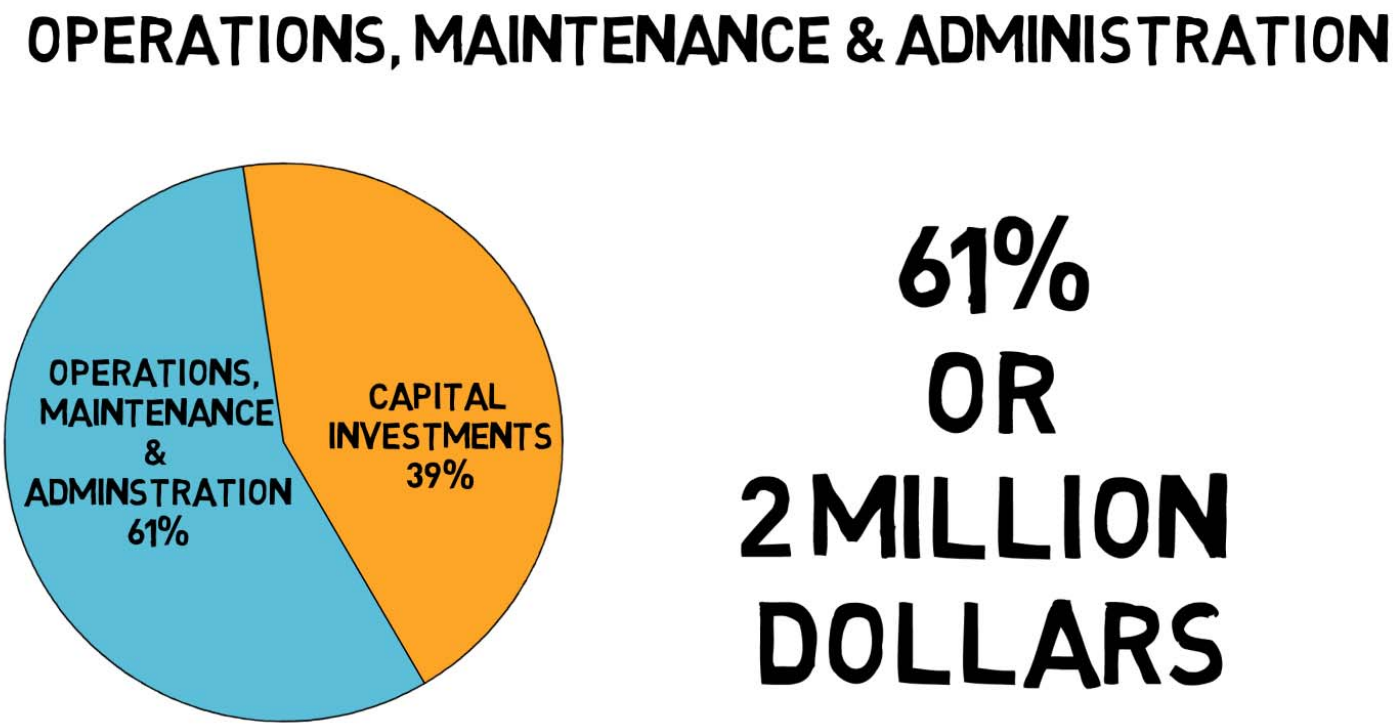


As mentioned earlier, this rate increase is largely driven by increased costs which we will be breaking down in the upcoming videos.

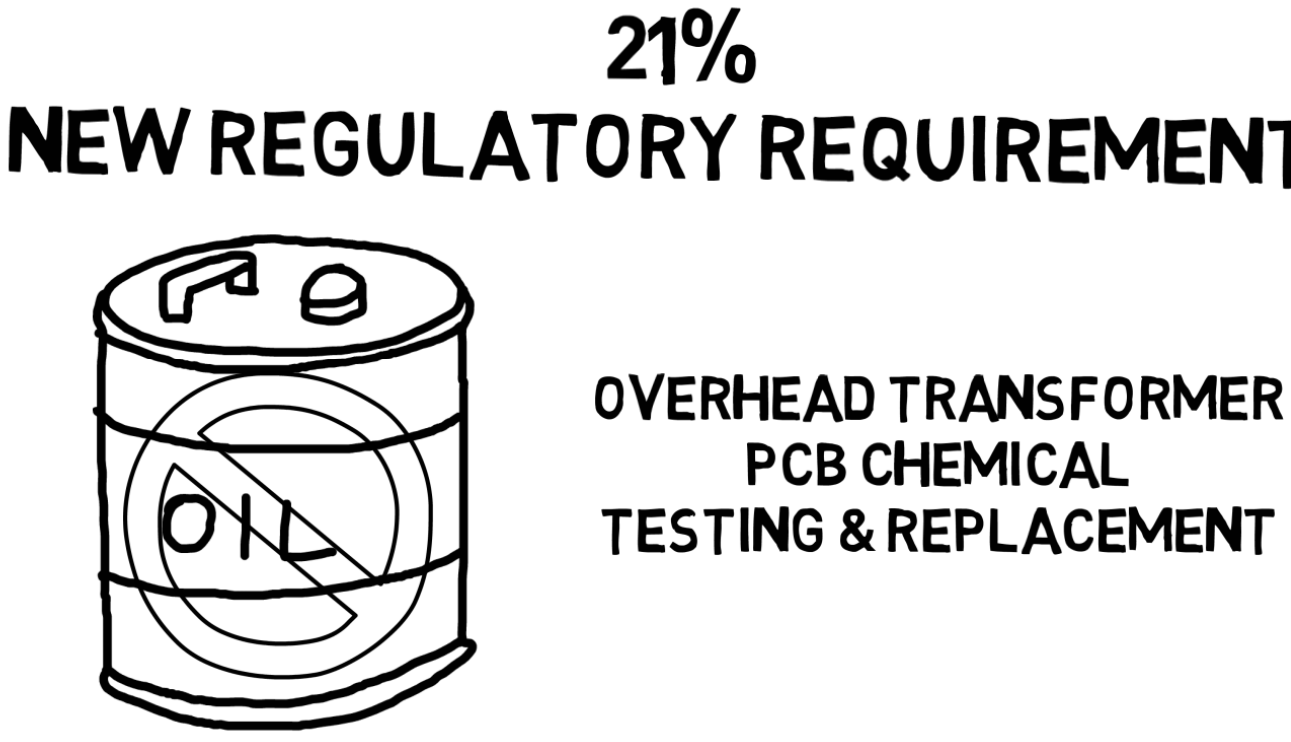


OPERATIONS, MAINTENANCE & ADMINISTRATION – VIDEO 5

In previous videos, we've talked about the 3.3 million dollar increase in our service revenue requirements. Approximately, 61% or 2 million dollars of this increase is driven by operational, maintenance and administrative costs. Here's a breakdown of those costs:



21 percent of the 2 million dollar increase is made up of new Regulatory Requirements.
These include things like: PCB chemical testing for overhead transformers, to ensure they are all PCB-free by 2025.



New meter reading requirements for large general service customers.

21%
NEW REGULATORY REQUIREMENTS (CONT'D)

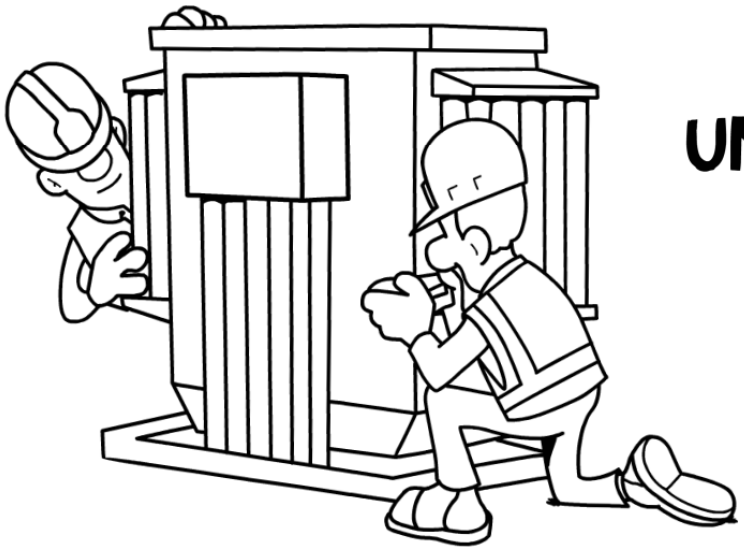


NEW METER READING REQUIREMENTS

FOR LARGE GENERAL SERVICE CUSTOMERS

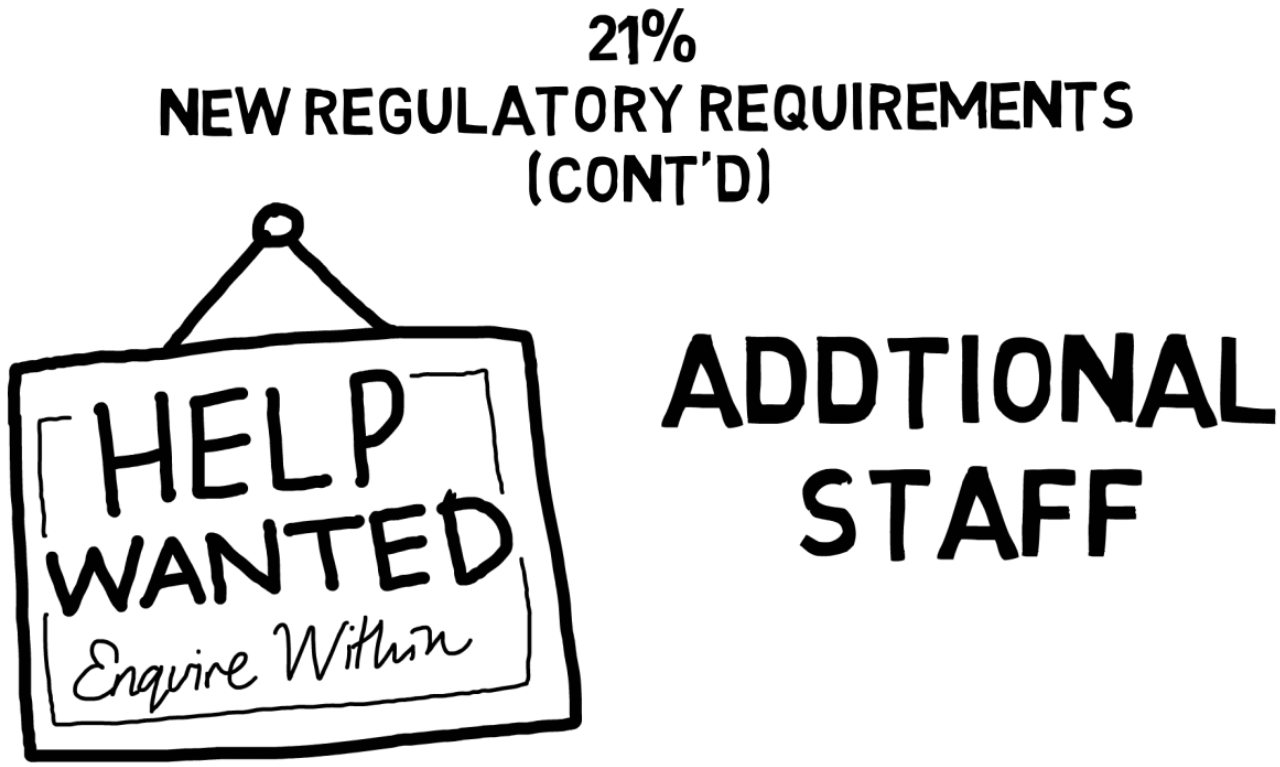
Newly mandated initiatives, like the Under Frequency Load Shedding program – which is designed to improve the reliability of the Provincial electricity grid.

