Rideau St. Lawrence Distribution Inc.

EB-2021-0056 Responses to Interrogatory Questions

0-Staff-1

Updated Revenue Requirement Work Form (RRWF) and Models

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 understanding of changes.

In addition, please file an updated set of models that reflects the interrogatory responses. Please ensure the models used are the latest available models on the OEB's 2022 Electricity Distributor Rate Applications webpage.

Response:

A set of updated models that reflects the interrogatory responses was filed with this submission. The updated models are:

- RSL_2022_Filing_Requirements_Chapter_2_Appendices
- RSL_2022_Rev_Reqt_Workform
- RSL_2022_RTSR_Workform
- RSL_2022_Cost_Allocation_Model
- RSL_2022_Test_Year_Income_Tax_PILs
- RSL_2022_DVA_Continuity_Schedule_COS
- RSL_2022_Tariff_Schedule_and_Bill_Impact_Model

0-Staff-2

Updated Bill Impacts

Upon completing all interrogatories from OEB staff and intervenors, please provide 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, etc.)

Response:

An updated Tariff Schedule and Bill Impact Model was filed with this submission.

1-Staff-3

Ref 1: Exhibit 1 / Tab7 / Schedule 1
Ref 2: Exhibit 1 / Tab7 / Schedule 9

Preamble: In response to feedback from its customers Rideau St. Lawrence Distribution Inc. (Rideau St. Lawrence Distribution) states it is "in the process of a website redesign, and plan to have it in place by the end of 2021."

Question(s):

a) Please provide a revised schedule for the implementation of the website redesign.

Response:

a) Rideau St. Lawrence Distribution revised the website implementation's completion timeline to December 31st 2022. The delay was driven by 3 main reasons:

   a. In 2021, the web design contractor paused work during Covid.
   b. In the same year, Rideau St. Lawrence had an unexpected transition of the CEO position with the new CEO starting in September 2021.
   c. In 2022, Rideau St. Lawrence is having a CFO transition with the new CFO planned start in April 2022.

The completion date was changed to allow the new leadership input into the website design.

1-Staff-4

Ref 1: Exhibit 1

a) Does Rideau St. Lawrence Distribution have a corporate scorecard, that differs from the OEB scorecard? If so, please provide a copy of its corporate scorecard for each year over 2016-2021.

Response:

a) RSL does not have a corporate scorecard that differs from the OEB scorecard.

1-Staff-5

Ref 1: Exhibit 1/ p. 220
Ref 2: Exhibit 1/ Appendix 1-10

Preamble:

Rideau St. Lawrence Distribution provided its audited financial statements for 2018, 2019 and 2020 and the related Audited Financial Statements to RRR trial balance reconciliation.

Question(s):
a) Please provide a reconciliation showing how the 2020 PP&E and intangible amounts shown in the financial statements reconcile to the 2020 net book value in Appendix 2-BA.

Response:

a) The following is the reconciliation requested. RSL found that a small adjustment made to depreciation for account 1820 was the cause. RSL will update 2-BA.

Reconciliation of Capital		
in Financial Statements		
to 2-BA		
Financial Statement Capital	$	7,230,836
Deferred Revenue	-	602,396
Work in Progress	-	15,775
Adj to 1820 depreciation		1,509
Adjusted Financial Statement Capital		6,614,174
Tab 2-BA - 2020		6,614,174

2-Staff-6

Ref 1: Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ p. 12, Table 4

Preamble:
It is noted on page 12 and Table 4 of the DSP that Rideau St. Lawrence Distribution's Total Cost per Customer is $194 and that its Total Cost per km of distribution line is $14,040.
It is also noted on the information presented by Rideau St. Lawrence Distribution on the OEB Scorecard that Rideau St. Lawrence Distribution's Total Cost per Customer is $572 and that its Total Cost per km of distribution line is $31,636.

Question(s):

a) Can Rideau St. Lawrence Distribution explain what has caused this inconsistency?

b) Please state the Total Cost per Customer and the Total Cost per km of distribution line.

Response:

a) The Total Cost per Customer and Total Cost per km of distribution line as shown in Table 4 of the DSP on page 12 are calculated based on the total of 2020 actual O&M costs and 2020 actual capital expenditure. This method is consistent with the filing requirement and the notes to the table Appendix 5-A in the Ch5 Appendix Model as quoted below:

" b) Unit cost metrics for capital expenditures and operating & maintenance (O&M) per customer, kilometer of line, and peak capacity as outlined in Appendix 5-A."

*"1 The Total Cost per Customer is the sum of a distributor's capital and **O&M** costs divided by the total number of customers that the distributor serves.*

*2 The Total Cost per km of Line is the sum of a distributor's capital and **O&M** costs divided by the total number of kilometers of line that the distributor operates to serve its customers.*

*3 The Total Cost per MW is the sum of the distributor's capital and **O&M** costs divided by the total peak MW that the distributor serves."*

The total cost per unit numbers on the scorecard are provided by the OEB based on the PEG report where the total cost is the total of actual **OM&A** and capital expenditure adjusted to economic conditions.

Therefore, the different scopes of the unit costs caused the inconsistency in Table 4 and the scorecard.

b) Given the filing requirement and the notes to table Appendix 5-A both request **O&M** and capital expenditure, **not OM&A** and capital expenditure as used in the scorecard, RSL does not consider it is appropriate to restate the Total Cost per Customer and the Total Cost per km of distribution line with the scorecard numbers.

2-Staff-7

Ref 1: Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ p. 27

Preamble: Rideau St. Lawrence Distribution states, "Recent assessment by a third party determined this station to be in good condition, with only minor capital maintenance required over the five-year budget period."

Question(s):

a) Several references throughout the DSP were made to assessments undertaken by a third party. Please confirm which third party or parties, and its or their qualifications to complete such assessments?

Response(s):

a) The references in the DSP to third party assessments was the company Spark Power Corp. The assessments were signed off by Professional Engineers from Spark Power Corp. Please see 3 attachments filed separately:

    a. 30934_RSL MS2 – SubstationAssessment_R01 – 2020-03-18

    b. 30934_RSL_Substation Memo_R02 – 2021-09-30

    c. RSL MS2 – Condition Assessment letter – 2021-09-30

2-Staff-8

Ref 1: Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ p.56 and 58/ Tables 39 and 40

Preamble:

[Tables not included in preamble]

Question(s):

a) In each of 2018-2021, Rideau St. Lawrence Distribution did not spend its System O&M Plan budget. Have the implications of underspending on O&M been assessed, and have the impacts been reflected in the new plan?

b) Was the underspending a factor of capacity (i.e., resources to execute the O&M plan)? a. If, so, what changes have been made to ensure the 2022-2026 O&M plan, which is, on average, is budgeted at 10% higher than the 2016-2021 O&M budgets can be completed?

Response:

a) In each year RSL did spend its System O&M budget. The amounts shown in Tables 39 and 40 are for capital spending, not O&M.

b) As there was no underspending, there should be no need for further clarification.

2-Staff-9

Ref 1: Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ p. 21

Preamble: As stated on page 21: "In developing and implementing the Asset Management Plan, Rideau St. Lawrence Distribution has pursued the best practices of the electricity distribution industry and continues to work collaboratively with CHEC utilities for improved efficiencies and implementation of benchmark standards …
In developing this Asset Management Plan, the following factors were considered:

a. Available asset inventory and lead time for inventory purchases,
b. Asset condition based on a visual inspection and stress calculation/measurement
c. Current capital expense programs, and
d. Best practices of the electricity industry"

Question(s):

a) Is the referred to "best practices of the electricity distribution industry" the ISO 55000 series for asset management, or another similar standard?
b) Please confirm whether there are Rideau St. Lawrence Distribution asset management governance documents and if so, whether they have been approved and issued (i.e., policy, strategy and asset management plan)?
   i. If these documents are available, could you please point to the sections in this DSP where these were included, or provide them?
   ii. If not, could you please indicate if Rideau St. Lawrence Distribution plans to include the asset management governance documents in future and the anticipated timeline?
c) Please explain what equipment is in the asset inventory and what assets are purchased outside of regular inventory. How are replacements for equipment not in the asset inventory managed?
d) Does continuing to "work collaboratively with CHEC utilities" include comparing and combining common component failure data?

Response(s):

a) The Rideau St. Lawrence Distribution reference to "best practices of the electricity distribution industry" is not directly following the ISO 55000 series for asset management. RSL is following the standards set out by Kinectrics consistent with the last DSP application.

b) Rideau St. Lawrence Distribution does not have asset management governance documents. The DSP describes how RSL inspects and maintains its assets.
   i. RSL does not currently have asset management documents.
   ii. RSL does not have a timeline to implement asset management governance documents. RSL will be exploring asset management governance practices.
c) The equipment in asset inventory and outside of asset inventory are as follows:
   i. Asset Inventory list: Poles, transformers, wire, meters, switches/fuses
   ii. Assets purchased outside of regular inventory: Substation Transformers, Reclosures
   iii. Replacements for equipment not in asset inventory are managed by: Need for time based maintenance, Inspection based maintenance, and condition based maintenance. Parts are ordered for the necessary time. For breakdowns, order parts or seek our other CHEC LDC members urgency, cost, and delivery time.

d) Working collaboratively with CHEC utilities has not yet included comparing and combining common component failure data.

2-Staff-10

Ref 1: Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ p. 21

Preamble: The sixth paragraph on page 21 states: “Each project identified is rated and ranked, based on the following factors, prescribed by the OEB”

Question(s):

a) Could you please provide an explanation of what types of projects are considered for inclusion in the asset management system and for planning purposes (e.g. replacement, refurbishment, IT upgrade, annual inspections, testing, maintenance, condition assessments, tree trimming, etc.) and include examples so that it is understood what the meaning of “project” is? Each project proposed needs to be identified by type and rated and ranked based on the factors presented in Table 7. The definitions for these types of projects should be referenced.

Response(s):

a) All projects are considered for inclusion to the asset management system and for planning purposes. The projects get a cost estimate and the ones that meet materiality threshold (>$50,000) are listed in the DSP.

Some examples of material projects are to meet regulations of ESA small conductor replacement and Ministry of Environment PCB replacement. Separate to that we have projects for replacement, refurbishment, and IT upgrades that also meet material thresholds. Annual Inspections, testing, condition assessments, and tree trimming are being done but did not meet materiality threshold for the list.

2-Staff-11

Ref 1: Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ p. 22

Preamble: On page 22, below Table 7, under “Factors for Rating Projects” the text continues: “The detailed descriptions for each factor in Tables 7 to 11, resulting in a rating of 1 to 4, have been established based on the projects identified in this forecast period.”

Question(s):

a) Please point to where in this DSP the Health Scores and Weights were determined for Table 7 and provide text explaining how each Factor listed in Table 7 was determined.
b) Please provide a rating table for “Safety”, as has been done for the other factors in Table 7.

Response(s)

a) This weights for each factor were determined by the RSL leadership. These weights were based on the Rideau St. Lawrence Distribution’s overall objective to deliver safe, reliable electricity in a cost-effective manner for our communities. The meeting used to determine the weights is not documented in the DSP. The Health score is strictly math used to scale the results for a health score to be based out of a max score of 100.

b) The rating table for Safety is as follows:

	Safety
1	No safety issue
2	Potential for indirect risk to people
3	Potential for direct risk to people
4	High risk to customers / staff

2-Staff-12

Ref 1: Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ p. 23

Preamble: On page 23, the first paragraph states: "The material projects, identified in Section 4.5.2 show the rating and the score for each project, based on these factors."

Questions:

a) Section 4.5.2 provides a grouping of 18 projects, (11 renewal, 4 system access and 3 General Plant). Each project shows the rating and total score, which is based on the rating, weight and scores outlined in this DSP. Please provide a total list of all the capital projects which were considered and their prioritized ranking together with their ratings and weights.
   i. From the total list of projects prepared, please indicate which projects were excluded from the planning process for the 2022- 2026 period?
   ii. Did Rideau St. Lawrence Distribution establish a scoring threshold below which projects would not be included in the 2022-2026 period and if so, which project were the ones excluded from above or from below the threshold score?
   iii. Was the selection of projects to carry forward in the 2022-2026 period aligned with the established scoring?
   iv. Could you please explain how projects that were included in the plan and could not be started are handled? How are these projects would be re-introduced into the planning cycle?
   v. The total score for each General Plant project was "zero". How is planning and prioritization done for projects with "zero" score?

Response(s):

a) In addition to the 18 projects, below is list of capital projects considered but not listed.
   i. In Addition to the 18 projects, below is a list of capital projects considered but excluded. The excluded projects were not submitted to the OEB in the DSP. All projects listed are in the plan for 2022-2026 DSP.

	Centennial Park 44kv Insulator replacement	MS2 – New Feeder F3 on opposite side of road	Concession St. – Replace 1km of 1/0	Double Bucket Truck
Safety	3	0	0	0
Environment	0	0	0	0
Customer Value	2	3	0	0
Coordination, Interoperability	1	4	4	0
Economic Dev. Impact	1	4	4	0
Cyber Security, Privacy	0	0	0	0
Index	36	47	32	0

ii. We prioritized essential projects that we had capacity to complete in 2022-2026. RSL did not establish a threshold based on score. It was limited based on capital and capacity. The essential projects with the highest scores were listed.

iii. The projects to carry forward in the 2022-2026 period were aligned with established scoring.

iv. Previous projects that were not started are carried forward based on ranking in the same manner as all other projects. When projects get re-introduced they are ranked. The top ranked projects within our capital and capacity are chosen and listed.

v. The 3 general plant projects were not scored and done outside of the ranking system for essential capital project:

   i. 2026 RSL Truck: Trucks are not ranked because trucks are replaced when it is no longer safe and reliable to execute the work to maintain the distribution system assets.

   ii. 2024 Elster/Olameter Smart meter Software Upgrade – The Smart meter software upgrade is not ranked because we will only execute if it is necessary to maintain operability.

   iii. 2023 IVR – This was not ranked because it is necessary to enhance customer service and allow the operations to effectively communicate to all customers directly.

2-Staff-13

Ref 1: Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/Section 3.1./ p. 23

Preamble: Rideau St. Lawrence Distribution states it "uses the GIS database as the central storage for all asset information, asset assessment and project identification. In the future, this will allow RSL better data mining and improved decision making."

Question(s):

a) Please provide more detailed information to clarify what characteristic and condition information is input into the GIS?

Response(s):

a) The Rideau St. Lawrence Distribution GIS database has the capability to store asset information, asset assessment, and project identification. Rideau St. Lawrence Distribution is inputting asset information into the GIS. Rideau St. Lawrence Distribution GIS database is not up to date with inputting asset condition assessments and project identification into the system.

2-Staff-14

Ref 1: Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ p. 24

Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ p. 27

Preamble: Rideau St. Lawrence Distribution stated on page 24, "The distribution network includes nine distribution stations owned by RSL and two stations that are shared with Hydro One Networks Inc. (HONI)."

Also stated on page 24: "This section summarizes the results of the Asset Condition Assessment study completed in 2020, with the objective of establishing the health and condition of fixed assets currently in service in RSL's system."

… The assets covered by the report include:

a. Substations / Feeders

b. Distribution Transformers

c. Poles

d. Conductors

e. Switches

f. Meters

g. General Plant"

It is stated on page 27, regarding Morrisburg MS2, "assessment by a third party determined this station to be in critical condition and recommended replacement to provide stable reliability."

Question(s):

a) Please provide indication of the terminal points between Rideau St. Lawrence Distribution and HONI stations and a list of equipment shared between Rideau St. Lawrence Distribution and Hydro One? (There are two distributing stations that are shared with Hydro One- Networks Inc. (HONI) – Glen Becker DS and Newboro DS)
b) Please confirm whether the Asset Condition Assessment study completed in 2020 is included with this DSP and if so, please point to the Section in this DSP where it can be found. Also, in several instances the DSP refers to assessments done by a third party. Please explain whether these assessments by a third party are included in the above 2020 Asset Condition Assessment study or whether they are from separate assessments.
    i. If the 2020 Asset Condition Assessment study is not included, could you please provide it?
    ii. If these third-party assessments are not from the above 2020 study, or if these assessments are not included in this DSP, could you please provide them?
c) Please confirm whether all these listed assets are assets which are intended to be included, monitored, scored, weighted, prioritized, planned, and managed by the asset management process in the future, as it continues to evolve.
    i. If some of these assets will not be included in the asset management process in the future, could you please confirm which assets are intended to be included?
    ii. Could you please confirm whether each of the assets included in the asset management process would require the same rigor of monitoring to implement asset management principles and methods?
d) The heading of the Section "General Plant" is listed in the DSP text. Could you please confirm whether the Section "General Plant", with the description of assets in it, is included with this DSP and if so, please point to the Section in this DSP where it can be found?
e) To clarify, from Section 3.2.1.1 "Station Summary", on pages 26 and 27, the following information is requested:
    iii. Please provide examples of minor capital maintenance and the category of maintenance to which they belong, (e.g., preventative maintenance, corrective maintenance, breakdown maintenance)
    iv. Please provide the evaluation that determined that the Morrisburg MS2 station is in critical condition.

Response(s)

a) Generally, the terminal point between Rideau St. Lawrence Distribution and HONI is the metering unit with 2 switches and an isolation point upstream of the metering unit. For the 2 shared distribution stations listed, Rideau St. Lawrence Distribution and HONI have 2 dedicated circuits.

b) The asset conditions assessment completed in 2020 was not included in the DSP.

    iii. The 2020 asset conditions assessment completed by Spark Power is attached. Subsequent updates are also attached separately:

        i. 30934_RSL MS2 – SubstationAssessment_R01 – 2020-03-18

ii. 30934_RSL_Substation Memo_R02 – 2021-09-30

iii. RSL MS2 – Condition Assessment letter – 2021-09-30

iv. The third party assessment are from the 2020 asset conditions assessment.

c) Asset inclusion

iii. All assets are included in the asset management process.

iv. All assets in the asset management process get the same thoroughness and rigor. Not all assets are managed through the same manner. Not all assets get a "3rd party assessments".

d) The heading of Section "General Plant" was included in the list, however, the "General Plant" Section with the description of assets were not included. The material items in General Plant are the large bucket trucks, and they are maintained and inspected by third party services (one for truck mechanics, the other for the hydraulics). Computer hardware and software is maintained by a 3rd party IT specialist. These assets have standard life cycles and are scheduled for replacement based on the standard life cycles.

e) Clarifying section 3.2.1.1:

iii. Minor capital maintenance

i. Bushing Repair on MS1 in Cardinal – Corrective Maintenance.

ii. Cracked insulators on the structure – Preventative Maintenance

iii. Fuse switches on structure due to crack – Preventative maintenance

iv. The Sparks Power Assessment for Morrisburg MS2 indicating critical condition is attached separately:

i. 30934_RSL MS2 – SubstationAssessment_R01 – 2020-03-18

ii. 30934_RSL_Substation Memo_R02 – 2021-09-30

iii. RSL MS2 – Condition Assessment letter – 2021-09-30

2-Staff-15

Ref 1: Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ p. 33

Ref 2: Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ Appendix A/ Project Number CP2211

Preamble: In Table 19 Station Health Index Summary Rideau St. Lawrence Distribution has evaluated Morrisburg MS2 to have an asset condition of critical. Rideau St. Lawrence Distribution is planning to rebuild the station in a new location and has categorized the investment category as System Access.

Question(s):

a) Please elaborate on the statement in CP2211 that states "An additional feeder is required to supply demand in the community and provide reasonable reliability".
b) Please confirm that the total project cost is $1 million as outlined in CP2211 and CP2311.
c) What existing Rideau St. Lawrence Distribution property will the substation be relocated to, or is a new property required?
d) What coordination work is required with Hydro One? Has Hydro One already provided an estimate for its costs, and are those costs included in the total project costs?
e) What is the current MVA rating of the current substation and the new substation?
f) Has Rideau St. Lawrence Distribution retained the design and construction resources for the project? If not, what is the timeline?
g) Please consider if the project has been appropriately categorized within System Access.

Response(s):

a) Morrisburg MS2 station infrastructure is deteriorating. Also, there are only 2 feeders there to back feed the 4 in MS1. Even if MS2 was refurbished an additional feeder would be necessary to back feed the MS1. Instead of refurbishing MS2 and adding a feeder, relocating the MS2 station to MS1 will eliminate the need for an additional feeder. This in turn reduced the capital requirement estimate by $350,000.

b) Yes, the total project cost for the station build is estimated at $1 million as outlined in CP2211 and CP2311.

c) The property will be on the same property that Morrisburg MS1 is on. No new property is required.

d) Minimal coordination work with Hydro One is required. This project has no cost in scope for Hydro One.

e) The current rating of the current MS2 substation is 5mva and the new one will be 5mva as well.

f) Rideau St. Lawrence Distribution has retained resources for a preliminary design of this project. The preliminary design is being utilized for the tendering process. The tendering process will determine the best value approach for design and construction resources.

g) The project is appropriately categorized within System Access.

2-Staff-16

Ref 1: Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ p. 29

Preamble: As stated on page 29, Section 3.2.1.2 “Inspections”: “Rideau St. Lawrence Distribution Inc. owns and operates its nine substations, which are patrolled on the first business day of each month. Patrols at substations require the use of the “Record of Substation Inspection” which includes a checklist of items to inspect visually for defects.”

Question(s):

a) Please provide completed representative samples of this information, that is, completed “Record of Substation Inspection” and the checklist used to carry out the inspections?
b) Where are the results of the inspections recorded?
c) How are inspections evaluated against past inspections to determine if condition is worsening?

Response(s):

a) Below are the set of the 9 inspections for November of 2021:

SUBSTATION MAINTENANCE CHECKS

DATE: Nov.24, 2021

	YES	NO	NEEDS ATTENTION
WEED CONTROL	☐	☒	☐
FENCE	☐	☒	☐
LOCKED	☒	☐	☐
OIL LEAKS	☐	☒	☐
NEEDS PAINTING	☐	☒	☐
BROKEN INSULATORS	☐	☒	☐
AIR BREAK CONDITION	☐	☒	☐
GROUND MAT	☒	☐	☐

Transformer Location: Cardinal MS#2

Comments: Oil samples taken by Spark all good

Initials of Inspector: DR

SUBSTATION MAINTENANCE CHECKS

DATE: Nov.23, 2021

	YES	NO	NEEDS ATTENTION
WEED CONTROL	☐	☒	☐
FENCE	☐	☒	☐
LOCKED	☒	☐	☐
OIL LEAKS	☐	☒	☐
NEEDS PAINTING	☐	☒	☐
BROKEN INSULATORS	☐	☒	☐
AIR BREAK CONDITION	☐	☒	☐
GROUND MAT	☒	☐	☐

Transformer Location: Cardinal MS#1

Comments: Oil samples taken by Spark

Initials of Inspector: DR

SUBSTATION MAINTENANCE CHECKS

DATE: Nov.24, 2021

	YES	NO	NEEDS ATTENTION
WEED CONTROL	☐	☒	☐
FENCE	☐	☒	☐
LOCKED	☒	☐	☐
OIL LEAKS	☐	☒	☐
NEEDS PAINTING	☐	☒	☐
BROKEN INSULATORS	☐	☒	☐
AIR BREAK CONDITION	☐	☒	☐
GROUND MAT	☒	☐	☐

Transformer Location: Iroquois MS#1

Comments: Oil samples taken by Spark no othe issues

Initials of Inspector: DR

SUBSTATION MAINTENANCE CHECKS

DATE: Nov.23, 2021

	YES	NO	NEEDS ATTENTION
WEED CONTROL	☐	☒	☐
FENCE	☐	☒	☐
LOCKED	☒	☐	☐
OIL LEAKS	☐	☒	☐
NEEDS PAINTING	☐	☒	☐
BROKEN INSULATORS	☐	☒	☐
AIR BREAK CONDITION	☐	☒	☐
GROUND MAT	☒	☐	☐

Transformer Location: Morrisburg MS#1

Comments: Oil samples taken by Spark and Ground study performed for upcoming work. Changed one loadbreak insulator as well

Initials of Inspector: DR

SUBSTATION MAINTENANCE CHECKS

DATE: Nov.23, 2021

	YES	NO	NEEDS ATTENTION
WEED CONTROL	☐	☒	☐
FENCE	☐	☒	☐
LOCKED	☒	☐	☐
OIL LEAKS	☐	☒	☐
NEEDS PAINTING	☐	☒	☐
BROKEN INSULATORS	☐	☒	☐
AIR BREAK CONDITION	☐	☒	☐
GROUND MAT	☒	☐	☐

Transformer Location: Morrisburg MS#2

Comments: Oil samples taken by Spark .

Extra sample taken at this location to verify if transformer can be refurbished after decommissioning

Initials of Inspector: DR

SUBSTATION MAINTENANCE CHECKS

DATE: Nov.25, 2021

	YES	NO	NEEDS ATTENTION
WEED CONTROL	☐	☒	☐
FENCE	☐	☒	☐
LOCKED	☒	☐	☐
OIL LEAKS	☐	☒	☐
NEEDS PAINTING	☐	☒	☐
BROKEN INSULATORS	☐	☒	☐
AIR BREAK CONDITION	☐	☒	☐
GROUND MAT	☒	☐	☐

Transformer Location: Prescott MS#1

Comments: no issues found and oil samples taken.

Initials of Inspector: DR

SUBSTATION MAINTENANCE CHECKS

DATE: Nov.23, 2021

	YES	NO	NEEDS ATTENTION
WEED CONTROL	☐	☒	☐
FENCE	☐	☒	☐
LOCKED	☒	☐	☐
OIL LEAKS	☐	☒	☐
NEEDS PAINTING	☐	☒	☐
BROKEN INSULATORS	☐	☒	☐
AIR BREAK CONDITION	☐	☒	☐
GROUND MAT	☒	☐	☐

Transformer Location: Prescott MS#2

Comments: Annual Maintenance performed no major issue found and oil samples taken.

Initials of Inspector: DR

SUBSTATION MAINTENANCE CHECKS

DATE: Nov.24, 2021

	YES	NO	NEEDS ATTENTION
WEED CONTROL	☐	☒	☐
FENCE	☐	☒	☐
LOCKED	☒	☐	☐
OIL LEAKS	☐	☒	☐
NEEDS PAINTING	☐	☒	☐
BROKEN INSULATORS	☐	☒	☐
AIR BREAK CONDITION	☐	☒	☐
GROUND MAT	☒	☐	☐

Transformer Location: Prescott MS#3

Comments: Annual Maintenance performed some minor issues fixed and oil samples taken.

Initials of Inspector: DR

SUBSTATION MAINTENANCE CHECKS

DATE: Nov.25, 2021

	YES	NO	NEEDS ATTENTION
WEED CONTROL	☐	☒	☐
FENCE	☐	☒	☐
LOCKED	☒	☐	☐
OIL LEAKS	☐	☒	☐
NEEDS PAINTING	☐	☒	☐
BROKEN INSULATORS	☐	☒	☐
AIR BREAK CONDITION	☐	☒	☐
GROUND MAT	☒	☐	☐

Transformer Location: Prescott MS#4

Comments: Annual Maintenance performed and no issues found and oil samples taken.

Initials of Inspector: DR

b) The current inspections and results are stored online on our One Drive cloud storage service. Before 2021 paper copies were utilized. Those records and results are stored physically in Operations Managers office.

c) These monthly inspections are reviewed vs. past inspections to determine if there is change over time. Separate to monthly inspections there are also oil sampling on a yearly basis to determine the condition of the substations. The results of the oil sampling over time are used to determine the if the conditions are worsening of substation transformers.

2-Staff-17

Ref 1: Filing Requirements Chapter 2 Appendices / App.2-AA Capital Projects

Preamble: In the capital projects listing, general plant category for 2022, there is $60k forecast for vehicles.

Question(s):

a) Please provide a material projects sheet, or similar business case and description, for this expenditure.

