Ontario Energy Board | Commission de l'énergie de l'Ontario

BY E-MAIL

April 11, 2022

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

Dear Ms. Marconi:

Re: Cooperative Hydro Embrun Inc. (Cooperative Hydro Embrun)
Application for 2023 Electricity Distribution Rates
OEB Staff Interrogatories
Ontario Energy Board File Number: EB-2022-0022

In accordance with Procedural Order No. 1, please find attached OEB staff's interrogatories in the above noted proceeding. Cooperative Hydro Embrun and intervenors have been copied on this filing.

Responses to interrogatories, including supporting documentation, must not include personal information unless filed in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

Yours truly,

Georgette Vlahos
Digitally signed by Georgette Vlahos
Date: 2022.04.11 14:53:02 -04'00'

Georgette Vlahos
Advisor, Electricity Distribution: Major Rate Applications & Consolidations

Attach.

*Responses to interrogatories, including supporting documentation, must not include personal information unless filed in accordance with rule 9A of the OEB's Rules of Practice and Procedure.

OEB Staff Interrogatories
Cooperative Hydro Embrun Inc.
2023 Cost of Service Application

Exhibit 1 – Administrative

1-Staff-1
Updated Revenue Requirement Workform (RRWF) and Models

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

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

1-Staff-2
Financial and Load Information
Ref: Exhibit 1, pages 6-7

Due to the early filing of this application, 2021 financial and load information had not been finalized and audited.

(a) Please update the applicable models for 2021 final/audited information for the applicable matters listed in the reference above which noted 10 months actuals and two months forecast have been used. Examples of items that should be updated include: rate base, capital expenditures, other revenues, OM&A expenses, PILs, deferral and variance accounts, depreciation expenses etc.

(b) Given the early filing of this application, please also update 2022 forecasts if required, and specify how many months are actuals and how many are forecasts.
(c) Please provide a table summarizing and commenting on any material differences from what was included in the as-filed application.

1-Staff-3
Corporate Organization and Governance
Ref: Exhibit 1, page 18

Cooperative Hydro Embrun is structured as a cooperative utility. It is based on voluntary membership with a one-time cost of $10 per member. Members are owners of the business with an equal say in decision making.

(a) Please describe what types of decision-making Cooperative Hydro Embrun's members actively participate in. In the discussion, please explain if members participate in the decision making on specific capital and OM&A programs to undertake.
(b) Please describe the system used in decision making. In the response, please explain how the utility's customers are engaged on an on-going basis to make decisions about the utility's operations.

1-Staff-4
Facilitating Innovation
Ref: Exhibit 1, page 21

Cooperative Hydro Embrun notes that it will continue to seek to collaborate with other similar sized and like-minded utilities toward innovation goals, which could offer a more appropriate potential for supporting innovation while also helping to tame costs.

(a) For the historical period, please describe any collaboration efforts with other utilities towards innovation goals and the results of those efforts.
(b) Does Cooperative Hydro Embrun anticipate, or is it aware of, further collaboration in the forecast period towards innovation goals? If yes, please describe the nature of the goals set out and the anticipated savings. If applicable, have these savings been incorporated into the current application?

1-Staff-5
Broadband Regulation
Ref: Exhibit 1, pages 21-22

In response to Bill 257, *Building Broadband Faster Act*, 2021, Cooperative Hydro Embrun notes that it reached out to the area's telecom providers to provide the utility with plans for pole attachments in the service area going forward.

The evidence states that the telecom companies indicated that:

> Since this is new to all parties, and that the most effective way to address it would be for CHEI to provide the telecom companies with a capital plan, showing the deployment of new or replacement pole lines. The telecom company could then determine if they might use those pole lines in the future.

Cooperative Hydro Embrun plans to send its Distribution System Plan (DSP) to the telecom companies once the rates are approved and notes that “although the utility regularly keeps an open line of communication with its telecom companies, it intends on collaborating with its telecom companies when planning its pole replacement”.

(a) Please describe how many consultations were conducted with the area’s telecom providers, and how Cooperative Hydro Embrun determined who to consult with.
(b) Please confirm if Cooperative Hydro Embrun has adapted its DSP for the forecast period as a result of the consultations.
(c) If the answer to (b) is no, how has Cooperative Hydro Embrun ensured that its planned spending in certain programs (i.e., pole replacement) has been prioritized correctly.
(d) Please explain why Cooperative Hydro Embrun does not plan to send the completed DSP until after a decision in this application is issued.

1-Staff-6
Green Button
Ref: Exhibit 1, page 21

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

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

The evidence in this application states that Cooperative Hydro Embrun, “feels that current innovation ideas such as Green Button (quoted at approximately $30k) were designed with larger utilities in mind rather than smaller utilities whose primary goal is to provide safe, reliable electricity at the lowest price possible.” However, Cooperative Hydro Embrun will continue to meet the requirements of its regulator. Cooperative Hydro Embrun notes that a scheduled call with select representatives was to be held on January 19, 2022, to discuss the cost of Green Button.

(a) Please describe the outcomes of the call to discuss the cost of Green Button.

(b) Please confirm if any costs have been included in Cooperative Hydro Embrun's proposed operating or capital budgets for Green Button implementation, instead of recording amounts in the generic deferral account. If confirmed, please identify where and the quantum(s).
(c) Does Cooperative Hydro Embrun have a project plan in place to implement Green Button? If yes, please provide a high-level description of those plans. If not, please advise when distributor expects to have a project plan in place.
(d) If applicable, please indicate the overall percentage of completion of the project plan.
(e) Please confirm if Cooperative Hydro Embrun is managing or planning to manage Green Button implementation internally or through an external vendor.

1-Staff-7
Productivity

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

1-Staff-8
Strategic Goals and Objectives
Ref: Exhibit 1, Business Plan, page 5

Cooperative Hydro Embrun plans on achieving its strategic goals by setting and meeting the following objectives:

- Improve grid reliability
- Create a service-based utility whose primary goal is to exceed customers' expectations at a reasonable cost
- Promote the long-term, efficient provision of utility services consistent with OEB policy
- Work with other utilities in the promotion of both an efficient and sustainable environment
- Operate effectively with the staff currently in place
- Reduce operational costs where and when possible
- Develop and adopt an actionable plan to improve the customer experience

Please identify any work/projects/initiatives described in this application that support the achievement of the objectives above.

1-Staff-9
Customer Engagement
Ref: Exhibit 1, page 24

Cooperative Hydro Embrun notes that it sent a newsletter (Appendix D of Exhibit 1) to its customers to get feedback on its proposed capital and operational budget. The newsletter was sent via e-billing and bill inserts on January 19, 2022.

OEB staff notes that the current application was filed on February 1, 2022.

(a) Please confirm that no comments were received on either the proposed capital or operating expenses. If not confirmed, please describe any changes made to Cooperative Hydro Embrun's proposed capital and operating plans as a result of any feedback received.
(b) Please discuss why Cooperative Hydro Embrun did not distribute the newsletter sooner in order to provide a longer time period to solicit customer feedback.

1-Staff-10
Customer Engagement
Ref: Exhibit 1, page 24

Cooperative Hydro Embrun held an Annual General Assembly held in April 2021 where the General Manager presented the utility's 2021 budgets.

(a) How many customers attended the Annual General Assembly?
(b) Does Cooperative Hydro Embrun find the attendance rates acceptable as a basis for measuring customer wants? If so, why?
(c) Please provide any meeting minutes, presentations or reports as available.

1-Staff-11
Customer Engagement
Ref: Business Plan, page 10

A customer satisfaction survey was conducted in the spring of 2021. Cooperative Hydro Embrun notes that in its most recent customer satisfaction survey, although satisfied with the level of service, some concerns were raised by customers with respect to more timely notification when outages occur.

Has Cooperative Hydro Embrun implemented/or is it considering implementing any remedy for this concern? If so, when?

1-Staff-12
Customer Engagement
Ref: Chapter 2A Filing Requirements for Small Utilities, December 16, 2021, page 10

Please document any communications with unmetered load customers, including street lighting customers, and how Cooperative Hydro Embrun assisted them in understanding the regulatory context in which distributors operate and how it affects unmetered load customers.

1-Staff-13
Scorecard
Ref: Exhibit 1, pages 26-29

At the reference above, Cooperative Hydro Embrun provides a discussion on its OEB Scorecard. Please provide a definition of the Distribution System Plan Implementation Progress metric.

1-Staff-14
ROE Information
Ref 1: Error Checking Response #7, March 21, 2022
Ref 2: Exhibit 1, 2020 Scorecard

OEB staff notes a discrepancy in the ROE achieved between reference 1 and reference 2 for 2018. Reference 1 shows a 2018 achieved ROE of 6.12%. Reference 2 shows 8.12%.

(a) Please confirm if the Scorecard information is correct.
(b) Please explain the drivers for the ROE achieved in 2020.

Exhibit 2 – Rate Base

2-Staff-15
COVID-19

Please confirm if Cooperative Hydro Embrun has made any assumptions or inclusions for expenses related to COVID-19 in its capital budgets. If assumptions or inclusions have been made, please specify the impacts and the year in which assumptions have been included.

2-Staff-16
Rate Base
Ref 1: Exhibit 1, Appendix 1B
Ref 2: Excel Appendix 2-BA, February 14, 2022

At reference 1, Cooperative Hydro Embrun has submitted its 2020 audited financial statements. A copy of the 2021 audited financial statements has not been provided, given the timing of the filing of this application.

(a) Please provide a copy of the final 2021 audited financial statements, or a draft version, as available.
(b) Please confirm that Cooperative Hydro Embrun has already reconciled the property, plant, and equipment values shown in the 2021 audited financial statements to the December 31, 2021 values shown in Excel Appendix 2-BA (reference 2).
(c) If these amounts do not reconcile, please file a reconciliation and explanation, as well as update Excel Appendix 2-BA.

2-Staff-17
Rate Base, Depreciation, and PILs
Ref 1: Response to Error Check Q#19, March 21, 2022
Ref 2: Excel Appendix 2-BA and Appendix 2-C, March 21, 2022
Ref 3: Excel PILs Model, February 14, 2022

At reference 1, Cooperative Hydro Embrun indicated that it would address this error check question in its response to interrogatories. However, in its response to the error check question, Cooperative Hydro Embrun also suggested that the Excel Appendix 2-BA and Excel PILs model values were correct, but the Excel Appendix 2-C values were incorrect.

- For 2022 capital additions: The Excel Appendix 2-BA and the Excel PILs model (B8 Sch 8 CCA Bridge) of $375,225 do not tie to the Excel Appendix 2-C of $138,925.
- For 2023 capital additions: The Excel Appendix 2-BA and the Excel PILs model (T8 Sch 8 CCA Test) of $148,750 do not tie to Excel Appendix 2-C of $143,750.

Please update the Excel Appendix 2-BA, Excel Appendix 2-C, and the Excel PILs model to resolve these discrepancies.