21%
NEW REGULATORY REQUIREMENTS (CONT'D)

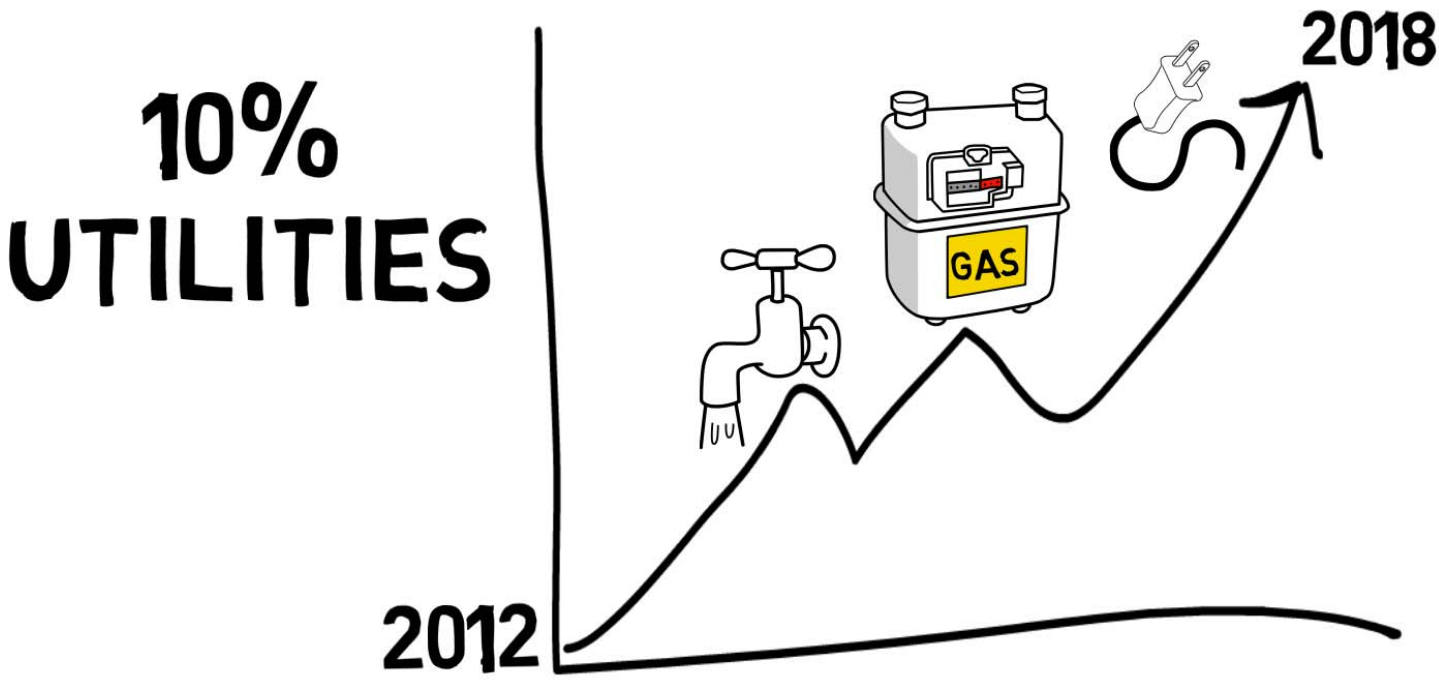


UNDER FREQUENCY LOAD SHEDDING

And finally, the hiring of an additional staff member to assist with growing OEB requirements – all contribute to the increased costs in Regulatory Requirements.

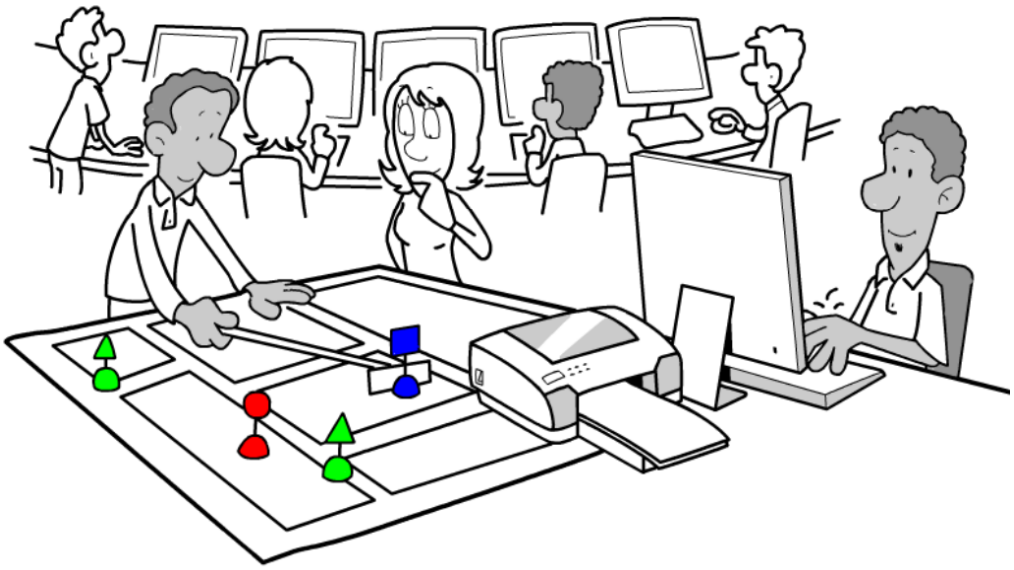


10 percent of the increase covers the rising cost of utilities since our last application. This accounts for basic utilities for the transmission and distribution stations, and the administrative building and service center.



5 percent of the increase is a result of the growing cost of utilizing the Smart Meter Network, which include things like the automated meter-reading software fees.

5% SMART METER BILLING SYSTEM



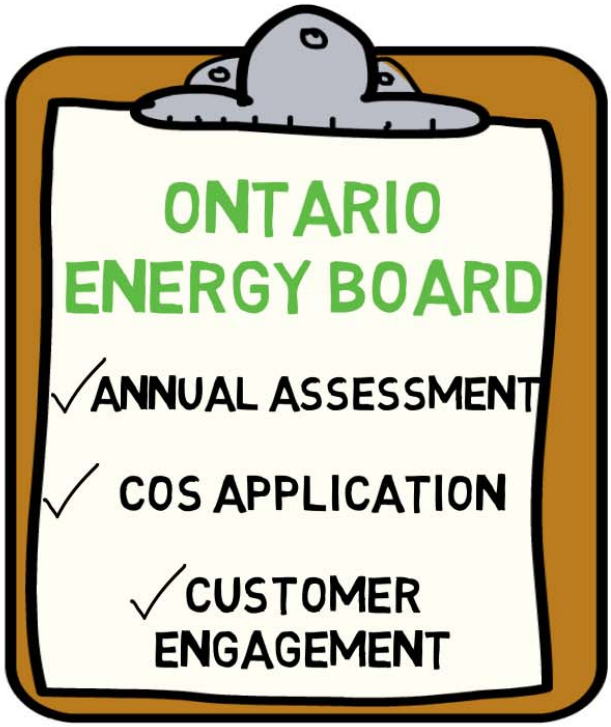
Another 7 percent of the increase is needed to cover Bad Debt, which has grown, due to the rising number of customers unable to pay their electricity bill. This can be attributed to the combination of; the rising cost of electricity, the moratorium on winter disconnections, and the state of our local economy.

7% BAD DEBT



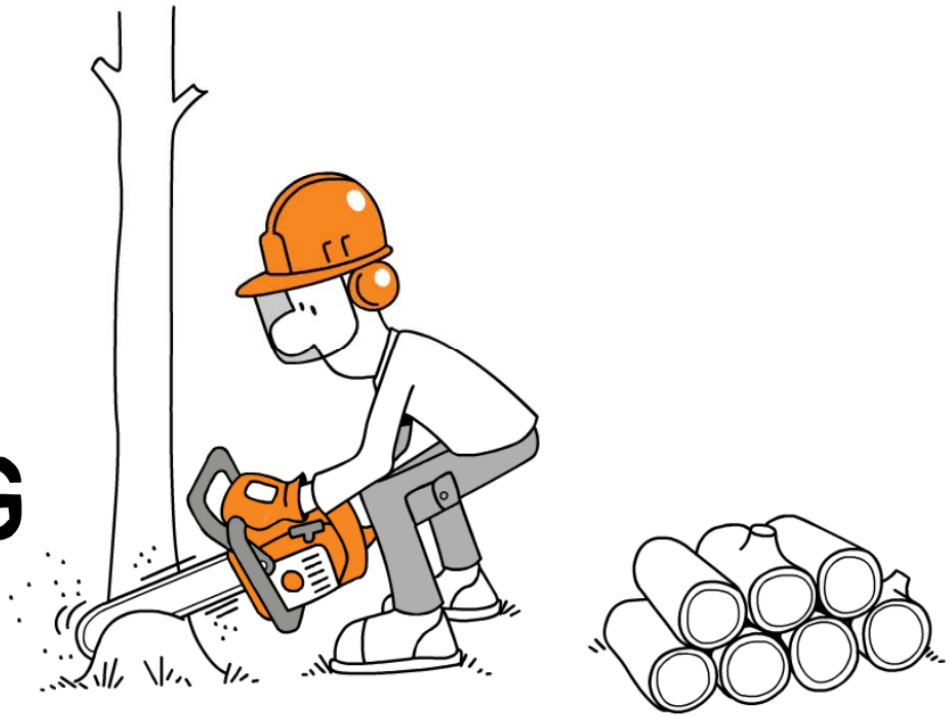
9 percent of the increase accounts for the growing costs of meeting Industry Regulations. For example, costs for things like; OEB Annual Assessments, Cost of Service Applications, and mandated Customer Engagement Programs have all grown since 2012.

9% ELECTRICITY INDUSTRY REGULATIONS



7 percent of the increase covers the cost to operate our Vegetation Management or Tree Trimming program. While, PUC has extended this program to a four-year cycle to reduce costs annually, costs fluctuate based on the total area needing to be cleared, and the number of contractors bidding on that year's cycle.

7% TREE TRIMMING



The remaining 41% of the increase in service revenue requirements is driven largely by inflationary growth in things like; employee wages, benefits, contracted services, insurance costs, and fuel expenses.