Response(s):

a) Please see project below:

RIDEAU ST. LAWRENCE DISTRIBUTION INC.		
	Project Year	2022
	Investment Category	Transportation Equipment
	Project Number	
	Community	RSL Fleet
	Project Title	Pick-up Truck Replacement

Account No	Amount	OEB Category	Rating
1930 - Transport	$ 60,000.00	Safety	0
	$ -	Environment	0
	$ -	Customer Value	0
	$ -	Economic Dev	0
		Co-ordination	0
		Security	0
TOTAL	**$ 60,000.00**	**Total Score**	**0**

Project Description
RSL has had an operating policy of replacing light trucks in a 5 to 7 year period and/or under 200,000km. This provides RSL with a reasonable trade-in value on the used vehicle, while reducing maintenance costs. This truck is used by the Operations Manager; it is used on a daily basis, so reliability is a must. These vehicles get a very high usage, since the Operations Manager oversees all aspects of field operations and coordination with third parties and customers. With the technology and ergonomics changing so quickly, it is good to be up to date on the latest vehicle technology to maintain efficient, safe and reliable operations.

Safety
An older vehicle, even maintained, will not have the safety features of a newer design vehicle. This will improve the safety for our workers and lower maintenance and operating costs.

Environment
Older vehicles are less efficient – a newer vehicle will likely be better for the environment.

Efficiency, Customer Value, Reliability
As mentioned above, since this vehicle is used by the Operations Manager, reliability is critical to keep response and recovery times down and outage statistics under check.

Economic Dev
This is not applicable to this project

Co-ordination
This is not applicable to this project

Security
This is not applicable to this project.

2-Staff 18

Ref 1: Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ p. 11/ Table 3 Exhibit 2/ Appendix 2.1 Distribution System Plan (DSP)/ p. 21

Preamble: Typical useful life of smart meters is listed as 15 years in Table 3 Rideau St. Lawrence Distribution's Asset Class Useful Life. Rideau St. Lawrence Distribution started installing smart meters in 2009.

Question(s):

a) When was the smart meter roll out completed?
b) Has Rideau St. Lawrence Distribution experienced increased volumes of smart meter failures due to age?
c) Does Rideau St. Lawrence Distribution anticipate implementing a smart meter replacement program during the test period?

Response(s):

a) The smart meter roll out was primarily completed in 2009 with the remaining completed in 2010.

b) Rideau St. Lawrence Distribution has seen increased meter failures due to age. Smart meter failures seem to occur with age and environment. In addition to age, Meters in direct sunlight fail quicker than meters not in sunlight.

c) Rideau St. Lawrence Distribution does not anticipate implementing a comprehensive smart meter replacement program during the test period. Smart meters are replaced as they fail. Samples of meters have been tested and verified by our third-party provider.

2-Staff-19

Ref 1: Exhibit 2/ p. 65

Preamble:

Rideau St. Lawrence Distribution stated that in the 2018 IRM it received approval for a rate rider for capital funding, which would end when rebased rates come into effect in 2022. In addition, Rideau St. Lawrence Distribution provided a summary of the actual capital funding received between 2018 and 2020 and the forecasted amount for 2021 (Table 2.24).

Question(s):

a) Please confirm that the 2021 rate rider revenues are actual rate riders collected. If not confirmed, please provide actual 2021 revenues, and explain why actual revenues are not used.

Response:

a) As stated in the preamble, the amount shown for 2021 of $53,000 was a forecast. The unaudited actual amount for 2021 is $53,779.76.

2-Staff-20

Ref 1: Exhibit 2/ p. 64-67
Ref 2: Decision and Rate Order, EB-2017-0265 Rideau St. Lawrence Distribution Inc./ p 4-5

Preamble:

At the above reference Rideau St. Lawrence Distribution confirms the digger truck arrived in 2017 and depreciation was recorded in 2017.

Rideau St. Lawrence Distribution indicated that the cost recovery for the digger truck beginning in 2018 is not an Incremental Capital Module as the digger truck entered service prior to 2018.

Question(s):

At the second reference above, the OEB stated that it "considers the approach used for incremental capital funding as part of this settlement proposal consistent with the OEB's Policy for the ICM." The OEB further indicated that the "name of the capital funding rate riders from the 2017 ICM rate rider to the 2018 ICM rate rider."

a) Please explain why Rideau St. Lawrence Distribution is proposing not to treat the digger truck as an ICM.

b) Please provide a calculation comparing the actual revenue requirement for the rate year and the actual rate riders collected up to April 30, 2022, similar to an ICM true-up calculation.

i) Please explain if the half year or full year depreciation was used on the actual revenue requirement true up calculation.

c) Please confirm the half year rule was applied in calculating the depreciation in 2017 when the truck came into service, and whether the opening rate base inclusion amount reflects four and a half years of depreciation (half year in 2017, and full year from 2018-2021).
d) Please indicate if half year or full year depreciation was used when determining the 2018 capital funding rate rider.

Response:

a) RSL understands that its treatment of the truck addition was unusual, but we believed it to be appropriate under the circumstances. This was our first opportunity to get capital funding after the 2016 Cost of Service application. The timing was backward. Our view was that an ICM is meant for a future purchase, not for a transaction that had occurred in the previous fiscal year. From our perspective, the truck was in our 2017 capital additions, and had a half year of depreciation recorded. RSL treated the truck as a normal capital addition, not knowing at the time if there would ever be any capital funding. When capital funding was approved in 2018, it did not seem correct to reverse audited historical entries for additions and depreciation and move the amounts into account 1508. Instead, we recorded the amounts from the rate rider as revenue, and recorded depreciation normally, as the truck was in our fixed assets.

b) The following table shows the annual revenue requirement and capital funding received. Please note that 2021 funding is unaudited as our external audit has not yet begun. 2022 funding is based on 4/12 of the 2021 funding.

In answer to i) we are unsure of the question. Reviewing the ICM model, the incremental capital was calculated by taking the net value of the truck ($355,327) as of December 31, 2017 (with half year depreciation). This amount was reduced by a full year of depreciation ($47,377) resulting in $307,950 in incremental capital to be included in the rate base.

Year	Revenue Requirement	Comments
2018	35,857.00	prorated from May 1 - December 31
2019	53,786.00	
2020	53,786.00	
2021	53,786.00	
2022	17,929.00	prorated from January 1 - April 30
	215,144.00	
Year	Capital Funding	Comments
2018	36,565.03	
2019	54,092.15	
2020	53,526.64	
2021	53,779.76	Unaudited
2022	17,933.00	Estimated from January 1 - April 30
	215,896.58	

c) The half-year rule was applied in calculating the depreciation in 2017. The opening rate base amount reflects 7.5 years of depreciation.

d) The full year depreciation was used when determining the 2018 capital funding rate rider. The following from the ICM model shows the full year of depreciation.

Return on Rate Base		
Incremental Capital	$	355,327
Depreciation Expense	$	47,377
Incremental Capital to be included in Rate Base	$	307,950

2-Staff-21

Ref 1: Exhibit 2/ p. 60

Preamble:

Rideau St. Lawrence Distribution stated the labour burden rate for this application was 54% compared with a 2020 rate of 53%.

Question(s):

a) Please explain the drivers for the labour burden rate.

b) Table 2.23 Overhead expense indicates the total O&M before capitalization increased 7.3% from the bridge to the test year. During the same period, administrative and general expenses increased by 11%. Please explain the drivers behind this increase.

Response:

a) The labour burden rate is determined by two primary drivers: Benefits (OMERS, CPP, EI, WSIB, EHT, and MEARIE health care premiums) and Days Off (vacation, statutory holidays, and sick time).

b) Administrative costs have increased in the test year at a higher percentage than OM&A in total. There are two primary drivers for the increase. The first is for labour. RSL hired a new President and CEO in the third quarter of 2021 and will hire a new CFO in the second quarter of 2022. The increased labour cost is expected due to higher market rates for the positions plus anticipated transition costs. The other driver may be considered the “return to normal” from the pandemic. Costs such as travel, training, and conferences were put on hold in 2020 and 2021. RSL test year amounts presume that pre-pandemic functions will return.

3-Staff-22

Load Forecast

Ref 1: Exhibit 3/ pages 5, 18

Preamble:
The load forecast is based on ten years of historic data, 2011 to 2020. The year 2021 is included as a

forecast year.

Question(s):

a) Please provide the customer connection counts by rate class for 2021.

b) Please provide actual energy consumption and demand by rate class for 2021.

c) Please provide monthly IESO purchases plus microFIT for 2021.

d) Please provide predicted purchases for each month of 2021 using the proposed load forecast model and actual 2021 heating and cooling degree days.

Response:

a) & b) RSL's 2021 actual customer counts and consumptions are provided in the following Table 3-Staff-22 a&b.

Table 3-Staff-22 a&b: 2021 Actual Customers and Consumptions

Rate Class	Actual Customers/Connections	Actual Consumption kWh	Actual Demand kW
Residential	5,117	43,612,856	
GS <=50 kW	730	17,739,759	
GS>50 kW	61	37,832,568	110,834
Unmetered	57	555,040	
Street Lights	1,712	643,596	1,746
Sentinel	70	88,607	246
Total	7,747	100,472,426	112,826

c) RSL's monthly IESO purchases plus microFIT for 2021 are provided in the following Table 3-Staff-22.c.

Table 3-Staff-22.c: 2021 Monthly Purchase kWh

Month	IESO Purchases	Microfit	Actual Purchases kWh
Jan-21	10,499,396	1,179	10,500,575
Feb-21	9,792,629	1,846	9,794,475
Mar-21	9,788,308	5,980	9,794,288
Apr-21	7,927,584	7,745	7,935,329
May-21	8,042,340	10,422	8,052,762
Jun-21	8,737,900	9,155	8,747,055
Jul-21	8,943,567	8,251	8,951,818
Aug-21	10,027,304	8,440	10,035,743
Sep-21	8,054,742	6,535	8,061,276
Oct-21	8,075,869	4,122	8,079,991
Nov-21	9,085,639	3,483	9,089,121
Dec-21	10,218,754	1,783	10,220,537
Total	109,194,032	68,940	109,262,972

d) Predicted monthly purchase for 2021 using the proposed load forecast model and actual 2021 heating and cooling degree days is shown in the following table.

Table 3-Staff-22.d: 2021 Predicted Monthly Purchase with Actual HDD & CDD

Month	Predicted Purchases kWh
Jan-21	10,385,227
Feb-21	9,671,543
Mar-21	9,605,250
Apr-21	7,677,658
May-21	7,664,691
Jun-21	8,274,292
Jul-21	8,019,997
Aug-21	9,469,844
Sep-21	7,096,098
Oct-21	7,367,331
Nov-21	8,678,226
Dec-21	9,924,387
Total	103,834,543

3-Staff-23

Customer Connection Forecast

Ref 1: Exhibit 3/ pages 18-19

Preamble:
Customer connections are forecasted based on a five-year geometric mean growth rate based on the years 2015 to 2020. Rideau St. Lawrence Distribution states that the customer connections are presented in a year-end format.
Question(s):
a) As a scenario, please provide the forecast that would result if the five years used were 2014 to 2019.

b) Please explain why a year-end forecast was used, and comment on the suitability of customer connections at the end of 2022 as opposed to the average for 2022 for setting billing determinants.

Response:

a) The following table displays the forecast for customer counts if 5 years of 2014-2019 were used.

Table 3-Staff-23.a: Forecasted Customer Counts with 5 years 2014-2019 Used

	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lights	Sentinel Lights	Unmetered Loads	Total
2021	5122	727	61	1712	73	57	7752
2022	5137	723	61	1712	73	57	7763

b) Year-end data has been used to forecast customer counts in RSL's COS applications. RSL understands that in a growing area where customer counts can change significantly over a year, using average numbers in forecast is necessary. In RSL's service areas, however, the customer base has been stable with a very small change in Residential and almost no change in other rate classes. RSL believes that using year end data is appropriate in the customer count forecast.

3-Staff-24

CDM

Ref 1: Exhibit 3/ page 23

Preamble:
Rideau St. Lawrence Distribution states that it expects CDM will continue to be implemented in its service territory in the bridge and test year. It states that the impact of this would be captured in the trend variable.

Question(s):
a) Please indicate the amount of new CDM estimated to have been delivered or forecasted to be delivered in each year from 2011 to 2022.

b) Please comment on the suitability of a trend variable influenced by historic CDM activity to the test year influenced CDM in the bridge year and test year.

Response:

a) The following table displays the forecast for customer counts if 5 years of 2014-2019 were used.

Table 3-Staff-24.a: New CDM Savings

Year	New CDM Savings	Source
2011	1,014,000	Verified within IESO CDM framework
2012	585,366	Verified within IESO CDM framework
2013	412,313	Verified within IESO CDM framework
2014	1,210,843	Verified within IESO CDM framework
2015	1,471,773	Verified within IESO CDM framework
2016	724,699	Verified within IESO CDM framework
2017	1,919,195	Verified within IESO CDM framework
2018	1,216,918	Verified within IESO CDM framework
2019	N/A	4,764 is verified within IESO CDM framework upon April. Saving information in the interim framework not available
2020	N/A	94,582 is verified Legacy CFF projects completed in 2020. Saving information in the interim framework not available
2021	N/A	Saving information in the new IESO CDM framework not available
2022	N/A	Saving information in the new IESO CDM framework not available

b) The time trend variable in the regression model is statistically significant. The time trend variable may be reflecting a number of potential consumption trends, including: conservation activities inside and outside of the CFF, improved building efficiency, and an increase in the proportion of customers that operate less energy-consuming businesses. The time trend reflects a gradual decline in consumption that is not explained by the other variables.

The time trend variable has been used in other LDCs's applications, such as ENWIN Utilities Ltd. COS (EB-2019-0032), and Greater Sudbury Hydro Inc.'s COS (EB-2019-0037).

RSL believes that the time trend is a suitable variable for RSL's load forecast model.

4–Staff–25

Ref 1: Exhibit 4, pages 31-32
Ref 2: EB-2015-0040 – Report of the Ontario Energy Board - Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs – pages 12, 13, September 14, 2017.

Preamble:
On December 15, 2021, Rideau St. Lawrence Distribution filed an Employee Post-Retirement Benefits document to update some of the information included in Exhibit 4. The updated information included interests and actuarial gain/loss in the calculation of the total defined benefit cost included in OM&A.
Reference 2 states:
"Under International Financial Reporting Standards (IFRS), a utility must recognize all actuarial gains and losses in OCI, but these amounts are never amortized into net income. Under Accounting Standards for Private Enterprises, all actuarial gains and losses are immediately recognized in net income. As the pension and OPEBs accrual amount that is recovered in rates is derived from the accounting expense recognized in net income, utilities who are recovering their pension and OPEB costs on an accrual basis under IFRS will not be able to dispose of any amounts pertaining to actuarial gains and losses because they will never form part of net income".
Question(s):
a) Please explain why Rideau St. Lawrence Distribution included actuarial gain/loss when calculating total defined benefit cost included in OM&A (Tables 4.40 – 4.16 and 4.41).

b) To ensure completeness of the record, please update Exhibit 4 and correct/update any other evidence impacted by the changes identified in responding to the interrogatories.

Response:

a) The Applicant agrees to exclude the actuarial gain/loss from the total defined benefit cost being used in OM&A calculation.

b) The tables related to Future Benefit Costs in Exhibit 4 were updated and presented as below.

Updated Table 4.40: 2020 Actual Post-Retirement Benefits

		December 31, 2019	December 31, 2020
Accrued Benefit Obligation, beginning of period	a	40,041	47,460
Current Service Cost for the ear	b	1,232	1,292
Cash Payments during the year	c	- 2,278	- 2,214
Interest Cost	d	1,135	1,495
Actuarial (Gain)/Loss	e	7,331	2,592
Accrued Benefit Liability, end of period	**f = a + b + c + d + e**	**47,460**	**50,625**
Defined Benefit Cost Recognized in Income Statement	g = b + d	2,367	2,787
Defined Benefit Cost Recognized In Other Comprehensive Income	h = e	7,331	2,592
Total Defined Benefit Cost included in OM&A	**I = g + h**	**$ 2,367**	**$ 2,787**

Updated Table 4.16: Post Retirement Benefit Costs in OM&A

Year	Expense
2016	$ 2,307
2017	$ 2,262
2018	$ 2,202
2019	$ 2,367
2020	$ 5,379
2021 Forecast	$ 3,307
2022 Forecast	$ 3,872

Updated Table 4.41: Forecast for Post-Retirement Benefits

		December 31, 2021	December 31, 2022
		Bridge Year Forecast	Test Year Forecast
Accrued Benefit Obligation, beginning of period	a	50,625	55,639
Current Service Cost for the ear	b	1,733	2,178
Cash Payments during the year	c	- 2,986	- 4,353
Interest Cost	d	1,574	1,694
Actuarial (Gain)/Loss	e	4,693	3,128
Accrued Benefit Liability, end of period	**f = a + b + c + d + e**	**55,639**	**58,286**
Defined Benefit Cost Recognized in Income Statement	g = b + d	3,307	3,872
Defined Benefit Cost Recognized In Other Comprehensive Income	h = e	4,693	3,128
Total Defined Benefit Cost included in OM&A	**I = g + h**	**$ 3,307**	**$ 3,872**

4-Staff-26

Ref 1: Exhibit 4/ p. 78

Preamble:
Rideau St. Lawrence Distribution stated that the detailed project level savings file and the third-party evaluation reports have not been submitted with its application due to the sensitivity of privacy information of our customers listed in the file. Rideau St. Lawrence Distribution further stated that if this file is required, it will submit with confidentiality at the OEB's request.

Questions(s):
c) Please identify what projects and savings and for what years in the LRAMVA Workform that the project level savings file relates to.

d) Please identify what projects and savings and for what years in the LRAMVA Workform that the third-party evaluation reports relates to.

Response:

c) Below is a table derived from the LRAMVA Model that summarizes CDM savings related to the Participation and Cost Report.

Table 4-Staff-26.a: CDM Savings from Participation and Cost Report

Source	Implementation Year	Projects	Savings in kWh
2019.04 Participation and Cost & Project List	2017	Save on Energy Coupon Program	413
	2017	Save on Energy Heating and Cooling Program	8,681
	2017	Save on Energy Home Assistance Program	90,046
	2017	Save on Energy Small Business Lighting Program	65,502
	2017	Save on Energy Retrofit Program	78,004
	2017	Save on Energy Energy Manager Program	623,157
	2018	Business Refrigeration Local Program	13,909
	2018	Save on Energy Retrofit Program	977,601
	2018	Save on Energy Small Business Lighting Program	61,149
	2018	Save on Energy Heating and Cooling Program	36,059
	2018	Save on Energy Coupon Program	127,199
	2019	Save on Energy Small Business Lighting Program	4,764

d) Below is a table derived from the LRAMVA Model that summarizes CDM savings related to third party reports.

Table 4-26.b: CDM Savings from Third Party Reports

Source	Implementation Year	Projects	Savings in kWh
Third Party Reports	2017	Save on Energy Retrofit Program	44,975
	2017		4,873
	2017		1,167
	2018	Save on Energy Retrofit Program	1,001

4-Staff-27

Ref 1: LRAMVA Workform/ Tab 1
Ref 2: Exhibit 4/ p. 81

Preamble:
The note in tab 1 (cell B87) of the LRAMVA Workform states the following: “Management decided to request an interim disposition of 2019 LRAMVA only in 2022 COS. Leave 2020 and 2021 to 2023 IRM.” However, as part of the application, in Exhibit 4, when discussing the LRAMVA Rate Rider, Rideau St. Lawrence Distribution indicates that it is “proposing disposition for Account 1568 LRAMVA over 1 year through LRAMVA Rate Riders, effective from January 1, 2022, to December 31, 2022.”
Questions:

a) Please reconcile these two statements referenced above and confirm whether Rideau St. Lawrence Distribution is seeking disposition of its LRAMVA balance on an interim or final basis.

Response:

a) RSL is seeking disposition of its 2019 LRAMVA balance on an interim basis through this Application.

5-Staff-28

Cost of Capital

Ref 1: Exhibit 5

Question(s):
a) Please update 2022 cost of capital parameters in accordance with the OEB's letter dated October 28, 2021.

Response:

a) RSL has used the short-term debt rate in its application. Consistent with its 2016 Cost of Service application, RSL has used its actual long-term debt rate of 3.69%. RSL believes that the use of the actual rate is appropriate.

7-Staff-29

Weighting Factors

Ref 1: Exhibit 7/ pages 8-10

Preamble:

A services weighting factor over zero exists for every rate class.
Rideau St. Lawrence Distribution states that it reviewed the billing and collecting weighting factors used in its 2016 COS Application and concluded that it is appropriate to use them in this application.
OEB staff notes that the proposed billing and collecting weighting factor for GS 50 to 4,999 in this application is 2.3, while in the cost allocation model from the 2016 approved settlement, it was 2.6. Similarly, the Street Lighting weighting factor is 0.8 in this proceeding, and 0.9 in the 2016 approved settlement.
Question(s):

a) Please confirm that Rideau St. Lawrence Distribution customers are not responsible for providing their own service connections regardless of rate class.

b) If part a) cannot be confirmed, please briefly explain the circumstances under which Rideau St. Lawrence Distribution provides the service connection and in which circumstances the customer is responsible.

c) Please explain the reason for the difference between the billing and collecting weighting factors from the 2016 approved settlement and the 2022 application.

Response:

a) RSL confirms that customers are not responsible for providing their own service connections.

b) Not applicable.

c) In the Cost Allocation submitted as part of the settlement proposal for the 2016 rate application, billing and collecting weighting factors for GS 50 to 4,999 was 2.7, Street Lighting was 0.8., and Sentinel Lighting was 0.7. It appears that an error was made when entering the GS 50 – 4,999 and Sentinel Lighting weighting factors. It will be changed from 2.3 to 2.7 for GS 50-4,999 kW and from 0.8 to 0.7 for Sentinel Lighting.

7-Staff-30

Demand Allocators

Ref 1: Exhibit 7/ page 14

Preamble:

Rideau St. Lawrence Distribution states that it "intends to put plans in place to update its load profiles the next time when a cost allocation model is filed."

Question(s):

a) Please confirm that Rideau St. Lawrence Distribution commits to include a proposal to update its load profiles and resulting demand allocators in the next proceeding where it is required to file a cost allocation model.

Response:

a) RSL is reluctant to commit to including a proposal as it does not know the scope and cost of a project of this nature. RSL commits to begin the process by communicating with other LDCs to find out who has worked with them to create an updated profile, the cost, and the data required. Assuming that RSL can find an appropriate vendor to create the updated load profile, we will use that profile when we are next required to file a cost allocation model.

7-Staff-31

Revenue to Cost

Ref 1: Exhibit 7/ page 25

Preamble:

Rideau St. Lawrence Distribution proposes to adjust its revenue-to-cost ratios for every rate class closer to 100%. This is "in order to reduce some of the cross-subsidization that was occurring."

The Status Quo ratios result in one rate class, GS 50 to 4,999 kW above the range at 124.38%, while all remaining rate classes have revenue to cost ratios within the target ranges.

Question(s):

a) As a scenario, please provide the revenue-to-cost ratios, and rates that would result if Rideau St. Lawrence Distribution were to reduce the revenue-to-cost ratio for GS 50 to 4,999 kW to the upper bound of its range, 120%, and make offsetting increases to the rate classes below the range (Residential and Sentinel Lights) as required.

Response:

a) The resulting revenue-to-cost ratios and rates under the scenario that the upper boundary of 120% is set for GS 50 to 4,999 kW are displayed in the following table:

Table 7-31a： Requested Revenue to Cost Ratio Scenario with 120% for Industrial

Name of Customer Class	Previously Approved Ratios Most Recent Year: 2016	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	92.63%	90.83%	94.08%	85 - 115
General Service < 50 kW	111.95%	118.53%	108.01%	80 - 120
General Service 50 to 4,999 kW	114.20%	123.91%	120.00%	80 - 120
Street Lights	120.00%	111.32%	107.86%	80 - 120
Sentinel Lights	92.63%	85.22%	85.22%	80 - 120
Unmetered Loads	108.83%			80 - 120

7-Staff-32

Meter Reading

Ref 1: Cost Allocation Model, I7.1 Meter Capital/ I7.2 Meter Reading

Preamble:

On sheet I7.2 Meter Reading, the Street Lighting rate class has 72 meter reads per year. However, on sheet I7.1 Meter Capital, there are no meters assigned to the Street Lighting rate class.

Question(s):

a) Please explain the apparent inconsistency.

Response:

a) There are no physical meters for the street light class, but there are 6 customers with 12 billings each per year which is the source of the 72 meter readings. There is a cost related to the maintenance of consumption data at our service provider. The same number of meter readings were used in RSL's 2016 Cost of Service application, so we are being consistent with past practice.

8-Staff-33

Ref 1: Tariff Schedule and Bill Impact Model/ 3. Regulatory Charges

Question(s):

a) Please update 2022 Wireline Pole Attachment Charge in accordance with the OEB's letter dated December 16, 2021.

Response:

a) The Tariff Schedule and Bill Impact Model was updated for 2022 Wireline Pole Attachment Charge in accordance with the OEB's letter dated December 16, 2021.

8-Staff-34

Retail Transmission Service Rates

Ref 1: RTSR Workform/ sheet 4. UTRs and Sub-Transmission

Preamble:

Rideau St. Lawrence Distribution is fully embedded in Hydro One Networks Inc. (Hydro One). The RTSR model has been completed using 2021 rates for Hydro One. On December 14, 2021, after Rideau St. Lawrence Distribution's application, Hydro One's 2022 rates were approved.
Question(s):

a) Please provide an updated RTSR model populated with Hydro One's 2022 rates.

Response:

a) An updated RTSR model reflecting Hydro One's 2022 rates is being submitted together with this filing.

8-Staff-35

Low Voltage

Ref 1: Exhibit 8/ page 27

Preamble:

Rideau St. Lawrence Distribution has forecasted low voltage charges based on an estimate of inflation from 2021 host rates.

Question(s):

a) Please calculate the low voltage cost, and low voltage rates that would result if Hydro One's current 2022 rates were used.

Response:

a) The low voltage cost and low voltage rates forecast scenario based on the current Hydro One rates (EB-2021-0032) are calculated in the following Table 8-Staff-35 a.

It is noticeable that the requested 2022 LV forecast scenario with 2022 Hydro One rates is significantly lower than historical actuals, as shown in Table 8-Staff a2. RSL is concerned about the cash flow impact of future Hydro One's Low Voltage rate increases should this forecast scenario be used. RSL proposes to keep the Low Voltage total as included in its original application.

Table 8-Staff-35 a: Requested 2022 LV Cost Scenario with 2022 Hydro One Rates

Hydro One LV Charges	Unit	Forecast Volume	2022 Hydro One Rates	Resulting 2022 LV Expense Forecast	
			EB-2021-0032		
Monthly Service Charge	Account	10	612.97	73,556	
Fixed Rate Riders	Account	10	36.18	4,342	
Fixed Rate Riders	Account	10	-	-	
Common ST Lines	kW	204,328	1.6208	331,175	
Volumetric Rate Rider	kW	204,328	0.0540	11,034	
Shared LVDS	kW	20,498	1.6888	34,617	
Total				454,724	
	Requested 2022 Forecasted Low Voltage Charges & Rates Scenario				
Customer Class	**% Allocation**	**Allocated Charge $**	**Volumes (non loss adjusted)**	**Volumetric Rate Type**	**Resulting LV Rates**
Residential	44.70%	203,266	43,536,196	kWh	**$ 0.0047**
GS < 50 kW	16.22%	73,769	17,290,656	kWh	**$ 0.0043**
GS 50 to 4999 kW	38.03%	172,949	99,076	kW	**$ 1.7456**
Street Lighting	0.47%	2,134	1,744	kW	**$ 1.2236**
Sentinel Lighting	0.07%	322	258	kW	**$ 1.2488**
Unmetered Scattered Load	0.50%	2,284	535,316	kWh	**$ 0.0043**
TOTALS	100.00%	**454,724**			

Table 8-Staff a2: Historical Low Voltage Costs

Year	Amount ($)	$ Increase	%
2019 Actual	475,270		
2020 Actual	565,692	90,422	19%
2021 Actual	599,105	33,413	6%
Requested 2022 Test Year Scenario	**454,724**	(144,381)	-24%

8-Staff-36

Loss Factors

Ref 1: Exhibit 8/ pages 23-24
Ref: EB-2020-0053, Decision and Rate Order, May 27, 2021

Preamble:

Rideau St. Lawrence Distribution states that the generation from microFIT has been included in the A(2) line.