2-Staff-18
Ref 1: Chapter 2 Appendices, Tab 2-BA - Fixed Asset Cont
Ref 2: Chapter 2 Appendices, Tab 2-H – Other Revenue
Ref 3: Excel PILs model, February 14, 2022

There are no disposals in Appendix 2-BA for 2020-2023. There are no proceeds of dispositions in the UCC schedules of the Excel PILs model. There are no gains/losses on asset disposition/retirement in Appendix 2-H for 2021-2023. Please confirm that this is appropriate. If not confirmed, please revise the evidence as necessary.

2-Staff-19
Cost of Power
Ref: Chapter 2 Appendices, Tab 2-ZA – Com.Exp.Forecast

OEB staff has reproduced a portion of the table under "Step 2" on Tab 2-ZA of the Chapter 2 Appendices below:

Customer		**Revenue**	**Expense**				
Class Name	UoM	USA #	USA #	Class A Non-RPP Volume**		Class B Non-RPP Volume**	Class B RPP Volume**
Residential	kWh	4006	4705				21806912.26
General Service < 50 kW	kWh	4010	4705				5002577.645
General Service > 50 to 4999 kW	kWh	4035	4705			3204601.856	1078043.319
Unmetered Scattered Load	kWh	4010	4705			100857.461	
Street Lighting	kWh	4025	4705				261309.065
	kWh	4025	4705				
	kWh	4025	4705				
	kWh	4025	4705				
	kWh	4025	4705				
	kWh	4025	4705				
	kWh	4025	4705				
TOTAL				**0**		**3,305,459**	**28,148,842**

(a) Please confirm if the Street Lighting volume should be in the non-RPP column. If confirmed, please make the necessary corrections to the model.
(b) OEB staff is unable to reconcile the volumes entered in Tab 2-ZA to Cooperative Hydro Embrun's proposed load forecast adjusted for losses. Please reconcile the information provided. If changes are required, please make the necessary corrections to the model, and any other resulting edits because of this correction.

2-Staff-20
Cost of Power
Ref 1: Chapter 2 Appendices, Tab 2-ZB – Cost of Power
Ref 2: Tariff and Bill Impact Model

Tab 2-ZB of the Chapter 2 Appendices shows an Ontario Electricity Rebate (OER) of 19.8%. The Tariff and Bill Impact Model shows an OER of 21.2%. OEB staff notes that the current OER, effective November 1, 2021, is 17%.

Please update the models as required and confirm that Cooperative Hydro Embrun will again update the applicable references should an updated OER be announced prior to the conclusion of this proceeding.

2-Staff-21
Cost of Power
Ref: Application, Exhibit 2, page 29

In relation to the Smart Meter Charge, Cooperative Hydro Embrun notes that it applied the OEB-approved “rate of $0.57 per month for the forecasted Residential and General Service<50kW customers for test year 2021 and included the projected amount of $17,166 in its Cost of Power.”

(a) Please confirm the test year is intended to state 2023.
(b) Given that the current Smart Meter Charge expires on December 31, 2022, please confirm that the utility will update this rate should an updated charge be approved by the OEB prior to the conclusion of this proceeding.

2-Staff-22
Number of Poles
Ref 1: Application, Exhibit 2, page 36
Ref 2: Exhibit 2, DSP, page 6

At reference 1, the utility notes that approximately 432 primarily wood-type poles support the overhead distribution system. The table in reference 2 indicates the utility has 345 poles. Please confirm the correct number.

2-Staff-23
Ref: Exhibit 2, Page 36

Regarding Net Metering, Cooperative Hydro Embrun states:

> *CHEI has not received any requests for the connection of “net metering” in its service territory. Based upon the above information, CHEI does not expect to reach the current available capacity for renewable generation in the near future (i.e., over the 5-year forecast horizon).*

(a) What are Cooperative Hydro Embrun’s plans should a request be received for a net metering connection, Renewable Generation or DER?
    i. Please discuss how the request would be handled, and describe any limitations that would be faced in dealing with the request.

2-Staff-24
Ref: Exhibit 2, DSP, Section 1.1, Page 5

Cooperative Hydro Embrun states:

> CHEI is an embedded utility in Hydro One Distribution’s service territory and, as such, is supplied power from Hydro One’s Chesterville Transformer Station at 44kV.
>
> CHEI receives power from Hydro One Networks Inc. (“Hydro One”) at 44 kV and steps the voltage down to 8.32kV at its’ both Municipal Station (MS). The MS as

of TI rated at 7.5 MVA/ 10MVA (ONAN/ ONAF) act as a backup in the event of T2 failure, T2 rated at 10 MVA / 13.3 MVA (ONAN/ ONAF) built-in 2017. From these MS, it delivers power to its customers via four feeders emanating from its' MS. CHEI earns revenue by providing electric power to the homes and businesses in the service territory. The rates charged for this and the performance standards that the energy delivery system must meet are regulated by the Ontario Energy Board.

(a) Are T1 and T2 located at different Municipal Stations (MS), or are they both located at the same MS?
    i. If at the same MS, is there another transformer located at a second MS? Please explain.
(b) Are T1 and T2 energized in parallel, or is only T2 energized during normal operations, with T1 left de-energized unless required as a backup?
(c) Please confirm that both Municipal Substations receive power from a single 44 kV radial feeder emanating from Hydro One's Chesterville TS.
    i. If not confirmed, please describe the different sources of supply to the different CHEI Municipal Substations.
(d) If transformer T2 (10 MVA) becomes non-operational, for approximately how many hours per year in each of the next 10 years is the system load expected to exceed the capacity of T1 (7.5MVA)?

2-Staff-25
System Reliability
Ref: Exhibit 2, DSP, page 17

Please explain why the Emergency Urban Response line item dropped to 83.33% in 2020 compared to 100% in 2016-2020.

2-Staff-26
System Reliability
Ref: Exhibit 2, Section 2.4, Page 33

Regarding its System Reliability & Performance, Cooperative Hydro Embrun provided the following:

Table 31 – All Causes of Power Interruptions (2018-2020)

		2016		2017		2018		2019		2020	
Cause Code	Description	# of Customer Interruption	# Customers Hours	# of Customer Interruption	# Customers Hours	# of Customer Interruption	# Customers Hours	# of Customer Interruption	# Customers Hours	# of Customer Interruption	# Customers Hours
0	Unknow/Other	0	0	0	0	0	0	1	2.75	2	7.5
1	Scheduled Outage	485	88	10	10	113	896	120	32	20	60
2	Loss of Supply	10622	53070	2175	2175	6830	63651	0	0	0	0
3	Tree Contact	0	0	0	0	0	0	0	0	0	0
4	Lightning	0	0	0	0	0	0	0	0	0	0
5	Defective Equipment	0	0	5	14	13	473.25	6	3	2	4.5
6	Adverse Weather	0	0	0	0	2	2	1	1.75	0	0
7	Adverse Environment	0	0	0	0	0	0	0	0	0	0
8	Human Element	0	0	0	0	0	0	0	0	0	0
9	Foreign Interference	0	0	0	0	0	0	1	3	1	2

(a) What actions is Cooperative Hydro Embrun taking to ensure that Hydro One reduces the frequency and duration of Loss of Supply outages? Please elaborate.

(b) Has Hydro One made any commitments to Cooperative Hydro Embrun to reduce future Loss of Supply event frequency and/or duration?

   i. If yes, please provide details.

2-Staff-27
Ref: Exhibit 2, DSP, Section 2.4.1, Page 19

Regarding its System Reliability, Cooperative Hydro Embrun provided the following:

Table 13 - Interruption 2018

		2018	2018	2018
Cause Code	Description	# Interruption / As a result of the cause interruption	# Of Customer Interruption	# Customers Hours
0	Unknow/Other	0	0	0
1	Scheduled Outage	14	113	896
2	Loss of Supply	4	6830	63651
3	Tree Contact	0	0	0
4	Lightning	0	0	0
5	Defective Equipment	7	13	473
6	Adverse Weather	2	2	2
7	Adverse Environment	0	0	0
8	Human Element	0	0	0
9	Foreign Interference	0	0	0

In 2018 27 interruptions occurred due to loss of supply from Hydro One and scheduled outages. The 13 interruptions of lost power recorded under "Defective Equipment" were due to a blown fuse at a transformer, and 2 interruptions were caused by adverse weather was due to a severe thunderstorm.

Regarding its Fuse Replacement Program, Cooperative Hydro Embrun states on DSP PDF page 62 of 121 the following:

> CHEI has a fused cutout and porcelain air gap lightning arrestors replacement program.

(a) What equipment defect caused the "blown fuse at a transformer" in 2018?
(b) Did the same equipment defect cause blown fuses in other years during the period 2016 – 2019?
    i. If no, please list the equipment defects that caused the blown fuses in each year.
    ii. Does the same type of defective equipment still exist in Cooperative Hydro Embrun's system?
        i. If yes, what actions are being taken to mitigate the defective equipment?
(c) Please confirm that the Fuse Replacement Program is not intended to address the issue of defective equipment that caused the blown fuses referenced in the above questions.
    i. If not confirmed, please reconcile the apparent contradiction with the statement on DSP PDF 67 of 121 "CHEI…is replacing the porcelain fused cutouts with polymer fused cutouts and replacing porcelain air gap type lightning arrestors with polymer, solid dielectric arrestors. These projects are being planned proactively because of the problems with this equipment in various utilities, **even if it has not caused outages or health risks at CHEI**." *(emphasis added for clarity).*

2-Staff-28
Unit Cost Metrics
Ref: Exhibit 2, Section 2.4, Page 35

Regarding its Efficiency Assessment & Unit Cost Metrics:
(a) Are the costs shown in "Table 33 - Total Cost per Kilometer of Line" in real or nominal dollars?
    i. If in nominal dollars, please provide a revised graph showing costs in real dollars.
(b) Please provide a graph similar to Table 33 showing Cost ($) per Unit of Energy Delivered (MWh), in real dollars.

2-Staff-29
System Access Clarification
Ref 1: Response to Error Checking Question 9, March 21, 2022
Ref 2: Chapter 2 Appendices, Tab 2-AB – Capital Expenditures
Ref 3: EB-2017-0035, Settlement Proposal, Page 13, December 22, 2017

Error checking question 9 noted an inconsistency in the originally filed application between Exhibit 2, page 20 and the Chapter 2 Appendices, Tab 2-AB. Exhibit 2 showed a 2018 planned System Access amount of $83,200 and capital contributions of $132k, whereas Tab 2-AB showed $34,500 in planned System Access spending, and capital contributions of $5,775.

In response to the error checking question, Cooperative Hydro Embrun updated Tab 2-AB for 2018 planned System Access to $215,200, and capital contributions of $132k. OEB staff notes that the planned System Access amount of $215,200 does not reconcile to Cooperative Hydro Embrun's 2018 settlement proposal (pg. 13), which shows planned 2018 System Access of $83,200. Please reconcile and provide an explanation for the discrepancy.

2-Staff-30
Ref 1: Response to Error Checking Question 9, March 21, 2022
Ref 2: Exhibit 2, DSP, pages 35, 37

As noted in the interrogatory above, Cooperative Hydro Embrun updated Tab 2-AB to show 2018 planned System Access of $215,200, and capital contributions of $132k. Because of this update, the DSP on pages 35 and 37 does not reflect the same figures.