41% INFLATIONARY GROWTH

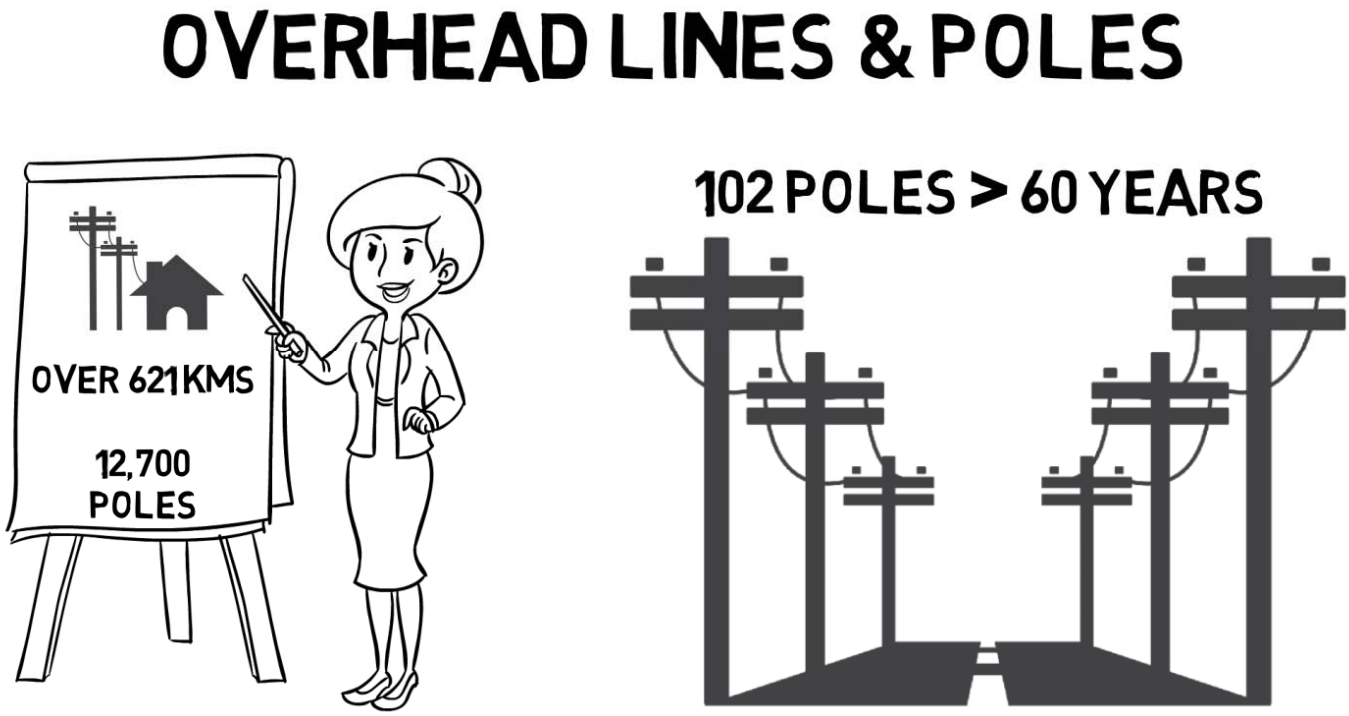


CAPITAL INVESTMENT PROJECTS – VIDEO 6

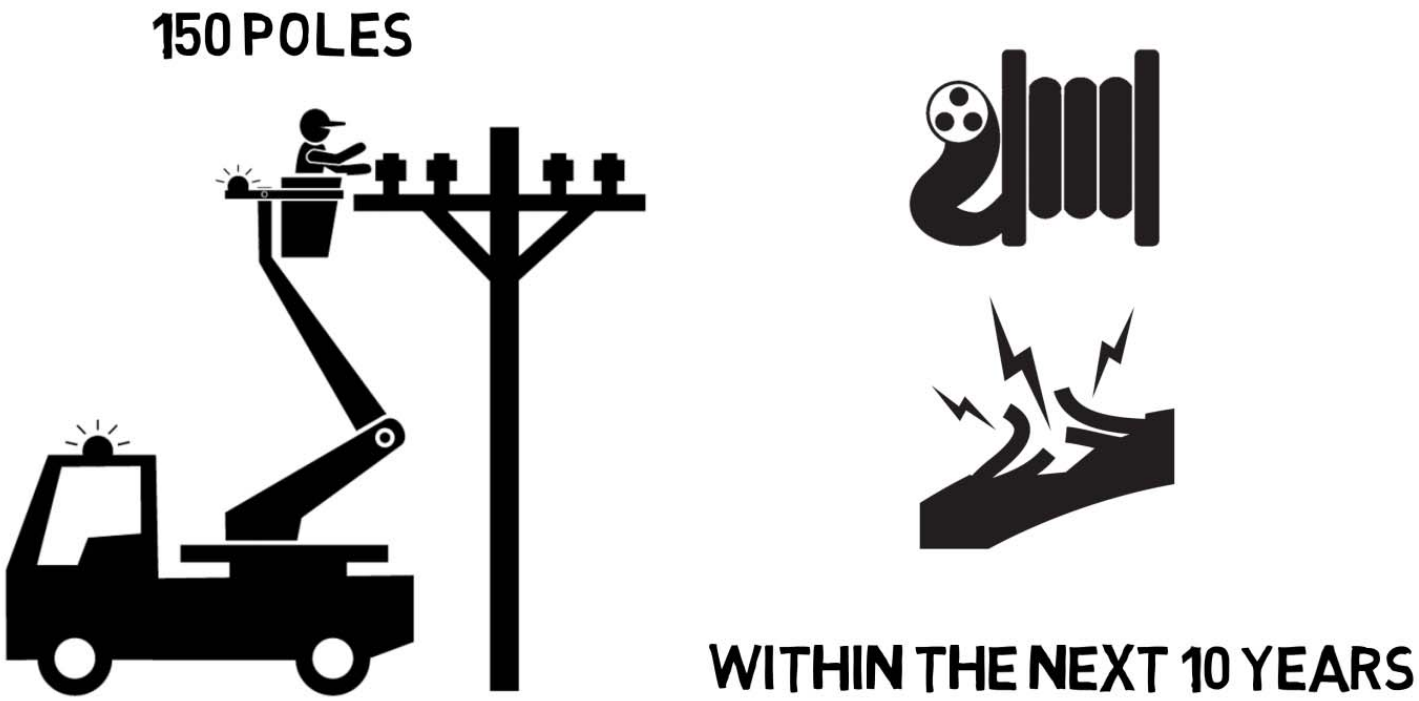
As mentioned, operations, maintenance and administrative expenses account for two-thirds of the total service revenue requirement increase. The remainder is driven by Capital Investments in infrastructure renewal. Let's explore some of the infrastructure renewal projects PUC has planned for the next few years.



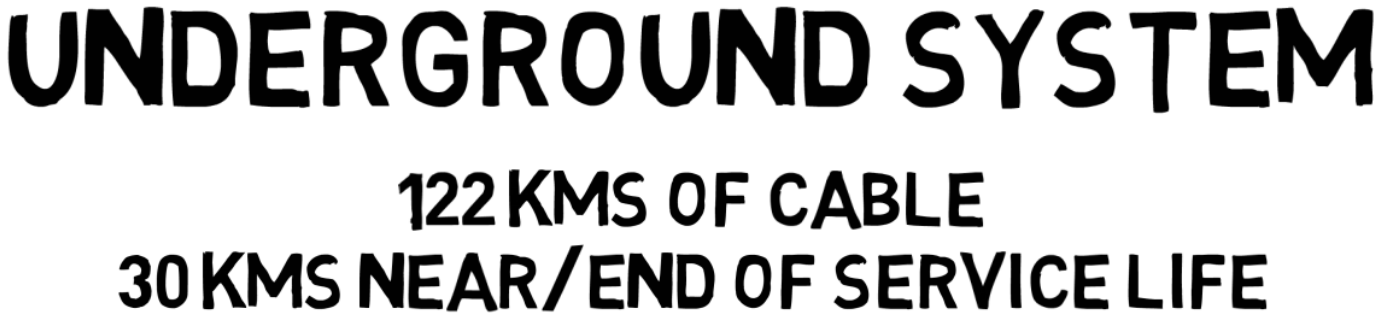
Probably, the most visible components of the electrical distribution system are the overhead lines and poles. PUC has about 621 km of overhead lines using about twelve thousand, seven hundred poles. Of those, approximately 102 poles have been in service for more than 60 years.



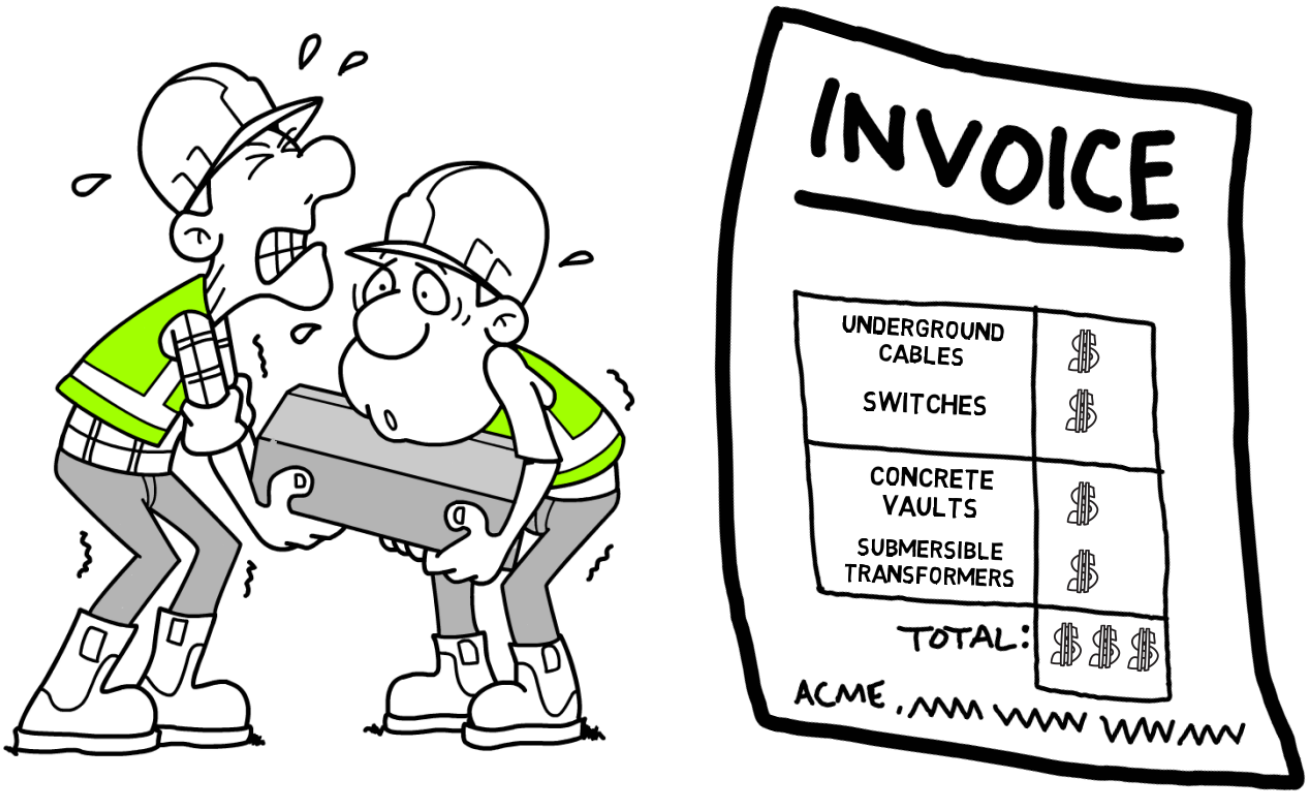
Over the next five years, our plan is to replace approximately 150 poles, identified as being in poor or very poor condition. Additionally, some of the older overhead lines in our system were constructed with a type of copper wire, which no longer meets reliability and safety standards. Our proposed plan would see those lines replaced within the next ten years.



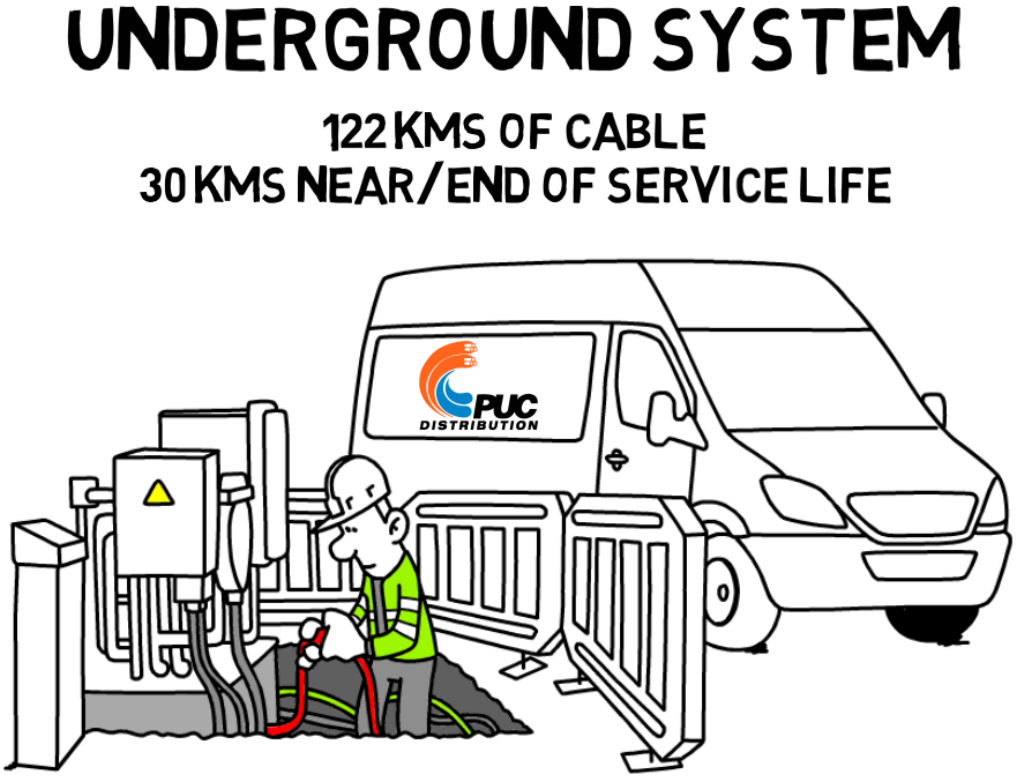
The underground electrical distribution system is comprised of approximately 122 kms of cable, 30 kms of which are approaching the end of their service life.