The proposed total secondary loss factor of 1.0835 reflects an increase from the current approved loss factor of 1.0819.

Question(s):

a) Please explain the source for the A(1) line, and what is included in these values.

b) Is the supply from microFIT included in the A(1) line?

c) Please explain what has caused losses to increase since Rideau St. Lawrence Distribution's previous cost of service. What measures could Rideau St. Lawrence Distribution take to reduce losses or prevent losses from increasing further in the future?

Response:

a) RSL completed the Appendix 2-R Loss Factors per the instructions on that tab. Line A(1) is power purchase from the IESO. The kWh in line A (1) includes transmission losses as recorded at our metering points by our Settlement provider.

b) The supply from microFIT is not included in the A(1) line, as per the instructions on that tab.

c) The increase in RSL's losses is minor, 0.1479%. We have discussed the losses with our third-party engineer, and in his opinion, there is no sure way to determine the cause of this small change. Factors such as cold weather or small conductor can lead to increased losses. RSL does not have system monitoring equipment to identify and rectify potential loss issues.

8-Staff-37

Bill Impact Mitigation

Ref 1: Exhibit 8/ page 29

Preamble:

Residential customers consuming 304 kWh have a total bill impact of 15.2%. Rideau St. Lawrence Distribution states that it has explored various scenarios with respect to revenue-to-cost ratios and disposition of deferral and variance accounts.

Question(s):

a) As a scenario, please provide the bill impact that would result if the deferral and variance account recovery were extended to a second year.

Response:

a) The following table illustrates the bill impact scenario that the deferral and variance account recovery were 2-year period. The total recovery of deferral and variance accounts is $377,374. It would have a significant impact on RSL's cash flow status if the recovery were extended to a second year.

Table 8-staff-37 a: Requested Bill Impact Scenario with 2-year disposition of DVA Balances

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)	Units	Sub-Total						Total	
		A		B		C		Total Bill	
		$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ 8.06	29.7%	$ 9.68	25.5%	$ 11.08	23.1%	$ 10.18	8.4%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	$ 5.66	10.0%	$ 9.80	11.7%	$ 13.31	12.3%	$ 12.23	4.0%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 97.45	9.5%	$ (22.77)	-1.1%	$ 171.89	5.1%	$ 224.56	0.9%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	$ 3.46	17.2%	$ 4.97	16.7%	$ 6.24	16.2%	$ 5.73	5.2%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kw	$ 4.97	18.8%	$ 5.60	18.5%	$ 6.10	18.0%	$ 5.60	9.1%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	$ 548.30	16.7%	$ 524.40	15.3%	$ 555.06	15.2%	$ 631.93	8.6%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ 8.06	29.7%	$ 7.74	19.0%	$ 9.13	18.0%	$ 8.39	6.7%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	$ 8.01	29.5%	$ 8.67	27.2%	$ 9.24	25.7%	$ 8.48	13.2%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ 8.01	29.5%	$ 7.88	23.9%	$ 8.45	22.8%	$ 7.76	11.8%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	$ 5.66	10.0%	$ 4.61	5.1%	$ 8.12	7.0%	$ 7.46	2.4%

9-Staff-38

Ref 1: DVA Continuity Schedule/ Tab 2A
Ref 2: Exhibit 9/ p. 7

Preamble:

Rideau St. Lawrence Distribution indicated that: "the variance in account 1588 RSVA-Power is to reverse the true up amounts for 2017 and 2018 RPP GA costs which were included in the disposition from 2020 IRM as a result of the review of 2017 GL balances under the New Accounting Guidance". Table 9.3 details the adjustments shown in the Continuity Schedule, which is consistent with GA Analysis Workform.

Question(s):

a) Please provide further details on this adjustment, which pertained to changes in 2017 and 2018 RPP GA costs.

Response:

a) During the 2020 IRM (EB-2019-0066) interrogatory process, an adjustment of $44,796 was added to the 2017 balance of Account 1588 and another adjustment of $32,177 was added to the 2018 balance of Account 1588. The adjustments reflected the changes in RPP GA costs resulted from the review of our 2017-2018 GL balances under the New Accounting Guidance. The counter adjustments were made to 1589.

Since the two amounts have been disposed, reversal adjustments were made to 1588 and 1589 balances for this 2022 COS Application.

For reference, below is a table that RSL provided as a part of its IR response (Staff question 2 f) during 2020 IRM. The table summarized the result of RSL's review of 2017 and 2018 balances of Account 1588 and 1589.

Comparison of True-up Between Original RPP Billed Approach and the Wholesale Purchase Approach (New Accounting Guidance)

				Impact on 1588			Impact on 1589		
2018	New Accounting Guidance	RPP Billed Approach	Variance	Variance	Energy Cost	Materiality	Variance	GA Cost	Materiality
Adjustment Items	a	b	c = a -b	d = c	e	f = d/e	g =-c	h	i = g/h
RPP True up Amount	(2,093,257)	(2,091,201)	(2,056)	(2,056)					
RPP GA Cost	5,968,584	6,000,762	(32,177)	(32,177)			32,177		
Total	3,875,328	3,909,560	(34,233)	(34,233)	6,218,545	-0.55%	32,177	3,374,439	0.95%
	3,875,328	3,909,560	(34,233)	(34,233)	6,218,545	-0.55%	32,177	3,374,439	0.95%

				Impact on 1588			Impact on 1589		
2017	New Accounting Guidance	RPP Billed Approach	Variance	Variance	Energy Cost	Materiality	Variance	GA Cost	Materiality
Adjustment Items	a	b	c = a -b	c = a -b	d	e = c/d	f =-c	g	h = f/g
RPP True up Amount	(1,213,572)	(1,182,923)	(30,649)	(30,649)					
RPP GA Cost	6,185,601	6,140,804	44,796	44,796			(44,796)		
Total	4,972,029	4,957,882	14,147	14,147	6,762,075	0.21%	(44,796)	4,282,034	-1.05%
	4,972,029	4,957,882	14,147	14,147	6,762,075	0.21%	(44,796)	4,282,034	-1.05%

				Impact on 1588			Impact on 1589		
Two Years	New Accounting Guidance	RPP Billed Approach	Variance	Variance	Energy Cost	Materiality	Variance	GA Cost	Materiality
Adjustment Items	a	b	c = a -b	c = a -b	d	e = c/d	f =a-b	g	h = f/g
RPP True up Amount			-	(32,705)					
RPP GA Cost			-	12,619			(12,619)		
Total			-	(20,085)	12,980,620	**-0.15%**	(12,619)	7,656,473	**-0.16%**

9-Staff-39

Ref 1: DVA Continuity Schedule
Ref 2: Exhibit 9/ p. 25-26

Preamble:

Rideau St. Lawrence Distribution is requesting to dispose of Account 1518 – RCVA Retail and Account 1548 – RCVA STR, as of December 31, 2020, on a final basis and discontinue the accounts effective January 1, 2022.

Question(s):

a) Rideau St. Lawrence Distribution is requesting to discontinue the accounts effective January 1, 2022. Please explain whether Rideau St. Lawrence Distribution is able to forecast the 2021 balances in the accounts with reasonable accuracy. If so,

i. Please provide the 2021 transactions forecasted in a format similar to that in Table 9.22 and 9.24. If actuals are available, please provide them.

ii. Please discuss Rideau St. Lawrence Distribution's views on disposing the forecasted balance.

Response:

a) i. Below is an updated schedules of Account 1518 and Account 1548 to reflect our unaudited 2021 actual. Since the variance between the unaudited actual and the forecast in the original submission is so small for both accounts that the Applicant considers no need for updating the Continuity Schedule.

Table 9-staff a: Updated Table 9.22: 1518 Retail Cost Variance Account - Retail

	Revenues - USoA 4082	Expenses - USoA 5315	Principal (Variance)	Interest	Total Claim	2020 RRR 2.1.7	Variance of Account Bal. and RRR
2016	7,011	6,756	(255)				
2017	6,492	6,861	370				
2018	6,160	6,964	804				
2019	9,341	7,045	(2,296)				
2020	9,168	7,152	(2,017)				
Balance as of December 31, 2020			(3,394)	(129)		(3,523)	-
Add:							
Unaudited 2021 Actual	9,555	7,251	(2,304)	(26)			
Total			(5,697)	(155)	**(5,852)**		
Original Submission					**(5,587)**		

Table 9-Staff-39 a2: Updated Table 9.24: 1548 Retail Cost Variance Account - STR

	Revenues - USoA 4084	Expenses - USoA 5315	Principal (Variance)	Interest	Total Claim	2020 RRR 2.1.7	Variance of Account Bal. and RRR
2016	45	356	311				
2017	28	361	334				
2018	31	365	333				
2019	36	371	335				
2020	34	376	342				
Balance as of December 31, 2020			1,655	234		1,889	(0)
Add:							
Unaudited 2021 Actual	35	382	347	10			
Total			2,002	244	**2,246**		
Original Submission					**2,239**		

a) ii. Since the transaction amounts can be forecasted with reasonable accuracy, RSL requested disposing the forecasted balances of Accounts 1818 and 1548 as per the OEB's report dated November 29, 2018 on Retailer Services Charges (EB-2015-0304). The report states:

"The OEB does not see merit in electricity distributors continuing to track these variances any further past rebasing. Following rebasing, those distributors are expected to include in their revenue requirement the difference between forecast costs and revenues associated with retail services".

9-Staff-40

Ref 1: DVA Continuity Schedule/ Tab 2A
Ref 2: Exhibit 9/ p. 29-30

Preamble:

At the references 1 and 2, Rideau St. Lawrence Distribution shows a net impact to account 1592.

Question(s):

a) Please provide the detailed UCC continuity schedules used to calculate the differences between the legacy CCA rules and the accelerated rules for 2018 to 2021. As well, please show the revenue requirement impact of those annual CCA differences.

b) Please confirm if the 1592 balance was calculated based on approved capital additions from Rideau St. Lawrence Distribution's last cost-of-service proceeding, or actual capital additions in each year.

Response:

a) The following pages contain RSL's calculation of the differences between the legacy CCA rules and the accelerated rules.

1. The difference for 2018 was recorded in 2019. The accounting guidance letter issued July 25, 2019 ordered LDCs to record the CCA savings in a sub account of 1592.

2. The difference for 2019 was recorded in 2019 and the difference for 2020 was recorded in 2021. We have revised the amount of savings for each year. There was a misunderstanding at RSL about the way to calculate the difference between the accelerated CCA and the prior CCA amounts. We received guidance from our auditors and made the adjustments.

3. The estimated difference for 2021 has been recorded in 2021. We will confirm the numbers when the tax return has been completed for 2021.

4. The revenue impact should be the sum of the four years of CCA savings, which is $36,649 plus interest.

2018 CCA Savings

Class	Opening	Pre Nov 20 Additions	50% Rule	Net	CCA Rate	CCA	Post Nov 20 Additions	Uplifted by 1.5	CCA Rate	CCA	Total CCA	Undepr CCA
1	3,159,460	2,277	- 1,139	3,160,599	4%	126,424			4%	-	126,424	3,035,313
10	458,196	1,179	- 590	458,786	30%	137,636			30%	-	137,636	321,739
8	56,819	8,500	- 4,250	61,069	20%	12,214	5,259	7,888	20%	1,578	13,792	56,786
45	10,780		-	10,780	45%	4,851			45%	-	4,851	5,929
46	94		-	94	30%	28			30%	-	28	66
47	3,559,644	401,658	- 200,829	3,760,473	8%	300,838	118,957	178,435	8%	14,275	315,113	3,765,146
50	52,673	16,734	- 8,367	61,040	55%	33,572	3,564	5,346	55%	2,940	36,512	36,459
	7,297,666	430,348	- 215,174	7,512,840		615,563	127,780	191,669		18,793	634,356	7,221,438

Calculations without policy change

Class	Opening	Additions	50% Rule	Net	CCA Rate	CCA	Undepr CCA
1	3,159,460	2,277	- 1,139	3,160,599	4%	126,424	3,035,313
10	458,196	1,179	- 590	458,786	30%	137,636	321,739
8	56,819	13,759	- 6,879	63,698	20%	12,740	57,838
45	10,780		-	10,780	45%	4,851	5,929
46	94		-	94	30%	28	66
47	3,559,644	520,615	- 260,307	3,819,951	8%	305,596	3,774,663
50	52,673	20,298	- 10,149	62,822	55%	34,552	38,419
	7,297,666	558,128	- 279,064	7,576,730		621,827	7,233,967

***THIS IS THE UNDEPRECIATED BALANCE AS OF 2018-12-31
IF THERE HAD BEEN NO POLICY CHANGE.

Increase in CCA	12,529
Tax Rate	15%
Savings	1,879

2019 CCA Savings

Class	Opening	Additions	Uplifted by 1.5	CCA Rate	CCA	Undepr CCA
1	3,035,313	-		4%	121,413	2,913,900
10	321,739	1,246	1,869	30%	97,082	225,903
8	56,786	4,729	7,094	20%	12,776	48,739
45	5,929			45%	2,668	3,261
46	66			30%	20	46
47	3,765,146	500,296	750,444	8%	361,247	3,904,195
50	36,459	65,156	97,734	55%	73,806	27,809
	7,221,438	571,427	857,141		669,012	7,123,854

Calculations without policy change

Using opening balances as if nothing had ever changed and CCA was calculated the old way

Class	Opening	Additions	50% Rule	Net	CCA Rate	CCA	Undepr CCA	
1	3,035,313	-	-	3,035,313	4%	121,413	2,913,900	
10	321,739	1,246	- 623	322,362	30%	96,709	226,276	
8	57,838	4,729	- 2,365	60,202	20%	12,040	50,527	
45	5,929	-	-	5,929	45%	2,668	3,261	
46	66	-	-	66	30%	20	46	
47	3,774,663	500,296	- 250,148	4,024,811	8%	321,985	3,952,974	
50	38,419	65,156	- 32,578	70,997	55%	39,048	64,527	
	7,233,967	571,427	- 285,714	7,519,681		593,883	7,211,512	***THIS IS THE UNDEPRECIATED BALANCE AS OF 2019-12-31 IF THERE HAD BEEN NO POLICY CHANGE.
Increase in CCA					Increase in CCA	75,129		
					Tax Rate	15%		
					Savings	11,269		

2020 CCA Savings

Class	Opening	Additions	Uplifted by 1.5	CCA Rate	CCA	Undepr CCA
1	2,913,900	1,914	2,872	4%	116,671	2,799,144
10	225,903	-	-	30%	67,771	158,132
8	48,739	661	991	20%	9,946	39,454
45	3,261			45%	1,467	1,794
46	46			30%	14	32
47	3,904,195	588,909	883,364	8%	383,005	4,110,099
50	27,809	135,473	203,209	55%	127,060	36,222
	7,123,854	726,958	1,090,436		705,934	7,144,878

Calculations without policy change

Using opening balances as if nothing had ever changed and CCA was calculated the old way

Class	Opening	Additions	50% Rule	Net	CCA Rate	CCA	Undepr CCA	
1	2,913,900	1,914	- 957	2,914,858	4%	116,594	2,799,221	
10	226,276	-	-	226,276	30%	67,883	158,393	
8	50,527	661	- 330	50,858	20%	10,172	41,016	
45	3,261	-	-	3,261	45%	1,467	1,794	
46	46	-	-	46	30%	14	32	
47	3,952,974	588,909	- 294,455	4,247,428	8%	339,794	4,202,089	
50	64,527	135,473	- 67,736	132,264	55%	72,745	127,255	
	7,211,512	726,958	- 363,479	7,574,991		608,669	7,329,801	***THIS IS THE UNDEPRECIATED BALANCE AS OF 2020-12-31 IF THERE HAD BEEN NO POLICY CHANGE.
					Increase in CCA	97,265		
					Tax Rate	15%		
					Savings	14,590		

2021 CCA Savings

Class	Opening	Additions	Uplifted by 1.5	CCA Rate	CCA	Undepr CCA
1	2,799,144	-	-	4%	111,966	2,687,178
10	158,132	65,795	98,693	30%	77,048	146,879
8	39,454	10,469	15,703	20%	11,031	38,892
45	1,794			45%	807	987
46	32			30%	10	22
47	4,110,099	1,052,667	1,579,001	8%	455,128	4,707,638
50	36,222	20,327	30,490	55%	36,692	19,857
	7,144,878	1,149,258	1,723,887		692,682	7,601,454

Calculations without policy change

Using opening balances as if nothing had ever changed and CCA was calculated the old way

Class	Opening	Additions	50% Rule	Net	CCA Rate	CCA	Undepr CCA
1	2,799,221	-	-	2,799,221	4%	111,969	2,687,252
10	158,393	65,795	- 32,898	191,291	30%	57,387	166,801
8	41,016	10,469	- 5,234	46,250	20%	9,250	42,235
45	1,794	-	-	1,794	45%	807	987
46	32	-	-	32	30%	10	22
47	4,202,089	1,052,667	- 526,334	4,728,423	8%	378,274	4,876,482
50	127,255	20,327	- 10,163	137,419	55%	75,580	72,002
	7,329,801	1,149,258	- 574,629	7,904,430		633,277	7,845,782
					Increase in CCA	59,405	
					Tax Rate	15%	
					Savings	8,911	

***THIS IS THE UNDEPRECIATED BALANCE AS OF 2021-12-31 IF THERE HAD BEEN NO POLICY CHANGE.

b) The 1592 balance was calculated based on actual capital additions for 2018 to 2020. The calculations for 2021 are based on the unaudited additions.

An updated Table 9.28: 1592 Sub Account - CCA Changes and an updated Table 9.7 & Table 29: Reconciliation of 1592 Sub account CCA are provided below.

	Updated Table 9.28: 1592 Sub Account - CCA Changes				
	CCA Acceleration Savings (Principal)	Interest	Total Claim	2020 RRR 2.1.7	Variance of Account Bal. and RRR
2018	(1,879)				
2019	(5,789)				
2020					
Balance as of December 31, 2020	(7,668)	(144)		(7,812)	0
Add: 2020 Addition Recorded in 2021 GL	(14,590)				
Add: 2019 Correction to Savings	(5,480)				
Add: 2021 Forecasted Savings	(8,911)	(149)			
	(36,649)	(293)			
Remove 50% per Tax Sharing Rule	18,325	146			
	(18,325)	(146)			
Total	(18,325)	(146)	**(18,471)**		

Updated Table 9.7 & Table 29. : Reconciliation of 1592 Sub account CCA				
	Principal	Interest	Total	Note
2020 GL/RRR	(7,668)	(144)	(7,812)	
Add: 2020 Addition Recorded in 2021 GL	(14,590)		(14,590)	Adjustment
Add: 2019 Correction to Savings	(5,480)		(5,480)	Adjustment
Add: 2021 Forecasted Savings	(8,911)	(149)	(9,060)	Adjustment
2020 Adjustment to Remove 50% of 2020 Balance in the Continuity Schedule	18,325	146	18,471	Adjustment
			-	
2020 Balance in "2b.Continuity Schedule"	(18,325)	(146)	(18,471)	
Minus Disposition in 2021	-	-	-	
Projected Interest up to December 2021		(48)	(48)	
Claim as shown in "2b. Continuity Schedule"	(18,325)	(195)	(18,519)	
Variance			**(10,659)**	

9-Staff-41

Ref 1: Exhibit 9/ p. 16-17

Preamble:

At the first reference, Rideau St. Lawrence Distribution includes a paragraph from the OEB's Wireline Pole Attachment Charges Report (EB-2015-0304) that reads:

"For those LDCs that the new charge applies to, the increase in the pole attachment charge in the midst of an incentive rate-setting term will result in revenues earned being greater than amounts previously approved in an LDC's distribution rates. The excess incremental revenues will need to be accumulated by LDCs in a new variance account, with the closing balance ultimately refunded to ratepayers in the LDC's next cost-based rate application."

Also, at reference 1 Rideau St. Lawrence Distribution indicted that the incremental pole attachment revenue collected was offset by the incremental cost paid to Hydro One and Bell Canada to have access to their poles and it is proposing to include the incremental pole rental expense, and this dispose the net impact through this application.

Question(s):

a) Please provide a summary of amounts and quantity of poles driving the actual pole attachment revenues each year (2018, 2019, 2020, and 2021 forecast). Table 9.17 includes the dollar amounts but not quantities.

Response:

a) The calculation of joint use revenue at our 2016 COS rate and actual rate is detailed in the following table 9-Staff-41 a1. A variance analysis between the calculation and the amounts recorded in our GL is provided in table 9-Staff-41 a2. Since the GL revenue balances reflect actual revenues being reduced to match the COS rate, there is no need to make adjustments for the variance between the recorded revenue (before reduction to match the COS rate) and calculated revenue.

Table 9-Staff-41 a1: Calculation of Pole Rental Revenue (Account 4210)

Table 9-Staff-41 a1: Calculation of Pole Rental Revenue (Account 4210)															
	2016 Approved			2018 September - December						2019					
	Quantity	Unit Price	Amount	Quantity	Unit Price	Approved Price	Actual Amount	Amount at Approved Price	Incremental Revenue	Quantity	Unit Price	Approved Price	Actual Amount	Amount at Approved Price	Incremental Revenue
Company 1	383	22.35	8,560	383	28.09	22.35	3,586	2,853		383	43.63	22.35	16,710	8,560	
Company 2	470	22.35	10,505	470	28.09	22.35	4,401	3,502		470	43.63	22.35	20,506	10,505	
Company 3	151	22.35	3,375	151	28.09	22.35	1,414	1,125		151	43.63	22.35	6,588	3,375	
Company 4	24	11.18	268	24	14.04	11.18	112	89		24	21.81	11.18	523	268	
Company 5	146	22.35	3,263	146	28.09	22.35	1,367	1,088		146	43.63	22.35	6,370	3,263	
Company 6	795	22.35	17,768	804	28.09	22.35	7,528	5,990		804	43.63	22.35	35,079	17,969	
		-	-												
	1,969	22.35	$ 43,739	1,978			$18,408	$ 14,647	3,762	1,978	43.37	22.21	$ 85,776	$ 43,940	41,836
				2020						2021 Unaudited					
				Quantity	Unit Price	Approved Price	Actual Amount	Amount at Approved Price	Incremental Revenue	Quantity	Unit Price	Approved Price	Actual Amount	Amount at Approved Price	Incremental Revenue
Company 1				383	44.50	22.35	17,044	8,560		383	44.50	22.35	17,044	8,560	
Company 2				470	44.50	22.35	20,915	10,505		470	44.50	22.35	20,915	10,505	
Company 3				151	44.50	22.35	6,720	3,375		151	44.50	22.35	6,720	3,375	
Company 4				24	22.25	11.18	534	268		24	22.25	11.18	534	268	
Company 5				146	44.50	22.35	6,497	3,263		146	44.50	22.35	6,497	3,263	
Company 6				874	44.50	22.35	38,893	19,534		874	44.50	22.35	38,893	19,534	
				2,048	44.50	22.21	$90,602	$ 45,505	45,097	2,048	44.50	-	$ 90,602	$ 45,505	45,097
Grand Total													$285,389	$ 149,596	

Table 9-Staff-41 a2: Variance Analysis of Pole Rental Revenue Recorded and Calculated

	GL		Calculated		Variance		
	Actual Revenue	Revenue at 2016 COS Rate	Actual Revenue	Revenue at 2016 COS Rate	Variance at COS rates	Variance at Actual rates	
2016							
2017							
2018	18,408	14,647	18,408	14,647	(0)	(0)	
2019	70,206	44,208	85,776	43,940	268	(15,571)	*
2020	86,989	44,409	90,602	45,505	(1,095)	(3,613)	*
2021 Unaudited	90,602	46,332	90,602	45,505	827	-	
	266,204	149,596	285,389	149,596	0	(19,184)	
Note:	* Difference between actual current year billhng and prior year billing recorded in the current year for Bell.						
	Actual current year billing for Bell is not awailable until next year.						

1.0-VECC-1

Reference: Exhibit 1, Tab 4, Schedule 10

a) The referenced Conditions of Service at www.rslu.ca indicated it was prepared (by CHEC) in August 2014. Please confirm (or correct) that the document has been updated for all changes required by the OEB since August 2014.

Response:

a) RSL uses the Conditions of Service document that is prepared by CHEC. RSL is currently using the version that was updated by CHEC on March 15, 2017. The previous version from 2014 is on the RSL website in error.

CHEC released a new version of the Conditions of Service document in November 2021. RSL notified CHEC of our decision to use the new version. RSL will post the notice of the new document on its website and on Twitter for a three-month period to encourage customer input.

1.0-VECC-2

Reference: Exhibit 1, Tab 7, Schedule 4

a) What is the proportion of customers receiving e-bills?

b) In the last month (or other recent period) for which RSL has records please provide a breakdown of the methods of payment (e.g., mail cheque, e-payment, bank, or in person cash/cheque).

c) What programs does RSL have to encourage customers to move to e-billing and online or bank payment?

Response:

a) 15% of RSL customers receive eBills.

b) For payment information, using recent history does not provide a "normal" view of how our customers pay their bills. The RSL offices have been closed to the public since March 2020, only allowing customers inside by appointment. More customers have been paying their bills online during the pandemic. RSL expects payment patterns to return closer to normal once the offices are completely opened.

Payment Type	Quantity Dec-21
EFT	160
Credit Card	87
Mailed Cheque	253
Preauthorized Payment	1,640
Online/Bank	4,093
Cash	70
Cheque	193
Total	6,496

c) RSL regularly encourages customers to use eBilling and preauthorized payments. The RSL website has information about the eBilling program. RSL has sent bill stuffers promoting eBilling and promotes both programs every month on the bill envelopes.

2.0-VECC -3

Reference: EB-2015-0100, Exhibit 2, Appendix 2.1 2016 DSP, page 57-

The following tables were provided as part of RSL's last distribution system plan (DSP).

2016 Material Project List				
Project ID	Community	Description	OEB Category	Total Project Cost
1602	All Areas	PCB Transformer Replacements	System Renewal	$ 52,374.00
1607	Westport	Sewage Plant	System Access	$ 119,570.42
1610	Iroquois	MS - Second Transformer - remaining work	System Renewal	$ 50,000.00
Truck	All	Digger Truck	General Plant	$ 390,000.00

2017 Material Project List				
Project ID	Community	Description	OEB Category	Total Project Cost
1703	Iroquois	Church St North side rear lot along park	System Renewal	$ 70,655.40
1705	All Areas	PCB Transformer Replacements	System Renewal	$ 52,374.00
1707	Prescott	MS#1 QL2 - Change 3 main breakers to reclosers	System Renewal	$ 150,000.00

2018 Material Project List				
Project ID	Community	Description	OEB Category	Total Project Cost
1801	Iroquois	Church St South side rear lot from Bay to Elizabeth	System Renewal	$ 92,873.63
1803	Prescott	Victor Rd. Small Conductor #4	System Renewal	$ 94,900.70
1807	All Areas	PCB Transformer Replacements	System Renewal	$ 52,374.00

2019 Material Project List				
Project ID	Community	Description	OEB Category	Total Project Cost
1901	Morrisburg	Kyle St rear lot South side from Farlinger to Laurier	System Renewal	$ 72,610.60
1904	Prescott	South Square Small Conductor	System Renewal	$ 54,319.40
1905	Prescott	Royal Crescent Small Conductor	System Renewal	$ 62,106.80
1908	All Areas	PCB Transformer Replacements	System Renewal	$ 52,374.00

2020 Material Project List				
Project ID	Community	Description	OEB Category	Total Project Cost
2001	Morrisburg	MS2 - New feeder F3 on opposite side of road	System Service	$ 76,730.80
2007	All Areas	PCB Transformer Replacements	System Renewal	$ 52,374.00

a) For each year of the referenced material projects shown in these tables please indicate whether the project was completed, the year it was put in service, and the total capital expended. If any projects attracted capital contributions please note that separately.