Please provide an itemized breakdown of the difference between 2018 actual spending of $79,865, and 2018 planned spending of $215,200 (if it is in fact confirmed that this is the correct number). In the response please also provide an explanation for the difference in capital contributions as the DSP indicates planned contributions for 2018 of $5,775.

2-Staff-31
Efficiency Assessment
Ref: Exhibit 2, page 33

Cooperative Hydro Embrun notes that its:

> …costs fall below the average cost range of all Ontario electricity distributors. Using the benchmarking forecast model, CHEI expects to remain in Group 1's efficiency performance. Will being in group 1, CHEI is still improving its efficiency, with 2023 proposed costs predicted to be 70.1% lower than the model's predicted costs.

(a) Please describe or itemize the areas in which Cooperative Hydro Embrun is achieving these efficiencies.
(b) Please explain how Cooperative Hydro Embrun ensures and maintains the health of its distribution system given its proposed costs being significantly lower than predicted costs.

2-Staff-32
Subdivisions - Historical
Ref 1: Exhibit 2, pages 5-6
Ref 2: Exhibit 2, DSP, page 11
Ref 3: Exhibit 2, DSP, page 37

For 2020, the Versailles III and Patenaude East Subdivision Phase II projects are listed as major capital cost drivers in reference 1. Reference 2 contains the following information:

Since its last DSP in 2017, two new developments have been energized:

- Subdivision Faubourg Ste-Marie Phase II (2021) - 54 lots (Purple Area)
- Subdivision Versailles Phase III (2021) - 42 lots (Pink Area)

Table 5 - Historical Subdivision Development Costs by Year

Year/ Development	2018	2019	2020	2021	2022
Faubourg Ste-Marie Phase II	$ 0	$ 0	$ 0	$99,219	$ 0
Versailles Phase III	$ 0	$ 0	$ 0	$89,877	$ 0
Faubourg Ste-Marie Phase III	$ 0	$ 0	$ 0	$ 0	$115,000
Central Park	$ 0	$ 0	$ 0	$ 0	$173,000
Total	$ 0	$ 0	$ 0	$189,096	$288,000

Reference 3 notes approximately $29k in unforeseen expenses incurred relating to connecting a new building (26 units) in 2018. OEB staff believes this to be the Centre Urgel Forget Addition based on the evidence.

(a) Please reconcile reference 1 which lists the Versaille III as a cost driver for 2020, with reference 2, which lists it under 2021.
(b) Please explain why the Patenaude East Subdivision Phase II is not listed in the table in reference 2.
(c) Please explain why the Centre Urgel Addition is not listed in the table in reference 2.
(d) If applicable, please provide an updated table showing historical subdivision development costs by year.

2-Staff-33
Subdivisions - 2022
Ref 1: Exhibit 2, page 6
Ref 2: Exhibit 2, DSP, page 11
Ref 3: Chapter 2 Appendices, Tab 2-BA – Fixed Asset Continuity Schedule
Ref 4: Exhibit 2, DSP, page 55

The evidence indicates that two new subdivision projects are planned for 2022 requiring a service area amendment. Subdivision Faubourg Ste-Marie Phase III (~65 lots) is scheduled to start in July 2022. The forecasted capital expenditure is $115k. Subdivision Central Park (~250 lots) is also expected to start in July 2022. The forecasted cost is approximately $173k. Cooperative Hydro Embrun and the developer expect a formal decision and arrangement by March 2022.

(a) Please provide a summary of the formal decision and arrangement between Cooperative Hydro Embrun and the developer as noted in the last sentence above.

(b) Please provide the current status of the two projects, any updated cost details and the estimated timelines for completion.

  i. How confident is Cooperative Hydro Embrun that these projects will be in service by the end of the 2022?

(c) Reference 4 indicates a forecast of $80k in capital contributions for these projects. How have these total capital contributions been forecasted?

2-Staff-34
Capital Expenditures
Ref: Chapter 2 Appendices, Tab 2-AB – Capital Expenditures

The proposed net capital expenditures for 2023 is about 19% higher than the average level of forecasted capital expenditures for 2024-2027. Has Cooperative Hydro Embrun considered a more balanced pacing of its capital plan during the DSP period? If so, please explain what has been done.

2-Staff-35
Capital Expenditures – System Access
Ref 1: Chapter 2 Appendices, Tab 2-AB – Capital Expenditures
Ref 2: Exhibit 2, DSP, pages 35-55

Over the historical period, Cooperative Hydro Embrun's actual gross capital expenditures exceeded its planned capital expenditures in System Access by approximately $329k. OEB staff has summarized the variance in the table below:

	2018	2019	2020	2021	2022	Total
System Access	-$135.3k	$20.9k	$185.7k	$4.7k	$253.3k	$329.2k

(a) Of the $329k variance in System Access:

  i. Please provide the portion attributable to new development.

  ii. Please explain why the SCADA improvement cost in 2019 (unforeseen expense not accounted for in last DSP) of $34k is categorized as System Access.

  iii. Please explain Cooperative Hydro Embrun's process/method used in forecasting subdivision development.

2-Staff-36
Capital Expenditures – System Renewal
Ref 1: Chapter 2 Appendices, Tab 2-AB – Capital Expenditures
Ref 2: Exhibit 2 – Rate Base, Section 2.2.3, Page 20 of 38

Regarding its Summary of Capital Expenditure and Contribution, Cooperative Hydro Embrun provided the following:

Table 17 – Gross Fixed Asset Additions – System Renewal

	2018 BA	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Projection	2023 Projection
Sub-Total System Renewal	$115,780	$143,563	$36,215	$77,545	$108,065	$112,225	$107,050
Planned per 2018 DSP		$115,780	$20,000	$60,000	$62,000	$40,000	
Contributed Capital		$0	0	0	0	0	0
Total System Renewal	$115,780	$143,563	$36,215	$77,545	$108,065	$112,225	$107,050

OEB staff prepared the following table based on the information provided in Table 17:

	2018	2019	2020	2021	2022
Actual (Forecast 2022)	$ 143,563.00	$ 36,215.00	$ 77,545.00	$ 108,065.00	$ 112,225.00
Plan	$ 115,780.00	$ 20,000.00	$ 60,000.00	$ 62,000.00	$ 40,000.00
Difference	$ 27,783.00	$ 16,215.00	$ 17,545.00	$ 46,065.00	$ 72,225.00
% Overspend	24.0%	81.1%	29.2%	74.3%	180.6%
Cumulative Overspend	$ 179,833.00				
Average Overspend	77.8%				

(a) Cumulative System Renewal overspend above plan for the five referenced years (2018 to 2022) is approximately $180K, with average annual expenditures running 77.8% above plan. What actions is Cooperative Hydro Embrun taking to ensure better alignment between Planned and Actual System Renewal spending over the upcoming test period?

(b) What drove the annual percentage departures in Actual vs Planned System Renewal spending in each of the referenced historical years and forecast 2022?

   i. Are common themes driving the spending above Plan, or are the drivers random? Please discuss.

   ii. Does Cooperative Hydro Embrun have asset condition knowledge gaps that contribute to annual System Renewal spending running above Plan?

If yes, please explain what actions are being taken to mitigate these knowledge gaps.

2-Staff-37
Ref 1: Exhibit 2, DSP, Section 1.2, Page 6
Ref 2: Chapter 2 Appendices, Tab 2-AB – Capital Expenditures

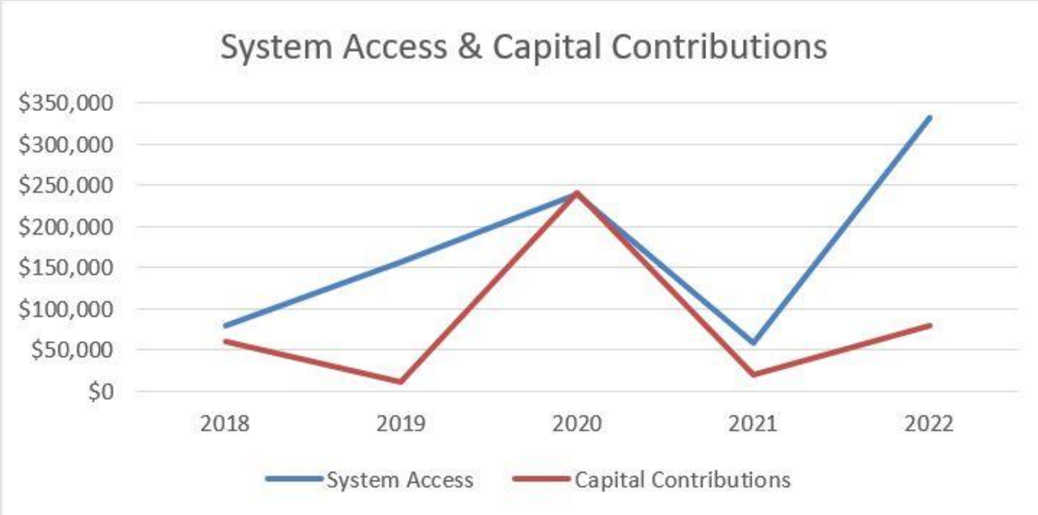
Regarding its Investment Category, Cooperative Hydro Embrun provided the following:[1]

Table 2 - Historical Capital Investments by Year (Table ES-1)

	Historical (previous actual)				
	Test-5	Test-4	Test-3	Test-2	Test-1
	2018	**2019**	**2020**	**2021**	**2022**
CATEGORY	Actual	Actual	Actual	Actual	Projected Y/E
	$	$	$	$	$
System Access	79,865	155,912	238,671	57,728	331,300
System Renewal	143,563	36,215	77,545	108,065	112,225
System Service	0	0	11,532	10,123	6,000
General Plant	3,854	8,495	4,676	37,605	5,700
Total	227,282	200,622	332,424	213,521	455,225
Contributed Capital	-60,245	-11,125	-240,151	-20,000	-80,000
Net Capital	167,037	189,497	92,273	193,521	375,225
System O&M	89,782	82,775	111,374	90,830	93,828

OEB staff prepared the following tables and figure based on the information provided in Table 2:

[1] **Note**: The Actual Net Capital Expenditures value for Year 2020 in Table 2 above was adjusted in Cooperative Hydro Embrun's Response to OEB Staff Error Checking Questions #10 from $92,273 to $120,678 because of a $28,405 gain on Disposition of Utility and Other Property. This adjustment is irrelevant for the purposes of the questions below because Net Capital is not referenced.



	2018	2019	2020	2021	2022
System Access	$79,865	$155,912	$238,671	$57,728	$331,300
Capital Contributions	$60,245	$11,125	$240,151	$20,000	$80,000
Capital Contributions as % of System Access	75%	7%	101%	35%	24%

	2018	2019	2020	2021	2022
System O&M	$ 89,782.00	$ 82,775.00	$ 111,374.00	$ 90,830.00	$ 93,828.00
Delta from average	$ (3,935.80)	$ (10,942.80)	$ 17,656.20	$ (2,887.80)	$ 110.20
% Delta from average	-4.2%	-11.7%	18.8%	-3.1%	0.1%
Average Annual O&M	$ 93,717.80				

(a) Please explain the significant inter-year volatility in contributed capital, with specific consideration of the apparent lack of correlation with annual System Access spending.
(b) Cooperative Hydro Embrun has forecasted capital contributions of $10k for each of 2023-2027. Please describe how capital contributions were forecasted for the 2023 test year and forecast period.
(c) Please explain the inter-year variability in System O&M spending over the historical period.
    i. What action is Cooperative Hydro Embrun taking to reduce inter-year System O&M spending over the test period?