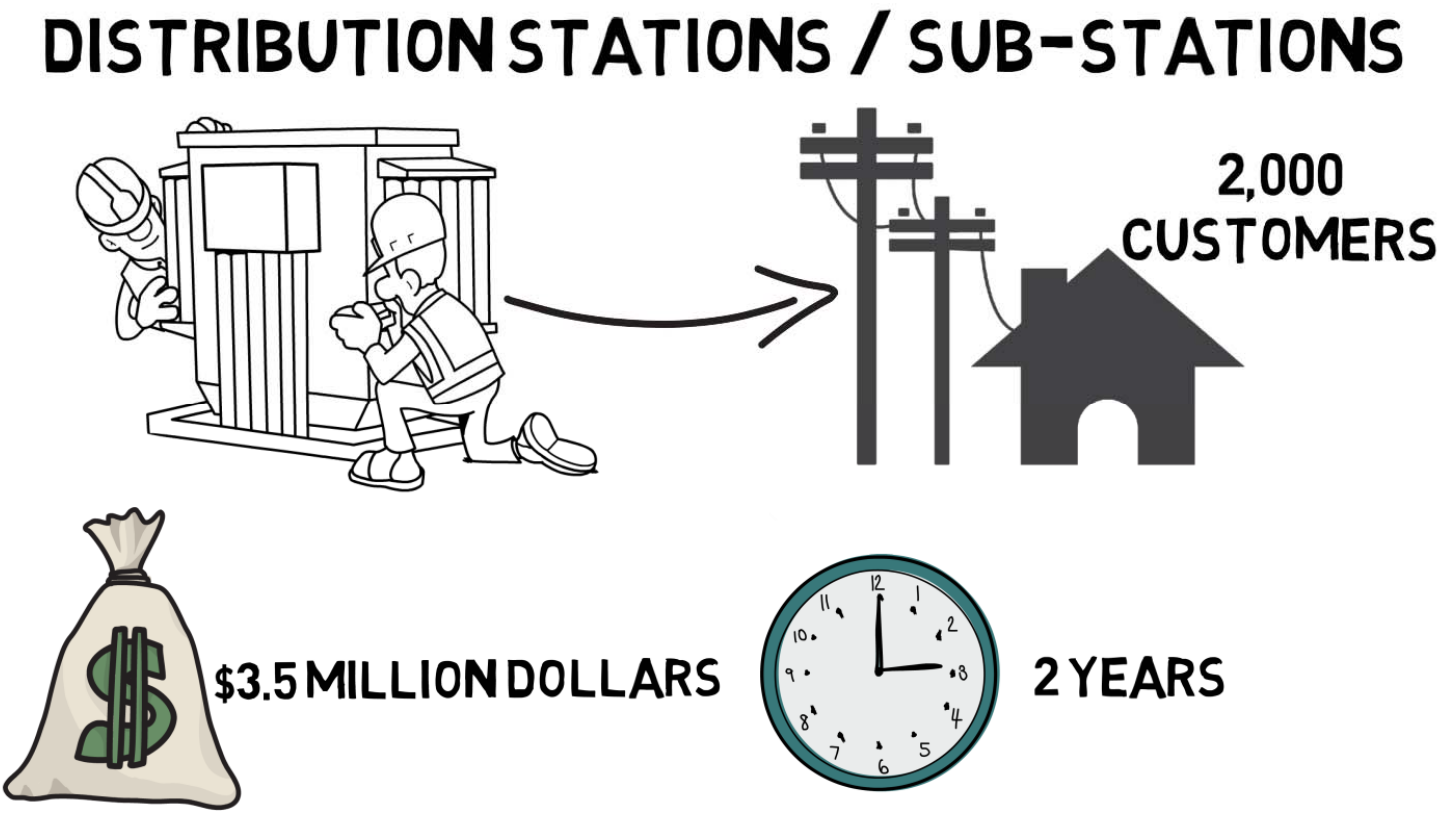
Additionally, underground infrastructure like switches, concrete vaults, and submersible transformers are also a priority for replacement based on their condition.



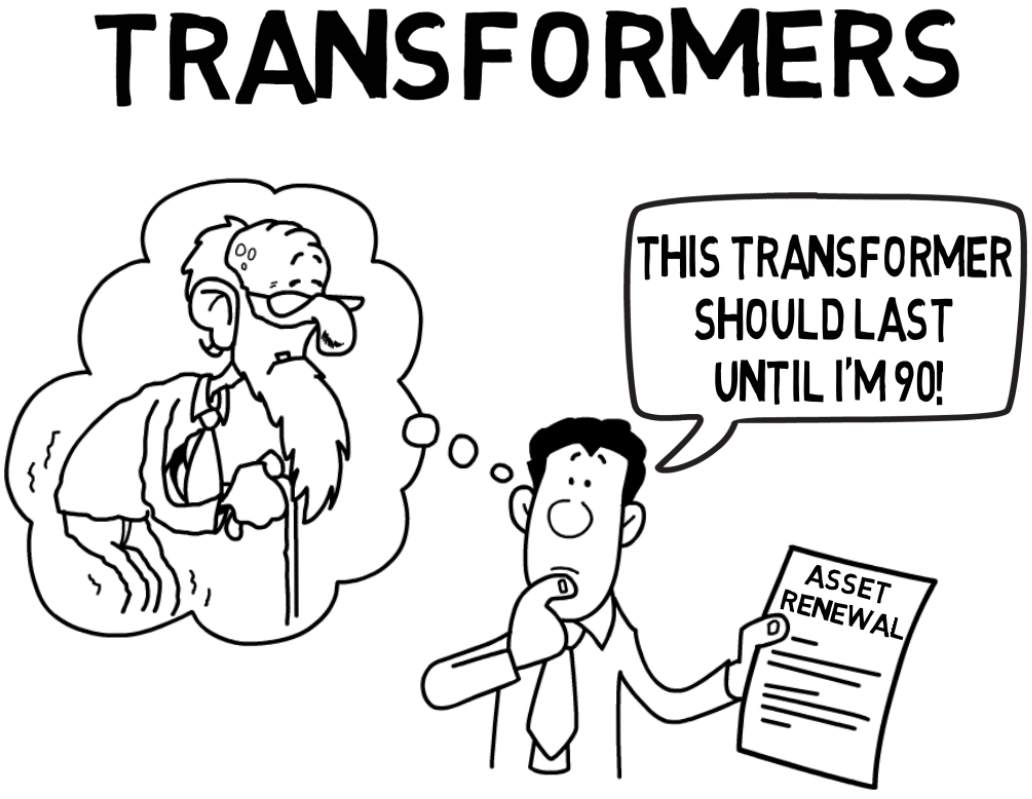
Our plan will continue addressing this aging infrastructure, and focus on neighbourhoods with high equipment failure rates.



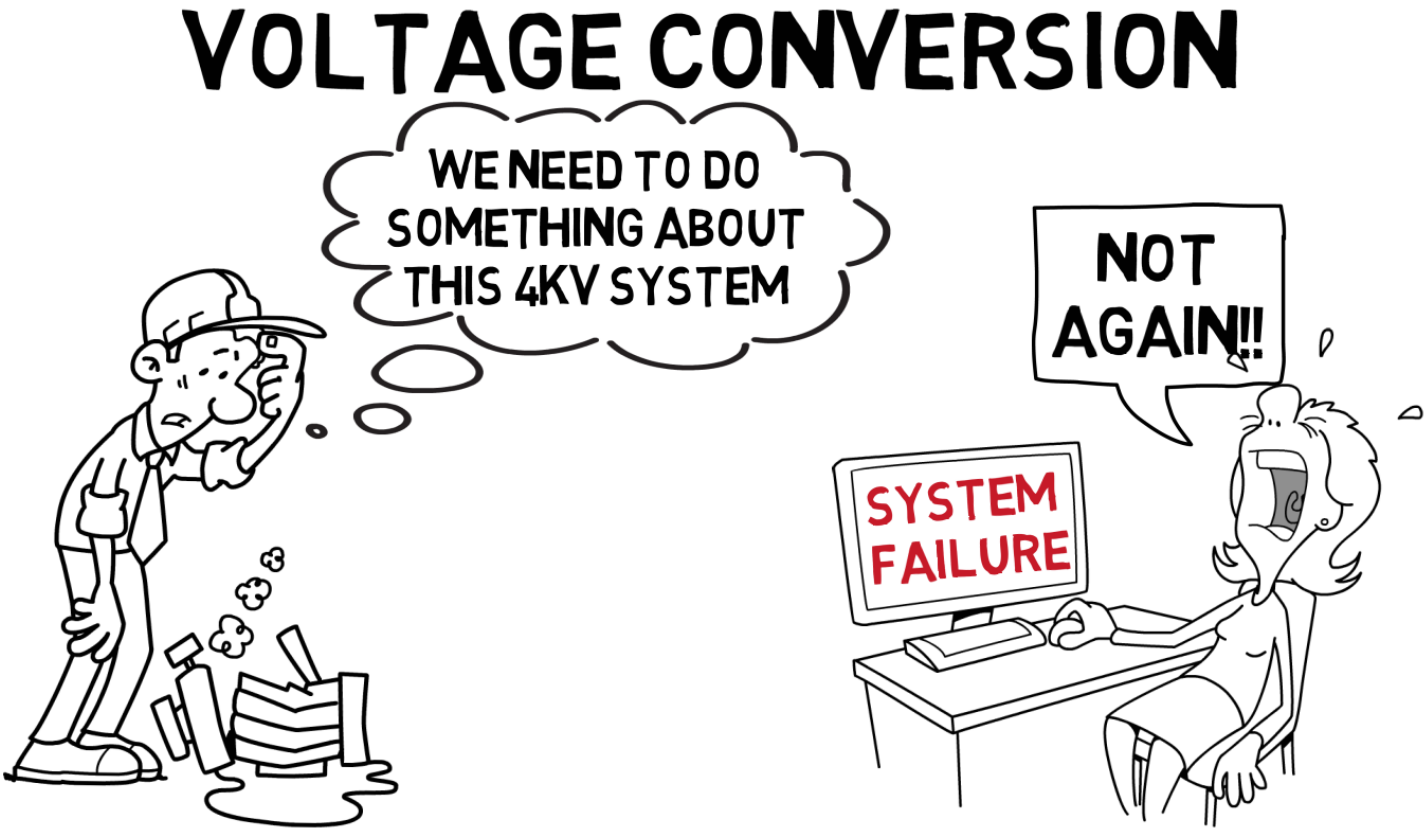
Substations are a critical part of any electrical system, as they supply entire neighbourhoods with power. A single substation can provide enough power for 2,000 homes. Replacing a sub-station costs approximately three point five million dollars and takes about two years to complete.



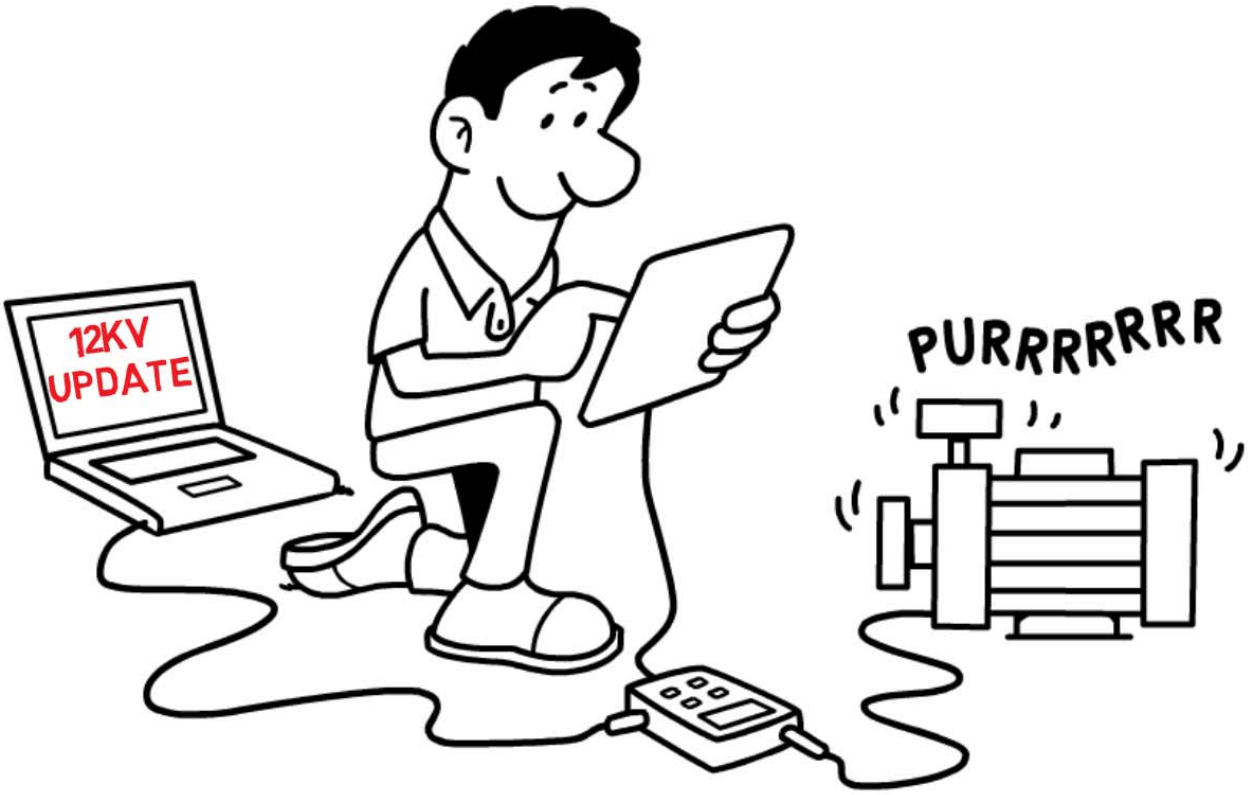
It's important to note that the average service life for a transformer is 40 years so special attention needs to be paid to those located within our substations, as 66% of station transformers have been in service longer than 35 years. With that in mind, we plan on replacing two substations by 2022.