Response:

a) The following table provides information about the projects. Please note that some of the individual projects were cancelled and absorbed into Bell Fibre To Home projects which encompass large areas of the community. Because of this, we can confirm that projects were completed, but specific costs are not available.

PCB transformer replacements are ongoing. Each year a project is set up to capture the costs. However it is important to understand that in many cases the PCB transformers are replaced as part of a larger job and as such the costs become part of the job instead of being in the specific PCB replacement job.

Project Name	DSP Year	In Service Year	DSP Budget	Comments	Costs 2016	2017	2018	2019	2020	Contributed
Westport Sewage Plant	2016	2017	119,570			73,130				- 95,523
Iroquois remaining work	2016	2016	50,000		90,203					
Digger Truck	2016	2017	390,000			379,015				
Church St North Side	2017	2017	70,655			83,431				
Prescott breakers to reclosers	2017	2018	150,000				224,582			
Church St South	2018		92,874	moved to 2024						
Victor Rd	2018	2019	94,901					108,178		- 37,400
Kyle St South	2019	2022	72,611							
South Square	2019	2022	54,319	Became part of Bell Fibre project						
Royal Cresc	2019	2021	62,107	Became part of Bell Fibre project						
Morrisburg MS2 New Feeder	2020		76,731	Project cancelled						
PCB Transformers	ALL		209,496	Ongoing - some costs in various projects	750	11,371	17,131	36,607	4,181	

2.0-VECC -4

Reference: Exhibit 2 Appendix 2.1 DSP, page 18 (PDF 89)

a) Table 6 shows that RSL's actual capital spending during the 2016 to 2020 period was significantly different than the DSP forecast (35% higher). While detailed variance analysis is provided at section 4.4 of the DSP no explanation has been provided as to the reasons RSL was unable to maintain a capital plan more closely aligned (in dollars) with its original estimates. Please explain the main reasons for the significant capital overspending during the last rate period as compared to the last Board reviewed DSP.

Response:

a) The DSP created for 2016 to 2020 was for gross, not net capital expenditures. This was our first DSP, and it was viewed as a starting point, a living document that would change every year as projects developed and evolved. In other words, the DSP is constantly changing to meet the needs of our customer and of RSL. The DSP filed with a rate application is a snapshot of what we want to do over the next 5 years, with an inherent assumption that nothing will change. Customer-driven projects can greatly change the timing of DSP – planned projects.

There were three projects that increased our capital spending:

1. Iroquois Backup Transformer – the amount in the DSP was an estimate, and the actual cost was an additional $40,000.

2. The Prescott MS1 Breakers to Reclosers project had a change in scope. Instead of the original replacement, our then Operations Manager and our CEO agreed to change the switchgear instead. The project cost increased by $75,000 because of this decision.

3. Bell began an unexpected major project, the Fibre To Home project. In 2020, our gross capital expenditure for this project was $172,000.

It is important to note that our overall net capital expenditures were 13% higher than the DSP total. Please see the following summary:

DSP versus Gross and Net Capital Expenditures									
								% Variance	% Variance
	2016	2017	2018	2019	2020	Total		From Plan	From Plan
Plan	809,000	459,000	450,000	457,000	454,000	2,629,000			
Gross	480,000	1,202,000	559,000	571,000	760,000	3,572,000		943,000	36%
Net	381,000	1,078,000	496,000	432,000	584,000	2,971,000		342,000	13%

2.0-VECC -5

Reference: Exhibit 2, Appendix 2-AB/ Exhibit 2, Tab 2, Schedule 1, page 29, Table 2.10

a) Please explain how the forecast capital contribution amount of $200k for 2022 was estimated.
b) Please explain why the 2016 through 2021 capital contributions shown in Appendix 2-AB do not match those shown in Table 2.10 of the evidence.

Response(s):

a) The forecast capital contribution of $200K for 2022 was estimated by working with the Bell Fibre to Home project manager. In 2021 Bell Fibre to Home was completed in many streets in Prescott. Rideau St. Lawrence Distribution utilized the capital cost contribution in Prescott in 2021 to scale for the Bell Fibre to Home work in scope for 2022.

b) Capital Contributions from 2016 – 2021 in Appendix 2-AB do not match those shown in Table 2.10 of the evidence because 2.10 is a cumulative number while Appendix 2-AB is an annual number.

2.0-VECC -6

Reference: Exhibit 2, Tab 4, Schedule 2 / Appendix 2-AB/Table 2.20

a) In the 2017 the DSP planned capital expenditures were $459k. The actual expenditures in that year were considerably different - $1,202k, a difference of approximately $743k. In addition to the digger truck (379k) in 2017 what were the other reasons for the major variation from the DSP forecast for that year.

Response:

a) RSL agrees that the purchase of the digger truck was the single most significant variance factor. There were others. In the DSP, there was a station project to change breakers. The project was budgeted at $150,000, but the final cost was $239,000. A decision was made at the time to replace the switchgear instead of the original plan to change breakers to reclosers.

   Two other additions were unusual. First, in the 2016 Cost of Service decision, MDMR costs in account 1555 were disposed. The financial transactions resulted in offsetting increases to assets and accumulated depreciation of $41,897. The second addition was the result of Hydro One Long Term Load Transfer assets being added to our system. The addition was $55,082.

2.0-VECC -7

Reference: Exhibit 2, Appendix 2-AA

a) Are the 2021 capital projects amounts shown in Appendix 2-AA (in Excel Updated 20220201) actuals amounts (audited or unaudited)?

Response:

a) The amounts in Appendix 2-AA are unaudited. Audited amounts will be available in late April or early May 2022.

2.0-VECC -8

Reference: Exhibit 2, Appendix 2.1 DSP, page14 (PDF 85)

a) Please provide the number of interruptions (frequency and number) by cause code for each year 2016 through 2021.

Response:

2016 Outages			
Outage Type	Number	Customers	Hours
Scheduled Outage	49	1,499	4,161.50
Loss of Supply	5	3,886	8,522.67
Tree Contacts	6	531	1,097.00
Lightning	1	1	3.00
Defective Equipment	10	59	152.00
Adverse Weather	3	130	420.00
Foreign Interference	4	30	73.50

2017 Outages			
Outage Type	Number	Customers	Hours
Scheduled Outage	32	599	1,422.50
Loss of Supply	6	8,163	19,890.60
Tree Contacts	5	43	116.00
Lightning	1	30	60.00
Defective Equipment	10	107	290.50
Adverse Weather	5	883	721.50
Foreign Interference	2	52	41.00

2018 Outages			
Outage Type	Number	Customers	Hours
Scheduled Outage	18	335	1,084.00
Loss of Supply	5	9,007	16,963.00
Tree Contacts	1	8	24.00
Lightning	1	50	200.00
Defective Equipment	8	222	415.00
Adverse Weather	8	944	958.50
Foreign Interference	2	11	41.50

2019 Outages			
Outage Type	Number	Customers	Hours
Scheduled Outage	23	1,316	5,028.50
Loss of Supply	7	6,395	16,650.00
Tree Contacts			
Lightning			
Defective Equipment	8	2,583	2,267.00
Adverse Weather	7	325	1,085.00
Foreign Interference	1	35	70.00

2020 Outages			
Outage Type	Number	Customers	Hours
Scheduled Outage	10	165	435.50
Loss of Supply	5	7,666	11,693.75
Tree Contacts			
Lightning			
Defective Equipment	1	250	75.00
Adverse Weather	2	65	190.00
Foreign Interference			

2021 Outages			
Outage Type	Number	Customers	Hours
Scheduled Outage	23	317	831.00
Loss of Supply	2	1,800	9,844.00
Tree Contacts			
Lightning			
Defective Equipment	5	42	107.00
Adverse Weather	2	55	105.00
Foreign Interference	4	117	509.00

2.0-VECC -9

Reference: Exhibit 2 Appendix 2.1 DSP, page 14 (PDF 87)

a) RSL shows a higher-than-average duration and frequency of outages (excluding loss of supply) in 2019. What were the reasons for this?

Response(s):

a) For 2019, Rideau St. Lawrence Distribution experienced 1.43 hours of interrupted power per customer. Two major outages contributed to the increase of this measure in 2019 over previous years.

   i. An outage was caused by defective connection at station #2 in Prescott, which affected 2,387 customers for 45 minutes.

   ii. A scheduled related to station maintenance in Iroquois, which affected 623 customers for 4 hours.

   Without the two events, RSL's measure would have been 0.71, comparable to prior years. The two events also caused the increase in frequency of outages in 2019.

   During the Prescott MS2 work in 2019, the primary connections crossed phases. When the station was brought online, the crossed phases led to a short circuit which seized the mainline for the outage. Upon fixing the issue the operations team reviewed the RSL work process and implemented countermeasures to prevent the issue from occurring in the future. The method of checking phasing on the job was adjusted. Feedback and training were provided to the power line technicians.

   The scheduled station maintenance at Iroquois, is an outage that RSL plans every 3 years. RSL only has a single station in Iroquois, the execution of maintenance on that station requires the shut down of the station which causes an outage for all customers in Iroquois. This station maintenance is planned with 3rd party contractors to maximize efficiency by minimizing the time required. The work is planned in the evening to minimize the impact to customers. This event will reoccur every 3 years.

2.0-VECC -10

Reference: Exhibit 2, Appendix 2.1 DSP, page 12

In the prior settlement the following commitment was made by RSL and ordered by the Board: "*prior to its next cost of service rebasing application, it will carry out an assessment of the underlying causes of its level of planned outages and scheduled outages and will file that assessment* ***together with Rideau St. Lawrence Distribution's recommendations*** *as part of Rideau St. Lawrence Distribution's next cost of service rebasing application*." (emphasis added)

a) Other than a description of outages by cause code (pages 13-17) We are unable to locate the agreed upon assessment or a report providing a summary of the results of the assessment and including the recommended actions to be taken. Please provide any such report or explain how this commitment was fulfilled.

b) What are the main causes of outages due to defective equipment?

c) Since the last DSP what steps has RSL taken to reduce the duration of scheduled outages?

Response(s):

a) Please see the Assessment of high numbers of planned and scheduled outages below.

Planned and Scheduled Outages Assessment

Note: Planned outage and Schedule outage terms are used interchangeably

Scheduled Outage occurrence are by far the largest greatest outages in the last DSP. Although the occurrences are reducing, it continues to be the highest outage for RSL.

	Number of Interruptions					
	5 years 2011-2015	5 years 2016-2020	Avg/year 2011-2015	Avg/year 2016-2020	Improvement Delta	Improvement %
9 - Foreign Interference	16	7	3.2	1.4	1.8	56%
8 - Human Element	0	0	0	0	0	0%
7 - Adverse Environment	1	0	0.2	0	0.2	100%
6 - Adverse Weather	26	21	5.2	4.2	1	19%
5 - Defective Equipment	51	31	10.2	6.2	4	39%
4 - Lightning	4	3	0.8	0.6	0.2	25%
3 - Tree Contacts	6	11	1.2	2.2	-1	-83%
2 - Loss of Supply	37	26	7.4	5.2	2.2	30%
1 - Shceduled Outage	134	115	26.8	23	3.8	14%
0 - Unknown/Other	3	0	0.6	0	0.6	100%
Total Unplanned	144	99	28.8	19.8	9	31%
Total Planned	134	115	26.8	23	3.8	14%
Overall Outages	278	214	55.6	42.8	12.8	23%

	Customer-Hours of interruption					
	5 years 2011-2015	5 years 2016-2020	Avg/year 2011-2015	Avg/year 2016-2020	Improvement Delta	Improvement %
9 - Foreign Interference	8866	186	1773.2	37.2	1736	98%
8 - Human Element	0	0	0	0	0	0%
7 - Adverse Environment	4	0	0.8	0	0.8	100%
6 - Adverse Weather	3140	2964	628	592.8	35.2	6%
5 - Defective Equipment	6497	3136	1299.4	627.2	672.2	52%
4 - Lightning	266	263	53.2	52.6	0.6	1%
3 - Tree Contacts	174	1222	34.8	244.4	-209.6	-602%
2 - Loss of Supply	97652	72120	19530.4	14424	5106.4	26%
1 - Shceduled Outage	4727	11162	945.4	2232.4	-1287	-136%
0 - Unknown/Other	42	0	8.4	0	8.4	100%
Total Unplanned	116641	79891	23328.2	15978.2	7350	32%
Total Planned	4727	11162	945.4	2232.4	-1287	-136%
Overall Outages	121368	91053	24273.6	18210.6	6063	25%

Areas of assessment:

Ongoing Trend:

The most recent 5 years results continue to show a healthy improvement of outage occurrences. Overall outages occurrences continue to decrease while driving down both unplanned and planned outage occurrences.

While scheduled outage occurrence continue to decrease, there is an increase of scheduled outage time.

Safety:

In every job task, a tailboard is utilized to discuss and align on the task at hand while evaluating the safety risk. The operations at RSL does not encourage the line worker employees to reduce scheduled outages occurrences or time by increasing safety risk. Safety and caring for each other is a value that is not compromised at RSL.

Preventative Maintenance Effectiveness & Efficiency:

RSLs preventative maintenance targets driving effectiveness then efficiency (unplanned then planned occurrences). Effectiveness is demonstrated by a reduction of Unplanned Outage Occurrences and unplanned customer-hours. Efficiency is driven by reduction in planned outage occurrences and customer-hours. Over the past 5 years effectiveness has improved by greater than 30% in both occurrence and customer time. While the planned outage occurrences decreased by 14%, the planned outage time increased.

Although RSL aims to getting to an ideal theoretical state of 0 outages in a cost-effective manner, RSL recognizes this is a journey. The results indicate RSL is on the right path of improvement. Increased scheduled customer-hours with reduced scheduled occurrences indicates the operations executed more maintenance and improvement per outage.

Approach to Staffing:

In order to optimize cost, RSL staffs and plans the scheduled work for 5 line workers or 4 (on occasions where one is on vacation). RSL staffs the crew based on the amount that are needed to complete the annual work in a safe manner, not based on reducing planned events. Increasing amount of line workers and assets could further reduce both planned outage occurrence and customer-hours. Based on our customer engagement results, this is not approach customers want to spend on achieving improved results.

Contractors are generally not utilized due to cost. The exception is work driven by Bell and Cogeco requests to upgrade the poles.

In Summary:

The amount of scheduled outage occurrences will continue to be the greatest outage occurrence at RSL. RSL will continue to drive efficiency in reduce the amount of scheduled outage occurrences.

b) The main cause of outages due to defective equipment was in 2019 the Prescott MS2 work, the primary connection in Prescott MS2 crossed phases. The downtime was < 1 hour but it affected 2387 customers. This event caused 57% of our overall outage duration. When the station was brought online, the crossed phases led to a short circuit which seized the mainline for the outage. Upon fixing the issue the operations team reviewed the RSL work process and implemented countermeasures to prevent the issue from occurring in the future. The method of checking phasing on the job was adjusted. Feedback and training were provided to the power line technicians.

c) Since the last DSP, RSL has taken the following action to reduce duration of scheduled outages:

   a. Recurring planning & scheduling meetings to group multiple outages together to drive efficiency.

   b. Increase thoroughness in reviewing of outage plan prior to outage plan for improved organization.

   c. Post outage review to seek opportunities to improve safety, coordination, and overall efficiency.

2.0-VECC -11

Reference: Exhibit 2 Appendix 2.1 DSP, page 18 (PDF 87)

a) Were the Asset Management System and the Job Cost software new initiatives as compared to the last DSP?

Response(s):

a) Asset management System and Job cost software system are not new initiatives as compared to the last DSP. They were in existence in the last DSP.

2.0-VECC -12

Reference: Exhibit 2 Appendix 2.1 DSP, page 27 (PDF 98)

a) With respect to the MS2 Morrisburg Relocation we are unable to find a business plan showing a detailed budget, construction start, and key milestone and completion dates. Please provide the implementation plan for this project.

b) Please provide the total amount estimated to be spent on this project and the expected in-service date for the relocated assets.

c) Please include an explanation of the plans for the retirement of the current station site.

Response(s):

a) Implementation plan
   a. Detailed Plan for Morrisburg MS2
      i. Cost Estimate: $1,000,000
         1. Tendering & Project management $25,000
         2. 5MVA Substation Transformer $500,000
         3. Civil work $250,000
         4. Poles, Wires, Conduit $225,000
      ii. Timeline

1.	Lock in on Engineering and Project Management	OND 2021
2.	Submission to OEB	OND 2021–JFM 2022
3.	Tendering Process	JFM 2022
4.	Civil work + awarded	May 2022
5.	Civil work complete	October 2022
6.	RSL construction of poles, crossarms, feeders	October 2022
7.	Transformer reclosure delivery	JFM 2023
8.	Station completion	July 2023
9.	MS2 in new location Online	October 2023
10.	OLD MS2 transformer offline	OND 2023
11.	Decommission Approach	Nov 2023
12.	Decommission	Dec 2023

   b. Total estimated spend is 1MM. In service date – October 2023.

   c. The decommissioning approach of Morrisburg MS2 OND of 2023.

2.0-VECC -13

Reference: Exhibit 2, Appendix 2.1 DSP, Appendix A

a) We are unable to locate any information with respect to the Bell Fibre to Home" project. Please provide a description of this project which details the spending beginning in 2020 and continuing through each year of the DSP.

Response(s):

a) Bell Fibre to Home project provides high speed, broadband internet service to homes which required 3rd party attachments to our poles. With the changes to RSL poles, it requires engineering to ensure proper strength and clearances are maintained on pole according to current 22/04 regulations.

$172,000	2020 Actual
$424,000	2021 Unaudited Actual
$178,000	2022 Estimate

2.0-VECC -14

Reference: Exhibit 2, Appendix 2.1 DSP, Appendix A Material Projects.

a) Please provide summary tables, similar to those provided in the last DSP (as shown in question #3) which shows the material projects in each of the years of the DSP (2022-2026) by category (i.e., System Access, Renewal, Service and General Plant). Please include a “Miscellaneous” category so as to show these tables with sums which are congruent with those in Appendix 2-AB (i.e., show Appendix 2-AB by material projects in each category).

Response:

2022 Material Project List				
Project ID	Community	Description	OEB Category	Total Project Cost
2211	Morrisburg	MS 2 Relocation Ph 1	System Access	500,000.00
Several	Morrisburg	Bell Fibre To Home	System Renewal	177,869.13
2202	All	Transformer Replacements	System Renewal	58,698.41
None	None	Vehicle Replacement	General Plant	60,000.00
Several	All	Miscellaneous	System Renewal	98,444.04
None	None	Miscellaneous	General Plant	34,000.00

2023 Material Project List				
Project ID	Community	Description	OEB Category	Total Project Cost
2311	Morrisburg	MS 2 Relocation Ph 2	System Access	500,000.00
2303	Cardinal	Hwy 2 E Small Conductor	System Renewal	54,337.13
2302	All	Transformer Replacements	System Renewal	58,698.41
2305	Westport	Concession St	System Service	49,105.00
None	None	Vehicle Replacement	General Plant	65,000.00
None	None	IVR System	General Plant	50,000.00
Several	All	Miscellaneous	System Renewal	145,407.55
None	None	Miscellaneous	General Plant	24,000.00

2024 Material Project List				
Project ID	Community	Description	OEB Category	Total Project Cost
2410	Prescott	MS 1 Transformer Replacement	System Renewal	250,000.00
2403	Iroquois	Church St S Rebuild	System Renewal	112,808.97
2404	Cardinal	Reid St Pole Trans	System Renewal	44,831.31
2402	All	Transformer Replacements	System Renewal	58,698.41
None	None	Elster Software Update	General Plant	50,000.00
Several	All	Miscellaneous	System Renewal	126,326.70
None	None	Miscellaneous	General Plant	39,000.00

2025 Material Project List				
Project ID	Community	Description	OEB Category	Total Project Cost
2509	Iroquois	MS 1 Transformer Replacement	System Renewal	250,000.00
2502	All	Transformer Replacements	System Renewal	58,698.41
2504	Prescott	Kingston Cr Pole Trans	System Renewal	93,928.64
2505	Prescott	Fort Town Dr Pole Trans	System Renewal	44,831.31
2503	Morrisburg	Kyle St Rebuild	System Renewal	92,373.18
None	None	Harris CIS/Financials Software Update	General Plant	75,000.00
Several	All	Miscellaneous	System Renewal	91,311.70
None	None	Miscellaneous	General Plant	89,000.00

2026 Material Project List				
Project ID	Community	Description	OEB Category	Total Project Cost
2602	Prescott	Boundary St New Feeder	System Service	150,000.00
2603	Prescott	Roberta Cr Pole Replacement	System Renewal	50,192.41
None	None	Bucket Truck Replacement	General Plant	400,000.00
All	All	Smart Meter reverification/replacement	System Renewal	70,244.00
Several	All	Miscellaneous	System Renewal	24,500.00
None	None	Miscellaneous	General Plant	40,000.00

2.0-VECC -15

Reference: Exhibit 2, Appendix 2.1 DSP, Appendix A Material Projects.

a) Other than the Morrisburg MS1 project (500k in each of 2022 and 2023) please confirm (or correct) that RSL is forecasting no amounts for new customer connections during the term of the DSP.

Response(s):

a) The demand forecasts show minimal additional demand residentially and a lower demand for industrial customers. RSL confirms, other than Morrisburg projects 2022-2023, it is not forecasting new customer connections during the term of DSP.

3.0-VECC -16

Reference: Exhibit 3, page 8

a) Please confirm that none of RSL's customers are market participants.

Response:

a) None of RSL's customers are market participants.

3.0-VECC -17

Reference: Exhibit 3, pages 12 & 14 and Appendix 3.2

Preamble: The Application states (page 12):
"*A Trend variable was used, indicating 1 in January 2011, and increasing by one each month, reaching 120 in the last month of the regression, December 2020. The time trend reflects a gradual decline in consumption that is not explained by the other variables. A number of the potential factors may be related to the trend, including conservation activities from and outside of the CFF, improved building efficiency, and an increase in the proportion of customers living in apartments, etc*."

The Application states (page 14):
"*In preparing its Load Forecast, RSL also considered but rejected the following variables:*
1) Customer Count (residential + commercial + industrial) – this was excluded because the variable yielded a negative coefficient, which is unintuitive.
2) GDP - this was also excluded because the variable yielded a negative coefficient, which is unintuitive."

a) It is noted that in Appendix 3.2 the appropriateness of a Customer Count variable was tested using equations with and without a Trend variable. However, the appropriateness of a GDP variable was only tested using an equation without a Trend variable. Please provide the results for a regression model similar to that use in Appendix 3.2 but which includes both a GDP and a Trend variable.

Response(s):

a) A regression scenario that uses both a GDP and a Trend variable is provided below. Similar to the regression scenario that uses a GDP but without a Trend, the coefficient for the GDP variable is a negative number, which is not intuitive.

SUMMARY OUTPUT									
Regression Statistics									
Multiple R	0.985432801								
R Square	0.971077805								
Adjusted R Square	0.968993322								
Standard Error	204916.6851								
Observations	120								
ANOVA									
	df	*SS*	*MS*	*F*	*ignificance F*				
Regression	8	1.56495E+14	1.9562E+13	465.8604	1.15E-81				
Residual	111	4.66098E+12	4.1991E+10						
Total	119	1.61156E+14							
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*ower 95.0%*	*lpper 95.0%*	
Intercept	6259288.704	1440946.72	4.34387241	3.11E-05	3403957	9114621	3403957	9114621	
HDD	4466.413963	94.8712744	47.0786757	3.49E-75	4278.42	4654.408	4278.42	4654.408	
CDD	15780.16709	772.6668128	20.4229906	2.15E-39	14249.08	17311.26	14249.08	17311.26	
Number of Days in Month	150691.1489	27243.8947	5.53118967	2.14E-07	96705.55	204676.7	96705.55	204676.7	
Winter/Summer Flag	344679.3861	49361.2834	6.98278818	2.24E-10	246866.7	442492.1	246866.7	442492.1	
Number of Workdays in Month	55531.74652	19927.63128	2.78667072	0.006265	16043.81	95019.68	16043.81	95019.68	
August Flag	429403.1735	76323.64925	5.62608284	1.4E-07	278162.8	580643.6	278162.8	580643.6	
Ontario Real GDP	-42681.51858	11861.13969	-3.5984332	0.00048	-66185.2	-19177.9	-66185.2	-19177.9	
Trend	-1385.344059	2261.045032	-0.6127008	0.541327	-5865.76	3095.068	-5865.76	3095.068	
Intuitive									

3.0-VECC -18

Reference: Exhibit 3, pages 12 & 23
RSL Load Forecast Model, CDM Activity Tab
The IESO’s 2021-2024 Conservation and Demand Management Framework Program Plan

Preamble: The Application states (page 12):
“A Trend variable was used, indicating 1 in January 2011, and increasing by one each month, reaching 120 in the last month of the regression, December 2020. The time trend reflects a gradual decline in consumption that is not explained by the other variables. A number of the potential factors may be related to the trend, including conservation activities from and outside of the CFF, improved building efficiency, and an increase in the proportion of customers living in apartments, etc.”

a) Table 3.17 includes savings in 2020 from 2020 CDM programs. However, the CDM Activity Tab in the Load Forecast Model does not identify any savings in 2020 from 2020 CDM programs. Please indicate (and provide) the source for the savings in 2020 from 2020 CDM programs as set out in Table 3.17.

b) It is noted that the CDM Activity Tab in the Load Forecast Model includes estimates of monthly CDM savings for the period 2011-2020. Did RSL test a purchase power model where either:

    i. Monthly CDM savings (adjusted for the ½ year rule) was included as an explanatory variable, or

    ii. Monthly CDM savings (adjusted for the ½ year rule) were added to the monthly purchased power values and regression models tested using the resulting total as the dependent variable?

   If either approach was tested please provide the resulting models along with the model's regression statistics.

c) If neither of the approaches in part (b) were tested or only approach (i) was tested please provide the results for approach (ii) as described in part (b).

d) Based on RSL's a share of total Ontario energy what would be RSL's share of the planned GWh savings for 2021 and 2022 per the IESO's 2021-2024 Conservation and Demand Management Framework Program Plan where total planned incremental savings are 542.9 GWh and 541.0 GWh respectively. Note: If RSL has a better estimate of the expected CDM savings from 2021 and 2022 programs, please provide.

e) Using the 2021 and 2022 CDM savings for RSL per part (d) and the regression model (per part (b)(ii) or part (c) – as applicable) please provide a forecast for RSL's 2022 power purchases – net of CDM activity.

Response(s):

a) The savings from 2020 new CDM programs are from a third party - Burman Energy's reports. The programs were in the previous CFF but were not completed until 2020.

b): RSL did try to test a purchase power model that reflected approach I and ii in preparing its load forecast. However due to the unavailability of CDM information in RSL's service areas for years after 2019, the test was abandoned.

c): As explained in answer to b), RSL is not able to prepare a regression model with a CDM adjustment or a CDM variable without a reliable source for CDM savings in RSL's service territory.

d) and e): There is no evidence showing that RSL's shares of the provincial CDM savings match RSL's shares of the provincial electricity consumptions each year. Therefore RSL does not endeavor to make a CDM estimate based on historical shares of provincial electricity consumption and then use this estimate to produce a load forecast.

3.0-VECC -19

Reference: Exhibit 3, page 16

a) Please provide a chart that compares the actual and predicted monthly purchases for the years 2018-2020.

Response(s):

a) The chart was included in the load forecast model tab “Purchased Power Model no CDM” (cellAH77) in the original submission.

3.0-VECC -20

Reference: Exhibit 3, pages 18 to 19

Preamble: The Application states: “The Customer Counts are presented in year-end format”.

a) If not provided in response to 3-Staff-22, please provide the actual 2021 year end customer count for each customer class.

b) Please explain why the historical 5-year geometric mean growth rate was used for the Residential and General Service customer classes to forecast the customer counts (as opposed to a longer period).

Response(s):

a) Please refer to the response to 3-Staff-22 for details.

b): RSL used a 5-year geometric mean growth rate to better reflect the most recent customer count trend.

