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File No. 21902.17

August 8, 2023

<u>BY EMAIL & RESS</u>
registrar@oeb.ca

Ms. Nancy Marconi
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: InnPower Corporation ("InnPower")
Application for 2024 Distribution Rates – Ontario Energy Board File Number: EB-2023-0033
Interrogatory Responses

In accordance with Procedural Order No. 1, please find enclosed InnPower's responses to the interrogatories filed in the above noted proceeding.

Despite best efforts, InnPower was not able to provide responses to 1-Staff-1, 4-Staff-56, 8-Staff-64 and 8-VECC-32 within the allotted time in Procedural Order No. 1. InnPower is requesting an extension until August 10, 2023 to provide responses to these interrogatories, along with the associated model updates.

Please contact the undersigned with any questions.

Yours truly,

BORDEN LADNER GERVAIS LLP

J Vellone

John Vellone

JV/CB

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Ontario Energy Board (OEB) Interrogatories

Reference:

1-Staff-2

Ref 1: Exhibit 1, Tab 3, Schedule 3, page 328
Ref 2: Chapter 2 Appendix 2-BA

Question:

According to Reference 1, InnPower adopted IFRS 16 – Leases on January 1, 2019. InnPower stated that there was no right-of-use asset or related lease liability recognized at the transition as there were no outstanding lease contracts at that time.

a) Please file a copy of InnPower's 2019 AFS, demonstrating that there was no right-of-use asset capitalized from the application of the IFRS-16.

Response:

a) Please see the 2019 Audited Financial Statements attached as ***Att 1-Staff-2_2019_InnPower_Audited_Financial_Statements***. As confirmed in Note 4, InnPower did not have any outstanding lease contracts as of January 1, 2019. InnPower did however, recognize $171k in right-of-use assets and $171k of lease liabilities for lease contracts entered after January 1, 2019.

Reference:

1-Staff-3

Conditions of Service
Ref 1: EB-2016-0085 Decision and Order
Ref 2: Exhibit 1 – 14.4 Directive #4
Ref 3: Distribution System Code

Question:

In reference 1, the OEB noted that InnPower's Conditions of Service did not include the business process it uses to disconnect and reconnect consumers as required by the DSC. In reference 2, InnPower stated that it updated its Conditions of Service with a disconnection policy. The policy included wording from the distribution system code. In section 4.8 of the distribution system code, it also discusses winter disconnections, reconnections, and load devices.

a) Please explain how InnPower has addressed winter disconnections in its disconnection policy.

Response:

a) We have updated our Disconnection Policy *(Policy 5.06 Disconnection/Reconnection Policy*) and are awaiting the next Conditions of Service revision to include the Winter Moratorium information from the DSC.

   The revised policy to be updated with next Conditions of Service revision is uploaded for review as ***Att 1-Staff-3a_Revised_Policy_5.06_Disconnection_and_Reconnection_Policy.***

Reference:

2-Staff-4

2023 Bridge Year Actual
Ref 1: Appendix 2-AA and Appendix 2-AB

Question:

InnPower provided its 2023 Bridge Year forecasts with zero months of actual spending included.

a) Please update capital expenditures for the 2023 Bridge Year in Appendix 2-AA format and Appendix 2-AB format (and update other related tabs in Chapter 2 Appendices accordingly) to account for updates to the work schedule since the application was filed. Please specify for which months actual data has been used versus forecast.
b) In Appendix 2-AA, please provide the capital expenditures to date for the 2023 Bridge Year.

Response:

a) Appendix 2-AA and 2-AB (attached as ***Att 2-Staff-4a_Updated_2023_2-AA*** and ***Att 2-Staff-4a_Updated_2023 _-AB***) has been updated to account for changes in the work schedule as requested. The data consists of actual data for January 1 to June 30, 2023, and forecasted data for the remainder of 2023.
b) Capital expenditures to June 30, 2023, have been provided in the Appendix 2-AA format as requested in the attached excel file as ***Att 2-Staff-4b_Updated_June_2023 _TD_2-AA***.

Reference:

2-Staff-5

Historical Underspending
Ref 1: Chapter 2 Appendices – Appendix 2-AB

Question:

InnPower has historically underspent compared to its capital expenditure plans. The OEB approved a 2017 net capital expenditure amount of $4.405 million, while InnPower spent $3.481 million, a difference of 21%. Between 2017 and 2021, InnPower's total planned capital expenditure amount was $27.577 million, while InnPower's actual spending was $21.812 million, also a difference of 21%.

a) How has InnPower strived to improve the accuracy of its estimates for the Test year and beyond?
b) What is the process that InnPower undertakes to forecast planned expenditures?
c) What level of certainty does InnPower have that the forecasted projects and expenditures will proceed as planned?
d) What are the key risks that may impact the schedule and budget over the forecast period?
e) What actions does InnPower have planned to manage or mitigate these risks?
f) How does InnPower proactively identify ongoing risks?
g) What is the escalation process that InnPower undertakes to mitigate or avoid the impacts of identified risks?
h) Should the historical level of variability continue over the forecast period, how will InnPower manage and (re)prioritize its schedule and budget, ensuring that high priority projects are completed?

   InnPower has deferred many projects throughout the historical years in order to complete higher priority projects.

i) What is InnPower's plan to ensure that the deferred projects are completed in the future?
j) If InnPower has deemed any of the deferred projects no longer necessary, what was the process undertaken to reach this determination?

Response:

a) The following are the changes InnPower implemented to improve the accuracy of the estimates:

   I. Include engineering input as part of the estimating process to address accuracy which is based on the most recent material, construction costs and quotes from suppliers.

   II. Implemented a new Quadra estimating software to ensure estimating consistency. This job costing software integrates with engineering standards and financial systems which allows for consistent, accurate and most up-to-date project estimates based on pre-defined scopes of work.

   III. Actual expenditure incurred from previously completed projects are used to assist in developing estimates for projects in the test year and beyond. In addition, due to the volatile material costs over the last three years, InnPower has attempted to account for this in its forecast expenditure, by utilizing the latest material and construction costs, and information from supplier quotes.

b) InnPower utilizes the planning process, outlined in Exhibit 2: DSP- Section 5.3.1, pg 185/758 of the Exhibit, to forecast its planned capital expenditures.

c) Forecasted projects and expenditures contained in this application are result of InnPower's planning process as outlined within its DSP (Exhibit 2: DSP- Section 5.3.1, pg 185/758 of the Exhibit). InnPower is confident that the majority of these investments will proceed as planned. As with most forecasts, the further out the forecast is, the higher the probability that items that occur that will require InnPower to adjust its plans. For example, a developer may delay its project, which would have an impact on the timing of the related System Access investment.

d) InnPower has outlined its key risks in each material narrative within Exhibit 2: Appendix A of the DSP, Pages 302 – 443.

e) InnPower has outlined its key risks and mitigations in each material narrative within Exhibit 2: Appendix A of the DSP, Pages 302 – 443.

f) InnPower meets regularly with third parties who are driving projects (developers, road authorities and telecoms) to update schedules and risks associated with all planned and forecasted projects. In addition, as outlined in Step 5 of its planning process, InnPower monitors all its investments on an ongoing basis. (Exhibit 2: DSP- Section 5.3.1- page 192 of 758).

g) InnPower's escalation process is both internally and externally depending on the driver of the project. Consistent communication regarding budgets, timelines and supply chain are carried out to ensure all parties understand the constraints of a project. All groups have individual escalation if issues are unable to be resolved in the working groups.

h) InnPower meets monthly to review the status and schedule of all capital projects to understand the impacts on timing against the budget. Communication with projects driven by third parties is critical to understand any impacts on the budget to ensure there is enough time for InnPower to reprioritize its expenditure plans. push and pull.

i) InnPower evaluates all projects during the yearly budgeting process. All projects that were deferred are re-evaluated against planned projects using new information (inspection, maintenance, outages, etc) to ensure the proper allocation of costs for projects.

j) InnPower utilizes future expansion projects, inspection and maintenance data, asset health, timelines, scope and recent outage trends to evaluate the justification of a project. Based on this information, a project may be deemed no longer necessary, and it is removed from the planned expenditure.

Reference:

2-Staff-6

System Access: Historical Variance
Ref 1: Distribution System Plan, p.102, Table 5.4-1 Historical and Bridge Year Capital Expenditures and System O&M
Ref 2: Distribution System Plan, Section 5.4.1.1.1 System Access, pp.104-112

Question:

There was an underspend in the System Access category over the historical period, with an average variance of 31% under planned. Most of this underspend is related to planned customer connections not materializing or projects out of InnPower's control being deferred.

a) Does the total underspend in System Access over the historical period represent a backlog of projects that might take place during the forecast period (For example, was expected subdivision growth simply delayed rather than foregone)? If so, is this backlog accounted for in the planned expenditures for the forecast period?
b) If so, is this backlog accounted for in the planned expenditures for the forecast period?
c) Many System Access projects related to subdivision connections during the historical period were delayed as a result of developer timelines. What steps has InnPower taken to improve engagement with stakeholders (developers, road authorities, etc.) to proactively anticipate and manage potential delays?

Response:

a) Yes, the underspend in System Access over the historical period does represent a backlog of projects. Based on regular communication with these third parties, projects are recorded in the planned expenditures for the forecast period.
b) Yes. Please see answer '2-Staff-6-a'.
c) InnPower meets on a regular basis with developers, road authorities and telecoms to review timelines, scope and risks to ensure all parties are aligned. InnPower

ensures developers follow the Offer to Connect and connection horizon provided and work to ensure projects remain on schedule by working with suppliers to approve alternative materials due to supply chain constraints.

Reference:

2-Staff-7

System Access: Forecast Expenditures

Ref 1: Distribution System Plan, p.102, Table 5.4-1 Historical and Bridge Year Capital Expenditures and System O&M

Ref 2: Distribution System Plan, p.129, Figure 5.4-3 Forecast Net Expenditures by Investment Category [Excl. BATU & TS Project]

Ref 3: Distribution System Plan, Section 5.4.1.2.1 System Access, p.130

Question:

Excluding the Barrie Area Transmission Upgrade (BATU) and TS Project costs, System Access expenditures represent the largest planned capital expenditure over the forecast period, at 37.5% of overall spending. This represents an increase from 26% of overall spending from the historical period.

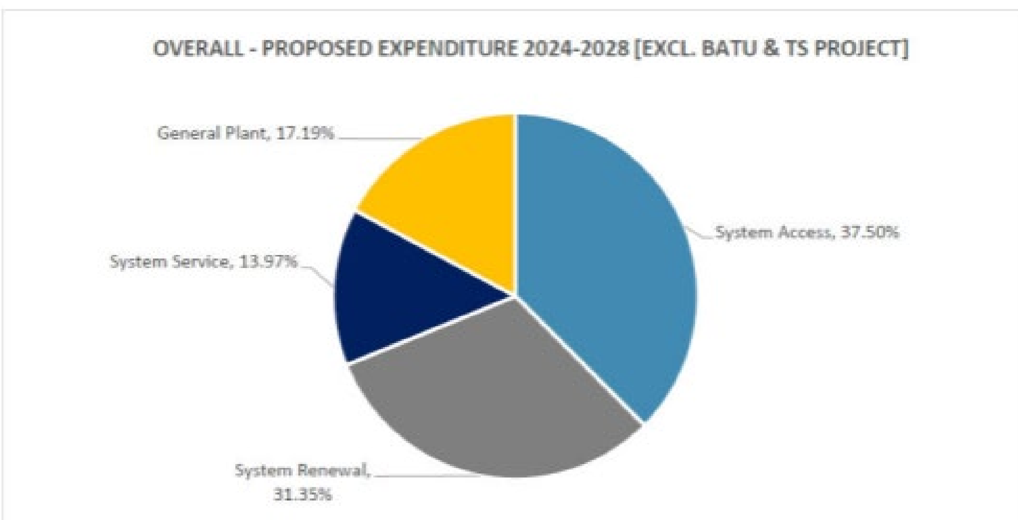


Figure 5.4-3: Forecast Net Expenditures by Investment Category [Excl. BATU & TS Project]

a) Approximately 48% of these expenditures represent servicing new subdivisions.
   i. Please provide additional information on the specific projects (i.e., which subdivisions are expected to be developed and when) that

informed InnPower's planned System Access expenditures over the forecast period.

ii. For each of the projects identified, has an Offer to Connect agreement been executed?

Response:

a) i. InnPower's System Access material narratives outline its proposed System Access investments. (See Exhibit 2 – DSP – Appendix A)

ii. InnPower has agreements with Hewitt and Salem landowners' group for upstream expansion work. It then has individual Offer to Connects for each local subdivision expansions.

Reference:

2-Staff-8

System Renewal: Forecast Expenditures
Ref 1: Distribution System Plan, p.146, Figure 5.4-15 System Renewal Comparative Expenditures

Question:

InnPower's planned average System Renewal spending during the forecast period is expected to be 16% less than what was spent on average during the historical period and bridge year, as shown in the figure below. How will InnPower ensure that this reduced spending will not have adverse impacts on the health of system assets in the coming years?

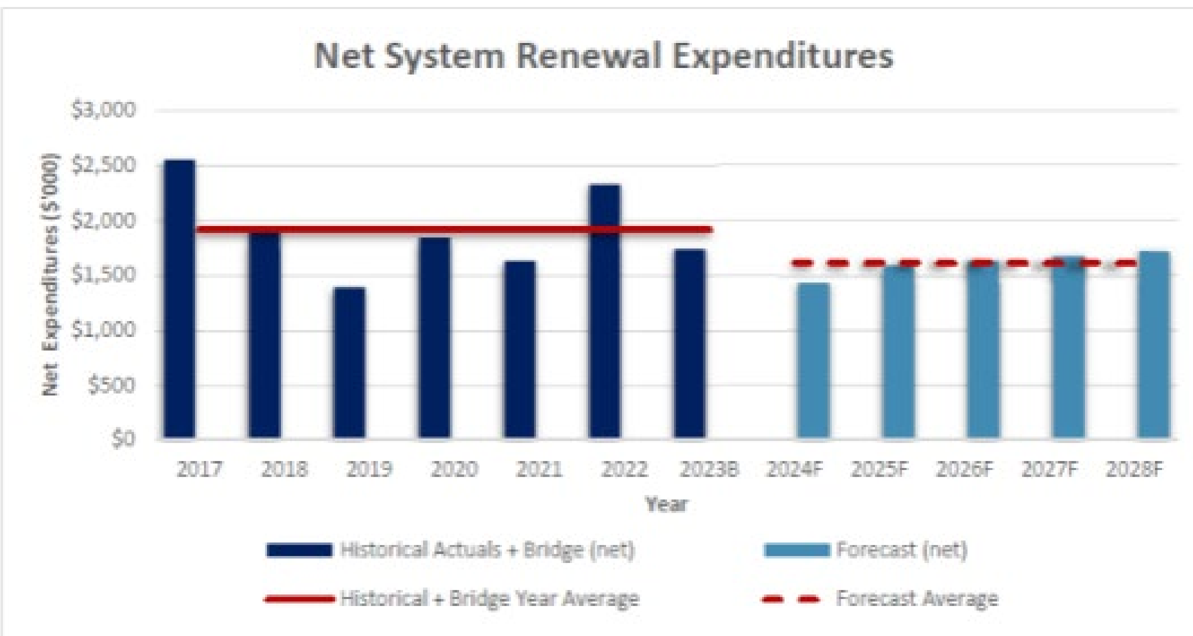


Figure 5.4-15: System Renewal Comparative Expenditures

Response:

Due to the number of expansion projects planned during the forecast period, many assets in poor or very poor condition will be replaced to accommodate growth and road authority projects. As a result of the volume of replacements/rebuilds the number of assets that are in poor and very poor condition has been reduced. As a result, InnPower was able to slightly reduce budgets in the System Renewal category. Should any expansion or other System Access projects be deferred, InnPower will utilize its asset condition information along with its prioritization process to identify any increase in System Renewal expenditure.

Reference:

2-Staff-9

Market Conditions
Ref 1: Distribution System Plan, Section 5.4.1.1 Plan Versus Actual Variances for the Historical Period, p.137

Question:

Market conditions in recent years such as supply chain difficulties, labour shortages, and cost escalation have had a significant impact on the ability of owners to deliver capital works on time and within budget. Inn Power cites supply chain constraints and cost increases as factors contributing to spending variability and project delays over the historical period (e.g., BATU project cost escalation and delays, switch commissioning project delays, buyout of leased vehicles rather than purchase of new vehicles).

a) What steps has InnPower taken to ensure it can maintain the planned schedule for forecast expenditures?
b) What steps has InnPower taken to incorporate recent cost escalation into its forecasted investments?
c) What are InnPower's plans to mitigate and address risks presented by supply chain constraints, which have more recently had a significant impact on lead times for electrical equipment?

Response:

a) InnPower has joined a purchasing group for the purchase of transformers moving forward to help ensure as timely delivery as possible and guaranteed spots within the production schedule. InnPower is working with vendors to hold material based on early designs to ensure material is available when required. InnPower is also working towards designing and planning a year in advance to allow for any supply chain disruptions to minimize the impact on the construction schedule.
b) InnPower has sent out RFPs for different types of work including overhead line services, vegetation management and some inspection and maintenance works that include up to three-year terms with fixed rate increases. Using this information

and actual costs from recently completed projects, InnPower is able to produce forecast expenditure that reflects any recent cost escalation whilst also including known costs due to its robust RFP process.

c) Please see the response to question ‘2-Staff-9a’.

Reference:

2-Staff-10

Projected System Growth
Ref 1: Distribution System Plan, Section 5.3.2 Overview of Assets Managed, pp.55-59

Question:

In predicting customer and load growth over the forecast period, InnPower has considered a conservative and an optimistic growth case. The conservative case predicts 5% annual customer growth, resulting in a total increase in customer numbers of 34%. The optimistic case predicts 12% annual customer growth, resulting in a total increase in customer numbers of 100% by 2028. The conservative and optimistic case results in a total increase of system peak demand of 58% and 86% by 2028, respectively.

a) The 12% annual customer growth prediction used in the optimistic forecast case is a significant jump from the historical average of 3.6%. What are the underlying assumptions associated with the optimistic case?
b) There is a significant difference between the total growth in customer numbers and system peak demand over the forecast period using either the conservative or optimistic case.
    i. How has InnPower reconciled the difference between these projections?
    ii. How have these projections informed investment decisions over the forecast period?
c) InnPower has calculated a conservative and optimistic case for projected customer growth and peak demand growth but presented only one projection for total energy delivered over the forecast period.
    i. Is the total energy forecast based on the conservative or optimistic case used to project customer growth and peak demand growth?
    ii. How has this estimate informed investment decisions over the forecast period?

Response:

a) In recent years, InnPower has observed the demand for new developments increasing. The optimistic scenario is based on the registered units as provided by the developers.

b) i. InnPower is anticipating significant growth in the Industrial/Commercial/Institutional sectors, which will result in a higher peak demand compared to projections based solely on residential customer units.

   ii. InnPower system planning maps any identified new load demands in its service area to their actual locations. Engineers review the existing infrastructure in each area to evaluate whether it can supply the new demands. If necessary, new expansion projects will be developed considering the demand of the entire system.

c) i. The total energy forecast is based on the conservative case.

   ii. The investment decision is based on the conservative forecast with consideration and provisioning of the ultimate system need. New projects are planned to ensure that the capacity will be available in the long term. InnPower is constantly monitoring the loads and plans accordingly for future expansion projects.

Reference:

2-Staff-11

Annual Asset Condition Assessment

Ref 1: Distribution System Plan, p.52, Table 5.3-2 Information Comprising InnPower's Asset Database

Question:

InnPower stated that it conducts annual asset condition assessments.

a) What are the annual costs associated with the asset condition assessment from 2017-2028?

b) Has InnPower considered shifting to a 2-3 year cycle for asset condition assessments? What drawbacks would there be to shifting asset condition assessments to a 2-3 year cycle?

Response:

a) The following costs are the annual costs associated with InnPower's annual inspection and maintenance programs that provide input into its asset condition.

    2017 - $36,547
    2018 - $34,563
    2019 - $29, 675
    2020 - $32,526
    2021 - $41, 173
    2022 - $57,095
    2023 - $63,350
    2024 - $69,150

b) InnPower performs an annual inspection and maintenance program, which provides critical information to update asset condition. While this will be performed and updated yearly, InnPower optimizes inspection and maintenance on a 3, 4 or 6 year cycle depending on the asset type, therefore a global (entire distribution system) update to asset condition would occur approximately every three years.

Through continually inputting data received from the inspection and maintenance programs, InnPower is able to maintain accurate records to improve data quality used in calculating the asset condition.

Reference:

2-Staff-12

Asset Data Collection Improvements
Ref 1: Asset Condition Assessment, Section 6.3 Data Collection Improvements, p.78
Ref 2: Asset Condition Assessment, p.13, Table 0-3 Asset Condition Assessment Overall Results

Question:

METSCO has recommended several changes to improve asset data collection for future asset condition assessments. Improvements include collecting missing data and changing condition grading schemes to a five-tier system (e.g. very good to very poor) where some are currently graded on a three-tier system (e.g. good, fair, and poor). METSCO also recommends introducing more variables that can provide further insight into the condition of assets such as visual inspects of station capacitors and age data of station switches.

a) It was noted that 98 Polemount Transformers, 136 Padmount Transformers, and five Lightning Arresters did not have sufficient data to allow a Health Index score to be calculated during the ACA. Other assets with data limitations included overhead conductors and underground cables. How will InnPower collect data on these assets and assess their condition?
b) Will InnPower be changing its condition grading scheme to a five-tier system for all assets as recommended by METSCO?

Response:

a) InnPower performs yearly padmount inspection of transformers and switchgears. During this inspection, data is collected from the nameplate of the device and a number of categories are evaluated to provide inputs into the asset condition. Over a three year cycle, InnPower expects to collect all required information in this section of assets (unless name plates are not legible). For overhead assets (polemount transformers, conductors and lightning arrestors), InnPower will utilize the ESRI GIS to capture information for all new projects as well as gather information from outages and feedback from the field to update its records. Asset condition for overhead assets will primarily be driven by active inspections through the use of infrared and visual inspection.

b) The current objective is to maintain the same weights and grading scheme moving forward, with further review of the grading system and weights in the future.

Reference:

2-Staff-13

Outage Cause Codes
Ref 1: Distribution System Plan, Section 5.2.3.2.3 Outage Details for Years 2017-2022, pp.39-40
Ref 2: Distribution System Plan, Section 5.2.3.2.3 Outage Details for Years 2017- 2022, pp.41-42
Ref 3: Distribution System Plan, 5.2.3.2.3 Outage Details for Years 2017-2022, p.34
Ref 4: Distribution System Plan, 5.2.3.2.3 Outage Details for Years 2017-2022, pp.37, 40-41

Question:

In Reference 1, InnPower has identified 20.8% of outages as being due to scheduled outages. InnPower stated that it aims to plan and execute capital work and maintenance appropriately.

a) Does InnPower have a formal plan to lower the number of scheduled outages during the Distribution System Plan period?

   In Reference 2, InnPower has reported that 29.2% of customer hours of interruption are due to adverse weather.

b) Does InnPower have a breakdown of adverse weather outages (e.g., Wind, Ice, Snow, and Other)?
c) InnPower has stated that it invests in system hardening to address adverse weather events that continue to increase in frequency as a result of climate change. Please provide details on how InnPower hardens its system in light of climate change and resiliency efforts. How much has InnPower invested in storm hardening during the forecasted period (compared to InnPower's standard design practices)?
d) Do pole outages fall under adverse weather? If not, where are they categorized?
   In Reference 3, InnPower notes that performance in SAIDI, SAIFI and CAIDI improves when excluding outages due to Loss of Supply (LOS) and Major Event Days (MED).

e) Has InnPower communicated with Hydro One to express concern over LOS outages? If so, what was the resulting action plan? If not, will InnPower be expressing concern to Hydro One over the increasing LOS outages?

In Reference 4, InnPower has identified 9.8% of outages, 21.9% of customers interrupted, and 8.5% of customer hours of interruption as being from unknown/other causes.

f) Has InnPower taken any steps to further categorize unknown/other outages?

Response:

a) InnPower does not have a formal plan to reduce the number of scheduled outages during the DSP period. InnPower individually evaluates how planned work is completed and looks to minimize the number of scheduled outages and outage duration through switching and project and resource coordination.

b) Yes, please see the below chart:

	2017	2018	2019	2020	2021	2022
HIGH WINDS	14	18	1	10	9	20
ICE	1	6				
HEAVY RAIN	1				1	
WIND, RAIN & LIGHTNING		7		7		
BLIZZARD			5			6
TORNADO					3	
OTHER	5	8	2		2	1

c) One example of the type of storm hardening investment is that InnPower has buried its overhead station feeders. In addition, InnPower ensures that any planned work addresses as many concerns as possible with respect to storm hardening. For overheard systems, InnPower utilizes a combination of Spidacalc, additional storm guys, updated pole classes and vegetation management to help mitigate these issues. Storm hardening costs are difficult to segregate as the storm hardening activities are bundled with engineering standards and standard investments.

d) No, pole outages are classified as a foreign interference due to motor vehicle accidents.

e) InnPower follows up with Hydro One on every LOS outage. Also, InnPower will raise concerns with Hydro One if the LOS outages increase compared to previous historical stats.

f) Yes, InnPower is training its staff on the updated cause codes as per Amendments to Reporting and Record-keeping Requirements Reliability and Power Quality Review – OEB File No. EB-2021-0307 that will come into effect on January 1st, 2024.

Reference:

2-Staff-14

Defective Equipment Outages
Ref 1: Distribution System Plan, Section 5.2.3.2.3 Outage Details for Years 2017-2022, pp.41-42
Ref 2: Distribution System Plan, Section 5.3.2.2.3 Asset Failures/Performance, pp.82-83

Question:

In Reference 1, InnPower reported that there were only 902 hours of interruption associated with defective equipment in 2022 whereas in 2020 and 2021, the number of hours were greater than 7,000.

a) Does InnPower have any explanation for why the number of hours of interruption caused by defective equipment were so low in 2022? Is InnPower seeing a similar trend in 2023 thus far?
b) As per Reference 2, fuses and secondary conductors were the asset types with the highest rates of failure during the historical period, however these do not appear to be included in the planned material System Renewal projects. What actions are planned to improve the reliability of these assets?

Response:

a) InnPower proactively reviews its asset condition assessment and identifies the poor and very poor assets in its system that require attention. By addressing these poor and very poor assets, through its capital and maintenance programs, InnPower should see a reduction in the number of outages caused by defective equipment. InnPower is experiencing the same trend as 2022 and its defective equipment outage duration is 306 hours YTD for 2023.
b) InnPower has implemented CYME DIST and CYME CAP software. This is a power engineering distribution system analysis and simulation software. This software has helped improve InnPower's system protection and coordination which leads to better power fuses selection to avoid future failure in the system. Also, utilizing this

software InnPower is planning to identify the poor and very poor secondary cables and will develop a plan to address these assets, either as a separate program or combined within an existing overhead program. Currently, InnPower tracks the number of failures on a secondary cable to determine if a replacement is required. Due to the sporadic nature of secondary cable failures to date, InnPower has determined that there is no requirement to build a planned replacement program at this time.

Reference:

2-Staff-15

Subdivision Projects
Ref 1: Distribution System Plan, Material Investment Narrative, IPCSA – Subdivision Projects

Question:

InnPower stated that the subdivision projects involve, in some cases, replacing existing poles, overhead switches, and pad-mounted switches.

a) Can InnPower confirm that the replacement of assets as part of the subdivision projects are not included in those replacements completed as part of System Renewal programs?
b) InnPower stated that it estimated subdivision projects based on an average net connection cost of $0.9 million yet it plans to connect 1030 units at a cost of $663k in 2024. Can InnPower please clarify unit cost estimates per connection from 2023-2028? Please provide the number of connections for each year.
c) How did InnPower estimate the number of connections/costs for the 2025-2028 years? Has InnPower been given estimates by developers for these years or are these forecasts solely developed based on InnPower's growth estimates?

Response:

a) Yes, InnPower can confirm that the replacement of assets as part of the subdivision projects are not included in those replacements completed as part of System Renewal programs.
b) InnPower approximated the economic evaluation (EE) payments for each subdivision in the budgets for 2023 and 2024. For 2025-2028, InnPower utilized an average cost per connection based on actual EE payments in 2021 for the years 2025-2028, which is a net $910k per connection.

   The number of connections used in the budget for each year (2023-2028) are as follows:

2023 – 1,053

2024 – 729

2025 – 1,067

2026 – 892

2027 – 1,196

2028 – 1,784

c) For the 2025-2028 cost estimation and number of connections, please see the answer to 2-Staff-15b. InnPower estimated the number of units that would be energized during 2025-2028, based on load absorption conservation factors.

Reference:

2-Staff-16

System Access: Road Authority Projects
Ref 1: Distribution System Plan, Section 5.4.1.2.1 System Access, p.132
Ref 2: Distribution System Plan, pp.103-112, Tables 5.4-3 to 5.4-7

Question:

There is no spending forecasted for System Access projects related to road authority works during the years 2027 and 2028 due to a lack of planned projects during these years. However, the System Access budget variance explanations presented in Tables 5.4-3 to 5.4-7 indicate that there were at least nine road authority-driven projects over the historical period that were unplanned or over budget. One project, IPC2017SA02, was 1840% over budget. How does InnPower plan to manage its budget and ensure it is able to cover costs should unanticipated road authority projects arise in 2027/2028?

Response:

InnPower meets regularly with all road authority agencies in the service territory to understand upcoming project timelines and scopes. The Road Authorities are unable to commit to timelines on projects in the years 2027 and 2028 and as a result InnPower did not budget for projects and notified the Road Authorities. In the event an urgent request comes in to complete a project, InnPower will re-prioritize budgets and work with the Road Authority to ensure overall budgets are met.

Reference:

2-Staff-17

Smart Meter Capital Expenditures

Ref 1: Distribution System Plan, Material Investment Narrative, IPCSA05 – Metering

Question:

InnPower has provided the number of historical meters purchased and the associated capital expenditure between 2017-2022. Unit cost per meter is $1.3k/meter in 2017 and $6.3k/meter in 2020 compared to approximately $0.3k/meter in 2018-2020 and 2022.

a) Please explain the higher unit cost for smart meters in 2017 and 2020.

   The average unit cost per meter is $0.53k during the forecasted period of 2024-2028 assuming 1,000 meters are purchased annually.

b) Please explain the increase in unit cost over the forecasted period in comparison to 2018-2020 and 2022.

c) When will InnPower need to start mass replacements of its smart meter inventory?

Response:

a) Suite meters that were purchased for projects in 2017 and 2020 were not reflected in Table 2. Please see below for the original and the updated version of this table.

   Original Table 2:

Year	# of meters purchased
2017	303
2018	1,112
2019	495
2020	109
2021	592
2022	651

Updated Table 2:

Year	# of meters purchased
2017	753
2018	1,112
2019	495
2020	1013
2021	592
2022	651

For 2017, the unit cost is $0.53k

For 2020, the unit cost is $0.678k

b) The costs for the projected periods are based on the projected increases in new services.

c) InnPower plans to reverify all smart meters as their seal life expires in order to extend the service life rather than a mass replacement of the meters.

Reference:

2-Staff-18

System Renewal: Capital Trouble Calls & Emerging Projects
Ref 1: Distribution System Plan, Appendix A Material Narratives, IPCSR01 – Capital Trouble Calls & Emerging Projects
Ref 2: Chapter 2 Appendices, Appendix 2-AA

Question:

InnPower notes that projected spending on Capital Trouble Calls and Emerging Projects is based on historical trends. However, the average forecasted spending on this project is $377k, as compared with $654k during the historical period.

a) What is the rationale for the decrease in spending as compared to the historical trends?
b) What plans are proposed to ensure InnPower is able to cover costs if future requirements more closely resemble the historical period?

Response:

a) InnPower has implemented an enhanced inspection and maintenance program in an effort to reduce the number of trouble calls and emerging projects. One example of this is the lack of tree related outages after the completion of a vegetation management cycle. InnPower projects the positive impacts of these programs will shift any remaining issues into planned regular time work. Based on these assumptions, InnPower has forecasted reduced spending related to Capital Trouble Calls and Emerging Projects.
b) InnPower meets monthly to monitor budgets, reviews trends and ensure budgets are met. Should spending increase during the forecasted period, InnPower will re-prioritize its overall budget accordingly.

Reference:

2-Staff-19

Wood Pole Replacements
Ref 1: Asset Condition Assessment, p.13, Table 0-3 Asset Condition Assessment Overall Results
Ref 2: EB-2016-0085 Distribution System Plan, p.62

Question:

METSCO has reported the percentage of wood poles in poor and very poor condition to be 21% of the total population in the 2021 asset condition assessment. In InnPower's last Distribution System Plan as part of the EB-2016-0085 proceeding, InnPower reported that 4% of wood poles were in poor and very poor condition (2016 asset condition assessment).

a) Why did the number of poles in poor condition increase significantly in a five-year period?
b) Has the pole testing methodology changed since the last Distribution System Plan?
c) InnPower plans to replace 40 poles per year on average during the forecast period, which is a reduction from the average of 53 poles per year that were replaced from 2018 to 2022. How will InnPower ensure that the planned rate of replacement will be sufficient to ensure the reliability of this asset class given the increase to the number of poles identified in poor condition?
d) How many wood poles does InnPower expect to degrade further into the poor or very poor category by the end of the Distribution System Plan period?
e) Is InnPower's plan to maintain the current condition of its pole population or improve it?

Response:

a) The number of poles in poor condition increased due to result from pole testing and Asset Condition Assessment. Pole testing is completed on a six-year cycle and the result from this inspection are a primary input to asset condition. InnPower prioritizes pole replacements based on Asset Health, immediate concerns and in conjunction with expansion projects.

b) Pole testing methodology has not changed since the last Distribution System Plan.

c) InnPower is undergoing significant growth and due to that growth, there are a large number of expansions and road relocation projects which require the replacement of poles. Due to this, InnPower can replace a number of poles in poor condition within these projects allowing for the reduction of pole replacements through its annual pole replacement program.

d) Please refer to Exhibit 2, Figure 5.3-24: Wood Poles Age Distribution and Figure 5.3-25: Wood Pole ACA Results - Extrapolated. InnPower utilizes asset condition as its primary driver for asset replacement. From the charts referenced, there is a high likelihood more poles will fall into the poor and very poor condition from the fair and good condition categories.

e) InnPower's plan is to maintain current condition of poles overall.

Reference:

2-Staff-20

Maintenance of Wood Poles
Ref 1: EB-2016-0085 Distribution System Plan, p.81

Question:

In InnPower's last Distribution System Plan, InnPower stated that it used butt treatment and pole-top maintenance to extend the life of poles.

a) InnPower has not mentioned butt treatment or pole-top maintenance in its current Distribution System Plan. Does InnPower still perform these maintenance measures?
b) If not, why were these measures stopped?

Response:

a) InnPower moved from butt treatment to fully treated poles in correlation with good utility practice in all new installations. InnPower has not forecasted plans to install pole top extensions.
b) Pole top extensions were only applicable on single phase poles in the past. InnPower performs engineering loading analysis to determine if a pole replacement is required or if there is enough useful life remaining and asset health, investigating the application of pole top extensions.

Reference:

2-Staff-21

Recloser Replacement
Ref 1: Distribution System Plan, Material Investment Narrative, IPCSR04 – Recloser Replacement

Question:

InnPower has provided the number of historical reclosers replaced from 2017-2022 and their associated costs. InnPower notes that after 2022, InnPower began installing solid dielectric units with automation instead of oil-filled reclosers.

a) What benefits has InnPower seen from using dielectric units with automation over oil-filled units given that the unit cost per recloser replacement has significantly increased to $51k in 2022 compared to $28k in 2021?
b) InnPower has estimated that the unit cost will increase to $61k in 2023, a 19% increase. InnPower further estimates the unit cost to increase to $67k in 2024, another 9% increase. Please explain the rationale for the estimated increase.

Response:

a) To be clear, the costs stated in 2021 were for the refurbishment of oil-filled recloser and the costs stated in 2022 were for installing solid dielectric reclosers. The benefits InnPower has seen are highlighted in Exhibit 2: Appendix A of the DSP, Pages 393 – 399.
b) The estimated increase is mainly due to trends observed in the last two years regarding the increase in material costs. InnPower is purchasing units in advance to minimize cost fluctuations where possible.

Reference:

2-Staff-22

Switch Replacement
Ref 1: Distribution System Plan, Material Investment Narrative, IPCSR05 – Switch Replacement
Ref 2: Distribution System Plan, pp.82-83, Table 5.3-13: Defective Equipment Outages by Asset Type
Ref 3: Asset Condition Assessment, p.13, Table 0-3 Asset Condition Assessment Overall Results

Question:

InnPower has provided the number of gang and in-line switches replaced from 2017-2022 and their associated costs. InnPower states in reference 1 that it replaces switches that are in very poor condition and that are functionally obsolete, no longer operable or incapable of interrupting load current. InnPower has identified units for replacement based on previous infrared inspections and has developed an active replacement program which started in 2023.

According to the METSCO asset condition assessment, one 44kV motorized switch is in poor condition and two station switches are in very poor condition (Reference 3), yet InnPower is aiming to replace two gang switches and several in-line switches each year going forward (Reference 1).