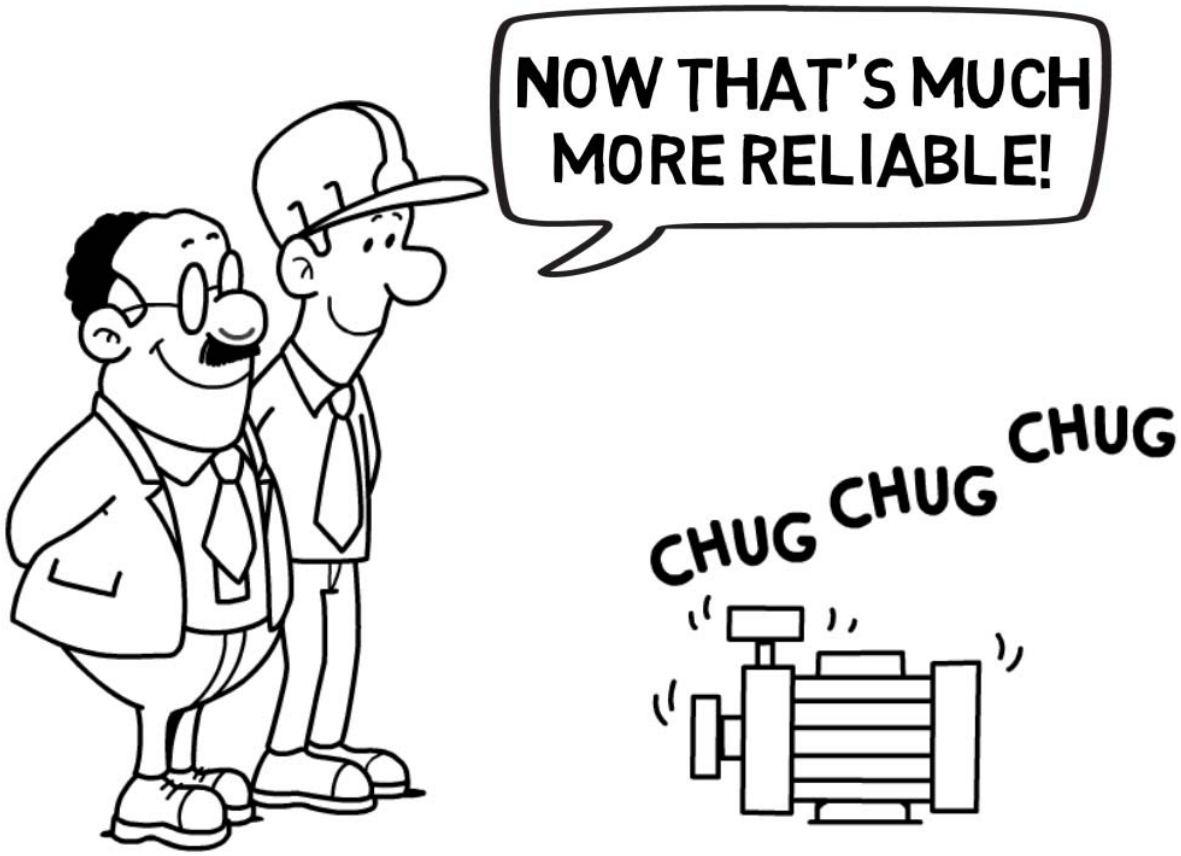
Locally, our substations transform electricity from 34 thousand volts to twelve or four thousand volts. Over the last few years, PUC has been converting the four thousand volt system to a twelve thousand volt system. This is because the four thousand volt system is at, or very near, the end of its service life.



PUC is proposing a replacement plan that will completely retire the 4 thousand volt system by 2022; including poles, wires and transformers and replace it with the more efficient and reliable 12 thousand volt system.

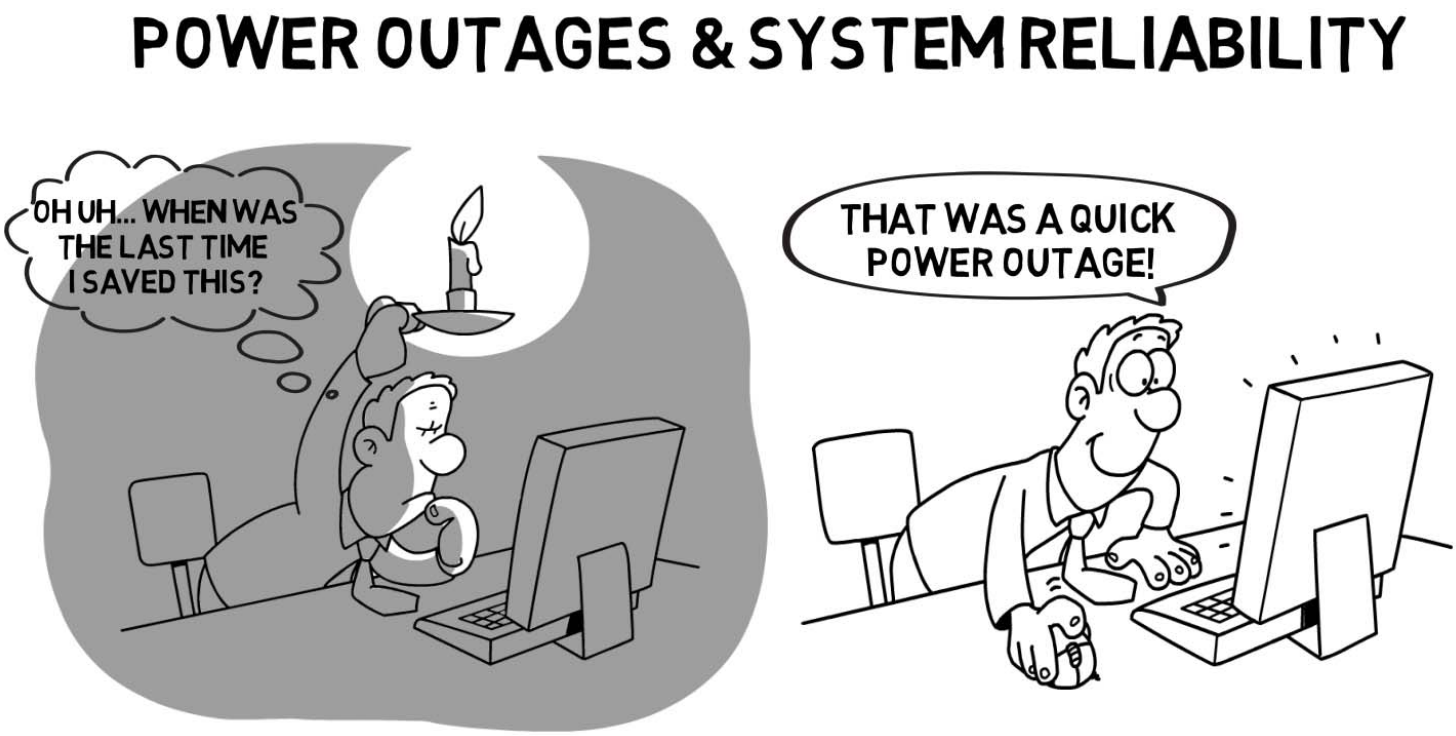


PUC is proposing a replacement plan that will completely retire the 4 thousand volt system by 2022; including poles, wires and transformers and replace it with the more efficient and reliable 12 thousand volt system.