3.0-VECC -21

Reference: Exhibit 3, pages 20-22
RSL Load Forecast Model, Rate Class Energy Model Tab

a) Please explain why a 5-year average loss factor was used to determine billed energy as opposed to a 10-year average (consistent with the historical period used to model power purchases).

b) For each of the Residential, GS<50 and GS>50 customer classes please comment on RSL’s view as to whether the average use for 2020 has been impacted by the COVID-19 pandemic.

c) Please explain more fully how the forecasted 2021 and 2022 total energy use by the Street Lights class was derived.

Response(s):

a) The loss factor used to determine billed energy is consistent with the result on Appendix 2-R Loss Factor that was calculated based on 5 year average. This is a standard approach and was used in our last COS application.

b): <u>Residential</u>

The following table is from Appendix-2IB Load Forecast Analysis and was included in Exhibit 3 page 31. For 2020, the consumption and consumption per customer both showed an increase - 3.3% and 3.5% for actual consumption, 2.3% and 2.4% for weather normalized, while the customer count had a smaller decrease by -0.1%. The increase in consumption per customer can be reasonably attributed to the COVID pandemic year when more people stayed at home or worked from home.

1 **Customer Class:** Residential — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2022 Cost of Service	Customers				Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2016*	Actual	5,071	OEB-approved		Actual	40,480,043.33	41,459,183.58	OEB-approved		Actual	7,982.65	8,175.74	OEB-approved	
Historical	*2017*	Actual	5,089			Actual	39,379,535.36	40,816,523.81			Actual	7,738.17	8,020.54		
Historical	*2018*	Actual	5,105			Actual	42,538,788.82	41,907,612.07			Actual	8,332.77	8,209.13		
Historical	*2019*	Actual	5,113			Actual	42,182,601.00	41,645,385.82			Actual	8,250.07	8,145.00		
Historical	*2020*	Actual	5,107			Actual	43,593,897.00	42,606,035.39			Actual	8,536.11	8,342.67		
Bridge Year	*2021*	Forecast	5,118			Forecast		43,191,009.09			Forecast	0.00	8,439.04		
Test Year	*2022*	Forecast	5,129			Forecast		43,536,196.04			Forecast	0.00	8,488.24		

Variance Analysis	Year	Year-over-year	Test Year Versus OEB-approved	Year	Year-over-year		Test Year Versus OEB-approved	Year	Year-over-year		Test Year Versus OEB-approved
	2016			*2016*				*2016*			
	2017	0.4%		*2017*	-2.7%	-1.6%		*2017*	-3.1%	-1.9%	
	2018	0.3%		*2018*	8.0%	2.7%		*2018*	7.7%	2.4%	
	2019	0.2%		*2019*	-0.8%	-0.6%		*2019*	-1.0%	-0.8%	
	2020	-0.1%		*2020*	3.3%	2.3%		*2020*	3.5%	2.4%	
	2021	0.2%		*2021*		1.4%		*2021*		1.2%	
	2022	0.2%		*2022*		0.8%		*2022*		0.6%	
	Geometric Mean	0.2%		Geometric Mean	2.5%	1.0%		Geometric Mean	2.3%	0.8%	

<u>GS < 50 kW</u>

The following table is from Appendix-2IB Load Forecast Analysis and was included in Exhibit 3 page 33. For 2020, the consumption and consumption per customer both showed a decrease - -5.9% and -5.4% for actual consumption, -6.9% and -6.4% for weather normalized, while the customer count had a smaller decrease by -0.5%. The decrease in consumption per customer may be related to the COVID pandemic year when business reduced capacity or were closed. Other factors may affect the average consumption in this customer class too, such as CDM activities.

2 **Customer Class:** GS < 50 kW — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kWh

	Calendar Year (for 2022 Cost of Service	Customers				Consumption (kWh) (3)	Actual (Weather actual)	Weather-normalized		Weather-normalized	Consumption (kWh) per Customer	Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	*2016*	Actual	740	OEB-approved		Actual	20,348,622.96	20,840,819.95	OEB-approved		Actual	27,498.14	28,163.27	OEB-approved	
Historical	*2017*	Actual	741			Actual	19,816,422.94	20,539,538.91			Actual	26,742.81	27,718.68		
Historical	*2018*	Actual	739			Actual	20,252,448.66	19,951,949.40			Actual	27,405.21	26,998.58		
Historical	*2019*	Actual	735			Actual	19,700,297.00	19,449,404.49			Actual	26,803.13	26,461.77		
Historical	*2020*	Actual	731			Actual	18,533,558.00	18,113,577.41			Actual	25,353.70	24,779.18		
Bridge Year	*2021*	Forecast	729			Forecast		17,747,657.26			Forecast	0.00	24,345.21		
Test Year	*2022*	Forecast	727			Forecast		17,290,656.16			Forecast	0.00	23,783.57		

Variance Analysis	Year	Year-over-year	Test Year Versus OEB-approved	Year	Year-over-year		Test Year Versus OEB-approved	Year	Year-over-year		Test Year Versus OEB-approved
	2016			*2016*				*2016*			
	2017	0.1%		*2017*	-2.6%	-1.4%		*2017*	-2.7%	-1.6%	
	2018	-0.3%		*2018*	2.2%	-2.9%		*2018*	2.5%	-2.6%	
	2019	-0.5%		*2019*	-2.7%	-2.5%		*2019*	-2.2%	-2.0%	
	2020	-0.5%		*2020*	-5.9%	-6.9%		*2020*	-5.4%	-6.4%	
	2021	-0.3%		*2021*		-2.0%		*2021*		-1.8%	
	2022	-0.3%		*2022*		-2.6%		*2022*		-2.3%	
	Geometric Mean	-0.4%		Geometric Mean	-3.1%	-3.7%		Geometric Mean	-2.7%	-3.3%	

<u>GS < 50 kW</u>

The following table is from Appendix-2IB Load Forecast Analysis and was included in Exhibit 3 page 34. For 2020, the consumption and consumption per customer both showed a decrease - -2.4% and -0.8% for actual consumption, -2.9% and -1.3% for weather normalized, while the customer count had a smaller decrease by -1.6%. Since the change in consumption is in line with historical trend, it is unclear whether the COVID pandemic had an impact on this customer class.

3 **Customer Class:** GS 50 to 4,999 kW — Is the customer class billed on consumption (kWh) or demand (kW or kVA)? kW

	Calendar Year (for 2022 Cost of Service	Customers				Consumption (kWh) (3)					Consumption (kWh) per Customer				
							Actual (Weather actual)	Weather-normalized		Weather-normalized		Actual (Weather actual)	Weather-normalized		Weather-normalized
Historical	2016	Actual	64	OEB-approved		Actual	39,456,019.00	39,918,744.30	OEB-approved		Actual	616,500.30	623,730.38	OEB-approved	
Historical	2017	Actual	63			Actual	38,286,678.00	38,964,064.32			Actual	607,725.05	618,477.21		
Historical	2018	Actual	65			Actual	37,703,866.30	37,432,623.76			Actual	580,059.48	575,886.52		
Historical	2019	Actual	62			Actual	37,004,001.00	36,775,509.71			Actual	596,838.73	593,153.38		
Historical	2020	Actual	61			Actual	36,107,964.00	35,711,248.23			Actual	591,933.84	585,430.30		
Bridge Year	2021	Forecast	60			Forecast		34,605,282.26			Forecast	0.00	576,754.70		
Test Year	2022	Forecast	59			Forecast		33,433,327.13			Forecast	0.00	566,666.56		

Variance Analysis	Year	Year-over-year	Test Year Versus OEB-approved	Year	Year-over-year		Test Year Versus OEB-approved	Year	Year-over-year		Test Year Versus OEB-approved
	2016			2016				2016			
	2017	-1.6%		2017	-3.0%	-2.4%		2017	-1.4%	-0.8%	
	2018	3.2%		2018	-1.5%	-3.9%		2018	-4.6%	-6.9%	
	2019	-4.6%		2019	-1.9%	-1.8%		2019	2.9%	3.0%	
	2020	-1.6%		2020	-2.4%	-2.9%		2020	-0.8%	-1.3%	
	2021	-1.6%		2021		-3.1%		2021		-1.5%	
	2022	-1.7%		2022		-3.4%		2022		-1.7%	
	Geometric Mean	-1.6%		Geometric Mean	-2.9%	-3.5%		Geometric Mean	-1.3%	-1.9%	

3.0-VECC -22

Reference: Exhibit 3, pages 25-26

a) Please explain why the 2021 and 2022 billing demand for Street Lights is assumed to be the same as that for 2020 when the forecast energy use in 2021 and 2022 is less than that in 2020.

Response(s):

a) Street Lights billing is a combination of the number of connections and the kW of each connection.

As explained in exhibit 3 for the forecast of customer count, the 2020 Actual connection number was proposed for the 2022 Test Year for Street Lights because the connection number of Street Lights has been stable since 2015 with 1 addition in 2020 and RSL does not expect changes in the number of Street Lights Connection for the 2022 Test Year.

For kW, all municipalities in RSL service territory have completed LED conversion projects. It is fairly certain that Street Light’s billing will be based on the same demand data (for kW) and load profile (for kWh) for 2022.

Please note the kWh consumption for Street Lights is not weather sensitive.

3.0-VECC -23

Reference: Exhibit 3, page 27

a) On February 10, 2022 RSL advised parties to the current proceeding that one of its largest customers plans to end operations in early 2023. Does RSL have any preliminary thoughts/views as if/how this event should be addressed as part of the consideration of its current Application?

Response:

a) RSL wanted to make all parties aware of the pending loss of this customer as it is a significant event for the community and for RSL. There may be a reduction in consumption, demand, and revenue due to this business closure. RSL wanted to be sure that everyone knew about this upcoming event in case it impacted on decisions related to the application.

3.0-VECC -24

Reference: Exhibit 3, pages 43 and 49-51

a) Please provide the 2021 actual Other Operating Revenue in the same format as Table 3.35.

b) If the actual values for all of 2021 are not available please provide the 2021 year to date values for those months where actual are available and the results for 2020 for the same months.

c) What is the basis for the forecasted increase in Loss on Disposition (#4360) in 2021 and 2022?

d) What was the pole attachment charged used to estimate the forecast 2022 revenue for Account #4210?

   a. If required please update the revenue forecast for Account #4210 to reflect the OEB's EB-2021-0302 Decision regarding pole attachment rates.

e) If required please, please update the forecast revenues from Retail Service Charges (Account #4082 and #4084) to reflect the OEB's EB-2021-0301 Decision.

Response(s):

a) & b) Appendix 2-H has been revised to reflect unaudited 2021 actual and updated 2022 forecast that Other Revenue as per IR 3-SEC-20.

c) The amount for Loss on Disposition is normal based on past history. Between 2016 and 2020 the amount has averaged $7,000. The amount included in the application is an estimate. The most significant losses are due to smart meter replacements.

d) The 2022 forecast for pole attachment revenue has been updated to reflect the new pole attachment charge $34.76 from the OEB's EB-2021-0302. Please see Appendix 2-H for more details.

e) The 2022 forecast for retailer service charges is an estimate based on historical actuals. The RSL will maintain the forecast for Account 4082 and 4084 in the original submission.

4.0 -VECC -25

Reference: Exhibit 4, pages, 6, 18-19

RSL notes that postage costs have increased by 20k since the last cost of service application.

a) Using the latest monthly billing (or otherwise most recent information RSL has) what is the percentage of customers who
   i. Receive an e-bill
   ii. Make an electronic or bank payment
   iii. Pay by cheque or cash

b) What steps has RSL taken to encourage/increase the number of e-bills and electronic or bank payments?

Response:

a) Please see the response to 1-VECC-2.

b) Please see the response to 1-VECC-2.

4.0-VECC -26

Reference: Exhibit 2, Section 4.6, page 45

a) If RSL is a member of the EDA please provide the annual dues for the 2016 through 2022 (forecast) period.

Response:

a) The following table shows the annual EDA dues.

EDA Annual Fees	
Year	Amount
2016	16,700.00
2017	16,900.00
2018	17,200.00
2019	17,500.00
2020	17,900.00
2021	18,100.00
2022	18,100.00

4.0 -VECC -27

Reference: Exhibit 4, page 13

a) Is any amount of the one-time costs for this application recorded in the year 2021 and shown in either Appendix 2-JA or 2-JC?

b) Are the amortized one-time costs of this application shown in Appendix 2-JA and 2-JC for 2022?

Response:

a) There are no one-time costs for this application recorded in 2021 shown in Appendix 2-JA or 2-JC.

b) The amortized one-time costs are shown in Appendix 2-JA and 2-JC for 2022.

4.0 -VECC -28

Reference: Exhibit 4, page 28

a) Please provide the one-time recruitment costs incurred in 2020 and 2021.

b) What are the expected one-time recruitment costs in 2022?

Response:

a) There were no recruitment costs in 2020. Total one-time recruitment costs in 2021 were $43,988.

b) In 2022, one-time recruitment costs will be a minimum of $24,000. This does not include transition costs, which will increase the one-time costs.

4.0 -VECC -29

Reference: Exhibit 4, page 32

a) Total benefit costs have increased significantly above inflation as between 2019 (515k) and 2022 (626k). What are the main reasons for this increase?

b) What portion of this increase is due to premium or other costs paid to MEARIE?

c) When was the last time that RSL investigated an alternative benefit provide to MEARIE?

Response:

a) There are two primary reasons for the increase in cost. The largest is for "days off" which incorporates statutory holidays, vacations, and sick time. RSL has a work force with many employees with multiple weeks of vacation. As employees gain more service time with RSL, they earn more weeks of vacation, and at a higher rate of pay. Sick time has increased, directly and indirectly because of COVID-19. Assumptions made about the number of sick days that an employee will take have changed. Instead of having an expectation that employees will work unless they are extremely sick, RSL now encourages employees to stay home if they are not well. This results in a higher number of sick days.

   The second driver is OMERS pension. OMERS is calculated based on earnings, which have grown over the years. The amount included in the application uses the expected earnings of current employees and the replacement of the CFO in 2022.

b) Very little of the increase is due to MEARIE. An extra $10,000 is the MEARIE impact. This is a 5% increase over 2019.

c) It is unknown when RSL last investigated an alternative benefit provider.

4.0 -VECC- 30

Reference: Exhibit 4, page 39-41

a) Please explain why the charges from RSL to Utilities for meter reading are forecast to fall from $61,628 in 2021 to $54,061 in 2022.
b) Similarly, there is a decrease in Billing costs charged by RSL to Utilities as between 2021 and 2022. What are the reasons for this decline?

Response:

a) In 2021, The amount of $61,628 is the portion of meter reading for RSL. In 2022, the RSL amount is forecast to be $48,180, a reduction in cost of $13,448. More costs are being retained by the Utilities company.

b) As in the first part of the question, these are the costs to RSL. The costs are decreasing by $8,930. The reason for the reduction is the cancellation of a third-party printing and mailing service used temporarily during COVID.

4.0 -VECC -31

Reference: Exhibit 4, Appendix 2-M/Table 4.30

a) Please provide the actual OEB annual assessment for year 2021.

b) Please explain any difference between this amount and the forecast amount of $24,800.

Response:

a) The actual OEB annual assessment for 2021 was $24,114.

b) The difference between the amounts is very small. The cost to LDCs is determined by the OEB.

5.0 -VECC -32

Reference: Exhibit 5, page 9

"*RSL proposes a Long Term Debt cost rate of 3.69% for 2022 which is slightly higher than the OEB's Deemed Long-Term Debt rate of 3.49 as prescribed in the Board's letter of October 28, 2021, "2022 Cost of Capital Parameters*".

a) What is the rationale for departing from the Board's guidance with respect to the setting of affiliated long-term debt?

Response:

a) As with our 2016 Cost of Service application, RSL believed it was preferable to use its actual LTD interest rate. We are being consistent with past practice.

7.0-VECC-33

Reference: Exhibit 7, pages 6, 7 and 10
RSL, Cost Allocation Model, Tabs 6.1, 6.2 and I8

a) In Tab 6.1 there is no TOA provided to any of the customers in the GS<50 class. However, Tab 6.2 indicates that one customer in the class own its own transformer and Tab I8 indicates that that the 4NCP value for Line Transformers is less than the Primary value. Please reconcile and confirm if any customers in this class own their own transformer.

Response:

a) The original submission was incorrect and has been changed.

7.0-VECC-34

Reference: Exhibit 7, page 5

a) Does RSL offer its customer the option of e-billing? If yes, for each customer class, how as the proportion of customers opted for e-billing changed in 2016 and 2020?

b) Please provide a copy of the analysis of Accounts 5315 – 5340, except 5335, that was conducted for the 2016 COS and the associated derivation of the billing and collection weighting factors used in the 2016 COS.

Response:

a) The following is the proportion of each customer class receiving eBills:

Category	2016	2021
Residential	7%	15%
GS < 50	7%	15%
GS 50-4999	17%	25%
Scattered Loads	22%	23%
Sentinel Lights	0%	7%
Street Lights	17%	17%

b) The weighting factors used in the 2016 COS were included as part of a detailed spreadsheet where we analyzed each line item. We cannot share that file, as it contains sensitive information about our vendors. As evidence of our analytical work, we are providing the section of the spreadsheet for Collecting and for Billing to show the validation we did of the weighting factors.

Collecting	Cost Allocated to Class						
	Res	Comm	Ind	ST	SL	SC	Total $
	14,442.49	2,027.52	224.58	2.71	1.80	18.94	16,718.04
	1,971.61						1,971.61
			5,852.56				5,852.56
	27,249.99	3,825.51	423.73	5.11	3.40	35.74	31,543.48
	1.80	0.25	0.03	0.00	0.00	0.00	2.08
	1,498.84	210.42	23.31	0.28	0.19	1.97	1,734.99
							-
	-	-	-	-	-	-	-
	-	-	-	-	-	-	-
	-	-	-	-	-	-	-
Total $	45,164.73	6,063.71	6,524.21	8.09	5.39	56.64	57,822.77
Class share %	78%	10%	11%	0%	0%	0%	100%
$ Per Customer	8.92	8.21	101.94	1.35	0.16	0.96	
Weighting Factor for Collecting	1.0	0.9	11.4	0.2	0.0	0.1	

Billing	Cost Allocated to Class						
	Res	Comm	Ind	ST	SL	SC	Total
	$	$	$	$	$	$	$
	334.62	48.81	0.42	-	-	-	383.86
	8,454.01	616.61	53.40	5.01	11.35	19.69	9,160.07
	1,111.16	162.09	14.04	1.32	7.46	12.94	1,309.00
	45,917.97	6,698.26	580.09	54.38	308.17	534.77	54,093.66
	1,634.06	238.37	20.64	1.94	10.97	19.03	1,925.00
	5,801.40	1,403.13	296.82	26.98	53.97	26.98	7,609.28
	34,829.15	5,080.68	440.01	41.25	233.75	405.63	41,030.47
	1,060.05	154.63	13.39	1.26	7.11	12.35	1,248.79
	11.97	1.75	0.15	0.01	0.08	0.14	14.10
	613.40	89.48	7.75	0.73	4.12	7.14	722.62
	10,014.09	1,460.80	126.51	11.86	67.21	116.63	11,797.10
	86,637.68	12,638.22	1,094.51	102.61	581.46	1,009.01	102,063.50
	1,293.47	94.34	-	-	-	-	1,387.81
	168.28	24.55	2.13	0.20	1.13	1.96	198.24
	731.37	106.69	9.24	0.87	4.91	8.52	861.59
	605.01	88.25	7.64	0.72	4.06	7.05	712.73
	3,925.93	572.69	49.60	4.65	26.35	45.72	4,624.94
	336.64	49.11	4.25	0.40	2.26	3.92	396.57
	37,816.57	5,516.47	477.75	44.79	253.80	440.42	44,549.80
	467.98	68.27	5.91	0.55	3.14	5.45	551.30
	287.67	41.96	3.63	0.34	1.93	3.35	338.89
	328.52	47.92	4.15	0.39	2.20	3.83	387.01
	- 249.80	- 36.44	- 3.16	- 0.30	- 1.68	- 2.91	- 294.28
	913.53	133.26	11.54	1.08	6.13	10.64	1,076.18
	259.75	37.89	3.28	0.31	1.74	3.03	306.00
	11,801.43	1,721.53	14.91	-	-	-	13,537.87
	415.35	60.59	5.25	0.49	2.79	4.84	489.30
	340.48	49.67	4.30	0.40	2.29	3.97	401.10
	552.18	80.55	6.98	0.65	3.71	6.43	650.50
	305.03	44.50	3.85	0.36	2.05	3.55	359.34
	19,347.12	2,822.25	24.44	-	-	-	22,193.81
	23,228.89	3,388.50	352.15	33.01	155.90	270.53	27,428.99
	2,842.02	414.58	35.90	3.37	19.07	33.10	3,348.04
	19.34	2.82	0.24	0.02	0.13	0.23	22.78
	103.32	15.07	1.31	0.12	0.69	1.20	121.72
Total Billing $	302,259.63	43,937.86	3,673.03	339.77	1,778.25	3,019.12	355,007.67
Class share %	85%	12%	1%	0%	1%	1%	100%
$ Per Customer	59.66	59.46	57.39	56.63	52.30	51.17	
Weighting Factor for Billing	1.00	1.00	0.96	0.95	0.88	0.86	
		Summary					
Customer Number	Res	Comm	Ind	ST	SL	SC	Total
Collecting $	45,164.73	6,063.71	6,524.21	8.09	5.39	56.64	57,822.77
Billing + Collecting	347,424.36	50,001.56	10,197.24	347.87	1,783.65	3,075.77	412,830.44
Customer Number	5066	739	64	6	34	59	5968
$ per Customer	68.58	67.66	159.33	57.98	52.46	52.13	
Weighting factor for Billing and Collection per customer	1.00	0.99	2.32	0.85	0.76	0.76	

8.0-VECC-35

Reference: Exhibit 8, pages 9-10
RSL RTSR Workform, Tabs 3 and 5

a) Please confirm that the RRR data in Tab 3 and the billing unit data in Tab 5 are both based on 2020 actual values. If not, what year is data in each Tab based on?

Response(s):

a): The data in Tab 3 and Tab 5 in RTSR model is based on 2020 actual.

8.0-VECC-36

Reference: Exhibit 8, pages 11-12

a) Please update the proposed 2022 Retail Service Charges to reflect the OEB's EB-2021-0301 Decision.

Response(s):

a): The following table shows the Retail Service Charges set up in the OEB Decision and Order EB-2021-0301 dated November 25, 2021. Tariff and bill impact model was also updated for the new charges.

Updated Table 8.10: Current Retail Service Charges Effective January 1, 2022		
Retail Service Charges		
One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	107.68
Monthly fixed charge, per retailer	$	43.08
Monthly variable charge, per customer, per retailer	$/cust.	1.07
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.64
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.64)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.54
Processing fee, per request, applied to the requesting party	$	1.07
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year no charge	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.31
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.15

8.0-VECC-37

Reference: Exhibit 8, pages 17-18

a) Please update the proposed 2022 Pole Attachment Charge to reflect the OEB's EB-2021-0302 Decision.

Response(s):

a): The following table shows the current Specific Service Charges with an updated Pole Attachment Charge set up in the OEB Decision and Order EB-2021-0302 dated December 16, 2021. Tariff and bill impact model was also updated for the new charge.

Updated Table 8.11: Current Retail and Specific Service Charges - New Pole Attachment Charge		
Effective January 1, 2022		
Customer Administration		
Arrears certificate	$	15.00
Statement of account	$	15.00
Pulling post-dated cheques	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement letter	$	15.00
Income tax letter	$	15.00
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Special meter reads	$	30.00
Non-Payment of Account		
Late payment - per month		
(effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection at meter - during regular hours	$	65.00
Reconnection at meter - after regular hours	$	185.00
Reconnection at pole - during regular hours	$	185.00
Reconnection at pole - after regular hours	$	415.00
Other		
Service call - customer owned equipment	$	30.00
Service call - after regular hours	$	165.00
Temporary service install and remove - overhead - no transformer	$	500.00
Temporary service install and remove - underground - no transformer	$	300.00
Temporary service install and remove - overhead - with transformer	$	1,000.00
Specific charge for access to the power poles - per pole/year	$	34.76

8.0-VECC-38

Reference: Exhibit 8, pages 19-22

a) Please update Tables 8.12 and 8.13 to include the 2021 actual values.

b) Please provide a forecast of 2022 LV costs based on Hydro One's approved 2022 rates (per EB-2021-0032) and RSL's actual 2021 ST billing quantities.

Response(s):

a) &b): Please see the response to 8-Staff-35 for details. 2021 actual billed kW for shared LVDs is provided in the following table.

	Billed kW for Shared LVDS				
Month	2018	2019	2020	2021-2022 Forecat = 2020 Actual	2021
					Actual
January	2,448	2,336	2,187		2,030
February	2,033	2,181	2,138		2,075
March	1,823	1,941	1,709		1,862
April	1,753	1,818	1,355		1,569
May	1,198	1,291	1,414		1,334
June	1,538	1,379	1,557		1,643
July	1,702	1,742	1,793		1,601
August	1,608	1,487	1,627		1,851
September	1,653	1,280	1,266		1283
October	1,534	1,376	1,600		1,600
November	1,974	1,875	1,749		1,749
December	1,983	2,205	2,104		2,104
Total	21,247	20,913	20,498	**20,498**	20,700

8.0-VECC-39

Reference: Exhibit 8, page 24
Exhibit 3, page 16

a) Please explain why neither of the historical purchase values set out in Table 8.16 (Rows A(1) and A(2)) match the historical actual purchases values in Table 3.8.

Response(s):

Answer a): RSL completed the Appendix 2-R Loss Factors per the instructions on that tab. Row A(1) is power purchased from the IESO. Row A (2) is the electricity that the Utility received, including received from the IESO (after supply loss) and microFit.

Table 3.8 is total power purchased from the IESO and from microFit.

8.0-VECC-40

Reference: Exhibit 8, page 29

Preamble: The Application states: "Concerning Foregone Revenues, RSL recognizes that due to the delay in the filing of this application, distribution revenues have been lost. RSL believes that Foregone Revenues should be considered in the final rate decision and order."

a) Given RSL's acknowledgement that the Application was filed late, why should consideration be given to "Foregone Revenues"?

Response:

a) RSL did not intend to file this application late, but the realities of working through the pandemic combined with the loss of our President and CEO (project leader) during the creation of this application caused delays. We at RSL worked very hard to submit this in 2021.

RSL is of the opinion that it should not be financially affected due to the timing of the submission of the application.

9.0 –VECC-41

Reference: Exhibit 9, page 15

Table 9.13: 1508 Sub Account – OEB Assessment Cost

	Included in Rates	Actual Amount	Principal (Variance)	Interest	Total Claim	2020 RRR 2.1.7	Variance of Account Bal. and RRR
2016 - 2012 COS	11,250	20,093	8,843				
2017 - 6 months of 2012 COS + 6 months	15,698	26,946	11,248				
2018 - 2016 COS	16,396	24,942	8,546				
2019 - 2016 COS	16,396	25,156	8,760				
2020 - 2016 COS	16,396	24,942	8,546	2,001			
Balance as of December 31, 2020, RRR			45,943	2,001		47,943	-
Add:							
Forecast to December 2021	16,396	24,044	7,648	286			
Total			53,591	2,287	**55,877.39**		

a) Please confirm (or correct) that the amounts shown in the "Actual Amount" column only include the OEB Annual Assessment s charges (i.e., a not OEB Section 30 or any other regulatory costs).

Response:

a) RSL confirms that the amounts shown in the Actual Amount column only include the OEB Annual Assessment charges.

9.0-VECC-42

Reference: Exhibit 9, page 22

"Rideau St. Lawrence Distribution Inc. shall establish a new deferral account, effective July 1, 2019, to record the difference between the Collection of Account Charges revenue included in its 2016 Cost of Service application (EB-2015-0100) and the actual revenue recorded for all customer classes."

a) Please provide a reference to the forecast revenue from Collection of Account Charges that was included in 2016 rates in EB-2015-0100.

b) It is unclear to us why, if an amount of forecast revenues for Collection of Account Charges was included in 2016 rates as part of EB-2015-0100, no amounts are shown in the "Revenue Approved in COS" column of Table 9.19 for the years 2016-1018? Please clarify.