2-Staff-38
Ref 1: Exhibit 2, DSP, section 4.7
Ref 2: Chapter 5A Filing Requirements, pages 10-11

Please confirm that Cooperative Hydro Embrun does not have any capital investments that have a project life cycle greater than one year. If not confirmed, please outline the proposed accounting treatment, including the treatment of the cost of funds for construction work-in-progress.

2-Staff-39
Transformer Inventory
Ref: Exhibit 2, DSP, pages 39-54

OEB staff has summarized the transformer inventory planned versus actual based on the information at the reference above.

	2019	2020	2021	2022	2023
Planned	$0	$18k	$18k	$18k	$8k
Actual	$36,679	$9k	$8,465	$8k	-

Given that Cooperative Hydro Embrun exclusively uses outside contractors for maintenance and capital work, how does it determine the quantum to hold in inventory?

2-Staff-40
Depreciation Rates
Ref 1: Exhibit 2 – Rate Base, Section 2.2.2, page 16 of 38
Ref 2: Exhibit 2 – Distribution System Plan 2022, Section 1.2, page 7 of 61

Regarding its Depreciation Rates, Cooperative Hydro Embrun provided the following:

Table 9 - Depreciation Rates

Account	Description	As of
1611	Computer Software (Formally known as Account 1925)	5
1820	Distribution Station Equipment <50 kV	55
1830	Poles, Towers & Fixtures	40
1835	Overhead Conductors & Devices	60
1845	Underground Conductors & Devices	35
1850	Line Transformers	40
1855	Services (Overhead & Underground)	40
1860	Meters	25
1860	Meters (Smart Meters)	15
1915	Office Furniture & Equipment (10 years)	10
1920	Computer Equipment - Hardware	5
1935	Stores Equipment	10
1940	Tools, Shop & Garage Equipment	10
1945	Measurement & Testing Equipment	10
1995	Contributions & Grants	40

Regarding its Investment Category, Cooperative Hydro Embrun states:

> For the forecasted period, capital investments continue but at a more even pace. The focus going forward will be to continue with its replacements of aging transformers and the replacement of three poles per year. Overall, CHEI believes the proposed average annual investment is reasonable.
>
> Having a relatively small distribution system makes it easier to manage, including finding a reasonable balance between capital and operational (O&M) expenses. CHEI's spending in both categories are evenly paced and therefore is well balanced. O&M expenses and forecasts include costs such as "trouble calls," tree trimming, for example, which are for the most part stable and easy to forecast based on a review of past issues. CHEI considers the overall condition of its system

(a) Please confirm that replacing three poles per year from a portfolio of 345 poles[2], implies an expected service life of over 100 years for poles.
   i. If confirmed, please reconcile the over 100 year implied expected service life with the 40 year depreciation life for poles shown in Table 9.
   ii. If not confirmed, please explain.

(b) What is the historic replacement rate of poles in each of the past 10 years?

[2] DSP, Section 1.1, Table 2, Page 6 of 61

(c) Does Cooperative Hydro Embrun expect to increase its planned pole replacement rate in the future?
    i. If yes, please indicate when the rate will increase and by how many poles per year.
(d) How does Cooperative Hydro Embrun determine that individual assets in its different asset classes have reached end-of-life?
(e) Does Cooperative Hydro Embrun utilize the depreciation lives shown in Table 9 when determining end-of-life for individual assets in any of its asset classes? Please discuss.

2-Staff-41
Ref: Exhibit 2, DSP, Section 2, page 8

Regarding its Distribution System Plan, Cooperative Hydro Embrun states:

> Consistent with best practices, CHEI has replaced or upgraded equipment when economically viable or when the equipment is no longer functioning reliably. Hence it has a range of vintages of equipment that is planned to be replaced in a fiscally responsible manner. This has not presented any issues, and this will continue to be CHEI's practice. In general, only end-of-life assets will be replaced. The net result has been that while the average age of the system has increased slightly, the system's reliability has steadily improved to meet the expectations of CHEI's customers

(a) Define "economically viable" as the term is used in the reference.
    i. Please explain the circumstances in which equipment is replaced because Cooperative Hydro Embrun can afford to replace it, absent other more pressing drivers such as deteriorated condition or inadequate capacity?
(b) If "In general, only end-of-life assets will be replaced", does this mean that sometimes assets not at end-of-life will be replaced?
    i. If yes, please provide examples where assets that are not at end-of-life would be replaced.

2-Staff-42
Ref: Exhibit 2, DSP, Section 2.1, page 8

Regarding its Distribution System Plan, Cooperative Hydro Embrun states:

> While CHEI's focus is to replace aging equipment, other regulatory requirements that require additional major capital expenditures remain firmly in place (e.g., the "obligation to connect" new growth and maintaining the highest electrical safety standards by removing all PCB contaminants, for example).

(a) Please confirm that “aging equipment” as used in the reference, actually means “equipment determined to be at end-of-life due to unacceptably poor condition”.
    i. If not confirmed, please explain why “aging equipment” that is still in adequate condition to provide reliable service would need to be replaced, and provide examples of such replacements.

2-Staff-43
PCB Transformers
Ref: Exhibit 2, DSP, Section 3.3, pages 28-29

(a) In which year does Cooperative Hydro Embrun plan to complete its PCB testing program?
(b) What number of PCB-filled transformers is the testing program expected to identify as requiring replacement due to unacceptably high PCB levels?
    i. How many transformers does Cooperative Hydro Embrun expect to replace in each year of the planning period due to discovering unacceptably high PCB levels?

Exhibit 3 – Customer and Load Forecast

3-Staff-44
Ref 1: Exhibit 3, pages 3-4
Ref 2: Load Forecast model, Forecast sheet

Cooperative Hydro Embrun states that the November and December 2021 are estimated, and the load forecast model includes round numbers 2,425,000 kWh and 2,900,000 kWh for November and December.

(a) If possible, please update the load forecast using historic actual data for these months.
(b) Please explain how the values were estimated.
(c) Please explain why Cooperative Hydro Embrun’s method was preferable to using only historic actual data for estimating the regression equations – for example, 120 months from November 2011 to October 2021, and then using the regression model to forecast these months.

3-Staff-45
Ref: Load Forecast model, Bridge&Test Year Class Forecast sheet

The 2021 Residential ratio of class kWh to wholesale purchases is calculated as a historic average of 2012 to 2020, rather than as a ratio of rate class kWh to wholesale purchases for the year. For GS < 50 kW and GS 50 – 4,999 kW, the 2021 ratio is calculated as a ratio of rate class energy to wholesale purchases.

(a) Please explain the reason for the apparent inconsistency.
(b) As a scenario, please provide the forecasted residential energy if the 2021 ratio of rate class energy to wholesale purchases were calculated consistently with the general service rate classes.

3-Staff-46
Load Forecast
Ref 1: Load Forecast model – Bridge&Test Year Class Forecast
Ref 2: Clarification Question 22

The proposed 2023 energy forecast of 3,952,566 kWh for the GS > 50 kW rate class is found in cell G83 of the above reference. This cell references the 2022 forecast of 3,952,566 kWh in cell G82.

Please explain why the 2023 forecast of 3,960,650 kWh in cell F72 is not referenced.

3-Staff-47
Load Forecast
Ref 1: Load Forecast model – Bridge&Test Year Class Forecast

The GS > 50 kW to 4,999 kW appears to OEB staff to using a shrinking share of wholesale purchases. The average ratio of wholesale to wholesale used is 13.01%. This is less than the historic actual ratio for every year from 2012 to 2017, and more than the ratio for every year from 2018 to 2021. Similar trends may be present in other rate classes.

(a) As a scenario, for the Residential, GS < 50 kW, and GS 50 to 4,999 kW rate classes, please calculate ratios for 2022 and 2023 based on a trend of ratios from 2012 to 2019.
(b) Please use the ratios in part a) to forecast energy use by rate class under this scenario.

3-Staff-48
CDM
Ref 1: Exhibit 3, page 18

Cooperative Hydro Embrun states that the “persisting effects of CDM projects are embedded in the utility wholesale; therefore no adjustment was made.” It states that it is “not planning or aware of any new CDM programs in the test year (2023).”

(a) Please provide the historic CDM program delivery for each historic year, using estimates as required to complete any missing data
(b) Please estimate the CDM program delivery in 2022.
(c) If Cooperative Hydro Embrun is now aware of CDM programs impacting 2023, please provide an estimate of these.
(d) Please comment on the suitability of a forecasting model which exhibits a trend of CDM delivery in the historic years which may not match the trend of CDM delivery in the forecast period.

Exhibit 4 – Operating Expenses

4-Staff-49
COVID-19
Ref: Exhibit 4, page 14

With the exception of the increase in 2020 when compared to 2019 related to the vacation time incurred being paid to an employee rather than vacation time being taken, please confirm if Cooperative Hydro Embrun has made any other assumptions or inclusions for expenses related to COVID-19 in its OM&A budgets. If there are assumptions or inclusions, please specify the impacts, and the year in which assumptions have been included.

4-Staff-50
Efficiencies
Ref: Exhibit 4, page 4

Cooperative Hydro Embrun notes that although it does not document alternative solutions, part of the management's approach is to continually compare existing services and costs to more cost-effective alternatives wherever possible.

Has Cooperative Hydro Embrun worked with its third-party vendors to find efficiencies? If so, please explain what efficiencies have been identified.

4-Staff-51
Ref 1: Exhibit 4, page 7
Ref 2: Exhibit 4, page 3

The evidence states that most OM&A variances from the 2018 OEB-approved to the 2023 test year can be attributed to an increase in billing and collecting, and administrative costs for a total of $65,574. The major contributor to the rise in Billing and

Collecting costs is adjustments in salaries and increases in Ottawa River Energy Services (ORES) billing fees.

Reference 2 indicates that billing and collecting related costs include answering customer questions, managing their complaints, and responding to service outages and emergencies.

Please clarify the statement that the main contributor to the rise in Billing and Collecting costs is adjustments in salaries.

4-Staff-52
Ref: Exhibit 4, page 9

When preparing its budgets for 2019-2021, Cooperative Hydro Embrun notes that it used a combination of methods, including quotes or most up-to-date costs from recent invoices and inflation where applicable.

In preparing its current application, Cooperative Hydro Embrun notes that it was decided that the Price Cap index would be used going forward rather than a combination of both. To prepare its OM&A costs for the 2022 bridge and 2023 test year, Cooperative Hydro Embrun used the Price Cap inflation of 3.3%.