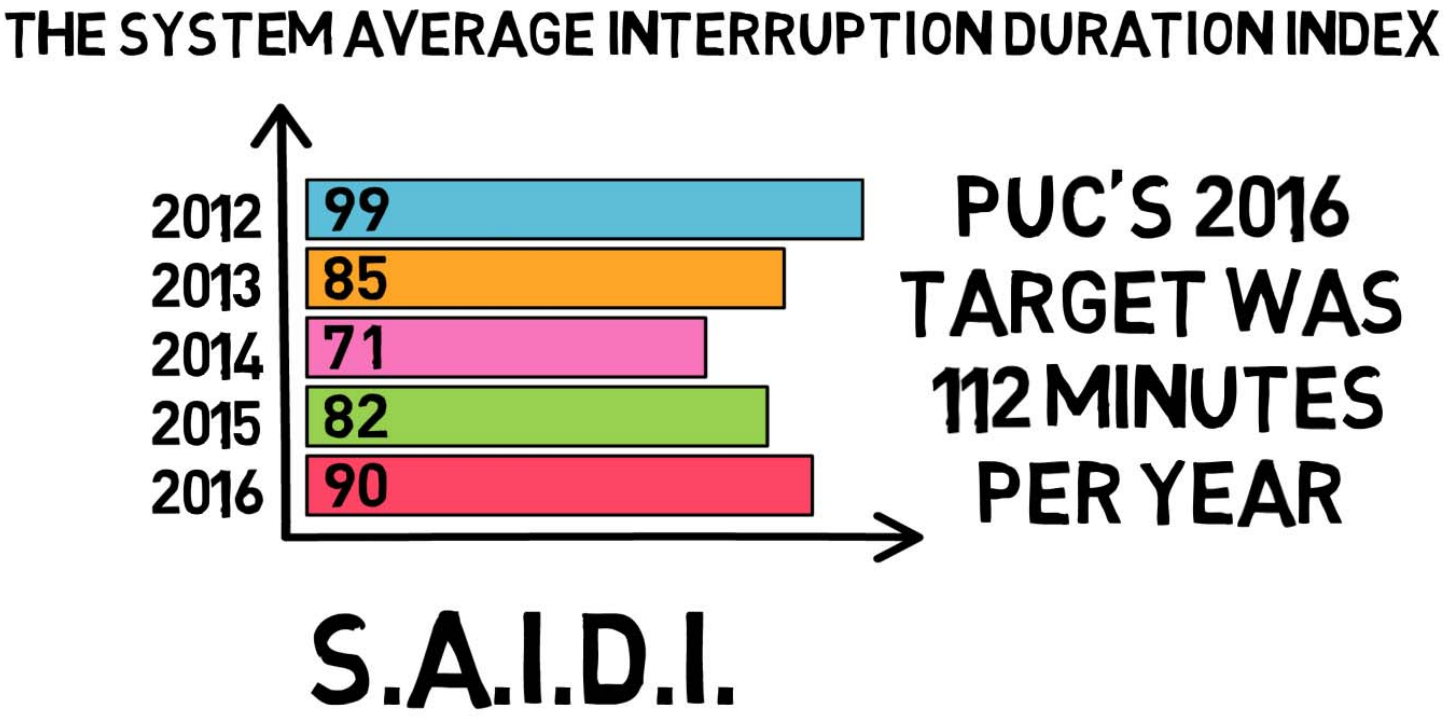


POWER OUTAGES AND SYSTEM RELIABILITY – VIDEO 7

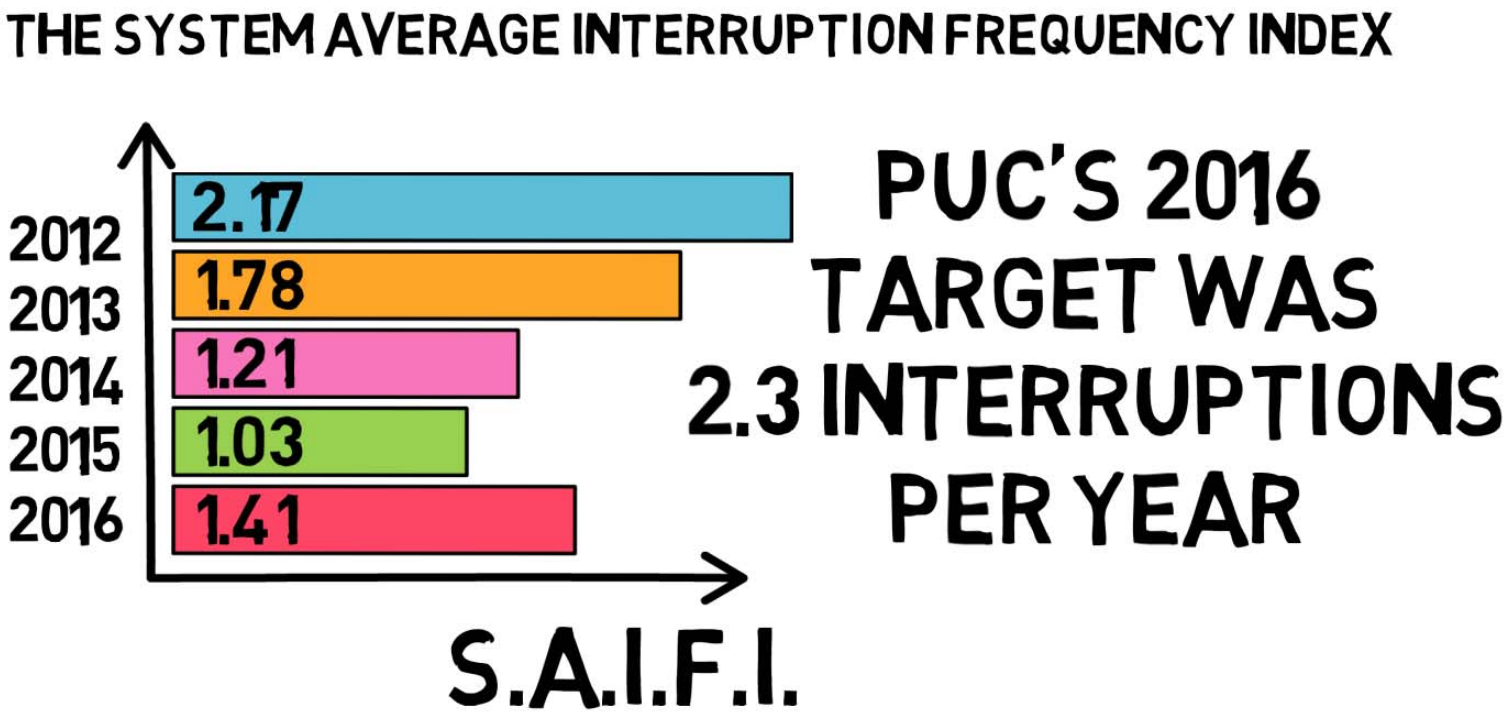
Power outages are an unfortunate reality in the electricity industry. That said, at PUC we work very hard to keep outages to a minimum and if required, as short as possible.



One of the annual industry measurements for system reliability is the System Average Interruption Duration Index, or SAIDI. This is measured by the average number of hours the power to a customer is interrupted. In 2016, the total time the average customer was without power was 90 minutes. This is below our target of 112 minutes, per year.



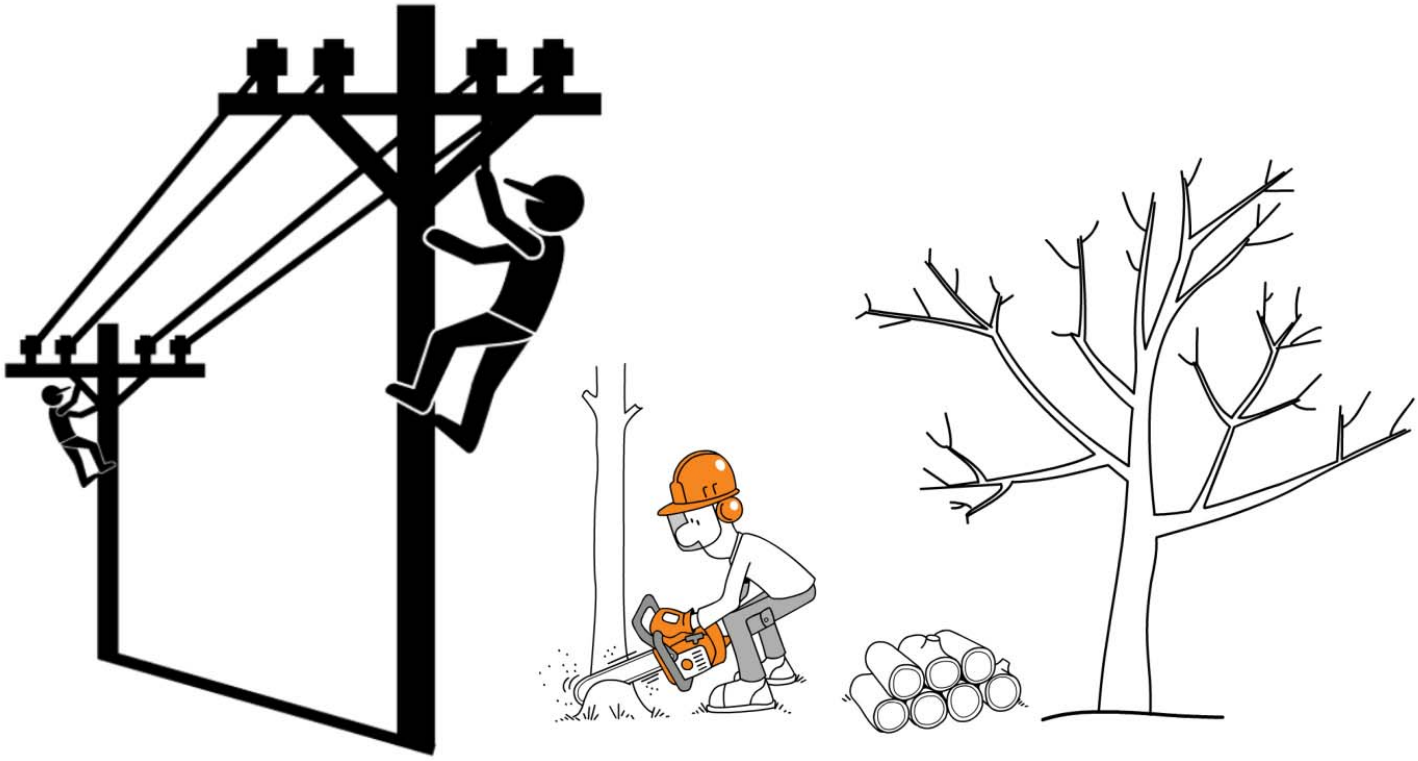
The other annual industry measurement is the System Average Interruption Frequency Index, or SAIFI. This is measured by the average number of times the power to a customer is interrupted. In 2016, the total number of times the average customer experienced an interruption was 1.4 times. This is well below the target of 2.3 interruptions per year.



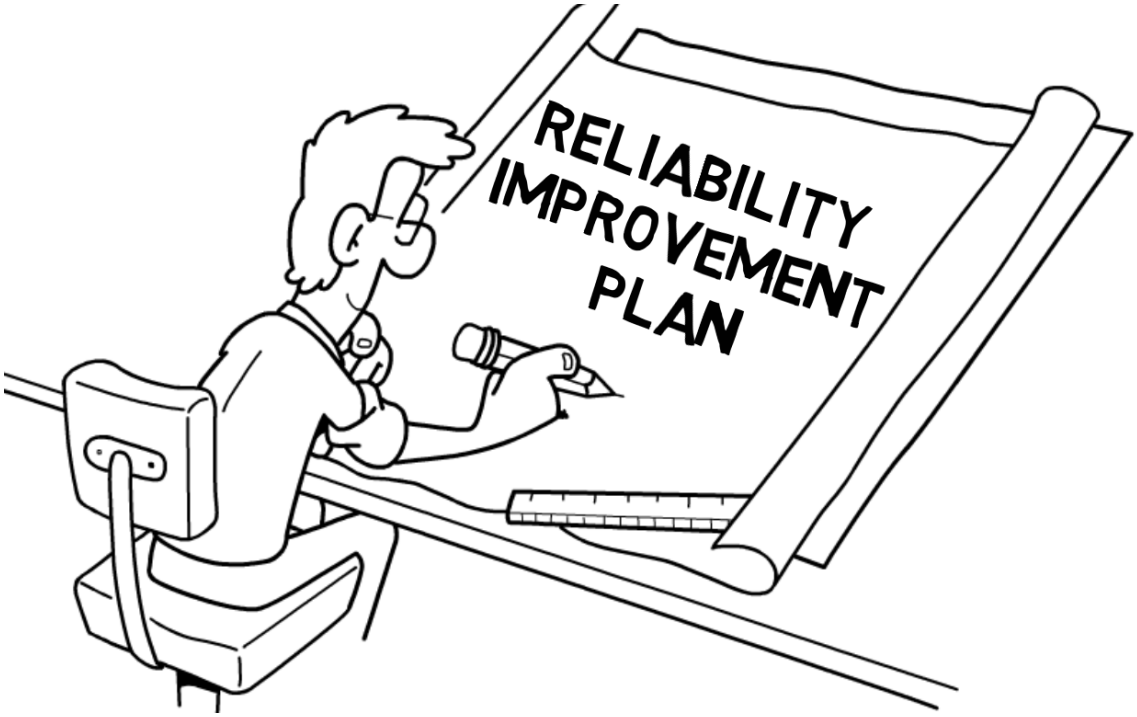
As you can see, PUC's reliability metrics are trending in a positive direction.



We attribute these results to our ongoing commitment to improving system reliability through infrastructure renewal and a successful vegetation management program, better known as tree trimming.



PUC knows that reliability is important to customers, and that's why we plan to increase our investment in infrastructure renewal to improve system reliability. This will ensure we continue to provide a safe, reliable and efficient electrical system for the community we serve.



Appendix IR16

PUC - Bill C97

Accelerated CCA

20221128 (Filed in Live Excel Format)

Appendix IR17

PUC Letter of Comment Reply

Dear Mr. Cushley

Thank you for your email dated October 5, 2022 regarding your concerns with the Cost of Service Application filed by PUC Distribution Inc. ("PUC") under Ontario Energy Board ("OEB") file number EB-2022-0059 ("Application"). As a valued customer, we appreciate hearing from you.

We understand your concerns with the Application relate to the following: (1) PUC's proposed increases to customer rates; and (2) notification of the Application. PUC will address each of these concerns below.

1. **PUC's proposed increases to customer rates**

In your email you raise two concerns with respect to PUC's proposed rates:

a) "The reasons cited in the application, in particular investment in the "Sault Smart grid project", do not seem adequate for raising rates. In fact, consumers have been led to believe these investments would reduce rates […]"

b) "I would urge the OEB to deny this application, or have it modified to require a proportional rate decrease after a specified duration i.e. when the benefits of the Smart Grid investments are being realized by the PUC."

With respect to (a), PUC would like to highlight the significant benefits the Sault Smart Grid ("SSG") investment will bring to PUC customers.

By integrating a number of complimentary smart grid technologies, including distribution automation, Voltage/VAR management and the enhancement of existing Advanced Metering Infrastructure ("AMI"), PUC will modernize the distribution infrastructure and improve reliability, efficiency, and resiliency of the grid.