Between 2017-2022, there have been on average 2.7 annual failures associated with switches (Reference 2).

a) Given that there are only a few switches in poor or very poor condition and there are only 2.7 annual failures associated with switches, what is the risk of pacing the program at a slower rate?

Response:

a) InnPower performs inspection and maintenance on gang-operated switches on a five-year cycle. In the 2022 inspection cycle, 3 switches were deemed inoperable requiring immediate replacement. Due to heavy salts along the Highway 400 corridor and some switches entering an obsolete timeframe, InnPower has forecasted to replace two units per year. The risk to pacing this program at a slower rate is InnPower will be unable to move load and perform switching when outages occur, either within the service territory or in a loss of supply event. Failure to perform switching for Loss of Supply events can cause an outage to several thousand customers and multiple Distribution Stations at a single time.

Reference:

2-Staff-23

Switchgear Replacement

Ref 1: Distribution System Plan, Material Investment Narrative, IPCSR06 – Switchgear Replacement

Ref 2: Distribution System Plan, pp.82-83, Table 5.3-13: Defective Equipment Outages by Asset Type

Ref 3: Asset Condition Assessment, p.13, Table 0-3 Asset Condition Assessment Overall Results

Question:

InnPower stated that it replaces switchgears in very poor condition based on the results of the asset condition assessment and infrared inspections.

a) According to the asset condition assessment, no switchgears are in poor condition (reference 3). As such, please clarify how InnPower prioritized which switchgears to replace each year and how many to replace each year.
b) In reference 2, InnPower provided a table of defective equipment outages. There is not a separate category for switchgears. Please clarify in which category switchgears would fall and how many outages are associated with switchgears each year, if available.
c) Given that no switchgear is in poor condition, what is the risk of deferring the replacement of a switchgear from the test and/or bridge year(s)?

Response:

a) InnPower replaces padmount equipment primarily based on asset condition, and the ability to operate and public safety. InnPower found multiple units during inspections in which the door is unable to open due to corrosion and being hit from a vehicle contact. InnPower is unable to utilize them for switching which can result in a significant increase in the outage time. InnPower proposed a slow pacing of the replacement of the units (one per year) to account for any damage to equipment or public safety.

b) InnPower has not experienced an outage due to switchgear failure in the historical period.

c) Switchgears are a central point within the subdivision for feeder level switching and load transfers. The failure of a switchgear could result in a whole subdivision being without power. The three units requiring replacement have been compromised and are unable to be operated due to corrosion and vehicle contact hits, which limits InnPower's restoration ability and poses a public safety hazard. There are two examples in the past three years, where InnPower is unable to open and operate these units, causing scheduled outages and increasing time of switching to safely replace these units.

Reference:

2-Staff-24

Voltage Regulators

Ref 1: Chapter 2 Appendices, Appendix 2-AB

Question:

InnPower has budgeted $160k for voltage regulators in the 2023 bridge year.

a) Please provide an explanation of the capital expenditure. Is the expenditure to install new voltage regulators or to replace existing ones?

Response:

a) These expenditures are to replace existing voltage regulators. In 2021, InnPower had three units fail, which provide power to downstream Hydro One customers. Due to supply chain issues, the lead times for replacement units were two years. Voltage Regulators are used to increase or decrease the voltage downstream of the device. In the case of InnPower, a three-phase line feeds Hydro One customers and depending on loading, the voltage is too low at the end of the line. These units provide adequate voltage for InnPower and Hydro One customers at all times.

Reference:

2-Staff-25

System Renewal: Transformer Replacement

Ref 1: Distribution System Plan, Appendix A Material Narratives, IPCSR02 – Transformer Replacement

Ref 2: Chapter 2 Appendices, Appendix 2-AA

Ref 3: Asset Condition Assessment, p.13, Table 0-3 Asset Condition Assessment Overall Results

Question:

The historical costs associated with the Transformer Replacement Program do not match between the Chapter 2 Appendices Excel and the Material Investments Narrative.

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	109	10	105	74	336	108	150	157	161	165	169	173
Contributions	0	0	0	0	(46)	(12)	0	0	0	0	0	0
Capital (Net)	109	10	105	74	290	95	150	157	161	165	169	173

Net Capital/Gross Capital: Gross Capital

Projects	2017	2018	2019	2020	2021	2022
IPCSR02 - TRANSFORMER REPLACEMENT PROGRAM	448,238	219,328	553,954	314,264	425,436	269,438

a) For historical comparison purposes, please confirm which are the correct historical amounts.

b) If the Excel amounts are correct, investments in Transformer Replacement are decreasing by more than half on average from the historical period to the forecast period. How has InnPower determined that this reduced investment will be sufficient to ensure the reliability of these assets in the future, given that transformers are the third largest contributor to outages caused by defective equipment, and according to the ACA there are 125 transformers in poor or very poor condition?

Response:

a) When InnPower purchases transformers, they are capitalized right away, but the system does not allow them to be linked to a project. It appears that Table 1 in the DSP did not include these transformers. The correct numbers can be found in Chapter 2 Appendix 2-AA. Table 1 (shown above) has also been updated to reflect the inclusion of these transformers.

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	448	219	554	314	425	269	250	157	161	165	169	173
Contributions	0	0	0	0	(46)	(12)	0	0	0	0	0	0
Capital (Net)	448	219	554	314	379	257	250	157	161	165	169	173

b) InnPower was forced to reduce the number of transformer replacements in 2020, 2021 and 2022 due to supply chain constraints. Due to lack of supply, InnPower only used transformers to replace failed units. In 2023, InnPower joined a transformer purchasing group to guarantee supply and economies of scale to address the results of the ACA on a prioritized basis. Please refer to Exhibit 2: Appendix A of the DSP, Pages 374-382.

Reference:

2-Staff-26

Ref 1: OEB Appendix 2-BA Fixed Asset Continuity Schedules

Ref 2: Exhibit 2.5.3 Distribution System Plan

IPCSR02 – Transformer Replacement (Material Investment Narrative, Investment Category: System Renewal)

Ref 3: APB Unit Cost Calculations: 2021 Results (xlsx) - 27 March 20237

Question:

Capital additions to Uniform System of Accounts (USoA) 1850 Line Transformers for historical years and the bridge year have been provided in reference 1 as follows:

Historical 2017 Actual	Historical 2018 Actual	Historical 2019 Actual	Historical 2020 Actual	Historical 2021 Actual	Historical 2022 Actual	Bridge 2023 Forecast
$641,354	$570,444	$1,038,208	$1,409,176	$1,293,633	$1,001,922	$246,000

Table 1 and 2 in reference 2 provides the historical and the bridge year capital expenditures related to transformer replacements and the number of transformer replacements respectively as follows:

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	400	264	156	687	201	216	524	500	513	525	538	552
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	400	264	156	687	201	216	524	500	513	525	538	552

Table 2: Historical Transformer Replacements

Year	Padmount	Polemount	# of Transformers Replaced
2017	2	7	9
2018	1	3	4
2019	9	1	10
2020	9	13	22
2021	2	14	16
2022	5	5	10

Activity and program benchmarking results in reference 3 provides the capital expenditures related to transformer replacements and the number of transformer replacements for the historical years.

USoA [1850] Capital Additions					
Cost ($1,000)					
2017	2018	2019	2020	2021	Average
641.4	570.4	1,042.2	1,405.2	1,293.6	990.6

Scale (Lines Transformer Additions)					
2017	2018	2019	2020	2021	Average
124.0	124.0	296.0	221.0	229.0	198.8

a) For the bridge year, capital additions in reference 1 for USoA 1850 is lower than gross capital expenditure in table 1 in reference 2. Please reconcile the differences.

b) For the historical years, the capital expenditures in table 1 in reference 2 are generally lower than the capital additions to account 1850 in reference 1. Please explain what other DSP programs are contributing to the capital additions to account 1850 in reference 1.

c) The number of units of transformers replaced per year as per table 2/reference 2 are significantly lower than the number of units of transformers replaced as per APB reference 3. Please reconcile the differences?

Response:

a) and b)

The difference in gross capital expenditure in Table 1 (Reference 2) and capital additions (Reference 1) for USoA 1850 is a result of other additions not included in transformer (TX) replacement capital narrative. These other additions include:

1. **Re-Used Transformers:** These are previously installed transformers that InnPower brings in from the territory and then re-uses in other jobs. As the transformers are reinstalled, they accumulate additional costs such as labour, vehicle time and minor components. The amount used to reconcile the differences (real addition) is the variance between the original asset cost and the costs to re-install the transformer.
2. **TX Betterment:** InnPower records capital work completed to existing transformers in the capital additions amount. As these are betterments, InnPower is not adding an additional transformer. The additions include minor components, labour and vehicle time.
3. **H1 Transformers:** Transformers purchased from Hydro One.
4. **Assumed Transformers from Subdivisions:** Transformers on subdivisions that are InnPower owned and have been assumed from the developers.

Please reference the table below for the reconciled balance between the gross capital expenditure total and capital additions.

	2017 $'000s	2018 $'000s	2019 $'000s	2020 $'000s	2021 $'000s	2022 $'000s	2023 $'000s
Continuity Schedule	641.4	570.4	1,038.2	1,409.2	425.4	269.4	149.5
TX Replacement	448.2	219	554	314.3	1,293.6	1,001.9	246
Difference	**(193.2)**	**(351.1)**	**(484.2)**	**(1,095)**	**(868.2)**	**(732.5)**	**(96.5)**
Other Additions:							
Re-Used Transforms	168.8	205.6	175.8	171.5	242.7	706.1	50

TX Betterments	18.5	98.1	181.1	141.5	27.2	26.4	46.5
H1 TX	0	4	0	0	0	0	0
Assumed TX's from Subdivisions	5.9	43.7	127.3	781.9	598.3	0	0
Remaining Differences	**0**	**0**	**0**	**0**	**0**	**0**	**0**

c) The number of assets in the material narratives (reference 2/table 2) are transformers that have been booked to a specific project. For APB, InnPower reports the following:

1. **Real Additions:** These are new transformer purchases. These are newly purchased transformers that are sitting in inventory or have been allocated to a project that is not specified as a transformer replacement project.
2. **Not Real – Used Additions:** These are previously used transformers that have been brought in from the territory and reused in other jobs. These additions accumulate costs on the new job to reinstall the transformer including labour, material, and vehicles, however, they do not increase the quantity of equipment.
3. **Not Real – Betterment Additions:** This is capital work completed to existing transformers that is recorded in the capital additions amount, without adding an additional transformer.

The number of transformed replaced per year based on table2/reference 2 has been reconciled to the APB reference 3 below. Please note that the 2017 amounts in APB reference 3 are the same as 2018.

	2017*	2018	2019	2020	2021
Transformers attached to a TX replacement project (Table 2/Reference 2 amounts)		4	10	22	16
Real Additions		41	165	129	124
Not Real-Used Additions		54	93	52	70
Not Real-Betterment		25	28	18	19
Total		**124**	**296**	**221**	**229**
APB Totals		124	296	221	229
Difference		**0**	**0**	**0**	**0**

* **(Reference is based on the same amounts from 2018)**

Reference:

2-Staff-27

Advanced Capital Module
Ref 1: ACM Model
Ref 2: 2024 Inflation Parameter letter, June 29, 2023

Question:

Please update the ACM model to reflect the 2024 inflation parameter has issued as per Reference 2.

Response:

Please find a revised version of the ACM model that will be submitted with 1-Staff-1, incorporating the 2024 inflation parameter.

Reference:

2-Staff-28

Station Rehabilitation

Ref 1: Distribution System Plan, Material Investment Narrative, IPCSS12 – Station Rehab

Question:

InnPower has performed station rehabilitation measures throughout the historical period with most of the costs being recoverable.

Table 1: Historical & Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	21	276	2,194	2,683	2,030	393	4,979	3,100	4,948	468	625	644
Contributions	0	0	(1,783)	(2,607)	(17)	0	(4,875)	(3,100)	(4,720)	0	0	0
Capital (Net)	21	76	411	76	2,013	393	104	0	228	468	625	644

a) Please explain the variance in the net cost to the Station Rehabilitation program in 2021, and why there were minimal capital contributions in 2021 compared to other historical years.

   InnPower notes that the majority of expenditures towards the Station Rehabilitation program under the System Service category are expected to be recoverable in the years 2023-2025, however, the actual contributions are still to be finalized.

b) How were the contribution estimates developed?

c) How does InnPower plan to accommodate any variances to the actual contribution amount?

d) Please provide the cost estimate report for the planned Station Rehabilitation program.

Response:

a) In 2021 InnPower had identified and carried out two station rehabilitation projects. These were in urgent need of rehabilitation which required capital investment with no contribution. These projects improved reliability for existing customers and according to DSC no contribution allows for this type of improvement.

b) The contribution estimates have been developed in accordance with the Section *3.2 Expansions* of the Distribution System Code and settles with the developers based on actual invoices.

c) InnPower calculates the forecast capital contribution as per the DSC requirements, with the contribution based on actual invoicing.

d) Please see the cost estimate as per the table below:

2023

Project	Cost	Contributions	Net
Bob Deugo DS T2_Build	2,875	2,875	-
Brian Wilson DS T2_Upgrade	2,000	2,000	-
Stroud DS Transformer Rehab.	104		104
	4,979	4,875	104

2024

Project	Cost	Contributions	Net
Bob Deugo DS T2_Build	1,220	1,220	-
Brian Wilson DS T2_Upgrade	604	604	-
Belle Ewart DS T2_Build	1,276	1,276	-
	3,100	3,100	-

2025

Project	Cost	Contributions	Net
Belle Ewart DS T2_Build	4,720	4,720	-
Lefroy DS Transformer Rehab.	228	-	228
	4,948	4,720	228

2026

Project	Cost	Contributions	Net
Stroud DS Structure Rehab.	468	-	468

2027

Project	Cost	Contributions	Net
Leonards Beach DS Structure	625	-	625
			-
			-

2028

Project	Cost	Contributions	Net
Brian Wilson DS Structure Rehab. + Inc. Transruptur	644	-	644

Reference:

2-Staff-29

InnPower TS Project
Ref 1: Distribution System Plan, p.144
Ref 2: Distribution System Plan – 5.2.1.2.3. System Service, p.9
Ref 3: Chapter 2 appendices – 2-AA and 2-BA

Question:

InnPower has a multi-year project for the development of a new transformer station project which is anticipated to be in-service by the end of the forecasted period or beyond.

a) Please provide a material investment narrative and cost estimate report for this project, if possible.
b) The 2022 Regional Infrastructure Plan identified supply constraints at the Barrie TS beginning in 2025, while the New TS is not expected to enter service until at least 2027.
    i. Has InnPower considered the impact of these constraints in the meantime?
    ii. Does InnPower have a plan to address potential supply constraints in the interim?
c) Please confirm who will control/operate and maintain InnPower TS once it is completed.

    In reference 2, InnPower stated that it will incur $1.35 million in costs for the InnPower TS for an Environmental Assessment in 2023. InnPower also stated that this spending will remain in work in progress until the next rebasing. In reference 3, the net total 2023 capital expenditures and in-service additions are equal in 2-AA and 2-BA.
d) Please confirm if the $1.35 million is recorded as work in progress in 2-BA.

Response:

a) A material investment narrative is not available for this project.

b) i. InnPower's latest load forecast shows that this demand will now not materialize until 2027-2028. InnPower will continue to monitor and will consider deferral or interim alternatives as needed, depending on any changes to the load forecast.

   ii. In the interim, if required, InnPower is capable of transferring loads to other feeders, or can go beyond the nominal capacity of the feeder in consultation with Hydro One.

c) It is anticipated that InnPower will control, operate and maintain the proposed InnPower TS.

d) The environmental assessment will be capitalized at the end of the year.

Reference:

2-Staff-30

IT Hardware and IT Software
Ref 1: Distribution System Plan, Material Investment Narrative, IPCGP01 – IT Hardware
Ref 2: Exhibit 4, Tab 1, Schedule 3, p.43
Ref 3: Distribution System Plan, Material Investment Narrative, IPCGP02 – IT Software

Question:

InnPower has budgeted $194k in the 2024 Test Year for IT hardware. The average annual IT hardware expenditure was $79k from 2017 to 2023, whereas InnPower estimates the annual average IT hardware expenditure to be $206k in the forecasted years.

InnPower has budgeted $125k in the 2024 Test Year for IT software. The average annual IT software expenditure was $73.6k from 2017 to 2023, whereas InnPower estimates the annual average IT software expenditure to be $131.4k in the forecasted years.

a) InnPower has stated that it has been investing in cybersecurity over the period of 2017-2024 in reference 2. As such, why is there such an increase in costs between the period of 2017-2023 and 2024-2028 for both hardware and software?
b) Please provide a breakdown of the 2024 expenditures for IT hardware and what makes up the rest of the costs from 2025-2028.

Response:

a) There are a multiple factors that have led to an increase in anticipated spend between the 2017-2023 and 2024-2028 periods, including:
    - During the 2017-2023 period, COVID-19 related supply chain issues necessitated the delay of many expenditures to the 2024-2028 period. Inflated costs, the inability to obtain equipment, limited ability to perform onsite, in-person work contributed to this delay. As a result, higher spending is expected between 2024-2028 due to these differed activities.

- Reviews of current hardware and software systems have taken place, with a number of aging systems requiring upgrades to enhance usability and maintain appropriate security protection. Many of the new solutions necessitated the replacement of aging hardware or migration to cloud solutions.
- The organization is more focused on technology solutions to improve cyber security and business efficiency through updated technology solutions.
- Inflationary pressures continue to affect IT hardware and software resulting in higher procurement costs.

b) The 2024 estimated hardware costs are shown in the table below:

Server / Client Switch Stack replacement	$60,000
Existing Laptop Hardware Refresh (30 devices 5+ years old)	$80,430
InnPower building Access Point replacement	$7,460
Disaster recovery site hardware	$6,000
Control Room Screen / hardware updates	$24,000
Boardroom Upgrades	$5,000
Unanticipated hardware failure costs	$10,000

Reference:

2-Staff-31

Fleet Management

Ref 1: Chapter 2 Appendices, Appendix 2-AB

Question:

InnPower has provided criteria for the replacement of its fleet.

a) Please provide the fleet management assessment performed for each vehicle, if available.
b) Was InnPower's fleet management assessment criteria peer-reviewed?
c) Please provide a status update on the timing of delivery for the bucket truck that is expected to be in-service in 2024.

   InnPower stated that it plans to lease a small service truck and a pool of other vehicles in 2023.

d) Please provide an update on the status of the small service truck pool of vehicles scheduled for 2023?

Response:

a) InnPower does not have this information available.
b) No, InnPower's fleet management assessment criteria was not peer-reviewed.
c) The latest update InnPower has received is that the bucket truck should be received in January 2024.
d) The latest update InnPower has is that the small service truck should be received in November 2023.

Reference:

2-Staff-32

Electrification
Ref 1: Distribution System Plan, Section 5.3.1.3 Process, p.48

Question:

InnPower has stated that it has not seen a large uptake in electric vehicles in its service territory. For any new connections, InnPower stated that it engages third parties to understand any information that indicates an uptake in electric vehicles to determine if capacity adjustments are required.
InnPower has not stated in its Distribution System Plan if it has seen an uptake in heat pumps.

a) Did InnPower perform any analysis to determine the energy demand and consumption impact of electric vehicle usage on the distribution system for the plan period? If not, on what basis has InnPower determined that there would be no impact on the Distribution System Plan as a result of the uptake in electric vehicles (or lack thereof)?
b) If InnPower performed a load and/or consumption analysis with electric vehicle considerations, did InnPower include the difference in loads associated with Level 1 versus Level 2 EV chargers?
c) Through the federal Greener Home Initiative, residents are being encouraged to switch to cold climate heat pumps for space heating.1 Has InnPower considered the uptake of cold climate heat pumps over the coming years? How has it affected planning during the Distribution System Plan period?
d) When replacing distribution transformers, what does InnPower do to determine if upsizing is warranted for future potential electrification needs?

Response:

a) As mentioned in DSP Section 5.3.1.3, InnPower assesses the future impact of electric vehicles (EVs) in its load forecast. InnPower requests each development to include EV type and consumption data in their Customer Connection Request form. After reviewing each request, InnPower engineers incorporate the EV consumption information into the load forecast.

b) Through the Customer Connection Request form, the developer consultant or engineer outlines the type of EV chargers required, along with their respective load demands. Subsequently InnPower will assess and incorporate these details into the load forecast.

c) InnPower has not considered the heat pump consumption in its load forecast. InnPower will look to incorporate this information in its future load forecast methodology. InnPower has not observed any recent inquiries about Heat Pumps within its service area, and therefore does not foresee any impact during the distribution system plan period.

d) InnPower's System Planning and Engineering departments continually monitor the actual load consumptions at the distribution transformer level. By utilizing the Savage system, they identify transformers that are either overloaded or nearing their maximum capacity. Based on historical consumption data and the number of connections (existing and new), the System Planning department will size the distribution transformer with about additional 25% margin to cover potential future electrification needs.

Reference:

2-Staff-33

CDM Considerations
Ref 1: Distribution System Plan, Section 5.3.5 CDM Activities to Address System Needs, p.100
Ref 2: 2021 CDM Guidelines, Chapter 3.1

Question:

InnPower notes that it considers CDM as part of its planning process to determine whether CDM can be considered a viable alternative to any of its planned investments over the forecast period. InnPower further notes that currently no viable CDM alternatives have been identified. As a result, there are no CDM activities currently planned over the forecast period. InnPower will continue to consider the ability to use distribution rate funded CDM to potentially defer or avoid investments.

a) Please describe how InnPower has addressed or plans to address the requirement in the OEB's CDM Guidelines for distributors to "make reasonable efforts to incorporate consideration of CDM activities into their distribution system planning process, by considering whether distribution rate-funded CDM activities may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure."
b) Please describe specific changes, if any, that InnPower has made to its distribution system planning process to address the requirement.

Response:

a/b) CDM programs are aimed at reducing electricity consumption to manage system costs by reducing peak demand and potentially deferring or avoiding infrastructure investments. Over the historical period, InnPower participated in the 2011 to 2014 CDM framework and the 2015 to 2020 Conservation First framework and offered all applicable programs. InnPower continues to promote and offer all provincially offered CDM programs which are managed through the IESO.

The decline in peak demand due to CDM initiatives alone has not historically been substantial enough to warrant any major avoided or deferred infrastructure investments. InnPower has not identified any opportunities to avoid or defer infrastructure investments as a result of CDM activities over the forecast period. Regarding the cited requirement in the OEB's CDM Guidelines, see section 5.3.1.3 of the DSP. Step 1 in InnPower's asset management process evaluates a range of different options to address the need identified by the asset conditions analysis or system performance requirements. This includes looking at options of full replacement, refurbishments, or doing nothing, and investigating pacing requirements and resource availability, and determining whether CDM is a feasible option to meet the identified system need. An overview of the InnPower asset management process is shown in Figure 5.3-1 of the DSP. For example, at section 5.2.2.4.4 of the DSP with respect to the Barrie / Innisfil IRRP, InnPower is monitoring uptake of the CDM framework as well as energy efficiency initiatives in the Community Energy Plans (CEPs) and will assess the impact of these additional savings on the timing of local reliability needs.

Since there are no known CDM activities at this time, InnPower did not adjust load forecast due to CDM, however InnPower will continue to monitor for the industry and customer base for potential implementation of CDM as part of its asset management process.

Reference:

2-Staff-34

Paperless Workflow
Ref 1: Exhibit 1, p.53, Table 1-7 InnPower Key Achievements from 2017 to 2023
Ref 2: Distribution System Plan, p.52, Table 5.3-2 Information Comprising InnPower's Asset Database

Question:

In Exhibit 1, InnPower states that it has implemented a $0 paperless workflow management system across the organization. In the Distribution System Plan, a number 1 NRCan, Canada Greener Home Initiatives of asset databases still use paper, such as the financial system, outage history, and general plant systems.
Is InnPower planning to digitize these systems? If so, please provide the budget for digitization.

Response:

These systems have been digitized for a few years and were done so at minimum to no cost.

Reference:

2-Staff-35

Additions and Disposals

Ref 1: Chapter 2 Appendix 2-BA

Ref 2: Exhibit 1, Appendix 1-3-1 (A) 2021 Audited Financial Statements, Note 12

Question:

OEB staff noted the additions and disposals recorded in Appendix 2-BA for Account 2005 Property Under Finance Lease deviate from what was reported in InnPower's 2021 Audited Financial Statements. Table 1 below presents a summary of the variances.

Table 1: Summary of Variances between App 2-BA and 2021 AFS

Property Under Finance Lease	A. Reference 1 App 2-BA Additions	B. Reference 2 2021 AFS Disposals	Variances (A-B)
Cost - Additions	$ 135,521	$ 65,000	$ 70,521
Cost - Disposals	$ (297,549)	$ (227,000)	$ (70,549)
Accumulated Amortization - Additions	$ (107,346)	$ (54,000)	$ (53,346)
Accumulated Amortization - Disposals	$ 125,851	$ 76,000	$ 49,851

a) Please reconcile and explain the discrepancies mentioned above and make any necessary updates to Reference 1 and other applicable schedules.

Response:

a) Appendix 2-BA has been updated. It was a misclassification error on InnPower's part. Appendix 2-C has also been updated. Please see below for the original submission and the corrected version of these appendices.

Original: Appendix 2-BA - 2021

Year 2021

Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,307,075	$ 152,645	$ -	$ 1,459,720	-$ 1,022,234	-$ 171,775	$ -	-$ 1,194,009	$ 265,711
CEC	1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ -	$ -	$ 397,396	-$ 91,462	-$ 12,758	$ -	-$ 104,219	$ 293,177
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1820	Distribution Station Equipment <50 kV	$ 12,615,481	$ 2,419,931	$ -	$ 15,035,412	-$ 1,530,348	-$ 470,450	$ -	-$ 2,000,799	$ 13,034,613
47	1830	Poles, Towers & Fixtures	$ 18,166,075	$ 4,034,416	-$ 7,542	$ 22,192,949	-$ 1,975,095	-$ 480,144	$ 1,831	-$ 2,453,408	$ 19,739,541
47	1835	Overhead Conductors & Devices	$ 17,472,773	$ 3,114,575	-$ 306,019	$ 20,281,330	-$ 1,734,484	-$ 369,357	$ 41,000	-$ 2,062,841	$ 18,218,490
47	1840	Underground Conduit	$ 3,999,862	$ 577,679	$ -	$ 4,577,541	-$ 657,209	-$ 128,046	$ -	-$ 785,255	$ 3,792,286
47	1845	Underground Conductors & Devices	$ 9,034,911	$ 724,359	-$ 3,821	$ 9,755,448	-$ 1,777,342	-$ 282,177	$ 1,166	-$ 2,058,354	$ 7,697,094
47	1850	Line Transformers	$ 9,263,612	$ 1,293,633	-$ 46,280	$ 10,510,964	-$ 1,254,205	-$ 272,574	$ 23,085	-$ 1,503,694	$ 9,007,270
47	1855	Services (Overhead & Underground)	$ 6,001,602	$ 743,587	-$ 44,932	$ 6,700,257	-$ 790,325	-$ 163,074	$ 8,793	-$ 944,607	$ 5,755,650
47	1860	Meters	$ 3,391,269	$ 231,866	-$ 22,879	$ 3,600,256	-$ 1,368,792	-$ 267,711	$ 10,794	-$ 1,625,710	$ 1,974,547
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,814,300	$ 43,734	$ -	$ 12,858,034	-$ 1,535,386	-$ 284,735	$ -	-$ 1,820,120	$ 11,037,914
8	1915	Office Furniture & Equipment (5 years)	$ 281,663	$ 23,353	$ -	$ 305,015	-$ 158,878	-$ 25,317	$ -	-$ 184,195	$ 120,820
10	1920	Computer Equipment - Hardware	$ 785,584	$ 24,956	$ -	$ 810,540	-$ 599,635	-$ 74,712	$ -	-$ 674,347	$ 136,193
10	1930	Transportation Equipment	$ 1,027,467	$ 668,543	$ -	$ 1,696,010	-$ 628,334	-$ 146,011	$ -	-$ 774,345	$ 921,665
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 80,226	-$ 12,720	$ -	-$ 92,946	$ 42,389
8	1940	Tools, Shop & Garage Equipment	$ 419,061	$ 74,701	$ -	$ 493,762	-$ 300,378	-$ 26,045	$ -	-$ 326,423	$ 167,339
8	1945	Measurement & Testing Equipment	$ 68,740	$ 2,290	$ -	$ 71,030	-$ 37,885	-$ 6,205	$ -	-$ 44,090	$ 26,940
47	1980	System Supervisor Equipment	$ 2,933,637	$ 251,848	$ -	$ 3,185,485	-$ 1,166,164	-$ 201,020	$ -	-$ 1,367,185	$ 1,818,300
47	2440	Deferred Revenue[5]	-$ 30,880,264	-$ 7,381,961	$ 14,421	-$ 38,247,803	$ 3,072,840	$ 926,727	-$ 715	$ 3,998,853	-$ 34,248,951
	2005	Property Under Finance Lease[7]	$ 398,091	$ 135,521	-$ 297,549	$ 236,063	-$ 117,984	-$ 107,346	$ 125,851	-$ 99,479	$ 136,584
		Sub-Total	**$ 71,698,760**	**$ 7,135,674**	**-$ 714,601**	**$ 78,119,834**	**-$ 13,753,526**	**-$ 2,575,450**	**$ 211,805**	**-$ 16,117,171**	**$ 62,002,663**
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055	$ -	$ -	-$ 2,406,055	$ 265,786	$ 48,822	$ -	$ 314,608	-$ 2,091,447
		Total PP&E for Rate Base Purposes	**$ 69,292,705**	**$ 7,135,674**	**-$ 714,601**	**$ 75,713,779**	**-$ 13,487,740**	**-$ 2,526,628**	**$ 211,805**	**-$ 15,802,563**	**$ 59,911,216**
		Construction Work In Progress	$ 5,120,525	$ -	-$ 1,313,631	$ 3,806,894				$ -	$ 3,806,894
		Total PP&E	**$ 74,413,230**	**$ 7,135,674**	**-$ 2,028,232**	**$ 79,520,673**	**-$ 13,487,740**	**-$ 2,526,628**	**$ 211,805**	**-$ 15,802,563**	**$ 63,718,110**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,526,628**			

Less: *Fully Allocated Depreciation*

Class		Description		
10		Transportation	Transportation	-$ 253,356
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 926,727
			Net Depreciation	**-$ 3,199,999**

Original: Appendix 2-C -2021

Year 2021

Account	Description	Book Values: Opening Book Value of Assets	Book Values: Less Fully Depreciated [1]	Book Values: Current Year Additions	Book Values: Disposals	Service Lives: Net Amount of Assets to be Depreciated	Service Lives: Remaining Life of Assets Existing [2]	Expense: Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1611	Computer Software (Formally known as Account 1925)	$ 1,307,075	$ 952,109	$ 152,645	$ -	$ 431,288	2.51	39.83%	**171,775**	171,775	**0**
1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ 15,109	$ -	$ -	$ 382,287	29.96	3.34%	**12,758**	12,758	**0**
1805	Land	$ 1,049,593	$ 1,049,593	$ -	$ -	$ -		0.00%	**0**	0	**0**
1820	Distribution Station Equipment <50 kV	$ 12,615,481	$ 174,200	$ 2,419,931	$ -	$ 13,651,246	29.02	3.45%	**470,450**	470,450	**0**
1830	Poles, Towers & Fixtures	$ 18,166,075	$ 325,830	$ 4,034,416	$ 7,542	$ 19,849,911	41.34	2.42%	**480,144**	480,144	**0**
1835	Overhead Conductors & Devices	$ 17,472,773	$ 244,624	$ 3,114,575	$ 306,019	$ 18,479,418	50.03	2.00%	**369,357**	369,357	**0**
1840	Underground Conduit	$ 3,999,862	$ 70,931	$ 577,679	$ -	$ 4,217,771	32.94	3.04%	**128,046**	128,046	**0**
1845	Underground Conductors & Devices	$ 9,034,911	$ 268,452	$ 724,359	$ 3,821	$ 9,124,817	32.34	3.09%	**282,177**	282,177	**0**
1850	Line Transformers	$ 9,263,612	$ 172,818	$ 1,293,633	$ 46,280	$ 9,691,330	35.55	2.81%	**272,574**	272,574	**0**
1855	Services (Overhead & Underground)	$ 6,001,602	$ 81,145	$ 743,587	$ 44,932	$ 6,247,318	38.31	2.61%	**163,074**	163,074	**0**
1860	Meters	$ 3,391,269	$ 223,535	$ 231,866	$ 22,879	$ 3,260,788	12.18	8.21%	**267,711**	267,711	**0**
1905	Land	$ 1,015,496	$ 1,015,496	$ -	$ -	$ -	0.00	0.00%	**0**	0	**0**
1908	Buildings & Fixtures	$ 10,408,245	$ 118,500	$ 43,734	$ -	$ 10,311,613	43.71	2.29%	**235,913**	235,913	**0**
1915	Office Furniture & Equipment (5 years)	$ 281,663	$ 50,531	$ 23,353	$ -	$ 242,808	9.59	10.43%	**25,317**	25,317	**0**
1920	Computer Equipment - Hardware	$ 785,584	$ 471,539	$ 24,956	$ -	$ 326,522	4.37	22.88%	**74,712**	74,712	**0**
1930	Transportation Equipment	$ 1,027,467	$ 454,176	$ 668,543	$ -	$ 907,562	6.22	16.09%	**146,011**	146,011	**0**
1935	Stores Equipment	$ 135,334	$ 10,237	$ -	$ -	$ 125,098	9.83	10.17%	**12,720**	12,720	**0**
1940	Tools, Shop & Garage Equipment	$ 419,061	$ 230,489	$ 74,701	$ -	$ 225,923	8.67	11.53%	**26,045**	26,045	**0**
1945	Measurement & Testing Equipment	$ 68,740	$ 15,346	$ 2,290	$ -	$ 54,539	8.79	11.38%	**6,205**	6,205	**0**
1980	System Supervisor Equipment	$ 2,933,637	$ 246,737	$ 251,848	$ -	$ 2,812,824	13.99	7.15%	**201,020**	201,020	**0**
2440	Deferred Revenue	-$ 30,880,264	-$ 279,424	-$ 7,381,961	-$ 14,421	-$ 34,277,399	36.99	2.70%	**-926,727**	-926,727	**0**
2005	Property Under Finance Lease	$ 398,091	$ -	$ 135,521	$ 297,549	$ 168,302	1.57	63.78%	**107,346**	107,346	**0**
	Total	**$ 69,292,705**	**$ 5,911,974**	**$ 7,135,674**	**$ 714,601**	**$ 66,233,968**			**2,526,628**	**2,526,628**	**0**