(a) Given that in the past a more detailed preparation of its budgets was being utilized (i.e., a combination of methods), please explain why Cooperative Hydro Embrun decided this more simplified approach of using the Price Cap Index is better suited for its budgeting processes.
(b) Please confirm if this inflation factor was applied to all USoA accounts.
   i. What is the basis for the assumption that all expenses will go up by 3.3%?
   ii. For those accounts where an increase other than 3.3% was utilized, please explain the reason(s).
(c) Has Cooperative Hydro Embrun considered the risks to its operations should inflation increase at a rate higher than budgeted or if any unforeseen expenditures arise? Please describe how Cooperative Hydro Embrun intends to mitigate those risks.

4-Staff-53
Ref 1: Exhibit 4, Pages 8, 13
Ref 2: Chapter 2 Appendices, Tab 2-JC – OM&A Programs

Cooperative Hydro Embrun notes that the increase in Billing and Collecting between 2021 and 2022 is partly due to a fee from Elster Solutions Canada for “Connecxo Net

Sense SMA". On page 8, this is described as "one future-proof application, providing a complete view to maximizing value from advanced metering infrastructure (AMI) investment. Connexo helps manage the core of a utility's business with a flexible, scalable, open-architecture framework based on industry standards and protocols."

(a) Please further describe or clarify what the function of this product/service is in the context of Cooperative Hydro Embrun's environment.
(b) Please confirm if this fee an ongoing expense. If not, is there another associated monthly/annual fee for this product/service.
(c) Given that Cooperative Hydro Embrun's billing is completed externally, please explain if this affects the fees charged by Cooperative Hydro Embrun's provider for billing services.

4-Staff-54
Ref 1: Exhibit 4, page 7
Ref 2: Chapter 2 Appendices, Tab 2-JB – OM&A Cost Drivers

The Billing and Collecting line item shows an increase of $44,324 from the last OEB-approved cost of service. Of that increase, $42,794 is due to an increase in Account 5315 – Customer Billing.

(a) Please provide an itemized breakdown of the major cost drivers for increases in this account.
(b) Please detail any cost control and/or efficiency measures Cooperative Hydro Embrun has implemented to limit increases in billing and collecting.

4-Staff-55
Ref: Chapter 2 Appendices, Tab 2 - JC

Account 5075 – Customer Premises – Materials and Expenses shows an increase of almost $13k from the 2018 OEB-approved amount of $21k. The 2018 and 2019 actual amount were slightly less than the OEB-approved amount. An increase is seen in 2020 which Cooperative Hydro Embrun notes is due to a high number of meters having reached their ten years and needing reverification.

(a) Please explain if the costs increases for 2022-2023 are also due to the need for reverification.
(b) If the answer to (a) is no, please explain why the 2021-2023 amounts in this account are relatively at the same level.

4-Staff-56
Ref: Exhibit 4, page 14

(a) Please explain what necessitated the increase to the number of Board Members to bring the count to five from three as explained in the variance between 2019 and 2018.
(b) Does Cooperative Hydro Embrun continue to have five Board Members?

4-Staff-57
Ref 1: Exhibit 2, page 36
Ref 2: Exhibit 4, page 18

Reference 1 states that Cooperative Hydro Embrun, with the input of its 3rd party capital work contractor, Sproule Powerline Construction Ltd., decide on the replacement of assets that are at risk of failing or are in poor health.

In discussing services that fall outside of Cooperative Hydro Embrun's procurement policy, reference 2 states that "specific suppliers offer services that are not commonly found in the service area or general surrounding area or offer efficiencies due to their intimate knowledge of CHEI's distribution system (i.e., Sproule Powerline Construction Ltd)."

(a) Please provide a high-level overview of the responsibilities of Sproule Powerline Construction Ltd. with respect to Cooperative Hydro Embrun's operating environment.
(b) Please explain the process by which the annual operations and maintenance budgets are determined. As part of the response, please confirm if Sproule Powerline Construction Ltd. provides input into the budgeting process.
(c) Please confirm if there is a formal contract signed with Sproule Powerline Construction Ltd. If confirmed, please provide a copy of the contract. Please redact any confidential information as deemed appropriate and necessary by Cooperative Hydro Embrun. If not confirmed, please explain how the costs paid to Sproule Powerlines Construction Ltd. are determined.

4-Staff-58
Benchmarking
Ref: Exhibit 4, page 20

Cooperative Hydro Embrun notes that it does not use specific benchmarking studies to determine salary ranges. Awareness of salary ranges in neighboring utilities and use of a combination of years of experience and neighboring salaries are used as a guideline.

Does Cooperative Hydro Embrun plan on undertaking any formal benchmarking analysis to comparable utilities in the future? If not, please explain why.

4-Staff-59
Benefits
Ref: Exhibit 4, page 21-22

The evidence states that total benefits have increased 4.13% between 2018 actual and 2023 test year from statutory rate increases and wage increases. OEB staff calculates an increase of 5.5% from 2018 actuals.

(a) Please confirm if Cooperative Hydro Embrun agrees.
(b) Please reconcile the information provided in Table 17 on page 22 to Appendix 2-K as shown on page 21.

4-Staff-60
Succession Planning
Ref 1: Exhibit 4, pages 19, 22
Ref 2: Exhibit 4, Attachment 4-A

Two of Cooperative Hydro Embrun's three full-time employees are eligible to retire in the next two years. One of the positions eligible for retirement is the long-time manager. In anticipation of the upcoming retirements, the utility developed a Succession Plan to start the process of finding a replacement for the two senior-level positions. Section 2 outlines the succession plan steps.

(a) Where in the process is Cooperative Hydro Embrun in with respect to its succession planning?
(b) Are there clear and definite timelines for the action steps laid out in Cooperative Hydro Embrun's plan? If yes, please provide the timelines.
(c) Please describe any training opportunities provided to ensure current employees develop the skills necessary.
(d) Please provide a discussion on the potential risks to Cooperative Hydro Embrun if unable to fill the vacancies when required, and how Cooperative Hydro Embrun intends to mitigate those risks.

Exhibit 5 – Cost of Capital and Capital Structure

5-Staff-61
Ref 1: Exhibit 1, Audited Financial Statements for the year ended December 31, 2020
Ref 2: Exhibit 5, page 5, table 3 and page 6
Ref 3: Exhibit 5, Appendix 5A

Appendix 5A is a copy of an agreement for a loan with a third-party financial institute initiated in 2017. Note 8 of the Audited Financial Statements for the year-end December 31, 2020 documents:

> Loan, 2.9%, renewable in February 2033, payable by monthly instalments of $4,898, principal and interest, secured by a general security agreement covering all assets.

It continues lower down:

> The principal repayments to be made during the next five years are as follows: 2021, $51,535; 2022, $83,049; 2023, $54,608; 2024, $56,213; 2025, $57,859. These payments have been calculated under the assumption that the repayment plan will be successfully renewed, based on the present payment terms and interest rates.

On page 6 of Exhibit 5, Cooperative Hydro Embrun states:

> CHEI confirms that the debt incurred to fund the substation in 2017 will be fully paid off at the end of 2022. The utility does not forecast any short-term or long-term debt going forward.

(a) Please confirm that the debt documented in Note 8 of the 2020 Audited Financial Statements is the same loan as is referred to in Exhibit 5 and documented in Appendix 5A. If not, please explain Cooperative Hydro Embrun's debt situation from 2017 onwards.
(b) Assuming a positive response to (a), please explain why Cooperative Hydro Embrun has retired the debt earlier than the repayment schedule documented in Note 8 to the 2020 Audited Financial Statements.
(c) In Table 3 of Exhibit 5, Cooperative Hydro Embrun shows a year-end balance owing of $273,263.28 for each of 2020 and 2021, but shows interest of $9,104 for 2020 versus $4,292 for 2021. Additionally, Cooperative Hydro Embrun shows interest of $250 for 2022.
    i. Please explain why 2021 and 2020 interest payments differ if the outstanding principal is the same at the same for both years.
    ii. Please explain the calculation of the 2022 interest of $250 shown.

Exhibit 6 – Revenue Requirement and Revenue Deficiency or Sufficiency

6-Staff-62
Account 1592
Ref 1: CHEI 2023 Accelerated CCA Excel spreadsheet, February 14, 2022
Ref 2: *Filing Requirements For Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications - For Small Utilities, Chapter 2A, Cost of Service*, December 16, 2021, pg. 35, 52
Ref 3: Exhibit 9, pg. 9

Cooperative Hydro Embrun has filed a spreadsheet (reference 1) showing its calculations that support its request to dispose of a debit balance of $4,725 for Account 1592, PILs and Tax Variances, sub-account CCA Changes.

Reference 2 outlines the information required to support the clearance of a balance in Account 1592, PILs and Tax Variances, sub-account CCA Changes. Some of the information required involves:

- Calculations for accelerated CCA differences per year
- The impacts of CCA rule changes for the period November 21, 2018 until the effective date of the distributor’s next cost-based rate order.

Reference 3 states that Cooperative Hydro Embrun has recorded the impact of the CCA rules changes in Account 1592, PILs and Tax Variances, sub-account CCA Changes, from November 21, 2018, up to the 2023 Test Year.

(a) OEB staff notes no balances are shown for 2022 in reference 1. Please confirm that the calculations shown in the CCA spreadsheet exclude a forecasted balance from January 1, 2022 to December 31, 2022. If this is not the case, please explain.
(b) If a reasonable forecast can be made, please re-file Cooperative Hydro Embrun’s analysis to include a balance in Account 1592, sub-account CCA Changes, from January 1, 2022 to December 31, 2022. Please include this balance in cell BF83 of Tab 2b of the DVA Continuity Schedule. If the applicant has any concerns with disposing of the 2022 forecasted amounts, please explain.
(c) OEB staff also notes no balances are shown for 2018 in reference 1. Please confirm that no amounts for the period November 21, 2018 to December 31, 2018 were included, as the impact of the Accelerated CCA amounts was not claimed on Cooperative Hydro Embrun’s 2018 tax return. If this is not the case, please explain.

6-Staff-63
Account 1592
Ref 1: CHEI 2023 Accelerated CCA Excel spreadsheet, February 14, 2022
Ref 2: Accounting Procedures Handbook For Electricity Distributors (APH), Effective: January 1, 2012, Article 440, pg. 8

In the “Summary” tab of the CCA spreadsheet (reference 1):

- Column H shows the tax impact by multiplying the CCA difference by Cooperative Hydro Embrun’s effective tax rate of 12.2%. However, the grossed-up income tax impact has not been reflected (i.e., the tax impact divided by (1-12.2%)).

- Column H shows the CCA impacts as the following:
  - Impacts with accelerated CCA less the impacts without accelerated CCA, resulting in a debit amount (collection from customers).
- Column I shows future tax impacts. The APH states that the OEB "does not consider it necessary to approve a deferral account for future income taxes."
- Some of the balances in Column C and Column D do not reconcile to the supporting tabs in the CCA spreadsheet.

(a) Please revise the "Summary" tab of the CCA spreadsheet to:
   i. Reflect the grossed-up income tax impact of the CCA differences (i.e., the tax impact shown in Column H divided by (1-12.2%))
   ii. Reflect the impacts without accelerated CCA less the impacts with accelerated CCA in Column H (instead of vice versa), such that the resulting Account 1592 balance is a credit and not a debit
   iii. Exclude any future tax impacts from the calculations (or explain why this is appropriate)
   iv. Reconcile the balances in Column C and Column D to the supporting tabs in the CCA spreadsheet.
   v. Explain why cells C9 and D9 are linked to the 2019, 2020, and 2021 tabs, instead of just the 2021 tab.