Response:

a) The Collection of Account Charges revenue was not included in 2016 rates in EB-2015-0100. This was a revenue offset. The first line displays the revenue offset of $83,067.

Account 4235 - Specific Service Charges	**Actual Year²**	**Actual Year²**	**Actual Year²**	**Actual Year²**	**Actual**	**Actual Year**
	2012	**2013**	**2014**	**2014**	**2015**	**2016**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**
Collection Charges	$ 81,596	$ 66,600	$ 83,273	$ 83,273	$ 70,713	$ 83,067
Account History Charges	$ 423	$ 389	$ 375	$ 375	$ 60	$ 45
Occupancy Charges	$ 25,410	$ 26,636	$ 26,970	$ 26,970	$ 27,855	$ 25,980
Returned Cheque Charges (NSF)	$ 888	$ 1,068	$ 1,170	$ 1,170	$ 900	$ 1,140
Disconnect/Reconnect Charges	$ 4,830	$ 3,805	$ 3,795	$ 3,795	$ 4,930	$ 5,690
Micro-Fit Service Charges	$ 315	$ 321	$ 434	$ 434	$ 454	$ 454
Miscellaneous Charges	$ -	-$ 15	$ -	$ -	$ 330	$ -
Total	$ 113,461	$ 98,803	$ 116,016	$ 116,016	$ 105,242	$ 116,376

b) The approval of the new deferral account was effective July 1, 2019. This is the reason why amounts from prior to this date are not shown in the referenced table.

9.0-VECC-43

Reference: Exhibit 9, page 24

a) Please explain the nature of the Customer Choice Initiative costs that were included ($8,990) and show how they are incremental costs.

Response:

a) Virtually all of the costs for Customer Choice are for software changes to accommodate the switches between time-of-use and tiered billing. The costs are incremental for two reasons: the work was done by our CIS vendor and invoiced to us. Second, if the government had not mandated the customer billing option choice initiative there would have been no need to make these software changes.

9.0-VECC-44

Reference: Exhibit 9, page 24

a) Please provide the “50% per Tax Sharing Rule” which RSL applied in removing $8,472 of the accelerated capital cost allowance from Account 1592.

b) Is the accelerated CCA program a tax rate change or a tax timing change, i.e., does the total amount of CCA tax shield change as a result of the AIIP?

Response:

a) Perhaps the use of the word “rule” is inaccurate. “Common practice” may be a better way of phrasing it. Generally, if an LDC receives a tax reduction due to a tax rate change, it is typical for the tax savings to be shared 50/50 with customers.

b) The accelerated CCA program is not a tax rate change, but it does result in a timing change.

1-SEC-1

[Ex.1] Please provide copies of all benchmarking studies, reports, and analyses that RSL has undertaken or participated in since its last rebasing application, that are not already included in the application.

Response:

The only benchmarking study that RSL participated in is the OEB’s “Activity and Program-Based Benchmarking” conducted by the Pacific Economics Group. SEC will have a copy of the report, as it was a participant in the project.

RSL has had station assessments done by Spark Power, and the reports are submitted separately:

i. 30934_RSL MS2 – SubstationAssessment_R01 – 2020-03-18

ii. 30934_RSL_Substation Memo_R02 – 2021-09-30

iii. RSL MS2 – Condition Assessment letter – 2021-09-30

1-SEC-2

[Ex.1] Please provide a copy of all documents that were provided to the Board of Directors in approving the underlying budgets contained in the Business Plan and this Application.

Response:

RSL can provide some but not all of what you are requesting. The RSL Board received updates on the application during each meeting in 2021. The 2022 budget was approved on December 2, 2021. The RSL Distribution Board and RSL Holdings Board approve a consolidated budget. The report to the Board concerning the budget cannot be shared, as it includes information about unregulated companies, and also has discussion points about the anticipated outcome of the Cost of Service application.

RSL held a special meeting of the Board in November 2021 to review the Cost of Service application and answer their questions. The budget approved in December was based on the rate application plus the revenues and costs of the unregulated companies. The following information is the Cost of Service report reviewed with the Board.

RSL BOARD REPORT – 2022 COST OF SERVICE RATE APPLICATION

Cost of Service Rate Application

The Cost of Service rate application is in the last stages of completion. The models have been completed, and the exhibits have been written. We are comparing our work with the OEB's filing checklist to verify that all the required information is in the submission. Borden Ladner Gervais reviewed our Load Forecast. BLG's expert is very experienced with rate applications, and his approval of our work will provides confirmation of our numbers. We have received an updated version of the Distribution System Plan from Oakley Engineering and will receive the final version very soon to include in the application.

The following information summarizes some of the key elements of our application, and shows comparisons of the amount approved in our 2016 Cost of Service application with our 2022 application:

Revenue Requirement:

The Revenue Requirement displays the costs that will be recovered through our Distribution Revenues. Operation Maintenance and Administrative (OM&A) expenses have increased by 19% since our last rate application. Approximately 15% can be attributed to inflation. OM&A has also increased due to the retirement and hiring of two Management positions including the cost of outside recruitment services. The PILs are shown as $0 for 2022. This is the result of the accelerated Capital Cost Allowance ('CCA') on capital purchases which significantly reduced the taxable income.

	OEB Approved	Proposed		
Particular	2016	2022	Var $	Var %
OM&A Expenses	2,092,824	2,488,912	396,088	19%
Amortization Expense	365,942	403,368	37,426	10%
Property Taxes	18,187	28,700	10,513	58%
Total Distribution Expenses	2,476,953	2,920,980	444,027	18%
Regulated Return On Capital	362,633	438,322	75,689	21%
Grossed up PILs	23,102	-	- 23,102	-100%
Service Revenue Requirement	2,862,688	3,359,302	496,614	17%
Less: Revenue Offsets	- 270,254	- 207,618	62,636	-23%
Base Revenue Requirement	2,592,434	3,151,684	559,250	22%

Rate Base:

Our rate base has increased since 2016, as the net value of our capital assets has increased. The capital spending increase includes the POSI truck purchased in 2017, capital projects over the years, and the planned substation work as outlined in the DSP. The following is an excerpt from the COS models, providing a short list of the planned projects from the DSP for 2022:

Projects	2022 Test Year
MS2 Morrisburg Relocation	500,000
Transformer Replacements	58,698
Meter Replacements	29,782
Bell Fibre to Home	177,869
Miscellaneous	15,689
High Street	52,974
Computer Software	5,000
Computer Hardware	19,000
Vehicles	60,000
Miscellaneous	10,000
Total	**929,012**

The following is a list of all of the material projects over the five year DSP:

Material Project Lists By Year			
Year	Category	Description	Amount
2022	Overhead	High Street	52,974
	Overhead	PCB Transformers	58,698
	Station	Morrisburg Relocate Phase 1	500,000
2023	Overhead	PCB Transformers	58,698
	Overhead	Highway 2 East	54,337
	Station	Morrisburg Relocate Phase 2	500,000
	General Plant	IVR System	50,000
2024	Overhead	PCB Transformers	58,698
	Overhead	Church St South Side	112,809
	Station	Prescott MS1 replacement	250,000
	General Plant	Elster Software Upgrade	50,000
2025	Overhead	Kyle St	92,373
	Overhead	PCB Transformers	58,698
	Overhead	Kingston Cres	93,929
	Station	Iroquois MS1 replacement	250,000
2026	Overhead	MS Boundary Feeder	50,000
	Overhead	Feeder Boundary to Grocery	100,000
	Overhead	Roberta Cres	50,192
	Vehicle	Replace Altec Truck	400,000

The decrease to the working capital allowance is due to a reduction in the cost of power purchased. This is primarily due to lower commodity and global adjustment rates and the Ontario Electricity Rebate.

	Board App	Test		
Particulars	2016	2022	Var $	Var%
Net Capital Assets in Service:				
Average Balance	5,626,388	6,839,129	1,212,741	21.6%
Working Capital Allowance	1,264,638	1,023,694	(240,944)	-19.1%
Total Rate Base	6,891,026	7,862,823	971,797	14.1%

Expenses for Working Capital	Board Appr 2016	Test Year 2022	Var $	Var%
Eligible Distribution Expenses:				
Distribution Expenses - Operations	254,368	362,465	108,097	42%
Distribution Expenses - Maintenance	433,201	450,600	17,399	4%
Billing and Collecting	506,836	551,220	44,384	9%
Customer Relations	30,592	32,500	1,908	6%
Administrative and General Expenses	867,827	1,092,127	224,300	26%
Taxes other than Income Taxes	18,187	28,700	10,513	58%
Total Eligible Distribution Expenses	2,111,011	2,517,612	406,601	19%
Power Supply Expenses	14,750,833	11,131,644	(3,619,189)	-25%
Total Expenses for Working Capital	16,861,844	13,649,256	(3,212,588)	-19%
Working Capital Factor	7.5%	7.5%		
Total Working Capital	1,264,638	1,023,694	(240,944)	-19%

Load Forecast:

Customer Class Name	2016 Board Approved	Test Year 2022	Variance $	Variance %
Residential	40,480,043	43,536,196	3,056,153	8%
General Service < 50 kW	20,348,623	17,290,656	- 3,057,967	-15%
General Service 50 - 4999 kW	39,456,019	33,433,327	- 6,022,692	-15%
Sentinel Lighting	106,791	92,955	- 13,836	-13%
Street Lighting	773,158	642,914	- 130,244	-17%
Unmetered Scattered Loads	546,384	535,316	- 11,068	-2%
Total	101,711,018	95,531,364	- 6,179,654	-6%

Bill Impacts:

For our customers, the overall impact on the bill is important. The low-usage Residential customers are affected more than other Residential customers because of the OEB's mandated switch to 100% fixed distribution rates. The increase in our distribution rates is the same, regardless of usage.

It is very important to remember that this is a "starting point" and that the actual bill impacts will not be known until the application is fully reviewed, the revenue requirement is settled, and the allocation between customer classes is confirmed.

RATE CLASSES / CATEGORIES (eg: Residential TOU, Residential Retailer)		Sub-Total						Total	
		A		B		C		Total Bill	
	Units	$	%	$	%	$	%	$	%
RESIDENTIAL SERVICE CLASSIFICATION - RPP	kwh	9.52	35.10%	11.44	30.16%	11.30	23.57%	10.37	8.58%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - RPP	kwh	3.86	6.82%	8.80	10.51%	8.41	7.77%	7.73	2.54%
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION - Non-RPP (Other)	kw	- 50.79	-4.96%	- 12.27	-0.61%	- 34.37	-1.01%	- 8.51	-0.03%
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION - RPP	kwh	1.99	9.93%	3.79	12.75%	3.65	9.44%	3.35	3.05%
SENTINEL LIGHTING SERVICE CLASSIFICATION - RPP	kw	6.71	25.37%	7.49	24.70%	7.43	21.92%	6.82	11.11%
STREET LIGHTING SERVICE CLASSIFICATION - Non-RPP (Other)	kw	440.25	13.43%	444.18	12.93%	440.59	12.06%	502.57	6.88%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	9.52	35.10%	10.10	24.83%	9.95	19.64%	9.14	7.30%
RESIDENTIAL SERVICE CLASSIFICATION - RPP (10th Percentile Low Usage)	kwh	9.47	34.93%	10.25	32.20%	10.19	28.40%	9.36	14.56%
RESIDENTIAL SERVICE CLASSIFICATION - Non-RPP (Retailer) (10th Percentile Low Usage)	kwh	9.47	34.93%	9.71	29.46%	9.65	26.08%	8.86	13.45%
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION - Non-RPP (Retailer)	kwh	3.86	6.82%	5.21	5.73%	4.82	4.17%	4.43	1.40%

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	750	kWh
Demand	-	kW
Current Loss Factor	1.0819	
Proposed/Approved Loss Factor	1.0835	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 26.59	1	$ 26.59	$ 34.16	1	$ 34.16	$ 7.57	28.47%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ 0.52	1	$ 0.52	$ 2.39	1	$ 2.39	$ 1.87	359.62%
Volumetric Rate Riders	$ -	750	$ -	$ 0.0001	750	$ 0.08	$ 0.08	
Sub-Total A (excluding pass through)			**$ 27.11**			**$ 36.63**	**$ 9.52**	**35.10%**
Line Losses on Cost of Power	$ 0.1072	61	$ 6.58	$ 0.1072	63	$ 6.71	$ 0.13	1.95%
Total Deferral/Variance Account Rate Riders	$ 0.0001	750	$ 0.08	$ 0.0009	750	$ 0.68	$ 0.60	800.00%
CBR Class B Rate Riders	$ (0.0001)	750	$ (0.08)	$ -	750	$ -	$ 0.08	-100.00%
GA Rate Riders	$ -	750	$ -	$ -	750	$ -	$ -	
Low Voltage Service Charge	$ 0.0049	750	$ 3.68	$ 0.0064	750	$ 4.80	$ 1.13	30.61%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 37.94**			**$ 49.38**	**$ 11.44**	**30.16%**
RTSR - Network	$ 0.0065	811	$ 5.27	$ 0.0065	813	$ 5.28	$ 0.01	0.15%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0058	811	$ 4.71	$ 0.0056	813	$ 4.55	$ (0.16)	-3.31%
Sub-Total C - Delivery (including Sub-Total B)			**$ 47.92**			**$ 59.21**	**$ 11.30**	**23.57%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	811	$ 2.76	$ 0.0034	813	$ 2.76	$ 0.00	0.15%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	811	$ 0.41	$ 0.0005	813	$ 0.41	$ 0.00	0.15%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0850	488	$ 41.44	$ 0.0850	488	$ 41.44	$ -	0.00%
TOU - Mid Peak	$ 0.1190	128	$ 15.17	$ 0.1190	128	$ 15.17	$ -	0.00%
TOU - On Peak	$ 0.1760	135	$ 23.76	$ 0.1760	135	$ 23.76	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 131.70**			**$ 143.00**	**$ 11.30**	**8.58%**
HST	13%		$ 17.12	13%		$ 18.59	$ 1.47	8.58%
Ontario Electricity Rebate	21.2%		$ (27.92)	21.2%		$ (30.32)	$ (2.40)	
Total Bill on TOU			**$ 120.90**			**$ 131.28**	**$ 10.37**	**8.58%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	
RPP / Non-RPP:	RPP	
Consumption	2,000	kWh
Demand	-	kW
Current Loss Factor	1.0819	
Proposed/Approved Loss Factor	1.0835	

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 32.29	1	$ 32.29	$ 32.29	1	$ 32.29	$ -	0.00%
Distribution Volumetric Rate	$ 0.0116	2000	$ 23.20	$ 0.0125	2000	$ 25.00	$ 1.80	7.76%
Fixed Rate Riders	$ 1.14	1	$ 1.14	$ -	1	$ -	$ (1.14)	-100.00%
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0016	2000	$ 3.20	$ 3.20	
Sub-Total A (excluding pass through)			**$ 56.63**			**$ 60.49**	**$ 3.86**	**6.82%**
Line Losses on Cost of Power	$ 0.1072	164	$ 17.55	$ 0.1072	167	$ 17.90	$ 0.34	1.95%
Total Deferral/Variance Account Rate Riders	$ 0.0001	2,000	$ 0.20	$ 0.0009	2,000	$ 1.80	$ 1.60	800.00%
CBR Class B Rate Riders	$ (0.0001)	2,000	$ (0.20)	$ -	2,000	$ -	$ 0.20	-100.00%
GA Rate Riders	$ -	2,000	$ -	$ -	2,000	$ -	$ -	
Low Voltage Service Charge	$ 0.0045	2,000	$ 9.00	$ 0.0059	2,000	$ 11.80	$ 2.80	31.11%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 83.75**			**$ 92.56**	**$ 8.80**	**10.51%**
RTSR - Network	$ 0.0060	2,164	$ 12.98	$ 0.0060	2,167	$ 13.00	$ 0.02	0.15%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0053	2,164	$ 11.47	$ 0.0051	2,167	$ 11.05	$ (0.42)	-3.63%
Sub-Total C - Delivery (including Sub-Total B)			**$ 108.20**			**$ 116.61**	**$ 8.41**	**7.77%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,164	$ 7.36	$ 0.0034	2,167	$ 7.37	$ 0.01	0.15%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,164	$ 1.08	$ 0.0005	2,167	$ 1.08	$ 0.00	0.15%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0850	1,300	$ 110.50	$ 0.0850	1,300	$ 110.50	$ -	0.00%
TOU - Mid Peak	$ 0.1190	340	$ 40.46	$ 0.1190	340	$ 40.46	$ -	0.00%
TOU - On Peak	$ 0.1760	360	$ 63.36	$ 0.1760	360	$ 63.36	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 331.21**			**$ 339.63**	**$ 8.42**	**2.54%**
HST	13%		$ 43.06	13%		$ 44.15	$ 1.09	2.54%
Ontario Electricity Rebate	21.2%		$ (70.22)	21.2%		$ (72.00)	$ (1.78)	
Total Bill on TOU			**$ 304.05**			**$ 311.78**	**$ 7.73**	**2.54%**

Customer Class:	GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	147,135 kWh
Demand	297 kW
Current Loss Factor	1.0819
Proposed/Approved Loss Factor	1.0835

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 307.78	1	$ 307.78	$ 307.78	1	$ 307.78	$ -	0.00%
Distribution Volumetric Rate	$ 2.3698	297	$ 703.83	$ 2.2779	297	$ 676.54	$ (27.29)	-3.88%
Fixed Rate Riders	$ 12.86	1	$ 12.86	$ -	1	$ -	$ (12.86)	-100.00%
Volumetric Rate Riders	$ -	297	$ -	$ (0.0358)	297	$ (10.63)	$ (10.63)	
Sub-Total A (excluding pass through)			**$ 1,024.47**			**$ 973.68**	**$ (50.79)**	**-4.96%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.0232	297	$ 6.89	$ 0.2763	297	$ 82.06	$ 75.17	1090.95%
CBR Class B Rate Riders	$ (0.0346)	297	$ (10.28)	$ -	297	$ -	$ 10.28	-100.00%
GA Rate Riders	$ 0.0034	147,135	$ 500.26	$ 0.0016	147,135	$ 235.42	$ (264.84)	-52.94%
Low Voltage Service Charge	$ 1.6712	297	$ 496.35	$ 2.4049	297	$ 714.26	$ 217.91	43.90%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		297	$ -	$ -	297	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 2,017.69**			**$ 2,005.42**	**$ (12.27)**	**-0.61%**
RTSR - Network	$ 2.4831	297	$ 737.48	$ 2.4999	297	$ 742.47	$ 4.99	0.68%
RTSR - Connection and/or Line and Transformation Connection	$ 2.1300	297	$ 632.61	$ 2.0388	297	$ 605.52	$ (27.09)	-4.28%
Sub-Total C - Delivery (including Sub-Total B)			**$ 3,387.78**			**$ 3,353.41**	**$ (34.37)**	**-1.01%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	159,185	$ 541.23	$ 0.0034	159,421	$ 542.03	$ 0.80	0.15%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	159,185	$ 79.59	$ 0.0005	159,421	$ 79.71	$ 0.12	0.15%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	159,185	$ 17,526.31	$ 0.1101	159,421	$ 17,552.23	$ 25.92	0.15%
Total Bill on Average IESO Wholesale Market Price			**$ 21,535.16**			**$ 21,527.63**	**$ (7.53)**	**-0.03%**
HST	13%		$ 2,799.57	13%		$ 2,798.59	$ (0.98)	-0.03%
Ontario Electricity Rebate	21.2%		$ -	21.2%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 24,334.73**			**$ 24,326.22**	**$ (8.51)**	**-0.03%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	727 kWh
Demand	- kW
Current Loss Factor	1.0819
Proposed/Approved Loss Factor	1.0835

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 4.55	1	$ 4.55	$ 5.21	1	$ 5.21	$ 0.66	14.51%
Distribution Volumetric Rate	$ 0.0208	727	$ 15.12	$ 0.0238	727	$ 17.30	$ 2.18	14.42%
Fixed Rate Riders	$ 0.41	1	$ 0.41	$ -	1	$ -	$ (0.41)	-100.00%
Volumetric Rate Riders	$ -	727	$ -	$ (0.0006)	727	$ (0.44)	$ (0.44)	
Sub-Total A (excluding pass through)			**$ 20.08**			**$ 22.08**	**$ 1.99**	**9.93%**
Line Losses on Cost of Power	$ 0.1072	60	$ 6.38	$ 0.1072	61	$ 6.51	$ 0.12	1.95%
Total Deferral/Variance Account Rate Riders	$ 0.0001	727	$ 0.07	$ 0.0009	727	$ 0.65	$ 0.58	800.00%
CBR Class B Rate Riders	$ (0.0001)	727	$ (0.07)	$ -	727	$ -	$ 0.07	-100.00%
GA Rate Riders	$ -	727	$ -	$ -	727	$ -	$ -	
Low Voltage Service Charge	$ 0.0045	727	$ 3.27	$ 0.0059	727	$ 4.29	$ 1.02	31.11%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		727	$ -	$ -	727	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 29.73**			**$ 33.53**	**$ 3.79**	**12.75%**
RTSR - Network	$ 0.0060	787	$ 4.72	$ 0.0060	788	$ 4.73	$ 0.01	0.15%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0053	787	$ 4.17	$ 0.0051	788	$ 4.02	$ (0.15)	-3.63%
Sub-Total C - Delivery (including Sub-Total B)			**$ 38.62**			**$ 42.27**	**$ 3.65**	**9.44%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	787	$ 2.67	$ 0.0034	788	$ 2.68	$ 0.00	0.15%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	787	$ 0.39	$ 0.0005	788	$ 0.39	$ 0.00	0.15%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0850	473	$ 40.17	$ 0.0850	473	$ 40.17	$ -	0.00%
TOU - Mid Peak	$ 0.1190	124	$ 14.71	$ 0.1190	124	$ 14.71	$ -	0.00%
TOU - On Peak	$ 0.1760	131	$ 23.03	$ 0.1760	131	$ 23.03	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 119.84**			**$ 123.50**	**$ 3.65**	**3.05%**
HST	13%		$ 15.58	13%		$ 16.05	$ 0.47	3.05%
Ontario Electricity Rebate	21.2%		$ (25.41)	21.2%		$ (26.18)	$ (0.77)	
Total Bill on TOU			**$ 110.02**			**$ 113.37**	**$ 3.35**	**3.05%**

Customer Class:	SENTINEL LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	294 kWh
Demand	1 kW
Current Loss Factor	1.0819
Proposed/Approved Loss Factor	1.0835

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 2.82	2	$ 5.64	$ 3.65	2	$ 7.30	$ 1.66	29.43%
Distribution Volumetric Rate	$ 20.6153	1	$ 20.62	$ 26.6574	1	$ 26.66	$ 6.04	29.31%
Fixed Rate Riders	$ 0.19	1	$ 0.19	$ -	1	$ -	$ (0.19)	-100.00%
Volumetric Rate Riders	$ -	1	$ -	$ (0.8022)	1	$ (0.80)	$ (0.80)	
Sub-Total A (excluding pass through)			**$ 26.45**			**$ 33.16**	**$ 6.71**	**25.37%**
Line Losses on Cost of Power	$ 0.1072	24	$ 2.58	$ 0.1072	25	$ 2.63	$ 0.05	1.95%
Total Deferral/Variance Account Rate Riders	$ 0.0247	1	$ 0.02	$ 0.3015	1	$ 0.30	$ 0.28	1120.65%
CBR Class B Rate Riders	$ (0.0360)	1	$ (0.04)	$ -	1	$ -	$ 0.04	-100.00%
GA Rate Riders	$ -	294	$ -	$ -	294	$ -	$ -	
Low Voltage Service Charge	$ 1.3055	1	$ 1.31	$ 1.7204	1	$ 1.72	$ 0.41	31.78%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		1	$ -	$ -	1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 30.32**			**$ 37.81**	**$ 7.49**	**24.70%**
RTSR - Network	$ 1.8821	1	$ 1.88	$ 1.8948	1	$ 1.89	$ 0.01	0.67%
RTSR - Connection and/or Line and Transformation Connection	$ 1.6809	1	$ 1.68	$ 1.6089	1	$ 1.61	$ (0.07)	-4.28%
Sub-Total C - Delivery (including Sub-Total B)			**$ 33.88**			**$ 41.31**	**$ 7.43**	**21.92%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	318	$ 1.08	$ 0.0034	319	$ 1.08	$ 0.00	0.15%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	318	$ 0.16	$ 0.0005	319	$ 0.16	$ 0.00	0.15%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0850	191	$ 16.24	$ 0.0850	191	$ 16.24	$ -	0.00%
TOU - Mid Peak	$ 0.1190	50	$ 5.95	$ 0.1190	50	$ 5.95	$ -	0.00%
TOU - On Peak	$ 0.1760	53	$ 9.31	$ 0.1760	53	$ 9.31	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 66.88**			**$ 74.31**	**$ 7.43**	**11.11%**
HST	13%		$ 8.69	13%		$ 9.66	$ 0.97	11.11%
Ontario Electricity Rebate	21.2%		$ (14.18)	21.2%		$ (15.75)	$ (1.58)	
Total Bill on TOU			**$ 61.39**			**$ 68.22**	**$ 6.82**	**11.11%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Other)
Consumption	22,825 kWh
Demand	62 kW
Current Loss Factor	1.0819
Proposed/Approved Loss Factor	1.0835

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 3.54	690	$ 2,442.60	$ 4.03	690	$ 2,780.70	$ 338.10	13.84%
Distribution Volumetric Rate	$ 13.4847	62	$ 836.05	$ 15.3588	62	$ 952.25	$ 116.19	13.90%
Fixed Rate Riders	$ 0.09	1	$ 0.09	$ -	1	$ -	$ (0.09)	-100.00%
Volumetric Rate Riders	$ -	62	$ -	$ (0.2251)	62	$ (13.96)	$ (13.96)	
Sub-Total A (excluding pass through)			**$ 3,278.74**			**$ 3,718.99**	**$ 440.25**	**13.43%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.0252	62	$ 1.56	$ 0.3087	62	$ 19.14	$ 17.58	1125.00%
CBR Class B Rate Riders	$ (0.0359)	62	$ (2.23)	$ -	62	$ -	$ 2.23	-100.00%
GA Rate Riders	$ 0.0034	22,825	$ 77.61	$ 0.0016	22,825	$ 36.52	$ (41.09)	-52.94%
Low Voltage Service Charge	$ 1.2790	62	$ 79.30	$ 1.6856	62	$ 104.51	$ 25.21	31.79%
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		62	$ -	$ -	62	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 3,434.98**			**$ 3,879.16**	**$ 444.18**	**12.93%**
RTSR - Network	$ 1.8726	62	$ 116.10	$ 1.8853	62	$ 116.89	$ 0.79	0.68%
RTSR - Connection and/or Line and Transformation Connection	$ 1.6469	62	$ 102.11	$ 1.5764	62	$ 97.74	$ (4.37)	-4.28%
Sub-Total C - Delivery (including Sub-Total B)			**$ 3,653.19**			**$ 4,093.78**	**$ 440.59**	**12.06%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	24,694	$ 83.96	$ 0.0034	24,731	$ 84.09	$ 0.12	0.15%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	24,694	$ 12.35	$ 0.0005	24,731	$ 12.37	$ 0.02	0.15%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1101	24,694	$ 2,718.85	$ 0.1101	24,731	$ 2,722.87	$ 4.02	0.15%
Total Bill on Average IESO Wholesale Market Price			**$ 6,468.60**			**$ 6,913.35**	**$ 444.75**	**6.88%**
HST	13%		$ 840.92	13%		$ 898.74	$ 57.82	6.88%
Ontario Electricity Rebate	21.2%		$ -	21.2%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 7,309.52**			**$ 7,812.09**	**$ 502.57**	**6.88%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0819
Proposed/Approved Loss Factor	1.0835