Updated: Appendix 2-BA - 2021

Year 2021

Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 1,307,075	$ 152,645	$ -	$ 1,459,720	-$ 1,022,234	-$ 171,775	$ -	-$ 1,194,009	$ 265,711
CEC	1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ -	$ -	$ 397,396	-$ 91,462	-$ 12,758	$ -	-$ 104,219	$ 293,177
N/A	1805	Land	$ 1,049,593	$ -	$ -	$ 1,049,593	$ -	$ -	$ -	$ -	$ 1,049,593
47	1820	Distribution Station Equipment <50 kV	$ 12,615,481	$ 2,419,931	$ -	$ 15,035,412	-$ 1,530,348	-$ 470,450	$ -	-$ 2,000,799	$ 13,034,613
47	1830	Poles, Towers & Fixtures	$ 18,166,075	$ 4,034,416	-$ 7,542	$ 22,192,949	-$ 1,975,095	-$ 480,144	$ 1,831	-$ 2,453,408	$ 19,739,541
47	1835	Overhead Conductors & Devices	$ 17,472,773	$ 3,114,575	-$ 306,019	$ 20,281,330	-$ 1,734,484	-$ 369,357	$ 41,000	-$ 2,062,841	$ 18,218,490
47	1840	Underground Conduit	$ 3,999,862	$ 577,679	$ -	$ 4,577,541	-$ 657,209	-$ 128,046	$ -	-$ 785,255	$ 3,792,286
47	1845	Underground Conductors & Devices	$ 9,034,911	$ 724,359	-$ 3,821	$ 9,755,448	-$ 1,777,342	-$ 282,177	$ 1,166	-$ 2,058,354	$ 7,697,094
47	1850	Line Transformers	$ 9,263,612	$ 1,293,633	-$ 46,280	$ 10,510,964	-$ 1,254,205	-$ 272,574	$ 23,085	-$ 1,503,694	$ 9,007,270
47	1855	Services (Overhead & Underground)	$ 6,001,602	$ 743,587	-$ 44,932	$ 6,700,257	-$ 790,325	-$ 163,074	$ 8,793	-$ 944,607	$ 5,755,650
47	1860	Meters	$ 3,391,269	$ 231,866	-$ 22,879	$ 3,600,256	-$ 1,368,792	-$ 267,711	$ 10,794	-$ 1,625,710	$ 1,974,547
N/A	1905	Land	$ 1,015,496	$ -	$ -	$ 1,015,496	$ -	$ -	$ -	$ -	$ 1,015,496
47	1908	Buildings & Fixtures	$ 12,814,300	$ 43,734	$ -	$ 12,858,034	-$ 1,535,386	-$ 284,735	$ -	-$ 1,820,120	$ 11,037,914
8	1915	Office Furniture & Equipment (5 years)	$ 281,663	$ 23,353	$ -	$ 305,015	-$ 158,878	-$ 25,317	$ -	-$ 184,195	$ 120,820
10	1920	Computer Equipment - Hardware	$ 785,584	$ 24,956	$ -	$ 810,540	-$ 599,635	-$ 74,712	$ -	-$ 674,347	$ 136,193
10	1930	Transportation Equipment	$ 1,027,467	$ 668,543	$ -	$ 1,696,010	-$ 628,334	-$ 146,011	$ -	-$ 774,345	$ 921,665
8	1935	Stores Equipment	$ 135,334	$ -	$ -	$ 135,334	-$ 80,226	-$ 12,720	$ -	-$ 92,946	$ 42,389
8	1940	Tools, Shop & Garage Equipment	$ 419,061	$ 74,701	$ -	$ 493,762	-$ 300,378	-$ 26,045	$ -	-$ 326,423	$ 167,339
8	1945	Measurement & Testing Equipment	$ 68,740	$ 2,290	$ -	$ 71,030	-$ 37,885	-$ 6,205	$ -	-$ 44,090	$ 26,940
47	1980	System Supervisor Equipment	$ 2,933,637	$ 251,848	$ -	$ 3,185,485	-$ 1,166,164	-$ 201,020	$ -	-$ 1,367,185	$ 1,818,300
47	2440	Deferred Revenue[5]	-$ 30,880,264	-$ 7,381,961	$ 14,421	-$ 38,247,803	$ 3,072,840	$ 926,727	-$ 715	$ 3,998,853	-$ 34,248,951
	2005	Property Under Finance Lease[7]	$ 398,091	$ 65,451	-$ 227,479	$ 236,063	-$ 117,984	-$ 53,900	$ 72,405	-$ 99,479	$ 136,584
		Sub-Total	**$ 71,698,760**	**$ 7,065,604**	**-$ 644,531**	**$ 78,119,834**	**-$ 13,753,526**	**-$ 2,522,004**	**$ 158,359**	**-$ 16,117,172**	**$ 62,002,662**
		Less Other Non Rate-Regulated Utility Assets (input as negative)	-$ 2,406,055	$ -	$ -	-$ 2,406,055	$ 265,786	$ 48,822	$ -	$ 314,608	-$ 2,091,447
		Total PP&E for Rate Base Purposes	**$ 69,292,705**	**$ 7,065,604**	**-$ 644,531**	**$ 75,713,779**	**-$ 13,487,740**	**-$ 2,473,182**	**$ 158,359**	**-$ 15,802,563**	**$ 59,911,216**
		Construction Work In Progress	$ 5,120,525	$ -	-$ 1,313,631	$ 3,806,894				$ -	$ 3,806,894
		Total PP&E	**$ 74,413,230**	**$ 7,065,604**	**-$ 1,958,162**	**$ 79,520,673**	**-$ 13,487,740**	**-$ 2,473,182**	**$ 158,359**	**-$ 15,802,563**	**$ 63,718,110**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 2,473,182**			

Less: *Fully Allocated Depreciation*

Class		Description		
10		Transportation	Transportation	-$ 199,911
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 926,727
			Net Depreciation	**-$ 3,199,999**

Updated: Appendix 2-C - 2021

Year 2021

		Book Values				Service Lives		Expense			
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated** [1]	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing** [2]	**Depreciation Rate Assets**	**Depreciation Expense on Assets** [3]	**Depreciation Expense per Appendix 2-BA Fixed Assets, Column J**	**Variance** [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1611	Computer Software (Formally known as Account 1925)	$ 1,307,075	$ 952,109	$ 152,645	$ -	$ 431,288	2.51	39.83%	**$ 171,775**	$ 171,775	**-$ 0**
1612	Land Rights (Formally known as Account 1906)	$ 397,396	$ 15,109	$ -	$ -	$ 382,287	29.96	3.34%	**$ 12,758**	$ 12,758	**$ 0**
1805	Land	$ 1,049,593	$ 1,049,593	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 12,615,481	$ 174,200	$ 2,419,931	$ -	$ 13,651,246	29.02	3.45%	**$ 470,450**	$ 470,450	**-$ 0**
1830	Poles, Towers & Fixtures	$ 18,166,075	$ 325,830	$ 4,034,416	$ 7,542	$ 19,849,911	41.34	2.42%	**$ 480,144**	$ 480,144	**-$ 0**
1835	Overhead Conductors & Devices	$ 17,472,773	$ 244,624	$ 3,114,575	$ 306,019	$ 18,479,418	50.03	2.00%	**$ 369,357**	$ 369,357	**$ 0**
1840	Underground Conduit	$ 3,999,862	$ 70,931	$ 577,679	$ -	$ 4,217,771	32.94	3.04%	**$ 128,046**	$ 128,046	**-$ 0**
1845	Underground Conductors & Devices	$ 9,034,911	$ 268,452	$ 724,359	$ 3,821	$ 9,124,817	32.34	3.09%	**$ 282,177**	$ 282,177	**-$ 0**
1850	Line Transformers	$ 9,263,612	$ 172,818	$ 1,293,633	$ 46,280	$ 9,691,330	35.55	2.81%	**$ 272,574**	$ 272,574	**-$ 0**
1855	Services (Overhead & Underground)	$ 6,001,602	$ 81,145	$ 743,587	$ 44,932	$ 6,247,318	38.31	2.61%	**$ 163,074**	$ 163,074	**-$ 0**
1860	Meters	$ 3,391,269	$ 223,535	$ 231,866	$ 22,879	$ 3,260,788	12.18	8.21%	**$ 267,711**	$ 267,711	**-$ 0**
1905	Land	$ 1,015,496	$ 1,015,496	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 10,408,245	$ 118,500	$ 43,734	$ -	$ 10,311,613	43.71	2.29%	**$ 235,913**	$ 235,913	**$ 0**
1915	Office Furniture & Equipment (5 years)	$ 281,663	$ 50,531	$ 23,353	$ -	$ 242,808	9.59	10.43%	**$ 25,317**	$ 25,317	**-$ 0**
1920	Computer Equipment - Hardware	$ 785,584	$ 471,539	$ 24,956	$ -	$ 326,522	4.37	22.88%	**$ 74,712**	$ 74,712	**-$ 0**
1930	Transportation Equipment	$ 1,027,467	$ 454,176	$ 668,543	$ -	$ 907,562	6.22	16.09%	**$ 146,011**	$ 146,011	**-$ 0**
1935	Stores Equipment	$ 135,334	$ 10,237	$ -	$ -	$ 125,098	9.83	10.17%	**$ 12,720**	$ 12,720	**-$ 0**
1940	Tools, Shop & Garage Equipment	$ 419,061	$ 230,489	$ 74,701	$ -	$ 225,923	8.67	11.53%	**$ 26,045**	$ 26,045	**-$ 0**
1945	Measurement & Testing Equipment	$ 68,740	$ 15,346	$ 2,290	$ -	$ 54,539	8.79	11.38%	**$ 6,205**	$ 6,205	**$ 0**
1980	System Supervisor Equipment	$ 2,933,637	$ 246,737	$ 251,848	$ -	$ 2,812,824	13.99	7.15%	**$ 201,020**	$ 201,020	**-$ 0**
2440	Deferred Revenue	-$ 30,880,264	-$ 279,424	-$ 7,381,961	-$ 14,421	-$ 34,277,399	36.99	2.70%	**-$ 926,727**	-$ 926,727	**$ 0**
2005	Property Under Finance Lease	$ 398,091	$ -	$ 65,451	$ 227,479	$ 203,337	3.77	26.51%	**$ 53,900**	$ 53,900	**-$ 0**
	Total	**$ 69,292,705**	**$ 5,911,974**	**$ 7,065,604**	**$ 644,531**	**$ 66,269,003**			**$ 2,473,182**	**$ 2,473,182**	**-$ 0**

Reference:

2-Staff-36

PP&E

Ref 1: Chapter 2 Appendix 2-BA

Ref 2: Exhibit 1, Appendix 1-3-1 (A) 2021 Audited Financial Statements

Ref 3: Exhibit 1, Appendix 1-3-1 (B) 2022 Audited Financial Statements

Question:

Please provide a reconciliation of the PP&E reported in Appendix 2-BA and the 2021 and 2022 Audited Financial Statements.

Response:

Please see the attached reconciliations as ***Att 2-Staff-36_PPE_Reconciliations***.

Reference:

2-Staff-37

Capital Additions

Ref 1: Chapter 2 Appendices_20230512_rev, Tab Appendix 2-AB

Ref 2: Chapter 2 Appendices_20230512_rev, Tab Appendix 2-BA

Question:

OEB staff notes a discrepancy between the net capital expenditures (in service additions) amounts provided in Reference 1 and the capital addition amounts recorded in Reference 2. Based on the variance amounts, it seems like the additions in Account 2005 Property Under Finance Lease are not included in Appendix 2-AB for the years 2019 - 2024. Table 2 below presents a summary of the variances.

Table 2: Summary of Variances between App 2-AB and App 2-BA

Year	Net Capital Expenditures App 2-AB $,000	Net Additions App 2-BA $,000	Variances $,000
2017 (Actual)	3,481	3,425	**56**
2018 (Actual)	4,066	4,067	**(1)**
2019 (Actual)	2,778	2,948	**(170)**
2020 (Actual)	4,487	4,714	**(227)**
2021 (Actual)	7,000	7,136	**(136)**
2022 (Actual)	4,376	4,451	**(75)**
2023 (Plan)	11,485	11,960	**(475)**
2024 (Plan)	9,120	9,120	-

Please provide an explanation/reconciliation for the discrepancies noted above and update the applicable schedules as necessary.

Response:

2-AB has been corrected for the following discrepancies.

- 2017 – the adjustment for the non-regulated portion of the building was not deducted in 2-AB under IPCGP04
- 2018 – rounding

- 2019 – 2023 are the amounts of the capital leases. They have now been included in 2-AB

Please see below for the original submission and the corrected version of this appendix.

Original: Appendix 2-AB

CATEGORY	Historical Period (previous plan[1] & actual)																					2024
	2017			2018			2019			2020			2021			2022			2023			
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var	
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	
System Access	3,509	1,523	-130.4%	13,778	2,096	-557.5%	11,682	5,169	-126.0%	12,103	7,640	-58.4%	13,192	8,945	-47.5%		3,856	100.0%	25,415		-100.0%	23,410
System Renewal	1,348	2,553	47.2%	1,142	1,908	40.1%	3,326	1,495	-122.4%	2,862	2,006	-42.7%	2,577	1,798	-43.3%		8,042	100.0%	9,994		-100.0%	1,429
System Service	248	21	-1081.0%	660	276	-139.1%	393	2,273	82.7%	534	2,737	80.5%	422	2,412	82.5%		503	100.0%	11,967		-100.0%	7,519
General Plant	1,168	363	-221.8%	1,423	1,147	-24.1%	962	273	-252.4%	745	649	-14.8%	706	1,227	42.5%		970	100.0%	1,155		-100.0%	1,022
TOTAL EXPENDITURE	6,274	4,460	-40.7%	17,003	5,426	-213.4%	16,362	9,210	-77.7%	16,244	13,032	-24.6%	16,897	14,382	-17.5%	-	13,372	100.0%	48,530	-	-100.0%	33,380
Capital Contributions	- 1,869	- 980	-90.7%	- 11,826	- 1,360	-769.6%	- 9,928	- 6,433	-54.3%	- 10,450	- 8,545	-22.3%	- 11,129	- 7,382	-50.8%		- 8,996	100.0%	- 37,046		-100.0%	- 24,260
NET CAPITAL EXPENDITURES	4,405	3,481	-26.5%	5,176	4,066	-27.3%	6,434	2,778	-131.6%	5,794	4,487	-29.1%	5,768	7,000	17.6%		4,376	100.0%	11,485		-100.0%	9,120
System O&M	$ 2,179	$ 2,217	1.7%	$ 2,245	$ 2,029	-10.6%	$ 2,246	$ 1,966	-14.2%	$ 2,246	$ 1,867	-20.3%	$ 2,246	$ 2,598	13.5%		$ 2,318	100.0%	$ 2,622		-100.0%	$ 3,091

Updated: Appendix 2-AB

CATEGORY	Historical Period (previous plan[1] & actual)																					2024
	2017			2018			2019			2020			2021			2022			2023			
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var	
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	
System Access	3,509	1,523	-56.6%	13,778	2,096	-84.8%	11,682	5,169	-55.8%	12,103	7,640	-36.9%	13,192	8,945	-32.2%		3,856	--	25,415		-100.0%	23,410
System Renewal	1,348	2,553	89.3%	1,142	1,908	67.0%	3,326	1,495	-55.0%	2,862	2,006	-29.9%	2,577	1,798	-30.2%		8,042	--	9,994		-100.0%	1,429
System Service	248	21	-91.5%	660	276	-58.2%	393	2,273	478.4%	534	2,737	412.5%	422	2,412	471.6%		503	--	11,967		-100.0%	7,519
General Plant	1,168	307	-73.7%	1,423	1,147	-19.4%	962	444	-53.9%	745	876	17.6%	706	1,363	93.0%		1,045	--	1,631		-100.0%	1,022
TOTAL EXPENDITURE	6,274	4,404	-29.8%	17,003	5,426	-68.1%	16,362	9,381	-42.7%	16,244	13,259	-18.4%	16,897	14,518	-14.1%	-	13,447	--	49,006	-	-100.0%	33,380
Capital Contributions	- 1,869	- 980	-47.6%	- 11,826	- 1,360	-88.5%	- 9,928	- 6,433	-35.2%	- 10,450	- 8,545	-18.2%	- 11,129	- 7,382	-33.7%		- 8,996	--	- 37,046		-100.0%	- 24,260
NET CAPITAL EXPENDITURES	4,405	3,424	-22.3%	5,176	4,067	-21.4%	6,434	2,948	-54.2%	5,794	4,714	-18.6%	5,768	7,136	23.7%		4,451	--	11,960		-100.0%	9,120
System O&M	$ 2,179	$ 2,217	1.7%	$ 2,245	$ 2,050	-8.7%	$ 2,246	$ 1,966	-12.4%	$ 2,246	$ 1,867	-16.9%	$ 2,246	$ 2,598	15.7%		$ 2,318	--	$ 2,622		-100.0%	$ 3,091

Reference:

2-Staff-38

Barrie Area Transmission Upgrade Project

Ref 1: Exhibit 2, Section 2-5-7 Advanced Capital Module, p.92

Ref 2: EB-2018-0017 Decision and Order, April 23, 2020

Question:

InnPower is requesting approval for four DVA sub accounts related to the BATU project. InnPower is expected to pay Hydro One $4.1 million each year from 2023-2027 in capital contributions for the project. InnPower notes that it would only be recording contribution installments in the DVAs for the years 2025-2027 since the 2023 and 2024 amounts would be included in rate base.

a) Did InnPower also consider the impact of using a DVA account to track the 2023 and 2024 capital contributions?
b) Hydro One provided a cost estimate for the Barrie Area Transmission Upgrade project in April 2022. Does InnPower have an updated cost and time estimate?
c) If the Barrie Area Transmission Upgrade is not completed in Q4 2023 but in 2024 how does InnPower propose to credit customers the difference that would be imbedded in rates?
d) If the Barrie Area Transmission Upgrade is not completed will the $1.4 million in 44kV work from Barrie TS be in-service for 2023?
e) If the project cost increases following the cost of service proceeding, will InnPower seek to recover deficiencies in funding?
f) Is InnPower on track to meet the load forecast it provided to Hydro One for the capital contribution calculations? In reference 2, the Barrie Area Transmission Upgrade project was forecasted to cost approximately $91 million but has now been revised to $125 million.
g) What are the primary causes of cost increases that have arisen since the project was first approved?
h) If OEB does not fully approve the $125 million at Hydro One’s next rebasing how will this affect InnPower? Has InnPower considered this scenario?

Response:

a) InnPower did not consider using a deferral and variance account (DVA) for 2023 or 50% 2024 as the proposed in-service date of the Barria Area Transmission Upgrade (BATU) coincided with InnPower's final test and bridge years. It is prudent to include, in rate base, the 2023 and 50%, half year rule, of 2024 BATU capital contribution payments. The remaining 50% of the 2024 BATU capital contribution payment will be captured in the deferral account.
b) There have been no changes to the cost of time estimates as of the date of filing these interrogatory responses.
c) In the unlikely event the in-service date is extended to 2024, InnPower would make a credit entry to Account 1508 – Other Regulatory Assets, Sub-Account BATU Installments Paid equal to the 2023 installment included in rate base from the bridge year. Over the course of 2024 through 2028 InnPower would make entries related to this credit in each of Sub-Accounts Carrying Charges, Depreciation Expense, and Accumulated Depreciation which run inverse to the standard entries used for actual installments made. The effect of these inverse entries would be to create a balance owing to ratepayers in InnPower's next Cost of Service application which is equal to the revenue requirement of the 2023 BATU installment included in base rates from 2024 through 2028. On disposition, these inverse balances would offset a portion of the balances relating to the other entries in the BATU Installment Account and its sub-accounts, resulting in a smaller recovery of costs from ratepayers at that time.
d) Per discussion with Hydro One, the 44kV line extension from BATU will not be in-service prior to December 31, 2023. The capital costs paid to Hydro One for the construction will be in work in process and will be carried over and put in-service in 2024.
e) If there are cost increases for the BATU project following InnPower's cost of service application, InnPower will capture the variance between the actual capital contribution and the budgeted capital contribution for 50% of the 2024 contribution and the actual contributions in 2025 through 2027 in the DVA.
f) InnPower actively monitors the progress of developments, and the oncoming load is in alignment with the load forecast.

g) See attached evidence for 2-Staff-38 filed by Hydro One Networks Inc Hydro One with the OEB under EB-2018-0117
h) InnPower will be responsible for its share of the BATU project as per the discounted cash flow models and agreements signed between InnPower and Hydro One. As with other recoverable projects, the only amounts being included in rate base are net capital.

Please be advised, the new BATU Draft Accounting Order has been filed as ***Att 2-Staff-38_Revised_BATU_DVA_Draft_Accounting_Order_20230808.***

Reference:

2-Staff-39

Barrie Area Transmission Upgrade
Ref 1: Exhibit 1, Appendix 1-1-4 (F) 1508 ACM Draft Accounting Order Ref 2: OEB Chapter 2 Filing Requirements 2023 Edition for 2024 Rate Applications
Ref 3: Chapter 2 Appendix 2-BA
Ref 4: Exhibit 2, Tab 5, Schedule 7, pages 92 and 93
Ref 5: EB-2018-0117, Decision and Order, April 23, 2020, page 16
Ref 6: Exhibit 9, Table 2, Schedule 1, page 45

Question:

InnPower is requesting approval of a new deferral account, 1508, Other Regulatory Assets, Sub-Account BATU Installment Account with four sub-accounts. In Reference 1, InnPower has described the mechanics of the request account and subaccounts:

- Sub-Account BATU Installments Paid: Will record InnPower's cumulative capital contribution installments as they are paid to Hydro One, exclusive of amounts paid in 2023 and 2024
- Sub-Account BATU Installment, Carrying Charges: Will record return on rate base (i.e., interest and return on equity, PILs) on the amounts included in Sub-Account BATU Installments paid.
- Sub-Account BATU Installment Depreciation Expense: Will record depreciation expense associated with the capital contributions recorded in Sub-Account BATU Installments paid.
- Sub-Account BATU Installment Accumulated Depreciation: Will be credited with the amounts charged to the BATU Installment Depreciation Expense Sub-Account

Additionally, InnPower stated that the deferral account and its sub-accounts will become effective on January 1, 2024.

In Reference 1, InnPower states that:

In the alternative, and only if the OEB does not approve this new deferral account, InnPower is requesting approval of three ACM requests relating to capital contributions paid to Hydro One for InnPower's calculated portions of the BATU Project. This request is based on the evidence provided above (including the results of the OEB's ACM model), and the OEB's Decision and Order in EB2018-0117.

As per Reference 3, OEB staff notes that InnPower has recorded installments paid in 2023 and 2024 under Account 1609 Capital Contribution Paid, which are included in the Appendix 2-BA Fixed Assets Continuity Schedule and the PILs workform.

In Reference 4, InnPower states that:
The new deferral account will ensure that InnPower does not suffer a loss on approximately 78% of the installments made to Hydro One, which would be the consequence of using the OEB's ACM model.

InnPower provided a table 2-48 showing the shortfall of $9.62 M (78%) in its collection of the capital contributions in 2025 to 2027 because InnPower can only request for the maximum eligible incremental capital amount in each year of 2025 to 2027, using the ACM approach.

In Reference 5, the OEB finds it is appropriate that InnPower only records in its rate base the amounts that it has paid.

a) Please explain why InnPower is requesting the new DVA account, and the sub-accounts become effective on January 1, 2024.
b) OEB staff understands that the tax impacts of the 2023 and 2024 installments are included in the revenue requirement in this application. Please explain how the tax impacts of 2025 to 2027 installments are to be recorded in the proposed DVA. Please elaborate on the tax treatments and any differences in the tax treatments of the DVA approach as compared to the tax treatment when the 2023 and 2024 installments are included in the revenue requirements. Please calculate the 2025 balances in four sub-accounts of the proposed BATU DVA and show the calculations, using the 2025 installment amount and show any necessary assumptions.

c) Please explain what would be the net book value of the capital contributions that had not been depreciated and would be transferred to the rate base in the next rebasing application. Please clarify whether any entries would be recorded in the sub-accounts for the years after 2027 and before the next rebasing year.
d) InnPower provides two options to recover the BATU project installments: the VA approach and the ACM approach. Please explain the following regarding these two approaches:
    i. Please provide any precedent that any LDC request the capital contribution through a DVA rather than the ACM.
    ii. Please provide any precedent that InnPower is aware of the conditional proposal (i.e. if one proposal is not approved, the OEB is to approve another proposal).
    iii. Please provide the regulatory impact of both approaches regarding the revenue requirements in the base year and the incentive period.

Response:

a) InnPower determines that January 1, 2024, is an appropriate effective date for the new DVA account and sub-accounts, as InnPower intends to capture the 50% of the 2024 installment which will not be entered into rate base due to the half-year rule.
b) InnPower will be still able to claim CCA for tax purposes for the 2025 to 2027 capital installments recorded in the proposed DVA accounts. These 2025 to 2027 CCA tax impacts will be included in the 1508 account.

    The tax impacts of 2025 to 2027 installments to be recorded in the proposed DVA are outlined as follows:

BATU Contribution Rate Base (2025-28)	2025	2026	2027
Opening Gross PP&E	$ 2,060,000	$ 6,180,000	$ 10,300,000
Additions	$ 4,120,000	$ 4,120,000	$ 4,120,000
Closing Gross PP&E	$ 6,180,000	$ 10,300,000	$ 14,420,000
Average Gross PP&E	$ 4,120,000	$ 8,240,000	$ 12,360,000
Opening Accumulated Depreciation	$ 20,600	$ 103,000	$ 267,800
Additions	$ 82,400	$ 164,800	$ 247,200
Closing Accumulated Depreciation	$ 103,000	$ 267,800	$ 515,000
Average Accumulated Depreciation	$ 61,800	$ 185,400	$ 391,400
Average Net PP&E	**$ 4,058,200**	**$ 8,054,600**	**$ 11,968,600**

Return on Rate Base			
Equity	$ 1,623,280	$ 3,221,840	$ 4,787,440
ROE	9.36%	9.36%	9.36%
Deemed Return on Equity	$ 151,939	$ 301,564	$ 448,104
Long Term Debt	$ 2,272,592	$ 4,510,576	$ 6,702,416
Short Term Debt	$ 162,328	$ 322,184	$ 478,744
Long Term Rate	3.72%	3.72%	3.72%
Short Term Rate	4.79%	4.79%	4.79%
Deemed Interest	$ 92,316	$ 183,226	$ 272,262
Return on Rate Base	**$ 244,255**	**$ 484,790**	**$ 720,366**

Taxes / PILs			
Regulatory Taxable Income	$ 151,939	$ 301,564	$ 448,104
Add Back Amortization Expense	$ 82,400	$ 164,800	$ 247,200
Deduct CCA	$ 329,600	$ 659,200	$ 988,800
Taxable Income	-$ 95,261	-$ 192,836	-$ 293,496
Income Tax / PILs Before Gross-Up	-$ 25,244	-$ 51,101	-$ 77,776
Income Tax / PILs Grossed Up	**-$ 34,346**	**-$ 69,526**	**-$ 105,818**

Incremental Revenue Requirement	2025	2026	2027
Return on Rate Base - Total	$ 244,255	$ 484,790	$ 720,366
Amortization Expense - Total	$ 82,400	$ 164,800	$ 247,200
Grossed Up Taxes / PILs - Total	-$ 34,346	-$ 69,526	-$ 105,818
Incremental Revenue Requirement	**$ 292,309**	**$ 580,064**	**$ 861,748**
	Total Deferred Revenue Requirement		

Principal Balance	$ 336,057	$ 916,122	$ 1,777,869
Interest	$ 9,457	$ 31,179	$ 67,080
Combined Balance	**$ 345,514**	**$ 947,301**	**$ 1,844,950**

For 2023 and 2024 there will not be any tax impacts as the capital contributions will not be included in the proposed DVA accounts.

The 2025 balances in four sub-accounts of the proposed BATU DVA and calculations are shown below:

Sub-Acct BATU Installments Paid	$6,180,000	
Sub-Acct BATU Installment Depreciation Expense		$103,000
Sub-Acct BATU Installment Accumulated Deprec	$103,000	
Sub-Acct BATU Installment, Carrying Charges	$9,457	

c) The net book value of the capital contributions that had not been depreciated and transferred to the rate base in the next rebasing application is calculated as follows:

Capital Contributions	Deprec Start Date	Depreciation Method	Useful Life	Cost Basis	Annual Depreciation	2025	2026	2027	2028	NBV as of Dec 2028
2024 Capital Contribution (50% half year)	12/31/24	Straight-Line	70	2,114,454	30,206	30,206	30,206	30,206	30,206	1,993,628
2025 Capital Contribution	12/31/25	Straight-Line	70	4,120,000	58,857	58,857	58,857	58,857	58,857	3,884,571
2026 Capital Contribution	12/31/26	Straight-Line	70	4,120,000	58,857	58,857	58,857	58,857	58,857	3,884,571
2027 Capital Contribution	12/31/27	Straight-Line	70	4,120,000	58,857	58,857	58,857	58,857	58,857	3,884,571
				14,474,454	**206,778**	**206,778**	**206,778**	**206,778**	**206,778**	**13,647,342**

Yes, there will be depreciation in 2028, but after the next rebasing these amounts would go from 1508 to 1609 if approved.

d) i) A highly similar DVA was approved as part of the settlement agreement in Hydro Ottawa's 2016 to 2020 Custom Incentive Regulation application.[1] Specifically, Hydro Ottawa removed $5 million in forecast capital contributions to be paid to Hydro One under the terms of Connection Cost Recovery Agreements (CCRA).[2] In lieu of including these capital contributions in rate base and the revenue requirement, a new CCRA DVA was established to record and "recover from customers the annual revenue requirement impact of CCRA payments paid to Hydro One commencing in the year *in* which the facilities to which each CCRA payment relates provides services to Hydro Ottawa customers."[3]

ii) In InnPower's assessment it is not uncommon for Applicants, OEB Staff or Interveners to file conditional proposals (i.e., if one proposal is not approved, the OEB is to approve another proposal) during the course of a proceeding.

iii) Please find as ***Att 2-Staff-39_BATU_Contribution_Revenue_Requirement_20230808*** to this interrogatory response an excel model which provides:

1. The multi-year revenue requirement associated with the BATU capital contributions not included in InnPower's 2024 rate base, as proposed to be recorded in the new BATU Payment Installment DVA;

[1] EB-2015-0004, Amended Settlement Proposal, December 7, 2015
[2] Ibid., page 14
[3] Ibid., page 25

2. The revenue requirements associated with the eligible portions of the BATU capital contributions paid from 2025 through 2027 prepared in compliance with the OEB's ACM policy, utilizing the 2023 inflation factor included in pre-filed evidence;
3. The revenue requirements associated with the eligible portions of the BATU capital contributions paid from 2025 through 2027 prepared in compliance with the OEB's ACM policy, utilizing the 2024 inflation factor issued after submission of InnPower's application and evidence; and,
4. A comparison of the three noted scenarios above, demonstrating deficient cost recovery where the OEB approves an ACM utilizing the 2023 inflation factor, an ACM utilizing the 2024 inflation factor, or no relief in this matter.

	BATU Contribution Revenue Requirement Eligible for Recovery					
	2024	2025	2026	2027	2028	Total
DVA Approach	$ 43,748	$ 292,309	$ 580,064	$ 861,748	$ 1,049,864	$ 2,827,733
ACM Approach - 2023 Inflation Factor	$ -	$ 82,336	$ 148,009	$ 195,780	$ 195,780	$ 621,906
ACM Approach - 2024 Inflation Factor	$ -	$ 20,397	$ 20,397	$ 20,397	$ 20,397	$ 81,587
Deficiency - ACM 2023 Inflation Factor	$ 43,748	$ 209,973	$ 432,055	$ 665,968	$ 854,083	$ 2,205,827
Deficiency - ACM 2024 Inflation Factor	$ 43,748	$ 271,912	$ 559,668	$ 841,351	$ 1,029,467	$ 2,746,146
Deficiency - No Relief / Recovery	$ 43,748	$ 292,309	$ 580,064	$ 861,748	$ 1,049,864	$ 2,827,733

Reference:

3-Staff-40

Customer Forecast

Ref 1: Exhibit 3, page 19

Ref 2: Distribution System Plan, Section 5.3.2 Overview of Assets Managed, pages 55-59

Question:

InnPower has calculated geometric mean growth of 3.2% in the Residential class and less than that in the general service rate classes. It has used this growth to underpin the customer connection forecasts for 2023 and 2024. In the Distribution System Plan it has estimated conservative growth to be 5% per year, and optimistic growth to be 12% per year.

a) Please provide details on connections added in each year from 2018-2022 resulting from subdivision growth.
b) Please provide details on new subdivisions with connections completed or anticipated in 2023 or 2024. For those not yet connected, please provide details on the stage of construction, and when the connections are anticipated.

Response:

a) Please see below estimated connections added from subdivisions in each year below:

    2018 – 628
    2019 – 352
    2020 – 305
    2021 – 222
    2022 – 517

b) The following is the table of new subdivisions with connections completed or anticipated in 2023 and 2024. For those not yet connected, InnPower does not have detailed information on the stage of construction at this point in the process as it with the developers' consultants and contractors.

Reference:

3-Staff-41

Demand Forecast
Ref 1: Load Forecast Model, sheet Rate Class Load Mode

Question:

The ratio of GS > 50 kW demand to GS > 50 kW energy is higher than the historic average for 2021 and 2022. The same pattern exists in the embedded distributor class. This indicates that there is more customer peak demand relative to overall energy use in recent years.
Is InnPower aware of any changes that would result in peak demand increasing since 2021-?

Response:

InnPower is not aware of any clear or specific changes to customer usage patterns which would drive an increase in peak demand since 2021. Of note, while the 2021 and 2022 ratios of demand to energy in the GS >50kW rate class exceed the same ratios from 2015 through 2020, they are comparable to those experienced in 2013 and 2014. Similarly, while the 2022 demand to energy ratio for the Embedded Distributor rate class is the highest in the 10-year historical period, the 2021 ratio is comparable to 2013, 2015, 2016, and 2018. InnPower has no credible basis to determine that the 2021 and 2022 ratios for these two rate classes indicate the beginning of a trend with persistence into and beyond the Test Year. For this reason InnPower submits that the use of a 10-year average continues to be the most appropriate method to establish demand to energy ratios for the GS >50kW, Street Lights, Sentinel Lights, and Embedded Distributor rate classes.

Reference:

4-Staff-42

Salaries and Wages

Ref 1: Chapter 2 Appendices, App.2-K

Ref 2: Exhibit 4, page 145

Ref 3: Exhibit 4 – Variance Analysis

Ref 4: Chapter 2 appendices - 2-JB

Question:

InnPower has projected a CAGR of 5.3% when comparing the 2024 management salary per FTE forecast with the 2017 OEB-approved rate, and a CAGR of 8.3% when comparing the 2024 management salary and benefits package per FTE with the 2017 OEB-approved rate. InnPower stated in Reference 2 that it has tried to match salary increases for management and non-union workers with those of union workers.

a) Please reconcile the explanation for management salaries stated in Reference 2 given that non-management employees have a forecasted CAGR salary increase of 3% when compared to the 2017 OEB-approved amount?

   In Reference 3, the Variance Analysis section, there is mention of FTE additions in OM&A drivers other than within Salaries and Wages section.

b) Please confirm if all the additional FTE salaries are included in the Salaries and Wages line in Reference 4. If not, please provide the number of FTEs added for each driver and the description of FTE functions.

Response:

a) InnPower's goal is to match compensation increases with Union and management staff whenever possible, however this cannot always be accomplished. In order to attract and retain staff InnPower must ensure that compensation is competitive compared to the industry average. InnPower regularly checks this through the release of the MEARIE compensation survey data released annually. InnPower's management positions are positioned near the 50th percentile of the industry range.

Other factors include:

- InnPower underwent a Compensation review of its management positions in 2019 to ensure that InnPower remains competitive in attracting talent.
- InnPower also introduced a bonus in 2021 that has increased total compensation.
- Effective July 1, 2022, the company now pays 100% of the Employee Benefit program. Previously, employees were paying 4% of the cost of benefits.

b) Confirmed. All additional FTE Salaries are included in the Salaries and Wages line in Reference 4.

Reference:

4-Staff-43

Cost Drivers – Regulatory Rate Application and Other Regulatory Costs
Ref 1: Exhibit 4 – 2.6 Regulatory Rate Application and Other Regulatory Costs, p. 42

Question:

InnPower stated that one of the cost drivers for Regulatory Rate Application and Other Regulatory Costs are the two administrative penalties related to Assurance of Voluntary Compliance (AVC).

Please confirm whether the $25k penalty issued in 2019 and the $5k penalty issued in 2020 were included in OM&A in their respective years.

Response:

Yes, IPC confirms that it recorded the $25k penalty in May 2019 and the $5k penalty in January 2021 (as the AVC was filed December 30th, 2020). Both penalties were recorded to OM&A accounts.

Reference:

4-Staff-44

IT and Cybersecurity
Ref 1: Exhibit 4 – 2.7 IT and Cyber Security, p. 44

Question:

InnPower stated that it has invested in Software-as-a-Service (SaaS), transitioning expenses from capital to OM&A.

a) Please explain what programs or applications have transitioned to SaaS. Please provide the cost in each program that has transitioned from capital to OM&A as a result of the SaaS.

Response:

a) There have been several systems that have transitioned from On-Prem to SaaS / Cloud-based. Microsoft 365, Prophix, MyGlue, SOTI MobiControl, SiteDocs are examples of SaaS / Cloud-based migrations that have occurred in 2022. More applications will be migrated in coming years as they reach the end of their useful life in our on-prem environment.

Annual Costs:

Microsoft 365	$31,132.80
Prophix	$50,038.00
MyGlue	$2,399.52
SOTI MobiControl	$3,186.60 USD
SiteDocs	$3,093.53

Reference:

4-Staff-45

Building and Office Supplies
Ref 1: Exhibit 4 – 2.8 Building and Office Supplies, pp. 44-45

Question:

Based on the annual OM&A program variance sheet, 7% of the OM&A increase has come from building and office supplies. InnPower stated that building and office supply costs increased in 2022 due to janitorial and plumbing services, and costs increased in 2023 due to full-time snow clearing at all station driveways.

a) Please explain the increased janitorial and plumbing services in 2022. How much of the $67k increased OM&A cost from 2021 to 2022 is associated with janitorial and plumbing services? Was this a one-time maintenance cost or an on-going operational cost increase?
b) Please explain what is meant by full-time snow clearing.
c) Please provide the business case for implementing full-time snow clearing. How much of the $72k increased OM&A cost from 2023 is associated with the full-time snow clearing?

Response:

a) Out of the $67k increase in OM&A cost from 2021 to 2022, $5.8k was for one-time plumbing issues and $26.6k was for increased costs in janitorial services.
b) Full-time snow clearing means the contractor will ensure the station driveways are accessible for the winter season.
c) InnPower did not prepare a written business case. We have had multiple occasions where staff could not access stations due to snowbanks not being cleared out of the driveway, or our vehicles getting stuck in the driveway due to the amount of snow and then we would require a tow truck to get them out. The main increase in the snow removal for the 2022/2023 season was driven by the cost of

salt. To add the station driveways to our contract was an additional $3k for the 2022/2023 season.

Reference:

4-Staff-46

Vegetation Management

Ref 1: Exhibit 4 – 2.13 Vegetation Management, p. 48

Question:

InnPower invested heavily into changing its vegetation management program in 2021 to reduce tree contacts. Vegetation management costs increased by $324k in 2021. Costs are expected to increase a further by $50k in 2024.

a) Please explain changes made to the vegetation management program in 2021.
b) Please explain the driver for the increase in vegetation management costs in 2024.