(b) Please insert the revised balances in Account 1592, PILs and Tax Variances, sub-account CCA changes, calculated in the "Summary" tab of the CCA spreadsheet to Tab 2b of DVA Continuity Schedule.

(c) Please calculate the applicable carrying charges in Account 1592, PILs and Tax Variances, sub-account CCA changes, and reflect these amounts in Tab 2b of DVA Continuity Schedule.

6-Staff-64
Account 1592
Ref 1: 2023 Accelerated CCA Excel spreadsheet, February 14, 2022

In the tabs "2018", "2019", "2020", and "2021" of the CCA spreadsheet, Cooperative Hydro Embrun has provided UCC continuity schedules which are missing some information. As well, a new tab "2022" should be populated (provided the applicant does not have concerns with forecasting 2022 capital additions).

(a) For each year up to December 31, 2022 in the CCA spreadsheet, please address two scenarios: "Impacts without Accelerated CCA" and "Impacts with Accelerated CCA".

(b) For each scenario, please provide complete detailed UCC continuity schedules, as limited information has been provided.
(c) Please reconcile the relevant UCC and CCA balances for 2021 and 2022 used in the CCA spreadsheet to the Excel PILs model for the historic and bridge years, as some currently do not reconcile.[3] Please see the footnote for an example.
(d) Please reconcile the actual capital additions used in the CCA spreadsheet to other parts of the application (i.e., Appendix 2-BA, Appendix 2-C, and the Excel PILs model), as applicable, as some currently do not reconcile.[4] Please see the footnote for an example.

6-Staff-65
Account 1592
Ref: Exhibit 6, pg. 10

Cooperative Hydro Embrun stated that it is proposing not to continue using Account 1592 going forward, unless there are new changes to the CCA rules.

(a) Please confirm whether it is Cooperative Hydro Embrun's understanding that Account 1592, PILs and Tax Variances, sub-account CCA Changes, is a generic account which is subject to continuance or discontinuance on a generic basis by the OEB. If this is not the case, please explain.
(b) Please confirm that Cooperative Hydro Embrun's intentions are to not record any amounts in the sub-account pertaining to the Accelerated Investment Incentive Program (AIIP), over the upcoming 5-year rate term, including the impact of the phase out of the AIIP, starting in 2024. If this is not the case, please explain.

6-Staff-66
Account 1592
Ref 1: Exhibit 9, pg. 8
Ref 2: APH, Article 440, pg. 8
Ref 3: EB-2017-0035, Cooperative Hydro Embrun 2018 CoS Proceeding, Response to interrogatory 9-Staff-65, November 3, 2017
Ref 4: EB-2017-0035, Cooperative Hydro Embrun 2018 CoS Proceeding, DVA Continuity Schedule, December 22, 2017, Tab 2
Ref 5: *Filing Requirements For Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications - For Small Utilities, Chapter 2A, Cost of Service*, December 16, 2021, pg. 58 and 59

At reference 1, Cooperative Hydro Embrun is requesting to dispose a debit balance of $80,207 in a sub-account of Account 1592, PILs and Tax Variances. OEB staff will refer

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[3] For example, the 2021 accelerated CCA balance in the Excel PILs model of $282,248 does not reconcile to the 2021 accelerated CCA balance of $55,377 in the CCA spreadsheet.
[4] For example, the 2020 capital additions of $92,274 in the CCA spreadsheet do not reconcile to the 2020 capital additions in Appendix 2-BA and Appendix 2-C of $120,679.

to this sub-account as “sub-account Deferred Taxes”, as Cooperative Hydro Embrun did not articulate a specific name for this sub-account.

Cooperative Hydro Embrun explained that this balance represents the impact of the temporal differences (or timing differences) between the accounting amortization and the income tax amortization (i.e., capital cost allowance), resulting in future tax (or deferred tax) impacts.

The use and associated recovery of balances in this sub-account of Account 1592, PILs and Tax Variances, by Cooperative Hydro Embrun is generally not permitted by the OEB. The APH states that the OEB “does not consider it necessary to approve a deferral account for future income taxes.”

At reference 3, in response to an interrogatory (9-Staff-65) in the 2018 CoS proceeding, Cooperative Hydro Embrun requested recovery of a debit balance of $13,097 in Account 1592 for deferred income taxes. However, the final balance agreed to by parties for disposition in the settlement proposal included a nil balance for Account 1592 in Tab 2 of the DVA Continuity Schedule (reference 4).

(a) Please explain Cooperative Hydro Embrun’s rationale for requesting disposition of the debit balance of $80,207 in Account 1592, PILs and Tax Variances, sub-account Deferred Taxes, given the facts described above with respect to deferred/future income taxes.
(b) If Cooperative Hydro Embrun agrees to withdraw its request, please update Tab 2b of the DVA Continuity Schedule to remove this balance.
(c) If Cooperative Hydro Embrun maintains its request, please file, for the OEB’s consideration, a draft accounting order for this new sub-account, and discuss the causation, materiality, and prudence criteria required when requesting the establishment of a new DVA, in accordance with the OEB’s direction at reference 5 (the filing requirements).

6-Staff-67
PILs
Ref: Excel PILs model, February 14, 2022

In the Excel PILs model, Cooperative Hydro Embrun has recorded taxable income additions for “Transitions [sic] costs capitalized for Financial statements”, as follows:

- Tab T1 Sch 1 Taxable Income Test $17,600
- Tab B1 Sch1 Taxable Income Bridge $17,000
- Tab H1 Sch 1 Taxable Income Hist of $11,659

In tab T1 Sch 1 Taxable Income Test, Cooperative Hydro Embrun has recorded a taxable income deduction of a credit of $58,000, citing the same explanation.

(a) Please explain the above noted additions and deduction to taxable income, relating to “Transitions costs capitalized for Financial statements.”
(b) Please explain why the test year taxable income deduction of $58,000 is shown as a credit in the Excel PILs model, given that the formula in the PILs model automatically subtracts items recorded as deductions to taxable income. Please update the PILs model, as required.

6-Staff-68
PILs
Ref 1: Exhibit 6, Appendix 6A
Ref 2: Excel PILs model, February 14, 2022

Cooperative Hydro Embrun has submitted a portion of its 2020 tax return. The copy (or draft version) of the 2021 tax return has not been provided, given the timing of the filing of this application.

(a) Please provide a copy of the 2021 tax return, or a draft version, as available. Please remain cognizant of any potential personal information included in the tax returns.
(b) Please reconcile the closing UCC values in Schedule 8 of the 2021 tax return to those shown in Tab H8 Sch 8 CCA Hist of the Excel PIL model.
(c) Please confirm that Cooperative Hydro Embrun has no loss carryforwards available (other than those that may be generated by accelerated CCA deductions) to apply to reduce its 2023 test year taxable income in the Excel PILs model.
(d) If there are loss carryforwards available that have not yet been applied to reduce Cooperative Hydro Embrun’s 2023 test year taxable income, please explain.

6-Staff-69
Property Taxes
Ref 1: Exhibit 6, pg. 8
Ref 2: *Filing Requirements For Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications - For Small Utilities, Chapter 2A, Cost of Service*, December 16, 2021, pg. 36
Ref 3: RRWF, February 14, 2022

At reference 1, Cooperative Hydro Embrun noted that it does not pay property taxes as its office space is leased, but property taxes on the distribution system are recorded in OM&A.

At reference 2, the OEB states that property taxes should only be included in Account 6105. Account 6105 is not an OM&A account and should therefore be excluded from all OM&A totals.

(a) Please quantify the amount of property taxes recorded in OM&A.
(b) If there are property taxes recorded elsewhere in the application, please explain and quantify.
(c) If the amount of property taxes is material, please record property taxes as a separate line item on Tab 9. Rev_Reqt (line no. 3) of the RRWF (reference 3), in accordance with the OEB's requirements at reference 2.

6-Staff-70
Ref 1: Exhibit 1, Business Plan, Page 30
Ref 2: Exhibit 6, Pages 17-21

It is unclear based on the evidence what the main drivers for the calculated revenue sufficiency are. Please provide an itemized list of the driver(s) for the calculated revenue sufficiency.

6-Staff-71
Other Revenues
Ref 1: Exhibit 6, Page 16
Ref 2: Chapter 2 Appendices, Tab 2-H

Cooperative Hydro Embrun notes that an inflation rate of 3.3% is embedded in its "Other Operating Revenue" projections for the bridge and test year.

(a) Please confirm if this applies specifically to Accounts 4082, 4084, 4086 and 4210. If not, please explain which Accounts the inflation rate is embedded into.
(b) Please confirm if the OEB's EB-2021-0301 decision was used to forecast 2023 revenues from Retail Service Charges (Accounts 4082 and 4084).
(c) Please explain the method Cooperative Hydro Embrun used to forecast its Other Revenues for 2023 for:
    - Account 4225 – Late Payment Charges
    - Account 4235 - Miscellaneous Service Revenues
    - Accounts 4390 and 4405 – Other Income and Expenses

6-Staff-72
Other Revenue
Ref 1: 2021 Chapter 2 Appendices, Tab 2-H – Other_Oper_Rev
Ref 2: Chapter 2A Filing Requirements, December 16, 2021, page 37

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

6-Staff-73
microFIT
Ref 1: Exhibit 6, page 16
Ref 2: EB-2017-0035, Application, Exhibit 3, page 61

Cooperative Hydro Embrun notes that it analysed its microFIT related costs compared to its revenues and despite its yearly costs of $6k for having its microFIT read vs its revenues of $1.5k per year, it is not proposing to change its microFIT charges.

In its previous rebasing application, Cooperative Hydro Embrun noted that it incurs a $10 monthly fee per microFIT meter point from its vendor.

Please confirm if this continues to be the case.

Exhibit 7 – Cost Allocation

7-Staff-74
Meter Reading
Ref 1: Exhibit 7, page 10

In the GS < 50 kW rate class, on sheet I7.1, 139 meters reads are identified as two types of Smart Meters, while 26 are identified as demand with IT meters. On sheet I7.2, 127 reads of smart meters, and 38 reads of interval meters are required.

The residential rate class uses both types of smart meters, and all identified as requiring smart meter reads.

Please explain the apparent discrepancy and why only 127 of the meters are counted as smart meter reads for the GS < 50 rate class.

7-Staff-75
Load Profiles
Ref 1: Exhibit 7, page 11

Cooperative Hydro Embrun indicates that one methodology for updating load profiles is proprietary to a group that it is not a member of, and therefore is unavailable to the utility. It states that the required data is hosted by another utility which has confirmed that the data cannot be provided.

A new methodology is proposed for determining load profiles and demand allocators. The methodology appears to OEB staff to assume that within each historic month, all rate classes exhibited the same load profile. The process is repeated for 60 months (5 years). The final proposed load profile for each hour in each rate class the average load for that hour across the five historic years.

OEB staff notes that in addition to the above noted assumption, this approach has the potential to average across weekends and weekdays, warm days, and cold days.