Modernization of PUC's grid will result in energy savings of 2.7% on average for residential customers, a reduction in the frequency and duration of power outages, and an outage management system ("OMS") that will communicate more accurate and timely information.

It is important to note that PUC's successful application to the Smart Grid Program under Natural Resources Canada ("NRCan") has resulted in federal funding equal to 25% of total project costs. This funding has allowed PUC to implement the SSG in a responsible and prudent manner that will result in a no net bill increase to customers.

While the investments in Sault Smart Grid do increase the distribution portion of a customers bill,

as outlined in the Notice of Hearing, it also significantly decreases the cost of power/consumption portion of the customers bill which results in the no net bill increase as identified in PUC's ICM Smart Grid Application (EB-2018-0219/EB-2020-0249).

Additionally, the rates proposed by PUC are not solely driven by PUC's Sault Smart Grid investment. There are a multitude of factors, such as inflationary pressures, that influence rates.

With respect to (b), this application represents a balance of keeping the bill impacts to customer minimal while investing in innovative, safe and reliable solutions to deliver electricity to customers.

2. Notification of the Application

In your email you raise a concern with respect to PUC's notification of the Application:

a) "…the notice from OEB states that comment can be made at www.oeb.ca/notices, however this case EL-2022-0059 is not listed. I do not feel that this application has been fully transparent and that opportunity has been granted for proper public response. Providing the incorrect URL and no other instructions on the notice for contacting the OEB impedes due process."

There has been widespread public notification of the Application by PUC to allow for appropriate public engagement. On September 23, 2022, the OEB directed PUC to:

(i) Arrange for service of the Application on interveners from OEB proceedings EB-2017-0071, EB-2018-0219 and EB-2020-0249;

(ii) Post a copy of the notice of hearing, Application and evidence on PUC's website;

(iii) Serve a copy of the notice of hearing by electronic mail directly to all customer for which PUC has an email address; and

(iv) Post an OEB prescribed message on PUC's Twitter account. On September 28, 2022, PUC confirmed compliance with the OEB's direction.[1]

We would like to assist you in accessing the information that you require. We note there is a typographical error in your OEB reference number. Please use "**EB**-2022-0059". Alternatively, PUC posted the Application on its website at the following link:

https://ssmpuc.com/electricity/rates/ontario-energy-board-rate-application/

A copy of the Notice of Hearing and all application information throughout this proceeding can be obtained on the OEB's Web Drawer by accessing case EB-2022-0059, or following the link below.

https://www.rds.oeb.ca/CMWebDrawer/Record?q=casenumber:eb-2022-0059&sortBy=recRegisteredOn-&pageSize=400#form1

[1] See here: https://www.rds.oeb.ca/CMWebDrawer/Record/757117/File/document

We want to ensure that you have all the information that you need. If you require any further assistance with accessing application information please don't hesitate to contact us.

Finally, PUC would like to address your concern around the affordability of electricity. This is certainly not an issue that is not unique to Sault Ste. Marie; in fact, it's one that's shared by many Ontarians across the province. In response to these worries, the Province established a number of programs to assist consumers struggling with their electricity bills. We would like to take this opportunity to reference a couple of these programs that are available to help low-income energy consumers:

Ontario Electricity Support Program (OESP) (www.ontarioelectricitysupport.ca)
This program provides ongoing help for low-income consumers with a monthly on-bill credit to reduce their electricity bill.

Low-income Energy Assistance Program (LEAP)
This program (for emergency situations) provides a one-time grant towards your electricity or natural g a s bill if you are behind on your bill and may face having your service shut off. The intake agency that provides this service in Sault Ste. Marie is the *United Way - Community Assistance Trust,* and they can be reached at 705-541-7327.

Thank you for taking time to submit your comment; it is vital that customers participate as much as they can in the rate-setting process. We hope that you find this information helpful, and please don't hesitate to contact us if you have any further questions.

Sincerely,
PUC Distribution Inc**.**

Appendix IR18

Exhibit 9 Table Updates
20221128

Table 1-12 Deferral and Variance Accounts

Accounts Requested for Disposal	Account Number	Claim	RPP	Non RPP
Group 1 Accounts:				
Smart Metering Entity Charge Variance Account	1551	($17,194)	($16,443)	($750)
RSVA - Wholesale Market Service Charge	1580	$914,291	$602,033	$312,259
RSVA - Wholesale Market Service Charge - CBR	1580	($76,540)	($53,945)	($22,595)
RSVA - Retail Transmission Network Charge	1584	$452,702	$298,090	$154,612
RSVA - Power (excluding Global Adjustment)	1588	($1,187,959)	($782,234)	($405,724)
RSVA - Global Adjustment	1589	($73,875)	$0	($73,875)
Subtotal - Group 1 Accounts		**$11,425**	**$47,500**	**($36,075)**
Group 2 Accounts:				
Other Regulatory Assets - Sub-Account - Pole Attachment Variance	1508	$69,334	$45,654	$23,680
COVID-19 Rate Implementation Delay Variance Account (net)	1509	($1,929)	($1,270)	($659)
COVID-19 ICM Rate Implementation Delay Variance Account (net)	1509	$13,754	$9,057	$4,697
COVID-19 Incremental Expense Variance Account	1509	$405,498	$267,008	$138,490
Retail Cost Variance Account - Retail	1518	($18,852)	($12,413)	($6,438)
Retail Cost Variance Account - STR	1548	$65,798	$43,326	$22,472
PILs & Taxes Variance	1592	($619,378)	($407,841)	($211,537)
Subtotal - Group 2 Accounts		**($85,774)**	**($56,480)**	**($29,295)**
Other Accounts:				
LRAM Variance Account	1568	$198,189	$130,891	$67,298
Subtotal - Other Accounts		**$198,189**	**$130,891**	**$67,298**
Subtotal - Group 2 Accounts &Other Accounts		**$112,415**	**$74,411**	**$38,003**
Total		**$123,840**	**$121,911**	**$1,929**

Table 9-3 - Interest Rates Applied to Deferral and Variance Accounts

Period	Interest Rate
Q1 2018	1.50%
Q2 2018	1.89%
Q3 2018	1.89%
Q4 2018	2.17%
Q1 2019	2.45%
Q2 2019	2.18%
Q3 2019	2.18%
Q4 2019	2.18%
Q1 2020	2.18%
Q2 2020	2.18%
Q3 2020	0.57%
Q4 2020	0.57%
Q1 2021	0.57%
Q2 2021	0.57%
Q3 2021	0.57%
Q4 2021	0.57%
Q1 2022	5.70%
Q2 2022	1.02%
Q3	2.20%
Q4 2022 -2023 forecast	3.87%

Table 9-4: DVAs Requested for Disposal in 2023 Application

Account Name	Account Number	Total Principal & Interest (Dec 31, 2021)	2021 Disposal	COS Adjustments	Principal & Interest Disposed	Interest to April 30, 2023	Balances April 30, 2023 Total Claim
Group 1 Accounts:							
Smart Metering Entity Charge Variance Account	1551	($16,709)	$50	$0	($16,659)	($535)	($17,194)
RSVA - Wholesale Market Service Charge	1580	$656,641	$229,218	$0	$885,859	$28,432	$914,291
RSVA - Wholesale Market Service Charge - CBR	1580	($106,818)	$32,083	$0	($74,735)	($1,805)	($76,540)
RSVA - Retail Transmission Network Charge	1584	$687,230	($248,553)	$0	$438,677	$14,025	$452,702
RSVA - Power (excluding Global Adjustment)	1588	($980,375)	($170,617)	$0	($1,150,993)	($36,966)	($1,187,959)
RSVA - Global Adjustment	1589	$481,319	($552,595)	$0	($71,276)	($2,599)	($73,875)
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	$25,810	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	($24,486)	$0	$0	$0	$0	$0
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	$228,535	$0	$0	$0	$0	$0
Subtotal - Group 1 Accounts		**$951,147**	**($710,414)**	**$0**	**$10,874**	**$552**	**$11,425**

Account Name	Account Number	Total Principal & Interest (Dec 31, 2021)	2022/2023 Forecast Transactions	COS Adjustments	Principal & Interest Disposed	Interest to April 30, 2023	Total Claim
Group 2 Accounts:							
Other Regulatory Assets - Sub-Account - Pole Attachments	1508	($26,732)	$0	$93,876	$67,144	$2,190	$69,334
Other Regulatory Assets - Sub-Account - ICM Substation 16	1508	$6,020,120	$0	($6,020,120)	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Substation 16 Rate Rider	1508	($269,820)	($337,006)	$606,826	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Substation Forgone Revenue	1508	($115,142)	$0	$115,142	$0	$0	$0
COVID-19 Delayed Implementation ICM Substation Forgone Revenue	1508	$115,142	$0	$0	$115,142	$3,690	$118,832
COVID-19 Delayed Implementation ICM Substation Rate Rider	1508	($59,155)	($42,661)	$0	($101,816)	($3,263)	($105,079)
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid	1508	$0	$21,357,909	($21,357,909)	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Rate Rider	1508	$0	($871,634)	$871,634	$0	$0	$0
COVID-19 Delayed Implementation IRM Forgone Revenue	1509	$192,359	$0	$0	$192,359	$6,165	$198,524
COVID-19 Delayed Implementation IRM Rate Rider Recovery	1509	($101,703)	($92,525)	$0	($194,228)	($6,225)	($200,453)
COVID-19 Incremental Expense Variance Account	1509	$393,222	$0	$0	$393,222	$12,276	$405,498
Retail Cost Variance Account - Retail	1518	($6,188)	($12,107)	$0	($18,295)	($557)	($18,852)
Retail Cost Variance Account - STR	1548	$53,395	$10,433	$0	$63,828	$1,970	$65,798
PILs & Taxes Variance	1592	($410,974)	($189,219)	$0	($600,193)	($19,185)	($619,378)
Subtotal - Group 2 Accounts		**$5,784,524**	**$19,823,191**	**($25,690,551)**	**($82,836)**	**($2,939)**	**($85,775)**
Other Accounts:							
LRAM Variance Account (2018 COS)	1568	$14,263	($22,841)	$0	($8,578)	($645)	($9,223)
LRAM Variance Account (2023 COS)	1568	$0	$201,460	$0	$201,460	$5,952	$207,412
Subtotal - Other Accounts		**$14,263**	**$178,619**	**$0**	**$192,882**	**$5,307**	**$198,189**
Total Group 2 Accounts		**$5,798,787**	**$20,001,810**	**($25,690,551)**	**$110,046**	**$2,368**	**$112,414**
Total		**$6,749,934**	**$19,291,396**	**($25,690,551)**	**$120,920**	**$2,920**	**$123,840**

Table 9-5: Principal Activity included in Group 2 Disposition

Group 2 Account Description	Account Number	Principal Amounts Included in Proposed Disposition
Group 2 Accounts:		
Other Regulatory Assets - Sub-Account - Pole Attachments	1508	to December 31, 2021
COVID-19 Delayed Implementation IRM Forgone Revenue	1509	to October 31, 2022
COVID-19 Delayed Implementation IRM Rate Rider Recovery	1509	to October 31, 2022
COVID-19 Incremental Expense Variance Account	1509	to December 31, 2021
COVID-19 Delayed Implementation ICM Substation Forgone Revenue	1509	to October 31, 2022
COVID-19 Delayed Implementation ICM Substation Rate Rider	1509	to October 31, 2022
Retail Cost Variance Account - Retail	1518	to April 30, 2023
Retail Cost Variance Account - STR	1548	to April 30, 2023
PILs & Taxes Variance	1592	to December 31, 2022
LRAM Variance Account (2018 COS)	1568	to December 31, 2021
LRAM Variance Account (2023 COS)	1568	to April 30, 2022
Other Regulatory Assets - Sub-Account - ICM Substation 16	1508	to December 31, 2021
Other Regulatory Assets - Sub-Account - ICM Substation 16 Rate Rider	1508	to April 30, 2023
Other Regulatory Assets - Sub-Account - ICM Substation Forgone Revenue	1508	to October 31, 2022
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid	1508	to December 31, 2021
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Rate Rider	1508	to April 30, 2023