Response:

a) Please reference 1-SEC–4a response for an updated cost table. InnPower updated the vegetation management procedure to include a four-year cycle, with adequate cutbacks to ensure minimal tree growth issues over those four years between trimming. InnPower also introduced a Hazard tree identification and removal within the vegetation management procedure. Please reference 1–SEC–4a response for an explanation of 2021 costs.
b) InnPower has completed cycle trimming in accordance with the updated procedure for Cycle 3 (2021), Cycle 4 (2022) and Cycle 1 (2023). Cycle 2 is slated for 2024 and is an area of significant tree density. There are also numerous ash trees in this cycle that will need to be addressed due to being within proximity to InnPower distribution lines.

Reference:

4-Staff-47

Distribution Meters

Ref 1: Exhibit 4 – 2.15 Distribution Meters, p. 49

Ref 2: Exhibit 4 – 3.1.4. Distribution Meter Operations

Question:

InnPower explained that the increase in Distribution Meters OM&A was due to in suite metering projects, backorder of Sensus meters, and purchase of conventional meters. InnPower also stated that the cost increase is due to an increase in the number of meter upgrades, installations and verifications based on significant growth in customer base.

a) In reference 1 the variance explanations all appear to be capital costs. Please explain how the capital cost of meters affects the OM&A costs.
b) How does the installation of new meters increase OM&A?
c) Please provide the number of staff in the Distribution Meter Operations group and the positions of the staff.
d) Please provide the number of meter upgrades, installations, and verifications between 2017 and 2023.

Response:

a) The bullets 2 through 6 in 2.15 Distributed Meters were copied to this exhibit in error. Please see the correction below.

   Original explanation:

2.15 Distribution Meters

- The costs included in distribution meters area includes expenses for meter materials betterments, minor repairs, meter vehicles, meter tools, meter communications and meter seminars and training.
- In 2017 and 2018, InnPower placed a large order of meters, as the utility predicted significant growth in developments. However, the anticipated growth was not fully achieved, resulting in an excess of meters and a subsequent decrease in meter purchases for 2019.
- In 2020, the decrease in meter purchases was a direct result of the COVID-19 pandemic with factors including COVID restrictions, supply chain issues, and a decrease in housing developments.
- In 2021, the increase was a result of an uptake in suite metering projects worth $133k, as well as the addition of a new meter technician position.
- In 2022, InnPower received backorders of Sensus meters (originally ordered in 2020 and 2021) that were delayed due to supply chain issues.
- In 2022, InnPower also purchased approximately $40,000 of conventional meters (Itron) to help alleviate further shortages and supply chain issues for standard Sensus meters.

Updated explanation:

2.15 Distribution Meters

- The costs included in distribution meters area includes expenses for meter materials
- betterments, minor repairs, meter vehicles, meter tools, meter communications and meter
- seminars and training.
- In 2021, the increase was a result of the addition of a new meter technician position in May 2021.
- In 2022, the additional meter technician (hired in May 2021) was employed for a full year.
- In 2023, a Meter Supervisor was budgeted in addition to the two existing meter technicians.

b) New meters would not affect OM&A costs. See response in a).

c) The Distribution Meter Operations group currently has two Metering Technicians (one position is currently vacant) and one Supervisor.

d) InnPower does not currently store data for upgrades in our system in a manner that can quantify the requested information.

Installations and verifications for 2017 to 2022 are shown in the table below.

Year	Installations	Verifications
2017	725	12
2018	734	249
2019	460	249
2020	391	198
2021	400	113
2022	887	62

Reference:

4-Staff-48

Engineering/Operations Expenses
Ref 1: Exhibit 4 – 4.1.4 OM&A Variance analysis
Ref 2: Exhibit 4 – 4.1.6.3.3 Staff Increases in 2023 and 2024

Question:

InnPower stated that decreases in 2020 and 2022 to the Engineering / Systems Ops / Line Construction / SCADA / Ops Admin program were due to the reallocation of staff and change in work orders. InnPower also added a control room operator, P&C technologist, stations project engineer, and asset management engineer in 2023 and an additional control room operator, an additional P&C technologist, and station/planning supervisor in 2024.

a) Please explain which programs the dollars were redirected to for reallocation of staff and change in work orders in 2020 and 2022.
b) In reference 2, InnPower stated that the new control room operator is required due to system expansions and increases in day-to-day controlling activity and requests. Please provide information on yearly controlling activity and requests seen by the control room for the past five years.
c) Please provide the current number of P&C technologists and stations project engineers.

Response:

a) In 2020, InnPower moved an employee from Protection and Control to the Stockkeeper position. In 2022, InnPower implemented a detailed breakdown of how to allocate costs to jobs (whether it was capital or OM&A) and had greater insight and review due to the addition of a new Lines Supervisor.
b) Yearly control room activities and requests include (not limited to):
    - Issue Hold offs, prepare and direct switching procedures and operations for the electric distribution system.

    - Each year the Controlling Authority receives approximately 415 hold off requests and authorizes 175 PC17B OTOs, 35 PC10A work protection permits, issues 25 PC10C Supporting Guarantees, and logs 15 Caution Tags. As the system expands, it is expected that these requests will continue to increase annually.
- Monitor, control and authorize the efficient operation of the electrical distribution system under both normal and emergency conditions.
- Coordination with Hydro One, InnPower operations and engineering team, as well as customers
- Respond to electrical distribution system anomalies by operating remote switching devices.
- Maintain system records, maps, open points, and prepare reports on the operation of the electrical distribution system.
- Responsible for updating, maintaining, and troubleshooting SCADA, OMS, GIS and all related computer software for safe and reliable electrical distribution system operations.

c) InnPower recently employed one stations project engineer as of May 2023. InnPower does not currently employ a P&C Technologist.

Reference:

4-Staff-49

Overhead Distribution Lines and Feeders
Ref 1: Chapter 2 Appendices, App.2-JC
Ref 2: Exhibit 4 – 3.2.1 Overhead Distribution Lines and Feeders

Question:

InnPower has estimated an increase in 'overhead distribution lines and feeders' from $780k in 2022 and $723k in 2023 to $948k in 2024. InnPower explains the 'overhead distribution lines and feeders' category to include the majority of InnPower's inspection and maintenance program, including switch maintenance, trouble calls, overhead conductors, tree calls, and DIRs.

a) Please explain the 31% increase in 'overhead distribution lines and feeders' in 2024 given that InnPower has increased its capital spending on the replacement of many of the assets within this program?

   InnPower stated in reference 2 that the decrease in the budget for 2022 was due to the reallocation of costs between various programs.

b) Please provide the amounts re-allocated and the programs the amounts were reallocated to.

   InnPower stated in reference 2 that the cost increase for Overhead Distribution Lines and Feeders is due to an increase in station maintenance.

c) Please provide a breakout of cost and explain why there are station maintenance costs in the Overhead Distribution Lines and Feeders program.

   InnPower stated in reference 2 that the 2023 to 2024 increase of $224k is driven by disconnects/reconnects, vegetation management, and station maintenance. In Appendix 2-JB the vegetation management increase in 2024 is $50k.

d) Please provide a breakdown of the cost increase between 2023 and 20224 by disconnects/reconnects, vegetation management, and station maintenance.

e) InnPower stated that the disconnect/reconnect budget was increased to align with historical increases. Please provide the forecasting methodology and the historical data used for the forecast.

Response:

a) The 31% increase in ‘overhead distribution lines and feeders’ in 2024 is primarily driven by an increase in Station Maintenance Labour ($150,000 increase from 2023) and Vegetation Management ($50,000 increase from 2023). While InnPower has increased capital spending, vegetation management (VM) and disconnect/reconnect (DIR’s) are fully OM&A costs so there are no offsets due to the increase in the capital program. InnPower needs to invest on extra recourses to meet its Maintenance program requirements. Additional P&C and control room operator has been budgeted for 2024.

b) InnPower implemented a new approach to classifying costs based on the OEB APH. This was implemented at the start of 2022, so the re-allocation refers to the difference between 2021 and 2022. No actual funds were moved within the 2022 calendar year, just a more detailed cost allocation.

c) Distribution Station Maintenance (SM) costs are included in this section to align with InnPower’s previous submission. Each GL is tracked independently in alignment with the OEB APH but has been combined under this heading.

d) Please see below:

    2023 DIRs - $148,220; 2024 DIRs - $161,443
    2023 VM - $312,374; 2024 VM - $364,447
    2023 SM - $145,337; 2024 SM - $299,327

e) Between 2017 and 2020, InnPower spent on average $95,144 on DIRs per year. Due to the COVID pandemic, InnPower saw costs increase for 2021 and 2022 to an average of $240,323. These costs were primarily driven by customers spending more money on personal dwellings (panel upgrades, generator installations, roofing and siding projects). InnPower does not believe the numbers seen in 2021 and 2022 represent the new normal and the forecast lies more in the middle so the average forecasted cost in 2023 and 2024 is shown as $154,827.

Reference:

4-Staff-50

Customer Service & Billings

Ref 1: Chapter 2 Appendices, App.2-JC

Ref 2: Exhibit 4 – 1.1.3. Customer Service & Billings, p. 60

Question:

Reference 1 shows an increase of $150k between 2017 and 2018 actuals for Customer Service and Billings. InnPower also saw an increase of $168k between 2018 and 2019, which InnPower attributed to stepping up several staff to a higher pay band.

a) Please confirm if this increase in 2017 to 2018 was also driven by moving staff to a high pay band. If not, please explain the increase.

b) Please provide the number of staff in the Customer Service & Billings group that received the step-up.

Response:

a) In August 2017 InnPower hired a Manager, Customer Relations and Engagement as well as a contract person to do scanning in 2018.

b) There was one person on step–up in the Customer Service and Billing area in 2022.

Reference:

4-Staff-51

Audit, Legal, and Consulting

Ref 1: Exhibit 4 – 1.1.7 Audit, Legal, and Consulting

Ref 2: Chapter 2 appendices – 2-JC OM&A Programs

Question:

InnPower stated that increases in Audit, Legal, and Consulting between 2024 and 2017 were due to union negotiations, and consulting costs for an IT audit, cyber security/network monitoring, job evaluation restructuring for union staff, succession planning, EDI program, and Miscellaneous HR consulting.

a) Please confirm if any of the cost drivers listed above are expected between 2024 to 2028.
b) Are there other planned consulting studies planned for 2024 to 2028? If so, please provide background on the studies.
c) Do the 2024 costs shown in Reference 2 represent an annual amount expected to be spent each year 2024-2028, or one-fifth of the total amount expected to be spent over the 2024-2028 period?

Response:

a) Yes, these same cost drivers are expected to continue in the 2024 to 2028 time period.
b) InnPower has no specific plans for any additional consulting studies from a Human Resources or IT perspective, however IT may engage with consultants/vendors to address specific IT requirements as part of normal operations.
c) The 2024 costs shown in Reference 2 represent an annual amount expected to be spent each year on Audit, Consulting & Legal Fees from 2024-2028.

Reference:

4-Staff-52

Building and Office Supplies
Ref 1: Exhibit 4 – 2.8 Building and Office Supplies

Question:

InnPower stated that the cost drivers for Building and Office supplies are due to new heating systems, cameras, more contact points, and shatterproof sensors on main floor windows.

a) Please explain why these capital investments would increase OM&A costs for building and office supplies.

Response:

a) Overall, the costs of maintaining the building have increased. None of the items specified above are OM&A costs. Items that have led to the increase in OM&A costs include;
   i. Heating System (not new) – The costs of heating the building increased over time.
   ii. Security – We have had to replace contacts and sensors for our security system as they have worn out over time. We also added a new camera system for our yard (which was capital); however, the OM&A impacts is the maintenance and monitoring of that system.
   iii. Garage door repairs were a contributing factor for higher OM&A in 2022 (not a regular expense)
   iv. Janitorial services cost increased as the original quote was based on the incorrect square footage of the building and has since been corrected.
   v. Snow clearing costs went up due to us adding additional locations for clearing (all our station driveways throughout our territory) then the cost of the salt has substantially increased as well.

vi. A contractor was also added to provide regular preventative maintenance on our building generator.

Reference:

4-Staff-53

Management, Finance, Administrative, Regulatory, and Information Technology
Ref 1: Exhibit 4 – 1.1.9 Management, Finance, Administrative, Regulatory, and Information Technology
Ref 2: Chapter 2 appendices – 2-N Corporate Cost Allocation

Question:

In reference 1, InnPower provided explanations for variances in this program but omitted explanations for 2020 and 2021.

a) Please explain the $219k increase between 2019 and 2020 and the $107k decrease between 2020 and 2021.
b) Please explain the difference between the costs for the Information Technology Division and the Information Systems program and provide examples of IT costs that would fall under each program.
c) InnPower stated that it acquired contracted services in 2023 and 2024 associated with the Chief Compliance Officer, Corporate Services, Information Technology, health and safety, and legal services. Please confirm if these services were from InnPower's affiliates. If so, why are the costs not shown in Reference 2?

Response:

a) The explanations for the missing variances are as follows:
   i) The $219k increase between 2019 and 2020 is due to the following:
      i. Increase of $93k in pension cost
      ii. Decrease of $69k due to the COVID-19 pandemic; therefore, staff were unable to attend planned conferences and training
      iii. The $200k increase in labour costs was due to:
         1. One staff moving to higher paid non-union position
         2. Addition of accounting clerk position
         3. Overlap of financial analyst position due to maternity leave

4. Overlap of CEO and President position
5. Additional board member

ii) $107k decrease between 2020 and 2021

i. The $107k decrease in labour costs was due to:

1. These was a short vacancy in Manager, Regulatory Affairs position, October 2021 ($135k)
2. Less overlap in CEO and president position ($37k)
3. Difference in payroll accrual at the end of the year ($152k).
4. Board of Directors met less often in 2021 than 2020
5. Short vacancy in Finance Supervisor position, Jan 2021
6. The remaining difference is due to annual wage increases and allocation of time (capital vs. expense or between affiliates).

b) The “Information Systems Program” is the account where OM&A software expenses are charged. The “Information Technology Division” refers to departmental expenses, such as staff labour and training.

c) That is correct. The services in 2023 and 2024 for the Chief Compliance Officer, Corporate Services, Information Technology, health and safety, and legal services have been contracted with InnPower’s affiliates. These costs have been added to Chapter 2 appendices – 2-N Corporate Cost Allocation.

Reference:

4-Staff-54

Employee Burnout Survey
Ref 1: Exhibit 4, page 135

Question:

InnPower performed an employee survey, evaluating the burnout of its employees to gauge the need for more FTEs.

a) Was this survey developed by InnPower or a third party?
b) Did InnPower consider using a rating format (i.e., 1-5) with neutral language instead of a binary ‘agree or disagree’ format that may lead to certain responses?

Response:

a) The employee survey evaluating the potential warning signs of burnout was developed by InnPower.
b) InnPower used a 5-point Likert scale ranging from Strongly agree to Strongly disagree to determine any potential risks or trends regarding Employee Burnout.

Reference:

4-Staff-55

FTE Additions 2017-2024

Ref 1: Exhibit 4, page 126

Question:

InnPower has increased its total number of FTEs by 17.8 from 2017 to 2022 and by another 16.5 FTEs in the years 2023-2024.

a) Please provide a list of FTE additions and removals from 2017 to 2024, by year, with a general description of the need for the additions.

Response:

a) The following is a list of FTE additions and Removals from 2017-2024 (Not including Students & Fixed-Term Employees):

Year	Roles Added	Roles Removed
2018	• Chief Operating Officer • Power Systems Engineer • Powerline Technician • Customer Service Representative • Purchaser/Stockkeeper • Stockkeeper • Engineering Technologist • Information Systems Analyst	• Manager, Distribution Engineering
2019	• Engineering Technologist • Powerline Technician Apprentice • Accounting Supervisor • Payroll & Benefits Specialist • Billing & Business Process Supervisor • Supply Chain Operations Supervisor	• Information Systems Analyst • Customer Service Representative • GIS Technician • Stockkeeper
2020	• Supervisor, Stations • Financial Analyst	• Accounting Supervisor

	• Customer Service Representative	
2021	• Power Systems Engineer • Metering Technician • Customer Account Representative • Powerline Technician • Stockkeeper	• Protection & Control Technologist
2022	• Powerline Technician • Powerline Technician Apprentice (0.5 FTE)	
2023	• Customer Service Supervisor • Project Engineer • Asset Management Engineer • Financial Analyst • Accounting Supervisor • Metering Supervisor • Protection & Control Technologist (Not yet hired) • Control Room Operator (Not yet hired • Computer User Support Technician • Customer Service Representative	

Reference:

4-Staff-57

Affiliate Allocation
Ref 1: Exhibit 4, page 161
Ref 2: Exhibit 4, page 168

Question:

In reference 1, InnPower stated that it has estimated the common space in its office building to be approximately 30% of the office space area. In reference 2, InnPower stated that the market price per square foot used to calculate affiliate costs was based on a 2015 study that escalated rates up to 2025.

a) How was the 30% common space determined?
b) Please provide the 2015 study that shows the market price escalation from 2015-2025. Does the escalation accurately represent the actual economic conditions since 2015?
c) When calculating the hours of labour for affiliates, did InnPower consider hours worked from home and the impact on shared services revenue?

Response:

a) The 30% common space was determined by calculating the proportion of common space square footage to office/cubicle square footage using the InnPower building floor plan.
b) The 2015 Rent Study is attached as ***Att 4-Staff-57_Yonge_7251_Rent_Study_2015***.
When InnPower first marketed the “excess” space for rental purposes, there was no interest in the space. A tenant was found and the per square foot rental rate negotiated was below the market study. It was decided that the best interest would be to get a tenant into the space as opposed to the space remaining vacant. The original term of the agreement was for 5 years with one 5-year extension. InnPower recently extended the rental agreement through August 2027. There

have been significant changes in the rental market over the past 3 years due to COVID. In the interest of maintaining the existing tenant an annual increase of approximately 4% was agreed to through the term of the agreement.

c) The work from home arrangement did not impact the shared services revenue or cost. It is assumed that shared services employees occupy their space in the office 100% of the time, as office and cubicle spaces are currently designated for specific employees.

   Additionally, employees book their labour time using the same method if they are in the office or at home, therefore, it would not affect the number of labour hours used to allocate funds.
   Overall, no credits or adjustments are required during periods when the employee is working from home.

Reference:

4-Staff-58

Non-Affiliate Services

Ref 1: Exhibit 4 – 4.2.2 Purchase of Non-Affiliate Services

Question:

InnPower acquires approximately $13 million in services for capital and maintenance work from multiple non-affiliates.

a) Please provide the breakdown for maintenance work and capital work.
b) Has InnPower considered potential savings by adding additional FTEs for the maintenance work instead of contracting it? If so, what were the results?

Response:

a) Please see the breakdown below.

Supplier Name	Capital	Maintenance	Total
ANIXTER POWER SOLUTIONS CANADA INC	805,818.99	699.60	806,518.59
BLACK & McDONALD LIMITED	3,454,315.96	-	3,454,315.96
CAM TRAN COMPANY LIMITED	197,356.75	-	197,356.75
CES TRANSFORMERS	174,520.00	-	174,520.00
Domino HighVoltage Supply Inc	134,223.76	-	134,223.76
G & W CANADA	300,720.00	-	300,720.00
Hitachi Energy Canada Inc	168,342.69	-	168,342.69
JUBB UTILITY SUPPLY LTD.	106,157.44	412.52	106,569.96
K.P.C. POWER ELECTRICAL LTD.	185,808.19	-	185,808.19
K-LINE MAINTENANCE & CONSTRUCTION L	2,004,836.72	47,488.42	2,052,325.14
KTI LIMITED	116,129.00	-	116,129.00
NBM ENGINEERING INC.	950,835.13	-	950,835.13
NORAMCO WIRE & CABLE	1,585,917.36	-	1,585,917.36
PTI Transformers LP	151,700.00	-	151,700.00
Red Power Electric	438,163.00	77,170.00	515,333.00
S&C ELECTRIC CANADA LTD	213,260.00	-	213,260.00
STELLA-JONES INC.	604,009.03	-	604,009.03
STURDY POWER LINES LTD.	136,004.11	40,855.99	176,860.10
Trane Canada ULC	67,531.00	15,379.86	82,910.86
W.M. WELLER TREE SERVICE LTD.	272,250.51	272,526.84	544,777.35
Grand Total	**12,067,899.64**	**454,533.23**	**12,522,432.87**

b) Due to the nature of maintenance work, e.g. tree trimming it is generally not feasible for InnPower full time staff. InnPower assesses the cost implications of using contract staff and full-time employees on an on-going basis. Due to the rapid growth in our service territory, InnPower must have the ability to quickly ramp up and ramp down resources as required. Working with the contractors allows InnPower to get operational flexibility, address third parties' demands, complement internal staffing during major events, tap into a bigger pool of resources (talent and equipment) as well as procure expert technical services.

It should be noted that the majority of the $13M services noted above are to address the capital rapid growth InnPower is currently experiencing.

When making hiring decisions InnPower considers the following main aspects:

i. Customer Impact (e.g., best value for money spent)
ii. Long term job stability and job security to our employees/personnel
iii. Fiscal prudency and cost savings.

Reference:

4-Staff-59

One-time Costs
Ref 1: Chapter 2 appendices – 2-M Regulatory Costs
Ref 2: Exhibit 4 – 4.2.3 One-Time Costs

Question:

InnPower budgeted $100k for legal costs, $92k in consultant costs, and $50k in intervenor costs for the 2024 test year. InnPower also made a manual adjustment of $44k in cell C82.

a) Please provide the spending in legal costs and consultant costs to date.
b) Please provide the number of intervenors InnPower budgeted for this application.

In 2020 (EB-2020-0282), InnPower was issued a $5,000 penalty as a result of overcharging customers by continuing a rate rider beyond the approved expiry date, contrary to the Rate Order.

c) Please explain why InnPower included $5,000 from the assurance of voluntary compliance in the one-time costs.

Response:

a) The following table provides the spending in legal costs and consultant costs to date for the Cost of Service Application (as of June 30, 2023).

	2021	2022	2023	Total
Legal Costs			$18,257	**$18,257**
Consulting Costs	$39,442	$11,662	$99,213	**$150,317**
Total	**$39,442**	**$11,662**	**$117,470**	**$168,574**

b) In addition to Board Staff, InnPower budgeted for two intervenors (VECC and SEC) in the current application. It was not anticipated that Hydro One would apply for intervenor status.

c) The $5k expense was included in the one-time costs for the current application in error. The total amount for the current application should be $309,324 ($314,324 - $5,000), making 1/5 of Total One-Time costs $61,865. InnPower has made the correction to the appropriate models. The $1,000 difference for 2024 was moved from 5655 Regulatory Costs to 5615 General and Administrative expenses, therefore, the impact on total OM&A is nil.

Reference:

5-Staff-60

Debt Instruments

Ref 1: Chapter 2 Appendices, App.2-OB

Question:

In reference 1, InnPower provided its debt instruments. Most of the loans taken by InnPower are through TD Bank.

a) Did InnPower consider other lenders besides TD Bank?

In 2024, InnPower renewed TD-20 and TD-21 loans at a rate of 3.9% but acquired new debt (2023 CAPEX Loan) at 5%.

b) Please explain the difference in debt rate in the same year.

InnPower acquired new debt in 2023 and 2024 at a rate of 5%. The BATU leave to construct decision was issued in 2020.

c) Please confirm if the new debt in 2023 and 2024 was due to the BATU project. If so, please explain why InnPower did not acquire debt earlier when interest rates were historically low.

Response:

a) InnPower's banking and borrowing arrangements are reviewed annually. Other lenders are considered as part of this process.

b) It appears that the old rates for TD-20 & TD-21 had been copied to 2024 at renewal. We concur that these loans should show a consistent renewal rate of 5% as used throughout the Application.

Please see below for the original submission and the corrected version of this appendix.

Original: Appendix 2-OB - 2023

Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,416,801	2.70%	$ 65,254
TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,655,854	5.27%	$ 139,964
TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov-23	10	$ 2,191,326	4.59%	$ 100,582
TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-14	10	$ 1,604,074	3.96%	$ 63,521
TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-14	10	$ 1,619,022	3.91%	$ 63,369
TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,617,075	3.68%	$ 59,508
TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,723,518	2.88%	$ 280,037
TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,453,588	3.48%	$ 85,385
TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,648,500	3.60%	$ 95,346
TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,505,817	4.09%	$ 61,588
TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,176,017	3.28%	$ 71,373
TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,431,931	2.45%	$ 59,582
Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033
TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 907,019	1.92%	$ 17,415
2022 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-23	15	$ 2,189,040	5.00%	$ 109,452
						$ 36,472,914	3.52%	$ 1,285,409

Original: Appendix 2-OB - 2024

Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,218,160	2.70%	$ 59,890
TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,506,102	5.27%	$ 132,072
TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov-23	10	$ 2,088,716	4.59%	$ 95,872
TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-24	10	$ 1,552,634	3.96%	$ 61,484
TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-24	10	$ 1,568,095	3.91%	$ 61,375
TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,565,516	3.68%	$ 57,611
TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,392,408	2.88%	$ 270,501
TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,378,844	3.48%	$ 82,784
TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,573,529	3.60%	$ 92,647
TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,469,359	4.09%	$ 60,097
TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,121,541	3.28%	$ 69,587
TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,343,764	2.45%	$ 57,422
Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033
TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 781,584	1.92%	$ 15,006
2022 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-23	15	$ 2,080,943	5.00%	$ 104,047
2023 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-24	15	$ 5,284,649	5.00%	$ 264,232
						$ 40,259,177	3.72%	$ 1,497,662

Updated: Appendix 2-OB – 2023

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,416,801	2.70%	$ 65,253.63	
2	TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,655,854	5.27%	$ 139,963.50	
3	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov-23	10	$ 2,191,326	5.00%	$ 109,566.31	
4	TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-14	10	$ 1,604,074	3.96%	$ 63,521.31	
5	TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-14	10	$ 1,619,022	3.91%	$ 63,368.51	
6	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,617,075	3.68%	$ 59,508.35	
7	TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,723,518	2.88%	$ 280,037.32	
8	TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,453,588	3.48%	$ 85,384.88	
9	TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,648,500	3.60%	$ 95,345.99	
10	TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,505,817	4.09%	$ 61,587.90	
11	TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,176,017	3.28%	$ 71,373.37	
12	TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,431,931	2.45%	$ 59,582.30	
13	Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033.34	
14	TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 907,019	1.92%	$ 17,414.77	
15	2022 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-23	15				
Total							$ 34,283,874	3.46%	$1,184,941.47	

Updated: Appendix 2-OB - 2024

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]	Additional Comments, if any
1	TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,218,160	2.70%	$ 59,890.32	
2	TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,506,102	5.27%	$ 132,071.59	
3	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov-23	10	$ 2,088,716	5.00%	$ 104,435.81	
4	TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-24	10	$ 1,552,634	5.00%	$ 77,631.68	
5	TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-24	10	$ 1,568,095	5.00%	$ 78,404.75	
6	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,565,516	3.68%	$ 57,610.99	
7	TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,392,408	2.88%	$ 270,501.35	
8	TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,378,844	3.48%	$ 82,783.77	
9	TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,573,529	3.60%	$ 92,647.04	
10	TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,469,359	4.09%	$ 60,096.80	
11	TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,121,541	3.28%	$ 69,586.53	
12	TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,343,764	2.45%	$ 57,422.22	
13	Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033.34	
14	TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 781,584	1.92%	$ 15,006.40	
15	2022 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-23	15				
16	2023 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-24	15	$ 5,284,649	5.00%	$ 264,232.45	
Total							$ 38,178,234	3.76%	$1,435,355.04	

c) The BATU project is included in our capital program spending in 2023 and 2024. InnPower typically budgets for new debt at 60% of the preceding year's CAPEX program, as demonstrated in 2023 and 2024.

InnPower has spent the last few years focused on strengthening its financial indicators in preparation for the impending substantial capital program. InnPower was able to negotiate the prepayment of planned annual design and constructions costs from developers. This has decreased InnPower's reliance on its line of credit (or requirement for external financing) and allowed for better cash flow management. InnPower will continue to evaluate alternate solutions to support our capital program.

Reference:

6-Staff-61

Provincial Tax Return

Ref 1: Exhibit 6, Tab 2, Schedule 1, page 17

Question:

InnPower indicated in Reference 1 that it has been selected for an audit of its 2018 and 2019 Provincial tax returns by the CRA. InnPower stated that there are no/immaterial adjustments expected once the audit is complete.

a) Please provide the status of the audit and if the audit is expected to be completed before the record-closing date of this proceeding. If so, please confirm that InnPower will provide the summary of the audit.
b) Please clarify the purpose of the audit and any potential regulatory impacts.

Response:

a) The audit is still ongoing. It is not anticipated that it will be complete before the record-closing of this proceeding. InnPower still contends that there will be no / immaterial adjustment once the audit is completed.
b) The purpose is to audit the Hydro Payment in Lieu amounts as submitted on InnPower's combined Federal/Ontario income tax return. We are unaware of any potential regulatory impacts at this time.

Reference:

6-Staff-62

Depreciation/Amortization
Ref 1: Chapter 2 Appendix 2-BA
Ref 2: 2024 Income Tax PILs Workform

Question:

OEB staff notes that the Net Depreciation figures in Reference 1 do not align with the Amortization amounts recorded in Sch 1 in Reference 2 for the historical, bridge, or test years. It seems that InnPower has included the depreciation amounts of Other Non Rate-Regulated Utility Assets in the depreciation and amortization add-back in the PILs model. OEB staff notes that the non rate-regulated utility assets should not be included in the PILs model.

a) Please confirm OEB staff's observation above.
b) If confirmed, please update the applicable schedules by removing the non rate-regulated utility assets in the PILs model.
c) Please complete Tab S1. Integrity Checks in Reference 2.

Response:

a) The OEB Staff observation is correct.
b) The depreciation on the non-regulated portion of the building has been deducted from the historical, bridge and test years Schedule 1's, Line 104.

   Please note that with this change, the PILs Model Schedule 1 in the historical year and the Schedule 1 in the income tax return filed with CRA and Minister of Finance will not agree.
   Please see below for the original submission and the corrected version of these appendices.

Original: H0 PILs, Tax Provision History

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

			Reference	Wires Only	
Regulatory Taxable Income			H1	$ 808,207	A
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	11.50%	B		
	Federal tax rate (Maximum 15%)	15.00%	C		
	Combined tax rate (Maximum 26.5%)			26.50%	D = B+C
Total Income Taxes				$ 214,175	E = A * D
Investment Tax Credits					F
Miscellaneous Tax Credits				$ -	G
Total Tax Credits				$ -	H = F + G
Corporate PILs/Income Tax Provision for Historical Year				$ 214,175	I = E - H

Original: H1 Sch 1 Taxable Income History

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	(A + 101 + 102)	2,703,000		2,703,000
Additions:				
Interest and penalties on taxes	103	612		612
Amortization of tangible assets	104	3,584,000		3,584,000
Loss on disposal of assets	111	61,000		61,000
Charitable donations and gifts from Schedule 2	112	1,250		1,250
Non-deductible meals and entertainment expense	121	2,073		2,073
Reserves from financial statements – balance at the end of the year	126	142,732		142,732
Recapture of SR&ED expenditures	231	18,054		18,054
Customer Deposits (ITA 20(1)(a))	295	7,676,000		7,676,000
Capital Contributions Received (ITA 12(1)(x))		9,002,299		9,002,299
Amortization expensed in Distribution expenses		213,148		213,148
Amortization expensed of Capital Lease		30,000		30,000
Tax component of OCI		11,709		11,709
Total Additions		**20,742,877**	**0**	**20,742,877**
Deductions:				
Capital cost allowance from Schedule 8	403	4,661,942		4,661,942
Reserves from financial statements - balance at beginning of year	414	162,065		162,065
Capital Lease Payments	395	26,000		26,000
Customer Deposits (ITA 20(1)(m))	395	7,676,000		7,676,000
ITA 13(7.4) Election - Capital Contributions Received		8,996,458		8,996,458
Deferred Revenue - ITA 20(1)(m) reserve		1,115,205		1,115,205
Total Deductions		**22,637,670**	**0**	**22,637,670**
Net Income for Tax Purposes		**808,207**	**0**	**808,207**
TAXABLE INCOME		**808,207**	**0**	**808,207**

Original: B0 PILs, Tax Provision Bridge

PILS Tax Provision - Bridge Year

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate		Reference	Wires Only	
Regulatory Taxable Income						B1	$ 5,633,300	A
Ontario (Max 11.5%)	11.5%	11.5%	$ 647,830	11.5%	B			
Federal (Max 15%)	15.0%	15.0%	$ 844,995	15.0%	C			
Combined effective tax rate (Max 26.5%)							26.50%	D = B + C
Total Income Taxes							$ 1,492,825	E = A * D
Investment Tax Credits								F
Miscellaneous Tax Credits								G
Total Tax Credits							$ -	H = F + G
Corporate PILs/Income Tax Provision for Bridge Year							$ 1,492,825	I = E - H

Original: B1 Sch 1 Taxable Income Bridge

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	(A + 101 + 102)		3,558,240
Additions:			
Amortization of tangible assets	104		4,464,726
Recapture of capital cost allowance from Schedule 8	107	B8	0
Non-deductible meals and entertainment expense	121		5,505
Reserves from financial statements- balance at end of year	126	B13	186,918
Customer Deposits (ITA 20(1)(a))	295		7,676,000
Capital Contributions Received (ITA 12(1)(x))			65,088,473
Amortization expensed in Distribution expenses			110,901
Total Additions			**77,532,523**
Deductions:			
Capital cost allowance from Schedule 8	403	B8	5,237,706
Reserves from financial statements - balance at beginning of year	414	B13	142,732
Capital Lease Payments	395		124,909
Customer Deposits (ITA 20(1)(m))	395		3,040,000
ITA 13(7.4) Election - Capital Contributions Received			65,088,473
Deferred Revenue - ITA 20(1)(m) reserve			1,823,643
Total Deductions		calculated	**75,457,463**
Net Income for Tax Purposes		calculated	**5,633,300**
TAXABLE INCOME		calculated	**5,633,300**

Original: T0 PILs, Tax Provision Test

PILs Tax Provision - Test Year

							Wires Only	
Regulatory Taxable Income						T1	$ 702,384	A
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate				
Ontario (Max 11.5%)	11.5%	11.5%	$ 80,774	11.5%	B			
Federal (Max 15%)	15.0%	15.0%	$ 105,358	15.0%	C			
Combined effective tax rate (Max 26.5%)							26.50%	D = B + C
Total Income Taxes							**$ 186,132**	E = A * D
Investment Tax Credits								F
Miscellaneous Tax Credits								G
Total Tax Credits							**$ -**	H = F + G
Corporate PILs/Income Tax Provision for Test Year							**$ 186,132**	I = E - H S. Summary
Corporate PILs/Income Tax Provision Gross Up [1]					73.50%	J = 1-D	**$ 67,109**	K = I/J-I
Income Tax (grossed-up)							**$ 253,241**	L = K + I S. Summary

Original: T1 Sch 1 Taxable Income Test

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	2,874,895
Additions:			
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		5,076,455
Non-deductible meals and entertainment expense	121		5,515
Reserves from financial statements- balance at end of year	126	T13	186,918
Customer Deposits (ITA 20(1)(a))	295		3,040,000
Capital Contributions Received (ITA 12(1)(x))			24,260,348
Amortization expensed in Distribution expenses			110,901
Total Additions			**32,680,138**
Deductions:			
Capital cost allowance from Schedule 8	403	T8	4,994,314
Reserves from financial statements - balance at beginning of year	414	T13	186,918
Capital Lease Payments	395		117,136
Customer Deposits (ITA 20(1)(m))	395		3,040,000
ITA 13(7.4) Election - Capital Contributions Received			24,260,348
Deferred Revenue - ITA 20(1)(m) reserve			2,253,932
Total Deductions		calculated	**34,852,649**
NET INCOME FOR TAX PURPOSES		calculated	**702,384**
REGULATORY TAXABLE INCOME		calculated	**702,384**

Updated: H0 PILs, Tax Provision History

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

					Wires Only	
Regulatory Taxable Income				H1	$ 759,385	A
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	11.50%	B			
	Federal tax rate (Maximum 15%)	15.00%	C			
	Combined tax rate (Maximum 26.5%)				26.50%	D = B+C
Total Income Taxes					$ 201,237	E = A * D
Investment Tax Credits						F
Miscellaneous Tax Credits						G
Total Tax Credits					$ -	H = F + G
Corporate PILs/Income Tax Provision for Historical Year					$ 201,237	I = E - H

Updated: H1 Sch 1 Taxable Income History

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	(A + 101 + 102)	2,703,000		2,703,000
Additions:				
Interest and penalties on taxes	103	612		612
Amortization of tangible assets	104	3,535,178		3,535,178
Loss on disposal of assets	111	61,000		61,000
Charitable donations and gifts from Schedule 2	112	1,250		1,250
Non-deductible meals and entertainment expense	121	2,073		2,073
Reserves from financial statements – balance at the end of the year	126	142,732		142,732
Recapture of SR&ED expenditures	231	18,054		18,054
Customer Deposits (ITA 20(1)(a))	295	7,676,000		7,676,000
Capital Contributions Received (ITA 12(1)(x))		9,002,299		9,002,299
Amortization expensed in Distribution expenses		213,148		213,148
Amortization expensed of Capital Lease		30,000		30,000
Tax component of OCI		11,709		11,709
Total Additions		**20,694,055**	**0**	**20,694,055**
Deductions:				
Capital cost allowance from Schedule 8	403	4,661,942		4,661,942
Reserves from financial statements - balance at beginning of year	414	162,065		162,065
Capital Lease Payments	395	26,000		26,000
	395	7,676,000		7,676,000
ITA 13(7.4) Election - Capital Contributions Received		8,996,458		8,996,458
Deferred Revenue - ITA 20(1)(m) reserve		1,115,205		1,115,205
Total Deductions		**22,637,670**	**0**	**22,637,670**
Net Income for Tax Purposes		**759,385**	**0**	**759,385**
TAXABLE INCOME		**759,385**	**0**	**759,385**

Updated: B0 PILs, Tax Provision Bridge

PILS Tax Provision - Bridge Year

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate		Reference
Regulatory Taxable Income						B1
Ontario (Max 11.5%)	11.5%	11.5%	$ 646,831	11.5%	B	
Federal (Max 15%)	15.0%	15.0%	$ 843,692	15.0%	C	
Combined effective tax rate (Max 26.5%)						
Total Income Taxes						
Investment Tax Credits						
Miscellaneous Tax Credits						
Total Tax Credits						
Corporate PILs/Income Tax Provision for Bridge Year						

Updated: B1 Sch 1 Taxable Income Bridge

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	(A + 101 + 102)		3,558,240
Additions:			
Amortization of tangible assets	104		4,378,388
Non-deductible meals and entertainment expense	121		5,505
Reserves from financial statements- balance at end of year	126	B13	186,918
Customer Deposits (ITA 20(1)(a))	295		7,676,000
Capital Contributions Received (ITA 12(1)(x))			65,088,473
Amortization expensed in Distribution expenses			110,901
Total Additions			**77,446,185**
Deductions:			
Capital cost allowance from Schedule 8	403	B8	5,160,053
Reserves from financial statements - balance at beginning of year	414	B13	142,732
Capital Lease Payments	395		124,909
	395		3,040,000
ITA 13(7.4) Election - Capital Contributions Received			65,088,473
Deferred Revenue - ITA 20(1)(m) reserve			1,823,643
Total Deductions		calculated	**75,379,810**
Net Income for Tax Purposes		calculated	**5,624,615**
TAXABLE INCOME		calculated	**5,624,615**

Updated: T0 PILs, Tax Provision Test

PILs Tax Provision - Test Year

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate				Wires Only	
Regulatory Taxable Income							T1	$ 613,135	A
Ontario (Max 11.5%)	11.5%	11.5%	$ 70,511	11.5%	B				
Federal (Max 15%)	15.0%	15.0%	$ 91,970	15.0%	C				
Combined effective tax rate (Max 26.5%)								26.50%	D = B + C
Total Income Taxes								$ 162,481	E = A * D
Investment Tax Credits									F
Miscellaneous Tax Credits									G
Total Tax Credits								$ -	H = F + G
Corporate PILs/Income Tax Provision for Test Year								$ 162,481	I = E - H
Corporate PILs/Income Tax Provision Gross Up [1]						73.50%	J = 1-D	$ 58,582	K = I/J-I
Income Tax (grossed-up)								$ 221,062	L = K + I

Updated: T1 Sch 1 Taxable Income Test

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	2,870,840
Additions:			
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		4,980,878
Non-deductible meals and entertainment expense	121		5,515
Reserves from financial statements- balance at end of year	126	T13	186,918
Customer Deposits (ITA 20(1)(a))	295		3,040,000
Capital Contributions Received (ITA 12(1)(x))			24,260,348
Amortization expensed in Distribution expenses			110,901
Total Additions			**32,584,560**
Deductions:			
Capital cost allowance from Schedule 8	403	T8	4,983,930
Reserves from financial statements - balance at beginning of year	414	T13	186,918
Capital Lease Payments	395		117,136
Customer Deposits (ITA 20(1)(m))	395		3,040,000
ITA 13(7.4) Election - Capital Contributions Received			24,260,348
Deferred Revenue - ITA 20(1)(m) reserve			2,253,932
Total Deductions		calculated	**34,842,264**
NET INCOME FOR TAX PURPOSES		calculated	**613,135**
REGULATORY TAXABLE INCOME		calculated	**613,135**

c) Completed. See the updated PILs Model attached in 1-Staff-1.