(a) Please explain:
    i. Which required data is unavailable?
    ii. If the missing data is hourly meter data, how does Cooperative Hydro Embrun bill its customers?
    iii. If the required data is only available for a period of time, can Cooperative Hydro Embrun obtain the data when it is available, and store the data for future use?

(b) Has Cooperative Hydro Embrun taken any steps towards determining what would be required to gain access to the methodology in question – e.g. whether it can be licensed, and costs of these options?

(c) As a scenario, please provide the revenue-to-cost ratios that would result if the Hydro One methodology were used.

(d) As a scenario, please modify the demand allocator calculations as follows.
    i. Use deemed load profiles for USL and Street Light based on the best information available to Cooperative Hydro Embrun. For example, the Hydro One methodology has load profiles for street light which assumes lights to be on at night, and off during daylight hours.
    ii. Determine each rate class's share of the residual utility load as initially proposed.
    iii. Scale each year's load profiles to be consistent with the 2023 load forecast.
    iv. Determine demand allocators that would result for each year.
    v. Calculate a five-year average of the demand allocators.

7-Staff-76
Revenue to Cost
Ref 1: Exhibit 7, page 19

The revenue-to-cost ratios for the GS > 50 to 4,999 kW rate class and the residential rate class were within the target ranges before adjustment. The revenue-to-cost ratio for the Residential rate class is proposed to be reduced to 1.00 while the ratio for the GS > 50 to 4,999 kW rate class is proposed to increase to 0.96.

(a) Please explain why it was necessary to transfer revenue responsibility from the Residential rate class to the GS > 50 to 4,999 kW rate class.

(b) As a scenario, please provide the revenue-to-cost ratio for the GS > 50 to 4,999 kW rate class that would result from

  i. Reducing the USL revenue-to-cost ratio to 1.20 and

  ii. Not adjusting the residential rate class revenue-to-cost ratio.

Exhibit 8 – Rate Design

8-Staff-77
Loss Factor
Ref 1: EB-2017-0035, Exhibit 2, DSP, Appendix G Stantec Study, Section 3.3 (PDF Page 170)
Ref 2: EB-2017-0035, Interrogatory Response 2.0-VECC-9, November 3, 2017
Ref 3: EB-2017-0035, Settlement Proposal, Page 33, December 22, 2017
Ref 4: EB-2022-0022, Exhibit 1, Page 19
Ref 5: EB-2022-0022, Exhibit 8, Page 13

As part of Cooperative Hydro Embrun's 2018 rebasing application, a report by Stantec (reference 1) recommended system upgrades to reduce losses. As part of its interrogatory responses, Cooperative Hydro Embrun noted that "As it has in the past, CHEI takes Stantec's recommendations seriously and plans on performing the suggested upgrades starting in 2018. CHEI notes that all costs associated with the recommendations are part of the utility's Operation and Maintenance programs." (Reference 2)

As part of the settlement proposal in the 2018 rebasing application, parties agreed that Cooperative Hydro Embrun will continue to pursue recommendations presented to it in its most recent Line Loss Study through 2018, and to initiate a new line loss study in 2019 to, in part, review the impact of those recommendations once implemented (reference 3).

As part of the current 2023 application, Cooperative Hydro Embrun notes that it reached out to Stantec for a quote in the later part of 2019 and the utility planned on conducting the study in 2020. However, when the pandemic hit in early 2020, the proposed study was postponed indefinitely in favor of focusing on the customer, the utility and the community's needs. To date, the study has not been conducted.

While it is clear that a new line loss study was not initiated in 2019, it is unclear based on the evidence if the recommendations from the previous study were pursued.

(a) Please describe the recommendations from the most recent line loss study referenced in the 2018 settlement proposal and which recommendations were pursued.
  i. If none were implemented, please explain why.
  ii. If only a select number of recommendations were implemented, please explain why, and for those that were not, please provide the reasoning behind the decision to not proceed with the recommendation.

(b) Please describe the impact of the recommendations that were implemented.

8-Staff-78
Smart Meter Entity Charge
Ref: Exhibit 8, page 11

Cooperative Hydro Embrun notes that it proposes maintaining its existing smart meter charge of $0.79.

OEB staff notes that the current generic charge is **$0.57** as indicated in table 13 on page 11 of exhibit 8. Further, as per Cooperative Hydro Embrun's current Tariff of Rates and Charges, OEB staff notes that the current generic OEB-approved charge expires on December 31, 2022.

(a) Please confirm if the language in Exhibit 8, page 11 was provided in error.
(b) Please confirm that Cooperative Hydro Embrun will adopt any new generic charge as may be approved by the OEB.

8-Staff-79
Ref 1: Exhibit 8, Appendix 8B – Proposed Tariff of Rates and Charges
Ref 2: Tariff and Bill Impact Model, Tab 3 – Regulatory Charges

Cooperative Hydro Embrun's proposed Tariff of Rates and Charges, and the Tariff and Bill Impact Model filed with its application shows the previously approved pole attachment charge of $44.50. OEB staff notes that the current pole attachment charge, effective January 1, 2022, is $34.76 as per the OEB's generic Decision and Order in EB-2021-0302.

(a) Please make the necessary corrections as noted above.
(b) Please confirm that Cooperative Hydro Embrun will continue to charge the current OEB-approved rate of $34.76 until such time the OEB announces any updated charge by way of a generic order for 2023.

8-Staff-80
Ref 1: Tariff and Bill Impact Model, Tab 3 – Regulatory Charges
Ref 2: Exhibit 8, pg. 15

Cooperative Hydro Embrun has applied the OEB's 2022 inflation factor of 3.3% to the OEB-approved retail service charges for 2022.

Please confirm that this inflation factor was included as a proxy for purposes of this 2023 application, and that Cooperative Hydro Embrun will continue to apply the current 2022 OEB-approved charges until any generic order for 2023 retail service charges is issued by the OEB.

8-Staff-81
Tariff and Bill Impact Model
Ref: Tariff and Bill Impact Model, Tab 4 and Tab 6

OEB staff notes that the calculated rate riders for the disposition of the global adjustment account have been included in sub-total A on Tab 4 of the Tariff and Bill Impacts Model for the General Service 50 to 4,999 kW and Street Lighting rate classes.

OEB staff notes these rate riders should be included in sub-total B (i.e., Distribution) as per Tab 6 of the model.

Please make the required corrections to the model.

Exhibit 9 – Deferral and Variance Accounts

9-Staff-82
LRAMVA
Ref 1: Exhibit 9, p. 15
Ref 2: DVA Continuity Schedule

In the application, Cooperative Hydro Embrun stated that it is not requesting disposition of the LRAMVA which has a credit balance of $752. In response to an error checking question[5] from OEB staff asking Cooperative Hydro Embrun to confirm whether or not disposition is being requested, Cooperative Hydro Embrun stated that "[Cooperative Hydro Embrun] will updated the DVA model in the next accordingly in the next phase of the application (most likely the interrogatories)."

(a) Please confirm whether or not disposition of the LRAMVA is being requested.

[5] Response to OEB Staff Error Checking Question #29, March 31, 2022

(b) If disposition is being requested, please update the application to include all the details on the request and all applicable supporting models (e.g., LRAMVA workform, IESO supporting documents, etc.) in accordance with the OEB's Chapter 2 Filing Guidelines.
(c) If disposition is being requested, please also update the DVA Continuity Schedule as follows:
  i. Tab 4, column AC
  ii. Tab 5, most of row 59
  iii. Tab 7, rows 202 to 228
(d) If disposition is not being requested, please confirm whether there will be any future LRAMVA amounts related to persisting CDM savings in the future, and whether Cooperative Hydro Embrun has incorporated historical CDM results into its load forecast.

9-Staff-83
DVAs
Ref 1: *Filing Requirements For Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications - For Small Utilities, Chapter 2A, Cost of Service*, December 16, 2021, pg. 50
Ref 2: DVA Continuity Schedule, February 14, 2022
Ref 3: Exhibit 9, pg. 3

At reference 1, the OEB states that an explanation needs to be provided if the account balances in the DVA Continuity Schedule differ from the account balances in the trial balance reported through the Electricity RRR and documented in the distributor's audited financial statements.

Given the timing of filing this application, Cooperative Hydro Embrun has not populated the December 31, 2021 RRR 2.1.7 values in the DVA Continuity Schedule. However, at reference 3, Cooperative Hydro Embrun stated that it plans on updating the DVA Continuity Schedule for this information in its response to interrogatories.
(a) If available, please populate the December 31, 2021 RRR 2.1.7 values in the DVA Continuity Schedule.
(b) Please confirm that Cooperative Hydro Embrun has already reconciled all of the DVAs shown in the following:
  i. The 2021 audited financial statements
  ii. The December 31, 2021 RRR 2.1.7 values
  iii. The December 31, 2021 values shown in the DVA Continuity Schedule (reference 2)
(c) If these amounts do not reconcile, please file a reconciliation and explanation, as well as update the DVA Continuity Schedule. This explanation should also

address any differences in Column BW which shows the “Variance RRR vs. 2021 Balance (Principal + Interest)” in Tab 2a and Tab 2b of the DVA Continuity Schedule.

(d) Please confirm that the specific DVA amounts and associated rate riders being requested for clearance in this proceeding by Cooperative Hydro Embrun will be reflected in the DVA Continuity Schedule filed in response to the interrogatories, as opposed to the DVA balances listed in Exhibit 1 and Exhibit 9. If this is not the case, please explain.

9-Staff-84
DVAs
Ref 1: Response to Error Check Q#2, March 21, 2022
Ref 2: Account 1595 Workform, March 21, 2022
Ref 3: EB-2018-0026, 2019 IRM Decision and Rate Order, December 13, 2018, pg. 10, Table 8.2
Ref 4: EB-2020-0011, 2021 IRM Decision and Rate Order, December 17, 2020, pg. 12, Table 7.2
Ref 5: DVA Continuity Schedule, February 14, 2022

In response to the error question at reference 1, Cooperative Hydro Embrun has filed an Account 1595 Workform relating to Account 1595 (2019) at reference 2 which shows a debit balance of $12,294. This document had not been filed earlier by Cooperative Hydro Embrun, given the timing of filing this application.

OEB staff notes that the reference to Account 1595 (2019) is intended to represent the 2019 rate year balances and not the December 31, 2019 balances that were disposed in the 2021 rate year.

Regarding the Account 1595 Workform, Cooperative Hydro Embrun has not shown the DVA amounts approved for disposition in the 2019 IRM decision and rate order (reference 3) and the associated rate rider amounts collected (returned), as well as the applicable carrying charges. Instead, Cooperative Hydro Embrun has included amounts that pertain to the 2021 IRM decision and rate order (reference 4).

OEB staff is not requesting Cooperative Hydro Embrun to submit an updated Account 1595 Workform as part of its responses to interrogatories, but is asking clarifying questions below to confirm that the correct balance is being requested for disposition in this proceeding.

(a) Please confirm that it is Cooperative Hydro Embrun’s understanding that Account 1595 (2019) is eligible for disposition in this proceeding, as opposed to Account 1595 (2021).