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 26.59	1	$ 26.59	$ 34.16	1	$ 34.16	$ 7.57	28.47%
Distribution Volumetric Rate	$ -	750	$ -	$ -	750	$ -	$ -	
Fixed Rate Riders	$ 0.52	1	$ 0.52	$ 2.39	1	$ 2.39	$ 1.87	359.62%
Volumetric Rate Riders	$ -	750	$ -	$ 0.0001	750	$ 0.08	$ 0.08	
Sub-Total A (excluding pass through)			**$ 27.11**			**$ 36.63**	**$ 9.52**	**35.10%**
Line Losses on Cost of Power	$ 0.1101	61	$ 6.76	$ 0.1101	63	$ 6.90	$ 0.13	1.95%
Total Deferral/Variance Account Rate Riders	$ 0.0001	750	$ 0.08	$ 0.0009	750	$ 0.68	$ 0.60	800.00%
CBR Class B Rate Riders	$ (0.0001)	750	$ (0.08)	$ -	750	$ -	$ 0.08	-100.00%
GA Rate Riders	$ 0.0034	750	$ 2.55	$ 0.0016	750	$ 1.20	$ (1.35)	-52.94%
Low Voltage Service Charge	$ 0.0049	750	$ 3.68	$ 0.0064	750	$ 4.80	$ 1.13	30.61%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		750	$ -	$ -	750	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 40.67**			**$ 50.77**	**$ 10.10**	**24.83%**
RTSR - Network	$ 0.0065	811	$ 5.27	$ 0.0065	813	$ 5.28	$ 0.01	0.15%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0058	811	$ 4.71	$ 0.0056	813	$ 4.55	$ (0.16)	-3.31%
Sub-Total C - Delivery (including Sub-Total B)			**$ 50.65**			**$ 60.60**	**$ 9.95**	**19.64%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	811	$ 2.76	$ 0.0034	813	$ 2.76	$ 0.00	0.15%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	811	$ 0.41	$ 0.0005	813	$ 0.41	$ 0.00	0.15%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1101	750	$ 82.58	$ 0.1101	750	$ 82.58	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 136.39**			**$ 146.34**	**$ 9.95**	**7.30%**
HST	13%		$ 17.73	13%		$ 19.02	$ 1.29	7.30%
Ontario Electricity Rebate	21.2%		$ (28.91)	21.2%		$ (31.02)		
Total Bill on Non-RPP Avg. Price			**$ 125.20**			**$ 134.34**	**$ 9.14**	**7.30%**

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	304 kWh
Demand	- kW
Current Loss Factor	1.0819
Proposed/Approved Loss Factor	1.0835

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 26.59	1	$ 26.59	$ 34.16	1	$ 34.16	$ 7.57	28.47%
Distribution Volumetric Rate	$ -	304	$ -	$ -	304	$ -	$ -	
Fixed Rate Riders	$ 0.52	1	$ 0.52	$ 2.39	1	$ 2.39	$ 1.87	359.62%
Volumetric Rate Riders	$ -	304	$ -	$ 0.0001	304	$ 0.03	$ 0.03	
Sub-Total A (excluding pass through)			**$ 27.11**			**$ 36.58**	**$ 9.47**	**34.93%**
Line Losses on Cost of Power	$ 0.1072	25	$ 2.67	$ 0.1072	25	$ 2.72	$ 0.05	1.95%
Total Deferral/Variance Account Rate Riders	$ 0.0001	304	$ 0.03	$ 0.0009	304	$ 0.27	$ 0.24	800.00%
CBR Class B Rate Riders	$ (0.0001)	304	$ (0.03)	$ -	304	$ -	$ 0.03	-100.00%
GA Rate Riders	$ -	304	$ -	$ -	304	$ -	$ -	
Low Voltage Service Charge	$ 0.0049	304	$ 1.49	$ 0.0064	304	$ 1.95	$ 0.46	30.61%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		304	$ -	$ -	304	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 31.84**			**$ 42.09**	**$ 10.25**	**32.20%**
RTSR - Network	$ 0.0065	329	$ 2.14	$ 0.0065	329	$ 2.14	$ 0.00	0.15%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0058	329	$ 1.91	$ 0.0056	329	$ 1.84	$ (0.06)	-3.31%
Sub-Total C - Delivery (including Sub-Total B)			**$ 35.88**			**$ 46.08**	**$ 10.19**	**28.40%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	329	$ 1.12	$ 0.0034	329	$ 1.12	$ 0.00	0.15%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	329	$ 0.16	$ 0.0005	329	$ 0.16	$ 0.00	0.15%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0850	198	$ 16.80	$ 0.0850	198	$ 16.80	$ -	0.00%
TOU - Mid Peak	$ 0.1190	52	$ 6.15	$ 0.1190	52	$ 6.15	$ -	0.00%
TOU - On Peak	$ 0.1760	55	$ 9.63	$ 0.1760	55	$ 9.63	$ -	0.00%
Total Bill on TOU (before Taxes)			**$ 69.99**			**$ 80.19**	**$ 10.19**	**14.56%**
HST	13%		$ 9.10	13%		$ 10.42	$ 1.33	14.56%
Ontario Electricity Rebate	21.2%		$ (14.84)	21.2%		$ (17.00)	$ (2.16)	
Total Bill on TOU			**$ 64.25**			**$ 73.61**	**$ 9.36**	**14.56%**

Customer Class: RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP: Non-RPP (Retailer)
Consumption 304 kWh
Demand - kW
Current Loss Factor 1.0819
Proposed/Approved Loss Factor 1.0835

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 26.59	1	$ 26.59	$ 34.16	1	$ 34.16	$ 7.57	28.47%
Distribution Volumetric Rate	$ -	304	$ -	$ -	304	$ -	$ -	
Fixed Rate Riders	$ 0.52	1	$ 0.52	$ 2.39	1	$ 2.39	$ 1.87	359.62%
Volumetric Rate Riders	$ -	304	$ -	$ 0.0001	304	$ 0.03	$ 0.03	
Sub-Total A (excluding pass through)			**$ 27.11**			**$ 36.58**	**$ 9.47**	**34.93%**
Line Losses on Cost of Power	$ 0.1101	25	$ 2.74	$ 0.1101	25	$ 2.79	$ 0.05	1.95%
Total Deferral/Variance Account Rate Riders	$ 0.0001	304	$ 0.03	$ 0.0009	304	$ 0.27	$ 0.24	800.00%
CBR Class B Rate Riders	$ (0.0001)	304	$ (0.03)	$ -	304	$ -	$ 0.03	-100.00%
GA Rate Riders	$ 0.0034	304	$ 1.03	$ 0.0016	304	$ 0.49	$ (0.55)	-52.94%
Low Voltage Service Charge	$ 0.0049	304	$ 1.49	$ 0.0064	304	$ 1.95	$ 0.46	30.61%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		304	$ -	$ -	304	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 32.94**			**$ 42.65**	**$ 9.71**	**29.46%**
RTSR - Network	$ 0.0065	329	$ 2.14	$ 0.0065	329	$ 2.14	$ 0.00	0.15%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0058	329	$ 1.91	$ 0.0056	329	$ 1.84	$ (0.06)	-3.31%
Sub-Total C - Delivery (including Sub-Total B)			**$ 36.99**			**$ 46.64**	**$ 9.65**	**26.08%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	329	$ 1.12	$ 0.0034	329	$ 1.12	$ 0.00	0.15%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	329	$ 0.16	$ 0.0005	329	$ 0.16	$ 0.00	0.15%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1101	304	$ 33.47	$ 0.1101	304	$ 33.47	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 71.74**			**$ 81.39**	**$ 9.65**	**13.45%**
HST	13%		$ 9.33	13%		$ 10.58	$ 1.25	13.45%
Ontario Electricity Rebate	21.2%		$ (15.21)	21.2%		$ (17.25)		
Total Bill on Non-RPP Avg. Price			**$ 65.86**			**$ 74.72**	**$ 8.86**	**13.45%**

Customer Class: GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP: Non-RPP (Retailer)
Consumption 2,000 kWh
Demand - kW
Current Loss Factor 1.0819
Proposed/Approved Loss Factor 1.0835

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 32.29	1	$ 32.29	$ 32.29	1	$ 32.29	$ -	0.00%
Distribution Volumetric Rate	$ 0.0116	2000	$ 23.20	$ 0.0125	2000	$ 25.00	$ 1.80	7.76%
Fixed Rate Riders	$ 1.14	1	$ 1.14	$ -	1	$ -	$ (1.14)	-100.00%
Volumetric Rate Riders	$ -	2000	$ -	$ 0.0016	2000	$ 3.20	$ 3.20	
Sub-Total A (excluding pass through)			**$ 56.63**			**$ 60.49**	**$ 3.86**	**6.82%**
Line Losses on Cost of Power	$ 0.1101	164	$ 18.03	$ 0.1101	167	$ 18.39	$ 0.35	1.95%
Total Deferral/Variance Account Rate Riders	$ 0.0001	2,000	$ 0.20	$ 0.0009	2,000	$ 1.80	$ 1.60	800.00%
CBR Class B Rate Riders	$ (0.0001)	2,000	$ (0.20)	$ -	2,000	$ -	$ 0.20	-100.00%
GA Rate Riders	$ 0.0034	2,000	$ 6.80	$ 0.0016	2,000	$ 3.20	$ (3.60)	-52.94%
Low Voltage Service Charge	$ 0.0045	2,000	$ 9.00	$ 0.0059	2,000	$ 11.80	$ 2.80	31.11%
Smart Meter Entity Charge (if applicable)	$ 0.57	1	$ 0.57	$ 0.57	1	$ 0.57	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders		2,000	$ -	$ -	2,000	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)			**$ 91.03**			**$ 96.25**	**$ 5.21**	**5.73%**
RTSR - Network	$ 0.0060	2,164	$ 12.98	$ 0.0060	2,167	$ 13.00	$ 0.02	0.15%
RTSR - Connection and/or Line and Transformation Connection	$ 0.0053	2,164	$ 11.47	$ 0.0051	2,167	$ 11.05	$ (0.42)	-3.63%
Sub-Total C - Delivery (including Sub-Total B)			**$ 115.49**			**$ 120.30**	**$ 4.82**	**4.17%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,164	$ 7.36	$ 0.0034	2,167	$ 7.37	$ 0.01	0.15%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,164	$ 1.08	$ 0.0005	2,167	$ 1.08	$ 0.00	0.15%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1101	2,000	$ 220.20	$ 0.1101	2,000	$ 220.20	$ -	0.00%
Total Bill on Non-RPP Avg. Price			**$ 344.12**			**$ 348.95**	**$ 4.83**	**1.40%**
HST	13%		$ 44.74	13%		$ 45.36	$ 0.63	1.40%
Ontario Electricity Rebate	21.2%		$ (72.95)	21.2%		$ (73.98)		
Total Bill on Non-RPP Avg. Price			**$ 315.91**			**$ 320.34**	**$ 4.43**	**1.40%**

1-SEC-3

[Ex.1] Please provide details of all productivity and efficiency measures RSL has undertaken since its last rebasing application in 2016. Please quantify the savings and explain how they were calculated.

Response:

RSL has completed the replacement of industrial demand meters with smart meters. In the past, RSL staff had to manually read the meters. Due to the meter changes, no meter reading labour and burden is charged to RSL. Previously, 15% of these shared costs were allocated to RSL. This can be seen in the Shared Services, with a reduction in meter reading costs of $13,448.

RSL conducts a Customer Satisfaction Survey every two years. The cost of the first survey in 2017 was $18,000. RSL joined with other CHEC member LDCs to negotiate group pricing. The Customer Satisfaction Survey completed in 2021 was at a cost of $10,021, a saving of $8,000.

The other efficiency that must be considered is the "hidden efficiency". The regulated industry changes constantly, with changes to laws, codes, practices, and rates. RSL implements the changes with existing staff, on top of the normal day-to-day work. When you consider the changes that occur in our industry every year, it is an efficiency that we do not increase headcount to deal with the volume and complexity of changes. Using an assumption of one additional person needed due to the noted changes, the annual cost avoided is at least $75,000. Even with a more conservative assumption of half of a person, the saving is $37,500.

1-SEC-4

[Ex.1] Please provide details of all productivity and efficiency measures RSL plans to undertake in the test year. Please quantify the savings and explain how they were calculated.

Response:

RSL has a new President & CEO and will shortly have a new CFO. One of their plans for the test year is to review all existing contracts to see where efficiencies and savings can be found. At this time it is unknown if savings will be found, so there is nothing to quantify.

2-SEC-5

[Appendix 2-AB, Ex.1 p. 15] SEC notes in 2016 and 2019 RSL System Reliability indicators are worse than the OEB Target for distributors. Regarding the below-target reliability:

a. SEC also notes RSL underspent on a net capital expenditure basis between 2016 and 2019, which coincide with the years of low reliability performance. Please explain the underspending and how it impacted system reliability.
b. Please provide any other explanation for the below target reliability.

Response:

a) RSL disagrees with SEC's comparison of RSL's capital spending. RSL's planned expenditures did not include capital contributions. For that reason, it is important to compare gross, not net expenditures. RSL overspent its plan in each year. As there was not underspending, there is no related impact on system reliability.

b) The reliability numbers for 2016 were increased by one event: a planned outage for a new substation transformer. This outage affected 813 customers for 3 hours. Without this one event, reliability numbers would have been normal.

In 2019, two events occurred to influence the reliability statistics. The first was a planned outage in Iroquois for station maintenance. This outage affected 623 customers for 4 hours.

The second event was an equipment failure at a Prescott station which affected 2,387 customers for 45 minutes.

The point that RSL is making is that in a small system like ours, a single event or a small quantity of events in a year can greatly influence the reliability statistics, making it look like our system has reliability issues when it does not.

2-SEC-6

[Ex.2 p.5-20] Please provide revised Tables 2.2-2.9 including 2021 actuals.

Response:

Tables 2.6 – 2.9 did not change. Tables 2.2 – 2.5 have been updated. 2021 actuals are not available, as the external audit has not begun. RSL is providing unaudited 2021 totals.

Table 2.2: Rate Base Trend

	Board App						Unaudited	Test
Particulars	2016	2016	2017	2018	2019	2020	2021	2022
Net Capital Assets in Service:								
Opening Balance	5,626,388	5,619,076	5,629,754	6,277,948	6,362,790	6,409,717	6,612,664	6,778,501
Ending Balance	5,626,388	5,629,754	6,277,948	6,362,790	6,409,717	6,612,664	6,778,501	7,099,722
Average Balance	5,626,388	5,624,415	5,953,850	6,320,368	6,386,254	6,511,191	6,695,583	6,939,112
Working Capital Allowance	1,264,638	2,324,672	1,151,692	1,092,574	1,147,309	1,293,369	1,144,602	1,051,751
Total Rate Base	6,891,026	7,949,087	7,105,542	7,412,942	7,533,563	7,804,560	7,840,185	7,990,863

Expenses for Working Capital	Board Appr 2016	2016	2017	2018	2019	2020	2021 Unaudited	2022 Test	Var $	Var%
Eligible Distribution Expenses:										
Distribution Expenses - Operations	254,368	247,781	340,099	354,881	335,193	351,313	353,777	362,465	108,097	42%
Distribution Expenses - Maintenance	433,201	429,760	474,059	398,021	470,618	390,659	425,934	450,600	17,399	4%
Billing and Collecting	506,836	526,212	526,242	548,505	535,954	541,821	575,037	551,220	44,384	9%
Customer Relations	30,592	20,924	13,441	25,277	29,410	29,166	5,548	26,700	(3,892)	-13%
Administrative and General Expenses	867,827	886,178	898,621	877,772	874,630	936,208	986,108	1,092,127	224,300	26%
Taxes other than Income Taxes	18,187	18,186	18,438	39,033	29,246	30,831	28,258	28,700	10,513	58%
Total Eligible Distribution Expenses	2,111,011	2,129,041	2,270,900	2,243,489	2,275,051	2,279,998	2,374,662	2,511,812	400,801	19%
Power Supply Expenses	14,750,833	14,476,880	13,082,377	12,333,811	13,029,710	14,964,924	12,886,694	11,508,740	(3,242,093)	-22%
Total Expenses for Working Capital	16,861,844	16,605,921	15,353,277	14,577,300	15,304,761	17,244,922	15,261,356	14,020,552	(2,841,292)	-17%
Working Capital Factor	7.5%	14.0%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%		
Total Working Capital	1,264,638	2,324,672	1,151,692	1,092,574	1,147,309	1,293,369	1,144,602	1,051,751	(212,887)	-17%

Table 2.3: 2022-2021 Rate Base Variances

	Unaudited	Test		
Particulars	2021	2022	Var $	Var%
Net Capital Assets in Service:				
Opening Balance	6,612,664	6,778,501	165,837	2.5%
Ending Balance	6,778,501	7,099,722	321,221	4.7%
Average Balance	6,695,583	6,939,112	243,529	3.6%
Working Capital Allowance	1,144,602	1,051,751	(92,851)	-8.1%
Total Rate Base	7,840,185	7,990,863	150,678	1.9%

Expenses for Working Capital	2021 Unaudited	2022 Test	Var $	Var%
Eligible Distribution Expenses:				
Distribution Expenses - Operations	353,777	362,465	8,688	2%
Distribution Expenses - Maintenance	425,934	450,600	24,666	6%
Billing and Collecting	575,037	551,220	(23,817)	-4%
Customer Relations	5,548	26,700	21,152	381%
Administrative and General Expenses	986,108	1,092,127	106,019	11%
Taxes other than Income Taxes	28,258	28,700	442	2%
Total Eligible Distribution Expenses	2,374,662	2,511,812	137,150	6%
Power Supply Expenses	12,886,694	11,508,740	(1,377,954)	-11%
Total Expenses for Working Capital	15,261,356	14,020,552	(1,240,804)	-8%
Working Capital Factor	7.5%	7.5%		
Total Working Capital	1,144,602	1,051,751	(92,851)	-8%

Table 2.4: 2021-2020 Rate Base Variances

		Unaudited		
Particulars	2020	2021	Var $	Var%
Net Capital Assets in Service:				
Opening Balance	6,409,717	6,612,664	202,947	3.2%
Ending Balance	6,612,664	6,778,501	165,837	2.5%
Average Balance	6,511,191	6,695,583	184,392	2.8%
Working Capital Allowance	1,293,369	1,144,602	(148,767)	-11.5%
Total Rate Base	7,804,560	7,840,185	35,625	0.5%

Expenses for Working Capital	2020	2021 Unaudited	Var $	Var%
Eligible Distribution Expenses:				
Distribution Expenses - Operations	351,313	353,777	2,464	1%
Distribution Expenses - Maintenance	390,659	425,934	35,275	9%
Billing and Collecting	541,821	575,037	33,216	6%
Customer Relations	29,166	5,548	(23,618)	-81%
Administrative and General Expenses	936,208	986,108	49,900	5%
Taxes other than Income Taxes	30,831	28,258	(2,573)	-8%
Total Eligible Distribution Expenses	2,279,998	2,374,662	94,664	4%
Power Supply Expenses	14,964,924	12,886,694	(2,078,230)	-14%
Total Expenses for Working Capital	17,244,922	15,261,356	(1,983,566)	-12%
Working Capital Factor	7.5%	7.5%		
Total Working Capital	1,293,369	1,144,602	(148,767)	-12%

Table 2.5: 2020-2019 Rate Base Variances

Particulars	2019	2020	Var $	Var%
Net Capital Assets in Service:				
Opening Balance	6,362,790	6,409,717	46,927	0.7%
Ending Balance	6,409,717	6,612,664	202,947	3.2%
Average Balance	6,386,254	6,511,191	124,937	2.0%
Working Capital Allowance	1,147,309	1,293,369	146,060	12.7%
Total Rate Base	7,533,563	7,804,560	270,997	3.6%

Expenses for Working Capital	2019	2020	Var $	Var%
Eligible Distribution Expenses:				
Distribution Expenses - Operations	335,193	351,313	16,120	5%
Distribution Expenses - Maintenance	470,618	390,659	(79,959)	-17%
Billing and Collecting	535,954	541,821	5,867	1%
Customer Relations	29,410	29,166	(244)	-1%
Administrative and General Expenses	874,630	936,208	61,578	7%
Taxes other than Income Taxes	29,246	30,831	1,585	5%
Total Eligible Distribution Expenses	2,275,051	2,279,998	4,947	0%
Power Supply Expenses	13,029,710	14,964,924	1,935,214	15%
Total Expenses for Working Capital	15,304,761	17,244,922	1,940,161	13%
Working Capital Factor	7.5%	7.5%		
Total Working Capital	1,147,309	1,293,369	146,060	13%

2-SEC-7

[Ex.2 p.14] Please explain and justify the 18% or $72,597 increase in Distribution Expenses – Maintenance in 2019 rate base.

Response:

The increase is due to increased labour and benefits costs for the line crew. The primary change was the hiring of a full-time lineman, filling a vacancy that had been partially covered by co-op students for several years. Apart from that addition, one member of the crew advanced to a higher pay level because of training and experience.

The addition of the full-time employee is important for the company, as the employee over time will develop into a completely trained lineman. Co-op students are useful for simple tasks but cannot be expected to do the work of a lineman. This new lineman is taking his training and is developing as expected.

2-SEC-8

[Ex.2 p. 15-16] Please provide the actual amount of poles and wires replaced and actual cost per pole for the replacement project, for each year from 2016 to 2021 and 2022 forecast.

Response(s):

	Poles (#)	Fully Cost per Pole Including labour, hardware, etc.
2016	13	$1984
2017	3	$2215
2018	19	$2449
2019	35	$2633
2020	23	$3082
2021 forecast	43	$3317
2022 Forecast	33	$3317

	Primary Wires (M)
2016	1035
2017	285
2018	2924
2019	6356
2020	910
2021 forecast	2273
2022 forecast	1065

2-SEC-9

[Ex.2 p.6, 36] Please provide cost details and completion timeline for the various planned investments that contributed to the increase in 2022 rate base, including the Morrisburg substation project.

Response(s):

2022 Material Projects contributing to rate base cost details and completion timeline

Morrisburg Station MS2 2022–

Substation Civil and transformer $350,000

Poles & Feeders $150,000

Completion December 2022

High Street

$20,391.07 - Pole Labour

$9,135.00 - Pole Material

$6,011.73 - Primary Labour

$5,836.00 - Primary Material

$11,600 - New services

Completion Date: September 2022

PCB Transformer replacement

$15,423.41 - labour

$3,900.00 - vehicle

$39,375.00 – material

Completion by December 2022

2-SEC-10

[Ex.2, p.63-67] With respect to the capital funding approved in RSL's 2018 IRM Application:

a. Is RSL proposing any form of true-up? Please explain your response.
b. Please provide a table that shows for each year, the actual revenue collected from the rate rider.
c. Please provide a table that shows for each year, a revenue requirement calculation based on the both the ICM and Actual Accounting.
d. Please file a copy of the Capital Module settlement model approved in RSL's 2018 IRM application.

Response:

a) RSL believes that a true-up could be done but is uncertain of the appropriate method. The timing of the financial events is unusual. The incremental capital approved was net of both 2017 and 2018 depreciation, yet the capital funding began in 2018. Please see the table below for comparisons of the projected versus actual funding received. The amounts are very similar.

b) The following is a table showing the rate rider collections to the end of 2021 and projected to April 30, 2022.

Year	Revenue Requirement	Comments
2018	35,857.00	prorated from May 1 - December 31
2019	53,786.00	
2020	53,786.00	
2021	53,786.00	
2022	17,929.00	prorated from January 1 - April 30
	215,144.00	

Year	Capital Funding	Comments
2018	36,565.03	
2019	54,092.15	
2020	53,526.64	
2021	53,779.76	Unaudited
2022	17,933.00	Estimated from January 1 - April 30
	215,896.58	

c) RSL does not understand the purpose of this question, or the methodology to be used to calculate an annual revenue requirement for the different approaches. In the 2018 IRM, a revenue requirement of $53,786 was generated by the ICM model. As shown in Exhibit 2, tables 2.24, 2.25, 2.26, and 2.27, the two accounting approaches end up with the same amount in rate base. RSL proposes that the existing accounting be left as it is, and the capital funding rate rider will end when the new rates begin.

d) The ICM model approved in the 2018 IRM will be filed as part of this submission.

2-SEC-11

[Ex.2, Appendix 2-AB] Please confirm that capital expenditures are equal to in-service additions.

Response:

RSL confirms that capital expenditures are intended to equal in-service additions with the exception of transformers and meters, which are capitalized at the time of purchase. As the year-end work related to fixed asset additions is done, we confirm with the Operations Manager if there are any outstanding projects that should be considered work in progress. If a project is incomplete, all costs are moved to Work In Progress. Sometimes a small amount of work is required in the following year on projects that were considered finished. RSL capitalizes the additional cost in the year it is incurred.

2-SEC-12

[Ex.2, Appendix 2-AA] Please provide a revised version of Appendix 2-AA that includes 2023-2026 expenditures, that align with the proposed DSP spending included in Appendix 2-AB.

Response:

Appendix 2-AA
Capital Projects Table

Projects	2017	2018	2019	2020	2021 Bridge Year	2022 Test Year	2023 DSP	2024 DSP	2025 DSP	2026 DSP
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
System Access										
Prescott Fire Hall	31,954	8,874								
Westport Sewage Plant	73,130									
Long Term Load Transfer Assets	55,082									
Northern Cables			45,094							
King St Apt			1,985		17,000					
Tim Hortons Iroquois			7,777	41,918						
9 Mile Repair			16,606	28,032						
Hollands				12,059						
Landark Homes					55,000					
Ross Video					131,000					
Miscellaneous	58,407	9,685	3,431	303	5,000					
MS2 Morrisburg Relocation						500,000	500,000			
Sub-Total	218,573	18,559	74,893	82,312	208,000	500,000	500,000	0	0	0
System Renewal										
Substations	11,188	18,369	40,195	20,658	25,000					
Transformer Replacements	-11,491	95,465	15,731	23,612	40,000	58,698	58,698	58,698	58,698	
Meter Replacements	20,361	87,867	64,934	37,744	65,000	29,782	24,720	30,940	31,425	70,244
Wholesale Meters	4,109	10,681	18,799							
Mackenzie Rd	80,423	2,630								
Orchardway		13,877								
Church St N		83,431								
Dibble St & Edward St		23,138	2,761							
Victor Rd			108,178							
Henry St			21,355	19,338						
Williamsburg Small Conductor			53,455							
Bell Fibre to Home				172,401	325,000	177,869				
Compendium				11,936						
Ontario St				52,536						
Miscellaneous	125,349	148,093	81,628	181,989	100,000	15,689	60,307	50,387	59,887	24,500
High Street						52,974				
Hwy 2 East							54,337			
McKenzie Rd Pole Trans							30,381			
Live Front Padmounts							30,000	45,000		
Church St S								112,809		
Reid St Pole Trans								44,831		
MS1 Morrisburg Transformer								250,000		
Kyle St S									92,373	
Fort Town Rd Pole Trans									44,831	
MS1 Iroquois Transformer									250,000	
Roberta Cres										50,192
Sub-Total	229,939	483,551	407,036	520,214	555,000	335,012	258,443	592,665	537,214	144,936
System Services										
MS1 Prescott	230,858									
Concession St							49,105			
Miscellaneous	8,199									
Kingston Cres Pole Trans									93,929	
Feeder Boundary Rd										100,000
Recloser/Switching - Feeder										50,000
Sub-Total	239,057	0	0	0	0	0	49,105	0	93,929	150,000
General Plant										
Computer Software	5,840	4,137	50,517	104,038	0	5,000	5,000	55,000	80,000	5,000
Computer Hardware	58,511	16,161	14,639	31,435	15,000	19,000	9,000	24,000	34,000	25,000
Vehicles	411,028	1,179	1,246		60,000	60,000	65,000		15,000	400,000
Communication Equip							50,000		25,000	
Miscellaneous	23,702	13,759	4,729	661	6,500	10,000	10,000	10,000	10,000	10,000
Sub-Total	499,081	35,236	71,131	136,134	81,500	94,000	139,000	89,000	164,000	440,000
Miscellaneous		2,277								
Total	**1,186,650**	**539,623**	**553,060**	**738,660**	**844,500**	**929,012**	**946,548**	**681,665**	**795,143**	**734,936**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*										
Total	**1,186,650**	**539,623**	**553,060**	**738,660**	**844,500**	**929,012**	**946,548**	**681,665**	**795,143**	**734,936**

2-SEC-13

[Ex.2, DSP, p.95-122] RSL's DSP included Asset Condition Assessment information:

a. For each asset type, RSL has provided a table that shows the asset rating, score, and a description, which includes information regarding when the asset should be replaced (i.e. within 7 year, or replace immediately). Please provide the basis for the asset rating/score and the replacement timeframe.

b. For each of its major asset types, please provide the number replaced or planned to be replaced between 2017 and 2026.