Reference:

7-Staff-63

Load Profiles
Ref 1: Exhibit 8, Pages 12-13

Question:

InnPower indicated that if it were to update load profiles, it would use a methodology that requires at least three years of historical data. It discovered that it did not have the required data to complete the update at this time.

a) Did InnPower consider other methodologies for updating load profiles with different data requirements? Why were these either not considered or dismissed as options?
b) Please confirm that InnPower is gathering the required data on a go-forward basis, so that the data required will be available the next time it files a rebasing application.
c) Please explain why InnPower believes that a 19-year-old load profile would be a relevant basis for cost allocation today.

Response:

InnPower believes the intended reference in the interrogatory is Exhibit 7, pages 11-12 and has prepared the following responses on this basis.

a) As noted in Exhibit 7, page 12, "InnPower assessed available methodologies to prepare updated load profiles for its rate classes based on more recent data and is of the view that the most appropriate methodology is the Historical Average approach using weather-actual data outlined in section 2.7.1.1 of the Filing Requirements".

   In completing its assessment, InnPower analyzed the approach to load profiles utilized in all 2023 electricity distributor Cost of Service applications, with the exception of Hydro One and Hydro One Remote Communities. While some of the methodologies utilized had different data requirements than the 3-year actual data required for InnPower's preferred methodology, in several instances the settlement agreements for such methodologies explicitly did not endorse the methodologies used. Conversely, two electricity distributors received approval of settlements in which load profiles relied on the historical Hydro One load profile data, accompanied by commitments to transition to utility-specific load profiles in their next Cost of Service rates application.

As noted above, InnPower believes the establishment of current and utility-specific load profiles is most appropriately and accurately completed through the use of a Historical Average approach using actual hourly data; at minimum based on 3 years' data, and ideally 5 years. Alternative methodologies were dismissed by InnPower given the apparent lack of industry consensus on the appropriateness of these methodologies, and InnPower's willingness and ability to commit to implementing its more appropriate and preferred methodology for its next Cost of Service application.

b) Confirmed.

c) InnPower believes the load profiles included within its application, which have underpinned rates up to and including 2023, continue to be adequate as an interim solution until the completion of updated load profiles on the basis of a Historical Average in its next Cost of Service application. Of note, the OEB determined reliance on the Hydro One load profiles to be appropriate to inform just and reasonable 2023 electricity distribution rates in the recently completed EB-2022-0022 and EB-2022-0049 proceedings.

Reference:

8-Staff-65

Specific Service Charges
Ref 1: Exhibit 8, pages 18-21

Question:

InnPower is proposing to create new charges for Customer Initiated Disconnection and Reconnection. The charges levels are consistent with the charges for reconnection following a disconnection due to non-payment of the account.
InnPower indicates that it collected a total of $1,480 from eight work orders in 2022 and expects the same volume in 2023 and 2024.

a) Please provide a breakdown of forecasted revenue for each of the proposed new charges.
b) Is InnPower able to identify groups of customers that would typically be required to pay for disconnects or reconnects under the new proposed charges?
c) What steps has InnPower taken to attempt to engage customers about the proposed changes to disconnection and reconnection charges?

Response:

a) Please reference Exhibit 6, Table 6-33: After Hours Disconnect Inspect Reconnects (DIRs) Revenue (Exhibit 6, Tab 3, Schedule 1, Section 5). While these amounts show revenue collected, InnPower will not recover enough money to cover the cost of the disconnect and reconnect. The fee charged aligns with the rate for non-payment and helps to offset some of the costs experienced.
b) The GS>50 customers were not eligible for a free DIR. Customers requesting a DIR are given a quote and charged actual costs. The new charges will only apply to residential and GS<50 customers who either request more than one DIR in a calendar year or require a reconnect after operations hours.
c) InnPower has not engaged with customers at the moment as these charges need to be approved by the OEB in this application.

Reference:

8-Staff-66

Loss Factor

Ref 1: Exhibit 8 – Loss Adjustment Factor

Ref 2: Chapter 2 appendices – 2-R Loss Factor

Question:

InnPower stated that a complete CYME model was needed prior to the line loss study, and the results were not obtained before filing the current application.

a) Please provide an update on the status of InnPower's line loss study.
b) InnPower's total loss factor is trending upwards. Please provide an explanation of the increase in losses and how InnPower plans to address them?

Response:

a) InnPower's system model has now been updated in CYME however there is an insufficient amount of data to be used for the purposes of the full and accurate analysis. InnPower continues to gather the required data and is anticipated to complete the line loss study by the end of the year.
b) Since InnPower is one of the fastest growing utility companies in Ontario it is normal that the loss factor increases upward from the time when an incremental asset is added to the system to the time when it is fully loaded. However, InnPower will monitor this trend and continue to try to minimize the loss by running the load flow analysis in CYME and eliminating unnecessary losses from its system.

Reference:

8-Staff-67

Bill Impact Model
Ref 1: Bill Impact Model

Question:

In tab 6 of the bill impact model, InnPower includes a formula that applies the loss factor to a residential fixed rate rider (Cell J101).

a) Please correct the formula.

Response:

a) The reference in cell J101 refers to the disposition of the Group 2 account allocated to the residential rate class. As this rate rider is based on number of customers (as opposed to kWh), the rate rider is separated from that in row 96.

Reference:

8-Staff-68

CCA

Ref 1: Exhibit 9, Tab 1, Schedule 4, Table 9-11, page 39

Ref 2: 2024 DVA Continuity Schedule

Question:

In Reference 1, InnPower has indicated that it has tracked the full revenue requirement impact related to the Bill C-97 CCA rule change up to December 31, 2022, in Account 1592 sub-account as directed by the OEB.

Furthermore, InnPower has requested the disposal of a credit balance amounting to $1,008,488.

To support the balances in Account 1592, PILs and Tax Variances, Sub-Account CCA Changes, InnPower has provided the following Table 3 in Reference 1.

Table 3 (Table 9-11): Tax Variance

Year	Prior CCA ($)	Accelerated CCA ($)	Difference in CCA ($)	Difference in Grossed Up PILs ($)	Cumulative Difference in Grossed Up PILs ($)
2018	3,713,285	3,884,828	(171,543)	(61,849)	(61,849)
2019	3,689,587	3,932,369	(242,782)	(87,534)	(149,382)
2020	3,672,032	4,129,248	(457,216)	(164,847)	(314,229)
2021	3,803,064	5,106,841	(1,303,777)	(470,069)	(784,298)
2022	4,040,132	4,661,942	(621,810)	(224,190)	(1,008,488)
2023	4,646,650	5,237,706	(591,056)	(213,102)	(213,102)
2024	5,143,549	4,994,314	149,235	53,806	(159,296)

According to Reference 2, there are no carrying charges accrued in this account. The following Table 4 presents the account balances for Account 1592, PILs and Tax Variances, Sub-Account CCA Changes recorded in InnPower's 2024 DVA Continuity Schedule.

Table 4: DVA Continuity Schedule: Account 1592, Sub-Account CCA Changes

Years	Continuity Schedule Balances ($)	Continuity Schedule Cumulatives Balances ($)
2018	-	-
2019	(370,926.00)	(370,926.00)
2020	205,920.00	(165,006.00)
2021	(113,869.00)	(278,875.00)
2022	(729,613.00)	(1,008,488.00)

a) Please provide supporting schedules for the prior CCA amounts corresponding to the respective years provided in the table above.
b) The cumulative balance as of December 31, 2022, recorded in the DVA Continuity Schedules agrees with the supporting schedule (Table 3) provided by InnPower. However, the annual balances recorded in the Continuity Schedules differ from the supporting schedule. Please explain.
c) Please explain why InnPower did not accrue carrying charges on the balances in Account 1592, Sub-Account CCA Changes.
    i. Please record interest on the balances in the respective years using the prescribed interest rates set by the OEB.
    ii. Please record forecasted interests up to December 31, 2023 on December 31, 2022 balance using the prescribed interest rates set by the OEB.
    iii. Please update the applicable schedules as necessary.

Response:

a) Supporting schedules have been attached as ***Att 9-Staff-68 _1592_CCA_Changes_2018-2022***.
b) The accounting guidance for 1592 did not come out until after our 2018 audit and tax returns were filed; therefore, no entry was made in our 2018 financial statements. For 2019 and 2020, our auditors used a tax rate of 15.5% rather than 26.5%. When preparing the Application, InnPower discussed this with its auditors, and it was suggested to recalculate the amounts using the 26.5% tax rate for all years from 2018 to 2022.
c) According to the OEB letter dated July 25, 2019, re: Accounting Direction Regarding Bill C-97 and Other Changed in Regulatory or Legislated Tax Rules for

Capital Cost Allowance, there was no direction to create a sub-account for carrying charges. As such, InnPower did not calculate any interest that accrued on the principal balance in the 1592 account. However, InnPower has since clarified with OEB Staff that carrying charges are required. InnPower has provided the schedules in the attachment as ***Att 9-Staff-68_1592_Carrying_Charges***.

i. InnPower has set up a sub-account and recorded the interest in the respective years using the prescribed interest rates.
ii. InnPower will record forecasted interests up to December 31, 2023, on December 31, 2022, balance using the prescribed interest rates set by the OEB.
iii. InnPower has updated the applicable schedules as necessary as noted in c).

Reference:

8-Staff-69

CCA

Ref 1: Exhibit 9, Appendix 9-1-4 (A) – (G)

Ref 2: Chapter 2 Appendix 2-BA

Ref 3: Exhibit 6, Appendix 6-2-1 (A)-(F)

Ref 4: 2024 Income Tax PILs Workform

Question:

In Reference 1, InnPower has provided accelerated CCA calculations for the years 2018 through 2024. The costs of acquisitions recorded in the accelerated CCA calculations align with the amounts filed in the prior tax returns (Reference 3) and the PILs workform (Reference 4). However, OEB staff has identified discrepancies between the total PP&E additions recorded in Appendix 2-BA and the cost of acquisitions provided in Reference 1. The variances between the schedules are summarized in Table 5 below.

Table 5: Summary of Variances in PP&E Additions

Year	A. App 2-BA Total PP&E Additions	B. App 2-BA Property Under Finance Lease	C. Adjusted Total Additions (A-B)	D. Cost of Acquisitions (Reference 1)	Variances (C-D)
2018	4,066,548	-	4,066,548	4,115,289	$ (48,741)
2019	5,418,211	170,612	5,247,599	5,134,808	$ 112,791
2020	6,097,675	227,479	5,870,196	5,776,390	$ 93,806
2021	7,135,674	135,521	7,000,153	6,890,217	$ 109,936
2022	6,652,705	75,328	6,577,377	6,497,240	$ 80,137
2023	11,960,286	475,689	11,484,597	11,484,597	$ -
2024	9,120,000	-	9,120,000	9,120,000	$ -

a) Please explain the variances shown in the table above and update the applicable schedules as applicable.

Response:

a) These variations are attributable to capital lease agreements that are not reflected in Schedule 8. There are no schedule changes required as capital leases do not belong on Schedule 8. Capital lease transactions are shown separately on Schedule 1.

Reference:

9-Staff-70

CCA

Ref 1: Exhibit 9, Tab 1, Schedule 4, page 39

Ref 2: Exhibit 9, Tab 1, Schedule 3, Table 9-8, page 27

Question:

According to Reference 1, InnPower is requesting disposition of Account 1592, PILs and Tax Variances, Sub-Account CCA Changes balance as of December 31, 2022. Additionally, InnPower has indicated in Reference 2 to continue Account 1592, PILs and Tax Variance for 2006 and Subsequent Years.

Per Reference 2, OEB suggested applicants may propose a mechanism to smooth the tax impacts over the five-year IRM term given there may be timing differences that could lead to volatility in tax deductions over the rate-setting term. The OEB will assess an applicant's smoothing proposal on a case-by-case basis. If the OEB approves the smoothing proposal, the distributor's use of (or access to) Account 1592, to record the impacts of the specific CCA changes contemplated in the smoothing proposal, will no longer be applicable.

a) Please confirm if InnPower plans to record subsequent changes including the expected phase-out of accelerated CCA beginning in 2024 in Account 1592, PILs and Tax Variances, Sub-Account CCA Change.
b) Please explain if InnPower has considered smoothing out the tax impacts over the five-year IRM term for the CCA changes. If not, why not? Otherwise, please provide a proposed tax smoothing method.

Response:

a) During 2024 to 2028, InnPower will still utilize DVA Account 1592 - PILs and Tax Variances, Sub-account CCA Changes, but only to reflect the impact of any further changes of the current tax laws and rules governing CCA from the CCA rules that are currently anticipated for the phase out of accelerated CCA.
b) InnPower considered smoothing out the tax impacts over the 5-year IRM term for CCA changes, but with the phase-out of accelerated CCA also beginning in the 2024 Test Year, we decided not to proceed with a smoothing approach.

Reference:

9-Staff-71

Global Adjustment
Ref 1: 2024 GA Analysis Workform, Tab GA 2021
Ref 2: 2024 DVA Continuity Schedule, Tab 2a
Ref 3: 2024 GA Analysis Workform Instructions, 5) a), page 6

Question:

InnPower reported a credit amount of $102,784 for the Net Change in Principal balance in the General Ledger in Reference 1. This amount does not agree with the Transactions during 2022 amount of a debit balance of $57,812 in Reference 2. Additionally, InnPower included the approved 2020 disposition amount of a debit balance of $160,596 as part of the Reconciling Items (item #6) in Reference 1.
OEB staff notes that the variance in the 2022 transactions amount between the Reference 1 and Reference 2 agrees with the OEB approved disposition amount during 2022 ($160,596). This amount is reported as part of the Reconciling Items in Reference 2.
Page 6 of the 2024 GA Analysis Workform Instructions per Reference 3 provides guidance on the GA tab- Note 5 that the input amount in the Net Change in Principal Balance in the General Ledger should equal the GA transactions recorded in Account 1589 for this year. Therefore, this amount should not include dispositions.

a) Please update the GA Analysis Workform based on Reference 3 to exclude the approved disposition amount of $160,596.

Response:

a) InnPower has updated the GA Analysis Workform to exclude the approved disposition amount of $160,596.

Reference:

9-Staff-72

Deferral and Variance Account

Ref 1: InnPower 2022 2.1.7 Balance Sheet & Income Statement RRR Filing

Ref 2: 2024 DVA Continuity Schedule, Tab 2b

Question:

According to Reference 2, there is a variance of a credit balance of $135,881 between the 2.1.7 RRR and the Continuity Schedule for Account 1580, Sub-Account Deferred IFRS Transition Costs. OEB staff recognizes that InnPower has utilized the 2023 model for the 2024 application, which might cause potential mapping issues.

The credit balance of $135,881 mis-mapped to Account 1508, Sub-Account Deferred IFRS Transition Costs in the Continuity Schedule representing the combined total of Account 1508, Sub-Account OEB Cost Assessment Variance (a credit balance of $72,487) and Account 1508, Sub-Account Pole Attachment Revenue Variance (a credit balance of $66,198) based on InnPower's 2022 RRR Filing per Reference 1.

a) Please update the 2024 DVA Continuity Schedule and other applicable schedules utilizing the OEB published 2024 CoS schedules and models.
b) Please update the total requested disposition amounts for Group 2 accounts and supporting evidence as necessary.

Response:

a) InnPower has updated the 2024 DVA Continuity Schedule utilizing the OEB published 2024 CoS schedules and models.
b) Please note, the 1508 balance is still mis-mapped in the 2024 models, however, this does not affect the amount requested for disposition for the Group 2 accounts, as these amounts are captured in individual line items listed below.

   InnPower has updated the total requested disposition amounts for Group 2 and supporting evidence based on other items noted in the interrogatory responses. Please refer to 1-Staff-1 for a list of these changes.

Reference:

9-Staff-73

RCVA

Ref 1 : Exhibit 9, Table 1, Schedule 5, pages 42 and 43

Question:

On page 43 of Reference 1, InnPower states that: “There is an apparent downward trend in the number of retailer associated customers and consequently in the amount of revenue collected from the retailers derived from fees based on the number of transaction”.

Table 9-12 on page 42 of Reference 1 shows that the incremental expense that is reflected in RCVA 1518 has increased from $24k in 2017 to $67k in 2021.

a) Please explain why the incremental expense has increased significantly while the number of retailer-associated customers has decreased over the same period.

Response:

a) Upon further investigation, InnPower discovered labour billing costs outside of retailer transactions that were recorded to the retailer expense account in error.

   InnPower has assembled a conservative estimate of the retailer activities that occurred over the period of 2017 to 2022. The estimate was done based on the retailer activity and number of hours performed annually multiplied by the burdened hourly rate for each job position.

   Please refer to ***Att. 9-Staff-73_RCVA_Analysis*** for the detailed calculation of the updated principal and carrying charges balance for account 1518.
   InnPower is requesting disposition of the updated 1518 balance as follows:

	Principal	Carrying Charge (Historical 2017-2022)	Carrying Charges (Projected 2023)	Total
Prior 1518 Balance	$240,029	$11,584	$3,594	$255,207
Updated 1518 Balance	**$83,180**	**$8,687**	**$4,091**	**$95,958**
Difference	$156,849	$2,897	($497)	$159,249

School Energy Coalition (SEC) Interrogatories

Reference:

1-SEC-1

[Ex.1]

Question:

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

Response:

InnPower has not conducted any benchmarking studies, reports or analyses since its last rebasing application that have not already been included in the application.

Reference:

1-SEC-2

[Ex.1]

Question:

Please provide a copy of all documents that were provided to InnPower's Board of Directors in approving the underlying budgets contained in this Application.

Response:

All documents provided to the Board of Directors in approving the 2023 and 2024 budgets are attached as ***Att 1-SEC-2 2023_2024_IPC_Budget Attachment***, ***Att 1-SEC-2 2023_IPC_Budget_Attachment*** and ***Att 1-SEC-2_Updated_2024_Budget_Attachment***.

Reference:

1-SEC-3

[1-1-5, Table 1.5]

Question:

Please redo Table 1.5 starting from 2017 approved Operation, Maintenance &Administration (OM&A), instead of actual 2017.

Response:

Table 1.5 has been updated beginning with the 2017 approved Operation, Maintenance, and Administration (OM&A). Please see the table below.

Table 1-5: Estimate Impact of Inflation, Stretch Factor and Customer Growth on OM&A

Year	2017 OEB Approved	2017	2018	2019	2020	2021	2022	2023	2024
Inflation		1.2%	1.2%	1.5%	2.0%	2.2%	3.3%	2.5%	2.5%
Customer Growth*0.5		2.6%	2.6%	2.5%	1.0%	2.0%	2.1%	1.6%	1.6%
Stretch (Group3)		-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%
Total		3.5%	3.5%	3.7%	2.7%	3.9%	5.1%	3.8%	3.8%
Calculated ($000)	$ 5,143	$ 6,001	$ 6,211	$ 6,440	$ 6,611	$ 6,867	$ 7,216	$ 7,491	$ 7,777
							Applied for OM&A		$ 8,328
							Difference		-$ 551

Year	2017 OEB Approved	2017	2018	2019	2020	2021	2022	2023	2024
Customers/ Connections (2)	19,907	19,957	20,996	22,042	22,460	23,343	24,316	25,102	25,914
Growth Rate		0.25%	5.21%	4.98%	1.90%	3.93%	4.17%	3.23%	3.23%

Notes: (1) Assumes 2024 inflation is the same as 2023

(2) Source: Table 3-1: Summary of Load and Customer/Connection Forecast

Reference:

1-SEC-4

[1-1-5, p. 42 & Appendix 2-JB]

Question:

InnPower notes that it has changed its approach to vegetation management in 2021, which has added an additional $50k annually from 2020 to 2023.

a) Please reconcile this additional $50k annually with the $324k shown as an increase in 2021 for Vegetation Management in Appendix 2-JB.
b) What additional work or changes are being made in each of 2022, 2023 and 2024 for the additional $50k?
c) What has been the impact on reliability of this increased spending on vegetation management?
d) How many tree contacts has InnPower experienced to date in 2023?

Response:

a) InnPower had two vegetation management expense accounts and only one was picked up in the cost driver table. Appendix 2-JB has been updated to reflect both accounts.

Original 2-JB:

Appendix 2-JB
Recoverable OM&A Cost Driver Table[1,3]

OM&A	Last Rebasing Year (2017 Actuals)	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Bridge Year	2024 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance²	$ 5,316,777	$ 6,013,192	$ 5,782,891	$ 5,639,860	$ 6,263,124	$ 6,458,122	$ 7,024,754	$ 7,522,941
Salaries & Benefits		-$ 100,806	$ 175,485	$ 72,922	$ 203,247	$ 68,207	$ 187,692	$ 539,908
Employee Pensions and Benefits	$ 973	$ 4,470	-$ 99,134	$ 92,825	-$ 1,269	$ 11,044	$ 347	$ 4,800
COVID Related Expenses				$ 172,844	-$ 172,844			
Legal and Consulting Services	-$ 2,409	-$ 115,738	$ 71,720	$ 130,080	-$ 54,717	-$ 18,647	$ 134,800	-$ 44,000
Regulatory (Assessments and Awards)	-$ 2,780	-$ 4,284	$ 3,050	$ 2,584	-$ 13,051	$ 30,945	$ 28	$ 2,819
Regulatory Rate Application Costs	$ 309,525	-$ 83,506	-$ 169,465	$ 11,843	-$ 40,497	-$ 16,200	$ 11,887	-$ 11,536
IT and Cybersecurity	$ 3,244	$ 23,276	-$ 19,397	$ 8,595	$ 6,336	$ 86,674	$ 68,057	$ 6,822
Building and Office Supplies	$ 24,626	$ 59,416	-$ 46,503	$ 14,793	$ 7,453	$ 67,392	$ 72,618	-$ 3,384
Insurance	$ 16,632	-$ 7,737	-$ 1,380	$ 9,134	$ 18,899	$ 17,203	$ 11,546	$ 4,800
Community Relations	-$ 3,925	$ 66,316	-$ 24,028	$ 27,941	$ 27,796	-$ 5,439	$ 10,708	$ 4,174
Bad Debts	$ 44,681	-$ 11,655	-$ 61,576	$ 198,062	-$ 179,588	$ 353,271	-$ 292,070	$ -
Property Tax	-$ 31,525	$ 3,606	$ 10,132	$ 27,099	-$ 934	-$ 494	$ 6,566	$ 3,780
Vegetation Management	$ 2,131	-$ 11,624	$ 2,622	$ 4,728	$ 323,940	-$ 52,442	$ 15,590	$ 50,000
Cable Locates	-$ 21,603	$ 219	$ 10,518	$ 1,419	$ 40,102	$ 21,460	-$ 52,284	$ 50,000
Distribution Meters	$ 22,433	$ 5,558	-$ 13,964	-$ 13,450	$ 141,960	$ 62,102	$ 126,314	$ 14,397
Underground Distribution Lines & Feeders	$ 90,432	-$ 69,063	$ 25,134	$ 7,044	-$ 86,288	-$ 1,996	$ 24,764	$ 3,796
Engineering/Systems Operations	$ 88,812	-$ 19,785	-$ 59,455	-$ 249,366	$ 170,389	-$ 253,239	$ 61,788	$ 14,506
Other	$ 155,169	$ 31,036	$ 53,209	$ 104,167	-$ 195,936	$ 196,792	$ 109,836	$ 163,795
Closing Balance²	$ 6,013,192	$ 5,782,891	$ 5,639,860	$ 6,263,124	$ 6,458,122	$ 7,024,754	$ 7,522,941	$ 8,327,618

Updated: 2-JB:

Appendix 2-JB
Recoverable OM&A Cost Driver Table[1,3]

OM&A	Last Rebasing Year (2017 Actuals)	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Bridge Year	2024 Test Year
Reporting Basis								
Opening Balance²	$ 5,316,777	$ 6,013,192	$ 5,782,891	$ 5,639,860	$ 6,263,124	$ 6,458,122	$ 7,024,754	$ 7,522,941
Salaries & Benefits		-$ 100,806	$ 175,485	$ 72,922	$ 203,247	$ 68,207	$ 187,692	$ 539,908
Employee Pensions and Benefits	$ 973	$ 4,470	-$ 99,134	$ 92,825	-$ 1,269	$ 11,044	$ 347	$ 4,800
COVID Related Expenses				$ 172,844	-$ 172,844			
Legal and Consulting Services	-$ 2,409	-$ 115,738	$ 71,720	$ 130,080	-$ 54,717	-$ 18,647	$ 134,800	-$ 44,000
Regulatory (Assessments and Awards)	-$ 2,780	-$ 4,284	$ 3,050	$ 2,584	-$ 13,051	$ 30,945	$ 28	$ 2,819
Regulatory Rate Application Costs	$ 309,525	-$ 83,506	-$ 169,465	$ 11,843	-$ 40,497	-$ 16,200	$ 11,887	-$ 11,536
IT and Cybersecurity	$ 3,244	$ 23,276	-$ 19,397	$ 8,595	$ 6,336	$ 86,674	$ 68,057	$ 6,822
Building and Office Supplies	$ 24,626	$ 59,416	-$ 46,503	$ 14,793	$ 7,453	$ 67,392	$ 72,618	-$ 3,384
Insurance	$ 16,632	-$ 7,737	-$ 1,380	$ 9,134	$ 18,899	$ 17,203	$ 11,546	$ 4,800
Community Relations	-$ 3,925	$ 66,316	-$ 24,028	$ 27,941	$ 27,796	-$ 5,439	$ 10,708	$ 4,174
Bad Debts	$ 44,681	-$ 11,655	-$ 61,576	$ 198,062	-$ 179,588	$ 353,271	-$ 292,070	$ -
Property Tax	-$ 31,525	$ 3,606	$ 10,132	$ 27,099	-$ 934	-$ 494	$ 6,566	$ 3,780
Vegetation Management	$ 2,131	-$ 31,026	$ 99,416	$ 63,774	$ 93,560	-$ 43,751	$ 6,899	$ 50,000
Cable Locates	-$ 21,603	$ 219	$ 10,518	$ 1,419	$ 40,102	$ 21,460	-$ 52,284	$ 50,000
Distribution Meters	$ 22,433	$ 5,558	-$ 13,964	-$ 13,450	$ 141,960	$ 62,102	$ 126,314	$ 14,397
Underground Distribution Lines & Feeders	$ 90,432	-$ 69,063	$ 25,134	$ 7,044	-$ 86,288	-$ 1,996	$ 24,764	$ 3,796
Engineering/Systems Operations	$ 88,812	-$ 19,785	-$ 59,455	-$ 249,366	$ 170,389	-$ 253,239	$ 61,788	$ 14,506
Other	$ 155,169	$ 50,438	-$ 43,585	$ 45,121	$ 34,444	$ 188,100	$ 118,527	$ 163,795
Closing Balance²	$ 6,013,192	$ 5,782,891	$ 5,639,860	$ 6,263,124	$ 6,458,122	$ 7,024,754	$ 7,522,941	$ 8,327,618

b) InnPower is a primarily rural area with very dense areas of trees. The additional costs are to complete cycle trimming on a four-year cycle, with proper cutbacks/clearances, as well as Hazard Tree identification and removal.

c) InnPower completed cycle 3 in 2021 and to date there have been no tree contacts causing outages since then. There have been some outages due to high winds causing healthy trees to fall, but the program has had a direct benefit to reliability. InnPower has experienced similar results in our cycle 4 area completed in 2022, but only have this years' worth of data to show no outages as a direct cause of tree growth and branches.

Innisfil is also full of dead or dying Ash trees, which pose a significant threat to public safety and outages. InnPower is working with the Town to most effectively use our resources to deal with this issue.

d) To date, InnPower has had eight outages caused by tree contacts. Multiple events have been related to high winds causing healthy trees to uproot. Other outages have taken place in Cycle 1 and 2 areas which will be completed in 2023 and 2024.

Reference:

1-SEC-5

[1-1-5, p. 42 & Distribution System Plan (DSP) Appendix A]

Question:

InnPower refers to moving to Software as a Service (SaaS) and the effect this has on OM&A costs.

Is InnPower moving from purchasing its own software to a SaaS model? If so,

a) Please explain the increased capital spending shown in the Material Investment Narratives for IPCGP02 – IT Software and IPCGP01 – IT Hardware.
b) What investments in hardware/software have been or will be avoided as a result of this corporate decision, i.e., what is the avoided cost?
c) What has been and is forecasted to be the resulting dollar impact on OM&A?

Response:

The decision to leverage SaaS / Cloud solutions is made on a case-by-case basis with security, business requirements, compatibility, and cost-effectiveness as the primary considerations. The industry trend is to move to cloud solutions, with many vendors providing limited support to legacy on-premises versions of their systems.

a) We have increased future year's budgets to support the maturation and maintenance and continued improvement of IT infrastructure. InnPower has recognized the need to modernize, replace aging hardware and software, and improve redundancy of critical systems. All Initiatives support critical cyber security and disaster recovery objectives, as well as continuous quality improvement.
b) In a typical SaaS migration, we avoid the following costs:
    - Server Infrastructure, either physical or virtual machines are not required, saving both physical hardware and software licensing fees.

- Staff time, including the initial setup, ongoing time commitments to maintain security, system patches, data migration, system hardware, end-user support, and version upgrades.
- Infrastructure savings such as minimizing bandwidth requirements of office circuits and VPN servers are minimized as well as electricity costs.
- Most importantly we are avoiding the organizational costs of system downtime, overtime, and lost productivity.
- With a higher emphasis on system security, we are avoiding potential reputational and financial risks associated with cyber security breaches.

c) The industry trend has been moving more towards Cloud / SaaS solutions. As a result, it is expected that Capital costs will decrease with some of the costs impacting the OM&A budget. It is expected, however, that overall costs will decrease for individual solutions as the most cost-effective solutions that still meet business requirements will be selected moving forward.

Reference:

1-SEC-6

[1-1-5 Appendix (B) Scorecard]

Question:

a) Please file on the record InnPower's preliminary Scorecard for 2022, if the data is available.
b) If the Scorecard is not available, provide a preliminary Return on Equity for 2022.

Response:

a) Please refer to ***Att 1-SEC-6_2022_Scorecard_InnPower_Corporation***.
b) Please see response to part a).

Reference:

1-SEC-7

[1-1-5 Appendix C]

Question:

InnPower has provided a copy of its 2022 internal scorecard. Please provide a copy of each internal scorecard since 2017. Also, if available, please provide a preliminary copy of the 2023 internal scorecard.

Response:

Please refer to ***Att 1-SEC-7-Q2_2023_IPC_Internal_Performance_Scorecard*** for the June year to dated 2023 internal scorecard.
Please refer to ***Att 1-SEC-7_Q4_2021_IPC_Internal_Performance_Scorecard*** for the internal scorecard results from 2017 to 2021. There were no changes made to the Scorecard during this period, therefore, the 2021 scorecard reflects metrics from all of the years requested.

Reference:

1-SEC-8

[1-1-5 Appendix (D), Appendix 2-IB]

Question:

Please explain the differences in forecasted customer #s (i.e., higher) between the 2024 Outlook Customer Growth and Appendix 2-IB, e.g., 86 vs. 80 for the GS > 50 kW class.

Response:

The 2024 Outlook Customer Growth numbers were forecasted by InnPower's Engineering team during budget planning in the summer/fall of 2023 based on information about future development we had at the time.

Appendix 2-IB is taken from the load forecast model based on the OEB's methodology of using the geomean for ten years of historical customer data. Because the customer numbers for the GS>50 class have historically been declining, the growth in this customer class (up to the year 2024) was low.

Since updating the load forecast with 2023 year-to-date actuals, the number of GS>50 customers forecasted in 2024 increased to 86. In 2023, InnPower added one new GS>50 connection and five customers have transitioned from the GS<50 rate class to GS>50 rate class. As such, the rate of growth has increased the geomean for the GS>50 rate class, bringing the number of customers in Appendix 2-IB in line with the 2024 Outlook Customer Growth.

Reference:

1-SEC-9

[1-1-9, Table 1-25]

Question:

InnPower is proposing a new Embedded Distributor rate class for a current GS > 50 kW customer.

a) How did InnPower determine the costs allocated to this new class in Table 1-25?
b) InnPower states that ‘by creating an Embedded Distributor rate, HONI customers will see a decrease of $31.57 in monthly fixed charges and $0.6174 in monthly variable charges.’ What is the impact of this proposal on the remaining customers in the GS > 50 kW class? I.e., please calculate the rates for the GS > 50 kW class if the Embedded Distributor rate class is not created.
c) Were the customers in the GS > 50 kW class informed of this proposal? If so, what feedback was received?

Response:

a) The costs allocated to the new class in Table 1-25 were taken from the Cost Allocation Model. The costs for the embedded distributor rate class can be referenced in tab “01 Revenue to cost/RR” in Column M.
b) The updated models, which exclude the embedded distributor rate class will be available with 1-STAFF-1, on August 10, 2023.
c) Yes, Hydro One was informed of the proposal to create an embedded distributor class. InnPower did not receive any feedback from Hydro One, however they have applied for intervenor status in the current application.

Reference:

1-SEC-10

[1-1-11, p. 126-153]

Question:

Please provide the underlying spreadsheet (with formulas intact) used to undertake the calculations on pages 126-153.