(b) In the event that revisions are required to line 38, please revise Tab 2a of the DVA Continuity Schedule (reference 5) for Account 1595 (2019) to reflect the residual balance representing the 2019 rate year balances (as opposed to the December 31, 2019 balances that were disposed in the 2021 rate year).
(c) Please also change cell BU38 to “yes” from “no”.

9-Staff-85
DVAs
Ref 1: Response to Error Check Q#2, March 21, 2022
Ref 2: Global Adjustment (GA) Analysis Workform, March 21, 2022
Ref 3: DVA Continuity Schedule, February 14, 2022

In Tab “GA 2021” of the GA Analysis Workform (filed at the response to the error check question, given the timing of filing this application), Cooperative Hydro Embrun has:

- Not entered data into cells G57 and J57.
- Recorded the “Net Change in Principal Balance in the GL (i.e. Transactions in the Year)” of a credit of $10,512, whereas tab 2a of the DVA Continuity Schedule shows a debit amount of $93 for Account 1589 for the “Transactions Debit / (Credit) during 2021”.

In Tab “Account 1588” of the GA Analysis Workform, Cooperative Hydro Embrun has recorded the Account 1588 2021 transactions of a credit of $37,346, whereas tab 2a of the DVA Continuity Schedule shows a credit amount of $42,098 for Account 1588 for the “Transactions Debit / (Credit) during 2021”.
(a) Please update the GA Analysis Workform, as required, to insert the missing data into cells G57 and J57 and explain any further material differences in cell K63 that relate to loss factor differences.
(b) If after updating cells G57 and J57, the “Unresolved Difference as % of Expected GA Payments to IESO” in cell C93 changes from 0.4% to a number greater than +/-1%, please explain.
(c) Please update the GA Analysis Workform and tab 2a of the DVA Continuity Schedule, as required, so that the Account 1588 and Account 1589 2021 transactions reconcile between the GA Analysis Workform and the DVA Continuity Schedule (as per the above observations).

9-Staff-86
DVAs
Ref 1: Exhibit 1, pg. 20
Ref 2: EB-2020-0011, 2021 IRM Decision and Rate Order, December 17, 2020
Ref 3: APH Update, Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589, February 21, 2019

Ref 4: Exhibit 9, pg. 15

At reference 1, Cooperative Hydro Embrun noted that the record of its 2021 IRM proceeding indicated deviations from the OEB's Accounting Guidance. Cooperative Hydro Embrun further stated that its accounting for the commodity accounts and settlement process is appropriate, pointing to its fully embedded status as one reason supporting its deviation from the Accounting Guidance. Cooperative Hydro Embrun further stated that the OEB accepted its rationale for deviating from the Accounting Guidance and approved the disposal of 2017-2019 balances on a final basis, in its 2021 IRM proceeding.

However, at reference 4, Cooperative Hydro Embrun also acknowledged the OEB's expectation that the distributor continue its efforts to adopt the Accounting Guidance in a manner that is pragmatic to do so, until the OEB directs the distributor otherwise.

Cooperative Hydro Embrun then further stated that:

- It continues to use the approach and process accepted in its 2021 IRM application
- The Accounting Guidance was implemented to the degree approved by the OEB

In its 2021 IRM Decision, the OEB also directed Cooperative Hydro Embrun to continue its internal review regarding its accounting and RPP settlement processes and to provide an update in its 2022 rate application with respect to its adoption of the Accounting Guidance.

(a) Is it Cooperative Hydro Embrun's position that since the OEB disposed of balances on a final basis in its 2021 IRM application, this suggests that no further changes were necessary to its accounting processes to align to the Accounting Guidance, despite the OEB's findings in that proceeding? Please elaborate on why the applicant has not discussed the changes it has made in this regard to respond to the OEB's directions.

(b) Please provide an update regarding Cooperative Hydro Embrun's internal review of its accounting and RPP settlement processes and its adoption of the Accounting Guidance.

9-Staff-87
DVAs
Ref 1: Exhibit 9, pg. 15 and 16
Ref 2: GA Analysis Workform, March 21, 2022
Ref 3: APH Update, Accounting Guidance Related to Commodity Pass-Through Accounts 1588 & 1589, February 21, 2019

At reference 1, Cooperative Hydro Embrun described a summary of its processes relating to Account 1588 and Account 1589.

One example of a deviation from the Accounting Guidance is described in Tab "GA 2021" of the GA Analysis Workform, regarding not accruing unbilled revenue on a monthly basis. Cooperative Hydro Embrun noted that although it does not accrue unbilled revenue on a monthly basis, it does perform an accrual at year-end.

(a) Please identify and explain all material deviations between Cooperative Hydro Embrun's processes and those contemplated in the Accounting Guidance.
(b) For each material deviation, please outline Cooperative Hydro Embrun's plan to resolve this, including the proposed timing.
(c) In the alternative, please describe why Cooperative Hydro Embrun is of the view that changes for any specific deviation are not required.

9-Staff-88
DVAs
Ref 1: EB-2021-0014, 2022 IRM Rate Generator Model, December 9, 2021, Tab 4
Ref 2: DVA Continuity Schedule, February 14, 2022

At reference 1 (2022 IRM Rate Generator Model), the billing determinants include "Metered kWh for Non-RPP Customers" for the residential and GS < 50 kW rate classes. However, at reference 2 (2023 DVA Continuity Schedule), these kWh have been excluded.

For the GS 50 to 4,999 kW rate class, there are significant differences between the "Metered kWh for Non-RPP Customers" in the 2022 IRM Rate Generator Model of 2,269,044 kWh and the 2023 DVA Continuity Schedule of 3,952,566 kWh.

(a) Please update Tab 4 of the DVA Continuity Schedule (reference 2) to include kWh for non-RPP customers for both the residential and GS < 50 kW rate classes, or explain the difference between the approach used in the 2022 rates application versus this one.
(b) Regarding the GS 50 to 4,999 kW rate class, please investigate the significant differences between the "Metered kWh for Non-RPP Customers" in the 2022 IRM Rate Generator Model and the 2023 DVA Continuity Schedule.

9-Staff-89
DVAs
Ref: Response to Error Check Q#28, March 21, 2022

There are some items in the Excel DVA Continuity Schedule that may require further consideration and revisions:

- Transactions in Account 1508, Customer Choice Initiative Costs are recorded on two lines of Tab 2b, instead of one line.
- In Tab 2a and Tab 2b, numbers have been included in column BF. In Tab 2a numbers have also been included in column BK. It is OEB staff's understanding that these represent the estimated November and December 2021 balances that were not available at the time of filing the current application. These balances may be removed and replaced with the actual audited 2021 transactions, to be included in column BD and column BI.
- Columns BR of Tab 2a and Tab 2b of the DVA Continuity Schedule should show zero carrying charges from January 1, 2023 to April 30, 2023, as this is a January 1, 2023 rate application.
- Cells BQ19 of Tab 2a and Tab 2b of the Excel DVA Continuity Schedule state "Projected Interest on Dec-31-22 Balances" and should instead reference December 31, 2021 balances.

(a) Please update the DVA Continuity Schedule to address the above noted observations.

9-Staff-90
DVAs
Ref 1: OEB Letter, Accounting Guidance on Wireline Pole Attachment Charges, July 20, 2018
Ref 2: DVA Continuity Schedule, February 14, 2022, Tab 5
Ref 3: Exhibit 9, pg. 8
Ref 4: Filing Requirements For Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications - For Small Utilities, Chapter 2A, Cost of Service, December 16, 2021, pg. 46

At reference 1, the OEB stated that when clearing Account 1508, Pole Attachment Revenue Variance, in a cost of service application, distributors are to allocate costs to customer classes based on test year forecast distribution revenue data. However, at reference 2, Cooperative Hydro Embrun has allocated the amounts based on kWh.

At reference 3, Cooperative Hydro Embrun stated that given that the pole attachment rate changes on a yearly basis, the assumption is that utilities will continue to record the difference between the amount charged and collected. Cooperative Hydro Embrun stated that it does not anticipate using the sub-account going forward, unless the OEB changes the provincial rate.

At reference 4, the OEB noted that amounts may be recorded Account 1508, Pole Attachment Variance, until the effective date of distributors' rebased rates. Distributors may forecast a balance up to the effective date of its new rates, provided it can do so with reasonable accuracy, and the OEB may consider disposing of the forecasted amount and closing the account.

OEB staff notes that in general, further transactions would not be expected to be recorded in this sub-account once amounts are forecasted up to the effective date of a distributor's rebased rates and disposed in the rebasing application, unless otherwise directed by the OEB (e.g., if there are material changes to the pole attachment rate). OEB staff notes that annual updates to the OEB's pole attachment rate generally mirror inflationary impacts and any underlying pole attachment rates in base rates would also be uplifted by inflationary impacts in a subsequent IRM application.

(a) Please update the DVA Continuity Schedule to reflect the allocation of this account based on test year forecast distribution revenue data, rather than based on kWh (or provide rationale for deviating from the OEB's guidance).
(b) Is it Cooperative Hydro Embrun's intent to record amounts in this sub-account, even if the OEB only changes the pole attachment rate by inflation each year during the rate term? If so, please rationalize this position with reference to the Filing Requirement sections referred to above. If not, please clarify Cooperative Hydro Embrun's position.
(c) If a reasonable forecast can be made, please forecast a balance in Account 1508, sub-account Pole Attachment Revenue Variance, from January 1, 2022 to December 31, 2022 and include this balance in cell BF49 of Tab 2b of the DVA Continuity Schedule. If Cooperative Hydro Embrun has any concerns with forecasting the balance in this sub-account through to the end of 2022, please discuss.

9-Staff-91
DVAs
Ref 1: *Filing Requirements For Electricity Distribution Rate Applications - 2022 Edition for 2023 Rate Applications - For Small Utilities, Chapter 2A, Cost of Service*, December 16, 2021, pg. 58
Ref 2: Exhibit 9, pg. 7
Ref 3: DVA Continuity Schedule, February 14, 2022

At reference 1, the OEB noted that it had established a variance account to capture the incremental revenues resulting from increased retail service charges authorized while under an approved IRM rate setting plan.[6] The balance in the account is to be refunded to ratepayers in a future rate application, and then the account is to be closed.

[6] EB-2015-0304, dated February 14, 2019

Distributors may forecast a balance up to the effective date of its new rates, provided it can do so with reasonable accuracy, and the OEB may consider disposing of the forecasted amount and then closing the account.

At reference 2 and reference 3, Cooperative Hydro Embrun is planning to dispose a balance in Account 1508, sub-account Retail Service Charge Incremental Revenue, but has not commented on whether it plans to close this sub-account.

(a) If a reasonable forecast can be made, please include a balance in Account 1508, sub-account Retail Service Charge Incremental Revenue, from January 1, 2022 to December 31, 2022 and include this balance in cell BF50 of Tab 2b of the DVA Continuity Schedule. If these amounts cannot be forecasted reasonably, please explain why not.

(b) Please confirm whether it is Cooperative Hydro Embrun's understanding that the Account 1508, sub-account Retail Service Charge Incremental Revenue, should be discontinued as of the proposed effective date of January 1, 2023, if the balance though to the end of 2022 is forecast and disposed in this proceeding. If this is not the case, please explain.