Table 9-6: Group 1 DVAs Requested for Disposal

Account Name	Account Number	Principal & Interest Disposed	Interest to April 30, 2023	Balances April 30, 2023 Total Claim
Group 1 Accounts:				
Smart Metering Entity Charge Variance Account	1551	($16,659)	($535)	($17,194)
RSVA - Wholesale Market Service Charge	1580	$885,859	$28,432	$914,291
RSVA - Wholesale Market Service Charge - CBR	1580	($74,735)	($1,805)	($76,540)
RSVA - Retail Transmission Network Charge	1584	$438,677	$14,025	$452,702
RSVA - Power (excluding Global Adjustment)	1588	($1,150,993)	($36,966)	($1,187,959)
RSVA - Global Adjustment	1589	($71,276)	($2,599)	($73,875)
Subtotal - Group 1 Accounts		**$10,874**	**$552**	**$11,425**

Table 9-7: Group 2 DVAs Requested for Disposal

Account Name	Account Number	Total Principal & Interest (Dec 31, 2021)	2022/2023 Forecast Transactions	COS Adjustments	Principal & Interest Disposed	Interest to April 30, 2023	Total Claim
Group 2 Accounts:							
Other Regulatory Assets - Sub-Account - Pole Attachments	1508	($26,732)	$0	$93,876	$67,144	$2,190	$69,334
Other Regulatory Assets - Sub-Account - ICM Substation 16	1508	$6,020,120	$0	($6,020,120)	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Substation 16 Rate Rider	1508	($269,820)	($337,006)	$606,826	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Substation Forgone Revenue	1508	($115,142)	$0	$115,142	$0	$0	$0
COVID-19 Delayed Implementation ICM Substation Forgone Revenue	1508	$115,142	$0	$0	$115,142	$3,690	$118,832
COVID-19 Delayed Implementation ICM Substation Rate Rider	1508	($59,155)	($42,661)	$0	($101,816)	($3,263)	($105,079)
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid	1508	$0	$21,357,909	($21,357,909)	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Rate Rider	1508	$0	($871,634)	$871,634	$0	$0	$0
COVID-19 Delayed Implementation IRM Forgone Revenue	1509	$192,359	$0	$0	$192,359	$6,165	$198,524
COVID-19 Delayed Implementation IRM Rate Rider Recovery	1509	($101,703)	($92,525)	$0	($194,228)	($6,225)	($200,453)
COVID-19 Incremental Expense Variance Account	0	$393,222	$0	$0	$393,222	$12,276	$405,498
Retail Cost Variance Account - Retail	0	($6,188)	($12,107)	$0	($18,295)	($557)	($18,852)
Retail Cost Variance Account - STR	0	$53,395	$10,433	$0	$63,828	$1,970	$65,798
PILs & Taxes Variance	1592	($410,974)	($189,219)	$0	($20,804)	($19,185)	($619,378)
Subtotal - Group 2 Accounts		**$5,784,524**	**$19,823,191**	**($25,690,551)**	**$496,553**	**($2,939)**	**($85,775)**
Other Accounts:							
LRAM Variance Account (2018 COS)	1568	$14,263	($22,841)	$0	($8,578)	($645)	($9,223)
LRAM Variance Account (2023 COS)	1568	$0	$201,460	$0	$201,460	$5,952	$207,412
Subtotal - Other Accounts		**$14,263**	**$178,619**	**$0**	**$192,882**	**$5,307**	**$198,189**
Total Group 2 Accounts		**$5,798,787**	**$20,001,810**	**($25,690,551)**	**$689,435**	**$2,368**	**$112,414**

Table 9-8 Account 1508 (Poles) Disposal

Acct 1508- Pole	2018	2019	2020	2021	01-Apr-23
Opening	$ -	$ (25,567)	$ (25,567)	$ 68,309	$ 68,309
4210	$ (25,567)				
Closing	$ (25,567)	$ (25,567)	$ (25,567)	$ 68,309	$ 68,309
Carrying costs					$ 1,025
Balance				$ 68,309	**$ 69,334**
Joint Poles	17,817				
Rate Jan-Aug	$ 22.35				
Rate Sept-Dec	$ 28.09				
Annual change	$ 5.74				
/ 4 mths	**$ 25,567**			**$ 93,876**	

Table 9-9: Account 1518 and 1548 (RSVA Retail) Disposal

Acct 1518	2017	2018	2019	2020	2021	Forecast to April 1, 2023
Opening	$ (139,578)	$ (123,129)	$ 24,370	$ 18,941	$ 4,005	$ (5,273)
4082	$ (18,458)	$ (17,492)	$ (25,442)	$ (26,764)	$ (21,816)	$ (24,290)
5315	$ 34,907	$ 25,412	$ 20,013	$ 11,828	$ 12,538	$ 12,183
Disposal		$ 139,578				
Closing	$ (123,129)	$ 24,370	$ 18,941	$ 4,005	$ (5,273)	$ (17,380)
Carrying costs					$ (915)	$ (1,472)
Balance					$ (6,187)	**$ (18,852)**
Acct 1548	**$ 2,017**	**$ 2,018**	**$ 2,019**	**$ 2,020**	**$ 2,021**	**$ 2,021**
Opening	$ 78,206	$ 89,176	$ 21,242	$ 30,157	$ 41,221	$ 51,023
4084	$ (126)	$ (118)	$ (220)	$ (236)	$ (130)	$ (183)
5315	$ 11,096	$ 10,389	$ 9,135	$ 11,300	$ 9,932	$ 10,616
Disposal		$ (78,206)				
Closing	$ 89,176	$ 21,242	$ 30,157	$ 41,221	$ 51,023	$ 61,455
Carrying costs					$ 2,373	$ 4,343
Balance					$ 53,395	**$ 65,798**

Table 9-10: Account 1509 COVID-19 Forgone Revenue – IRM Delayed Implementation

Acct 1509	Forecasted Foregone	Actual Foregone	Actual Collected	Forecast	Total Rider Collected	Variance
RESIDENTIAL SERVICE CLASSIFICATION	$ 155,117	$ 135,019	$ (115,306)	$ (17,652)	$ (132,958)	$ 2,061
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	$ 22,253	$ 21,994	$ (23,633)	$ (3,924)	$ (27,557)	$ (5,563)
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	$ 32,876	$ 33,296	$ (28,179)	$ (4,420)	$ (32,599)	$ 698
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	$ 269	$ 301	$ (139)	$ (22)	$ (161)	$ 140
SENTINEL LIGHTING SERVICE CLASSIFICATION	$ 274	$ 281	$ (455)	$ (72)	$ (527)	$ (247)
STREET LIGHTING SERVICE CLASSIFICATION	$ 1,433	$ 1,468	$ (368)	$ (59)	$ (427)	$ 1,041
Balance	**$ 212,221**	**$ 192,359**	**$ (168,080)**	**$ (26,148)**	**$ (194,228)**	**$ (1,869)**
Carrying Costs					$ (42)	$ (60)
Balance		**192,359**			**(194,270)**	**$ (1,929)**

Table 9-12: Account 1509 COVID-19 Incremental Expense Detail

Acct 1509	2020	2021	Total
Incremental billing expenses	$ 577	$ -	$ 577
Incremental labour	$ 199,927	$ 50,239	$ 250,166
Waived Interest	$ 119,153		$ 119,153
Additional LEAP funding	$ 13,133		$ 13,133
Principal	**$ 332,790**	**$ 50,239**	**$ 383,029**
Carrying Costs	$ 10,135	$ 8,603	$ 22,469
Balance	**$ 342,925**	**$ 58,842**	**$ 405,498**

Table 9-13: Account 1568 LRAM (2018 COS)

Acct 1568	2017	2018	2019	2020	2021	Forecast 2022 - Apr 2023
Opening	$ (13,391)	$ (109,860)	$ 419,118	$ 288,959	$ 35,062	$ (6,064)
1568 Disposition		$ 528,978				
1568 Recovery	$ (96,469)		$ (130,159)	$ (253,897)	$ (41,126)	$ (22,841)
Closing	$ (109,860)	$ 419,118	$ 288,959	$ 35,062	$ (6,064)	$ (28,904)
Carrying costs					$ 20,326	$ 20,326
Balance					**$ 14,262**	**$ (8,578)**

Table 9-14: Account 1568 LRAM (2023 COS)

Acct 1568	2018	2019	2020	2021	2022	Forecast Jan-Apr 2023
1568 Disposition	47,519	45,919	34,779	35,197	31,105	**194,519**
Carrying costs					6,941	**12,249**
Balance	**47,519**	**45,919**	**34,779**	**35,197**	**38,047**	**206,768**

LRAM - (2018 COS)	**(8,578)**
LRAM - (2023 COS)	**$ 206,768**
	198,189

Table 9-16: Total Billing Determinants

Rate Class	Customer Numbers	kWh	kW
RESIDENTIAL SERVICE CLASSIFICATION	30,340	273,629,866	-
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	3,400	78,837,024	-
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	344	219,167,959	542,043
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	25	878,528	
STREET LIGHTING SERVICE CLASSIFICATION	8,037	2,459,994	7,200
SENTINEL LIGHTING SERVICE CLASSIFICATION	317	193,841	566
Total	42,463	575,167,212	549,809

Table 9-17: Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj. and Account 1580 WMS CBR Class B)

Rate Class	Units	kW / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL SERVICE CLASSIFICATION	kWh	274,738,681	$ 69,712	0.0003
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	79,051,528	$ 22,807	0.0003
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	547,687	$ 68,221	0.1259
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	878,528	$ 273	0.0003
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,200	$ 766	0.1064
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	566	$ 60	0.1066
Total			**$ 161,840**	

Table 9-18: Rate Rider Calculation for Account 1580 WMS, sub-account CBR Class B

Rate Class	Units	kW / kWh / # of Customers	Allocated Sub-account 1580 CBR Class B Balance	Rate Rider for Sub-account 1580 CBR Class B
RESIDENTIAL SERVICE CLASSIFICATION	kWh	274,738,681	$ (38,975)	(0.0001)
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	79,051,528	$ (11,229)	(0.0001)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	458,921	$ (25,832)	(0.0570)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	878,528	$ (125)	(0.0001)
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,200	$ (350)	(0.0487)
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	566	$ (28)	(0.0488)
Total			**$ (76,540)**	

Table 9-19: Rate Rider Calculation for RSVA - Power - Global Adjustment

Rate Class	Units	kW / kWh / # of Customers	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment
RESIDENTIAL SERVICE CLASSIFICATION	kWh	3,364,092	$ (1,472)	(0.0004)
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	12,067,162	$ (5,279)	(0.0004)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kWh	151,116,068	$ (66,106)	(0.0004)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	-	$ -	-
STREET LIGHTING SERVICE CLASSIFICATION	kWh	2,330,282	$ (1,019)	(0.0004)
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	-	$ -	-
Total			**$ (73,876)**	

Table 9-20: Rate Rider Calculation for Group 2 Deferral / Variance 1 Accounts Balances

Rate Class	Units	kW / kWh / # of Customers	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	30,340	$ (212,942)	(0.5849)
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	79,051,528	$ (69,029)	(0.0009)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	547,687	$ (215,827)	(0.3982)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	878,528	$ (760)	(0.0009)
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,200	$ 7,019	0.9748
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	566	$ 266	0.4703
Total			**$ (491,274)**	

Table 9-21 - Rate Rider Calculation for Account 1568 LRAMVA

Rate Class	Units	kW / kWh / # of Customers	Allocated Account 1568 Balance	Rate Rider for Account 1568
RESIDENTIAL SERVICE CLASSIFICATION	kW	274,738,681	$ 44,507	0.0002
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	79,051,528	$ (110,221)	(0.0014)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	547,687	$ 263,903	0.4869
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	878,528	$ -	-
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,200	$ -	-
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	566	$ -	-
Total			**$ 198,189**	

Table 9-22 - Rate Rider Calculation for Account 1509 COVID-19 Incremental Expense

Rate Class	Units	kW / kWh / # of Customers	Allocated Account 1509 Balance	Rate Rider for Account 1509
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	30,340	$ 248,864	0.6835
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	# of Customers	3,400	$ 61,340	1.5034
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	# of Customers	344	$ 89,493	21.6794
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	# of Customers	25	$ 818	2.7272
STREET LIGHTING SERVICE CLASSIFICATION	# of Customers	8,037	$ 4,279	0.0444
SENTINEL LIGHTING SERVICE CLASSIFICATION	# of Customers	317	$ 705	0.1852
Total			**$ 405,498**	