Response:

Please refer to ***Att 1-SEC-10_IPC_Benchmarking_Analysis*** to find the underlying spreadsheets used to undertake the calculations on pages 126-253.

Reference:

1-SEC-11

[1-1-11, p. 160; IPC_2024_Benchmarking_Model_1-1-11_20230512]

Question:

Please reconcile the 2024 test year cost efficiency information contained in Table 1-47, which shows a cost performance of -5.1% (-5.6 three-year average), with that shown in the filed benchmarking model of 25.6% (14.08% three-year average).

Response:

The 2024 benchmarking model filed is based on InnPower's gross capital additions. However, InnPower believes that it was more appropriate to use net capital additions, given the large proportion of capital contributions being received in 2023 and 2024. As the contributions received will offset InnPower's costs, gross capital additions are not a true reflection of the financial impact on customers and the LDC's ability to manage costs. Please refer to page 60 of Exhibit 1 for reference to the net capital additions, as well as ***Att 1-SEC-11_IPC_2024_Benchmarking_Model*** for the updated results using net capital additions.

The differences between the two models can be found in the "Model Inputs" tab in row 9 and as indicated below:

	2022	2023	2024
Total Gross Capital Additions	$13,447,747	$49,005,861	$33,380,348
Total Net Additions	$4,375,962	$11,484,597	$9,120,000
Difference (Capital Contributions)	**$9,071,785**	**$37,521,264**	**$24,260,348**

Reference:

1-SEC-12

[1-1-12, p. 181]

Question:

Please provide a copy of the referenced Meyers, Norris, Penny LLP business process review and discuss any recommendations that InnPower did not implement.

Response:

As requested, please see the attached report ***Att 1-SEC-12_IPC_Business_Process_Review.***

MNP reviewed 36 processes in all. They prepared a current status assessment and classified prospective alterations as high, medium, and low based on an analysis. The majority of the recommendations for the processes that were assessed were implemented. The following recommendations were not carried out:

i. Manual matching of transformers (p.15) - This is a system limitation and will be something that will be considered with a new ERP.
ii. FAAC processing issues (p.15) - FAAC is a custom process developed by BDO for this industry. This system limitation will be considered with a new ERP.
iii. Information for building and vehicle maintenance (p.16) - our current ERP does not have this option but may be investigated in the future with the new ERP.
iv. Intercompany reconciliation (p.17) - this is a system limitation and will be something that will be considered with a new ERP.
v. Bank Reconciliation within GP (p.19) - we use GP's bank reconciliation feature for the affiliate companies but are unable to do so for InnPower currently due to the complexity of Harris integrations and report limitations within the CIS system. This will be investigated again with a new ERP.

Reference:

1-SEC-13

[1-1-12, p.190]

Question:

InnPower states that it “will conduct a detailed review of all department processes and procedures with a goal of reducing redundancy, improving department efficiency and ensuring that proper technology is deployed.” Please explain how, if at all, that the expected outcome of this detailed review has been incorporated into the test year budget.

Response:

InnPower will be undertaking this review in conjunction with the ERP system upgrade. The anticipated future savings will occur because of delaying or deferring the hiring of additional support staff due to the increased efficiency in the processes InnPower employs. There are no financial savings anticipated until the review and ERP implementation are completed which is expected to occur throughout 2023 and 2024. Over the past years and, as a result of COVID, InnPower has worked towards finding efficiencies in its processes and procedures. In most cases, as mentioned above, the efficiencies created did not seek to reduce costs but rather to allow for the deferral of hiring support staff. As part of InnPower’s strategic plan, InnPower is committed to find continuous improvements and efficiencies in its processes to improve productivity

Reference:

1-SEC-14

[1-2-1, p. 320 & 2-5-3, DSP, p. 14]

Question:

InnPower delivered a Cost-of-Service Customer Priorities Survey in order to establish what is most important to its customers.

a) Please provide a copy of the survey.
b) What information were the respondents given with respect to the cost of the various options when answering the survey?
c) Was InnPower's 2022 Customer Priority Survey developed in-house or by an external third party? If externally, what was the cost?
d) How did InnPower determine that the survey was statistically significant?
e) How did InnPower change its plans, subsequent to the results of the Customer Priority Survey?

Response:

a) A PDF copy of the survey is attached to this response ***Att 1-SEC-14_Customer_Priorities_Survey***.
b) There was no information provided on cost. We provided a list of options for customers to choose their top five priorities. We also asked which part of Innisfil they are from. InnPower's territory is made up of many hamlets, South Barrie and a resort, Friday Harbour. Priorities may vary throughout our territory, and it was important to understand our customer needs.
c) The survey was in-house at no extra cost with input from Regulatory, Operations, Customer Service and Communications.
d) The survey was determined to be statistically significant as the top five options selected were collectively chosen by a large majority of all respondents. There was not a small margin separating the various options, meaning the results of the survey clearly indicated respondents' top priorities.

The survey was offered to all InnPower customers in a variety of ways, including online, in-person, and on paper. The survey was also promoted via an array of channels including social media, bill inserts, bill messages, InnPower's website, and community events (MakerFest). To further these efforts, the survey was also sent via direct email to GS/Industrial/Commercial customers to be certain that they were also given a fair chance to participate. We did not target a specific or small percentage of customers, and in fact tried to reach as many and as wide of an array as possible to ensure a fair representation of our customer base.

Below is some other info that may support the statements above:
Total Responses Received – 150

- Responses from Online Efforts – 106
- Responses Received In-Person at MakerFest – 32
- Responses Received from Email to GS/Industrial/Commercial customers – 12 (sent to 235, resulting in a response rate of 5.1% for GS/Industrial/Commercial Customers.).

Top Priority Options Selected:

1. Affordable cost of electricity (92.67%)
2. Maintaining and upgrading equipment to ensure a safe and reliable electricity supply (80.00%)
3. Investing in storm hardening (physical improvements that can make utility infrastructure more resistant to weather (57.33%)
4. Improving electricity outage Response time (56.00%)
5. Two options tied for 5th
    - Better communication from InnPower when electricity outages occur (outage map, social media, etc.) (40%)
    - Investing in systems to accommodate new technologies (renewable energy generation, electric vehicles, charging stations, etc.) (40%)

Committed to engaging with customers, InnPower ran a Customer Priorities survey from August - October 2022. The survey established what is most important to our customers. Top priorities included price, reliability, communication, and investments in new technology. Using these results, InnPower's plan was established; making the changes customers want to see while ensuring that we continue to provide safe, reliable electricity distribution.

Our five-year plan will allow InnPower to maintain and improve reliability, service offerings and the overall customer experience, while ensuring costs are kept as low as possible. With customers at the forefront of what we do, the proposed plan is designed to provide benefits that align with the top priorities highlighted from the Customer Priorities Survey including:

- *Improved reliability (fewer and shorter outages, improved response times, severe weather resilience)*
- *Greater capacity to sustain population growth*
- *Enhanced customer experience and self-serve options*
- *Increased ability to connect new, renewable energy technologies to the grid*
- *More options for managing and monitoring energy use*
- *Lower costs, relative to other investment scenarios*

Reference:

2-SEC-15

[2-5-2, p. 72]

Question:

InnPower planned to introduce a new Enterprise Resource Planning system in 2023 with completion in 2024.

a) What is the total forecasted cost of the new system, for each year?
b) What is the status of implementation?

Response:

a) A new ERP system was forecasted in 2023 for $160k.
b) The new ERP implementation will be delayed until 2024.

Reference:

2-SEC-16

[2-5-2 Appendix (A), Appendix 2-AA]

Question:

In Exhibit 1, InnPower states that the 'philosophy of growth will pay for growth has guided InnPower in the development of its business plan, the DSP, and this entire Application. The average net capital expenditures for System Access have increased from $1,130k (2017 to 2022) to $1,853k (2023 to 2028) or 64% and total net capital expenditures from $4,365k (2017 to 2022) to $14,194k (2023 to 2028) or 225%. Please explain how this is in keeping with InnPower's growth pays for growth philosophy.

Response:

System Access investments are primarily attributed to the growth of the distribution system. Per the Distribution System Code (DSC), these 3rd party driven investments are subject to the economic evaluation or discounted cash flow (DCF) process whereby developers of individual developments must pay the shortfall between the total costs of the subdivision and what is recovered from rates.

With major developments such as the Hewitt and Salem lands with many individual landowners, InnPower has negotiated agreements that developers pay 100% of the non-subdivision costs ("spine works") including all poles, towers, fixtures, overhead lines, distribution station upgrades etc. With each individual subdivision being subject to the economic evaluation process.

InnPower is undertaking a similar process for developments occurring within a single, defined geographic area. For example, in Alcona, there are several developments that are ongoing. InnPower has encouraged the development community (Alcona Development Group) to enter into a similar spine works agreement for system investments for which they would all be responsible.

Finally, with respect to the bulk system investments, a large portion of the capital costs, $4.12M annually in 2024 through 2027 are directly attributable to capital contribution payments to Hydro One. Per the DSC, these growth costs are shared with all ratepayers.

Reference:

2-SEC-17

[2-5-2 Appendix (B), Appendix 2-AB]

Question:

With respect to Appendix 2-AB:

a) Please provide the basis for the 2017 to 2022 'plan amounts'.
b) Please provide the internal budgeted amounts for 2022 as determined at the beginning of 2022.

Response:

a) The plan amounts utilized in Appendix 2-AB for the years 2017 to 2022 are the approved amounts from InnPower's 2017 Cost of Service after the Technical Conference adjustments were made.

   We did not add a figure for 2022 because the Technical Conference only presented figures for 2017-2021.

b) The internal budgeted amounts for 2022 are as follows:

CATEGORY	Historical Period		
	2022		
	Plan	Actual	Var
	$ '000		%
System Access	29,867	3,856	-87.1%
System Renewal	13,334	8,042	-39.7%
System Service	3,723	503	-86.5%
General Plant	762	1,045	37.3%
TOTAL EXPENDITURE	47,685	13,447	-71.8%
Capital Contributions	- 40,472	- 8,996	-77.8%
NET CAPITAL EXPENDITURES	7,213	4,451	-38.3%
System O&M	$ 2,163	$ 2,318	7.2%

Reference:

2-SEC-18

[2-5-2 Appendix (B), Appendix 2-AB]

Question:

Appendix 2-AB shows planned capital versus actual/forecast capital spent over the period of 2017 to 2024. Please provide the following:

a) The actual spend to date for 2023.
b) The actual spend to date for the same period as provided for 2023 in part (a), for 2021 and 2022.

Response:

a) The actual capital spend through June 30, 2023, is provided in the table below in Appendix 2-AB format, as requested.
b) As requested, the actual capital spend for the same period in 2021 and 2022 is also presented in the table below.

CATEGORY	2021			2022			2023		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var
	$ '000		%	$ '000		%	$ '000		%
System Access	13,192	2,250	-82.9%	29,867	1,619	-94.6%	25,415	3,773	-85.2%
System Renewal	2,577	27	-99.0%	13,334	197	-98.5%	9,994	1,990	-80.1%
System Service	422	31	-92.6%	3,723	120	-96.8%	11,967	1,820	-84.8%
General Plant	706	-	-100.0%	762	9	-98.9%	1,155	478	-58.6%
TOTAL EXPENDITURES	16,897	2,308	-86.3%	47,685	1,944	-95.9%	48,530	8,061	-83.4%
Capital Contributions	- 11,129	- 1,885	-83.1%	- 40,472	- 2,849	-93.0%	- 37,046	- 3,486	-90.6%
NET CAPITAL EXPENDITURES	5,768	423	-92.7%	7,213	- 904	-112.5%	11,484	4,575	-60.2%

Reference:

2-SEC-19

[2-5-2 Appendix (B), Appendix 2-AB]

Question:

InnPower has over forecasted the gross capital expenditures and the contributed contributions for each year 2017 to 2021 resulting in an over forecasting of net capital expenditures in all years, except 2021.

a) How does InnPower forecast capital contributions for each of the four investment categories?
b) In 1-1-5 Appendix (D), InnPower lists each of its 2023 projects and the associated contribution. Please provide similar information for the 2024 capital budget.

Response:

a) InnPower forecasts capital contributions for each of the four investment categories as follows:
   i. Contributions are not common in General Plant projects.
   ii. System Access – Road authority contributions are typically 50% labour & labour saving devices. There are some cases, where due to new infrastructure being required to be replaced due to road authority works, and in this case are 100% recoverable.
   iii. System Access – Expansion projects – these types of projects are driven by growth and are 100% recoverable.
   iv. System Access - Subdivisions – average cost per connection based on the Economic Evaluation.
   v. Service Renewal – Contributions are not typical in this investment category unless there is an InnPower driven upgrade coupled with third party work.
   vi. SS - Contributions are not typical in this investment category unless there is an InnPower driven upgrade coupled with third party work.

b) Attached is a list of each of its 2024 projects and their accompanying contributions as requested. Please see ***Att 2-SEC-19_2024_Capital_Budget_Details***.

Reference:

2-SEC-20

[2-5-3, DSP, Table 5.2.14]

Question:

Defective equipment accounted for 24.2% of the total outages experienced by InnPower over the historical period. Please provide a breakdown of the Defective Equipment numbers in Table 5.2.15 by equipment type.

Response:

It is assumed the question is referring to table 5.2-14. Please refer to table 5.3-13 for Defective Equipment Outages by Asset Type in 2-5-3, DSP.

Reference:

2-SEC-21

[Appendix 2-5-3 DSP]

Question:

For each major asset type, please provide the number of assets replaced each year between 2017 and 2022 and forecast to be replaced in 2023 and 2024.

Response:

Please refer to Appendix 2-5-3 DSP, Material Narratives for Transformer, Pole, Switch, Recloser and Switchgear (Section 5 – Comparative Historical Expenditure), which provides the number of assets replaced each year between 2017 and 2022, as well as the forecast to be replaced in 2023 and 2024.

Reference:

2-SEC-22

[Appendix 2-5-3 DSP, p. 9 & Appendix 2-BA]

Question:

a) Please confirm the following information related to Construction Work in Progress (CWIP) obtained from Appendix 2-BA.

$000	2017	2018	2019	2020	2021	2022	2023	2024
CWIP opening	725	1,155	1,267	3,737	5,121	3,807	6,008	-
Change in CWIP	430	112	2,470	1,384	(1,314)	2,201	(6,008)	
CWIP closing	1,155	1,267	3,737	5,121	3,807	6,008	-	-

b) Please confirm that the capital expenditure numbers shown in Appendix 2-AB are actually capital in-service additions and include the above additions of CWIP to rate base. If this is correct, please provide a copy of Appendix 2-AB with capital expenditures. If not correct, please provide a copy of Appendix 2-AB with capital in-service additions.

c) At the end of 2023 the balance for CWIP is shown as zero in Appendix 2-BA. Page 9 of the DSP states 'The TS Project capital spending over the bridge and five-year forecast period will remain in Work in Progress (WIP) and will be addressed in InnPower's next rebasing application once the TS is energized.' $1,350k is shown in the bridge year as the budget for the TS Project. Please explain and adjust as necessary.

d) Are there any other projects which should be removed from in-service capital additions, as they will be CWIP?

Response:

a) The amounts in the chart above are CWIP and agree to what InnPower recorded in Chapter 2 Appendix 2-BA.

b) The capital expenditure numbers shown in Appendix 2-AB are capital in-service additions and do not include the above additions of CWIP to rate base.

c) The only project for the InnPower TS included in the 2023 Budget is the funding associated with an Environmental Assessment, which will be capitalized by the end of 2023.

d) There are no projects to be removed from in-service additions.

Reference:

2-SEC-23

[Appendix 2-5-3 DSP, p.65]

Question:

With respect to the METSCO Asset Condition Assessment:

a) Please provide a copy of the final report and/or deliverable provided by MESTCO.
b) Please explain how, if at all, METSCO uses age in the calculation of an assets Health Index.
c) Please provide in a single table, for each asset class/category, the number of assets by Health Index category, total number of assets, number of known assets with a Heath Index, number of assets where the Health Index was extrapolated, and Data Availability Indicator (DAI). Please also provide a copy of the table in Excel.

Response:

a) Please refer to Appendix J: 2021 Asset Conditions Assessment in Exhibit 2, Appendix 2-5-3 InnPower Distribution System Plan.
b) Please refer to Section 3.4.2: Use of Age as a Condition Parameter found in Appendix J: 2021 Asset Conditions Assessment of the Exhibit 2, Appendix 2-5-3 InnPower Distribution System Plan.
c) Please refer to Table 0-3: Asset Condition Assessment Overall Results found in Appendix J: 2021 Asset Conditions Assessment of the Exhibit 2, Appendix 2-5-3 InnPower Distribution System Plan. A copy of the table in excel is also attached as ***Att 2-SEC-23_part_c_ACA_Table***.

Reference:

2-SEC-24

[2-5-7, p. 93]

Question:

With respect to the proposal for a BATU Instalment Deferral Account:

a) Please confirm that under the OEB rate-setting policies, the only mechanism for additional capital funding for a utility on Price Cap IR is through the ACM or ICM.
b) Please confirm that the Applicant will have its rates set through Price Cap IR in each year of 2025, 2026 and 2027.
c) Please explain why under these circumstances, the Applicant believes that it should be granted a new rate-setting mechanism, as it has proposed, for each year of 2025, 2026, and 2027.

Response:

a) Confirmed; the only mechanisms available to utilities under a Price Cap IR rate-setting framework for incremental capital funding in rates is the ICM or ACM.
b) Confirmed; InnPower is seeking to establish rates for 2025 through 2028 through Price Cap IR rate-setting.
c) InnPower is not seeking approval of a new rate-setting mechanism, as its proposal will have no impact on rates in 2025, 2026 or 2027. InnPower is requesting approval of a new deferral account which will accumulate costs incurred by InnPower in the manner approved by the OEB in EB-2018-0117. InnPower will seek disposition of costs incurred in its next Cost of Service application.

Reference:

2-SEC-25

Exhibit 2, Tab 5, Schedule 7, p.93

Question:

The Applicant states "As more fully detailed in Table 2-47 below, the result of the OEB's ACM mechanism results in a material deficiency in revenue requirement due to the application of the maximum eligible incremental capital, driven in part due to the impact of high inflation and high growth rates on the arithmetic in the ACM model."

a) Please provide the Applicant's forecast revenue requirement for each year of 2025, 2026, and 2027, including all calculations and assumptions.
b) Please provide the Applicant's forecast base distribution and ACM rate rider revenue for each year of 2025, 2026, and 2027, including all calculations and assumptions.

Response:

a) InnPower has requested approval of a Price Cap IR rate-setting approach, as opposed to a Custom Incentive Regulation framework. As such, InnPower does not have a forecasted revenue requirement for the years beyond its 2024 Test Year, and cannot prepare a multi-year revenue requirement forecast within the time allotted for interrogatory responses.
b) InnPower has not forecasted base distribution revenues for the period beyond the 2024 Test Year, for the same reasons identified in a) above. Please see ***Att 2-Staff-39_BATU_Contribution_Revenue_Requirement_20230808*** to InnPower's response to Staff 39, which provides a multi-year revenue requirement associated with the BATU capital contributions under three scenarios; InnPower's proposed DVA approach, an ACM based on the OEB's 2023 inflation factor, and an ACM based on the OEB's 2024 inflation factor.

Reference:

3-SEC-26

Exhibit 3, Tab 1, Schedule 1, Table 3-17 & Appendix 2-IB

Question:

Please update the load forecast and customer numbers for the Bridge Year 2023 with actuals to date and revise the 2024 load forecast as required.

Response:

Please find as ***Att 3-SEC-26_IPC_Exhibit 3_LOAD FORECAST_20230808_rev2*** to this interrogatory response an updated load forecast model inclusive of 2023 Bridge Year year-to-date actuals. The updated load forecast incorporates customer/connection counts, wholesale power purchases, kWh consumption, and kW consumption up to the end of June 2023. Where 2023 year-to-date actual data has been incorporated, cells within the load forecast model have been coloured light blue. InnPower has relied on this updated Load Forecast for the purpose of updating all models associated with its 2024 Cost of Service application.

In analyzing 2023 year-to-date actual data to inform an updated load forecast, InnPower noted a significant increase in the number of customers in the GS >50kW rate class over the first half of 2023; rising from 79 in December of 2022 to 85 by June of 2023. Translated into an annualized growth rate, this indicates 15% growth in number of customers in 2023; higher customer growth in this rate class than any year in the 10-year historical period. Of the 6 new customers added to the GS >50kW rate class over the first half of 2023, five of them were customers transitioning from GS <50kW to GS >50kW. Of the five transitioning customers, 4 had previously been GS >50kW customers within the 10-year historical period.

Consistent with its obligations under Section 2.5.1 of the Distribution System Code, InnPower performs an annual reclassification of customers in the first half of the year. As a result of this reclassification exercise, five customers transitioned from GS<50kW to the

GS>50kW rate class. InnPower will not be doing another reclassification exercise until 2024

InnPower's load forecast methodology, consistent with the same or similar methodologies frequently presented to and approved by the OEB, relies on the most recent historical year's average kWh per customer by rate class for the purpose of forecasting both kWh and kW for each rate class in the Bridge and Test Year. This calculation is depicted in Exhibit 3, Table 3-10 and in tab Rate Class Energy Model, rows 21 to 23, columns H through N.

Left unaltered, this methodology generates inappropriate outcomes in the GS >50kW class when the five formerly GS <50kW customers are added to GS >50kW beginning in 2023. Specifically, exclusion of the five customers from the average kWh per customer calculation allows for a denominator which is too small (i.e. number of customers); increasing the average kWh per customer value for the GS >50kW rate class. When the five customers are added in 2023, this mathematically increases forecast 2023 kWh for the GS >50kW rate class by amounts well in excess of what the five customers' actual historical consumption would indicate.

To mitigate this inappropriate outcome, InnPower has adjusted all historical data such that the five transitioning customers are included within the customer count and kWh values across all years within the 10-year historical period (plus the first half of 2023). The adjustments made can be seen primarily in columns Z through AE of the Inputs Tab in the updated load forecast, with outputs seen in columns H and J. The result of this adjustment is that the average kWh per customer in both the GS <50kW and GS >50kW rate classes accurately reflects inclusion of these five customers in GS >50kW, given that this is known to be the case as of the first half of 2023.

Reference:

3-SEC-27

[3-1-1, p. 7]

Question:

InnPower states 'The regression analysis has been updated to include actual data to the end of 2022 and uses the same variables as those in InnPower's 2017 COS application.'

a) Please confirm that InnPower has not introduced a variable to adjust for any impacts due to COVID.
b) Why did InnPower not consider such a variable necessary?

Response:

a) Confirmed.
b) Please see response to 3-VECC-10.

Reference:

4-SEC-28

[4-1-1, Table 4-1]

Question:

Exhibit 1-1-5 page 99, InnPower states ‘2024 Test Year Operating Costs are $13.7M as shown in Table 4-1 above. The 2024 Test Year requested recovery is $0.1M greater than InnPower’s 2017 approved levels.’ Table 4-1 shows 2017 approved Operating Costs to be $8,289k. Please explain InnPower’s statement quoted above.

Response:

This statement is an error. It should read “InnPower’s 2024 Test Year Operating Costs are $13.7M as shown in Table 4-1 above. The 2024 Test Year requested recovery is $5.4M greater than InnPower’s 2017 approved levels and are a 0.8% increase from the 2023 Bridge Year.”

Reference:

4-SEC-29

[4-1-3, Table 4-7 & p. 49]

Question:

The OM&A associated with Distribution Meters has increased by $345k since 2017. The explanation for the increase provided on page 49 relates to the purchase of meters.

a) Is the acquisition of Distribution Meters considered an OM&A expense or a capital expense?
b) If OM&A, please explain why InnPower does not treat meters as a capital expense.
c) If capital, please provide an explanation of why Distribution Meters OM&A is increasing.

Response:

a) The acquisition of distribution meters is Capital. Please see the response in 4-Staff-47 for the correction.
b) Please see the response in a) above.
c) Please see the response in 4-Staff-47 for the correction.

Reference:

4-SEC-30

[4-1-3, Table 4-7 & p. 50]

Question:

The OM&A associated with 'Other' has increased by $618k since 2017. InnPower's explanation states 'The 'Other' category represents misc. changes in costs that allow the table to balance. These amounts are generally not material.' The total increase is material, so please provide more details of what makes up the increase in the 'Other' category.

Response:

Please see the table below for a more detailed breakdown of items included in 'Other'.

Program	2018 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Bridge Year	2024 Test Year
Station & Equipment Operating	75,142	(5,263)	3,806	52,627	(63,800)	38,718	16,971	(36,200)
Overhead Distribution Lines/Feeders	141,448	34,225	(34,612)	(6,182)	(33,947)	26,802	(25,260)	44,976
Customer Premise	15,142	(7,549)	(2,812)	(1,965)	1,673	505	6	0
Meter Testing	0	0	0	0	0	39,000	0	0
SMI/MDMR	0	1,296	3,128	6,197	(24,897)	(4,881)	(5,383)	1,750
Corporate Training	0	3,602	14,265	(28,869)	(5,248)	334	71,456	82,739
Donations	11,266	14,456	(18,585)	11,504	(5,950)	10,907	(3,098)	0
Miscellaneous	(87,828)	(9,731)	88,018	70,855	(63,766)	85,407	55,144	70,520

Most of the variances are immaterial, but some comments are as follows:

- Year-over-year variances in distribution programs are attributed to various factors, such as the number of trouble calls, etc.
- Variances in corporate training from 2021 over 2020 was due to covid restrictions and lock downs.
- The SMI/MDMR variance from 2021 over 2020 was due to the implementation of the Utilismart RSVA Risk Manager, Settlement Services and Utility Data Manager. The SMI/MDMR costs are included in the monthly fees to Utilismart.
- The 2023 and 2024 budgets include amounts for corporate development and training to support the strategic plan goals.

Reference:

4-SEC-31

[4-1-4 Appendix (A), Appendix 2-JA]

Question:

Please provide year to date actuals for 2023, as per Appendix 2-JA and equivalent year to date OM&A numbers for 2021 and 2022.

Response:

Please see the table below (in Appendix 2-JA format) 2023 year-to-date actuals, as well as corresponding year-to-date actuals for 2021 and 2022, as requested.

Program	2021 Actuals	2022 Actuals	2023 Actuals
Reporting Basis	MIFRS	MIFRS	MIFRS
Operations	691,232	651,537	693,793
Maintenance	367,215	359,678	420,027
Subtotal	**1,058,446**	**1,011,216**	**1,113,820**
%Change (year over year)		-4.5%	10.1%
%Change (Test Year vs Last Rebasing Year - Actual)			
Billing and Collecting	545,367	612,205	624,889
Community Relations	55,571	44,300	87,861
Administrative and General	1,422,907	1,546,611	2,227,468
SubTotal	**2,023,844**	**2,203,116**	**2,940,218**
%Change (year over year)		8.9%	33.5%
%Change (Test Year vs Last Rebasing Year - Actual)			
Total	**3,082,291**	**3,214,331**	**4,054,037**
%Change (year over year)		4.3%	26.1%

Reference:

4-SEC-32

[4-1-6, p. 109]

Question:

InnPower notes that ‘Beginning in 2024, InnPower, InnServices and InnTerprises will begin streamlining Human Resources under one department, leading to economies of scale for employees and a more efficient department.’ What reductions in costs has InnPower forecasted that will result from this streamlining, and point to where we can see this in the application?

Response:

By streamlining services with affiliate organizations, InnPower will have the ability to develop HR Programs and Services that may not be otherwise feasible for an organization of InnPower’s size. Streamlining services will lead to reduced administrative time for the Human Resources team by being able to invest in systems that can help automate tasks and more time spent on adding value and positively impacting the organization. While these may not be direct savings initially, investments will lead to positive impacts for employees and ultimately customers.

Reference:

4-SEC-33

[4-1-6, Table 4-34 & p. 127]

Question:

InnPower plans to add 10.13 and 6.41 new FTEs in 2023 and 2024 respectively.

a) What is the status of the hiring for 2023?

b) InnPower lists the BATU as one of the drivers for these new positions. InnPower will be providing a capital contribution to Hydro One for this work. What work will be required by InnPower specifically?

c) On page 138, InnPower states that it has experienced several high-profile retirements in key areas over the past few years. How is this related to the incremental addition of 16.54 FTEs?

d) InnPower states that 'Three of these staff (Human Resources, Information Technology, Stockkeeper) will be fully cost shared with InnPower's non-regulated Affiliate (InnServices)'. Please indicate where on Appendix 2-N, this increase in allocations can be seen.

Response:

a) Currently, hiring of additional FTEs are as follows:

- Customer Service Supervisor - Hired
- Accounting Supervisor – Hired
- Metering Supervisor – Hired
- Distribution Engineer – Hired
- Power Systems Engineer – Hired
- Co-Op Students in Operations, Engineering and Customer Engagement (Summer 2023) – Hired
- Part Time Employees in Customer Service and Accounting – Hired
- Control Room Operator – Not Hired
- Customer Engagement student (Fall 2023) – Not Hired
- Protection & Control Technologist – Not Hired

b) In order to connect BATU to the InnPower service territory it is required to expand distribution feeders work such as planning, design, procurement, project management, coordination with HONI (Hydro One), construction and complete any financial accounting requirements and administration as needed. This work would affect multiple departments at InnPower.

c) High-Profile retirements do not relate to the incremental addition of 16.54 FTEs. This section refers to vacancies that have been created and contributes to the overall picture of hiring at InnPower.

d) This increase in allocations can be seen in Financial labour in Appendix 2-N under Shared Services.

Reference:

4-SEC-34

[4-2-1, p187; 9-1-1, p. 14-15]

Question:

With respect to the audit of affiliate services:

a) Please provide a copy of the audit report.
b) Please provide a copy of the Assurance of Voluntary Compliance (AVC) that was issued on April 26, 2019.
c) Please provide a detailed list of changes made as a result of the findings and recommendations in the audit and the AVC.

Response:

a) Please refer to ***Att 4-SEC-34a_IPC_2018_Affiliate_Transactions_OEB_Inspection_Report_20190131*** for a copy of the audit report
b) Please refer to ***Att 4-SEC-34b_InnPower Ltr_Assurance of Voluntary Compliance_20190426*** for a copy of the Assurance of Voluntary Compliance (AVC) that was issued on April 26, 2019.
c) IPC has made the following changes as a result of the findings and recommendations in the audit and the AVC.
    a. InnPower's pricing methodology for services provided to affiliates is based on market price or fully allocated cost, as required by the ARC.
        i. More specifically InnPower:
            1. Determined whether a market price or fully allocated cost was the appropriate pricing methodology for each affiliate service and determined the amount (Exhibit 4, Tab 2, Schedule 1, Section 5).
            2. Included a return on invested capital in its calculation of fully allocated cost based on the current weighted average cost

of capital 5.58% (Exhibit 4, Tab 2, Schedule 1, Section 10.3.2).

3. Eliminated the 15% administrative fee that was not required under the ARC (Exhibit 4, Tab 2, Schedule 1, Section 10.3.1).
4. Conducted a market rate study for rental rates, which provides escalated rates up to the year 2025 (Exhibit 4, Tab 2, Schedule 1, Section 5.3).

b. InnPower costed the services provided to its affiliates on a fully allocated basis, as required by the ARC and the OEB's Accounting Procedure Handbook.
    i. More specifically:
        1. InnPower has utilized actual costs (instead of a mix of actual and budgeted noted in the 2017 submission).
        2. Determined costs on a fully allocated basis including both direct and a proportion of indirect costs (instead of incremental costs noted in the 2017 submission).
        3. Included depreciation expense, in addition to all other overhead expenses to determine indirect costs (Exhibit 4, Tab 2, Schedule 1, Section 9).
        4. Determined an appropriate method of cost allocation for each indirect cost that is reasonable and justified (Exhibit 4, Tab 2, Schedule 1, Section 6).
        5. Developed a methodology to allocate billing service costs between the various services (i.e., electricity, water, wastewater, etc.) (Exhibit 4, Tab 2. Schedule 1, Section 10).

c. Developed new service agreements that include all the terms specified in Section 2.2.1 of the ARC including cost allocation mechanisms, confidentiality arrangements, apportionment of risks and a dispute resolution process.
d. Established a process for management review to ensure ongoing compliance with the ARC (Exhibit 4, Tab 2, Schedule 1, Section 14).
e. Recorded costs in the appropriate OEB Accounting Procedure Handbook General Ledger account for affiliate services.

f. Completed an annual true-up of fully allocated costs following the financial audit. The variance from what was charged to the affiliate during the year is recovered or refunded (Exhibit 4, Tab 2, Schedule 1, Section 13).

Reference:

4-SEC-35

[4-2-1, p.190]

Question:

Please provide a copy of the shared services agreements with each of InnPower's affiliates.

Response:

Shared services agreements between InnPower and InnTerprises, InnPower and InnServices and InnPower and The Town of Innisfil have been provided as ***Att 4-SEC-35_InnPower_InnServices_shared_service_agreement_May_2023***, ***Att 4-SEC-35_InnPower_InnTerprises_shared_services_agreement_May_2023*** and ***Att 4-SEC-35_InnPower_Town_of_Innisfil_shared_services_agreement.***

Reference:

4-SEC-36

[4-2-4, Table 4-61]

Question:

InnPower has included $314k of one-time costs related to this application in its Regulatory Costs. This includes $44k in 2021, which is composed of $5k for an OEB penalty and $39k for consultants.

a) InnPower has stated that it 'will also not be seeking recovery of these AVC expenses in 2024 rates.' Please explain why the $5k was included.
b) Please provide details of what the $39k for consultants entails.

Response:

a) Please refer to response 4-Staff-59.
b) The $39k consultant fees were for:
    i. Asset condition assessment
    ii. Preliminary consultation work on the Distribution System Plan

Reference:

5-SEC-37

[5-1-1, p. 10]

Question:

InnPower has provided reasons why its actual ROE in 2022 has exceeded the deemed ROE built into its rates. Please explain how the increases in OM&A costs outlined and the increases in PP&E, which are not yet built into rate base, have contributed to this over-earning.

Response:

Increases in OM&A and PPE did not contribute to over-earning. If they had not increased, the ROE would have been significantly higher.

Reference:

5-SEC-38

[5-1-1, p. 14]

Question:

InnPower anticipates an additional CAPEX Loan with TD Bank in the 2023 Bridge Year in the amount of $2,189,040 and the 2024 Test year in the amount of $5,284,649.

a) Has InnPower finalized the 2023 loan? If so, please provide the details.
b) Did InnPower explore sourcing the 2024 loan through Infrastructure Ontario? If not, why not? If so, what were the results?

Response:

a) InnPower has not finalized a loan for its 2023 CAPEX funding. The need for borrowing will continue to be monitored throughout the year, but we do not anticipate borrowing $2,189,040 in 2023; therefore, the 2023 and 2024 schedules have been updated below to reflect this.

Original: Appendix 2-OB - 2023

Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,416,801	2.70%	$ 65,254
TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,655,854	5.27%	$ 139,964
TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov23	10	$ 2,191,326	4.59%	$ 100,582
TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-14	10	$ 1,604,074	3.96%	$ 63,521
TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-14	10	$ 1,619,022	3.91%	$ 63,369
TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,617,075	3.68%	$ 59,508
TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,723,518	2.88%	$ 280,037
TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,453,588	3.48%	$ 85,385
TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,648,500	3.60%	$ 95,346
TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,505,817	4.09%	$ 61,588
TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,176,017	3.28%	$ 71,373
TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,431,931	2.45%	$ 59,582
Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033
TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 907,019	1.92%	$ 17,415
2022 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-23	15	$ 2,189,040	5.00%	$ 109,452
						$ 36,472,914	3.52%	$ 1,285,409

Original: Appendix 2-OB - 2024

Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) 2	Interest ($) 1
TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,218,160	2.70%	$ 59,890
TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,506,102	5.27%	$ 132,072
TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov-23	10	$ 2,088,716	4.59%	$ 95,872
TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-24	10	$ 1,552,634	3.96%	$ 61,484
TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-24	10	$ 1,568,095	3.91%	$ 61,375
TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,565,516	3.68%	$ 57,611
TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,392,408	2.88%	$ 270,501
TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,378,844	3.48%	$ 82,784
TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,573,529	3.60%	$ 92,647
TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,469,359	4.09%	$ 60,097
TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,121,541	3.28%	$ 69,587
TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,343,764	2.45%	$ 57,422
Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033
TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 781,584	1.92%	$ 15,006
2022 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-23	15	$ 2,080,943	5.00%	$ 104,047
2023 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-24	15	$ 5,284,649	5.00%	$ 264,232
						$ 40,259,177	3.72%	$ 1,497,662

Updated: Appendix 2-OB – 2023

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) 2	Interest ($) 1	Additional Comments, if any
1	TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,416,801	2.70%	$ 65,253.63	
2	TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,655,854	5.27%	$ 139,963.50	
3	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov-23	10	$ 2,191,326	5.00%	$ 109,566.31	
4	TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-14	10	$ 1,604,074	3.96%	$ 63,521.31	
5	TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-14	10	$ 1,619,022	3.91%	$ 63,368.51	
6	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,617,075	3.68%	$ 59,508.35	
7	TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,723,518	2.88%	$ 280,037.32	
8	TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,453,588	3.48%	$ 85,384.88	
9	TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,648,500	3.60%	$ 95,345.99	
10	TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,505,817	4.09%	$ 61,587.90	
11	TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,176,017	3.28%	$ 71,373.37	
12	TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,431,931	2.45%	$ 59,582.30	
13	Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033.34	
14	TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 907,019	1.92%	$ 17,414.77	
15	2022 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-23	15				
Total							$ 34,283,874	3.46%	$1,184,941.47	

Updated: Appendix 2-OB - 2024

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) 2	Interest ($) 1	Additional Comments, if any
1	TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,218,160	2.70%	$ 59,890.32	
2	TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,506,102	5.27%	$ 132,071.59	
3	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov-23	10	$ 2,088,716	5.00%	$ 104,435.81	
4	TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-24	10	$ 1,552,634	5.00%	$ 77,631.68	
5	TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-24	10	$ 1,568,095	5.00%	$ 78,404.75	
6	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,565,516	3.68%	$ 57,610.99	
7	TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,392,408	2.88%	$ 270,501.35	
8	TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,378,844	3.48%	$ 82,783.77	
9	TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,573,529	3.60%	$ 92,647.04	
10	TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,469,359	4.09%	$ 60,096.80	
11	TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,121,541	3.28%	$ 69,586.53	
12	TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,343,764	2.45%	$ 57,422.22	
13	Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033.34	
14	TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 781,584	1.92%	$ 15,006.40	
15	2022 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-23	15				
16	2023 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-24	15	$ 5,284,649	5.00%	$ 264,232.45	
Total							$ 38,178,234	3.76%	$1,435,355.04	

b) Banking and borrowing arrangements are reviewed annually. Other lenders are considered as part of this process.