Response(s):

a. A combination of the following factors:

    a. best practice & Kinectrics

    b. experience with our Operations Manager – 33 years of experience and an asset condition 3rd party consultant with 45 years of experience in the industry.

    c. For assets outside the capability of RSL, a 3rd party consultant is used. Engineers from Spark Power are utilized to evaluate the condition of stations.

b. The following table provides the number replaced 2017-2020. The number planned to be replaced 2021-2026. The 2021 year is considered planned because the final months of 2021 were not fully through administration. However, the 2021 numbers will be close to actuals.

	'17	'18	'19	'20	'21	'22	'23	'24	'25	'26
Poles (#)	3	19	35	23	43	33	15	19	20	7
Wires (m)	285	2924	6356	910	1215	1065	2000	375	900	900
Station	0	0	0	0	0	0.5	0.5	0	0	0
Transformer	12	14	14	13	24	16	16	18	15	1
Switches	4	0	0	0	0	0	0	0	0	0
Vehicles	2	0	0	0	1	1	0	0	0	1

Note: Numbers above from 2021-2026 are unaudited and estimates.

2-SEC-14

[Ex.2 DSP p.127] Please provide the total cost of the POSI digger truck.

Response: The total cost of the POSI truck in 2017 was $379,015.

2-SEC-15

[Ex.2 DSP p.127-128] SEC notes there were several capital projects that incurred significant over-budget costs and contributed to increases in capital expenditures. Please provide cost details and explanation for the increase in costs for the following projects:

a. The backup transformer remaining work project that contributed to the increase of 80% (system renewal 2016).

b. Prescott MS1 changing the main breakers to reclosers (system renewal 2017).

Response:

a) At the time that the DSP was being prepared for the 2016 Cost of Service application, RSL's Operations Manager at that time advised that there would be additional costs related to the installation of the backup transformer. He provided an estimate of $50,000 to include in the DSP. RSL believes that the estimate was the Manager's opinion or based on a conversation with the contractor rather than a firm quote. The contractor invoiced RSL based on time and materials.

b) The Prescott MS1 project was changed. The original plan was to change the main breakers to reclosers, but the Operations Manager, with the approval of the President & CEO, decided to install new switchgear instead. Although this option was more expensive, it was viewed as a better long-term solution.

2-SEC-16

[Ex.2 DSP p.132]

Has RSL performed PCB Transformer Replacements in the previous rebasing period? If yes, please provide the number of PCB Transformers replaced in each year.
Response(s):

Response(s):

Yes, RSL has performed PCB transformer replacements in previous rebasing period. Please see the chart below shows our PCB transformer replacements.

Year	#PCB Transformers Replaced
2017	4
2018	12
2019	9
2020	4
2021	4

2-SEC-17

[Ex.2 DSP p.134]

Regarding Morrisburg MS Relocation Phase 1 project:

a. Please clarify if this project is building a new feeder or relocating the station, or both.
b. Please provide details regarding the increase in demand, or otherwise, justify the need for an additional feeder.
c. Please explain if RSL has considered cheaper alternatives.
d. Please provide cost details and completion schedule for the project.

Response(s)

a. Morrisburg MS Relocation Phase 1 project is a relocation the MS2 station to the location at MS1.

b. The project's objectives are the following:
    a. Morrisburg MS2 station transformer shows significant signs of deterioration through the oil analysis.
    b. Morrisburg MS2 station has infrastructure deterioration
    c. The MS2 needs additional feeders to support Morrisburg as a reliable back-up to MS1.

c. The original plan for RSL was:
    a. Replace the MS2 station transformer
    b. Repair the infrastructure deterioration
    c. Install additional feeders to support Morrisburg with a reliable back-up to MS1.

    During the evaluation and seeking cheaper alternatives, the current approach was taken. Since the load is closest to MS1 location, and there is space in the MS1 substation, the approach of installing a new transformer beside MS1 as back-up was chosen. This avoids the costs of repairing the deteriorating MS2 station infrastructure and avoids the need to install feeders for a long distance. Another benefit of being closer to the load is that there would be less line losses.

d. Implementation plan
    a. Cost Estimate: $1,000,000
        i. Tendering & Project management $25,000
        ii. 5MVA Substation Transformer $500,000
        iii. Civil work $250,000
        iv. Poles, Wires, Conduit $225,000

    b. Timeline

i.	Lock in on Engineering and Project Management	OND 2021
ii.	Submission to OEB	OND 2021–JFM 2022
iii.	Tendering Process	JFM 2022
iv.	Civil work + awarded	May 2022
v.	Civil work complete	October 2022
vi.	RSL construction of poles, crossarms, feeders	October 2022
vii.	Transformer reclosure delivery	JFM 2023

viii.	Station completion	July 2023
ix.	MS2 in new location Online	October 2023
x.	OLD MS2 transformer offline	OND 2023
xi.	Decommission Approach	Nov 2023
xii.	Decommission	Dec 2023

2-SEC-18

[EB-2015-0100 Settlement Proposal, p.12] The approved Settlement Proposal in EB-2015-0100 included the following provision:

> *RSL appears to have an unusually high number of planned outages and scheduled outages. RSL agrees that, prior to its next cost of service rebasing application, it will carry out an assessment of the underlying causes of its level of planned outages and scheduled outages and will file that assessment together with RSL's recommendations as part of RSL's next cost of service rebasing application.*

Please provide the assessment, recommendations, and explain how they were incorporated into RSL's DSP.

Response(s):

Planned and Scheduled Outages Assessment

Note: Planned outage and Schedule outage terms are used interchangeably

Scheduled Outage occurrence are by far the largest greatest outages in the last DSP. Although the occurrences are reducing, it continues to be the highest outage for RSL.

	Number of Interruptions					
	5 years 2011-2015	5 years 2016-2020	Avg/year 2011-2015	Avg/year 2016-2020	Improvement Delta	Improvement %
9 - Foreign Interference	16	7	3.2	1.4	1.8	56%
8 - Human Element	0	0	0	0	0	0%
7 - Adverse Environment	1	0	0.2	0	0.2	100%
6 - Adverse Weather	26	21	5.2	4.2	1	19%
5 - Defective Equipment	51	31	10.2	6.2	4	39%
4 - Lightning	4	3	0.8	0.6	0.2	25%
3 - Tree Contacts	6	11	1.2	2.2	-1	-83%
2 - Loss of Supply	37	26	7.4	5.2	2.2	30%
1 - Shceduled Outage	134	115	26.8	23	3.8	14%
0 - Unknown/Other	3	0	0.6	0	0.6	100%
Total Unplanned	144	99	28.8	19.8	9	31%
Total Planned	134	115	26.8	23	3.8	14%
Overall Outages	278	214	55.6	42.8	12.8	23%

	Customer-Hours of interruption					
	5 years 2011-2015	5 years 2016-2020	Avg/year 2011-2015	Avg/year 2016-2020	Improvement Delta	Improvement %
9 - Foreign Interference	8866	186	1773.2	37.2	1736	98%
8 - Human Element	0	0	0	0	0	0%
7 - Adverse Environment	4	0	0.8	0	0.8	100%
6 - Adverse Weather	3140	2964	628	592.8	35.2	6%
5 - Defective Equipment	6497	3136	1299.4	627.2	672.2	52%
4 - Lightning	266	263	53.2	52.6	0.6	1%
3 - Tree Contacts	174	1222	34.8	244.4	-209.6	-602%
2 - Loss of Supply	97652	72120	19530.4	14424	5106.4	26%
1 - Shceduled Outage	4727	11162	945.4	2232.4	-1287	-136%
0 - Unknown/Other	42	0	8.4	0	8.4	100%
Total Unplanned	116641	79891	23328.2	15978.2	7350	32%
Total Planned	4727	11162	945.4	2232.4	-1287	-136%
Overall Outages	121368	91053	24273.6	18210.6	6063	25%

Areas of assessment:

Ongoing Trend:

The most recent 5 years results continue to show a healthy improvement of outage occurrences. Overall outages occurrences continue to decrease while driving down both unplanned and planned outage occurrences.

While scheduled outage occurrence continue to decrease, there is an increase of scheduled outage time.

Safety:

In every job task, a tailboard is utilized to discuss and align on the task at hand while evaluating the safety risk. The operations at RSL does not encourage the line worker employees to reduce scheduled outages occurrences or time by increasing safety risk. Safety and caring for each other is a value that is not compromised at RSL.

Preventative Maintenance Effectiveness & Efficiency:

RSLs preventative maintenance targets driving effectiveness then efficiency (unplanned then planned occurrences). Effectiveness is demonstrated by a reduction of Unplanned Outage Occurrences and unplanned customer-hours. Efficiency is driven by reduction in planned outage occurrences and customer-hours. Over the past 5 years effectiveness has improved by greater than 30% in both occurrence and customer time. While the planned outage occurrences decreased by 14%, the planned outage time increased.

Although RSL aims to getting to an ideal theoretical state of 0 outages in a cost-effective manner, RSL recognizes this is a journey. The results indicate RSL is on the right path of improvement. Increased scheduled customer-hours with reduced scheduled occurrences indicates the operations executed more maintenance and improvement per outage.

Approach to Staffing:

In order to optimize cost, RSL staffs and plans the scheduled work for 5 line workers or 4 (on occasions where one is on vacation). RSL staffs the crew based on the amount that are needed to complete the annual work in a safe manner, not based on reducing planned events. Increasing amount of line workers and assets could further reduce both planned outage occurrence and customer-hours. Based on our customer engagement results, this is not approach customers want to spend on achieving improved results.

Contractors are generally not utilized due to cost. The exception is work driven by Bell and Cogeco requests to upgrade the poles.

In Summary:

The amount of scheduled outage occurrences will continue to be the greatest outage occurrence at RSL. RSL will continue to drive efficiency in reduce the amount of scheduled outage occurrences.

In this DSP, RSL plans to continue maintaining the distribution system through the planned maintenance program. The primary goal will be to maintain the trend of low unplanned outages while improving the efficiency of the planned maintenance program.

3-SEC-19

[Ex.3, p4, Table 3.2]

Please revise the referenced table to provide 2021 actual information.

Response(s):

Please see the response to IR 3-Staff-22 a) & b)

3-SEC-20

[Ex.3, Appendix 2-H]

Please provide a revised version of Appendix 2-H that includes 2021 actuals.

Response(s):

Appendix 2-H was revised to include unaudited 2021 and updated 2022 Test Year Forecast.

4-SEC-21

[Ex.4, Appendix 2-JA, Appendix 2-JB]

Please provide a revised version of Appendix 2-JA and 2-JB that include 2021 actuals.

Response:

2021 actuals are not available as our external audit has not begun. Appendices 2-JA and 2-JB have been updated with the pre-audit amounts.

Appendix 2-JA

Summary of Recoverable OM&A Expenses

	2016 Last Rebasing Year OEB Approved	2016 Last Rebasing Year Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Unaudited	2022 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	$ 254,368	$ 247,781	$ 340,099	$ 354,881	$ 335,193	$ 351,313	$ 353,777	$ 362,465
Maintenance	$ 433,201	$ 429,760	$ 474,059	$ 398,021	$ 470,618	$ 390,659	$ 425,934	$ 450,600
SubTotal	**$ 687,569**	**$ 677,541**	**$ 814,159**	**$ 752,902**	**$ 805,811**	**$ 741,973**	**$ 779,711**	**$ 813,065**
%Change (year over year)		-1.5%	20.2%	-7.5%	7.0%	-7.9%	5.1%	4.3%
%Change (Test Year vs Last Rebasing Year - Actual)								20.0%
Billing and Collecting	$ 506,836	$ 526,212	$ 526,242	$ 548,505	$ 535,954	$ 541,821	$ 575,037	$ 551,220
Community Relations	$ 30,592	$ 20,924	$ 13,441	$ 25,277	$ 29,410	$ 29,166	$ 5,548	$ 32,500
Administrative and General	$ 867,827	$ 886,178	$ 898,621	$ 877,772	$ 874,630	$ 936,208	$ 986,108	$ 1,089,127
SubTotal	**$ 1,405,255**	**$ 1,433,314**	**$ 1,438,304**	**$ 1,451,553**	**$ 1,439,994**	**$ 1,507,195**	**$ 1,566,693**	**$ 1,672,847**
%Change (year over year)		2.0%	0.3%	0.9%	-0.8%	4.7%	3.9%	6.8%
%Change (Test Year vs Last Rebasing Year - Actual)								16.7%
Total	**$ 2,092,824**	**$ 2,110,856**	**$ 2,252,463**	**$ 2,204,456**	**$ 2,245,805**	**$ 2,249,168**	**$ 2,346,404**	**$ 2,485,912**
%Change (year over year)		0.9%	6.7%	-2.1%	1.9%	0.1%	4.3%	5.9%

	2016 Last Rebasing Year OEB Approved	2016 Last Rebasing Year Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Unaudited	2022 Test Year
Operations[4]	$ 254,368	$ 247,781	$ 340,099	$ 354,881	$ 335,193	$ 351,313	$ 353,777	$ 362,465
Maintenance[5]	$ 433,201	$ 429,760	$ 474,059	$ 398,021	$ 470,618	$ 390,659	$ 425,934	$ 450,600
Billing and Collecting[6]	$ 506,836	$ 526,212	$ 526,242	$ 548,505	$ 535,954	$ 541,821	$ 575,037	$ 551,220
Community Relations[7]	$ 30,592	$ 20,924	$ 13,441	$ 25,277	$ 29,410	$ 29,166	$ 5,548	$ 32,500
Administrative and General[8]	$ 867,827	$ 886,178	$ 898,621	$ 877,772	$ 874,630	$ 936,208	$ 986,108	$ 1,089,127
Total	**$ 2,092,824**	**$ 2,110,856**	**$ 2,252,463**	**$ 2,204,456**	**$ 2,245,805**	**$ 2,249,168**	**$ 2,346,404**	**$ 2,485,912**
%Change (year over year)		0.9%		-2.1%	1.9%	0.1%	4.3%	5.9%

	Last Rebasing Year 2016 OEB Approved	Last Rebasing Year 2016 Actuals	Variance 2016 OEB Approved - 2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Unaudited	Variance 2021 Unaudited vs. 2020 Actuals	2022 Test Year	Variance 2022 Test vs. 2021 Unaudited
Operations	**$ 254,368**	**$ 247,781**	**$ 6,587**	**$ 340,099**	**$ 354,881**	**$ 335,193**	**$ 351,313**	**$ 353,777**	**$ 2,464**	**$ 362,465**	**$ 8,688**
Maintenance	**$ 433,201**	**$ 429,760**	**$ 3,441**	**$ 474,059**	**$ 398,021**	**$ 470,618**	**$ 390,659**	**$ 425,934**	**$ 35,275**	**$ 450,600**	**$ 24,666**
Billing and Collecting	**$ 506,836**	**$ 526,212**	**-$ 19,376**	**$ 526,242**	**$ 548,505**	**$ 535,954**	**$ 541,821**	**$ 575,037**	**$ 33,216**	**$ 551,220**	**-$ 23,817**
Community Relations	**$ 30,592**	**$ 20,924**	**$ 9,668**	**$ 13,441**	**$ 25,277**	**$ 29,410**	**$ 29,166**	**$ 5,548**	**-$ 23,618**	**$ 32,500**	**$ 26,952**
Administrative and General	**$ 867,827**	**$ 886,178**	**-$ 18,351**	**$ 898,621**	**$ 877,772**	**$ 874,630**	**$ 936,208**	**$ 986,108**	**$ 49,900**	**$ 1,089,127**	**$ 103,019**
Total OM&A Expenses	**$ 2,092,824**	**$ 2,110,856**	**-$ 18,032**	**$ 1,438,304**	**$ 2,204,456**	**$ 2,245,805**	**$ 2,249,168**	**$ 2,346,404**	**$ 97,236**	**$ 2,485,912**	**$ 139,508**
Adjustments for Total non-recoverable items[3]											
Total Recoverable OM&A Expenses	**$ 2,092,824**	**$ 2,110,856**	**-$ 18,032**	**$ 1,438,304**	**$ 2,204,456**	**$ 2,245,805**	**$ 2,249,168**	**$ 2,346,404**	**$ 97,236**	**$ 2,485,912**	**$ 139,508**
Variance from previous year				-$ 672,552	$ 766,152	$ 41,350	$ 3,362	$ 97,236		$ 139,508	
Percent change (year over year)				0%	53%	2%	0%	4%		6%	
Percent Change: Test year vs. Most Current Actual										10.53%	
Simple average of %variance for all years										13.11%	
Compound Annual Growth Rate for all years											2.8%
Compound Growth Rate (2020 vs. 2016 Actuals)										1.6%	

Appendix 2-JB

Recoverable OM&A Cost Driver Table[1,3]

OM&A	Last Rebasing Year (2016 Actuals)	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Unaudited	2022 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	
Opening Balance[2]	$ 2,092,824	$ 2,110,856	$ 2,252,463	$ 2,204,456	$ 2,245,805	$ 2,249,168	$ 2,346,403
Staffing (payroll and benefits)	$ 13,225	$ 64,283	-$ 104,801	$ 62,983	$ 23,913	$ 54,132	$ 79,397
Third Party Service Providers	$ 1,495	$ 5,887	$ 78,376	-$ 38,992	$ 6,355	$ 61,705	-$ 15,881
Regulatory	$ 639	$ 35	$ 13,600	-$ 960	$ 149	-$ 15,798	$ 19,987
Bad Debts	$ 2,157	-$ 4,397	-$ 5,750	-$ 17,987	$ 27,891	-$ 3,398	$ 5,060
Smart Meter Communications/MDMR	$ 2,741	$ 847	$ 1,549	-$ 5,862	-$ 2,003	$ 2,787	$ 935
Vegetation Management	-$ 114	$ 14,674	-$ 7,013	-$ 16,354	$ 8,200	$ 12,700	-$ 11,400
Training	-$ 78	$ 4,664	$ 406	-$ 3,791	-$ 15,395	$ 2,601	$ 25,772
PCB Transformer Removal	$ -	$ 449	$ 9,551	$ 10,000	$ -	$ -	-$ 10,000
Travel/Meetings	$ 137	$ 3,308	-$ 773	-$ 1,005	-$ 16,450	$ 2,137	$ 16,748
Joint Use of Poles	-$ 911	-$ 5,512	$ -	$ 33,665	-$ 7,850	$ 405	$ 16
Use of Utilities Company assets	$ 1,249	-$ 7,182	-$ 1,676	-$ 1,856	-$ 1,756	-$ 376	-$ 161
Insurance	$ 871	-$ 1,643	-$ 5,352	$ 1,486	$ 1,704	$ 293	$ 779
Other	-$ 3,379	$ 66,194	-$ 26,124	$ 12,440	-$ 21,395	-$ 19,953	$ 28,257
Closing Balance[2]	$ 2,110,856	$ 2,252,463	$ 2,204,456	$ 2,245,805	$ 2,249,168	$ 2,346,403	$ 2,485,912

4-SEC-22

[Ex.4, p.6, Table 4.3]

With respect to OM&A Cost Drivers and Variances:

a. Please provide cost details and an explanation to the $66,194 increase in “Other” category in 2017.
b. Please provide cost details and an explanation to the $104,801 decrease in Staffing cost in 2018.

Response:

a)

1) The variance in “Other” came from a combination of items. First, fleet expenses in 2017 were lower than in 2016, but the amount charged against OM&A was higher by $13,000. This means that less fleet charges were applied to capital projects.

2) Operations expense in 2016 was abnormally low, as an old accrual for inventory obsolescence of $30,000 was adjusted. This makes the expense in 2017 look high when it is normal.

3) An employee long-service award program was started in 2017. As it was the first year of the program, each employee that had reached one of the service milestones was given an award. This increased our one-time costs by $6,000.

b) The reduction in Staffing costs in 2018 was due to the retirement of an RSL manager. It took many months to replace the position. We also had a Billing Clerk leave in 2018, and it took several months to hire her replacement.

4-SEC-23

[Ex.4, p.31]

Please provide a revised Table 4.16 with Post Retirement Benefit Costs in OM&A forecast, for each year from 2023 to 2026.

Response(s):

Please refer to the response to 4-Staff-25 for 2021 unaudited and 2022 Test Year Forecast. The post retirement benefit costs in RSL's OM&A are immaterial and it is difficult and time consuming to prepare a forecast for years 2023-2026. As such, RSL does not believe that spending resources on forecasting beyond the Test year is justified.

4-SEC-24

[Ex.4, p.32]

Please provide any benchmarking or any kind of comparable study on management compensation level conducted by RSL, or any third party contracted by RSL, in the process of recruiting new CEO and CFO.

Response:

In the process of recruiting a new CEO and CFO the 3rd party firm Sartor and Associates was contracted to support the process. In this process Sartor and Associates provided up to date compensation trends in the Ontario LDC industry for both positions.

RSL is a member of CHEC. CHEC provides a study of the compensation for management and non-management positions within its membership. The CEO and CFO compensation in the CHEC study was utilized in the process of the recruiting process of the new CEO and CFO to establish compensation.

4-SEC-25

[Ex.4, p.28]

Please provide cost details and breakdown by programs to explain the variance in the Underground Maintenance program between 2016 and 2022.

Response:

The following is a breakdown by program for Underground Maintenance. Virtually all of the cost is related to labour and burden. A significant reason for the increase in labour is that RSL hired a Utility Person in 2016, and a large part of his job is to do underground wire locates and work along with Ontario One Call. The costs are charged to program 5070.

Underground Maintenance							Bridge	Test
Program	Type	2016	2017	2018	2019	2020	2021	2022
5070	Labour and Burden	17,839	25,478	29,260	27,903	30,918	31,000	33,480
5075								
5145		2,424	3,678	853	681	430	1,395	1,705
5150		8,167	12,248	8,645	14,745	5,829	10,850	13,640
5155		9,714	9,574	13,012	14,239	18,285	15,500	19,530
5070	Materials				110			
5075					1,315	1220	1,500	1,500
5145								
5150		142						
5155		124	72					
5070	Outside Services	669	863	787	126			
5075				858	1,802	828	1,000	1,000
5145			291			2,697	1,000	1,000
5150			560					
5155				270				
		39,079	52,763	53,685	60,922	60,208	62,245	71,855
5070	Program Total	18,507	26,341	30,047	28,139	30,918	31,000	33,480
5075		-	-	858	3,117	2,048	2,500	2,500
5145		2,424	3,968	853	681	3,128	2,395	2,705
5150		8,309	12,808	8,645	14,745	5,829	10,850	13,640
5155		9,839	9,646	13,282	14,239	18,285	15,500	19,530
		39,079	52,763	53,685	60,922	60,208	62,245	71,855

4-SEC-26

[Ex.4, p.28] Please provide and explain the basis for the conclusion that inflation, excluding costs associated with recruiting new CEO and CFO, is responsible for over $100,000 of the variance.

Response:

RSL believes that the conclusion that inflation can account for over $100,000 of the variance is reasonable. Our review of historical inflation resulted in an average rate of 2.5%. The following table uses RSL's 2016 actual Administration costs as a baseline and applies inflation to each following year. Even using a low average inflation rate of 1.5%, the variance is almost $83,000.

Expected costs based on an inflation rate of 2.5%								
Actual								Inflationary
2016	2017	2018	2019	2020	2021	2022		Impact
886,178	908,332	931,040	954,316	978,174	1,002,628	1,027,694		141,516
Expected costs based on an inflation rate of 2.%								
Actual								Inflationary
2016	2017	2018	2019	2020	2021	2022		Impact
886,178	903,902	921,980	940,420	959,228	978,413	997,981		111,803
Expected costs based on an inflation rate of 1.5%								
Actual								Inflationary
2016	2017	2018	2019	2020	2021	2022		Impact
886,178	899,471	912,963	926,657	940,557	954,665	968,985		82,807

4-SEC-27

[Ex.4, General] SEC notes during the past rebasing period, at least two key employees of RSL returned from extended leave, and they had material impact on OM&A costs. Please explain how RSL maintained its operation readiness during the period of their absence.

Response(s):

RSL lost one of its Managers for an extended period. During his absence, all employees in the department were given more responsibilities, and two co-op students were hired to cover the more basic work. RSL was fortunate to be able to stay in contact with the Manager when matters came up that required his experience. The President & CEO stepped in to provide support and guidance where possible.

An administrative employee also went on a significant leave. Ultimately, she was unable to return to work. In the short term, her duties were split among other staff and temporary staff was hired for a short period. RSL was unable to fill the position until two years after the employee started the leave of absence. The extra work was a burden on remaining staff until we were able to hire the replacement.

In 2021, a senior RSL manager unexpectedly retired. There was a six-month gap between his leaving and the hiring of his replacement. For that half year the manager's basic functions were covered by the RSL Chair and the other RSL managers. RSL managers worked many extra hours of overtime, working evenings and weekends to do as much of the retired manager's work as possible.

Any time that an employee is lost for an extended time, it places a heavy burden and stress on the other employees. In each of the cases described, RSL lost employees with over 25 years of experience individually. The extensive experience cannot be replaced by other employees filling in temporarily.

The loss of senior staff was a significant factor in the delay in filing this Cost of Service rate application.

5-SEC-28

[Ex.5] Please provide a table that shows RSL's regulated ROE for each year between 2017 and 2021.

Response:

The following table contains the regulated ROE for each year except 2021. Our external audit for 2021 has not begun, so ROE cannot be calculated.

Return on Equity	
Year	ROE
2017	1.18%
2018	5.11%
2019	5.72%
2020	6.09%
2021	NA

7-SEC-29

[Ex.7, p.4, Table 7.2]

Please provide detailed justification to the weighting factors assigned for GS 50 – 4999 for each of Services Account 1855 and Billing and Collecting Accounts 5315 – 5340.

Response:

Please see 7-VECC-34 for information about the weighting factors used for Billing and Collecting. The weighting was created for the 2016 Cost of Service application. RSL believes that the weighting factors are still valid, as the degree of complexity concerning GS 50- 4999 customers has not decreased.

Concerning the weighting of account 1855, RSL chose to stay with the existing weighting factors that have been in use by our company for many years. We have not been able to find any analysis or methodology to confirm or refute the factors used. Due to a lack of better information, RSL considers it prudent to stay with the status quo weighting factors for 1855.

9-SEC-30

[Ex.9, p.30]

With respect to Account 1592, Sub Account -CCA Changes:

a. Please confirm that RSL did not take any accelerated CCA on assets in 2018 and 2020.
b. Please revise Table 9.28 to include forecast principal entries in 2021.
c. Please provide the supporting CCA continuity schedules related to the principal amounts included in the revised Table 9.28 requested in part (a).

Response:

a) RSL took accelerated CCA on assets in 2018 and 2020. The transactions were recorded in 2019 and 2021 respectively.

b)

	Table 9.28: 1592 Sub Account - CCA Changes				
	CCA Acceleration Savings (Principal)	**Interest**	**Total Claim**	**2020 RRR 2.1.7**	**Variance of Account Bal. and RRR**
2018	(1,879)				
2019	(5,789)				
2020					
Balance as of December 31, 2020	(7,668)	(144)		(7,812)	0
Add: 2020 Addition Recorded in 2021 GL	(14,590)				
Add: 2019 Correction to Savings	(5,480)				
Add: 2021 Forecasted Savings	(8,911)	(149)			
	(36,649)	(293)			
Remove 50% per Tax Sharing Rule	18,325	146			
	(18,325)	(146)			
Total	(18,325)	(146)	**(18,471)**		

c) Please see 9-Staff-40 for this information.