Reference:

6-SEC-39

[6-3-1, Table 6-10]

Question:

Please provide year-to-date Other Revenue in the same format as Table 6-10 and provide the same information for the same period for 2021 and 2022.

Response:

Please see the table below (in Table 6-10 format) 2023 year-to-date actuals, as well as corresponding year-to-date actuals for 2021 and 2022, as requested.

USoA #	USoA Description	2021 Actual	2022 Actual	2023 Actuals
		2021	**2022**	**2023**
	Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**
4082	Retail Services Revenues	-$ 9,164	-$ 7,322	-$ 6,482
4086	SSS Admin Charge (SSS)	$ -	-$ 34,402	
4210	Rent from Electric Property	-$ 140,996	-$ 143,971	-$ 146,126
4225	Late Payment Charges	-$ 54,687	-$ 77,554	-$ 53,462
4235	Miscellaneous Service Revenues	-$ 70,209	-$ 85,900	-$ 99,071
4245	Deferred Revenue	-$ 431,166	-$ 504,566	-$ 610,354
4355	Gain on Disposal of Property	-$ 3	$ 6,659	$ 5,175
4375	Revenues from Non-Utility Operations	-$ 763,455	-$ 309,317	-$ 647,313
4380	Expenses of Non-Utility Operations	$ 556,334	$ 410,064	$ 435,450
4385	Non-Utility Rental Income	-$ 55,451	-$ 66,441	-$ 74,397
4390	Miscellaneous Non-Operating Income	-$ 20,237	-$ 1,607	-$ 11,902
4405	Interest and Dividend Income	-$ 21,720	-$ 36,389	-$ 294,513
Miscellaneous Service Revenues		-$ 70,209	-$ 85,900	-$ 99,071
Late Payment Charges		-$ 54,687	-$ 77,554	-$ 53,462
Other Operating Revenues		-$ 581,325	-$ 690,261	-$ 762,962
Other Income or Deductions		-$ 304,531	$ 2,970	-$ 587,500
Total		-$ 1,010,751	-$ 850,745	-$ 1,502,995

Reference:

9-SEC-40

[9-1-3, p. 29]

Question:

With respect to Account 1508 –Vegetation Management:

a) Please forecast amounts that would be invoiced to pole attachers for 2023.
b) For 2024, where would vegetation management revenue appear in the calculation of the revenue requirement?

Response:

a) The amount estimated to be invoiced to Rogers Communication in 2023 for vegetation management is estimated to be in the range of $19,000 to $19,500.
b) For 2024, the vegetation management revenue is included in "Other Revenue" under APH account 4235 (Exhibit 6, Tab 6, Schedule1, Table 6-25).

Reference:

9-SEC-41

[9-1-4, p. 39]

Question:

With respect to Account 1592:

a) Please provide similar Appendices that show the CCA for each year between 2018 and 2024 using the 'Prior Rules' (non-AII CCA rules).
b) Please provide the forecast balance of the account through to the end of 2023.
c) The Applicant has included in Table 9-11, the 2024 forecast balance of the account which includes a debit entry. Please explain what the 2024 calculation reflects.

Response:

a) Please see the attachment included in 9-Staff-68.
b) The table below shows the forecasted balance of the account through the end of 2023 as requested.

Year	Prior CCA	Accelerated CCA	Difference in CCA	Difference in Grossed Up PILs	Cumulative Difference in Grossed Up PILs
2018	3,713,285	3,884,828	(171,543)	(61,849)	(61,849)
2019	3,689,587	3,932,369	(242,782)	(87,534)	(149,382)
2020	3,672,032	4,129,248	(457,216)	(164,847)	(314,229)
2021	3,803,064	5,106,841	(1,303,777)	(470,069)	(784,298)
2022	4,040,132	4,661,942	(621,810)	(224,190)	(1,008,488)
2023	4,620,766	5,160,053	(539,287)	(194,437)	(1,202,925)
2024	5,105,575	4,994,314	111,261	40,115	40,115

c) The debit entry shown for 2024 in Table 9-11 reflects a reversal of the timing differences between CCA for tax purposes and deprecation for accounting purposes. As the AIIP allowed for larger CCA deductions up front, when assets depreciate, these amounts begin to be smaller than the depreciation for accounting purposes.

In addition, the Accelerated Investment Incentive (Bill C-97) will begin phasing-out for property that becomes available for use after 2023. The 1.5 factor applied to the prescribed CCA rate used for eligible property acquired after November 20, 2018 through the end of 2022 will decrease reversal of timing differences also the factor goes from 1.5 to 1.0 in 2024.

Vulnerable Energy Consumers Coalition (VECC) Interrogatories

Reference:

1.0-VECC-1

Exhibit 1, Tab 1, Schedule 4/ Exhibit 4, Tab 1, Schedule 3

Question:

"….*an AVC was issued on April 26, 2019 (EB-2019-0090) with a penalty of $25,000, as a result of violations to the Affiliate Relationship Code. InnPower assures that it has taken measures to remedy the contravention of the ARC and prevent contravention of those provisions*."

Please explain the nature of the contravention of the ARC and the measures that were subsequently taken to remedy this violation.

Response:

For the nature of the contravention of the ARC, please refer to response ***Att. 4-SEC-34b_InnPower_Ltr_Assurance_of_Voluntary_Compliance_20190426***
For the measures that were subsequently taken to remedy this violation, please refer to response 4-SEC-34c.

Reference:

1.0-VECC-2

Exhibit 1, Appendix 1-1-5

Question:

a) Please update the distribution scorecard to include 2022 results.

b) InnPower over earned its approved regulatory return in every year between 2018-2021. In 2017 it significantly underearned. Please explain the reasons for the underearning in 2017.

c) Appendix 2-AB shows that InnPower significantly underspend its total capital expenditure (Plan vs Actual) in every year 2018-2021 in which it reported earnings above the regulated set amount. During the upcoming rate plan period the Utility proposes to spend on a total basis significantly more than it has in the past. Please explain why it would not be correct to extrapolate from these facts that the Utility did not meet is regulatory compact of the prior DSP and is now seeking to recover its underspending on capital over the new rate plan period by accelerated investment plans.

Response:

a) Please reference ***Att. 1.0-SEC-6_2022_Scorecard_InnPower_Corporation*** for the distribution scorecard that includes 2022 results.

b) As a result of a delay in the effective date for rates in 2017, InnPower incurred significant expenses for its Cost of Service application in 2017 and did not collect rebased rates until mid 2018. As a result, the return on equity was lower than expected.

c) Past performance is not a reflection of future performance in this case for several reasons. First, during this period, InnPower experienced a higher than usual turnover in its critical operational management positions. New management identified a concern around capital underspending in the middle of the period and InnPower successfully began to scale up in 2020 to meet the approved overall $4.4M annual average over the period.

Further, much of the requested capital expenditure is related to growth and is not discretionary in nature. This means that since most of these projects are driven by or for third parties, InnPower must continue to meet its capital expenditure targets for growth to continue in the Town of Innisfil and South Barrie – a commitment it does not take lightly.

Over the last couple of years, InnPower has gained a reputation for meeting and exceeding its commitments to key stakeholders including municipalities, developers, and customers. InnPower has been able to successfully scale staffing and contracts with third-party contractors to help facilitate significant growth in the area. Coupled with improved processes and paperless workflows, InnPower continues to be equipped to properly handle the increase in capital expenditure.

Reference:

1.0-VECC-3

Exhibit 1, Appendix 1-2-1

Question:

Please provide a sample of the InnPower the old bill format that is being replaced by the Bill design shown at Appendix 1-2-1.

Response:

As requested, InnPower's old bill format is shown below.

Account Number	XXX-XXXXXX-XX
Amount Due	$225.70
Due Date	January 24, 2020
Amount Paid	

JANE DOE
JOHN DOE
123 HYDRO LANE
INNISFIL ON L9S 0J3

Account Number	XXX-XXXXXX-XX
Name	JANE DOE
Service Address	123 HYDRO LANE
Electric Account Type	RESIDENTIAL
Water Account Type	RESIDENTIAL SERVICE

Amount Due	225.70
Due Date	January 24, 2020
Payment Type	PLEASE PAY BY DUE DATE
Bill Date	January 08, 2020
Bill Type	FINAL BILL

CONSUMPTION HISTORY

Month	Days	Electric Use (kWh)	Elec. Usage per Day	Water Use m3	Water Usage per Day
11-19	38	644	17	17	0
10-19	31	357	12	13	0
09-19	30	408	14	15	1
08-19	31	514	17	17	1
07-19	31	627	20	16	0
06-19	30	426	14	14	0
05-19	31	370	12	16	1
04-19	30	385	13	14	0
03-19	31	510	16	16	1
02-19	28	462	17	15	1
01-19	31	527	17	20	1
12-18	31	515	17	19	1
11-18	30	470	16	15	1

BILLING SUMMARY

Previous Balance as of 2018-11-22	$163.36
Payments as of 2020-01-08	($163.36
Adjustments as of 2020-01-08	$0.00
Interest Charges as of 20-01-08	$0.00
Balance Forward as of 2020-01-08	$0.00
Current Charges as of 2020-01-08	$225.70
Total Amount Due	$225.70

	RATE	USAGE	CHARGES
PREVIOUS BALANCE			163.36
PAYMENT 2019-12-10			-163.36
BALANCE FORWARD			0.00
YOUR ELECTRICITY CHARGES -			
ELECTRICITY			
ON PEAK COMMODITY	0.208000	97.32	20.24
MID PEAK COMMODITY	0.144000	85.78	12.35
OFF PEAK COMMODITY	0.101000	424.06	42.83
DELIVERY			60.26
REGULATORY CHARGES			2.75
DEBT RETIREMENT CHARGE			0.00
OTHER CHARGES			
H.S.T # 89242 2817			18.00
ONTARIO ELECTRICITY REBATE			-44.02
TOTAL ELECTRIC CHARGES			112.41
WATER SERVICES			
WATER SERVICE CHARGE			29.41
WATER VARIABLE CHARGE	2.160000	17.00	36.72
TOTAL WATER CHARGES			66.13
SEWER SERVICES			
SEWER SERVICE CHARGE			22.68
SEWER VARIABLE CHARGE	1.440000	17.00	24.48
TOTAL SEWER CHARGES			47.16
CURRENT CHARGES			$225.70
TOTAL AMOUNT DUE			$225.70

Total Ontario support on this bill $50.56.

This bill reflects the new TOU rates set by the Ontario Energy Board (OEB) effective November 1 2019 showing actual costs to make your electricity bill more transparent. Also on this bill is the new Ontairo Electricity Rebate (OER) of 31.8%. For more details on these changes please visit our website at innpower.ca

No drugs down the drain!
Take unused and expired drugs, over-the-counter medications and natural health products to your local pharmacist for proper disposal.

Meter Number	Service Period		Billing Days	Read Type	Meter Reading		Mult / Size	Usage		Units	Adjust. Factor	Pwr/Load
	Present	Previous			Present	Previous		Metered	Adjusted			
ELE: XXXXXXXXXX	2019-12-09	2019-11-01	38	MR	45565	44957	1	607.16	643.83	kWh	1.0604	
WAT: XXXXXXXXXX	2019-12-09	2019-10-31	39	MR	00337	00320	1	17.00	17.00	m3		

Reference:

2.0-VECC-4

Exhibit 2, Tab 5, Schedule 1

Question:

For the road authority works forecast in 2023 and 2024 please provide the number and name description of the agreements that are currently agreed to with the municipal authority.

Response:

For 2023 - Yonge Street and Killarney Beach Road - this is an intersection improvement driven by the County of Simcoe. InnPower has secured the PO from the County for these works.

For 2024 - Innisfil Beach Road from Yonge St to 10th Sideroad - this is Phase 2 of the Innisfil Beach Road widening driven by the County of Simcoe. InnPower has secured the PO from the County for these works.

In both 2023 and 2024, there are a number of smaller jobs driven by the Town of Innisfil to install streetlights on intersections that require InnPower to install taller poles, but these are typically smaller, single pole jobs.

Reference:

2.0-VECC-5

Exhibit 2

Question:

Please explain why there were no vehicle acquisitions in 2019 and why the amounts spent on vehicles in 2017 and 2020 was significantly less than that spend in other years including 2023 and 2024?

Response:

In 2017, InnPower had budgeted to purchase a replacement double bucket truck ($373k) and three fleet vehicles ($132k). In 2019, InnPower decided to lease fleet vehicles rather than purchase them outright, due to favourable financial conditions. With the delay in the 2017 cost of service application, it was decided to delay these purchases to 2018.

These leases were set up as capital leases and are recorded in APH account 2005. As we replaced the fleet vehicles in 2019, there was no need to purchase any fleet vehicles in 2020.

2023 and 2024 budgets include downpayments for a bucket truck that is expected to be delivered and capitalized in 2024 as well as replacing the fleet vehicles that will have leases expiring.

Reference:

2.0-VECC-6

Exhibit 2, Tab 5, Schedule 7

Question:

Table 2-48: ACM Funding Shortfall Analysis

($ millions)	2025	2026	2027	Total
BATU Installment Payment	$4.12	$4.12	$4.12	$12.36
Maximum Eligible Incremental Capital	$1.15	$0.92	$0.67	$2.74 (22%)
ACM Shortfall	**$2.97**	**$3.2**	**$3.45**	**$9.62 (78%)**

a) Is InnPower's concern that if it uses an ACM to recover the capital contributions to Hydro One (BATU) it will significantly under recover its costs?

b) If this is the concern, what adjustments to the ACM methodology would it propose (in lieu of its preferred method of establishing a series of deferral accounts).

Response:

a) InnPower's concern, as described in Exhibit 2, Tab 5, Schedule 7, page 93, is that under the standard ACM methodology the vast majority of revenue requirement costs incurred as a result of the BATU capital contributions made from 2025 through 2027 will not be recovered in rates during the rate term. Please see ***Att 2-Staff-39_BATU_Contribution_Revenue_Requirement_20230808*** to 2-Staff-39 for a quantification of the revenue requirement which will be unrecovered under the standard ACM methodology.
b) InnPower is seeking approval of the most appropriate mechanism through which to implement the OEB's Decision in EB-2018-0117 with respect to its five capital

contribution payments of $4.12 million each to Hydro One relating to the BATU project. As noted in Exhibit 2, Tab 5, Schedule 7, page 91, the OEB's EB-2018-0117 Decision determined that "it is appropriate that InnPower only records in its rate base the amounts that it has paid", which will allow for "the distributor customer earning a return on rate base for any installment payments made on its capital contribution owing."

In InnPower's assessment, application of the ACM policy as written and implemented via the OEB's ICM/ACM Model fails to provide the cost recovery provisions explicitly provided for in the OEB's EB-2018-0117 Decision for these material expenditures. For this reason, InnPower has proposed an alternative approach which utilizes a new deferral account to capture the entirety of the revenue requirement associated with the 2025 to 2027 capital contributions for recovery.

InnPower has not proposed adjustments to the ACM methodology. The challenge presented by the ACM methodology results from application of the materiality threshold to determine maximum eligible incremental capital for each of InnPower's five capital contribution payments. Had InnPower elected to pay the BATU contribution in a single payment, such payment would have been made in 2023 and would be included in InnPower's opening 2024 rate base in its entirety, warranting full recovery. Conversely, had the entire payment been made in a different year, InnPower's net capital expenditure for that year would well exceed the materiality threshold and provide for more adequate (though potentially still incomplete) cost recovery. It is only due to InnPower's OEB-approved approach of elongating the capital contribution over a 5-year period that this cost recovery challenge arises; an approach which, as articulated in the evidentiary record of EB-2018-0117, was and is prudent.

Reference:

2.0-VECC-7

Exhibit 2, Appendix 2-5-3 DSP page 149

Question:

For the following subdivision developments:

- Sleeping Lion, a subdivision development with an anticipated build-out of 5,000 homes on the 6th Line in Innisfil.
- Friday Harbour, a resort community within the area of Big Bay Point is a 600-acre site with a total build-out of 3,000 units over a ten-year period.
- Hewitt Creek, a subdivision development with an anticipated build-out of 900 homes on Mapleview Drive.
- Barrie Lockhart Rd Gp, Sorbara, a subdivision development with an anticipated build-out of 485 homes on Lockhart east of Huronia.
- Bistro 6, a subdivision development with an anticipated build-out of 788 homes on Mapleview Drive east of Yonge.
- Blue Sky/Honey Field Lands, a subdivision development with an anticipated build-out of 890 homes on Big Bay Point Road and Mapleview drive East.

Please provide an update indicating the current status of the project (e.g., in what state of planning/build); whether an agreement has been signed with the developer for utility distribution work; and the status of that work.

Response:

- Sleeping Lion, a subdivision development with an anticipated build-out of 5,000 homes on the 6th Line in Innisfil.
    - Offer to Connect has been signed, all distribution system network has been installed and energized. Connecting homes as they are built.
- Friday Harbour, a resort community within the area of Big Bay Point is a 600-acre

site with a total build-out of 3,000 units over a ten-year period.

    - Offer to Connect has been signed, all distribution system network has been installed and energized. Connecting buildings/condos/homes as they are built.

- Hewitt Creek, a subdivision development with an anticipated build-out of 900 homes on Mapleview Drive.
    - Offer to Connect has been signed, all distribution system network has been installed and energized. Connecting homes as they are built.
- Barrie Lockhart Rd Gp, Sorbara, a subdivision development with an anticipated build-out of 485 homes on Lockhart east of Huronia.
    - Offer to Connect has been signed, all distribution system network has been installed and energized. Connecting homes as they are built.
- Bistro 6, a subdivision development with an anticipated build-out of 788 homes on Mapleview Drive east of Yonge.
    - Offer to Connect has been signed, all distribution system network has been installed and energized. Connecting buildings/condos as they are built.
- Blue Sky/Honey Field Lands, a subdivision development with an anticipated build-out of 890 homes on Big Bay Point Road and Mapleview drive East.
    - Offer to Connect has been signed, all distribution system network is currently being installed.

Reference:

3.0-VECC-8

Exhibit 3, page 19

Exhibit 2, Appendix 2-5-3, pages 2 & 6

Load Forecast Model, Rate Class Customer Model Tab

Question:

Preamble: The Application states:

"*InnPower is among the fastest growing utilities in Ontario, presently serving over 20,000 customers within a service area of 292 square kilometres (the same size as Mississauga)." (Appendix 2-5-3, page 2)*

"Load growth is primarily driven by new residential, commercial, and industrial development. There is significant future growth projected within InnPower's service area." (Appendix 2-5-3, page 6)

"*The growth factor resulting from the geometric mean analysis from 2013 to 2022 is applied to the 2022 customer numbers to determine the forecast of customer/connections for 2023. The factor is then applied again to the 2023 forecast to determine the 2024 forecast*." (Exhibit 3, page 19)

a) In what year did InnPower current high rate of growth first commence?

b) It is noted that the total customer growth in 2020 was materially less than that in the immediately preceding or subsequent years. To what does InnPower attribute this lower growth and, in particular, is it COVID-19 related?

c) Based on the responses to the previous two questions, is it reasonable to use the average annual growth rate from 2013 to 2022 as the basis for forecasting the 2024 customer counts by rates class.

Response:

a) InnPower has experienced a high level of growth over the entirety of the 10-year historical period informing the customer and connection forecast. InnPower notes that the growth rate for the first year in its 10-year historical period (2014) exceeds growth rates in the Residential and GS <50kW rate classes seen by all 2023 Cost of Service filers[4] with the exception of Milton Hydro's Residential class; another high-growth distributor. Further, its 10-year Geomean growth rate across these rate classes exceeds growth rates of all 2023 Cost of Service filers; in most cases by multiples.

b) It is reasonable to expect that COVID-19 and related policies had an impact on 2020 customer/connection growth rates.

c) The use of a 10-year historical average growth rate continues to be the most appropriate basis for forecasting customer/connection growth. Aside from being a frequently used and credible approach informing utility applications to the OEB, the use of a 10-year average prevents single-year impacts from skewing growth forecasts positively or negatively. This approach has the effect of appropriately muting the impact of both low years (e.g. 2020 growth impacted by COVID-19) and high years (e.g., 2015 which saw Residential customer growth which was double 2022 growth).

[4] Bluewater Power, Cooperative Hydro Embrun, EPCOR Electricity Distribution, Kingston Hydro, Milton Hydro, and PUC Distribution. Hydro One Networks' Joint Rate Application and Hydro One Remote Communities were not included in this review

Reference:

3.0-VECC-9

Exhibit 3, pages 10-11

Load Forecast Model, Inputs, Rate Class Energy Model, Rate Class Customer Model and Rate Class Load Model Tabs

Question:

a) Do the 2013 to 2022 monthly customer count, kWh and KW set out in the Inputs Tab for the GS>50 class include the values associated with the Embedded Distributor?

b) Do the values for the GS>50 class in Tables 3-3 and 3-4 (and the Rate Class Energy Model, Rate Class Customer Model and Rate Class Load Model Tabs) exclude the historical customer, kWh and kW values for the Embedded Distributor. In examining the Load Forecast Model, adjustments appear to have been made to remove the Embedded Distributor from the GS>50 annual energy use but no similar adjustments appear to have been made to remove the Embedded from the GS>50 customer counts or billed kW.

Response:

a) and b)

Please see 3-SEC-26 Attachment for an updated version of the Load Forecast named ***Att 3-SEC-26_IPC_Exhibit 3_LOAD FORECAST_20230808_rev2.*** InnPower's original submission removed the Embedded Distributor customer values from GS >50kW values with respect to customer/connection count and kWh but did not similarly adjust GS >50kW kW values. The above noted evidence has been corrected to remove Embedded Distributor kW values from GS >50kW kW values.

Reference:

3.0-VECC-10

Exhibit 3, page 7

Question:

Preamble: The Application states:

"*The regression analysis has been updated to include actual data to the end of 2022 and uses the same variables as those in InnPower's 2017 COS application*."

a) Did InnPower undertake any analysis to determine whether COVID-19 has had an impact on power purchases in 2020 through 2022?

b) If yes, please indicate what analysis was undertaken and provide the results.

c) If not, why not?

d) If not, what are InnPower's views as to whether or not COVID-19 has an impact on its historical power purchases?

Response:

a) to d)

In determining independent variables for inclusion in the load forecast regression analysis InnPower considered the inclusion of a COVID-19 flag to identify any impacts of COVID-19 on power purchases. In reviewing actual wholesale power purchases, InnPower noted a lack of discernable pattern or impact from COVID-19 during the time periods in which COVID-driven impacts would be most likely to materialize. On completion of the regression analysis without a COVID-19 independent variable the results returned demonstrated a high degree of statistical validity, with an R Square value of 96.7% and t-Stat values demonstrating a high degree of explanatory value across all independent variables. Based on the strong results generated absent a COVID-19 variable and the lack of discernible pattern arising from COVID-19 on power purchases, InnPower determined the addition of a COVID-19 variable was unnecessary.

Reference:

3.0-VECC-11

Exhibit 3, page

Exhibit 8, page 27

Load Forecast Model, Power Purchased Model Tab

Question:

Preamble: The. Application states:

"*InnPower has data regarding the amount of electricity (in kWh) purchased from the IESO for use by its customers*."

a) Do the Purchased Power values used in the Power Purchased Model Tab (Column B) include purchases from microFit and other embedded generators as well as load transfers (per Exhibit 8, Table 8-16)?

b) If not, please re-do the Load Forecast Model including purchases from embedded generators and load transfers in the Purchased Power values used.

Response:

a) Yes.

b) Please see a) above.

Reference:

3.0-VECC-12

Exhibit 3, page 18
Load Forecast Model, Inputs Tab

Question:

For each customer class please provide the 2023 monthly customer count for all months where actual values are available.

Response:

Please see Attachment ***Att 3-SEC-26_IPC_Exhibit 3_LOAD FORECAST_20230808_rev2***, where InnPower has provided an updated load forecast based on 2023 year-to-date actuals. The actual January to June 2023 monthly customer count by rate class can be found in the Inputs Tab, rows 144 to 149.

Reference:

3.0-VECC-13

Exhibit 3, pages 20-21

Question:

a) Please provide a schedule that sets out the actual CDD and HDD values for 2022 versus the weather normal values used in the Load Forecast.

b) Based on these values, please comment on whether one should expect the weather adjustment described on page 21 to be positive or negative.

Response:

a) Please see below.

Table 1: 2022 Actual Weather HDD & CDD

Date	HDD	CDD
22-Jan	809	0
22-Feb	627	0
22-Mar	524	0
22-Apr	340	0
22-May	108	37
22-Jun	18	64
22-Jul	0	145
22-Aug	0	141
22-Sep	52	49
22-Oct	237	0
22-Nov	380	1
22-Dec	575	0
Total	**3670**	**437**

Reference:

4.0-VECC-14

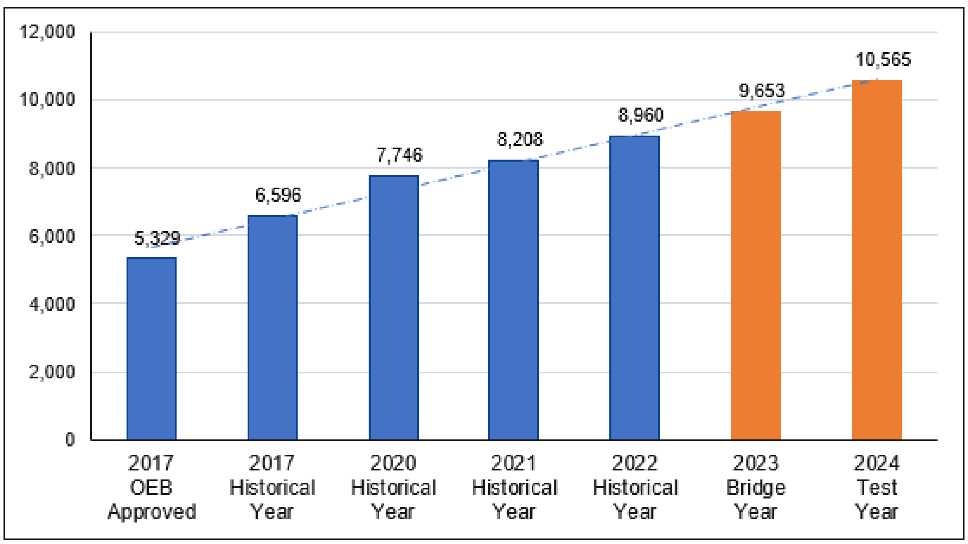
Exhibit 4, Tab 1, page 18

Question:

Please recast Figure 4-1 to show the total operating costs (i.e., before capitalization).

Response:

Please see the updated Figure 4-1 below that shows total operating costs before capitalization.



Reference:

4.0-VECC-15

Exhibit 4, Tab 1, Schedule 3, page 43

Question:

As compared to the last cost of service filing what are the incremental annual cyber security OM&A costs?

Response:

It is difficult to distinguish all the costs associated with cyber security, as many upgrade activities support the maintenance of cyber security. Examples of these types of activities include upgrading out-of-support software to supported versions, maintaining certificates, password management and staff resources. In essence, most activities in Information Technology have cyber security considerations.

Examples of new expenses in 2022 with cyber security-specific vendors include Arete / SentinelOne ($36,703.72) and Rocket Cyber ($7,560.00) commencing in 2022.

Reference:

4.0-VECC-16

Exhibit 4, Tab 1, Schedule 4

Question:

Please provide the job description for the Customer Engagement Representative.

Response:

The primary responsibilities and role accountabilities for the Customer Engagement Representative are outlined below:

PRIMARY ROLE PURPOSE:

This position will work closely with the Manager, Customer Relations & Engagement to enhance engagement with our customers and community stakeholders. The position will work on social media, websites, newsletters, customer communications, etc. The position will also take on some existing duties in the Customer Service Team, such as Customer Service Emails, Phone Calls and Written Responses. The position is an active member of the Customer Service Team.

ROLE ACCOUNTABILITIES:

- Collaborate with Manager, Customer Relations & Engagement in content planning including research, maintaining and executing content calendar: scheduling content, coordinating resources, research and meeting deadlines.
- Create and schedule social media posts on all relevant channels for Manager's approval.
- Coordinate distribution of marketing materials.
- Maintain knowledge of web trends and best practices. Follow competitors and industry leaders to contribute content. Monitor online reviews.

- In collaboration with the Manager, Customer Relations & Engagement, coordinate the creation and publishing of bill inserts newsletters, maintenance of website, etc.
- Respond to daily Customer Service email, phone and written inquiries as required. Will provide office back-up support as required.
- Assist with social media management, events, and community and regulatory engagement.
- Analyze and report audience information and demographics, and success of existing social media projects, prepare monthly reporting.
- Propose new ideas and concepts for social media content.

Reference:

4.0-VECC-17

Exhibit 4, Tab 1, Schedule 3 & 4

Question:

a) Please show the calculation of the $120k in bad debt forecast for 2023 and 2024.
b) What is the most recent bad debt incurred in 2023 by InnPower.

Response:

a) In 2023 and 2024 bad debt expense forecast was estimated using 2022 bad debt expense after eliminating an amount written off for one significant uncollectible customer, which was for $280k. The 2022 bad debt expense was $412k less $280k is $132k. In the current economy, InnPower anticipated that this amount would be reasonably steady for the following few years.
b) As of July 31, 2023, year-to-date bad debt is Residential $50,716.85, Commercial $1,328.00.

Reference:

4.0-VECC-18

Exhibit 4, Tab 1, Schedule 4, pages 72-73

Question:

Two separate and different amounts are shown for the variance as between 2024 and 2017 Actuals. Please clarify.

Response:

The variance indicated at the bottom of page 72 (+$196k) is the difference between the 2024 Test Year and the 2017 OEB Approved amounts. The variance indicated at the top of page 73 is the difference between the 2024 Test Year and the Actuals for 2017 (+$172k).

Reference:

4.0-VECC-19

Exhibit 4, Tab 1, Schedule 4

Question:

Table 4-34: InnPower FTE Levels from 2017 to 2024

	2017	2018	2019	2020	2021	2022	2023	2024
FTE's	43.83	46.31	48.60	51.00	55.24	56.79	66.92	73.33
Year over Year Change		2.48	2.29	2.40	4.24	1.55	10.13	6.41
2024 vs. 2017								29.50

How many of the 10.13 FTEs that are forecast to be added in 2023 have been hired to date?

Response:

We have currently hired 7.36 FTE's of the forecasted 10.13 FTE's to date.

Reference:

4.0-VECC-20

Exhibit 4, Tab 1, Schedule 4

Question:

InnPower is proposing an increase in FTEs of over 40% between 2020 and 2024. Please provide the HR plan supporting that plan that was approved by InnPower's Board of Directors.

Response:

The HR plan supporting the overall Strategic Plan can be found in Appendix 1-1-5 (A) InnPower 2023 to 2027 Strategic Plan in InnPower's Cost of Service Application.

The HR plan supports InnPower's efforts to reduce enterprise risk and burnout of employees that support the increased need for FTEs. Further information can also be found in the Budget Binder, which can be found with IR 1-SEC-2.

Reference:

4.0-VECC-21

Exhibit 4, Tab 1, Schedule 4

Question:

Please provide the MEARIE Salary Survey and the InnPower comparison from which the Utility makes the assessment that its “salaries are competitive.”

Response:

As requested, please reference ***Att 4.0-VECC-21-2022_MEARIE_Management_Salary_Survey_Report*** for the most recent MEARIE Salary Survey.

Reference:

4.0-VECC-22

Exhibit 4, Tab 1, Schedule 4

Question:

a) Using Appendix 2-K please show in each year 2017-2025 the number of FTEs directly employed by InnPower Corporation (distribution utility) and the number employed by an affiliate.

b) How many employees (and FTEs) employed by an affiliate provide 100% of their time to InnPower Corporation?

Response:

a) All of the FTEs included in Appendix 2-K were employed directly by InnPower between 2017 and 2024 (nil for any affiliates). 2025 FTE information is not currently available.

b) No current employees from an affiliate currently provide 100% of their time to InnPower.

Reference:

5.0-VECC-23

Exhibit 5, Appendix 2-OB

Question:

IPC_2024_Filing Requirements_Chapter2_20230622_rev2.xlms does not include complete Excel Tables for 2023 and 2024. Please provide an update with these tables completed.

Response:

It is InnPower's understanding that the macros are hiding the tables for these years each time the file is opened. InnPower is working with the OEB to have this corrected.

The 2023 and 2024 2-OB tables have been updated and are shown below for your reference. Please also refer to the response in 5-Staff-60 and 5.0-VECC-25 for more details on the update.

Year 2023

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,416,801	2.70%	$ 65,253.63
2	TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,655,854	5.27%	$ 139,963.50
3	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov-23	10	$ 2,191,326	5.00%	$ 109,566.31
4	TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-14	10	$ 1,604,074	3.96%	$ 63,521.31
5	TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-14	10	$ 1,619,022	3.91%	$ 63,368.51
6	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,617,075	3.68%	$ 59,508.35
7	TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,723,518	2.88%	$ 280,037.32
8	TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,453,588	3.48%	$ 85,384.88
9	TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,648,500	3.60%	$ 95,345.99
10	TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,505,817	4.09%	$ 61,587.90
11	TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,176,017	3.28%	$ 71,373.37
12	TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,431,931	2.45%	$ 59,582.30
13	Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033.34
14	TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 907,019	1.92%	$ 17,414.77
Total							$ 34,283,874	3.46%	$1,184,941.47

Year 2024

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,218,160	2.70%	$ 59,890.32
2	TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,506,102	5.27%	$ 132,071.59
3	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov-23	10	$ 2,088,716	5.00%	$ 104,435.81
4	TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-24	10	$ 1,552,634	5.00%	$ 77,631.68
5	TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-24	10	$ 1,568,095	5.00%	$ 78,404.75
6	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,565,516	3.68%	$ 57,610.99
7	TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,392,408	2.88%	$ 270,501.35
8	TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,378,844	3.48%	$ 82,783.77
9	TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,573,529	3.60%	$ 92,647.04
10	TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,469,359	4.09%	$ 60,096.80
11	TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,121,541	3.28%	$ 69,586.53
12	TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,343,764	2.45%	$ 57,422.22
13	Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033.34
14	TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 781,584	1.92%	$ 15,006.40
15	2023 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-24	15	$ 5,284,649	5.00%	$ 264,232.45
Total							$ 38,178,234	3.76%	$1,435,355.04

Reference:

5.0-VECC-24

Exhibit 5

Question:

InnPower appears to borrow mid-long-term debt almost exclusively from one issuer (TD Trust). Please explain how InnPower ensures that it is negotiating the most advantageous rate available.

Response:

InnPower historically borrowed from TD Bank as they offered competitive rates. InnPower will be requiring significant capital and construction work in progress borrowing in the future because of the Barrie Area Transmission Upgrade and InnPower transformer station construction. Borrowing arrangements are reviewed annually, which also includes investigating alternative lenders (such as Infrastructure Ontario).

Reference:

5.0-VECC-25

Exhibit 5

Question:

a) Please confirm that the 2022 CAPEX loan with a start date of 1-APR-23 (line 15) has been finalized at the rate of 5.00%.
b) With respect to the 2023 CAPEX Loan (1-APR-24) please clarify whether the rate and term of this loan have been agreed to or whether they are subject to negotiation. If the latter, please provide an estimate of when this loan is expected to be finalized.

Response:

a) InnPower has not borrowed on the 2022 CAPEX loan and does not anticipate borrowing $2,189,040 in 2023; therefore, the 2023 and 2024 schedules have been updated below to reflect this.

Original: Appendix 2-OB - 2023

Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,416,801	2.70%	$ 65,254
TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,655,854	5.27%	$ 139,964
TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov23	10	$ 2,191,326	4.59%	$ 100,582
TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-14	10	$ 1,604,074	3.96%	$ 63,521
TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-14	10	$ 1,619,022	3.91%	$ 63,369
TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,617,075	3.68%	$ 59,508
TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,723,518	2.88%	$ 280,037
TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,453,588	3.48%	$ 85,385
TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,648,500	3.60%	$ 95,346
TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,505,817	4.09%	$ 61,588
TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,176,017	3.28%	$ 71,373
TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,431,931	2.45%	$ 59,582
Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033
TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 907,019	1.92%	$ 17,415
2022 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-23	15	$ 2,189,040	5.00%	$ 109,452
						$ 36,472,914	3.52%	$ 1,285,409

Original: Appendix 2-OB - 2024

Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,218,160	2.70%	$ 59,890
TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,506,102	5.27%	$ 132,072
TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov-23	10	$ 2,088,716	4.59%	$ 95,872
TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-24	10	$ 1,552,634	3.96%	$ 61,484
TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-24	10	$ 1,568,095	3.91%	$ 61,375
TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,565,516	3.68%	$ 57,611
TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,392,408	2.88%	$ 270,501
TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,378,844	3.48%	$ 82,784
TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,573,529	3.60%	$ 92,647
TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,469,359	4.09%	$ 60,097
TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,121,541	3.28%	$ 69,587
TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,343,764	2.45%	$ 57,422
Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033
TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 781,584	1.92%	$ 15,006
2022 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-23	15	$ 2,080,943	5.00%	$ 104,047
2023 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-24	15	$ 5,284,649	5.00%	$ 264,232
						$ 40,259,177	3.72%	$ 1,497,662

Updated: Appendix 2-OB – 2023

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,416,801	2.70%	$ 65,253.63
2	TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,655,854	5.27%	$ 139,963.50
3	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov-23	10	$ 2,191,326	5.00%	$ 109,566.31
4	TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-14	10	$ 1,604,074	3.96%	$ 63,521.31
5	TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-14	10	$ 1,619,022	3.91%	$ 63,368.51
6	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,617,075	3.68%	$ 59,508.35
7	TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,723,518	2.88%	$ 280,037.32
8	TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,453,588	3.48%	$ 85,384.88
9	TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,648,500	3.60%	$ 95,345.99
10	TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,505,817	4.09%	$ 61,587.90
11	TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,176,017	3.28%	$ 71,373.37
12	TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,431,931	2.45%	$ 59,582.30
13	Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033.34
14	TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 907,019	1.92%	$ 17,414.77
15	2022 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-23	15			
Total							$ 34,283,874	3.46%	$1,184,941.47

Updated: Appendix 2-OB - 2024

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	TD-15 Loan	TD Canada Trust	Third-Party	Variable Rate	26-Mar-22	14	$ 2,218,160	2.70%	$ 59,890.32
2	TD-13 Loan	TD Canada Trust	Third-Party	Fixed Rate	7-Oct-22	4	$ 2,506,102	5.27%	$ 132,071.59
3	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Nov-23	10	$ 2,088,716	5.00%	$ 104,435.81
4	TD-20 Loan	TD Canada Trust	Third-Party	Fixed Rate	23-Jul-24	10	$ 1,552,634	5.00%	$ 77,631.68
5	TD-21 Loan	TD Canada Trust	Third-Party	Fixed Rate	25-Nov-24	10	$ 1,568,095	5.00%	$ 78,404.75
6	TD-03 Loan	TD Canada Trust	Third-Party	Fixed Rate	9-Jan-15	10	$ 1,565,516	3.68%	$ 57,610.99
7	TD-26 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Dec-21	3.5	$ 9,392,408	2.88%	$ 270,501.35
8	TD-10 Loan	TD Canada Trust	Third-Party	Fixed Rate	12-Feb-16	10	$ 2,378,844	3.48%	$ 82,783.77
9	TD-22 Loan	TD Canada Trust	Third-Party	Fixed Rate	31-Jan-17	30	$ 2,573,529	3.60%	$ 92,647.04
10	TD-16 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Mar-18	30	$ 1,469,359	4.09%	$ 60,096.80
11	TD-06 Loan	TD Canada Trust	Third-Party	Fixed Rate	26-Aug-19	30	$ 2,121,541	3.28%	$ 69,586.53
12	TD-17 Loan	TD Canada Trust	Third-Party	Fixed Rate	14-Jul-21	15	$ 2,343,764	2.45%	$ 57,422.22
13	Infrastructure Ontario Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Aug-11	15	$ 333,333	3.91%	$ 13,033.34
14	TD-01 Loan	TD Canada Trust	Third-Party	Fixed Rate	29-Oct-10	20	$ 781,584	1.92%	$ 15,006.40
15	2022 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-23	15			
16	2023 CAPEX Loan	TD Canada Trust	Third-Party	Fixed Rate	1-Apr-24	15	$ 5,284,649	5.00%	$ 264,232.45
Total							$ 38,178,234	3.76%	$1,435,355.04

b) The term and interest rate on the 2023 CAPEX loan has not been negotiated or agreed upon. InnPower's banking and borrowing arrangements are reviewed annually, which also includes the consideration of other lenders.

Reference:

6.0-VECC-26

Exhibit 6, page 20

Question:

a) For each of the USOAs set out in Table 6-10, please explain how InnPower forecasted the 2023 and 2024 amounts.

b) Please provide a schedule that sets out, for each of the USOAs set out in Table 6-10, the 2023 year-to-date values and the values for 2022 for the same months.

c) In which account are the revenues from the microFIT service charge recorded?

Response:

a) For each of the USOAs set out in Table 6-10, the amounts for the 2023 and 2024 budgets were forecasted as follows:

USoA #	USoA Description	Budget Method
4082	Retail Services Revenues	based on historical actuals
4084	Service Transaction Requests (STR)	based on historical actuals
4086	SSS Admin Charge (SSS)	based on budgeted customer count and tariff rate
4210	Rent from Electric Property (Pole Rentals)	based on estimated number of poles and tariff rates by customer
4225	Late Payment Charges	based on historical actuals
4235	Miscellaneous Service Revenues	based on historical actuals
4245	Deferred Revenue	based on existing contributions, budgeted PPE additions and disposals
4355	Gain on Disposal of Property	based on budgeted disposals
4375	Revenues from Non-Utility Operations	based on historical actuals and IPC labour allocated to recover from affiliates
4380	Expenses of Non-Utility Operations	based on historical actuals and IPC labour allocated to provide services for affiliates
4385	Non-Utility Rental Income	based on amounts included in lease agreements
4390	Miscellaneous Non-Operating Income	based on historical actuals
4405	Interest and Dividend Income	based on historical actuals

b) Please see the IRR 6-SEC-39 for the 2023 year-to-date actuals, as well as corresponding year-to-date actuals for 2021 and 2022.

c) The revenues from the microFit service charges are included in 4235.

Reference:

7.0-VECC-27

Exhibit 7, page 7

Question:

Preamble: The Application states:

"*InnPower updated the allocation of the accounts in the worksheet "I4 Break-out of Assets" with the 2024 forecasted data*."

Please provide a schedule that compares the asset breakout for USOA 1830, 1835, 1840 and 1845 as used in the 2017 Application with that used in the current Application. Please explain any changes of more than five percentage points.

Response:

InnPower has conducted a considerable amount of system renewal work since 2017, in addition to all work completed on behalf of developers, all of which is completely recoverable but is shown as gross amounts in this table. The breakout percentages themselves remained the same from the 2017 COS Application.

		2024				2017				
Account	Description	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	Break out Functions	BREAK OUT (%)	BREAK OUT ($)	After BO	% BO Change
1830	Poles, Towers and Fixtures	$66,264,188		($66,264,188)	-	$11,181,603		($11,181,603)	-	0%
1830-3	Poles, Towers and Fixtures - Subtrans Bulk Delivery			$0	-			$0	-	0%
1830-4	Poles, Towers and Fixtures - Primary		76.00%	$50,360,783	50,360,783		76.00%	$8,498,018	8,498,018	493%
1830-5	Poles, Towers and Fixtures - Secondary		24.00%	$15,903,405	15,903,405		24.00%	$2,683,585	2,683,585	493%
1835	Overhead Conductors and Devices	$22,831,900		($22,831,900)	-	$12,044,762		($12,044,762)	-	0%
1835-3	Overhead Conductors and Devices - Subtrans Bulk Delivery			$0	-			$0	-	0%
1835-4	Overhead Conductors and Devices - Primary		84.40%	$19,270,124	19,270,124		84.40%	$10,165,779	10,165,779	90%
1835-5	Overhead Conductors and Devices - Secondary		15.60%	$3,561,776	3,561,776		15.60%	$1,878,983	1,878,983	90%
1840	Underground Conduit	$12,068,232		($12,068,232)	-	$3,089,487		($3,089,487)	-	0%
1840-3	Underground Conduit - Bulk Delivery			$0	-			$0	-	0%
1840-4	Underground Conduit - Primary		36.00%	$4,344,564	4,344,564		36.00%	$1,112,215	1,112,215	291%
1840-5	Underground Conduit - Secondary		64.00%	$7,723,669	7,723,669		64.00%	$1,977,272	1,977,272	291%
1845	Underground Conductors and Devices	$11,239,561		($11,239,561)	-	$8,071,348		($8,071,348)	-	0%
1845-3	Underground Conductors and Devices - Bulk Delivery			$0	-			$0	-	0%
1845-4	Underground Conductors and Devices - Primary		97.00%	$10,902,374	10,902,374		97.00%	$7,829,208	7,829,208	39%
1845-5	Underground Conductors and Devices - Secondary		3.00%	$337,187	337,187		3.00%	$242,140	242,140	39%

Reference:

7.0-VECC-28

Exhibit 7, pages 8-9

Question:

Preamble: The Application states:

"In determining the Services Weighting Factors, InnPower has utilized the 2017 Cost of Service numbers filed (EB-2016-0085) to determine costs, rate class and primary/secondary connections charged to Account 1855. These amounts were approved by the Board and there have been no significant changes in InnPower's policies or practices that would impact the weightings."

a) Please confirm that the service weighting used in the 2017 COS were based on the analysis of 2 years (2014 & 2015) of layouts with charges to Account 1855 to determine costs, rate class and primary/secondary connections and that a 2-year timeframe was utilized as this was the timeframe in which InnPower had electronic versions of layouts (per EB-2016-0085, Exhibit 7, page 5).
b) Please explain why, for the purposes of the current Application, InnPower did not analyze any additional years of data.
c) If time permits prior to the response date for interrogatories (or the start date of the Settlement Conference), please undertake a similar analysis using 2021 and 2022 data.

Response:

a) Yes, this is correct.
b) Due to time constraints, as well as the fact that these amounts were approved by the Board and there have been no significant changes in InnPower's policies or practices that would impact the weightings, InnPower

found it reasonable and justified to use the weightings from the 2017 Cost of Service application.

c) InnPower was unable to undertake a similar analysis using the 2021 and 2022 data in the time allotted for interrogatory responses.

Reference:

7.0-VECC-29

Exhibit 7, pages 9-10

Question:

Preamble: The Application states:

"*The above table shows:*

- *The annual costs to produce an electricity bill including, but not limited to, vendor maintenance fees for Customer Information Systems, bill print solutions for document management and e-billing, collecting meter readings and interval data, bill validation and labour time to calculate, print and validate bills. Costs are allocated based on the number of accounts and whether the expense is unique to a certain rate class.*
- *Collection costs mainly relate to InnPower labour, as the utility performs the majority of its own collections. Final billed customers overdue in excess of 3 to 6 months are referred to a third-party collection agency*."

a) Please provide a schedule that sets out how each of the cost elements described in the Preamble were allocated to customer classes and the derivation of the resulting cost per bill as set out in Table 7-5.

Response:

a) Please refer to ***Att. 7.0-VECC-29_Weighting_Factor_for_Billing_and_Collecting*** for the schedule that sets out how each of the cost elements described in the Preamble we allocated to customer classes.

Reference:

7.0-VECC-30

Exhibit 7, pages 13-14

Cost Allocation Model, Tab I6.2, Customer Data

Question:

Preamble: The Cost Allocation Model shows the following customer breakdown:

	ID	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Billing Data									
Bad Debt 3 Year Historical Average	BDHA	$113,064	$105,435	$6,999	$630	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$101,333	$77,112	$10,655	$13,083	$283	$0	$200	$0
Number of Bills	CNB	259,055	239,480	15,886.31	960.00	96.00	1,764.77	855.79	12
Number of Devices	CDEV					4,334			
Number of Connections (Unmetered)	CCON	25,914	19,957	1,324	80	4,334	147	71	1
Total Number of Customers	CCA	21,588	19,957	1,324	80	8	147	71	1
Bulk Customer Base	CCB	-							
Primary Customer Base	CCP	21,680	19,957	1,324	80	100	147	71	1
Line Transformer Customer Base	CCLT	21,674	19,957	1,324	75	100	147	71	
Secondary Customer Base	CCS	19,554	18,959	331	38	8	147	71	

a) With respect to the Residential class Tab I6.2 shows values for CCP and CCLT of 19,957 but a value for CCS of 18,959. However, in Table 7-9 the values for PNCP4, LTNCP4 and SNCP4 are all the same – please reconcile.

b) With respect to the G<50 class Tab I6.2 shows values for CCP and CCLT of 1,324 but a value for CCS of 331. However, in Table 7-9 the values for PNCP4, LTNCP4 and SNCP4 are all the same – please reconcile.

c) With respect to the GS>50 class Tab I6.2 shows a value for CCP of 80, a value for CCLT of 75 and a value for CCS of 38. However, in Table 7-9 the values for LTNCP4 and SNCP4 are the same – please reconcile.

d) With respect to the Embedded Distributor class Tab I6.2 shows a value for CCP of 1, a value for CCLT of 0 and a value for CCS of 0. However, in Table 7-9 the values for PNCP4, LTNCP4 and SNCP4 are all the same (1,209) – please reconcile.

Response:

IPC has updated the cost allocation model along with other models to reflect changes resulting from the process of answering the interrogatories. For the classes mentioned in part a) to d) of this question the cost allocation has been revised to address the noted inconsistencies. Specifically, for each noted class the values for all PNCP, LTNCP and SNCP shown in Tab I8, which is also the information in Table 7-9, have been changed to reflect the number of customers in CCP, CCLT, and CCS shown in Tab I6.2

Reference:

7.0-VECC-31

Exhibit 7, pages 17-18

Question:

Preamble: The Application states:

"InnPower is requesting a new customer class in this application for an embedded distributor."

Please describe the InnPower facilities used to serve the Embedded Distributor.

Response:

The IPC metering equipment used for the Hydro One customers in the Thornton subdivision includes:

i) Single phase primary metering unit, includes 4800V/120V potential transformer and 150A/5A current transformer
ii) Single phase demand meter with ethernet output
iii) Cellular modem including SIM card

Reference:

8.0-VECC-33

Exhibit 8, page 12

Question:

Preamble: The Application states:

"*InnPower Corporation completed its 2024 proposed RTSR in accordance with the Guideline G-2008-0001: Electricity Distribution Retail Transmission Service Rates, October 22, 2008 (and any subsequent updates). The RTSR model provided by the Board is being filed in conjunction with this application as Appendix 8-2-1 (A). InnPower Corporation understands that RTSR rates for the years 2024 – 2028 will be updated via the annual update."*

a) What year's UTR rates and Hydro One ST rates has InnPower used in the RTSR Model to determine the proposed 2024 RTSRs.
b) Please outline InnPower's understanding as to the update for process for 2024.

Response:

a) The UTR rates used in the filed RTSR model are from Board Order EB-2022-0084, Ontario Uniform Transmission Rate Schedule effective April 1, 2022, Page 5 of 6. The Hydro One ST rates used the filed RTSR model are from Board Decision EB-2021-0032, Hydro One Networks Inc. Tariff of Rates and Charges for the Sub Transmission class effective January 1, 2022, Page 9 of 18. At the time of filing this was the current information available.
b) The RTSR model has been updated to reflect the most current approved UTR rates and Hydro One ST rates.

Reference:

8.0-VECC-34

Exhibit 8, page 13
RTSR Model, Tabs 3 and 5

Question:

Preamble: The Application states:

"*Please note, the transmission and network charges in Table 8-8 above were used to calculate the Cost of Power for InnPower's Working Capital Allowance. The loss adjusted billed kWh in Table 8-8 reflects the 2022 actual consumption, whereas the Cost of Power calculation uses 2024 loss adjusted forecasted consumption (as shown in Exhibit 3)*."

Please confirm that both the customer class usage data in Tab 3 and the billed data in Tab 5 are based on 2022 actuals. If not confirmed, please provide as revised RTSR Model where the same year's data is used in both Tabs.

Response:

Yes, this is correct. The customer class usage data in Tab 3 and the billed data in Tab 5 are based on 2022 actuals.

Reference:

8.0-VECC-35

Exhibit 8, page 14

Question:

Preamble: The Application states:
"*InnPower Corporation proposes to maintain the generic Retail Service Charges approved in the 2023 IRM application (EB-2022-0043).*"

Will InnPower update its proposed 2024 Retail Service Charges to reflect any revisions approved by the OEB for 2024?

Response:

Yes, InnPower will update its proposed 2024 Retail Service Charges to reflect any revisions approved by the OEB for 2024.

Reference:

8.0-VECC-36

Exhibit 1, Tab 1, Schedule 4, page 30/Exhibit 8, Tab 5, Schedule 1 pages 20-

Question:

"*For residential and small commercial customers, InnPower Corporation offers one free disconnect/reconnect per calendar year for residential and small commercial customers during operations hours*."

a) Under the new tariff being sought will the annual free disconnect/reconnect service be eliminated?
b) If yes, will the annual free disconnect/reconnect service remain available to residential customers or only those who qualify as Low-income?
c) In each of the past 3 calendar years how many customer-initiated (annual) disconnects/reconnects did InnPower provide?
d) How many annual disconnects/reconnects are to the same properties in each of those years?
e) Are the annual disconnect/reconnects primarily a service to recreational or lake front properties?

Response:

a) No, it will be available during operations hours. After hours and second requests will see fees charged.
b) See answer to 8-VECC-36a.
c) Please see below for number of customer initiated disconnects/reconnects over the entire historical period:

2022 – 332
2021 – 289
2020 – 76 (DIRs saw a significant reduction due to lockdowns associated with COVID)

d) InnPower does not have this data readily available as customers who request multiple DIRs are provided individual estimates and pay actual costs after the first free DIR.

e) No, they are primarily for panel upgrades, siding replacement, roof replacement or generator installations to ensure a safe work environment.

Reference:

8.0-VECC-37

Exhibit 8, page 18

Question:

Please confirm that current Reconnection Charges are for reconnection of services from non-payment of account were calculated solely on the cost of reconnection and did not include any costs associated with the initial disconnect for reasons of non-payment.

Response:

InnPower continues to use the OEB approved rates when dealing with a reconnection for non-payment and confirms that there are no costs associated with the initial disconnection for reasons of non-payment.

Reference:

8.0-VECC-38

Exhibit 8, pages 18-21

Question:

Why are the proposed new customer-initiated reconnection and disconnection charges only applicable to Residential and GS<50 customers? Are there no circumstances under which customers in the other classes would initiate either a disconnection or reconnection?

Response:

Customers not in the Residential and GS<50 class have always paid for disconnect and reconnects based on estimates of time and equipment. The proposed new charges are for multiple disconnects and/or reconnects at a single address and for after-hours requests.

Reference:

8.0-VECC-39

Exhibit 8, pages 22-24

Question:

a) Given the Board's comment in its EB-2016-0085 Decision and Order, why hasn't InnPower requested an update to its LV rates in any of the years following the 2017 COS application?
b) Please provide a schedule that for each of the years 2017 to 2022 sets out: i) InnPower's Total Metered kWh Customer Consumption, ii) InnPower's total kWh billed consumption for LV, and iii) the ratio of (ii) over (i).

Response:

a) InnPower has applied for a new LV rate in this application. InnPower did not update the LV rate in an IRM applications from 2018 to 2023 due to an oversight.
b) See table below

	2017	2018	2019	2020	2021	2022
i) Metered Consumption	262,143,775	288,210,355	288,210,355	299,261,030	303,807,771	307,736,609
ii) Total kWh Billed Consumption for LV	178,772,267	200,392,468	203,537,646	215,383,810	219,492,574	226,575,405
iii) Ratio (ii/i)	68.2%	69.5%	70.6%	72.0%	72.2%	73.6%

Reference:

8.0-VECC-40

Exhibit 8, page 26

Question:

Preamble: The Application states:

"*As the distribution system loss is greater than 5%, InnPower is undergoing a line loss study to gain further insights into the results. As the utility needed to complete the CYME model prior to the line loss study, the results were not obtained before filing the current application. InnPower anticipates these will be available in the interrogatory process of the application. The utility is committed to continuing its effort to maintain its losses at a minimum.*"

If available, please provide the referenced line loss study.

Response:

Please see the response to 8-Staff-66a.

Reference:

8.0-VECC-41

Exhibit 8, page 30
2024 Tariff Schedule and Bill Impact Model, Tab 6

Question:

Preamble: The Application states:
"*The impacts shown use InnPower's current OEB-approved rates effective January 1, 2023 compared to the proposed January 1, 2024 rates, including rate riders for the recovery of deferral and variance accounts (as discussed in Exhibit 9). Please note, total bill impacts include Distribution Rate Protection, as InnPower is one of eight distributors in the province eligible for funding through provincial rates*."

a) What is the basis for the 2024 DRP Adjustment ($11.10) used in the Bill Impact Model for Residential customers?
b) Is this the actual adjustment for 2024 or will/could it be updated? If it is subject to update, please explain the likely timing and basis for any update.

Response:

a) In 2017, through amendments to the Ontario Energy Board Act, 1998 (OEB Act) and a related regulation (the Distribution Rate Protection Regulation), the Government of Ontario established the Distribution Rate Protection (DRP) program for residential customers who live in certain areas with higher distribution costs, funded through provincial revenues.

   The DRP program provides for a cap on the amount that can be charged for base distribution charges, which consist of the base monthly fixed service charge and, for those distributors that still have one, the base variable distribution charge as well. The OEB calculates the cap or maximum monthly base distribution charge based on the parameters outlined in the

DRP Regulation. The DRP Regulation requires the OEB to establish the maximum charge annually.

The ($11.10) DRP Adjustment used in the Bill Impact Model is based on adjusting InnPower's proposed 2024 fixed residential rate to the DRP cap approved at the time the model was populated, which was $38.08 (EB-2022-0186).

It is important to note that the OEB model has been built by Staff to include the DRP adjustment.

b) Yes, the adjustment will be updated.

The DRP Regulation requires the OEB to establish the maximum charge annually. The DRP Regulation requires the OEB to set the maximum amount as the greater of: (a) the lowest of the monthly base distribution charges that were established in a rate order since the OEB's last determination of the maximum amount; and (b) the previously approved maximum amount, adjusted by the OEB's inflation factor for electricity distributors. The requirement to include an inflation adjustment in the calculation was introduced through amendments to the DRP Regulation that came into force on April 5, 2022.

Effective July 1, 2023, the DRP increase by a 3.3% inflationary factor to $39.49 per month (EB-2023-0119). The inflationary factor and DRP cap amount for July 1, 2024, will likely not be released by the OEB until late May to early June 2024.

Reference:

8.0-VECC-42

2024 Tariff Schedule and Bill Impact Model, Tab 6

Question:

Please explain why, in the bill impact calculations, the year over year impact of the change in deferral/variance account rate riders is positive (i.e., an increase) in the case of the Residential, Sentinel and Street Light classes but negative for the other customer classes.

Response:

For residential there are two deferral/variance account rate riders:

- A **volumetric rate** $0.0117 per kWh x 750 kWh (average) = $8.78
- A **fixed rate** per customer = ($2.42) (on row 101 in the bill impact model)
  - Total = $6.36
  - Year over Year change = ($1.97), calculated as ($6.36 - $8.33)

For sentinel light and streetlight (and all other rate classes), the Retail Cost Variance Account – Retail (1518) balance in the “5. Allocation of Balances” tab was allocated based on “# of customers”. However, in tab “7. Rate Rider Calculations” only one unit of measure is available for each rate class. As such, the high costs originally allocated based on # of customers were then allocated based on kW and kW, resulting in a positive year over year change in the DVA rate rider for Sentinel and Street Light classes.

Please refer to the 9-Staff-73a response. As InnPower will be amending the request for disposition of the Retail Cost Variance Account – Retail (1518), the issue noted above will be corrected. InnPower has updated all appropriate models to reflect the changes noted above.

Reference:

9.0-VECC-43

Exhibit 9, pages 28-30
DVA Continuity Schedule, Tab 5

Question:

Preamble: The Application states:

"*Please note, there is a principal adjustment of $7,131.15 in Appendix 9-1-1 (A) tab "2b. Continuity Schedule" in the DVA Continuity Schedule that reduces the balance refunded to customers. As such, the amount requested for disposition does not match the 2.1.7 RRR filing. In 2022, InnPower attempted to collect vegetation management fees from other telecommunication companies. The utility was only able to recover funds from Rogers Communications (to which InnPower has an agreement). As such, InnPower is requesting a reduced balance for disposition. The unrecovered balance will be reversed from the 1508 sub-account in 2023*."

a) What recourse does InnPower have in those instances where the telecom companies have not paid? For example, can it disconnect the telecom facilities?

b) It is noted (Tab 5) that the balance in the Vegetation Management account is allocated to customer classes using kWh. In InnPower's view is this the most appropriate allocator for these costs?

    a. If yes, why? As part of the response please explain why it is more appropriate than using distribution revenue by customer class.

    b. If not, what would be the appropriate allocator?

Response:

a) There is no recourse for telecom companies that have not contributed to vegetation management. InnPower cannot disconnect telecom facilities unless for non-payment like any other customer.

b) Yes, InnPower views this as the most appropriate allocator of the Vegetation Management credit. Vegetation Management occurs throughout InnPower's distribution system; therefore, benefits all customers. As the vegetation management expense is allocated based on consumption (kW/kWh), InnPower feels it is reasonable and justified to also refund customers using the same methodology (i.e., higher consumers bear a higher proportion of the costs, therefore, should be allocated a higher proportion of the credit).

Reference:

9.0-VECC-44

Exhibit 9, page 35
DVA Continuity Schedule, Tab 5

Question:

Preamble: With respect to the Stranded Meter variance account, the Application states:

> "*The balance requested for disposition, including carrying charges (projected to December 31, 2023) is a credit of ($51,509.64). The sub-account will be discontinued following the current application, as Smart Meter Initiative has ended*."

It is noted (Tab 5) that the balance in the Stranded Meter variance account is allocated to customer classes using kWh, including those with not meters. In InnPower's view is this the most appropriate allocator for these costs?

i. If yes, why? As part of the response please explain why it is more appropriate than using number of customers by and why it is appropriate to allocate to customers that do not have meters.
ii. If not, what would be the appropriate allocator?

Response:

i. Not applicable.
ii. Upon further review, InnPower finds it appropriate to allocate the credit based on the number of customers. As the nature of the variance account is related to meters, it is reasonable to refund the amount based on the proportion of the underlying item (i.e., one meter per one account). The stranded meter variance account relates to the Residential and GS<50 rate class. As such, Innpower has also removed the GS>50, Sentinel Light, Street Light, and Unmetered Scattered Load rate class from the allocation.

InnPower has updated the 2024 DVA continuity schedule to reflect the updated cost allocation.

Reference:

9.0-VECC-45

Exhibit 9, page
DVA Continuity Schedule, Tab 5

Question:

Preamble: With respect to the PILS and Tax variance account, the Application states:

"*The balance requested for disposal is a credit of ($1,008,488)*."

It is noted (Tab 5) that the balance in the PILs and Tax variance account is allocated to customer classes using kWh. In InnPower's view is this the appropriate allocator for these costs?

i. If yes, why? As part of the response please explain why it is more appropriate than using distribution revenue by customer class.
ii. If not, what would be the appropriate allocator?

Response:

i. The costs are allocated based on kWh; therefore, IPC considered this to be the appropriate basis.
ii. See response to i.

Hydro One Networks Inc (HONI) Interrogatories

Reference:

HONI-1

Appendix 8-2-1 (A) 2024 OEB RTSR Workform ("RTSR Workform")
Exhibit 8, Tab 2, Schedule 1, Retail Transmission Service Rates, Table 8-8: Proposed RTSR Rates – Network and Connection
Exhibit 8, Tab 6, Schedule 1, Low Voltage Service Charges, Table 8-13: Allocation of LV Charges based on Transmission Connection Revenues
Exhibit 1, Tab 1, Schedule 9, Host vs. Embedded Distributor, Table 1-29: Total Bill Impacts

Question:

Preamble:

Tab 3 of the RTSR Workform is populated based on actual historical data from InnPower's most recent RRR. A specific Embedded Distributor class RTSR is not calculated for this newly proposed rate class because of lack of historical data.

The proposed RTSRs for the General Service 50 to 4,999 kW class are applied to the Embedded Distributor class throughout the application, specifically in the exhibits listed as Reference 3 & 4, respectively.

a) Please confirm that the second occurrence labelled as "General Service 50 to 4,999 kW Service Classification", in the RTSR Workform Tab 9 LV Rates row 42, represents the LV rates calculation for the proposed Embedded Distributor class. If not, please explain which LV rates calculated in Tab 9 will apply to the proposed Embedded Distributor class.

b) Please confirm whether the consumption and demand for the proposed Embedded Distributor class are included with the General Service 50 to 4,999 kW class in Tab 3 of the RTSR Workform. If not, please explain where consumption and demand for the proposed Embedded Distributor class are included in Tab 3 of the RTSR Workform.

c) Tab 3 of the RTSR Workform separates the General Service 50 to 4,999 kW class between its non-interval and interval customers.

   i. Please confirm whether the consumption and demand values shown are adjusted for non-interval/interval customers, as required.
   ii. If yes, please confirm that the total Non-loss Adjusted Metered kW in Tab 3 RRR Data for the General Service 50 to 4,999 kW class is 314,755 kW
   iii. If not, please adjust the consumption and demand values provided in Tab 3 of the RTSR Workform, to account for non-interval/interval customers in the General Service 50 to 4,999 kW class and provide an updated RTSR Workform that includes the resulting updated proposed RTSRs and LV rates for all rate classes.

d) The RTSR Workform and Table 8-8 do not separate the RTSR calculation for the General Service 50 to 4,999 kW class and the proposed Embedded Distributor class. It is expected that the resulting RTSRs will continue to be equal for the General Service 50 to 4,999 kW class and the proposed Embedded Distributor class.

   i. Please explain why it is appropriate for the same RTSRs to be applied to the General Service 50 to 4,999 kW class and the proposed Embedded Distributor class.

Response:

a) Yes, this is correct.

b) Yes, this is correct.

c) i) InnPower has updated the RTSR Workform to separate out the GS>50 interval and non-interval data as well as the Embedded Distributor class. The model will be available with 1-Staff-1 on August 10, 2023.

   ii) Not applicable

   iii) Please see c i above

d) InnPower has updated the RTSR Workform, which separates the General Service 50 to 4,999 kW class from the Embedded Distributor Class and has filed the updated model. The model will be available with 1-Staff-1 on August 10, 2023.

Reference:

HONI-2

Exhibit 8, Tab 8, Schedule 1, Loss Adjustment Factor
Appendix 8-8-1 (A) Chapter 2 Appendices 2-R Loss Factor

Question:

Preamble:

InnPower is proposing to update the total loss factor pertaining to secondary-metered customers with demand less than 5,000 kW from 1.0604 to 1.0821.

Please confirm if InnPower is also requesting and update to the approved total loss factor pertaining to primary-metered customers, which is currently 1.0498? If so, please provide the proposed total loss factor pertaining to primary-metered customers and the supporting calculations.

Response:

Yes, InnPower is requesting an update to the approved total loss factor pertaining to primary-metered customers.

The total loss factor would be 1.0713 (99% of 1.0821), as the primary metering allowance for transformer losses is 1%.

Reference:

HONI-3

Exhibit 1, Tab 1, Schedule 9, Host vs. Embedded Distributor, Table 1-29: Total Bill Impacts
Exhibit 8, Tab 11, Schedule 1, Bill Impact Information, Table 8-20: Rate Classes, Pricing and Consumption / Demand
Exhibit 8, Tab 11, Schedule 1, Bill Impact Information, Table 8-29: Embedded Distributor Non-RPP at 196 kW

Question:

Preamble:

Table 1-29 provides a detailed bill calculation and bill impacts for the proposed Embedded Distributor class, and Table 8-20 presents the bill parameters for a typical customer in each rate class including the proposed Embedded Distributor class. In both tables, the total loss factor that pertains to secondary-metered customers is applied to the proposed Embedded Distributor class, where Hydro One is the only customer.

Hydro One is a primary-metered customer, and currently billed accordingly. Please confirm that InnPower will continue to apply the approved total loss factor that pertains to primary-metered customers to bill Hydro One's embedded delivery point.

i. If not confirmed, please provide the total loss factor that will apply to Hydro One's charges and explain why InnPower will not continue to apply the approved total loss factor that pertains to primary-metered customers to Hydro One.

Response:

i. Yes, this is correct. InnPower will apply the approved total loss factor that pertains to primary-metered customers to bill Hydro One's embedded delivery point. The appropriate models have been updated accordingly.

Reference:

HONI-4

Appendix 8-9-1 (A) 2024 Proposed Tariff of Rates and Charges

Question:

Preamble:

Appendix 8-9-1 (A) does not include the proposed tariff of rates and charges for the proposed Embedded Distributor Class. The current total loss factors are also maintained, and not updated to the proposed total loss factors.

Please update Appendix 8-9-1 (A) 2024 Proposed Tariff of Rates and Charges to include the proposed tariff of rates and charges for the proposed Embedded Distributor Class, and the proposed total loss factors.

Response:

The Proposed Tariff of Rates and Charges will be available with 1-Staff-1 on August 10, 2023.

List of Attachments

Att 1-Staff-2 2019 Audited Financial Statements

Att 1-Staff-3a_Revised_Policy_5.06_Disconnection_and_Reconnection_Policy

Att 2-Staff-4a Updated 2023 2-AA

Att 2-Staff-4a Updated 2023 2-AB

Att 2-Staff-4b Updated June 2023 YTD 2-AA

Att 2-Staff-36 PPE Reconciliations

Att 2-Staff-38_Revised_BATU_DVA_Draft_Accounting_Order_20230808

Att 2-Staff-38g HONI_Ltr_BATU_Cost_Update_20220630

Att 2-Staff-38g_HONI_s92_BATU_Response_to_OEB_20220808

Att 2-Staff-38g_OEB_LTR_Change_Update_HONI_BATU_20220725_signed

Att 2-Staff-39 1 BATU Contribution Revenue Requirement 20230808

Att 4-Staff-57_Yonge_7251_Rent_Study_2015

Att 9-Staff-68 1592 Carrying Charges

Att 9-Staff-68 1592 CCA Changes 2018-2022

Att 9-Staff-73 _RCVA_Analysis

Att 1.0-SEC-6_2022_Scorecard_InnPower_Corporation

Att 1-SEC-10_IPC_Benchmarking_Analysis

Att 1-SEC-11_IPC_2024_Benchmarking_Model

Att 1-SEC-12 IPC Business Process Review

Att 1-SEC-14 Customer Priorities Survey

Att 1-SEC-2 2023_2024_IPC_Budget Attachment

Att 1-SEC-2 2023_IPC_Budget Attachment

Att 1-SEC-2 Updated 2024 Budget Attachment

Att 1-SEC-7_Q2_2023_IPC_Internal_Performance_Scorecard

Att 1-SEC-7_Q4_2021_IPC_Internal_Performance_Scorecard

Att 2-SEC-19 2024 Capital Budget Details

Att 2-SEC-23 part c ACA Table

Att 3-SEC-26_IPC_Exhibit 3_LOAD FORECAST_20230808_rev2

Att 4-SEC-34a_IPC_2018_Affiliate_Transactions_OEB_Inspection_Report_20190131

Att 4-SEC-34b_InnPower Ltr_Assurance of Voluntary Compliance_20190426

Att 4-SEC-35_InnPower_InnServices shared service agreement_May_2023

Att 4-SEC-35_InnPower_InnTerprises shared services agreement_May_2023

Att 4-SEC-35_InnPower_Town_of_Innisfil shared services agreement

Att 4.0-VECC-21-2022_MEARIE_Management_Salary_Survey_Report
Att. 7.0-VECC-29_Weighting_Factor_for_Billing_and_Collecting

List of Models

3-SEC-26 Att1 - IPC_Exhibit 3_LOAD FORECAST_20230808_rev2
2024_Cost_Allocation_Model_1.0_20230623
2024_DVA_Continuity_Schedule_CoS_1.0_20230623_Innpower
2024_Filing_Requirements_Chapter2_Appendices_1.0_20230626
2024_GA_Analysis_Workform_1.0_20230623
2024_Rev_Reqt_Workform_1.0_20230623-v2
2024_RTSR_Workform_1.0_20230629 - NEW
2024_Test_year_Income_Tax_PILs_1.0_20230627 – NEW
2024-COS-Checklist (2)
IPC - ACM Model - 2025-2027 May2_2023
2024_Benchmarking_Model 20230318_GROSS CAPITAL
2024_Benchmarking_Model 20230318_NET CAPITAL_2 (1)
IPC 2024 Demand Data 20230318
2024_Tariff_Schedule_and_Bill_Impact_Model_20230622 (4)